CASCADE NATURAL GAS CORPORATION®
A Subsidiary of MDU Resources Group, Inc.

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October 30, 2018

Public Utility Commission of Oregon
P.O. Box 1088
201 High St SE, Suite 100
Salem, OR 97308-1088

**Re: UG 347, In the Matter of Cascade Natural Gas Corporation, Request for a General Rate Revision**

Attention Filing Center:

Attached for filing in docket UG 347 is an electronic copy of Cascade Natural Gas Corporation's Reply Testimony of Maryalice Peters, Michael Parvinen, Ryan Privratsky, Stephanie Barth, Linda Murray, Tammy Nygard, Brian Robertson, Del Herner, Pamela Archer, and Ronald Amen. Since this document over 100+ pages, a copy is being sent via Federal Express.

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

If you have any questions regarding this filing, please contact me at (509) 734-4593.

Sincerely,

Michael Parvinen

Michael Parvinen
Director, Regulatory Affairs
Email: michael.parvinen@cngc.com

Attachment

# Cascade Natural Gas Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have this day served by electronic mail the foregoing NOTICE OF APPLICATION FOR REAUTHORIZAION TO DEFER COSTS FOR ENVIRONMENTAL REMEDIATION upon all parties of record in UG-347, which is the Company's most recent general rate case.

| | |
|---|---|
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Dated this 30th day of October 2018.

*/s/ Maryalice Peters*

____________________________

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Maryalice Peters

# EXHIBIT CNGC/700

October 2018

**EXHIBIT CNGC/700 – REPLY TESTIMONY**

TABLE OF CONTENTS

## I. INTRODUCTION AND SUMMARY

**Q. Are you the same Maryalice Peters who filed direct testimony in this proceeding on behalf of Cascade Natural Gas Corporation (Cascade or Company)?**

A. Yes, as Exhibit CNGC/300.

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

A. The purpose of my testimony is to provide a summary of the changes and updates to the Company's proposed revenue requirement that are presented in the Company's reply filing. I also respond to and address Public Utility Commission of Oregon Staff (Staff) witness Paul Rossow's adjustment of miscellaneous administrative and general (A&G) expenses and charitable donations. I also address an adjustment proposed by the Alliance of Western Energy Consumers (AWEC) witness Bradley G. Mullins regarding the allocation of dues and subscriptions. Finally, I respond to Staff witness Marianne Gardner's adjustment of franchise fees.

**Q. Are any other Cascade witnesses providing reply testimony?**

A. Yes. I will briefly introduce the Cascade witnesses providing reply testimony and the issues that will be addressed in their testimony:

- Linda Murray responds to adjustments proposed by Staff, the Oregon Citizens' Utility Board (CUB), and AWEC regarding wages, incentives and full-time employees (FTEs).
- Michael Parvinen will address proposed adjustments from Staff, CUB, and AWEC regarding plant additions. Mr. Parvinen will also respond to CUB's and Staff's proposals regarding decoupling. Lastly, Mr. Parvinen will explain the Company's approach regarding transitioning Schedule 163 customers from interruptible service to firm service.
- Ryan Privratsky and Michael Parvinen will address Staff's and AWEC's comments and

recommendations regarding the Company's proposed safety cost recovery mechanism (SCRM). Mr. Privratsky and Mr. Parvinen will also respond to CUB and Staff regarding the Company's proposal to amortize amounts deferred in accordance with the deferral application in Docket UM 1816 regarding validation of the Company's maximum allowable operating pressure (MAOP) records.

- Pamela Archer will respond to adjustments proposed by CUB and Staff regarding miscellaneous revenues.
- Del Herner will respond to CUB's proposal concerning Cascade's collection of residential security deposits.
- Tammy Nygard respond to adjustments proposed by Staff, CUB, and AWEC regarding intercompany cost allocations.
- Stephanie Barth and Michael Parvinen will address adjustments proposed by Staff, CUB, and AWEC regarding income tax issues.
- Brian Robertson will respond to Staff's recommendations regarding the Company's load forecasting methodology.
- Finally, Ronald Amen will address the cost of service model recommendations sponsored by Mr. Mullins.

**Q. Please summarize your testimony.**

A. In my testimony I support a revised revenue requirement increase of $2,310,937, as compared to our originally-proposed increase of $2,310,808.[1] The revised revenue requirement is shown in the chart below.

[1] CNGC/300, Peters/2.

1 **Table 1. Cascade's Revised Revenue Requirement**

| Reply Testimony Exhibit No. | Cascade Witness | Issue No. | Issue Description | Revenue Requirement Effect |
|---|---|---|---|---|
| 700 | Peters | 1 | Original Revenue Requirement | $2,310,808 |
| 700 | Peters | 2 | Franchise Fee Expense | 0 |
| 700 | Peters | 3 | Franchise Fee - revenue sensitive rate 2.4493% | 0 |
| 700 | Peters | 4 | Misc. A&G | ($15,745) |
| 700 | Peters | 5 | Charitable Donations | ($1,310) |
| 700 | Peters | 6 | Dues and Subscription | ($8.214) |
| 700 | Peters | 7 | Depreciation | $136,013 |
| 700 | Peters | 8 | Inflation | $429 |
| 800 | Parvinen | 9 | Plant Additions | $8,071 |
| 800 | Parvinen | 10 | Decoupling | $0 |
| 800 | Parvinen | 11 | Retirement | ($119,047) |
| 900 | Privratsky/Parvinen | 12 | Safety Cost Recovery Mechanism | $ 0 |
| 900 | Privratsky/Parvinen | 13 | UM 1816 deferral | $ 0 |
| 1000 | Barth/Parvinen | 14 | Tax Issues | ($14,139) |
| 1100 | Murray | 15 | W&S, Incentives, new positions | ($13,824) |
| 1200 | Nygard | 16 | Cost Allocations | $ 0 |
| 1300 | Robertson | 17 | Load Forecast | $ 0 |

| | | | | |
|---|---|---|---|---|
| 1400 | Herner | 18 | Misc. Revenue: Customer Deposits | $ 0 |
| 1500 | Archer | 19 | Misc. Revenues: | $0 |
| 1600 | Amen | 20 | Cost of Service Study | $ 0 |
| 700 | Peters | 21 | Interest Coordination Adjustment | $27,895 |
| Revised Revenue Requirement Increase | | | | $2,310,937 |

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

A. My testimony is organized as follows:

Issue 1. Miscellaneous A&G Expenses;

Issue 2. Charitable Donations;

Issue 3. Dues and Subscriptions;

Issue 4. Franchise Fees;

Issue 5. Depreciation Adjustment; and

Issue 6. Inflation Calculation.

**Q. Are you sponsoring any exhibits in this proceeding?**

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

Exhibit CNGC/701 Miscellaneous A&G Expenses;

Exhibit CNGC/702 Dues and Subscriptions; and

Exhibit CNGC/703 OPUC-298 Data Response.

## II. ISSUE 1. MISCELLANEOUS A&G EXPENSES

**Q. Please describe Staff witness Mr. Rossow's proposed adjustment to Cascade's miscellaneous A&G expenses.**

A. Staff proposes to remove a portion of A&G expenses related to costs for gifts to employees, holiday activities, catering, promotional items, meals and entertainment, etc. The amount of this adjustment is $37,316.[2]

**Q. What is Staff's rationale for its proposed adjustment?**

A. In past proceedings before the Public Utility Commission of Oregon (Commission), these types of expenses have been characterized as discretionary expenses. In Order No. 09-020, in Docket UE 197, the Commission adopted the principle that for miscellaneous A&G expenses that are considered discretionary, these costs should be shared equally by shareholders and customers.[3] This policy results in a 50 percent disallowance of discretionary A&G expenses.

**Q. Did Cascade apply this policy for the A&G expenses presented in its initial filing?**

A. No.

**Q. Did Cascade remove certain miscellaneous A&G expenses from its initial filing?**

A. Yes. Cascade reviewed the Non-Labor costs recorded in all FERC accounts for the Base Year (calendar year 2017), to determine booked expenses that should not be included in the Company's request for rate recovery. We removed certain miscellaneous A&G expenses not appropriate for recovery through customer rates, which included expenses for a retirement party, sponsored event parking, party supplies, etc., and totaled ($5,635).[4] This analysis was also presented in the Company's response to Standard Data Request 57.

**Q. Please describe the Company's initial request associated with miscellaneous A&G expenses.**

A. For the 2018 test year, Cascade used the Company's 2017 actual A&G expense of $6.2

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[2] Staff/800, Rossow/4.
[3] *See In the Matter of Portland Gen. Elec. Co.*, Docket No. UE 197, Order No. 09-020 at 20 (Jan. 22, 2009).
[4] *See* Peters WP 301-306, tab "A&G Adj.".

million, which we adjusted for miscellaneous A&G by ($5,635) to remove amounts that the Company determined should not be recovered from customers.[5]

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

A. Staff reviewed Cascade's responses to Standard Data Request Nos. 57 and 58 and created tables for analysis of miscellaneous A&G expenses to identify any expenses that appeared to be discretionary in nature.[6] Staff adjusted six categories of miscellaneous A&G items within the Company's Federal Energy Regulatory Commission (FERC) accounts 902 through 930.2 by 50 percent. Table 2, below, was provided by Mr. Rossow and summarizes the expense amounts that he considered to be discretionary:

**Table 2: Staff Adjustment.[7]**

| | |
|---|---|
| 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 |

Table 3, below, was also presented in Staff's testimony and shows the proposed adjusted amount to be disallowed from each FERC account:

**Table 3: Discretionary Expenses by FERC Account.[8]**

| 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 |

**Q. Does the Company agree with Staff's proposal to categorize certain A&G expenses**

[5] CNGC/304, Peters/1.
[6] Staff/800, Rossow/3.
[7] Staff/800, Rossow/4.
[8] Staff/800, Rossow/4.

**as discretionary?**

A. In part. The Company agrees with certain expenses that Mr. Rossow has identified as discretionary, but disagrees with others. Cascade agrees that the initial adjustment of ($5,635) should be considered discretionary and subject to 50 percent sharing between shareholders and customers.[9] Regarding the other expenses, Cascade reviewed each line item within Mr. Rossow's workpapers[10] to determine whether each expense characterized as "discretionary" provides a benefit to customers. I reviewed Mr. Rossow's workpapers and added a column called "Cascade Full Recovery" in each tab. I moved each appropriate business expense that provides a benefit to customers to the "Cascade Full Recovery" column. The results of my analysis are presented in Exhibit CNGC/701.

**Q. What does Cascade consider a business expense that is appropriate for recovery from Cascade's customers?**

A. An appropriate business expense for Cascade is any expense necessary for the provision of safe and reliable natural gas service to its customers. For A&G expenses, these types of expenses would include any expenses necessary for business travel, including airfare, hotels, and meals.

**Q. Please explain why business travel and related expenses are necessary for the provision of safe and reliable natural gas service.**

A. Travel is an absolute necessity in order to provide safe and reliable service to the Company's Oregon customers, and is particularly important for Cascade due to its unique service territory, which is non-contiguous and geographically dispersed throughout the central and eastern portions of the state. Cascade and most of its employees are headquartered in Kennewick, Washington, and Cascade also has field offices in

[9] Staff/800, Rossow/3.
[10] *See* Staff electronic workpaper, UG 347 Exhibit 800 Meal and Entertainment Adj.

Baker/Ontario, Bend, and Pendleton.

Cascade personnel must travel to visit the Company's field offices, travel to Salem to meet with the Company's regulators and stakeholders at the Commission, and travel to attend conferences and trainings to be informed and trained on issues that benefit customers. Business travel and related expenses provide a direct benefit to customers and should not be included with the discretionary "meals and entertainment" expenses that are split 50/50 with customers and shareholders.

**Q. In addition to business travel expenses, were there other types of expenses that Mr. Rossow categorized as discretionary that you believe should be re-categorized?**

A. Yes. In Mr. Rossow's workpapers, tab Misc. Employee Benefit, he disallowed 50 percent of payroll labor distribution.[11] I believe this expense should be re-categorized.

**Q. What is payroll labor distribution and why do you believe this expense should be re-categorized?**

A. Payroll labor distribution within FERC account 926 includes awards provided to employees based on years of service. This program is designed to attract and retain qualified workers and provides a direct benefit to customers. These awards promote a positive business culture for the Company and allow us to continue to attract, motivate, and retain qualified workers.

**Q. Please summarize the results of your analysis and re-categorization of Cascade's expenses that Mr. Rossow had characterized as discretionary.**

A. The results of my analysis are shown in Exhibit CNGC/701, in the column called "Cascade Full Recovery" in each tab. I have also summarized the results of my analysis in Table 4, below, which shows the proposed adjusted amount (reflecting application of 50/50

[11] *See* Staff electronic workpaper, UG 347 Exhibit 800 Meal and Entertainment Adj., tab "5813 Misc. Employee Benefits".

sharing) to each FERC account.

**Table 4: Cascade Adjustment.**

| FERC No. | FERC Account Description | Discretionary Expense ($) (Adjusted by 50 Percent) |
|---|---|---|
| 902 | Meter Reading Expenses | $1,436 |
| 903 | Customer Records & Collect. Exp. | $56 |
| 908 | Customer Assistance Expenses | $248 |
| 921 | Office Supplies and Expenses | $8,156 |
| 926 | Employee Pensions and Benefits | $10,617 |
| 930.2 | Misc. General Expenses | $376 |
| TOTAL | Total Adjusted Discretionary Expenses | $20,890 |

**Q. What is Cascade's new overall adjustment to the proposed 2018 test year expense?**

A. Table 5 summarizes the miscellaneous A&G adjusted expense amount.

**Table 5: Selected Miscellaneous Base Year Expenses.**

| | |
|---|---|
| Total discretionary Expenses | $46,716 |
| Less Company Adjustment | ($5,635) |
| | $41,081 |
| Disallowance | 50% |
| Expenses after Disallowance | $20,540 |
| Escalation Factor | 1.7% |
| Total Adjustment with Escalation | $20,890 |

The Company is proposing an overall decrease to A&G expenses of ($20,890), a change to revenue requirement of ($15,745).

## III. ISSUE 2. CHARITABLE DONATIONS

**Q. What adjustment does Staff make to charitable donations?**

A. Staff proposed to remove a transaction for Cascade dues to the Association of Washington Business in the amount of $1,248, escalated by 1.7 percent to the amount in its 2018 test year, for a decrease to expense of ($1,269).[12]

**Q. What is the Company's response to Staff's proposed adjustment to charitable donations?**

[12] Staff/800, Rossow/7.

A. The Association of Washington Business expense was inadvertently included in the Company's initial filing, and Cascade agrees that it is appropriate to remove this expense. This adjustment is a change to revenue requirement of ($1,310).

## IV. ISSUE 3. DUES AND SUBSCRIPTIONS

**Q. Please describe the Company's approach to the Dues and Subscriptions expense in its initial filing.**

A. In my initial Exhibit CNGC/302 Revenue Requirement, I adjusted the Company's Dues and Subscriptions expense by ($33,673.79),[13] which reflected a removal of 50 percent of those expenses, consistent with last rate case settlement agreement with Staff in Docket UG 305.[14]

**Q. Please describe AWEC's proposed adjustment to the Company's expenses for Dues and Subscriptions.**

A. AWEC proposes to disallow *all* allocated cross-charges from Montana Dakota Utilities (MDU) for dues and subscriptions, claiming that "Cascade has no cost allocation policy in place with respect to these cost categories."[15] As a result, AWEC recommends a downward adjustment to operating expenses of ($9,131) to reflect disallowance of allocated cross-charges for dues and subscriptions, which results in an overall reduction of ($9,416) to the revenue requirement.[16]

**Q. Does Mr. Mullins have other concerns regarding these cross charges from MDU?**

A. Yes. The Company's responses to AWEC Data Requests 46 and 47 showed that MDU cross charges included a sponsorship of a minor league baseball team and a professional

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[13] CNGC/302, Peters/1.
[14] *In the Matter of Cascade Nat. Gas Corp.*, Docket No. UG 305, Staff/600, Zarate/6 (Aug. 11, 2016).
[15] AWEC/100, Mullins/15.
[16] AWEC/100, Mullins/16.

bull rider, which Mr. Mullins claims do not provide a benefit to Oregon customers.[17]

**Q. Does Cascade agree that these two charges should not be passed on to Oregon customers?**

A. Yes. As is shown in my workpapers,[18] Cascade removed certain utility advertising expenses in preparing the A&G expense to be included with its initial filing, including these two items.[19] Thus, the two expenses that Mr. Mullins refers to are not charged to Oregon customers.

**Q. What is the Company's overall response to AWEC's dues and subscriptions adjustment?**

A. Cascade reviewed AWEC's adjustment and agrees that certain expenses for dues and subscriptions that were cross-charged to Cascade should be removed. However, in Cascade's review, we found that there were a few cross charges that we believe are appropriate and adequately supported.

**Q. What types of cross-charged dues and subscriptions expenses does Cascade agree should be removed?**

A. Cascade agrees that some allocated costs from MDU have no bearing on Oregon rates, including dues for out of state Chambers of Commerce and the Wyoming Taxpayers Association. The Company agrees that these costs should be removed and has reflected removal of these amounts in Exhibit CNGC/702.

**Q. What types of cross-charged dues and subscriptions expenses does Cascade believe should be recoverable from customers?**

A. Cascade disagrees with AWEC's adjustment for cross-charged dues and subscriptions

[17] AWEC/100, Mullins/15-16.
[18] *See* Peters WP 301-306, tab "Promotional Advertising Adj".
[19] CNGC/300, Peters/4.

expenses relating to professional licenses and memberships, such as Human Resources memberships and Certified Public Accountant licenses. These types of memberships and licenses are either required for or beneficial to certain MDU employees that perform work that is either directly or indirectly allocated to Cascade. Accordingly, Cascade's customers benefit from these memberships and licenses, and it is appropriate to recover these expenses from customers.

**Q. Did you perform additional analysis of the MDU cross charges that AWEC had proposed to remove from the case?**

A. Yes. I analyzed Mr. Mullins' workpapers, AWEC 102-Revenue Requirement Analysis, tab A4 OPUC-90. AWEC relied on data that the Company provided in response to Staff Data Request No. 90, but did not seem to take into account information that Cascade provided in response to Staff Data Request No. 298, in which Cascade provided detailed information regarding each cross-charged item that was included in response to Staff Data Request No 90. See Exhibit CNGC/703.

To clarify, I created Exhibit CNGC/702, which relies on Mr. Mullins' workpapers as a foundation. In Exhibit CNGNC/702, tab A4 OPUC-90, lines 89 through 172, I reviewed each expense recorded to the dues and subscriptions account, line by line, and cross-referenced all line items labeled as MDU cross charges with the Company's response to Staff Data Request No. 298 for a more detailed description of the expense. Cascade excluded any expense item that did not include adequate detail to demonstrate the benefit to customers in column R.

**Q. What is the result of this analysis?**

A. The total of items removed as a result of this analysis are shown in the tab "Summary." Cascade's results show that AWEC's proposed adjustment should instead be modified to reflect an adjustment of ($7,959) to operating expenses, and a change of ($8,214) to revenue requirement.

## V. ISSUE 4. FRANCHISE FEES

**Q. Please explain Cascade's position regarding how to assess franchise fees.**

A. Franchise fees include licensure and operating fees—such as occupation taxes or other exactions—that are necessary for Cascade to operate in its areas of service. As a result, these costs (up to the Commission's 3 percent limit) are appropriately included in a utility's operating expenses.[20] In this case, Cascade included a test year franchise rate of 2.449 percent, which is identical to the actual 2017 rate.[21]

**Q. Does Staff propose adjusting this rate?**

A. Yes. Staff proposes using a three-year average of franchise fees, rather than the most recent year's franchise fee data.[22] Staff's approach yields a 2.387 percent rate.[23]

**Q. Is a three-year average consistent with Staff's approach in Cascade's previous rate case (UG 305)?**

A. No. In UG 305, Staff supported using the most recently-available (base year) data as the basis for test year expenses.[24]

**Q. Does Staff explain why it has changed its approach or why a three-year average is preferable to using the most recent available data?**

A. No.

**Q. Do you agree that using a three-year average is an appropriate way to determine Cascade's franchise fees for the Test Year?**

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[20] Where fees are particularly high in a given jurisdiction, excessive fees are charged to that jurisdiction's customers pursuant to OAR 860-022-0040(1).
[21] CNGC/303, Peters/1.
[22] Staff/100, Gardner/9.
[23] Staff/100, Gardner/9.
[24] Docket No. UG 305, Staff/100, Gardner/22 ("Staff does not propose any adjustment."); *see also* Docket No. UG 305, CNGC/203, Parvinen/1 (Apr. 29, 2016) (showing franchise taxes for base year 2015).

A. No. Cascade's franchise fees are most accurately calculated using the most recent available data. Staff's three-year average approach might be appropriate if franchise fees oscillated significantly over time, in which case using an average of multiple years would normalize these fluctuations. However, while the taxes and rates that comprise franchise fees do change over time, they generally *increase*—not decrease.

**Q. Has Cascade experienced any decrease in franchise fees in recent years?**

A. No. Since at least 2015, Cascade has experienced *only increases* in franchise fees. As a result, it is particularly unlikely that Staff's averaging approach accurately reflects Cascade's future costs.

## VI. ISSUE 5. DEPRECIATION ADJUSTMENT

**Q. How did the Company calculate its depreciation expense in its initial filing?**

A. Cascade annualized the December 2017 depreciation expense as an attempt to match the depreciation expense with the end of year investment.

**Q. Does Cascade propose an updated calculation in its reply filing?**

A. Yes. Cascade determined that its original method for calculating depreciation expense included depreciation expense based on the previous month's plant in service balance, and thus reflected plant in service only through November 30, 2017—inadvertently omitting the balance through December 31, 2017. The Company should have instead annualized the January 2018 depreciation expense, which would reflect all plant in service as of December 31, 2017.

**Q. What is the overall impact of this correction to the revenue requirement?**

A. This adjustment increases depreciation expense by $146,481, resulting in an increase of $136,013 to the revenue requirement.

## VII. ISSUE 6. INFLATION FACTOR

**Q. What allocation percentage was used in the Inflation Factor tab in the Company's initial filing to assign to Oregon its portion of total system salary and union wages?**

A. As shown in the Inflation Factor tab in my workpapers "Cascade Exhibit 301-306-Peters Workpapers," the Company allocated 25.15 percent of Cascade's total wages to Oregon. This 25.15 percent reflects the jurisdictional allocation amount for calendar year 2018.

**Q. Was this allocation percentage correct?**

A. No, I inadvertently applied the wrong allocation percentage, which was used for the base year salary and union wages.

**Q. What allocation percentage should have been used instead?**

A. The Company should have instead used 24.96 percent to calculate the base year wages allocation to Oregon. This 24.96 percent is the calendar year 2017 allocation amount.

**Q. What is the impact to the revenue requirement as a result of adjusting the inflation factor tab?**

A. This adjustment increases revenue requirement by $428.

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

A. Yes.

CNGC/701
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Maryalice C. Peters

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**Miscellaneous A&G Expenses**
**Exhibit CNGC/701**

**October 2018**

# Cascade National Gas Corporation A and G Adjustment
## UG 347

| FERC Acct. #'s | Category No. | OBJ | OBJ Description | Oregon Situs | Oregon Allocation | Customer Accts. | Customer Service | Summation of Inappropriate Expenses | Disallowance | Disallowed | Inflation Factor | Escalated $ Amount | Adjustment with Escalation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 930 | 1 | 5233 | Director's Meals and Entertainment | | 738.71 | | | 738.71 | 50% | 369.36 | 1.7% | 6.279 | 375.63 |
| 921, 926 | 2 | 5521 | Meals & Entertainment | 3,139.13 | 25,613.31 | 2,928.43 | 743.02 | 32,423.89 | 50% | 16,211.95 | 1.7% | 275.603 | 16,487.55 |
| 921, 926 | 3 | 5813 | Misc. Employee Benefits | 4,411.26 | 41,334.32 | 110.59 | | 45,856.17 | 50% | 22,928.09 | 1.7% | 389.777 | 23,317.86 |
| | | | | | | | | 79,018.77 | | 39,509.39 | | 671.66 | 40,181.04 |

**Peters**

| FERC Acct. #'s | Category No. | OBJ | OBJ Description | Oregon Situs | Oregon Allocation | Customer Accts. | Customer Service | Summation of Inappropriate Expenses | Disallowance | Disallowed | Inflation Factor | Escalated $ Amount | Adjustment with Escalation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 930 | 1 | 5233 | Director's Meals and Entertainment | | 738.71 | | | 738.71 | 50% | 369.36 | 1.7% | 6.279 | 375.63 |
| 921, 926 | 2 | 5521 | Meals & Entertainment | 122.60 | 21,552.83 | 2,823.50 | 487.76 | 24,986.69 | 50% | 12,493.35 | 1.7% | 212.387 | 12,705.73 |
| 921, 926 | 3 | 5813 | Misc. Employee Benefits | 4,411.26 | 16,468.66 | 110.59 | | 20,990.51 | 50% | 10,495.26 | 1.7% | 178.419 | 10,673.67 |
| | | | | | | | | 46,715.91 | | 23,357.96 | | 397.09 | 23,755.04 |

| Rossow | | Peters | |
|---|---|---|---|
| Total Discretionary Expenses | 79,018.77 | Total Discretionary Expenses | 46,715.91 |
| Less Company Adjustment (prevent | (5,635.21) | Less Company Adjustment (prevent do | (5,635.21) |
| | 73,383.56 | | 41,080.70 |
| 50% Sharing of Expenses | 50% | 50% Sharing of Expenses | 50% |
| Expenses after Disallowance | 36,691.78 | Expenses after Disallowance | 20,540.35 |
| Inflation Factor | 1.7% | Inflation Factor | 1.7% |
| Escalated $ Amount | 623.76 | Escalated $ Amount | 349.19 |
| Adjustment with Escalation | 37,315.54 | Adjustment with Escalation | 20,889.54 |

| | FERC No. | FERC Description | Adjustment | 50% Disallowance | 1.7% Inflation | Escalated Adjustment |
|---|---|---|---|---|---|---|
| Rossow | 902 | Meter Reading Expenses | 2,928.43 | 1,464.22 | 24.89 | 1,489 |
| | 903 | Customer Records & Collect. Exp. | 110.59 | 55.30 | 0.94 | 56 |
| | 908 | Customer Assistance Expenses | 743.02 | 371.53 | 6.32 | 378 |
| | 921 | Office Supplies and Expenses | 28,752.44 | 11,558.62 | 196.50 | 11,755 |
| | 921 | Company A&G Adjustment | (5,635.21) | | | |
| | 926 | Employee Pensions and Benefits | 45,745.58 | 22,872.81 | 388.84 | 23,262 |
| | 930.2 | Misc. General Expenses | 738.71 | 369.37 | 6.28 | 376 |
| | | | 73,383.56 | 36,691.83 | 623.76 | 37,316 |
| Rossow/Peters | 921 | Office Supplies and Expenses | 1,248.00 | | 21.22 | 1,269 |

| | FERC No. | FERC Description | Adjustment | 50% Disallowance | 1.7% Inflation | Escalated Adjustment |
|---|---|---|---|---|---|---|
| Peters | 902 | Meter Reading Expenses | 2823.5 | 1411.75 | 24.00 | 1435.75 |
| | 903 | Customer Records & Collect. Exp. | 110.59 | 55.295 | 0.94 | 56.24 |
| | 908 | Customer Assistance Expenses | 487.76 | 243.88 | 4.15 | 248.03 |
| | 921 | Office Supplies and Expenses | $ 21,675.43 | 8020.11 | 136.34 | 8156.45 |
| | 921 | Company A&G Adjustment | (5,635.21) | | 0.00 | 0.00 |
| | 926 | Employee Pensions and Benefits | 20879.92 | 10439.96 | 177.48 | 10617.44 |
| | 930.2 | Misc. General Expenses | $ 738.71 | 369.355 | 6.28 | 375.63 |
| | | | 41,080.70 | 20,540.35 | 349.19 | 20,889.54 |

CNGC/702
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Maryalice C. Peters

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**Dues and Subscriptions**
**Exhibit CNGC/702**

**October 2018**

**Mullins Adjustment Calculation:**

| | |
|---|---|
| 14,655 | Excluded Items |
| 56,330 | Allocable Amount |
| - | |
| - | |
| 28,165 | Apply 50% Limit |
| (42,820) | Adjustment |
| (33,674) | Company Adjustment |
| (9,146) | Delta |

**Peters Adjustment Calculations:**

| | |
|---|---|
| 12,280.44 | Excluded Items |
| 58,704.18 | Allocable Amount |
| - | |
| - | |
| 29,352.09 | Apply 50% Limit |
| (41,632.53) | Adjustment |
| (33,673.79) | Company Adjustment |
| (7,958.75) | Delta |

CNGC/703
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Maryalice C. Peters

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**OPUC-298 Data Response**
**Exhibit CNGC/703**

**October 2018**

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

**Request No. 298**

Date prepared: 09/12/2018

Preparer: Isaac Myhrum

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 298**

Please refer to the attached excel workbook titled Match FERC Acct No. with Cross Charges. Please provide the appropriate FERC Account Numbers for each transaction listed under tabs titled Charitable Donations, Misc. Employee Benefits, Meals & Entertainment, and Dues. See Cascade's data response OPUC-179 supplemental attachment.

**Response:**

Please see the attached file "OPUC-298 Attachment.xlsx". FERC codes have been provided for Charitable Donations, Misc. Employee Benefits, Meals & Entertainment, and Dues transactions. Cells containing "n/a" denote a "zero dollar amount" or a pairing of reverse transactions that net to zero.

CNGC/703
Peters/2

| FERC | Do T | Document N | G/L Date | Account Number | Business Unit | Obj Acct | Description | Category | Category desc | Sub | Sub- ledger | LT | FY | Per N | Co | Explanation Alpha Name | Explanation -Remark- | Amount | CNGC % | CNGC% | Washington 75.04% | Oregon 24.96% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 930.2 | JE | 1234821 | 1/19/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | CLEAN OUT PREPAID ACCTS | 1926089 TREASURE STATE RESOURC | 2000 | 272 | 14% | 204.1088 | 67.8912 |
| 921 | PV | 1929311 | 1/10/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | WSATR | 2016-2017 WSATR DUES | 100 | 13.6 | 14% | 10.20544 | 3.39456 |
| 426.4 | PV | 1925076 | 1/1/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00024264 | AA | 17 | 1 | 00001 | TREASURE STATE RESOURCE INDUST | 2017 ANNUAL DUES | 240 | 32.64 | 14% | 24.493056 | 8.146944 |
| 426.4 | PV | 1925076 | 1/1/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00024264 | AA | 17 | 1 | 00001 | TREASURE STATE RESOURCE INDUST | 2017 ANNUAL DUES | -240 | -32.64 | 14% | -24.493056 | -8.146944 |
| 930.2 | PV | 1925076 | 1/1/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | TREASURE STATE RESOURCE INDUST | 2017 ANNUAL DUES | 1760 | 239.36 | 14% | 179.615744 | 59.744256 |
| 930.2 | PV | 1925076 | 1/1/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | TREASURE STATE RESOURCE INDUST | 2017 ANNUAL DUES | -1760 | -239.36 | 14% | -179.615744 | -59.744256 |
| 930.2 | PV | 1933021 | 1/31/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | SD BROADCASTERS ASSOCIATION | 2017 ASSOCIATE MEM DUES | 135 | 18.36 | 14% | 13.777344 | 4.582656 |
| 930.2 | PV | 1983332 | 12/27/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 12 | 00001 | RMC RESEARCH & EDUCATION FOUN | 2017 Charity match- Brian Gray | 577 | 81.357 | 14% | 61.0502928 | 20.3067072 |
| 921 | PV | 1928971 | 1/6/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | BIG MUDDY BAR ASSOCIATION | 2017 dues | 75 | 10.2 | 14% | 7.65408 | 2.54592 |
| 426.4 | PV | 1945275 | 4/30/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00024264 | AA | 17 | 4 | 00001 | NORTH DAKOTA CHAMBER OF COMN | 2017 dues | 1500 | 204 | 14% | 153.0816 | 50.9184 |
| 930.2 | PV | 1924038 | 1/1/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | BISMARCK-MANDAN CHAMBER OF C( | 2017 dues | 8333.74 | 1133.38864 | 14% | 850.4948355 | 282.8938045 |
| 930.2 | PV | 1945275 | 4/30/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 4 | 00001 | NORTH DAKOTA CHAMBER OF COMN | 2017 dues | 8500 | 1156 | 14% | 867.4624 | 288.5376 |
| 921 | PV | 1925043 | 1/1/2017 | 979.7811 | 979 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | SDCEDC | 2017 DUES C FONG | 250 | 34 | 14% | 25.5136 | 8.4864 |
| 930.2 | PV | 1929478 | 1/10/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | SOUTH DAKOTA NEWSPAPER ASSOCI/ | 2017 DUES LAURA LUEDER | 150 | 20.4 | 14% | 15.30816 | 5.09184 |
| 930.2 | PV | 1971519 | 10/17/2017 | 970.7912 | 970 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 10 | 00001 | BISMARCK-MANDAN CHAMBER OF C( | 2017 EPIC IMPACT SPONSOR | 1000 | 141 | 14% | 105.8064 | 35.1936 |
| n/a | PV | 1948773 | 5/31/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00020973 | AA | 17 | 5 | 00001 | MONTANA TAXPAYERS ASSOCIATION | 2017 Membership Fee | 5400 | 727.92 | 13% | 546.231168 | 181.688832 |
| 921 | PV | 1920443 | 1/1/2017 | 982.7811 | 982 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020982 | AA | 17 | 1 | 00001 | ITCND | 2017 MEMBERSHIP INVESTMENT | 500 | 39.2 | 8% | 29.41568 | 9.78432 |
| 930.2 | PV | 1958915 | 8/4/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 8 | 00001 | MONTANA LEAGUE OF CITIES & TOW | 2017-2018 MEMBERSHIP | 275 | 38.775 | 14% | 29.09676 | 9.67824 |
| 930.2 | PV | 1980139 | 12/11/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 12 | 00001 | NORTH DAKOTA NEWSPAPER ASSOC | 2018 GOLD MEMBER DUES | 300 | 42.3 | 14% | 31.74192 | 10.55808 |
| 930.2 | PV | 1980456 | 12/12/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 12 | 00001 | SD BROADCASTERS ASSOCIATION | 2018 MEMBERSHIP DUES | 135 | 19.035 | 14% | 14.283864 | 4.751136 |
| 930.2 | PV | 1981803 | 12/18/2017 | 970.7912 | 970 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 12 | 00001 | BISMARCK-MANDAN CHAMBER OF C( | 2018 YOUNG PROF SILVER | 1000 | 141 | 14% | 105.8064 | 35.1936 |
| 930.2 | PV | 1981803 | 12/27/2017 | 970.7912 | 970 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 12 | 00001 | BISMARCK-MANDAN CHAMBER OF C( | 2018 YOUNG PROF SILVER | -1000 | -141 | 14% | -105.8064 | -35.1936 |
| 921 | CE | 1253621 | 7/31/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | A RIEHL 7-17 | ACC Membership Renewal | 140 | 19.74 | 14% | 14.812896 | 4.927104 |
| 921 | CE | 1235926 | 1/31/2017 | 975.7811 | 975 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | D SENGER 1-17 | AFP Membership | 495 | 67.32 | 14% | 50.516928 | 16.803072 |
| 921 | CE | 1256191 | 8/30/2017 | 762.7811 | 762 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020762 | AA | 17 | 8 | 00001 | J WENTZ 8-17 | AGC | 175 | 16.5025 | 9% | 12.383476 | 4.119024 |
| 921 | CE | 1252270 | 7/25/2017 | 974.7811 | 974 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | A GRIFFIN 7-17 | Annual CPA Registration | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1252330 | 7/25/2017 | 974.7811 | 974 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | K UKESTAD 7-17 | Annual CPA Registration | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1253195 | 7/28/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | S BEROGAN 7-17 | Annual Dues | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1253195 | 7/28/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | S BEROGAN 7-17 | Annual Dues | 265 | 37.365 | 14% | 28.038696 | 9.326304 |
| 921 | CE | 1259548 | 9/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 9 | 00001 | B TAYLOR 9-17 | Annual Dues | 184 | 25.944 | 14% | 19.4683776 | 6.4756224 |
| 921 | CE | 1260535 | 10/12/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 10 | 00001 | S BEROGAN 9-17 | Annual Dues | 140 | 19.74 | 14% | 14.812896 | 4.927104 |
| 921 | CE | 1262189 | 10/31/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 10 | 00001 | J THORSON 10-17 | Annual Dues | 135 | 19.035 | 14% | 14.283864 | 4.751136 |
| 921 | CE | 1247892 | 5/31/2017 | 984.7811 | 984 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 5 | 00001 | L LUEDER 5-17 | Annual Membership, PRSA | 255 | 34.68 | 14% | 26.023872 | 8.656128 |
| 921 | CE | 1252905 | 7/27/2017 | 975.7811 | 975 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | J INMAN 6-17 | Annual registration fee | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1252329 | 7/25/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | D GENORA 7-17 | Assoc Fees | 410 | 57.81 | 14% | 43.380624 | 14.429376 |
| 921 | CE | 1258829 | 9/29/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 9 | 00001 | C FROELICH 9-17 | Association for Training-Dev | 199 | 28.059 | 14% | 21.0554736 | 7.0035264 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020047 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | ATD Membership | 15.1 | 15.1 | 100% | 11.33104 | 3.76896 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020048 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | ATD Membership | 10.54 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020060 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | ATD Membership | 16.34 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020061 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | ATD Membership | 46.94 | 0 | 0% | 0 | 0 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | ATD Membership | 6.08 | 0.85728 | 14% | 0.643302912 | 0.213977088 |
| 930.2 | JE | 1232638 | 1/1/2017 | 970.7912 | 970 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | Expense PV 1926976 in 2017 | BisMan Chamb Commerc Inv 76118 | 1000 | 136 | 14% | 102.0544 | 33.9456 |
| 930.2 | PV | 1974455 | 10/31/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 10 | 00001 | PACIFIC NORTHWEST ECONOMIC REC | bronze sponsor | 5000 | 705 | 14% | 529.032 | 175.968 |
| 921 | PV | 1937836 | 3/3/2017 | 974.7811 | 974 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 3 | 00001 | D MOYLAN 2-17 | CA CPA License Renewal | 120 | 16.32 | 14% | 12.246528 | 4.073472 |
| 921 | JE | 1248321 | 5/31/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 5 | 00001 | CE 1244269 D KUNTZ 4-17 | CE 1244269 D KUNTZ 4-17 | 1200 | 163.2 | 14% | 122.46528 | 40.73472 |
| 930.2 | JE | 1248321 | 5/31/2017 | 980.7912 | 980 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 5 | 00001 | CE 1244269 D KUNTZ 4-17 | CE 1244269 D KUNTZ 4-17 | -1200 | -163.2 | 14% | -122.46528 | -40.73472 |
| 921 | CE | 1244262 | 4/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 4 | 00001 | C GLASSER 4-17 | CEBS Dues | 275 | 37.4 | 14% | 28.06496 | 9.33504 |
| 921 | CE | 1262292 | 10/31/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 10 | 00001 | D KETTERLING 10-17 | CFE Desingation Fee | 195 | 27.495 | 14% | 20.632248 | 6.862752 |
| 921 | CE | 1264988 | 11/30/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 11 | 00001 | D KETTERLING 11-17 | CISA Annual Membership Dues | 215 | 30.315 | 14% | 22.748376 | 7.566624 |
| n/a | JE | 1248329 | 5/31/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00020973 | AA | 17 | 5 | 00001 | Subledger corrections | Cor PV 1948773 | -5400 | -727.92 | 13% | -546.231168 | -181.688832 |
| 930.2 | JE | 1248329 | 5/31/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 5 | 00001 | Subledger corrections | Cor PV 1948773 | 5400 | 734.4 | 14% | 551.09376 | 183.30624 |
| 921 | CE | 1247892 | 5/31/2017 | 984.7811 | 984 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 5 | 00001 | L LUEDER 5-17 | Corporate Membership, IABC | 1500 | 204 | 14% | 153.0816 | 50.9184 |
| 426.4 | JE | 1261068 | 10/18/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00024264 | AA | 17 | 10 | 00001 | CORRECT LOBBYING CHARGES | CORRECT PV 1926089 | 240 | 33.84 | 14% | 25.393536 | 8.446464 |
| 930.2 | JE | 1261068 | 10/18/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 10 | 00001 | CORRECT LOBBYING CHARGES | CORRECT PV 1926089 | -240 | -33.84 | 14% | -25.393536 | -8.446464 |
| 426.4 | JE | 1261068 | 10/18/2017 | 970.7912 | 970 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00024264 | AA | 17 | 10 | 00001 | CORRECT LOBBYING CHARGES | CORRECT PV 1926976 | 20 | 2.82 | 14% | 2.116128 | 0.703872 |
| 930.2 | JE | 1261068 | 10/18/2017 | 970.7912 | 970 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 10 | 00001 | CORRECT LOBBYING CHARGES | CORRECT PV 1926976 | -20 | -2.82 | 14% | -2.116128 | -0.703872 |
| 426.4 | JE | 1261068 | 10/18/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00024264 | AA | 17 | 10 | 00001 | CORRECT LOBBYING CHARGES | CORRECT PV 1933021 | 122.31 | 17.24571 | 14% | 12.94118078 | 4.304529216 |
| 930.2 | JE | 1261068 | 10/18/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 10 | 00001 | CORRECT LOBBYING CHARGES | CORRECT PV 1933021 | -122.31 | -17.24571 | 14% | -12.94118078 | -4.304529216 |
| 921 | CE | 1249431 | 6/26/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 6 | 00001 | P DEEDE 6-17 | CPA Dues | 85 | 11.56 | 14% | 8.674624 | 2.885376 |
| 921 | CE | 1250936 | 6/30/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 6 | 00001 | R WATSON 6-17 | CPA Dues | 85 | 11.56 | 14% | 8.674624 | 2.885376 |
| 921 | CE | 1255748 | 8/24/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 8 | 00001 | P DEEDE 8-17 | CPA Dues | 140 | 19.74 | 14% | 14.812896 | 4.927104 |
| 921 | CE | 1257096 | 8/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 8 | 00001 | C GLASSER 8-17 | CPA Dues | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1252310 | 7/25/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | M SANDERSON 7-17 | CPA license renewal | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1253199 | 7/28/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | K FRENETTE 7-17 | CPA license renewal | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1252302 | 7/25/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | J JOHNSON 7-17 | CPA renewal | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | CE | 1235640 | 1/31/2017 | 967.7811 | 967 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | V KUNZ 1-17 | CRM Recertification | 100 | 13.6 | 14% | 10.20544 | 3.39456 |
| n/a | JE | 1253343 | 7/28/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020067 | AA | 17 | 7 | 00001 | D SACKMAN 6-17 | D SACKMAN 5-17 | -895 | 0 | 0% | 0 | 0 |
| 921 | CE | 1235640 | 1/31/2017 | 967.7811 | 967 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | V KUNZ 1-17 | Dept Membership | 1000 | 136 | 14% | 102.0544 | 33.9456 |
| 921 | PV | 1925880 | 1/1/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 1 | 00001 | CENTRAL DAKOTA HUMAN RESOURCI | dues | 45 | 6.12 | 14% | 4.592448 | 1.527552 |
| 930.2 | PV | 1930017 | 1/12/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | WYOMING TAXPAYERS ASSOCIATION | dues | 1600 | 217.6 | 14% | 163.28704 | 54.31296 |
| 930.2 | PV | 1930015 | 1/12/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 1 | 00001 | MONTANA TAXPAYERS ASSOCIATION | dues | 5400 | 734.4 | 14% | 551.09376 | 183.30624 |
| 921 | CE | 1252908 | 7/27/2017 | 966.7811 | 966 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | S BARTH 7-17 | Dues / License Fee | 28.05 | 3.95505 | 14% | 2.96786952 | 0.98718048 |
| 921 | CE | 1252908 | 7/27/2017 | 983.7811 | 983 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 7 | 00001 | S BARTH 7-17 | Dues / License Fee | 56.95 | 8.02995 | 14% | 6.02567448 | 2.00427552 |
| 930.2 | PV | 1950012 | 6/7/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 6 | 00001 | PUBLIC AFFAIRS COUNCIL | DUES- ID: 1142148 | 4000 | 544 | 14% | 408.2176 | 135.7824 |
| 930.2 | PV | 1933603 | 2/7/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | | 00029995 | AA | 17 | 2 | 00001 | MEDA - MONTANA ECONOMIC DEVEI | GARY FORRESTER MEMBERSHIP | 125 | 17 | 14% | 12.7568 | 4.2432 |
| 921 | CE | 1261408 | 10/25/2017 | 965.7811 | 965 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020965 | AA | 17 | 10 | 00001 | D BURDOLSKI 10-17 | HDI | 295 | 22.9805 | 8% | 17.2445672 | 5.7359328 |
| 921 | CE | 1264582 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 11 | 00001 | C FROELICH 11-17 | HR Annual Membership | 189 | 26.649 | 14% | 19.9974096 | 6.6515904 |
| 921 | CE | 1265067 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020047 | AA | 17 | 11 | 00001 | B STEFFES 11-17 | HR Membership | 31.64 | 31.64 | 100% | 23.742656 | 7.897344 |
| n/a | CE | 1265067 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020048 | AA | 17 | 11 | 00001 | B STEFFES 11-17 | HR Membership | 22.09 | 0 | 0% | 0 | 0 |
| n/a | CE | 1265067 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020060 | AA | 17 | 11 | 00001 | B STEFFES 11-17 | HR Membership | 34.23 | 0 | 0% | 0 | 0 |
| n/a | CE | 1265067 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020061 | AA | 17 | 11 | 00001 | B STEFFES 11-17 | HR Membership | 98.3 | 0 | 0% | 0 | 0 |
| 921 | CE | 1265067 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00029995 | AA | 17 | 11 | 00001 | B STEFFES 11-17 | HR Membership | 12.74 | 1.79634 | 14% | 1.347973536 | 0.448366464 |
| 921 | CE | 1256155 | 8/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020047 | AA | 17 | 8 | 00001 | R ROERICK 8-17 | HR Recertification | 23.85 | 23.85 | 100% | 17.89704 | 5.95296 |
| n/a | CE | 1256155 | 8/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | | 00020048 | AA | 17 | 8 | 00001 | R ROERICK 8-17 | HR Recertification | 16.65 | 0 | 0% | 0 | 0 |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| n/a | CE | 1256155 | 8/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020060 | AA | 17 | 8 | 00001 | R ROERICK 8-17 | HR Recertification | 25.8 | 0 | 0% | 0 | 0 |
| n/a | CE | 1256155 | 8/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020061 | AA | 17 | 8 | 00001 | R ROERICK 8-17 | HR Recertification | 74.1 | 0 | 0% | 0 | 0 |
| 921 | CE | 1256155 | 8/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 8 | 00001 | R ROERICK 8-17 | HR Recertification | 9.6 | 1.3536 | 14% | 1.01574144 | 0.33785856 |
| 921 | CE | 1238630 | 2/28/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 2 | 00001 | D SACKMAN 2-17 | IA Dept. Group Membership | 1600 | 217.6 | 14% | 163.28704 | 54.31296 |
| 921 | CE | 1249427 | 6/26/2017 | 978.7811 | 978 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 6 | 00001 | D SACKMAN 5-17 | IIA Audit Exec. Dues | 895 | 121.72 | 14% | 91.338688 | 30.381312 |
| 921 | CE | 1264630 | 11/30/2017 | 982.7811 | 982 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020982 | AA | 17 | 11 | 00001 | D BOESE 10-17 | Leadership Bismarck Mandan | 35 | 2.7755 | 8% | 2.0827352 | 0.6927648 |
| 930.2 | CE | 1235639 | 1/31/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 1 | 00001 | C FONG 1-17 | Lobbying Registration | 25 | 3.4 | 14% | 2.55136 | 0.84864 |
| 426.4 | CE | 1235637 | 1/31/2017 | 763.7912 | 763 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00024264 | AA | 17 | 1 | 00001 | V LOESCH 1-17 | mbrship - lobbying portion | 68.25 | 9.282 | 14% | 6.9652128 | 2.3167872 |
| 930.2 | CE | 1235637 | 1/31/2017 | 763.7912 | 763 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 1 | 00001 | V LOESCH 1-17 | mbrship - non lobbying | 386.75 | 52.598 | 14% | 39.4695392 | 13.1284608 |
| 921 | CE | 1235632 | 1/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 1 | 00001 | J HIRNING 1-17 | membership | 179 | 24.344 | 14% | 18.2677376 | 6.0762624 |
| 921 | CE | 1235632 | 1/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 1 | 00001 | J HIRNING 1-17 | membership | 50 | 6.8 | 14% | 5.10272 | 1.69728 |
| 930.2 | PV | 1978513 | 11/30/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 11 | 00001 | SD CHAMBER OF COMMERCE & INDU | MEMBERSHIP 2017-18 | 1685 | 237.585 | 14% | 178.283784 | 59.301216 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020047 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 30.05 | 30.05 | 100% | 22.54952 | 7.50048 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020047 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 7.16 | 7.16 | 100% | 5.372864 | 1.787136 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020048 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 20.98 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020048 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 5 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020060 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 32.51 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020060 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 7.74 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020061 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 93.36 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020061 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 22.22 | 0 | 0% | 0 | 0 |
| 921 | CE | 1256163 | 8/30/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 8 | 00001 | D GENORA 8-17 | Membership Dues | 265 | 37.365 | 14% | 28.038696 | 9.326304 |
| 921 | CE | 1264989 | 11/30/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 11 | 00001 | D KUNTZ 11-17 | Membership Dues | 335 | 47.235 | 14% | 35.445144 | 11.789856 |
| 921 | CE | 1265001 | 11/30/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 11 | 00001 | A RIEHL 11-17 | Membership Dues | 335 | 47.235 | 14% | 35.445144 | 11.789856 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 12.1 | 1.7061 | 14% | 1.28025744 | 0.42584256 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Membership Dues | 2.88 | 0.40608 | 14% | 0.304722432 | 0.101357568 |
| 426.4 | PV | 1977817 | 11/28/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00024264 | AA | 17 | 11 | 00001 | US CHAMBER OF COMMERCE | Membership Dues | 3750 | 528.75 | 14% | 396.774 | 131.976 |
| 930.2 | PV | 1977817 | 11/28/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 11 | 00001 | US CHAMBER OF COMMERCE | Membership Dues | 11250 | 1586.25 | 14% | 1190.322 | 395.928 |
| 930.2 | CE | 1268260 | 12/31/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 12 | 00001 | A SPILDE 12-17 | Membership Dues | 350 | 49.35 | 14% | 37.03224 | 12.31776 |
| 921 | CE | 1262373 | 10/31/2017 | 984.7811 | 984 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 10 | 00001 | A FONKERT 10-17 | Membership fee | 35 | 4.935 | 14% | 3.703224 | 1.231776 |
| 921 | CE | 1264635 | 11/30/2017 | 983.7811 | 983 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 11 | 00001 | S BARTH 11-17 | Membership Renewal | 140 | 19.74 | 14% | 14.812896 | 4.927104 |
| 930.2 | CE | 1244269 | 4/30/2017 | 980.7912 | 980 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 4 | 00001 | D KUNTZ 4-17 | Membership Renewal Fee | 1200 | 163.2 | 14% | 122.46528 | 40.73472 |
| 930.2 | PV | 1969125 | 10/12/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 10 | 00001 | MOTOR CARRIERS OF MONTANA | MEMDUES / ACCT 100905 | 250 | 35.25 | 14% | 26.4516 | 8.7984 |
| 921 | CE | 1256163 | 8/30/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 8 | 00001 | D GENORA 8-17 | Memebership Dues | 210 | 29.61 | 14% | 22.219344 | 7.390656 |
| 921 | CE | 1249562 | 6/26/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 6 | 00001 | K LIEPITZ 6-17 | MN Lawyer registration fee | 252 | 34.272 | 14% | 25.7177088 | 8.5542912 |
| 426.4 | JE | 1249287 | 6/20/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00024264 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | Montana Taxpayers Assoc | 540 | 73.44 | 14% | 55.109376 | 18.330624 |
| 426.4 | JE | 1249287 | 6/20/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00024264 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | Montana Taxpayers Assoc | 540 | 73.44 | 14% | 55.109376 | 18.330624 |
| 930.2 | JE | 1249287 | 6/20/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | Montana Taxpayers Assoc | -540 | -73.44 | 14% | -55.109376 | -18.330624 |
| 930.2 | JE | 1249287 | 6/20/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | Montana Taxpayers Assoc | -540 | -73.44 | 14% | -55.109376 | -18.330624 |
| 921 | CE | 1253632 | 7/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 7 | 00001 | R DORWART 7-17 | ND 2017-2018 CPA renewal | 85 | 11.985 | 14% | 8.993544 | 2.991456 |
| 921 | PV | 1977829 | 11/28/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 11 | 00001 | STATE BOARD OF LAW EXAMINERS | ND ATTORNEY LICENSE FEE | 1900 | 267.9 | 14% | 201.03216 | 66.86784 |
| 921 | CE | 1258820 | 9/29/2017 | 974.7811 | 974 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 9 | 00001 | A GRIFFIN 9-17 | ND CPA Society Registration | 140 | 19.74 | 14% | 14.812896 | 4.927104 |
| 921 | CE | 1253621 | 7/31/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 7 | 00001 | A RIEHL 7-17 | ND Report of Compliance fee | 25 | 3.525 | 14% | 2.64516 | 0.87984 |
| 921 | CE | 1253387 | 7/28/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 7 | 00001 | R WATSON 7-17 | ND State CPA Society Dues | 140 | 19.74 | 14% | 14.812896 | 4.927104 |
| 930.2 | CE | 1235634 | 1/31/2017 | 984.7912 | 984 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 1 | 00001 | L LUEDER 1-17 | NDNA Associate Membership | 300 | 40.8 | 14% | 30.61632 | 10.18368 |
| 921 | CE | 1253621 | 7/31/2017 | 980.7811 | 980 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 7 | 00001 | A RIEHL 7-17 | NY Attorney Registration fee | 375 | 52.875 | 14% | 39.6774 | 13.1976 |
| 921 | CE | 1256192 | 8/30/2017 | 762.7811 | 762 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020762 | AA | 17 | 8 | 00001 | S SENFTNER 8-17 | Organization Golf Outing | 175 | 16.5025 | 9% | 12.383476 | 4.119024 |
| 921 | CE | 1268020 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 12 | 00001 | A ROSS 12-17 | PHR certification | 250 | 35.25 | 14% | 26.4516 | 8.7984 |
| 921 | PV | 1954186 | 6/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 6 | 00001 | J HIRNING 6-17 | PHR Recertification | 150 | 20.4 | 14% | 15.30816 | 5.09184 |
| 921 | CE | 1244244 | 4/30/2017 | 973.7811 | 973 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 4 | 00001 | D GENORA 4-17 | Prof Member Dues | 225 | 30.6 | 14% | 22.96224 | 7.63776 |
| 921 | CE | 1246498 | 5/24/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 5 | 00001 | B STEFFES 5-17 | recertification fee | 150 | 20.4 | 14% | 15.30816 | 5.09184 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020047 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Refund dues- paid last mo. | -30.05 | -30.05 | 100% | -22.54952 | -7.50048 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020048 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Refund dues- paid last mo. | -20.98 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020060 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Refund dues- paid last mo. | -32.51 | 0 | 0% | 0 | 0 |
| n/a | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020061 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Refund dues- paid last mo. | -93.36 | 0 | 0% | 0 | 0 |
| 921 | CE | 1268108 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 12 | 00001 | B STEFFES 12-17 | Refund dues- paid last mo. | -12.1 | -1.7061 | 14% | -1.28025744 | -0.42584256 |
| 930.2 | CE | 1255710 | 8/23/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 8 | 00001 | R O''NEILL 8-17 | RENEWAL | 750 | 105.75 | 14% | 79.3548 | 26.3952 |
| 921 | CE | 1255701 | 8/23/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 8 | 00001 | R DORWART 8-17 | SHRM Membership | 199 | 28.059 | 14% | 21.0554736 | 7.0035264 |
| 921 | CE | 1265004 | 11/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 11 | 00001 | T SCHNEIDER 11-17 | SHRM Membership | 189 | 26.649 | 14% | 19.9974096 | 6.6515904 |
| 921 | CE | 1268020 | 12/31/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 12 | 00001 | A ROSS 12-17 | SHRM Membership | 209 | 29.469 | 14% | 22.1135376 | 7.3554624 |
| 426.4 | JE | 1249287 | 6/20/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00024264 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | The Chamber Inv 76069 | 166.67 | 22.66712 | 14% | 17.00940685 | 5.657713152 |
| 930.2 | JE | 1249287 | 6/20/2017 | 979.7912 | 979 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | The Chamber Inv 76069 | -166.67 | -22.66712 | 14% | -17.00940685 | -5.657713152 |
| 921 | PV | 1974048 | 10/31/2017 | 974.7811 | 974 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 10 | 00001 | S HERMAN 9-17 | Toastmaster Annual Dues | 98 | 13.818 | 14% | 10.3690272 | 3.4489728 |
| 921 | CE | 1253169 | 7/28/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 7 | 00001 | T SCHNEIDER 7-17 | TS-PHR Certification | 150 | 21.15 | 14% | 15.87096 | 5.27904 |
| 921 | PV | 1941645 | 3/31/2017 | 972.7811 | 972 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020972 | AA | 17 | 3 | 00001 | S WOTHE 3-17 | VMware certification Exam | 180 | 13.788 | 8% | 10.3465152 | 3.4414848 |
| 921 | CE | 1253920 | 7/31/2017 | 972.7811 | 972 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00020972 | AA | 17 | 7 | 00001 | S WOTHE 7-17 | VMware User Group | 180 | 14.058 | 8% | 10.5491232 | 3.5088768 |
| 921 | CE | 1244289 | 4/30/2017 | 970.7811 | 970 | 7811 | Professional/Organization Dues | Misc. Employee Expenses | Professional dues | 00029995 | AA | 17 | 4 | 00001 | A ROSS 4-17 | W@W membership | 265 | 36.04 | 14% | 27.044416 | 8.995584 |
| 426.4 | JE | 1249287 | 6/20/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00024264 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | Wyoming Tax Assoc #1815 | 160 | 21.76 | 14% | 16.328704 | 5.431296 |
| 930.2 | JE | 1249287 | 6/20/2017 | 973.7912 | 973 | 7912 | Company Organizational Dues | Misc. Other Expense & Credits | Organizational du | 00029995 | AA | 17 | 6 | 00001 | Correct PV's for Lobbying Exp | Wyoming Tax Assoc #1815 | -160 | -21.76 | 14% | -16.328704 | -5.431296 |
| | | | | | | | | | | | | | | | | | | 2940.93 | | | |

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Michael P. Parvinen

# EXHIBIT 800

October 2018

# EXHIBIT 800 – REPLY TESTIMONY

## TABLE OF CONTENTS

## I. INTRODUCTION

**Q. Are you the same Michael P. Parvinen that previously filed testimony in this case?**

A. Yes.

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

A. My reply testimony responds to the following issues or adjustments raised by Public Utility Commission of Oregon Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC):

- **Plant Additions.** My reply testimony describes the Company's budgeting process, provides updates regarding proposed plant additions, and addresses the adjustments proposed by Staff, CUB, and AWEC.
- **Decoupling.** My reply testimony responds to Staff's and CUB's proposed recommendations regarding the Company's decoupling mechanism and recommends that these concerns be addressed in the comprehensive review of the decoupling mechanism that will occur in September 2019 per the stipulation in Docket No. UG 287.
- **Rate Schedule 163 Redesign.** My reply testimony provides further explanation and support for the Company's proposal to convert Schedule 163 to a firm distribution service from interruptible service.

## II. PLANT ADDITIONS

**Updates to the Company's Initial Filing**

**Q. Does Cascade have any updates regarding the plant additions proposed for recovery in its initial filing?**

A. Yes. The Company provided the list of projects proposed for recovery in its initial filing, and the anticipated project costs, in Exhibit CNGC/305. An updated version of this project list—including the Company's current projections for project budgets, actual amounts spent for certain projects, and in-service dates—is provided as Exhibit CNGC/801.

**Q. What are the major changes reflected in the updated project list shown in Exhibit CNGC/801?**

A. The Company has removed projects that are not expected to be in service by December 31, 2018. The removed projects include:

- UG-Work Asset Management - $162,285.49;
- District Office Access Control Sys - $31,775.10;
- Turbine Prover - $31,512.50;
- UG-PCAD Annual Enhancements- $18,487.42;
- Intangibles – Software - $18,382.29; and
- GP TRAN. VEHICLE – INTERSTATE - $12,771.76.

Additionally, CNGC/801 includes updates to both budgeted and actual costs, based on the most current information available. Depending on the project, certain costs have increased, while costs for other projects have decreased. Some of the major updates include:

- Reducing the costs for the Madras project from $5,540,101.58 to $1,782,654.39;
- Reducing the costs for ERT Replacement 2018 from $3,485,554.13 to $2,857,903.72;
- Increasing project costs for SERV-GROWTH-OREGON from $1,417,460.32 to $2,514,325.08;
- Increasing project costs for MAIN-GROWTH-OREGON from $537,045.16 to $1,309,175.59; and

- Increasing project costs for MAIN-RELO-REPL-OREGON from $418,760.63 to $1,048,747.88

**Q. Has the Company proposed to add any projects that were not included in the Company's initial filing?**

A. Yes. The Company has proposed to add four projects that were not included in its direct case, totaling approximately $0.5 million of additional costs.[1] These projects include:

- Portable methane detectors - $185,972,000 - in service June 2018;
- Pendleton V-23 Replacement - $122,733 – in service August 2018;
- Family meter replacements - $93,953 – in service May 2018;
- UG GPS Based Leak Survey – Replacement - $95,824 – in service September 2018.

**Q. Why were these new projects not included in the Company's initial filing?**

A. Cascade's initial filing relied primarily on budget estimates, and these projects had not been included in the Company's budget process. The equipment for one project, the Portable Methane Detectors, was purchased in 2017, but programing of the units delayed the in-service date (and thus recording to Plant in Service) until June 2018.

The Pendleton V-23 Replacement project was the final step of a project to replace an old valve that had operational issues and was no longer in the optimal location, and included installing new pipe to circumvent the valve to be removed.

Late in 2017, Cascade discovered through routine and required meter testing that a family of meters was recording outside allowed parameters. Cascade completed the replacement of these meters by May 2018.

[1] Exhibit CNGC/801, Parvinen/1.

The UG GPS Based Leak Survey project was a system project to replace equipment that required manual notations of results. The new equipment produces leak survey data that can automatically load GPS coordinates and data into the Company's GIS system.

**Q. Are all of these projects complete as of the date of this testimony?**

A. Yes. As described above, all projects are currently in service and providing benefits to customers.

**Overview of Parties' Positions Regarding Plant Additions**

**Q. Please summarize the parties' testimony regarding the plant additions included in the Company's filing.**

A. Staff's positions include the following:

- Staff expresses some concern with the quality of the Company's documentation of its budgeting and project selection and approval process, though Staff does not propose a prudence adjustment for any of the projects.
- Staff does, however, propose adjustments for Work Asset Management, Bend Phase 7, Bend HP PH1, Madras – PH1, and Plant – ERT Replacement on the basis that these projects will not be in-service by the rate effective date or that costs may have changed from the Company's initial budget projections.

CUB's position is as follows:

- CUB proposes an adjustment for the Company's Power Equipment expense on the basis that the Company is trading in one-year-old equipment, which CUB claims artificially inflates rate base.

AWEC's positions include the following:

- AWEC proposes an adjustment for growth-related projects, arguing that Cascade has not reflected offsetting revenues related to growth.

- AWEC proposes disallowing the Madras Phase 1 project because it believes that the project will not be used and useful before the rate effective date.
- AWEC proposes an adjustment to reflect the impact of plant retirements on depreciation expense.

**Q. Please provide a brief summary of your responses to the positions taken by the parties.**

A. ***First,*** in response to Staff's concerns regarding the quality of the Company's data supporting its capital projects, Cascade has provided updated cost and schedule information. In addition, Cascade is exploring how it may provide more robust documentation of its budgeting and project selection processes.

***Second***, in response to CUB's concern regarding the Company's purchasing program for power equipment, Cascade agrees with removing a majority of the costs included in the proposal.

***Third,*** Cascade disagrees with AWEC's adjustment for growth-related projects because the Company has reflected growth-related revenues in its direct case, and additionally several of the projects that AWEC characterized as growth-related projects are in fact unrelated to growth.

***Fourth,*** regarding AWEC's adjustment for Madras Phase 1, Cascade believes that the project will be providing service to customers by December 31, 2018, and Cascade should be allowed to recover actual costs associated with the project.

***Finally,*** Cascade agrees with the principle underlying AWEC's adjustment for plant but has updated the calculation as it relates to the test year.

**Cascade's Documentation of its Budgeting and Project Selection and Approval Process**

**Q. Please summarize Staff's concern regarding the Company's documentation**

**supporting its plant additions.**

A. Staff expresses its view that the Company has provided a poor quality of documentation and is unconvinced that the Company has provided all studies and analysis supporting its capital additions.[2]

**Q. Please comment on the data that Cascade provided in discovery.**

A. Cascade provided all relevant available documentation to support its proposed plant additions in discovery—which included all data, studies, and analysis in the Company's possession. Cascade acknowledges, however, that in the future it could develop and provide more thorough documentation of the Company's budgeting and project selection and approval process.

**Q. Could you please describe the Company's current practices with respect to budgeting and project selection and approval?**

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

[2] Staff/200, Fox/13-15.

add appropriate overheads and approve the funding project. Blanket funding projects are used year after year to budget for high volume mass property work orders typically under $100,000 each.

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

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

**Q. Staff asserts that it expects improved documentation and responsiveness in**

**future rate cases.[3] Does Cascade plan to improve the documentation of its decision-making going forward?**

A. Yes. The Company is currently evaluating how it can develop and implement a more robust documentation system for its decision-making.

**Work Asset Management**

**Q. Please describe the Work Asset Management project.**

A. The Work Asset Management project refers to the implementation of the Maximo work management system, which will be used across all three of MDU's major utility brands. This system will be primarily used to link and access multiple programs for efficiency and accuracy.

**Q. What did Staff propose regarding the Work Asset Management project?**

A. Staff proposed removing the Work Asset Management project on the basis that the project will not be complete before the rate effective date, and thus costs incurred to date are not presently used for providing utility service to customers and should be removed from rate base.[4]

**Q. Do you agree that the Work Asset Management project will not be complete before the rate effective date?**

A. Yes, the Company agrees that this project will not be complete, and accordingly has removed it from the Company's request for recovery.

**Bend Phase 7**

**Q. Please explain why the Company is developing Phase 7 of the Bend Pipeline Replacement Project (Bend Phase 7).**

A. The core of the downtown Bend Intermediate Pressure (IP) Distribution System

[3] Staff/200, Fox/16.
[4] Staff/200, Fox/17.

consists of areas of 1930s pipe that was purchased by Cascade from the City of Bend. This pipe was used as a manufactured gas system prior to the arrival of natural gas to the Pacific Northwest and ownership by Cascade, and is referred to as Pre-CNG pipe in Cascade's system. Pre-CNG pipe is pipe that was constructed to distribute manufactured gas or natural gas prior to 1955, and these pipeline systems were installed, owned, operated, and maintained by other companies until Cascade purchased the pipeline systems in the late 1950s and the 1960s. Pre-CNG pipe tends to be bare or coal tar-wrapped steel pipe. The integrity of Pre-CNG pipe is concerning because it is at least 60 years old and had no, or inadequate, cathodic protection until the early 1970s, which means the pipe had a higher susceptibility to corrosion during the timeframe it was without cathodic protection. Pre-CNG pipe also has a higher missing value risk associated with the unknowns from purchasing the pipe from another company, and higher equipment risks due to age of the pipe and increased likelihood of failure.

**Q. Please describe the work the Company is performing in connection with Bend Phase 7.**

A. To address the risks associated with Pre-CNG pipe in the Bend area, the Company is systematically replacing this portion of its pipeline system. Bend Phase 7 includes two sections. Section 1 consisted of replacing 2,640 feet of main plus two services totaling 85 feet. Section 2 consisted of replacing 2,816 feet of main plus 2 services totaling 85 feet.

**Q. What is Staff's proposed adjustment regarding Bend Phase 7?**

A. Staff recommends a test year gross plant reduction of $433,000, which is the difference between the amount included in the rate case, $3.033 million, and the amount included in the Company's annual safety plan, $2.6 million.[5]

**Q. What is the basis for Staff's adjustment?**

A. Staff is concerned that the Company has not provided sufficient information about the project, and is also concerned about cost overruns, because the Company indicated that funds would be moved from the Madras project to the Bend project in its response to OPUC DR 266.[6]

**Q. How do you respond to Staff's concern that the Company provided inconsistent data regarding its cost estimates for Bend Phase 7?**

A. The Company's Safety Plan was filed with the Commission on May 21, 2018 and relied on data from the Company's 2018 approved capital budget dated November 2017. The initial rate case filing, on the other hand, was filed on May 31, 2018 and relied on information from a more current "working version" of the capital budget, which included updates anticipated since the earlier approved budget. Though the two documents were filed with the Commission close in time, different data was used. The "working version" of the capital budget includes investments that were made in previous years but not yet included in plant and service. Neither set of data is "wrong," as both were developed based on estimates available at a particular time. Importantly, the amount that Cascade proposes to include in rates will be based on actual costs of the projects that will be in-service by the end of December 2018.

As I explained above, the Company provided its initial estimates earlier in the year based on the data available at the time and has updated those estimates through discovery during the pendency of this case. As shown in Exhibit CNGC/801, Cascade's most recent estimate based on budgeted and actual data to date is

[5] Staff/200 Fox/17-18.
[6] Staff/200 Fox/17-18.

$2,610,021.13, which is approximately the same as the amount included in the Safety Plan.

**Q. Bend Phase 7 was scheduled to be in-service on September 18, 2018. Is the project now providing service to customers?**

A. Yes. The final costs should be invoiced and accounted for by the end of October.

**Q. What is your recommendation regarding Bend Phase 7?**

A. Based on the foregoing, this project is currently in service and actual final costs will be known by end of October to be included in the Company's surrebuttal filing, Cascade recommends inclusion of costs identified in Exhibit CNGC/801.

**Bend HP PH1**

**Q. Please explain why the Company is developing Phase 1 of the Bend high pressure pipeline replacement project (Bend HP PH1).**

A. The 6" Bend HP Line was installed in 1961 from the Bend Gate Station on Ward Rd, following Bear Creek Rd., until it terminates west of Bend Parkway and Highway 97 in Bend.

The Bend HP Line has been found to have many areas with minimal or no cover. The Company's Bend District subject matter experts believe the pipe is in good condition overall and has not experienced many corrosion or coating issues. However, the concern with this pipe is the minimal depth of cover and the potential for being exposed in some areas. Pipeline with minimal cover or possible exposure is at increased risk of the pipe being damaged by excavation or from outside forces. This line currently has a high-risk score in DIMP and presents a safety issue with not having sufficient cover on a HP line that operates at a maximum allowable operating pressures (MAOP) of 300 psig.

**Q. Please describe the work the Company is performing in connection with Bend**

**HP PH1.**

A. To address the risks I described above, the Company is replacing the 6" Bend HP line. Phase 1 of at least 6 phases was complete during 2018.

**Q. Please describe Staff's proposed adjustment regarding Bend HP PH1.**

A. Staff recommends a test year rate gross plant reduction of $90,000, which is the difference between the amount included in the rate case, $1.790 million, and the amount included in the Company's annual safety plan, $1.7 million.[7]

**Q. What is Staff's rationale for its adjustment?**

A. Similar to its proposed adjustment for Bend Phase 7, Staff proposes its adjustment based on concern that the project cost data for Bend HP PH1 is insufficient. Specifically, Staff points out that Cascade provided different cost information for the project in different documents and responses to data requests.[8]

**Q. How do you respond to Staff's concern that the Company provided inconsistent data regarding its cost estimates for Bend HP PH1?**

A. The Company provided its initial estimates earlier in the year based on the data available at the time, and has updated those estimates through discovery during the pendency of this case. As shown in Exhibit CNGC/801, Cascade's most recent estimate is based on actual costs through August 2018 with estimated costs for the remaining four months of 2018 at $1,968,776.86, which results in a total that is slightly higher than Cascade's initial forecast.

**Q. Bend HP PH1 was scheduled to be in-service on September 14, 2018. Is the project now providing service to customers?**

A. There have been construction delays, and the project is not yet in service. However,

[7] Staff/200, Fox/19.
[8] Staff/200, Fox/19.

based on the progress made to date, the Company anticipates that the project will be in-service in November 2018—well before the rate effective date in this case.

**Q. What is your recommendation regarding Bend HP PH1?**

A. Based on the foregoing Cascade recommends inclusion of the total estimated costs shown in Exhibit CNGC/801 and the project will be in-service by the time Cascade submits surrebuttal testimony.

**Madras PH1**

**Q. Please explain why the Company is developing Phase 1 of the Madras Pipeline Replacement project (Madras PH1) and describe the project.**

A. The 4" Madras HP Line (Madras Line) was installed in 1962 from the Madras Gate Station, east of Madras near NE Loucks Rd. and NE Hereford Rd., and runs through the Crooked River National Grassland, until it terminates in Madras.

The Madras Line—which represents the single feed into that area—presents multiple integrity concerns, which include:

- A history of multiple seam leaks, resulting in multiple leak repairs.
- Two electrically shorted casings.
- Poor weld quality for welds that have been exposed.
- Shallow depth of cover in areas.
- Poor backfill and trench conditions. Pipe was installed in rock with no padding and suitable backfill material.
- Insufficient material and construction records.

With the multiple integrity concerns that have been identified on this pipeline, Cascade began a multiple year project in 2017 to replace the existing 4" Madras Line, installed in 1962, with a new 6" steel pipeline. Phase 1 was completed in 2018, Phase 2 of this project is planned for 2019, and the final phase, Phase 3, is planned for 2020. By replacing this single feed with known integrity concerns, this project increases the safety and reliability in Madras.

**Q. Do Staff and AWEC propose adjustments to Madras PH1?**

A. Staff notes that Madras PH1 has been reduced in scope from the Company's initial filing, and recommends a test year rate gross plant reduction of $3.437 million to reflect the revised scope.[9] Staff's adjustment is based on the difference between the cost initially included in the rate case, $5.540 million, and the Company's revised budget projections of $2.103 million provided in response to OPUC DR 265, which reflects the reduced project scope.[10] AWEC also points out that the project scope has been reduced, but recommends disallowing Madras PH1 in its entirety stating concerns that it will not be used and useful in time to be reviewed in this case.[11]

**Q. Are Staff and AWEC correct that the project scope has been reduced?**

A. Yes. Cascade originally planned on completing two phases of the overall project in 2018. Cascade revised the scope to include only phase one in 2018 and each additional phase to be completed in each of the following years. Based on the Company's current projections, as shown in Exhibit CNGC/801, the revised total costs for phase one of the project is $1,782,654.39.

**Q. What reason does AWEC give for its concern that the project will not be used and useful in time to be reviewed in this case?**

A. AWEC claims that Cascade has not considered environmental or cultural contingencies that could delay the project, and notes that this has been problematic for other projects when not properly addressed in the planning and permitting phase

[9] Staff/200, Fox/19.
[10] Staff/200, Fox/19.
[11] AWEC/100, Mullins/30.

of the project.[12] AWEC also expresses concern about weather conditions in Madras in January, and expresses doubt that the project can be completed before the end of the current construction cycle.[13]

**Q. How do you respond to AWEC's concerns about environmental or cultural contingencies?**

A. AWEC's concerns about environmental and cultural contingencies are completely unfounded. AWEC cites no evidence to suggest that there may be environmental or cultural issues that were not properly addressed in permitting the project. Importantly, permitting for the project is complete, and construction for the project is also complete, and there were no environmental or cultural resource issues.

**Q. How do you respond to AWEC's concerns about the weather conditions in Madras in January?**

A. No phase of the Madras project will take place in January of any year. Moreover, the potential impacts of weather conditions in January on the construction schedule for Madras PH1 are irrelevant, as the project was completed at the end of September and is currently providing service to customers.

**Q. Based on the foregoing, what is the Company's recommendation with respect to Madras PH1?**

A. Because Madras PH1 is in service well before the rate effective date, and parties have had an opportunity to review the project and can review final projects costs, the Company proposes to include Madras PH1 based on the reduced scope and updated estimated amount of $1,782,654.39.

[12] AWEC/100, Mullins/30.
[13] AWEC/100, Mullins/30.

**ERT Replacement**

**Q. Please describe the ERT Replacement project.**

A. The ERT replacement project is a system wide, multi-year initiative, beginning in Bend, Oregon to replace the electronic recording device attached to the meter that sends electronically the metered value which is then used to determine monthly usage for billing purposes. The existing ERTs have reached the end of their expected lives, and therefore need to be replaced. The new ERTs will simply replace the existing ERT.

**Q. Do Staff and AWEC propose adjustments regarding the ERT Replacement?**

A. Yes. Staff recommends a test year rate gross plant reduction of $1.095 million, on the basis that per the Company's response to OPUC DR 267, only a portion of the ERTs are being replaced in 2018.[14] While AWEC does not provide testimony specifically addressing the ERTs, AWEC includes the ERTs in its adjustment for "growth projects" discussed below.[15] That adjustment would result in a wholesale disallowance of ERT Replacement.

**Q. How did Staff calculate its proposed adjustment?**

A. The cost for ERT Replacement proposed by the Company in its direct case was $3.486 million. Per the Company's response to OPUC DR No. 267, 36,500 of 53,000 total ERTs will be replaced in 2018, and the unit cost is $49-$82.[16] Staff used the midpoint unit cost of $65.50 to determine that the value of 36,500 installed units is $2.391 million, and proposed that cost of the uninstalled units should be removed from the rate case in the amount of $1.095 million.[17]

**Q. Is Staff correct that the costs for the ERT Replacement should be adjusted?**

[14] Staff/200, Fox/20.
[15] AWEC/102, Revenue Requirement, Mullins workpapers —Excel.xlsx, tab "A10 Remove Growth Projects".
[16] Staff/200, Fox/20.
[17] Staff/200, Fox/20.

A. No. ERTs are a component of the meter and as such are booked to FERC Account 381, Meters. The definition of Account 381 is:

> This account shall include the cost installed of meter or devices and appurtenances thereto, for the use in measuring gas delivered to users, whether actually in service or **held in reserve**. *(emphasis added)*

As these ERTs will be installed in 2019 it is appropriate to include the full amount in Plant in Service.

**Q. Has Cascade updated the estimated cost of the ERTS?**

A. Yes. Cascade was able to find a more moderately priced vendor which brings down the total cost of the ERTs. Accordingly, Cascade has updated this cost based on actual ERTs purchased through August 2018 plus estimated purchases through the remaining four months of 2018. Cascade originally projected $3,485,664.13 in costs and the most current estimated amount is $2,857,903.72.

**Q. Please explain AWEC's proposal for removal of the ERT Replacement expenses in its adjustment for "growth projects."**

A. AWEC proposed an adjustment to remove "growth projects," reasoning that if a project is being built to accommodate growth, there will be additional revenues as a result of the new plant addition, which will be an offset to the cost of the new plant addition. I discuss AWEC's growth-related adjustment in greater detail later in my testimony.

**Q. Is ERT Replacement appropriately characterized as growth-related?**

A. No. ERT Replacement is unrelated to growth. Instead, the Company is replacing a component of existing meters, the ERT, that has reached the end of its usable life. I will discuss this issue further in response to AWEC's growth-related projects adjustment, below.

**Q. What is your recommendation regarding ERT Replacement?**

A. Based on the foregoing, Cascade agrees that it is appropriate to adjust the proposed costs for ERT Replacement and has updated its proposed costs for ERT Replacement to reflect $2,857,903.72.

**Power Equipment**

**Q. Please describe the proposed rate base addition for the Company's purchases of power equipment that was included in the Company's initial filing.**

A. The Company included $730,721.28 in its initial filing for the purchase of power equipment. The original amount failed to account for the trade-in value, rebates, and credits associated with the purchasing program.

**Q. Please describe the Company's program for purchasing power equipment.**

A. The Company is currently in a program with Caterpillar (CAT) for large earth moving type equipment in which the Company can trade in year old models for new equipment with discounts and rebates that amount to approximately eighty percent of the purchase price.

**Q. Does CUB propose an adjustment regarding the level of rate base for power equipment?**

A. Yes. CUB states that the Company is artificially inflating rate base through its trade-in program, and also notes that per generally accepted accounting principles (GAAP) requirements, a purchase must have a useful life greater than a year to be considered a capital expense.[18] Accordingly, CUB proposes to disallow the power equipment purchases, and per CUB, the rate base impact of this disallowance would be $730,721.28 and the revenue requirement impact would be $81,952.[19]

**Q. How do you respond to CUB's claim that the Company is artificially inflating rate**

[18] CUB/100, Gehrke/5-6.
[19] CUB/100, Gehrke/5-6.

**base?**

A. It was certainly not the intent of the Company to overstate rate base. However, the accounting for the trade-in, discounts, and, rebates on the purchased equipment was not captured in the funding project for the purchases, so those offsets to the purchase price were not reflected in the Company's proposed increase to its rate base for the power equipment.

**Q. Is the Company's treatment of power equipment as a capital expenditure consistent with GAAP?**

A. Yes. However, as stated above the full impact of the transaction was not reflected in the case. The equipment itself does have an extended life so is properly classified as Plant in Service versus a lease type expense. The Company is unsure about how long this program will continue to be offered. In the meantime, customers are receiving the benefit of new equipment at a very low price. If the program were to end today, these power equipment assets will have a life of fifteen years as determined in the Company's last depreciation study.

**Q. What is your recommendation regarding power equipment?**

A. Based on the foregoing, Cascade is proposing to utilize the net purchase price recognizing the actual purchase price, trade-in amount, discounts, and rebates, so only the net difference is included as an increase in rate base. Exhibit CNGC/801 shows the actual purchase price of the equipment less the trade-in value, discounts, and rebates. In total the net purchase price to be included in rate base is $93,940.55.

**Growth-Related Projects**

**Q. Did the Company include growth-related projects in proposed plant additions?**

A. Yes. The Company's original filing included its budgeted level of costs for mains, service, meters, and regulators associated with growth during 2018. The growth projects are handled as blanket work orders, meaning that as customers are added, the costs of adding the customer are recorded to the blanket work orders.

**Q. Did the Company also include an adjustment to revenues to reflect forecasted growth?**

A. Yes. The increase in revenues for customer growth is derived from the Company's Integrated Resource Plan (IRP).

**Q. Did AWEC propose an adjustment related to growth?**

A. Yes. AWEC proposed to remove $6,455,388 in forecast capital for growth-related projects.[20] The revenue requirement impact of this adjustment is $1,399,553.[21]

**Q. Did AWEC also propose to remove the growth-related revenues included in the Company's case?**

A. No.

**Q. Why did AWEC propose to remove growth-related projects?**

A. AWEC contends that if a project is being built to accommodate growth, there will be additional revenues as a result of the new plant addition, which will be an offset to the cost of the new plant addition.[22] AWEC further reasons that because Cascade uses end-of-period rate base, the new plant additions are assumed to be in rate base for the entire year, but Cascade did not make a similar assumption with respect to revenues derived from the new plant additions, resulting in a mismatch between costs and revenues.[23]

**Q. Can you please describe how Cascade has reflected the additional revenues associated with growth-related projects?**

[20] AWEC/100, Mullins/28.
[21] AWEC/100, Mullins/29.
[22] AWEC/100, Mullins/29.
[23] AWEC/100, Mullins/29.

A. The Company projected an increase of 422 new customers over the 2017 levels. Exhibit CNGC/401 shows the increase in customers and calculations of associated revenue. The assumption is based on customers in place for the entire test year.

**Q. Has Cascade reviewed the projects that AWEC characterized as growth-related projects?**

A. Yes. These projects were identified in AWEC's workpapers at AWEC 102- Revenue Requirement analysis.

**Q. Does Cascade agree that all of these projects are related to growth?**

A. No. AWEC included five projects that are not related to growth. The five projects are the ERT Replacement Project, the Bend River Mall Main Replacement project, the STD M&R Relocate/Replace Project, and two Transportation Vehicle projects (one dedicated to Oregon and one Interstate). There are no additional revenues associated with these replacement projects. Had AWEC not included the investment associated with these five projects, the revenue requirement associated with growth projects would be $887,000. The revenue added for new customers at weather normalized loads total $1,152,830, as shown in Exhibit CNGC/304, column (g).

**Q. Did AWEC fail to identify any projects that are growth-related?**

A. Yes, there are two projects related to growth that were not included in AWEC's calculation. These are the Pre-Cap Meter-Growth-Interstate project and the STD M&R Growth project. It appears that AWEC may have inadvertently missed these two projects and picked up two of the non-growth projects identified above.

**Q. What is your recommendation regarding AWEC's adjustment for growth-related projects?**

A. Based on the foregoing analysis and identification of AWEC's inappropriate assumptions, the Company continues to recommend that the growth-related projects were appropriately included in the Company's original case, and AWEC's proposed adjustment should be rejected. However, simply correcting the AWEC adjustment to actual growth-related projects based on Exhibit CNGC/305, the plant investment would be $3,033,699.64 and associated revenue requirement would be $996,000. This revenue requirement is less than the revenue increase projected by the company of $1,152,830, as shown in Exhibit CNGC/304, column (g) thus demonstrating that Cascade has appropriately reflected revenues for these projects that offset the associated costs.

**Q. Are there any other corrections to be made to the Company's original proposed adjustment?**

A. Yes. In the original filing Cascade had calculated the impact on property tax expense for the plant additions in its work papers but had failed to include the amount in its proposed adjustment. The property tax expense associated with the revised plant additions is $320,369.74.

**Q. What is the impact of the plant related adjustments as compared to the Company's original request?**

A. The Company originally requested an increase in Plant in Service of $24,552,054.84 and based on the testimony above the revised request is a reduction in plant of $2,695,748.26 for a total of $21,856,306.58. The test year revenue requirement is increased by $8,070.95. The inclusion of the associated property tax offset the impact of the reduction in investment.

**Plant Retirements**

**Q. Did AWEC propose an adjustment related to plant retirements?**

A. Yes. AWEC proposed an adjustment to account for the effects of plant retirement on accumulated depreciation, resulting in a proposed $168,037 reduction to revenue requirement.[24]

**Q. What is the basis for AWEC's plant retirements adjustment?**

A. AWEC argues that Cascade considers incremental depreciation, as well as plant additions, but does not consider the effects of forecast plant retirements.[25] AWEC explains that while plant retirements have no impact on rate base, since they are applied as a reduction to both gross plant and accumulated reserve, retirements do have an impact on depreciation expenses.[26]

**Q. Do you agree with the basis for AWEC's adjustment?**

A. Yes.

**Q. How did AWEC calculate its proposed adjustment?**

A. AWEC used the level of retirements for 2016 that was reported in response to Staff Data Request 130, $5,560,629, and multiplied that by the 3.04% composite depreciation rate to determine the effects of these retirements in the test period. After considering the effects on accumulated depreciation, the impact of this adjustment is a $168,037 reduction to revenue requirement.

**Q. Do you agree with AWEC's calculation of its adjustment?**

A. No. AWEC assumes that the 2016 plant retirements are reflective of the 2018 test year retirements and the composite depreciation rate from Cascade's last depreciation study is also reflective of the depreciation rate to apply to the 2016 retirements. Both assumptions should be revised to properly match the retirements associated with the 2018 investments.

**Q. Has Cascade developed an alternative calculation for this adjustment?**

A. Yes. Cascade has developed an adjustment based on 2018 retirements to date, as

[24] AWEC/100, Mullins/31.
[25] AWEC/100, Mullins/31.
[26] AWEC/100, Mullins/31.

of August 31, 2018, and projected retirements through the last four months of the year. Cascade then applied the effective depreciation rate based on actual 2018 investments of 2.652067. Exhibit CNGC Exhibit/802, provides the calculation of the impact based on the corresponding 2018 investments. The depreciation rate is the same rate applied to the 2018 investments which corresponds to the actual associated retirement.

**Q. What is your recommendation regarding AWEC's adjustment for plant retirements?**

A. Based on the foregoing the revised depreciation expense impact is $115,342. The test year revenue requirement impact is $119,047.

## III. DECOUPLING MECHANISM

**Q. Please describe Cascade's Conservation Alliance Plan (CAP).**

A. The CAP is a comprehensive mechanism that encourages conservation and protects the Company from the adverse earnings impact from loss of load associated with weather and conservation. The Decoupling component of the CAP maintains a margin per customer recovery despite the effects of weather and conservation. The Public Purpose Charge (PPC) component collects funds from customers receiving service under Schedules 101 (residential) and 104 (commercial) to provide funding for the conservation measures, as well as low-income conservation and bill assistance. The conservation program is administered by the Energy Trust of Oregon (ETO).

**Q. Would you please describe the distinction between the terms CAP and Decoupling?**

A. These terms are usually used synonymously. However, there is a distinction with regard to Cascade's mechanism; the CAP refers to the complete mechanism including Decoupling, conservation programs, PPC, and the true-up mechanism. Decoupling is a major component within the CAP. The Decoupling component in particular breaks the link between revenues and usage.

**Q. Please provide a brief history of the current CAP, including the Decoupling mechanism, from its inception in 2006.**

A. Cascade first applied for the CAP on October 17, 2005, in docket UG 167. The parties held several workshops and settlement discussions, which ultimately led to a settlement filed on April 14, 2006. The Commission approved the settlement by Order No. 06-191, with the tariff sheets to become effective May 1, 2006.

In addition to recommending approval of the CAP, some of the key elements of the settlement were:

- A termination date of September 30, 2010, prior to which Cascade would sponsor an independent evaluation of the CAP.
- Establishment of the public purpose charge rate to collect funds from customers receiving service under Schedules 101 and 104 to provide funding for conservation programs administered by the ETO, including a portion of which to be distributed to community service agencies to administer for low-income conservation and bill assistance programs.
- Established that, in addition to the public purpose charge, the Company provide funding for additional conservation measures in the amount of 0.75 percent of current revenues from Schedules 101 and 104, but no less than $500,000 per year.
- Established Service Quality Measures.
- Established an Earnings Sharing Mechanism.
- Agreement that the Company would file a general rate case in the first quarter of 2008 if requested by the Commission.

**Q. Have any changes been made to the CAP since it was approved?**

A. Yes. On June 5, 2007, the Commission entered Order No. 07-221, approving a settlement and authorizing the acquisition of Cascade by MDU Resources, which included modifications to the CAP. Also, on June 5, 2007, the Commission entered Order No. 07-220 approving a settlement resolving the Staff investigation into Cascade's earnings. The following changes were made to the existing CAP:

- Extended the termination date to September 30, 2012, subject to changes resulting from the independent evaluation.
- Confirmed that the 0.75 percent of current revenue provided by Cascade for additional conservation measures is considered an above-the-line expense item for ratemaking and revenue-sharing purposes.[27]
- Adjusted the equity rate for Earnings Sharing. (This component was later modified per Commission order in docket UM 1286.)
- Removed the rights of settling parties to request the Commission to require Cascade to file a 2008 general rate case.

**Q. Were there any additional changes?**

A. Yes. In Order No. 13-079, issued in docket UG 224, the Commission accepted a settlement to modify the expiration date of the CAP to December 31, 2015, and required Cascade to file a general rate case by March 31, 2015.

In docket UG 287, the parties agreed to continue Cascade's current decoupling mechanism.[28] They further agreed that Staff and CUB would organize a decoupling

[27] *In the Matter of Pub. Util. Comm'n of Or. Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas*, Docket No. UG 173, Order No. 07-220, App. A at 3 (June 5, 2007) ("The parties agree that the public purposes funding provided by Cascade under paragraph 10 of the UG 167 Stipulation, or any other amounts for such purposes as may be required in the future, shall be reflected as an operating expense for ratemaking and revenue sharing purposes.").
[28] *In the Matter of Cascade Natural Gas Corporation, Request for a Gen. Rate Revision*, Docket No. UG 287, Order No. 15-412 at 5 (Dec. 28, 2015).

workshop for September 2016 to explore whether and how Cascade may implement a real-time weather adjustment, and they agreed to initiate full review of the mechanism on September 30, 2019, with any proposed changes to be effective January 1, 2020.

**Q. Have any parties recommended changes to Decoupling in this case?**

A. Yes. CUB recommends that the Company "move to a real-time recovery of the weather[-]related adjustment component of decoupling."[29] Under CUB's proposal, the "real-time weather decoupling mechanism would adjust for weather in each billing cycle" so that "when a billing month is warmer than normal, customers pay more to cover fixed costs, but have lower bills due to less gas consumption."[30]

**Q. How do you respond to CUB's recommendation?**

A. As an initial matter, the Company recommends that any potential changes to Decoupling occur in the context of the broader review of the entire mechanism that will occur next year. CUB's proposal would constitute a significant change to the mechanism and Cascade believes such a change should not be made in isolation.

Second, CUB's proposal raises a serious policy question that must be addressed before implementation.

**Q. Please describe the policy issue raised by CUB's proposal.**

A. CUB recommends that Cascade make monthly adjustments to customer bills to reflect the impact of weather changes occurring in that month. This approach differs from the current mechanism where the customer rate change occurs in the following year after the annual review of the Decoupling deferral balance and only after the Commission approves the rate change. Under CUB's approach, Cascade would change customer

[29] CUB/100, Gehrke/13.
[30] CUB/100, Gehrke/13.

rates on a monthly basis. Given that the rate change would be made in "real time," however, there would be no opportunity for the Commission to review and approve each monthly rate change. Although Cascade is confident that it can implement such a mechanism and appropriately perform the monthly rate adjustments if the Commission approves a real-time adjustment, Cascade believes that the lack of Commission approval of each monthly rate change is poor policy. For example, if the monthly rate change is disputed, for whatever reason, it is unclear how or if the Commission can address the dispute and provide an appropriate remedy, if one is required.

**Q. CUB claims that the under the current mechanism, "[i]f Cascade's service territory experiences a frigid winter followed by a mild winter, the current CAP mechanism could exacerbate winter heating bills for ratepayers" and that CUB's proposal "is in the public interest because it insulates ratepayers from seasonal bill shock while enabling the Company to be adequately compensated."[31] Is this a reason to adopt monthly price changes?**

A. No. CUB's proposal appears to be a solution in search of a problem. In the twelve years that Cascade has implemented Decoupling, the Company has received no customer complaints about the annual delay built into the mechanism. Moreover, while CUB's proposal may mitigate "seasonal bill shock," it replaces that with "monthly bill shock." It is not clear that customers would prefer that approach.

**Q. Are there any practical concerns over implementing CUB's proposal?**

A. Yes. Although Cascade's current billing system can accommodate CUB's proposal, there is a cost associated with modifying the system to allow monthly rate changes.

[31] CUB/100, Gehrke/13-14.

The Company estimates that it will cost approximately $500,000 initially and approximately $125,000 annually to operate the mechanism.

**Q. CUB also claims that the weather component of Decoupling may be illegal because ORS 757.259 "does not authorize the use of deferred accounting for weather decoupling programs" and that "[u]sing a real-time decoupling mechanism would avoid the use of a deferral for weather decoupling."[32] How do you respond to this concern?**

A. First, the Company does not believe that deferring the weather-related aspect of Decoupling is prohibited by ORS 757.259, but will address that issue in briefing.

Second, CUB's proposal for "real-time" Decoupling would not avoid the need for a deferral—it would just shorten the deferral period from a year to a month. So instead of one annual deferral to track the annual Decoupling balance, Cascade would have to implement 12 monthly deferrals.

**Q. Why would CUB's proposal not obviate the need for deferrals?**

A. As I understand CUB's proposal, at the end of each billing cycle, the Company would adjust each customer's bill to reflect the weather-related impact of decoupling based on the actual weather that occurred over the billing cycle that just ended. But this is still retroactive ratemaking because the ultimate amount a customer pays is determined *after* the customer consumes the gas. In other words, the tariffed rate at the beginning of the billing cycle is not the rate the customer will actually pay because of the weather-related adjustment that will occur at the end of the billing cycle. Thus, to the extent CUB believes that weather-related decoupling is illegal, its proposal does not solve the problem, it just changes the time horizon over which the illegality occurs. Again, Cascade does not believe there is anything illegal about weather-related

[32] CUB/100, Gehrke/14-15.

decoupling, but if CUB is correct, then their proposal suffers from the same flaw as the current mechanism.

**Q. Are there any other concerns about CUB's proposal?**

A. Yes. As I understand CUB's proposed mechanism, a customer's monthly bill would be adjusted each month based on normal usage. There appears to be a fundamental flaw in that the mechanism would discourage conservation. Also, those customers that have implemented conservation measures in the last several years would be adversely impacted.

**Q. Please elaborate how the CUB proposed mechanism would discourage conservation.**

A. As I understand the mechanism, a customer's actual monthly usage is adjusted to a weather normal amount on a more real-time basis. Therefore, during very cold months a customer would be inclined to simply turn up the heat to stay comfortable knowing they will only be paying based on normal weather. This is counter to the message that customers should try to reduce usage during colder events to help keep their bill lower.

**Q. Under CUB's proposal, would customers be penalized for installing high efficiency equipment and other conservation measures?**

A. Normal usage is calculated based on averages determined from past usage. On a customer class basis this works just fine. However, on an individual customer basis a customer that has taken measures to reduce usage will be billed based on past usage which would be higher than the going forward actual usage. So, even if the month was normal, a customer with usage below the calculated average would pay more thus eliminating the impact of the conservation measures taken.

**Q. Do any other parties address Decoupling?**

A. Yes. Staff recommends the addition of non-linear weather effects to Decoupling and an adjustment for new customers.[33] Staff, however, does not recommend either change in this case and instead recommends that these issues be addressed during the full review of Decoupling in 2019.[34]

**Q. How do you respond to Staff's recommendations?**

A. While Cascade has not yet taken a position on Staff's recommendations, it agrees with Staff that any modifications to Decoupling should be addressed during the holistic Decoupling review that will occur next year.

## IV. RATE SCHEDULE 163 REDESIGN

**Q. Please describe Cascade's proposal for redesigning rate schedule 163 (Schedule 163).**

A. Cascade is proposing to redesign Schedule 163 from an interruptible service schedule to a firm service.

**Q. Why is Cascade making this change?**

A. Cascade is simply proposing to organize the rate structure and to match the level of service customers receive.

**Q. Please elaborate on how Cascade is proposing to match the rate design with the actual service provided to customers.**

A. The current Schedule 163 is characterized as an interruptible service and, therefore, customers on that schedule do not pay for the capacity on Cascade's distribution system. This would be perfectly acceptable if the customers were receiving a truly interruptible service. However, these customers have never been interrupted during the past 10 years (or in some cases, 15 years). Given that these customers have not

[33] Staff/400, Gibbens/13.
[34] Staff/400, Gibbens/13.

been interrupted, they are actually receiving a firm service and should be paying for that service.

**Q. Why have these customers never been interrupted?**

A. For the most part, the Schedule 163 customers do not appear to be on the most constrained laterals, and accordingly interrupting these customers would not have an impact during peak events. Thus, there is virtually no benefit to the Company or core customers from interrupting these customers.

**Q. Can you provide an example explaining why interrupting the Company's transportation customers would not have an impact during a peak event?**

A. An example would be the Vale line in the Eastern Oregon District, which has the potential of having pressure problems during an extreme peak event. However, there has not been any need to interrupt any customers on the Vale line; and importantly, the last customer on the line is a transportation customer who does not operate during peak times thus there is no load to interrupt.

**Q. Is there any other reason why these customers should be considered and pay for a firm service?**

A. Distribution planning is an important element of properly assessing and planning for system needs. As such it is appropriate to classify this class of customers as firm instead of interruptible.

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

A. Yes it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Michael P. Parvinen

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**2018 Plant Additions**
**CNGC/801**

**October 2018**

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

| Line No. | Function | Funding Project | Description | Account No. | Actual or Estimated In Service Date | | 2018 Total - Figures exported from "Power Plan" the company's budget and plant accounting software |
|---|---|---|---|---|---|---|---|
| 1 | Gas Intangible | FP-101209 | INTANGIBLES - SOFTWARE | 303.00 | | | 0.00 |
| 2 | Gas Intangible | FP-101472 | UG-PIM Installation | 303.00 | 12/31/2018 | Multi Phase | 20,810.32 |
| 3 | Gas Intangible | FP-101480 | UG-Work Asset Management | 303.00 | | | 0.00 |
| 4 | Gas Intangible | FP-200064 | UG-Customer Self-Service Web/IVR | 303.00 | 10/1/2019 | 2018 Phase | 38,040.33 |
| 5 | Gas Intangible | FP-200663 | UG-GIS Enhancements | 303.00 | 12/1/2019 | 2018 Phase | 56,791.15 |
| 6 | Gas Intangible | FP-315865 | UG - ThoughtSpot Implementation Prj | 303.00 | 12/31/2018 | Multi Phase | 21,491.33 |
| 7 | Gas Intangible | FP-316269 | UG - JDE Weblogic - CNGC | 303.00 | 11/30/2018 | | 5,302.14 |
| 8 | Gas Intangible | FP-316289 | UG - PowerPlan Lease - CNGC | 303.00 | 12/1/2018 | | 11,716.50 |
| 9 | Gas Intangible | FP-316361 | UG-GAS SCADA System Enhancements | 303.00 | 12/31/2018 | | 10,125.62 |
| 10 | Gas Intangible | FP-316447 | UG-PragmaFIELD Implementation | 303.00 | 10/15/2018 | | 19,759.47 |
| | Gas Intangible | FP-101481 | UG-GPS Based Leak Survey - Replac | 303.00 | 9/30/2018 | | 95,823.51 |
| 11 | Gas Intangible | FP-316451 | UG-PCAD Annual Enhancements | 303.00 | | | 0.00 |
| 29 | | | **Total Intangible Plant** | | | | 279,860.37 |
| 30 | RESULTS OF OPERATIONS SUMMARY SHEET | | | | | | |
| 31 | Gas Distribution | FP-101170 | MAIN-GROWTH-OREGON | 376.00 | 12/31/2018 | | 1,309,175.59 |
| 32 | Gas Distribution | FP-200688 | Bend Pipe Replacement Phase 7 | 376.00 | 10/15/2018 | Multi Phase | 1,610,267.14 |
| 33 | Gas Distribution | FP-303142 | Pendleton Pipe Replacement Phase 2 | 376.00 | 11/30/2018 | Multi Phase | 2,281,422.26 |
| 34 | Gas Distribution | FP-316697 | RP; 4" ST; Bend; 2,500' PH 7 Sec 1 | 376.00 | 6/30/2018 | | 999,753.99 |
| 35 | Gas Distribution | FP-101171 | MAIN-REINFORCE-OREGON | 376.00 | 12/31/2018 | | 64,773.25 |
| 36 | Gas Distribution | FP-101172 | MAIN-RELO-REPL-OREGON | 376.00 | 12/31/2018 | | 1,048,747.88 |
| 37 | Gas Distribution | FP-200689 | RPL; 6" HP, BEND HP PH1 | 376.00 | 12/31/2018 | Multi Phase | 1,968,776.86 |
| 38 | Gas Distribution | FP-306989 | UMATILLA 2" REINFORCEMENT | 376.00 | 12/31/2018 | | 982,952.21 |
| 39 | Gas Distribution | FP-306997 | RPL; 4" HP, MADRAS PH1 | 376.00 | 12/31/2018 | Multi Phase | 1,782,654.39 |
| 40 | Gas Distribution | FP-316479 | Bend River Mall Main RPL Bend | 376.00 | 12/2/2018 | | 183,474.05 |
| 41 | Gas Distribution | FP-302370 | GB - GROUNDBED OREGON | 376.00 | 12/31/2018 | | 302,961.19 |
| 42 | Gas Distribution | FP-316430 | RP; 2" BRIDGE XING, ATHENA | 376.00 | 11/30/2018 | | 11,936.14 |
| 43 | Gas Distribution | FP-316478 | 27th St Bore Canal Bend | 376.00 | 2/2/2018 | | 186,917.91 |
| 44 | Gas Distribution | FP-316480 | Ward Rd Canal Bore | 376.00 | 2/2/2018 | | 114,961.37 |
| | Gas Distribution | FP-302714 | Pendleton V-23 replacement | 376.00 | 8/31/2018 | | 122,733.43 |
| | Gas Distribution | FP-302640 | 6" Pilot Rock HP Replacement | 376.00 | 6/30/2018 | | 45,286.18 |
| 45 | Gas Distribution | FP-101173 | R STA-GROWTH-OREGON | 378.00 | 12/31/2018 | | 67,846.46 |
| 46 | Gas Distribution | FP-101175 | R STA-RELO-REPL-OREGON | 378.00 | 12/31/2018 | | 164,294.32 |
| 47 | Gas Distribution | FP-316245 | RP; O-TBD(O-4) BAKER CITY | 378.00 | 10/31/2018 | | 164,747.39 |
| 48 | Gas Distribution | FP-316246 | RP; O-TBD(O-9) LA PINE | 378.00 | 10/31/2018 | | 29,722.68 |
| 49 | Gas Distribution | FP-101176 | SERV-GROWTH-OREGON | 380.00 | 12/31/2018 | | 2,514,325.08 |
| 50 | Gas Distribution | FP-101177 | SERV-RELO-REPL-OREGON | 380.00 | 12/31/2018 | | 377,615.35 |
| 51 | Gas Distribution | FP-101210 | PRE-CAP MTR-GROWTH-INTERSTAT | 381.00 | 12/31/2018 | | 656,413.79 |
| 52 | Gas Distribution | FP-308022 | ERT Replacement - 2018 | 381.00 | 12/31/2018 | Multi Phase | 2,857,903.72 |
| | Gas Distribution | FP-313621 | Family Meter Replacement | 381.00 | 5/31/2018 | | 93,953.36 |
| 53 | Gas Distribution | FP-101178 | STD M&R-GROWTH-OREGON | 382.00 | 12/31/2018 | | 109,501.63 |
| 54 | Gas Distribution | FP-101179 | STD M&R-RELO-REPL-OREGON | 382.00 | 12/31/2018 | | 216,338.79 |
| 55 | Gas Distribution | FP-101259 | PRE-CAP REG-GROWTH-INTERSTAT | 383.00 | 12/31/2018 | | 79,028.84 |
| 56 | Gas Distribution | FP-101180 | IND M&R-GROWTH-OREGON | 385.00 | 12/31/2018 | | 130,916.84 |
| 57 | Gas Distribution | FP-101181 | IND M&R-REMOVE&REPLACE-OREGON | 385.00 | 12/31/2018 | | 195,917.68 |
| 58 | | | **Total Distribution Plant** | | | | 20,675,319.77 |
| 59 | Gas General | FP-101252 | GP BUILDINGS - ONTARIO | 390.00 | 12/31/2018 | | 5,794.62 |
| 60 | Gas General | FP-101466 | GP BUILDINGS - BEND | 390.00 | 12/31/2018 | | 5,083.00 |
| 61 | Gas General | FP-101213 | GP BUILDINGS - INTERSTATE | 390.00 | 12/31/2018 | | 8,651.00 |
| 62 | Gas General | FP-200661 | Data Center & Network Equipment | 391.00 | 12/31/2018 | | 72,394.08 |
| 63 | Gas General | FP-200662 | Personal Computers & Peripherals | 391.00 | 12/31/2018 | | 39,164.32 |
| 64 | Gas General | FP-306967 | District Office Access Control Sys | 391.00 | | | 0.00 |
| 65 | Gas General | FP-316445 | Toughbook Replacements for Field | 391.00 | 12/31/2018 | | 23,643.61 |
| 66 | Gas General | FP-101184 | GP TRAN. VEHICLE - OREGON | 392.00 | 12/31/2018 | | 338,350.57 |
| 67 | Gas General | FP-101215 | GP TRAN. VEHICLE - INTERSTAT | 392.00 | | | 0.00 |
| 68 | Gas General | FP-101218 | GP TOOLS - BEND | 394.00 | 12/31/2018 | | 48,485.64 |
| 69 | Gas General | FP-101237 | GP TOOLS - PENDLETON | 394.00 | 12/31/2018 | | 15,830.60 |
| 70 | Gas General | FP-101255 | GP TOOLS - ONTARIO | 394.00 | 12/31/2018 | | 37,138.43 |
| 71 | Gas General | FP-101216 | GP TOOLS - INTERSTATE | 394.00 | 12/31/2018 | | 40,241.46 |
| 72 | Gas General | FP-316495 | Turbine Prover | 394.00 | | | 0.00 |
| | Gas General | FP-311969 | Sensit Portable Methane Detectors | 394.00 | 6/30/2018 | | 185,972.33 |
| 73 | Gas General | FP-101186 | GP POWER EQUIP - OREGON | 396.00 | 12/31/2018 | | 93,940.55 |
| 74 | Gas General | FP-101187 | GP COMM EQUIP - OREGON | 397.00 | 12/31/2018 | | 6,607.92 |
| 75 | Gas General | FP-101164 | General Purpose Communication Equip | 397.00 | 12/31/2018 | | 25,114.49 |
| 76 | | | **Total Distribution Plant** | | | | 946,412.62 |
| 77 | | | **Total** | | | | **21,901,592.76** |

| | | | | | |
|---|---|---|---|---|---|
| 78 | **FERC** | **Budgeted 2018** | **Depr. Rate** | **Depreciation** | |
| 79 | **Acct** | **Investment** | **Order 15-315** | **Expense** | |
| 80 | 303 | 279,860.37 | 10.00 | 27,986.04 | |
| 81 | 376-1 | 1,616,530.60 | 2.20 | 35,563.67 | |
| 82 | 376-2 | 7,157,080.18 | 1.25 | 89,463.50 | |
| 83 | 376-3 | 4,075,163.45 | 4.13 | 168,304.25 | |
| 84 | 378 | 426,610.85 | 1.92 | 8,190.93 | |
| 85 | 380 | 2,891,940.43 | 3.88 | 112,207.29 | |
| 86 | 381 | 3,514,317.51 | 2.27 | 79,775.01 | |
| 87 | 382 | 325,840.42 | 1.86 | 6,060.63 | |
| 88 | 383 | 79,028.84 | 2.32 | 1,833.47 | |
| 89 | 385 | 326,834.52 | 2.18 | 7,124.99 | |
| 90 | 390 | 19,528.62 | 1.24 | 242.15 | |
| 91 | 391 | 135,202.01 | 0.05 | 67.60 | |
| 92 | 392 | 338,350.57 | 6.15 | 20,808.56 | |
| 93 | 394 | 141,696.13 | 3.56 | 5,044.38 | |
| 94 | 396 | 93,940.55 | 5.18 | 4,866.12 | |
| 95 | 397 | 6,607.92 | 9.37 | 619.16 | |
| 96 | 397 | 25,114.49 | 0.13 | 32.65 | |
| 97 | | 21,453,647.46 | | 568,190.41 | 0.02648456 |

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Michael P. Parvinen

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**Retirement Adjustments**
**Exhibit CNGC/802**

**October 2018**

# Cascade Natural Gas Corporation
# Depreciation Expense on 2018 Retirements

## State Of Oregon

| | | | |
|---|---|---|---|
| 1 | Through August Actual Retirements | 1,986,822 | |
| 2 | Through August Actual Investments | 9,984,547 | |
| 3 | Ratio of retirement to investment | 19.90% | |
| 4 | Total 2018 Investment Request (Exhibit CNGC/801) | 21,856,307 | |
| 5 | 2018 Retirements | 4,349,181 | |
| 6 | Depreciation rate (Exhibit CNGC/801) | | 2.652067% |
| 7 | Effect on 2018 Depreciation Expense due to Retirements | | **115,343** |

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Ryan Privratsky and Michael P. Parvinen

# EXHIBIT 900

October 2018

**EXHIBIT 900 – REPLY TESTIMONY**

TABLE OF CONTENTS

## I. INTRODUCTION

**Q. Please state your names.**

A. Our names are Ryan Privratsky and Michael P. Parvinen.

**Q. Mr. Privratsky, what is your business address and present position with Cascade Natural Gas Corporation (Cascade or the Company)?**

A. My business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. I am the Director of System Integrity for Cascade, a wholly-owned subsidiary of MDU Resources Group, Inc. (MDU Resources).

**Q. Please briefly describe your duties with Cascade.**

A. I am responsible for all aspects of engineering, design, and development of the Company's Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP). Additionally, I am responsible for directing, coordinating, and exercising functional authority for planning, organization, control, integration and completion of major projects needed to support all aspects of integrity management including DIMP, TIMP, and maximum allowable operating pressure (MAOP) validation.

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

A. I have over ten years of experience working between engineering and operations in the natural gas industry, with previous experience working as a Pipeline Engineer at WBI Energy. I have a Bachelor of Science Degree in Civil Engineering from Montana State University, and am a licensed Professional Engineer in the State of Washington.

**Q. Have you previously written or presented testimony before the Public Utility Commission of Oregon (Commission) or any other commission?**

A. I have not previously submitted testimony in Oregon, but I presented testimony before the Washington Utilities and Transportation Commission (WUTC) in Cascade's 2017 Washington rate case, Docket UG-170929.

**Q. Mr. Parvinen, have you previously filed testimony in this case?**

A. Yes. I filed Direct Testimony in this case, CNGC/200, on May 31, 2018. In addition, contemporaneous with this testimony, I am also filing additional reply testimony, CNGC/800 and CNGC/1000.

**Q. Why are you jointly sponsoring this testimony?**

A. We are jointly sponsoring this testimony because the issues raised by the parties in this case regarding the Company's proposed safety cost recovery mechanism (SCRM) and the records review performed to validate MAOP for the Company's Oregon pipeline system implicate both ratemaking policy, which is Mr. Parvinen's area of expertise, and pipeline system integrity, which is within Mr. Privratsky's area of expertise. We decided to file this testimony jointly to avoid splitting up the discussion of these issues between two pieces of testimony.

## II. SCOPE AND SUMMARY OF TESTIMONY

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

A. Our reply testimony responds to the following issues or adjustments raised by Commission Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC):

- **Safety Cost Recovery Mechanism (SCRM).** Our reply testimony describes and supports the Company's proposed SCRM and describes a few proposed updates and modifications to the SCRM and related projects. We have also included a new exhibit, Cascade's Five-Year SCRM Plan,[1] which provides additional detail and support for the projects proposed for inclusion in the SCRM. Our reply testimony also responds to Staff and AWEC's criticisms of the SCRM and recommendations that the Commission decline to approve the SCRM.

- **UM 1816 Deferral.** Our reply testimony provides additional information to support the Company's request for deferral and amortization of the expenses related to records review and for the Company's pipeline system, and responds to Staff's and CUB's arguments in support of their recommendations that the Commission decline to approve the Company's request.

## III. SAFETY COST RECOVERY MECHANISM

***Updates to SCRM***

**Q. You described the Company's proposed SCRM in your direct testimony. Please explain why the Company is requesting an SCRM in this case.**

A. Over the last seven years, Cascade has made significant investments in replacing its infrastructure. During the first three years, Cascade used the synergy savings and efficiency gains from the acquisition of Cascade by MDU Resources to fund these system improvements. However, the need for capital investment, together with other cost increases, have driven Cascade to file rate cases in three of the last four years—and have been the primary drivers in seeking this current rate increase as well. The proposed SCRM can help reduce regulatory lag, which negatively impacts the financial health of the Company, and will alleviate the need for annual rate requests.

**Q. Has the Company prepared materials to supplement the information provided thus far regarding the projects proposed to be included in the SCRM?**

[1] Exhibit CNGC/901.

A. Yes. The Company has prepared a detailed Five-Year SCRM Plan, included as Exhibit CNGC/901. The Five-Year SCRM Plan provides detailed information about each of the projects proposed for inclusion in the SCRM and explains in detail how each project is required for safety reasons. The Five-Year SCRM Plan also provides detailed cost and schedule information, showing the total expected cost for each project and the expected annual budgets for each project.

**Q. Could you please summarize some of the major changes regarding projects proposed to be included in the SCRM, and the proposed project budgets and schedules from the Company's initial filing?**

A. Cascade originally proposed to include additional projects in the SCRM if they met the program's standards as safety-related. The proposed budget was based on a range by year with flexibility to include additional projects over time. The revised proposal, as detailed in the Five-Year SCRM Plan, includes only those projects that are specifically identified; we have included expected budgets for each project over the next five years.

**Q. Does Cascade expect to provide updates to the information provided in its Five-Year SCRM Plan in the future?**

A. Yes. As part of the stipulation in Docket No. UM 1722, stakeholders agreed that local distribution companies (LDCs) would file an annual safety plan (Safety Plan) with the Commission, and further agreed that if an SCRM is approved, the LDC will file an annual report with the Commission providing the status of the projects included in the SCRM, including comparisons of projected costs to actual costs, and relevant earnings test information.[2] While the Five-Year SCRM Plan outlines the Company's anticipated

[2] *In the Matter of Pub. Util. Comm'n of Or. Investigation into Recovery of Safety Costs by Natural Gas Utils.*, Docket No. UM 1722, Order No. 17-084, App. A at 4 (Mar. 6, 2017).

schedule and budget for the next five years, there is a possibility that schedules and budgets may vary slightly from year to year. If the SCRM is approved, Cascade will address this issue through its annual Safety Plan and SCRM report, through which Cascade will provide its most recent actual cost data, budget projections, and schedule updates.

***Parties' Responses to SCRM Proposal***

**Q. Could you please summarize the parties' responses to the Company's SCRM proposal?**

A. Staff and AWEC recommend that the Commission reject the Company's request for a SCRM.[3] CUB takes no position on the SCRM, but reserves the right to raise issues related to the SCRM in the future.[4]

**Q Please provide a brief overview of the parties' arguments regarding the SCRM.**

A. Staff's arguments include the following:

- Staff asserts that the SCRM does not meet several of the guidelines that were adopted in Docket No. UM 1722 to guide development of an SCRM (SCRM Guidelines).[5]
- Staff has concerns regarding the relationship of the projects proposed in the SCRM to the Company's Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP), budgeting issues, and the quality of the data underlying the Company's decision to include projects in the SCRM.[6]

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[3] Staff/200, Fox/22; AWEC/100, Mullins/4.
[4] CUB/100, Gehrke/10.
[5] Staff/200, Fox/22.
[6] Staff/200, Fox/29-30.

- Staff also notes that SCRMs were initially conceived to allow companies cost recovery for safety-investment programs developed to respond to major new federal requirements, and that there are currently no major new federal safety requirements.[7]

AWEC's arguments include the following:

- AWEC asserts that the SCRM is single-issue ratemaking, and that Cascade has not adequately demonstrated that traditional ratemaking is inadequate to provide cost recovery for the projects proposed in the SCRM.[8]
- AWEC also claims that the SCRM will allow recovery for plant in excess of what is used and useful because Cascade has not appropriately reflected the impacts of depreciation associated with plant retirements.[9]

**Q. How do you respond to parties' concerns?**

A. As discussed in greater detail , the Company addresses Staff's concerns as follows:

- To address Staff's concerns regarding consistency with the SCRM Guidelines, the Company has proposed several updates to the SCRM and has developed a Five-Year SCRM Plan, Exhibit CNGC/901, to provide additional detail regarding the proposed SCRM projects.
- The Company's Five-Year SCRM Plan, Exhibit CNGC/901, provides additional detail regarding the analysis of the SCRM projects in the Company's DIMP/TIMP, and also provides additional analysis for each project and budgeting.
- Regarding Staff's comment that there are no new major federal requirements driving the SCRM projects, Cascade notes that the SCRM Guidelines developed by stakeholders in the stipulation in Docket No. UM 1722—and which were

[7] Staff/200, Fox/30.
[8] AWEC/100, Mullins/33.
[9] AWEC/100, Mullins/37.

approved by the Commission—contemplate that an SCRM may be proposed to respond to new federal requirements ***or*** to address important safety-related investments. Cascade's proposed SCRM includes important safety-related projects, and these are thus properly within the scope of projects that stakeholders agreed should be eligible for an SCRM.

Regarding AWEC's concerns, the Company responds as follows:

- AWEC's claim that the SCRM constitutes single-issue ratemaking ignores the fact that, in Docket No. UM 1722, stakeholders—including AWEC's predecessor, Northwest Industrial Gas Users (NWIGU)—entered into a Stipulation agreeing that the Commission should allow an LDC to propose an SCRM to allow for timely cost recovery for important safety-related projects. The parties thus implicitly recognized that an SCRM is a permissible form of single-issue ratemaking. Regarding AWEC's claim that Cascade has not demonstrated that traditional ratemaking is inadequate, Cascade notes that it has filed a rate case in three of the last four years to recover its safety-related investments, and if an SCRM is not approved, Cascade will need to continue to file annual (or nearly annual) rate cases for the next several years.
- Finally, with respect to AWEC's concerns about plant retirements, a condition in the UM 1722 settlement was that the total company investments had to exceed total depreciation expense to ensure that the LDC would not be collecting costs through the SCRM that are already being collected in rates. Any concern regarding the plant retirements is offset by the showing that total investment far exceeds the depreciation expense from the last general rate case.

***SCRM Guidelines***

**Q. Please list the SCRM Guidelines that were adopted in the stipulation in Docket**

**No. UM 1722.**

A. Per the stipulation in Docket No. UM 1722, adopted by the Commission in Order No. 17-084,[10] the SCRM Guidelines include the following:

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

[10] Docket No. UM 1722, Order No. 17-084 at 4-5 (Mar. 6, 2017).

- **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.

**Q. Please provide an overview of Staff's testimony regarding whether the Company's proposed SCRM is consistent with the SCRM Guidelines.**

A. Staff agrees that Cascade's proposed SCRM meets Guideline 1 (SCRM proposed in a rate case or within three years of a rate case), Guideline 4 (requiring an earnings test), Guideline 5 (limit on cost recovery related to annual depreciation), and Guideline 6 (setting a limited duration for an SCRM).[11] Staff, however, proposes a few modifications to the SCRM with respect to Guidelines 5 and 6.

Staff claims that the Company's proposed SCRM has not satisfied Guideline 2 (discrete, safety-related projects with costs identifiable at time mechanism is established), because Staff feels that the Company has not provided adequate information about the projects to demonstrate that they are needed for safety reasons and has not provided specific cost detail for projects during the period 2020-2023. Staff also argues that the proposed SCRM does not satisfy Guideline 3 (requiring a cost recovery cap), because Cascade proposed a rate impact cap rather than a dollar amount cap.

**Q. Please describe Staff's proposed modifications to Cascade's SCRM, based on its concerns regarding Guidelines 5 and 6.**

A. Regarding Guideline 5, Staff notes that imposing a limit on cost recovery connected to the Company's annual amount of depreciation may create an economic incentive for the Company to increase its level of spending on capital projects not related to safety,

[11] Staff/200, Fox/23, 25-26.

and suggests that the Commission set a baseline level of spending to be considered for the duration of the SCRM.[12] Regarding Guideline 6, Staff proposes reducing the duration of the SCRM from five years to three years because Staff asserts that the Company has not provided sufficient information to support a five-year SCRM.[13]

**Q. How do you respond to Staff's recommendation to establish a baseline level of spending in order to remove the economic incentive for Cascade to increase spending on projects not related to safety?**

A. Cascade disagrees with the fundamental premise underlying Staff's recommendation. The Company would never arbitrarily increase investment to simply meet the depreciation expense criteria. Moreover, if Cascade were to increase investments in other non-SCRM investments, those investments would most likely be non-revenue producing investments, which would only add increased rate pressure and require the Company to file a general rate case.

**Q. How do you respond to Staff's recommendation to shorten the duration of the SCRM?**

A. Staff proposed a shorter duration for the SCRM because it felt that Cascade had not provided adequate information to support a five-year mechanism. Cascade believes that the Five-Year SCRM Plan, filed with this testimony, provides sufficient information to support a five-year cost recovery mechanism. Cascade has provided its most current projections for schedule and budget for the SCRM projects and will provide annual updates regarding anticipated schedule and budget through its annual Safety Plan filings. Importantly, Cascade will be seeking cost recovery only for projects identified in the SCRM, which have actually been placed in service and are used and

[12] Staff/200, Fox/25.
[13] Staff/200, Fox/26.

useful, and for which actual costs are known. Accordingly, Cascade believes that the proposed five-year duration for the SCRM is appropriate and should be adopted by the Commission.

**Q. Please address Staff's claims that the SCRM has not satisfied Guideline 2 because the Company has not provided adequate information about the projects to be included in the plan.**

A. Cascade seriously considered Staff's concern and, as discussed above, has prepared the Five-Year SCRM Plan, Exhibit CNGC/901. Cascade believes that the information provided in the Five-Year SCRM Plan—which includes detailed information about how the projects are related to safety, and detailed cost and schedule information—satisfies the requirements of Guideline 2.

**Q. Staff also expresses concern that the cost information presented to support the SCRM is unreliable.[14] How do you respond?**

A. As discussed above, the Company has provided additional detail regarding anticipated costs in its Five-Year SCRM Plan. The Company will update this budget information annually, and importantly, Cascade will only seek recovery for SCRM projects based on *actual* costs and projects that have been completed and placed in service.

**Q. Please address Staff's claims that the SCRM has not satisfied Guideline 3.**

A. While Cascade believes that the intent of Guideline 3 can be met with either a rate cap or a dollar amount cap, Cascade is amenable to adopting Staff's recommendation to set a dollar amount cap. Cascade proposes that the cost recovery cap be set at $2.5 million, which is equivalent to approximately a 2.5 percent impact on rates.

***DIMP/TIMP***

**Q. Please describe the TIMP.**

[14] Staff/200, Fox/31.

A. The TIMP resulted from the 2002 Pipeline Safety Improvement Act (2002 Improvement Act), which required the Office of Pipeline Safety and the Research and Special Programs Administration to issue a new rule that added incremental requirements on the operators of transmission pipelines. The new rule was called the Pipeline Integrity Management in High Consequence Areas Rule (IMP Rule). The IMP Rule required operators to identify transmission lines in certain “high consequence areas” and to implement written integrity management programs for such areas. A high consequence area (HCA) is a location that is defined in the pipeline safety regulations as an area where pipeline releases have greater consequences to safety, health and the environment. Generally, HCAs are areas with greater population density.

**Q. Please describe the DIMP.**

A. In 2006 Congress passed the Pipeline Inspection, Protection, Enforcement and Safety Act (2006 PIPES Act) which expands the scope of the 2002 Improvement Act by requiring the U.S. Department of Transportation Pipeline and Hazardous Material Safety Administration (PHMSA) to prescribe minimum standards for Distribution Integrity Management Programs for distribution mains, services, and other gas related appurtenances. In addition, the PIPES Act significantly increases the requirements of all stakeholders relative to excavation damage prevention.

The requirement for LDCs to have a DIMP became effective on February 12, 2010. Operators were given until August 2, 2011, to write and implement a DIMP that demonstrates an understanding of the distribution system design and material characteristics; describes the operating conditions and environment; provides the maintenance and operating history; identifies existing and potential threats; evaluates and ranks its risks; identifies and implements measures to address risks; measures program performance; monitors results; evaluates effectiveness; and periodically assesses and improves the plan.

**Q. Please describe the Company's implementation of the DIMP and TIMP.**

A. Cascade's TIMP and DIMP programs were initiated in 2004 and 2011, respectively. As part of Cascade's DIMP and TIMP, information is collected and entered into the appropriate risk models where it is analyzed to find areas of concern and trends. The risk models are updated and run annually not to exceed 15 months from the date of the last model run.[15] This allows Cascade to quantify the risk associated with each pipeline segment based on factors that are pertinent to the integrity of the system.

**Q. Please explain how the Company's DIMP and TIMP models inform the prioritization of safety-related projects in the proposed SCRM?**

A. The DIMP and TIMP are used to identify and assess integrity risks to Company-owned and operated infrastructure, and to prioritize work on Cascade's pipeline system. Once pipe segments requiring replacement have been identified, specific projects within these areas are planned and prioritized. This process ensures that higher risk threats are mitigated in a timely manner. Overall, the TIMP and DIMP programs:

- Support Cascade's understanding of the system and material characteristics;
- Describe the operating conditions and environment;
- Provide the maintenance and operating history of the Company's infrastructure;
- Identify existing and potential threats;
- Evaluate and rank risks;
- Identify and recommend measures that may be implemented to address risks;
- Measure program performance;
- Monitor results and evaluate effectiveness; and

[15] *See* Exhibit CNGC/902, Privratsky-Parvinen/21, DIMP Section 4.2.1.

- Periodically assess and improve the DIMP and TIMP plan.

**Q. How does the Company use the DIMP and TIMP to select safety-related projects?**

A. The DIMP and TIMP risk models and risk outputs are reviewed and analyzed after each model run for areas of increased risk from the last model run. As a part of this review, the Company considers and analyzes existing and proposed measures to address the threats to Cascade's pipeline system and associated risks. The possible remediation actions to address the pipeline safety threats are listed in Table 5.1 in Section 5.0 of DIMP.[16] The selection of appropriate remediation actions depends on the primary threat group being addressed, the associated subcategory threat, whether the threat is current or potential in the future, and the viability of the action in managing the relevant risk factors. One of the possible actions to reduce certain risks associated with a specific threat(s) is through replacement. If replacement is determined as an appropriate action to reduce the risk, a project is then established and included in the Company's Five-Year Year Capital Budget. For risks associated with corrosion, natural forces, material, weld, and/or equipment, replacement is typically the most viable option.

**Q. What are Staff's primary concerns with the Company's SCRM as it relates to the Company's DIMP and TIMP?**

A. Staff states that it has significant concerns about the relationship of the proposed SCRM to the existing DIMP and TIMP process.[17] Staff also has concerns about the age of the data in the DIMP, noting that the most recent DIMP was filed with the Commission on August 5, 2016 and appeared to contain 2012 data.[18] Staff states that

[16] Exhibit CNGC/902, Privratsky-Parvinen/99.
[17] Staff/200, Fox/29.
[18] Staff/200, Fox/29.

because the Company has not timely provided written safety plans to the Commission, Staff does not have the information necessary to review and evaluate the proposed SCRM projects.[19]

**Q. What is the relationship of the projects proposed in the SCRM to the TIMP and DIMP?**

A. As discussed in the Five-Year SCRM Plan, every project proposed for inclusion in the SCRM was identified as high-risk in the DIMP or TIMP, and/or by a subject matter expert required to address a known integrity concern. Cascade has compiled relevant excerpts from the DIMP and TIMP providing the analysis supporting inclusion of these projects in the SCRM, which is included as Exhibit CNGC/901.

**Q. Can you please comment on Staff's concern about the age of the data in the DIMP?**

A. Staff is incorrect that the data in the DIMP is from 2012. Certain elements in the DIMP and certain descriptions may not have changed since 2012, and thus may not have been updated, but as described above, the DIMP is a living and breathing model and is being updated on an ongoing basis to include new inputs based on the information the Company gathers from performing repairs, leak surveys, exposed pipe inspection reports, pipeline patrol records, corrosion control records, facility maintenance records, excavation activity, etc. The Company also gathers information from outside data sources to gain knowledge about facilities and identify threats associated with flood zones, population data, wild fire zones, etc. In addition to information about the Company's distribution system that is gained from Company records and outside data sources, knowledge is also acquired from operating staff that are familiar with construction and maintenance practices, operating systems and history, and prior and

[19] Staff/200, Fox/29.

present industry trends. Subject matter experts are also consulted to fill in operational record gaps.[20]

**Q. Please respond to Staff's claim that the Company's most recent DIMP on file with the Commission is from August 2016.**

A. Staff is incorrect. Cascade provided an updated DIMP to Lori Koho of the Commission's Pipeline Safety group on August 7, 2018.

**Q How do you respond to Staff's assertion that because the Company has not regularly provided updated written safety plans, Staff does not have adequate information to review the SCRM projects?**

A. It is Cascade's practice to provide an updated DIMP to the Commission only if there is a major update or change, and the last major update occurred in 2016. However, as described above, Cascade also provided an updated DIMP to the Commission in August 2018 in response to a request from the Commission's Pipeline Safety Staff.

To address Staff's concerns, however, Cascade proposes filing its DIMP with the Commission annually at the same time that it files its annual Safety Plan with the Commission. Cascade believes this approach should address Staff's concerns about evaluating the proposed SCRM projects based on the analysis available in the Company's DIMP.

**Q. Staff also noted that in the 2012 DIMP, corrosion and material concerns represent only 13 percent of the risk score for Oregon, and questions whether the Company may be grouping smaller sections of old pipe with a history of corrosion with larger portions that do not have that history.[21] Do you agree with Staff?**

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[20] *See* Exhibit CNGC/902, Privratsky-Parvinen/13, DIMP Section 2.0.
[21] Staff/200, Fox/29-30.

A. No. While Staff is correct that corrosion only represents about 13 percent of the risk score for all pipe and facilities in Oregon, the total risk score for a pipeline segment is made up of multiple threats and risk factors contributing to the overall risk score.[22] The segments Cascade had identified for replacement have higher risks associated with corrosion, materials, welds, missing valves, and equipment, compared to other segments that may have a higher excavation damage threat and lower corrosion threat. Pipe is also being replaced due to a higher total likelihood of failure and higher consequence factor.

Staff's concern that the Company may be grouping old pipe with newer pipe and replacing large sections of low-risk pipe is misplaced. Cascade is primarily replacing pipeline segments that have been identified as high risk. In the case of some pipeline replacement projects—for example, in Bend and Baker City—some smaller segments at a lower risk may also be replaced during the replacement to avoid creating areas of isolated steel, which would require additional maintenance if they were not replaced. However, to the extent that any lower risk pipeline is replaced in connection with those projects, it will be only a relatively small amount incidental to the replacement of higher risk pipeline and must be performed to allow for efficient maintenance of the system. Moreover, for the Madras, Bend HP, Baker Bridge Crossing, and Milton Freewater Canal Crossing projects, the only segments of pipeline that will be replaced are those with identified integrity concerns—and no lower risk pipeline will be replaced in connection with those projects.

**Q. Staff also notes that pipeline replacement is only one aspect of risk evaluation and ranking in the DIMP and TIMP and expresses concern that the Company**

[22] *See* Exhibit CNGC/902, Privratsky-Parvinen/99, Table E.3.2 in the DIMP, Risk Score and Ranking By State, which ranks the total risk score for each threat by state.

**may elevate the priority of pipeline replacement and improvement relative to other risk mitigation and management activities.**[23] **How do you respond?**

A. Cascade does not agree that the adoption of the SCRM will result in the Company inappropriately elevating pipeline replacement over other risk mitigation and management activities. The Company fully recognizes that, while pipeline replacement is the most viable option for addressing certain threats, O&M activities are appropriate for addressing other types of threats. Cascade commits that, in the event the SCRM is approved, it will continue to perform other risk management and mitigation activities as are identified in the DIMP[24] and the Company's safety planning documents. As shown in the Company's current Safety Plan, filed in Docket No. UM 1899, the Company's 2019 O&M budget for activities identified in the TIMP, DIMP, and public awareness and damage prevention is $500,000.[25] Additionally, the Company's DIMP recommends O&M spending from other actions associated with Leak Management,[26] Annual Maintenance Requirement,[27] Operator Qualification Program,[28] and Drug and Alcohol Misuse Prevention Plan.[29] Cascade will continue to pursue these essential safety-related O&M programs irrespective of whether the SCRM is approved.

***Absence of New Major Federal Requirements***

**Q. Does Staff also question the appropriateness of the SCRM in the absence of any new federal mandates?**

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[23] Staff/200, Fox/30.
[24] Exhibit CNGC/902, Privratsky-Parvinen/25-28. Section 5.0 of DIMP covers Risk Management Action and Table 5.1 lists possible actions for each threat.
[25] *In the Matter of Cascade Natural Gas Corp., Annual Natural Gas Safety Project Plan*, Docket No. UM 1899, Annual System Safety Plan at 13 (Sept. 28, 2018).
[26] Exhibit CNGC/902, Privratsky-Parvinen/25, DIMP Section 5.2.2.
[27] Exhibit CNGC/902, Privratsky-Parvinen/26, DIMP Section 5.2.3.
[28] Exhibit CNGC/902, Privratsky-Parvinen/27, DIMP Section 5.2.5.
[29] Exhibit CNGC/902, Privratsky-Parvinen/27, DIMP Section 5.2.6.

A. Yes. Staff notes that 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, and that there are currently no major new federal requirements scheduled to go into effect beyond the bare steel replacement program.[30] Staff thus questions the appropriateness of creating a special rate recovery mechanism in absence of new mandates.[31]

**Q. How do you respond to Staff's concern about the absence of new major federal requirements?**

A. While Staff is correct that SCRMs were initially developed to respond to federal mandates, the UM 1722 stakeholders and Commission recognized the importance of allowing recovery for safety-related investments—whether federally-mandated ***or*** identified by an LDC through its own evaluation of how to promote the safety of its system. Indeed, the stipulation in Docket No. UM 1722 contemplates that projects would be eligible for cost recovery if they are included in the Company's safety plan on the basis of the Company's risk analysis ***or*** to meet newly implemented federal code.[32] Thus, the absence of new federal mandates does not limit the availability of an SCRM.

***Single-Issue Ratemaking and Need for SCRM***

**Q. AWEC argues that with the Company's proposed SCRM, Cascade seeks to depart from the traditional form of cost recovery available for regulated utilities in Oregon for safety-related improvements, and is asking to implement a disfavored form of single-issue ratemaking.[33] How do you respond?**

[30] Staff/200, Fox/30.
[31] Staff/200, Fox/30.
[32] Docket No. UM 1722, Stipulation of all the Parties at 4.
[33] AWEC/100, Mullins/33.

A. While single-issue ratemaking is not generally favored, it is not prohibited; in fact, the Commission regularly approves recovery of specific investments in between rate cases, when consistent with the public interest.[34] As discussed above, in Docket No. UM 1722, all of the stakeholders—including AWEC—agreed to guidelines under which it would be appropriate for the Commission to adopt mechanisms for prompt cost recovery for safety-related investments—thus acknowledging that this form of single issue-ratemaking serves the public interest in the appropriate cases. Cascade will address this issue further on briefs.

**Q. AWEC claims that Cascade has failed to identify any reason why traditional ratemaking is not sufficient to recover the expenditures associated with its capital investment program.[35]**

A. Cascade described its need for the SCRM in its direct testimony,[36] in which the Company explained that it has planned a significant level of safety-related investments over the next five years, that the safety-related investments are non-revenue producing, and that Cascade would be in a position of needing to file annual rate cases if an SCRM is not approved.

**Q. Has Cascade had to file frequent rate cases to address its recent safety-related investments?**

A. Yes. Cascade has filed rate cases in three of the last four years, and one of the primary drivers for these rate case filings has been the Company's recent safety-related capital investments.

[34] *In the Matter of Idaho Power Co. Application for Authority to Implement Revised Depreciation Rates for Elec. Plant-in-Service*, Docket No. UM 1801, Order No. 17-186 at 6 (May 25, 2017); *In the Matter of PacifiCorp, dba Pac. Power, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 at 6 (May 27, 2015).
[35] AWEC/100, Mullins/33.
[36] CNGC/200, Parvinen/19-20.

**Q. Would Cascade continue to file annual rate cases if the SCRM is approved?**

A. Cascade does not anticipate that it would need to file annual rate cases if the SCRM is approved. This would benefit Cascade, the Commission, and parties as they would be spending less time and resources litigating rate cases, and customers would benefit through reduced rate case spending.

***Used and Useful / Plant Retirements***

**Q. AWEC claims that the SCRM will result in a return on a level of rate base exceeding the used and useful level, noting that while Cascade proposes to track additions to rate base, it excludes the corresponding subtractions from rate base attributable to plant retirements that will occur after the general rate case.[37] How is the Company addressing plant retirements?**

A. Guideline 5 provides that 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, so depreciation of plant is already incorporated into the SCRM.

**Q. AWEC presents a chart that purports to demonstrate that a safety cost recovery mechanism will result in over-recovery.[38] Do you agree with AWEC's analysis?**

A. No. The analysis presented in AWEC's chart recognizes only that plant investment that is being requested in the mechanism. However, when all new investment is considered, that amount offsets columns (c) and (d), which address depreciation reserves and plant retirements.[39]

**Q. AWEC also asserts that by excluding incremental depreciation reserves on existing plant in service, Cascade will ignore the revenue requirement effect of**

[37] AWEC/100, Mullins/36-37.
[38] AWEC/100, Mullins/38.
[39] AWEC/100, Mullins/38.

**retiring existing plant in order to implement its safety program, effectively providing it with a return on property that has been taken out of service, which will result in Cascade over-recovering its investment in utility plant.[40] Is this correct?**

A. No. Again, all new investment beyond the investment included in the SCRM offsets the reduction in depreciation expense due to the retirements. This was the intent of Guideline 5.

**Q. AWEC argues that customers pay more through trackers than they would have paid through rate case recovery because all charges are not synchronized to accurately reflect changes in "net" plant.[41] How do you respond?**

A. As explained in the discussion above, Guideline 5 was developed to address this concern. Additionally, to the extent that an SCRM may cause an increase in earnings beyond normal levels, there is an earnings sharing mechanism in place to protect customers.

## IV. UM 1816 DEFERRAL

***Background Regarding Docket No. UM 1816 Deferral***

**Q. Please describe the deferral request filed in Docket No. UM 1816.**

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

**Q. What was the purpose of the records review?**

A. The Company agreed to perform the records review for its Washington system as part

[40] AWEC/100, Mullins/36-37.
[41] AWEC/100, Mullins/39.

of a December 2016 settlement agreement which resolved an investigation by the Staff of the Washington Utilities and Transportation Commission into the completeness of Cascade's MAOP records.[42] After executing that settlement agreement, the Company determined that it would be prudent to perform a similar review in Oregon, which would inform the Company as to its records' compliance with existing MAOP guidelines, as well as new standards proposed by the U.S. Department of Pipeline and Hazardous Materials Safety Administration (PHMSA) that pipelines records must be "traceable, verifiable, and complete." We will discuss the "traceable, verifiable, and complete" standard in greater detail later in this testimony.

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

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

**Q. Did the Company defer the costs described in its deferral application in Docket No. UM 1816?**

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

**Q. How did the parties respond to the Company's request for approval of the deferral and amortization of the deferred amounts?**

A. CUB and Staff both recommended that the Commission reject the Company's request for approval of the deferral and amortization of the deferred costs, and AWEC took no position on this issue. CUB disputes that the costs were prudently incurred, and

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[42] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.,* Docket PG-150120, Settlement Agreement (Dec. 15, 2016).

argues that the Company should have hired additional personnel to perform the records review instead of contracting with a third-party vendor.[43] Staff agrees that the costs were prudently incurred, but recommends the Commission reject the Company's request for amortization because Staff claims the costs are routine operating expenses and not significant enough to be eligible for deferred accounting treatment.[44] We will discuss the parties' arguments—and the Company's responses to these arguments—in greater detail below.

***Prudence of MAOP Records Review Expense***

**Q. Does Staff contest the prudence of the MAOP records review expense?**

A. No. Staff agrees that the incurred expense is justifiable and necessary.[45]

**Q. What are CUB's concerns with respect to prudence of the MAOP records review?**

A. CUB makes the following arguments regarding the prudence of MAOP records review expense:

- Cascade should have maintained accurate records of its pipeline system since federal guidelines required the pipeline records to be complete, and routine utility operations require a utility to have accurate records of its high-pressure distribution and transmission pipelines;[46]
- The Company unilaterally sought to perform the records review based upon a ruling in Washington;[47]

[43] CUB/100, Gehrke/11-12.
[44] Staff/600, Moore/5.
[45] Staff/600, Moore/5.
[46] CUB/100, Gehrke/12.
[47] CUB/100, Gehrke/12.

- The Company's records review work was designed to meet the "traceable, verifiable, and complete" standard, but Cascade is not yet required by law in Oregon to adhere to that standard;[48] and
- Cascade could have mitigated costs by having its own employees perform the records review, but instead contracted with a third party.[49]

**Q. What is your response to CUB's argument that the Company should have maintained accurate records of its pipeline—which would have obviated the need to review the completeness of those records in 2017.**

A. Cascade agrees that it is required to maintain accurate records of its pipeline. However, the reality is that when it discovered that certain records were missing, taking steps to eliminate the information gaps was the only prudent course.

**Q. When did the Company first discover that it needed to perform a comprehensive records review to validate MAOP for its pipeline system?**

A. Cascade discovered that it had incomplete records for certain pipeline segments for its Washington system in 2013, as a result of an investigation initiated by the Washington Utilities and Transportation Commission (WUTC) in 2013 (WUTC Investigation).[50]

**Q. What actions did Cascade take after discovering that certain of its pipeline records were incomplete?**

A. Upon learning that its records were incomplete, Cascade collaborated with WUTC Staff to develop a plan for the Company to validate its MAOP records for the Company's Washington system—which Cascade engaged TRC to perform. Cascade also determined that it would be prudent and efficient to validate its Oregon records at

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[48] CUB/100, Gehrke/12.
[49] CUB/100, Gehrke/11-12.
[50] *Wash. Utils. and Transp. Comm'n v. Cascade Nat. Gas Corp.*, Docket PG-150120.

the same time.

**Q. What is your response to CUB's complaint that Cascade "unilaterally" decided to perform the records review, based on an agreement in Washington?**

A. To the extent that CUB is asserting that Cascade did not notify CUB of its intent to perform this work, Cascade agrees that this is the case. However, Cascade disagrees that this fact bears on the prudence of Cascade's decision. A utility is required to take all actions reasonable and prudent to ensure that its system is safe and reliable. The fact that the utility does not first consult with other stakeholders does not render the actions taken imprudent.

**Q. How did the Company determine that it would be prudent and efficient to validate the records for its Oregon pipeline system concurrently with validation of its Washington system?**

A. Cascade anticipated that the record gaps that were discovered for the Washington pipeline system would also be present in Oregon based on the timing of pipeline segments being installed in Oregon during the same time Cascade was installing pipelines in Washington. After performing a preliminary records review of its Oregon pipeline segments, Cascade confirmed that there were gaps in its Oregon records. As a result, Cascade determined that it would be necessary to perform a comprehensive review of its records for its Oregon system.

Cascade contracted with TRC because they specialize in MAOP validation and could quickly perform this important work. Cascade believes that completing the records review concurrently in Oregon and Washington through a single vendor, TRC, was efficient and resulted in a usable product to be able to address MAOP validation company-wide. Importantly, this end product provided by TRC was not just the records review, but included the additional benefits of creating a comprehensive GIS-linked electronic database and meeting the "traceable, verifiable, and complete" standard.

**Q. Did TRC complete the work they were engaged to perform?**

A. Yes. TRC reviewed all of Cascade's MAOP records and prepared a full report, summarizing Cascade's MAOP records and identifying any missing records. These records provide Cascade with the information it needs to determine what additional steps may be required to ensure that it has all required documentation.

**Q. Were there other benefits associated with the records review work?**

A. Yes. As a result of the records review, Cascade now has a fully searchable electronic database of digital files relating to MAOP information, and these files are linked to the Company's Geographic Information System (GIS) records. Prior to the study, the Company's files for MAOP validation required a manual review of existing records any time an issue came up. Those records were not centralized, which meant that locating records was often cumbersome and time-consuming. The new electronic files allow for more efficient and accurate retrieval of information, which will benefit customers into the future. Importantly, the Company has the same level of information, in the same format, for its Washington and Oregon systems—all of which will meet PHMSA's proposed rules that it be traceable, verifiable and complete.

**Q. What is your response to CUB's argument that the records review is intended to ensure compliance with PHMSA's proposed "traceable, verifiable, and complete" standard—but that standard has not yet been adopted?**

A. As noted above, the Company decided to move forward with the record review in Oregon prior to the adoption of proposed PHMSA rule, to ensure sufficient documentation, and the safety and integrity of its system, and because it was efficient to do so contemporaneously with the work being performed in Washington. However, we do expect that PHMSA's proposed rule will be adopted in 2019, and the review would have been required fairly soon, regardless.

**Q. What documentation is required by PHMSA's proposed "traceable, verifiable, and complete" standard?**

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

- **Traceable.** Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter.
- **Verifiable.** Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a line segment complemented by pressure charts or field logs.
- **Complete.** Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable.[51]

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

A. Pipeline records are an essential component of managing pipeline safety. When explaining the need for the "traceable, verifiable, and complete" standard, PHMSA has indicated that "inspections and investigations indicate that efforts to collect and integrate risk information can be inappropriately narrow, lack verification and fail to take into account relevant risk information and lessons learned from other parts of their system."[52] The proposed PHMSA standards are a complete system requirement to assure a safe pipeline system and Cascade's commitment to meet these standards reflects Cascade's commitment to safety.

**Q. Please respond to CUB's criticism that the Company should have performed the records review in-house, instead of engaging TRC to perform the work.**

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[51] *See* PHMSA ADB-2012-06, Fed. Reg. Vol. 77, No. 88 at 26,823-26,824 (May 7, 2012).
[52] Establishing Maximum Allowable Operating Pressure Using Record Evidence, 76 Fed. Reg. 1504, 1505 (Jan. 10, 2011).

A. Cascade had initially attempted to perform the work internally, but did not have the personnel available to perform the records review work, and so Cascade determined that it would contract with TRC to complete the records review work in both Washington and Oregon.

**Q. Why did Cascade decide to contract with TRC rather than hiring additional personnel?**

A Cascade decided to contract with TRC because the Company lacked the internal resources and believed that contracting with an outside vendor would result in deliver of a high-quality product. TRC is recognized as an expert in the industry for MAOP validation, and TRC's staff were appropriately trained regarding the "traceable, verifiable, and complete" standard. As a result, TRC was able to provide a thorough and independent audit of the Company's records. Additionally, TRC had resources available to deploy to quickly perform the records review work. TRC also had the capability to deliver a high quality and valuable product to Cascade in the form of a comprehensive electronic database. Finally, given the temporary nature of the job, it would not have been cost-effective to hire new Cascade employees to perform the work.

***MAOP Records Review Expense is Appropriate for Deferred Accounting***

**Q. Please explain Staff's position as to why the MAOP records review expense is not appropriate for deferred accounting.**

A. Staff believes the MAOP records review should be regarded as a routine operating expense, and that the Company should bear the risk for higher than anticipated operating expenses.[53] Staff explains 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,

[53] Staff/600, Moore/3-4.

and 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.[54]

Staff also argues that based on prior Commission precedent, a deferral is not appropriate. Staff explains that the Commission has historically applied a two-step approach to evaluating deferrals, asking first whether the expense at issue is the result of a stochastic or scenario risk, and applying different cost thresholds depending on the type of risk.[55] For a scenario (or unpredictable) risk, the Commission is more flexible regarding the magnitude of the event, and for a stochastic (or predictable) risk, the expense involved must be of a sufficient magnitude to justify deferred accounting treatment.[56] Staff points to a Commission order that suggests that in order to justify deferred accounting treatment, the cost must meet or exceed 250 basis points of the utility's revenue requirement. Using this two-step test, Staff argues that the MAOP records review expenses are a predictable expense and therefore constitute a stochastic risk, and that the records review expense does not meet threshold of magnitude to be eligible for deferred accounting treatment. Accordingly, Staff recommends that the Company's request for approval of the deferral and amortization of the deferred amounts should be denied.[57]

**Q. Please respond to Staff's argument that the MAOP records review should be regarded as a routine operating expense.**

A. Cascade disagrees with this characterization, as there was nothing "routine" about this one-time project. On the contrary, the MAOP records review represented a one-time

[54] Staff/600, Moore/3.
[55] Staff/600, Moore/5-6.
[56] Staff/600, Moore/5-6.
[57] Staff/600, Moore/7.

project that went far beyond typical records keeping and provided a comprehensive review that was designed to modernize the Company's records and facilitate compliance with the "traceable, verifiable, complete" standard.

**Q. Please respond to Staff's claim that the Commission uses the two-step test described above to analyze the appropriateness of a deferral request.**

A. Cascade agrees that the Commission has in the past applied this two-step analysis to requests for deferrals of excess power costs, and that the two-step test could be applied to other types of deferrals. However, the Commission has broad discretion to consider the facts particular to the request and balance the interests of customers and the utility.[58] Importantly, the Commission has on a number of occasions approved the deferral of operational and other expenses without reference to this two-step test. And finally, even if the two-step test were applied to this deferral, Cascade disagrees with the way in which Staff has implemented the analysis.

**Q. Please provide examples of deferrals approved by the Commission without reference to this two-step test**.

A. In 2012 the Commission approved Northwest Natural's request to defer expenses related to the installation of automated meter readers.[59] Similarly, in 1993 the Commission approved deferred ratemaking treatment for PGE's investments in a new

[58] For example, the Commission has indicated that it considers "both the nature of the event triggering the need for a deferral and the potential harm caused by denying deferred treatment in making [the] fact-specific determination" of "whether granting the deferral is an appropriate exercise of Commission discretion." *In the Matters of Pacific Power and Light, Portland Gen. Elec. Co. and Idaho Power Co. Applications for Deferred Accounting Treatment of Grid West Loans*, Docket Nos. UM 1256, 1257 and 1259, Order No. 06-483 at 2 (Aug. 22, 2006). Additionally, the Commission has explained that ORS 757.259 provides "a flexible, fact-specific review approach that acknowledges the wide range of reasons why deferred accounting might be beneficial to customers and utilities." *In the Matter of Pub. Util. Comm'n of Or. Staff Request to Open an Investigation Related to Deferred Accounting*, Docket No. UM 1147, Order No. 05-1070 at 1 (Oct. 5, 2005).
[59] *In the Matter of NW Nat. Application for Authorization to Defer Expenses Related to the Installation of Automated Meter Reading*, Docket No. UM 1413, Order No. 09-105, Appendix A at 4 (Mar. 30, 2009).

energy efficiency program.[60] Again in 2001, the Commission authorized deferral of PGE's investment in IT to prepare for Y2K, with the support of Staff.[61] These are precisely the same sorts of project-specific investments as the MAOP records review project, and should be afforded the same treatment.

**Q. Please explain your statement that even if the two-step test were appropriately applied to the MAOP deferral, you do not agree with Staff's analysis.**

A. Cascade disagrees with Staff's assessment that the risk addressed by the MAOP deferral is a stochastic as opposed to scenario risk, and we further disagree that it is appropriate to apply a 250 basis point threshold for the magnitude of the costs involved.

**Q. Why do you disagree with Staff's assessment that the risk addressed by the MAOP deferral is a stochastic risk?**

A. The Commission has clarified that "stochastic" risks are predictable fluctuations that would otherwise be accounted for through forecasting, whereas scenario risks are events that cannot reasonably be anticipated.[62] We disagree that the discovery of missing records could be planned for, and therefore disagree that the expense required to address this event should be categorized as a stochastic risk.

**Q. Even if the Commission were to conclude that the risk addressed by the MAOP deferral was stochastic in nature, do you agree that the expense must meet the 250 basis point threshold in order to be deemed recoverable?**

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[60] *In the Matter of the Application of Portland Gen. Elec. Co. for an Order Approving Deferral of Costs*, Docket No. UM 538, Order No. 93-346, Appendix A at 1 (Mar. 15, 1993)**.**
[61] *In the Matter of Portland Gen. Elec. Co.'s Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149. Docket No. UE 115*, Order No. 01-777, Appendix B at 3 (Aug. 31, 2001).
[62] "Stochastic risk is quantifiable as a known fluctuation around an expected value," as opposed to scenario risks that "represent abrupt changes in risk factors." *In the Matter of PacifiCorp Resource and Market Planning Program (RAMPP-7), Docket No. LC 31*, Order No. 03-508 at 6 (Aug. 25, 2003).

A. No. First, as explained above, Cascade disagrees that the expenses at issue should be characterized as a stochastic risk. Assuming for the sake of argument, however, that the expenses should be characterized as a stochastic risk, the Commission has previously applied a threshold of 250 basis points for such risks, but in doing so, specifically *declined* to adopt a bright line standard.[63] This suggests that the Commission has latitude to consider each request for deferral on a case-by-case basis, and set a threshold of magnitude that appropriately reflects the type of event and expenses incurred.

***If MAOP Records Review Expense Were Not Allowed as Deferral, the Expense Would be Treated as a Period Cost***

**Q. If Cascade would not have filed for a deferral, how would Cascade have treated the MAOP records review expense?**

A. If Cascade had not proposed deferred accounting treatment for the MAOP records review expense, Cascade would have recorded these costs to FERC account 874, operating and maintenance expense, for the 2017 base year.

**Q. If those costs would have been added to account 874, would the amount spent in 2017 be higher than normal in comparison with other years?**

A. Yes—which is the reason why Cascade filed for a deferral for the records review expense in the first place. The balances for account 874 for the past three years are shown in Exhibit CNGC/903. The average—which includes the amount proposed for the deferral in the 2017 expense level—is $1,306,206.57 per year.

**Q. What is your recommendation to the Commission on this issue?**

A. Cascade has demonstrated that the costs incurred in connection with its MAOP

[63] "Although we decline to set a numerical criterion…" *In the Matter of Portland Gen. Elec. Co. Application for Deferral of Hydro Replacement Power Costs*, Docket No. UM 1071, Order 04-108 at 9 (Mar. 2, 2004).

records review work were prudent and appropriate for a deferral. Accordingly, Cascade requests that the Commission approve the deferral requested in Docket No. UM 1816 and authorize amortization of the deferral in this rate case. If, however, the Commission declines to authorize amortization of the deferral, Cascade recommends that the Commission consider instead authorizing recovery of the normalized amount of expense, which would result in a decrease to the test period amount of $35,575 to revenue requirement.

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

A. Yes it does.

CNGC/901
Privratsky-Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Ryan Privratsky and Michael P. Parvinen

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**Five Year SCRM Plan**
**Exhibit CNGC/901**

**October 2018**

Cascade Natural Gas Corporation
A Subsidiary of MDU Resources Group, Inc.

*In the Community to Serve®*

# 5-Year Safety Cost Recovery Mechanism Proposal (SCRM)

OCTOBER 2018

## 1.0 Introduction

Cascade Natural Gas Corporation (Cascade or The Company) is committed to providing its customers with safe and reliable gas service. To accomplish this, Cascade is continuously engaged in proactive initiatives aimed at maintaining the integrity of the Company's pipeline system. To assist in meeting that commitment the Company is proposing a Safety Cost Recovery Mechanism (SCRM) to provide for timely recovery of the Company's safety-related capital investments.

In Docket UM-1722 the Public Utility Commission of Oregon (The Commission) adopted the stipulation addressing cost recovery of local distribution companies' (LDCs) safety investments which included guidelines governing proposals for safety cost recovery mechanisms as well as annual reporting requirements for staff and stakeholder review.[1]

In its initial SCRM filing the Company proposes to include the current phases of three identified projects in the Company's 2018 Annual Oregon System Safety Plan[2]. The Company also proposes pipe replacements at a bridge crossing near Baker City and in Milton-Freewater which are scheduled to begin in 2019 and 2020, respectively.

The Company's initial SCRM proposal would allow for the recovery of the safety replacement projects over a five-year horizon. The estimated annual budget for the projects proposed to be included in the SCRM totals approximately $7-$10 million per year.

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

The Company is using its Distribution Integrity Management Plan (DIMP) and Transmission Integrity Management Plan (TIMP) to identify and replace certain areas of the distribution system that are at elevated risks of failure.

## 2.0 Cascade Natural Gas DIMP/TIMP Modeling

When deciding to perform infrastructure replacement projects, such as a pipe replacement that is related to pipeline safety, both DIMP and TIMP are used as a basis to support the need for the project. The integrity management programs of DIMP and TIMP are both used to be able to

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

[2] *See In the Matter of Cascade Natural Gas Corp. Annual Natural Gas Safety Plan*, Docket No. UM 1899, Safety Plan at 13 (May 21, 2018). The three projects are Bend Pipeline Replacement Phase 8, the 6" Bend HP Replacement Phase 2, and the 4" Madras HP Replacement Phase 2.

identify and assess integrity risks to company owned and operated infrastructure. The programs demonstrate Cascade's understanding of the system and material characteristics; describes the operating conditions and environment; provides the maintenance and operating history; identifies existing and potential threats; evaluates and rank risks; identifies and implements measures to address risks; measures program performance; monitors results; evaluates effectiveness; and periodically assesses and improves the plan.

As part of Cascade's DIMP and TIMP, information is collected and entered into the appropriate risks models where it is analyzed to find areas of concern and trends. This allows Cascade to quantify the risk associated with each pipeline segment based on factors that are pertinent to the integrity of the system. Cascade's DIMP and TIMP are analyzed and updated on a yearly basis. As part of this analysis, trends are identified, and the plan and/or risk model is modified as needed.

Results from the risk models are then used to help prioritize and make decisions on the need to invest costs to replace or repair infrastructure. Cascade's DIMP and TIMP risk models are used to identify and prioritize work on the Cascade's pipeline system. Once pipe segments requiring replacement have been identified, specific projects within these areas are planned and prioritized. This process ensures that higher risk threats are mitigated in a timely manner.

Cascade's DIMP and TIMP risk models are ever changing as Cascade obtains new information. This information helps Cascade to continually validate the model or assists in making the necessary changes to the model. This information also further supports Cascades reasoning for performing the necessary measures to address integrity concerns. Two areas where new information is obtained include:

1. Company Forms – The Company gathers information from exposed pipeline reports, maintenance records, and leak investigations. The information from these forms is incorporated into the risk models.

2. Subject Matter Expert (SME) Panel Meetings – SME meetings are held on an appropriate basis. Information from the meetings is used to validate the risk model and new information is incorporated into the risk model.

The projects that have been identified in the 5-year SCRM plan are all projects that have been identified by the appropriate risk models and SME's as areas of concern where risks exist that impacts pipeline safety and the overall integrity of the system. Cascade has reviewed other possible actions to address the risks that have been identified and feels that pipe replacement is the most prudent measure in being able to eliminate the risks associated with each of these pipe segments.

## 3.0 Proposed Projects

Cascade has invested a significant amount over the last seven years making safety-related improvements to its infrastructure. In particular, Cascade has been focusing on the Bend, Oregon area and systematically replacing its gas pipeline system in that area. Cascade is also expanding its focus to other areas of its system including Madras, Baker City, and Milton-Freewater.

| Funding Project & Risks | 5 Yr. Total |
|---|---|
| FP-200688 - BEND PIPE REPLACEMENT:<br>Risks: Pre-CNG, 60+ year old steel pipe replacement, high corrosion risk | $15,647,801 |
| FP-303141 - BAKER CITY PIPE REPLACEMENT:<br>Risks: Pre-CNG, 60+ year old steel pipe replacement | $4,928,332 |
| FP-316401 - RP; 2,4" BRIDGE XINGS, BAKER CITY<br>Risks: Poor pipe coating for atmospheric corrosion risk | $283,667 |
| FP-316432 - RP; 2" BRIDGE XING, MILTON FREEWATER<br>Risks: Poor pipe coating for atmospheric corrosion risk | $198,476 |
| FP-316573 - RPL; 4" HP, MADRAS PH2 & PH3<br>Risks: Multiple integrity issues: seam leaks, poor welds, shallow depth | $4,413,541 |
| FP-316575 - RPL; 6" HP, BEND HP PH2 thru PH6<br>Risks: Multiple integrity issues: seam leaks, poor welds, shallow depth | $8,393,764 |
| Total | **$33,865,581** |

| Funding Project | 2019 | 2020 | 2021 | 2022 | 2023 | Total |
|---|---|---|---|---|---|---|
| FP-200688 - BEND PIPE REPLACEMENT | $2,871,578 | $3,145,140 | $3,087,586 | $3,251,536 | $3,291,961 | $15,647,801 |
| FP-303141 - BAKER CITY PIPE REPLACEMENT | $0 | $0 | $1,571,190 | $1,690,067 | $1,667,075 | $4,928,332 |
| FP-316401 - RP; 2,4" BRIDGE XINGS, BAKER CITY | $283,667 | $0 | $0 | $0 | $0 | $283,667 |
| FP-316432 - RP; 2" BRIDGE XING, MILTON FREEWATER | $0 | $198,476 | $0 | $0 | $0 | $198,476 |
| FP-316573 - RPL; 4" HP, MADRAS PH2-PH3 | $2,356,023 | $2,057,518 | $0 | $0 | $0 | $4,413,541 |
| FP-316575 - RPL; 6" HP, BEND HP PH2-PH6 | $1,639,631 | $1,541,380 | $1,555,155 | $1,845,721 | $1,811,877 | $8,393,764 |
| Annual Totals | $7,150,899 | $6,942,514 | $6,213,931 | $6,787,324 | $6,770,913 | **$33,865,581** |

**3.1 - 2,4" BRIDGE CROSSING REPLACEMENTS, BAKER CITY**

Project Description & Safety Assessment:

In Baker City, three bridge crossings were identified by local district management in Eastern Oregon as being a safety concern due to having a poor pipe coating condition and having difficult access to inspect for atmospheric corrosion. The three crossings are located on Madison St., Valley Ave., and Estes St. The crossings at Madison and Valley are both identified as Pre-CNG which presents a higher corrosion risk. The corrosion risk for these pipe segments is also increased from two corrosion sub-threats associated with Atmospheric Corrosion and Pipe Coating Condition. Atmospheric Corrosion sub-threat is higher for bridge crossings due to the lack of pipe coating and difficulties in being able inspect for atmospheric corrosion. Pipe coating condition of fair or poor also increases the overall corrosion risk by not providing adequate means to protect pipe from atmospheric corrosion. Spans and pipe attached to bridges are also more susceptible to damage from outside forces. The replacement of these bridge crossings will be by directionally drilling a new crossing under the river bottom to be able to eliminate the poor coating, atmospheric corrosion risk, and elimination of Pre-CNG pipe.

Total Project Budget: $283,667
Anticipated Project Schedule: 2019

# CONFIDENTIAL

**MAP**

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## 3.2 - BAKER CITY PIPE REPLACEMENT

Project Description & Safety Assessment:

The core of Baker City Intermediate Pressure (IP) Distribution System is primarily made of pipe that was purchased by Cascade from the Eastern Oregon Gas Company in the 1950's. This pipe is referred to as Pre-CNG pipe in Cascade's system. Pre-CNG pipe is pipe that was constructed to distribute manufactured gas or natural gas prior to 1955, and were installed, owned, operated, and maintained by other companies purchasing it in the late 1950's and the 1960's. Pre-CNG pipe tends to be bare or coal tar-wrapped steel pipe. The integrity of Pre-CNG pipe is concerning because it is at least 60 years old and had no, or inadequate, cathodic protection until the early 1970s, which means the pipe had a higher susceptibility to corrosion during the timeframe it was without cathodic protection. Pre-CNG pipe also has a higher missing value risk associated with the unknowns from purchasing the pipe from another company, and higher equipment risks due to age of the pipe and increased likelihood of failure.

In 2021, Cascade plans on starting a multiple year phased replacement of the Pre-CNG pipe in Baker City. The Pre-CNG pipe in Baker City is coal tar wrapped and is normally found in good condition, but has a number of corrosion leaks that have been reported and repaired. There is currently approximately 103,000' of 2", 4", and 6" Pre-CNG main in Baker City. Phasing for the Baker City pipe replacement has yet to be determined, but Cascade anticipates pipe replacement, of Pre-CNG main in Baker City, to take approximately 8-10 years to complete. This is based on historical spending amounts and an average completion of approximately 10,000' of main each year. Average is based on yearly averages on other ongoing distribution pipe replacement projects within Cascade.

Pipe replacement of Pre-CNG pipe in Baker City is an effort by Cascade to eliminate high risk pipe from the system, operate a safe and reliable system, and a measure to reduce overall risk in DIMP.

Total Project Budget: $4,928,332
Anticipated Project Schedule: 2021-2023

# CONFIDENTIAL

**MAP**

**Next 1 Page**

**3.3 - BEND PIPE REPLACEMENT**

Project Description & Safety Assessment:

The core of the downtown Bend Intermediate Pressure (IP) Distribution System consists of areas of 1930's pipe that was purchased by Cascade from the City of Bend. This pipe was used as a manufactured gas system prior to the arrival of natural gas to the Pacific Northwest and ownership by Cascade. This pipe is referred to as Pre-CNG pipe in Cascade's system. Pre-CNG pipe is pipe that was constructed to distribute manufactured gas or natural gas prior to 1955, and were installed, owned, operated, and maintained by other companies purchasing it in the late 1950's and the 1960's. Pre-CNG pipe tends to be bare or coal tar-wrapped steel pipe. The integrity of Pre-CNG pipe is concerning because it is at least 60 years old and had no, or inadequate, cathodic protection until the early 1970s, which means the pipe had a higher susceptibility to corrosion during the timeframe it was without cathodic protection. Pre-CNG pipe also has a higher missing value risk associated with the unknowns from purchasing the pipe from another company, and higher equipment risks due to age of the pipe and increased likelihood of failure.

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

In SME interviews Downtown Bend Pre-CNG pipe has been identified as one of Cascade's systems with the highest overall risk due to vintage of pipe, leaks, and severe corrosion concerns. Downtown Bend Pre-CNG pipe is also identified in model as high risk and it is predominate in the Top 100 OR Main risk, Top 50 OR Service Risk, and Top 25 OR Corrosion Risk.

In 2012 Cascade started the Bend Pipe Replacement project to begin replacing Pre-CNG pipe with a new a PE and Steel system and an Accelerated Action is setup for the replacement of the Pre-CNG pipe. Since 2012 Cascade has replaced several phases of this pipe totaling approximately 107,000' of main and services, and currently there is approximately 55,000' remaining to replace. Currently there are five remaining phases anticipated to be able to complete the Bend Pre-CNG pipe replacement project by the end of 2023. Each future phase will target approximately 11,000' of Pre-CNG main each year, along with connected service lines. The boundary of each phase can vary each year depending on construction challenges, planned municipal projects, resource availability, and permitting requirements. Cascade has been able to coordinate replacement work with City of Bend municipal projects to be able to reduce the overall costs needed for restoration.

The replacement of Pre-CNG pipe in Bend has had numerous challenges including construction in downtown infrastructure, construction within a highly populated and heavily visited tourist area, and solid rock construction.

As this replacement continues and condition/integrity is assessed it will allow for greater knowledge concerning severity, which will allow Cascade to further validate the model on risk assessment and determine aggressiveness of additional pipe replacement projects.

Effects of this replacement are being tracked in Pre-CNG statistics, overall risk scoring for Bend District and town of Bend will be reduced (specifically material failure risk, corrosion risk, and missing value risk), it is anticipated that Bend district leaks will be reduced over time with this replacement since this Pre-CNG pipe in downtown Bend is where majority of leaks are found in the Bend District, and as replacement phases are completed it will be eliminated from Top 100 OR main risk, Top 50 OR Service Risk, and Top 25 OR Corrosion risk evaluation. Overall this project improves safety and reliability in Bend by reducing overall risk and decreasing the likelihood of a failure to occur from operating a system with known SME experience and integrity concerns.

Total Project Budget: $15,647,801
Anticipated Project Schedule: 2019-2023

# CONFIDENTIAL

**MAP**

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**3.4 - REPLACE 6" HP, BEND**

Project Description & Safety Assessment:

The 6” Bend HP Line was installed in 1961 from the Bend Gate Station on Ward Rd, following Bear Creek Rd., until it terminates west of Bend Parkway and Highway 97 in Bend.

The Bend HP Line has been found to have many areas with minimal or no cover. The Bend District SME’s believe the pipe is in good condition overall and haven’t seen many corrosion or coating issues. The concern with this pipe is the minimal depth of cover and being exposed in some areas. With minimal cover or exposures this increases the risk of the pipe being damaged by excavation or from outside forces. This line currently has a high-risk score in DIMP and presents a safety issue with not having sufficient cover on a HP line that operates at an MAOP of 300 psig.

Cascade began a multiple year replacement project in 2017 to replace the high-risk sections of the 6” Bend HP Line with a new 12” steel pipe, to depth of cover that meets today’s construction requirements. Phase 1 will be completed in 2018 from Bend Parkway to Jaycee Park, Phase 2 of this project is planned for in 2019, Phase 3 in 2020, Phase 4 in 2021, Phase 5 in 2022, and Phase 6 in 2023. Cascade anticipates being able to complete approximately 2,500’ – 4,000’ per phase. Each phase will consist of replacing the existing 6” with a new 12” pipeline.

Total Project Budget: $8,393,764
Anticipated Project Schedule: 2019-2023

# CONFIDENTIAL

**MAP**

**Next 1 Page**

**3.5 - REPLACE 4" HP, MADRAS**

Project Description & Safety Assessment:

The 4” Madras HP Line was installed in 1962 from the Madras Gate Station, east of Madras near NE Loucks Rd and NE Hereford Rd., and runs through the Crooked River National Grassland, until it terminates in Madras.

The Madras Line has been found with multiple integrity concerns. Concerns that have been raised by Bend District SME’s include:

- A history of multiple seam leaks resulting in multiple leak repairs.
- Two electrically shorted casings.
- Poor weld quality of welds that have been exposed.
- Shallow depth of cover in areas.
- Poor backfill and trench conditions. Pipe was installed in rock with no padding and suitable backfill material.
- Insufficient material and construction records.

With the multiple integrity concerns that have been identified on this pipeline, Cascade began a multiple year replacement project in 2017 to begin replacement of the existing 4”, installed in 1962, with a new 6” steel pipeline. Phase 1 was completed September 19, 2018, and replaced pipe from the Madras Gate Station to Regulator Station R-75 (≈ 13,000’), Phase 2 of this project is planned for 2019 from Regulator Station R-75 to Regulator Station R-74 (≈ 9,500’), and the final phase, Phase 3, is planned for 2020 from Regulator Station R-74 to Regulator Station R-19 (≈ 7,000’). This project will increase the safety and reliability in Madras with replacing the single feed to Madras with known integrity concerns.

Total Project Budget: $4,413,541
Anticipated Project Schedule: 2019-2020

# CONFIDENTIAL

**MAP**

**Next 1 Page**

**3.6 - CANAL CROSSING, MILTON FREEWATER**

Project Description & Safety Assessment:

In Milton Freewater, a canal crossing was identified by local district management in Pendleton as being a safety concern due to having a poor pipe coating condition and having difficult access to inspect for atmospheric corrosion. The crossing is located at 83606 Winesap Rd. The corrosion risk for this pipe segment is also higher from two corrosion sub-threats associated with Atmospheric Corrosion and Pipe Coating Condition. Atmospheric Corrosion sub-threat is higher for exposed crossings due to the lack of pipe coating and difficulties in being able inspect for atmospheric corrosion. Pipe coating condition of fair or poor also increases the overall corrosion risk by not providing adequate means to protect pipe from atmospheric corrosion. Spans and pipe attached to bridges are also more susceptible to damage from outside forces. The replacement of this crossings will be by directionally drilling a new crossing under the canal bottom to be able to eliminate the poor coating and atmospheric corrosion risks.

Total Project Budget: $198,476
Anticipated Project Schedule: 2020

# Appendix

Cascade Natural Gas Corporation
Intermountain Gas Company

Great Plains Natural Gas Co.
Montana-Dakota Utilities Co.

# SUBJECT MATTER EXPERT INTERVIEW / INPUT

21762(7-11)

**Person(s) Conducting the Interview:** Kathleen Chirgwin

**Interview Date:** 6/15/2016

**Purpose of SME Interview:** To discuss pipe condition and risk on the 6 in Bend HP line 1, 4 in Madras HP line and Bend pipe replacement in the Bend district for budget consideration.

## SME Information:

SME Name: William Walker

SME Job Title: District Operations Manager

Operating Company: Cascade Natural Gas Corp.

Years of Experience: CNG 3 yrs Gas Industry- 32 yrs

Operating Region: Bend District - Southern Region

Other relevant information: Bill has worked in the utility industry for 35 years, 20 Years Henkels and McCoy Utility Construction, 6 years Northwest Natural District Management/Contractor Services, 6 years Walker Consultancy working for Puget Sound Energy, Peoples Gas, and Sempra Energy and 3 years with Cascade Natural Gas. Bill has held inspection certifications for both poly and steel in 4 states, and has a strong background in pipeline safety

## Audit Results and Conclusions:

**Summary of interview results:** See Bend pipe integrity meeting notes from 6-15-2017. Bill has been involved in the Bend pipe replacement project since 2014 and is familiar with the pipe condition and operational concerns of this 1930's vintage pre-cng pipe in downtown Bend. Bill is also familiar with the seam leak issues experienced on the 4 in Madras HP line. Bill's opinion is that the risk model is doing a good job of identifying high risk pipe with integrity concerns on the IP Bend pipe replacement and believes that the replacement project has reduced leaks and opertational cost for Cascade in downtown Bend since it is effectively replacing this pipe and improving the safety and reliability of Cascade's system.

**Are Changes Required to the Program?** ☒ YES ☐ No **If yes, changes to:** ☒ Risk Model ☐ Plan ☐ GIS ☐ Other (Describe)

**Describe Changes:**

Assign excavtation risk to shallow pipe (ex Bend HP Line 1)

Assign risk to HP lines with known seam failure issues (Madras HP Line)

Multiple leaks on lines and multiple plidko fittings need to elevate risk for the line (ex. Madras HP Line which has 3 plidko fitting on it, lines with repairs and plidkos should have priority over lines that do not have ongoing integrity concerns).

**Interviewer:** Kathleen Chirgwin

**Date:** 10 / 6 / 2017

SME: W. Walden Date: 10 / 5 / 17

Bend Pipe Integrity Meeting:

Conference call discussion on distribution pipe integrity for the town of Bend, 6 in HP Line 1 in Bend and the 4 in Madras line with a DIMP risk color coded map showing model risk.

June 15, 2016

Attendees: Jeremy Ogden, Kathleen Chirgwin, Bill Walker, Ryan Luelling, and Sue Potje

Discussed 4 in HP Madras line:

1. District mentioned that they have seen 3 documented seam failures on this line.
2. Line has two canal crossing with shorts
3. Line has 2 plidko fittings.
4. Noted 1 repair in 2016 which was a half mile from the gate.
5. 3 sections have been sent to Yakima for seam testing.
6. District had recently seen 2 visual welds on the line and the welds were acceptable to visual inspection.
7. District could not recall the wrap on the welds.
8. Depth concern on one plidko, which is only 18 inches deep due to soil erosion, district did not have any other concerns on depth for this line.
9. One of the seam failures was due to the line being buried on a rock and the district believes that stress from canal water (district called it thermal expansion) caused the seam failure leak (I think what they meant was the moisture content changes in the soil caused shifting in the support of the pipe due to the rock which may have caused shear stress on the pipe seam contributing to the leak).
10. District had no knowledge of cathodic protection issues on this line.

Discussed Bend H.P. Line 1:

1. District expressed concern that this pipe is shallow in many areas. Most concerning area is near the school.
2. District believes pipe is in good condition, mentioned that they have not seen corrosion or coating issues.

Discussed Bend Pipe Replacement briefly:

1. District mentioned concern by 3rd and Davis, they explained this was poor condition pipe (with poor condition coating) that they could not weld on due to metal loss, compression couplers, and since they could not weld on this pipe they did a 2 in steel squeeze.
2. District mentioned that we need to accelerate Florida due to poor pipe condition and recent leaks in this area.

As wrap up to meeting Bill mentioned his biggest concern at the district level is the Madras line since this is a single feed line with known seam failure issues and we have no other means to feed the town of Madras.

Cascade Natural Gas Corporation
Intermountain Gas Company

Great Plains Natural Gas Co.
Montana-Dakota Utilities Co.

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CNGC/902
Privratsky-Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Ryan Privratsky and Michael P. Parvinen

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**Distribution Integrity Management Program (DIMP)**
**Exhibit CNGC/902**

**October 2018**

# Standard Operating Procedure

Title: **Distribution Integrity Management**

Department: Engineering

Procedure Number: **3451.3** Revision Date: **August 5, 2016**

## Revision Summary

Second revision; remove references to integrated standard procedure numbers that were not implemented. A revision summary is in Appendix I.

## References:

Regulations

CFR 492 – Part 192 – Subpart P … Gas Distribution Integrity Management (IM)

Procedures

Leak Survey
Material and/or Component Failure

Programs

Distribution Integrity Management Program
Damage Prevention Program
Public Awareness Program

Forms

21760 … Additional or Accelerated Action Implementation
21761 … DIMP Review Summary
21762 … Subject Matter Expert Interview/Input
21763 … GIS Validation
21764 … SME Panel Decisions

# Standard Operating Procedure

Cascade Natural Gas Corporation — In the Community to Serve
Great Plains Natural Gas Co. — In the Community to Serve
Intermountain Gas Company — In the Community to Serve
Montana-Dakota Utilities Co. — In the Community to Serve

**REVISION CONTROL SHEET**

Document Number: 3451.3

Title: Distribution Integrity Management Program

Document Location: Company Policies and Procedures (General Office Engineering)

| Revision | Date | Comments |
|---|---|---|
| 0 | 8/1/2011 | Original procedure implemented due CFR 49 Part 192 Subpart P; Gas Distribution Integrity Management. |
| 1 | 3/29/2013 | Revisions to this plan were made as a result of a three state DIMP audit with Oregon, Washington and Idaho conducted on August 21-22, 2012. A summary of the revision is located in Appendix I. |
| 2 | 7/15/2013 | Revisions to this plan were made due to a change in corporate plans to not create integrated standard procedures with new procedure numbers. |
| 3 | 8/1/2016 | Revisions to the plan were made as part of the 5 year periodic evaluation requirement. Reference Appendix I and Form 21761 for further details. |
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# Standard Operating Procedure

## Table of Contents

# 1.0 INTRODUCTION

## 1.1 Overview

This Distribution Integrity Management Plan (Plan) will be used by Montana Dakota Utilities (MDU), Great Plains Natural Gas (GPNG), Intermountain Gas Company (IGC) and Cascade Natural Gas Corporation (CNGC) to meet the requirements of a Distribution Integrity Management Program (Program) as outlined by CFR Part 192, Subpart P. MDU, GPNG, IGC and CNGC are subsidiary companies operating under Montana Dakota Utility Resources and will be referred to as the "Company" throughout this Plan.

## 1.2 Purpose

The Company's Program includes all appropriate operating, maintenance and pipeline safety practices routinely performed in addition to the activities described in this written Plan. The Plan establishes the requirements and responsibilities necessary to ensure that the integrity management of natural gas distribution facilities owned and operated by the Company is performed in accordance with Subpart P of 49 CFR Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards (Code). The Company's objective is to operate, maintain, and manage all of its natural gas distribution facilities in a safe and responsible manner without failures or other incidents that could affect public or employee safety, or that could generate service interruptions.

## 1.3 Scope

All Company operated gas distribution facilities, as defined in §192.3 of the Code, including mains, service lines, service regulators, district regulating facilities, high pressure distribution systems and low pressure distribution systems are subject to the Company's Program.

The Company's specific system facilities are identified in accordance with Section 2.0 of the Plan.

## 1.4 Program Elements

Seven elements have been identified as the essential components of the Company Program and are discussed in more detail throughout this Plan. These seven elements are as follows:

1) Demonstrate knowledge of distribution system
2) Identify threats
3) Evaluate and prioritize risk
4) Identify and implement measures to address risks
5) Measure performance, monitor results and evaluate effectiveness
6) Perform periodic evaluation and improvement
7) Report results

Distribution integrity management is a comprehensive and continuous process that requires the integration of data, processes and operational knowledge. The process shown in Figure 1.1 will be used by the Company to meet the requirements of the seven Program elements.

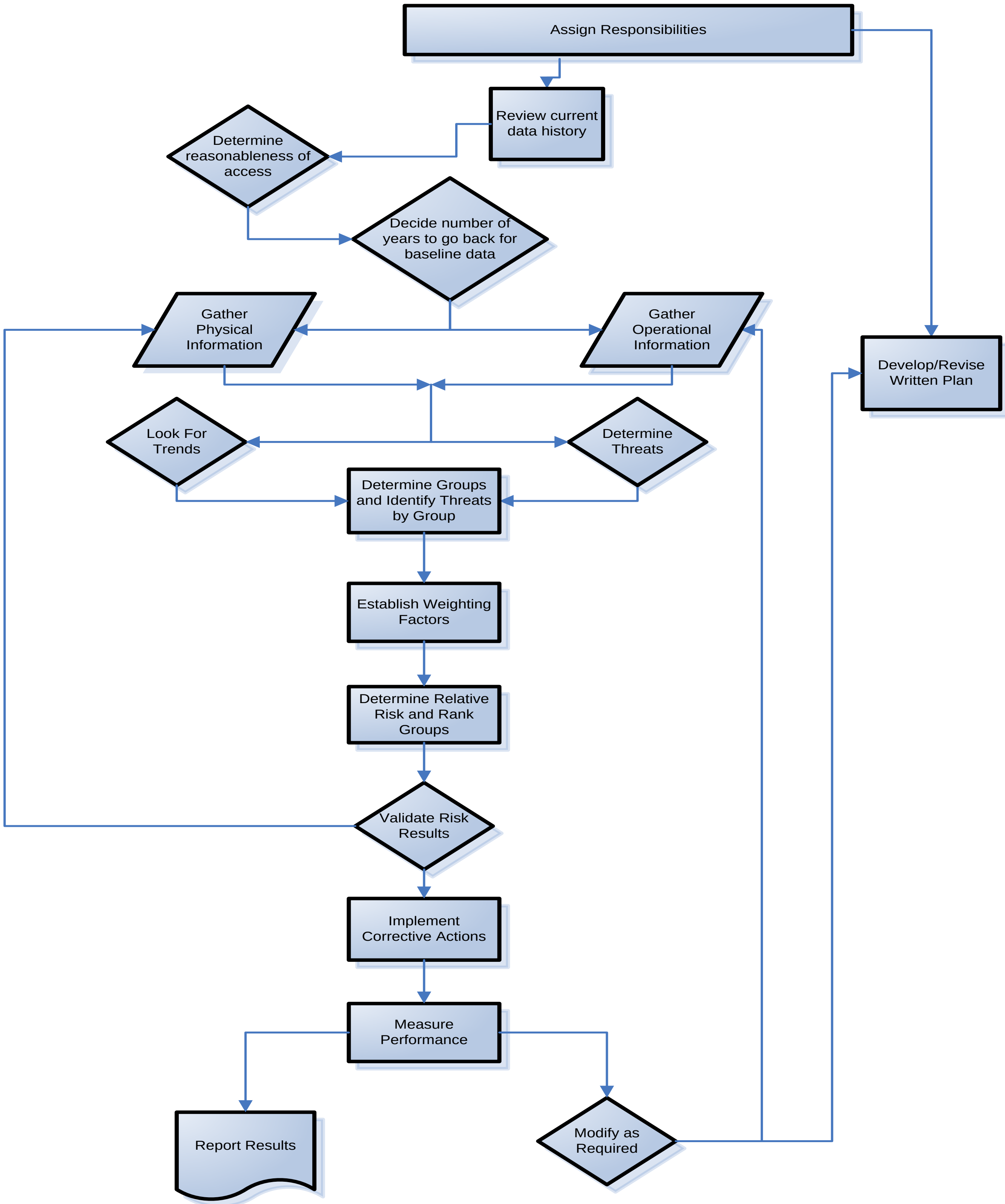


Figure 1.1: Distribution Integrity Management Program Process

## 1.5 Plan Appendices

This plan will consist of appendices specific to each Company. Information within each appendix will be compiled and updated by GO Engineering. Company appendices shall be reviewed annually for necessary updates. Information in appendices will be year specific and a copy of the current plan and current year appendices will be saved in a yearly plan edition. This plan edition will be compiled and stored by GO Engineering at each operating company. Annual updates shall be completed by March 31 and will be valid for one year.

## 1.6 Subject Matter Expert Involvement

Subject Matter Experts (SME) will be consulted throughout all sections of this plan. GO Engineering is responsible to qualify SMEs used in the Company's Program and provide documentation in Appendix G – *Subject Matter Expert*. SMEs may be consulted with regard to operational knowledge of distributions systems, threat identification, risk evaluation and ranking, and risk mitigation. Two types of SMEs will be utilized in this Program, Isolated SME and SME Panel.

### 1.6.1 Isolated Subject Mater Expert

Isolated SMEs will be used to identify and assess localized risk. Localized risk may apply to specific facilities, events or knowledge acquired through day to day operations and maintenance activities. Isolated SME information will be documented using Form 21762 which summarizes:

- Interview Date
- SME Information
- SME Experience
- Summary of Interview
- SME Signature

### 1.6.2 Subject Matter Expert Panel

The SME Panel will consist of selected individuals appointed by GO Engineering. The panel will be consulted to assist in making company decisions concerning the performance of the risk model, risk model scoring and weighting, threat subdivision and risk mitigation. SME Panel meetings shall be documented in the Appendix G - *Subject Matter Expert* and SME Panel decisions will be documented using form 21764: SME Panel Decisions; which will include at a minimum:

- Date of Panel Meeting
- Name (s) of SME Panel Members and Bios
- Objectives for Panel Meeting
- Decisions made by SME Panel
- Signatures of SME Panel Members

## 1.7 Definitions

1. **Code** – Code of Federal Regulations (CFR) 49, Part 192, Subpart P
2. **Company** – Montana Dakota Utilities, Great Plains Natural Gas, Intermountain Gas Company and Cascade Natural Gas Corporation
3. **DIMP** – Distribution Integrity Management Program
4. **GIS –** Geographical Information System
5. **Hazardous Leak** - leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous
6. **Transmission Pipeline** – A natural gas pipeline, other than a gathering line, that fits one of the following criteria:
    - Operates at a hoop stress of 20% or more of SMYS
    - Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center
    - Transports gas within a storage field
7. **Distribution Pipeline** – A natural gas pipeline other than a transmission or gathering line
8. **Subject Matter Expert (SME)** – Any individual knowledgeable about design, construction, operations, or maintenance activities, or the system characteristics of a particular distribution system. Designation as an SME does not necessarily require specialized education or advanced qualifications, some SMEs may possess these characteristics, but detailed knowledge of the pipeline system gained by working with it over time can also make someone an SME. SMEs may be employees, consultants, or contractors, or any appropriate combination.
9. **Specified Minimum Yield Strength (SMYS) –** The minimum yield strength of a steel pipeline in accordance with a listed specification or in accordance with 192.107
10. **Maximum Allowable Operating Pressure (MAOP) –** The maximum pressure at which a pipeline or segment may operate
11. **Plan –** Written document describing actions the Company will take to satisfy the requirements of a Distribution Integrity Management Program (CFR 192 Subpart P)
12. **Program –** The actions and/or activities the Company will take to satisfy the requirements of CFR 192 Subpart P

## 1.8 Responsibilities

### 1.8.1 IGC and CNGC

Responsibilities associated with the Program for IGC and CNGC are listed below. The Distribution Integrity Management Organization Structures for IGC and CNGC are shown in Figures 1.2 and 1.3 respectively.

#### *1.8.1.1 Vice President of Operations*

- Monitor the implementation and continuance of the Plan
- Ensure adequate budget and personnel are committed to effectively pursue the purpose of the Plan

- Perform oversight of the Plan
- Approve the Plan
- Approve changes to the Plan

***1.8.1.2 Management Personnel***

The Director of Engineering Services and the Director – Operations Services are responsible to:

- Provide adequate personnel, tools, equipment and supervision necessary to meet the required activities described in the Plan
- Ensure that appropriate employees receive training necessary to perform the duties required by the Plan
- Select and hire service providers as needed
- Program Approval

***1.8.1.3 General Office (GO) Engineering***

- Perform day-to-day implementation and management of Plan
- Communicate Plan requirements and activities to both Management and Regional Personnel
- Perform the documentation and communication responsibilities specified in the Plan
- Supervise service providers as necessary
- Review and make updates to the Plan as necessary or required

***1.8.1.4 Regional Directors***

- Provide adequate personnel, tools, equipment and supervision necessary to meet the required activities described in the Plan
- Ensure that appropriate employees receive training necessary to perform the duties required by the Plan
- Select and hire service providers as needed

***1.8.1.5 Operations/District Managers***

- Perform the documentation and communication responsibilities specified in this Plan
- Supervise service providers as necessary

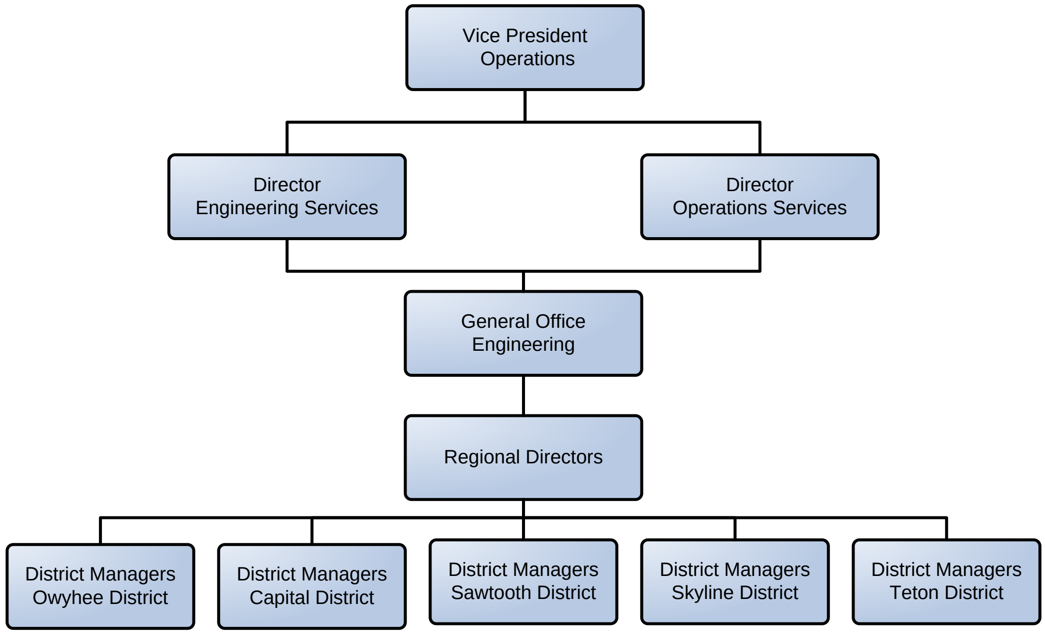


Figure 1.2: IGC Distribution Integrity Management Organization Structure

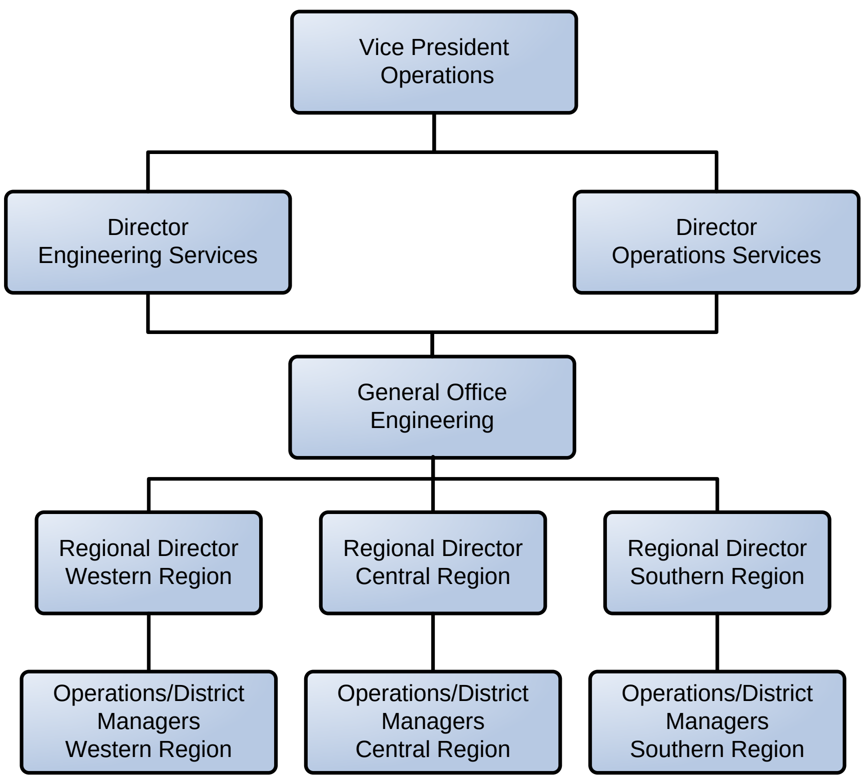


Figure 1.3: CNGC Distribution Integrity Management Organization Structure

### 1.8.2 MDU/GPNG

MDU/GPNG responsibilities as they relate to the Program are listed below. The Distribution Integrity Management Organization Structures for MDU/ GPNG is shown in Figure 1.4.

***1.8.2.1 Vice President of Operations and Region Managers***

- Monitor the implementation and continuance of the Plan within the company
- Ensure adequate budget and personnel are committed to effectively pursue the purpose of the Plan
- Perform oversight of the Plan
- Approve the Plan
- Approve changes to the Plan

***1.8.2.2 Gas Distribution Engineering (General Office Engineering)***

- Perform day-to-day implementation and management of the Plan
- Oversee and coordinate the implementation of the elements of the Plan
- Ensure all Documentation and Communications specified in the Plan are completed and submitted
- Provide adequate personnel, tools, equipment and supervision necessary to meet the required activities described in the Plan
- Ensure that appropriate employees receive training necessary to perform the duties required by the Plan
- Select and hire service providers as needed
- Review and make updates to the Plan as necessary or required

***1.8.2.3 Regional Gas Superintendents***

- Provide adequate personnel, tools, equipment and supervision necessary to conduct the Field activities described in the Plan.
- Ensure all Field documentation, Date collection, and Communications specified in the Plan are completed and submitted.

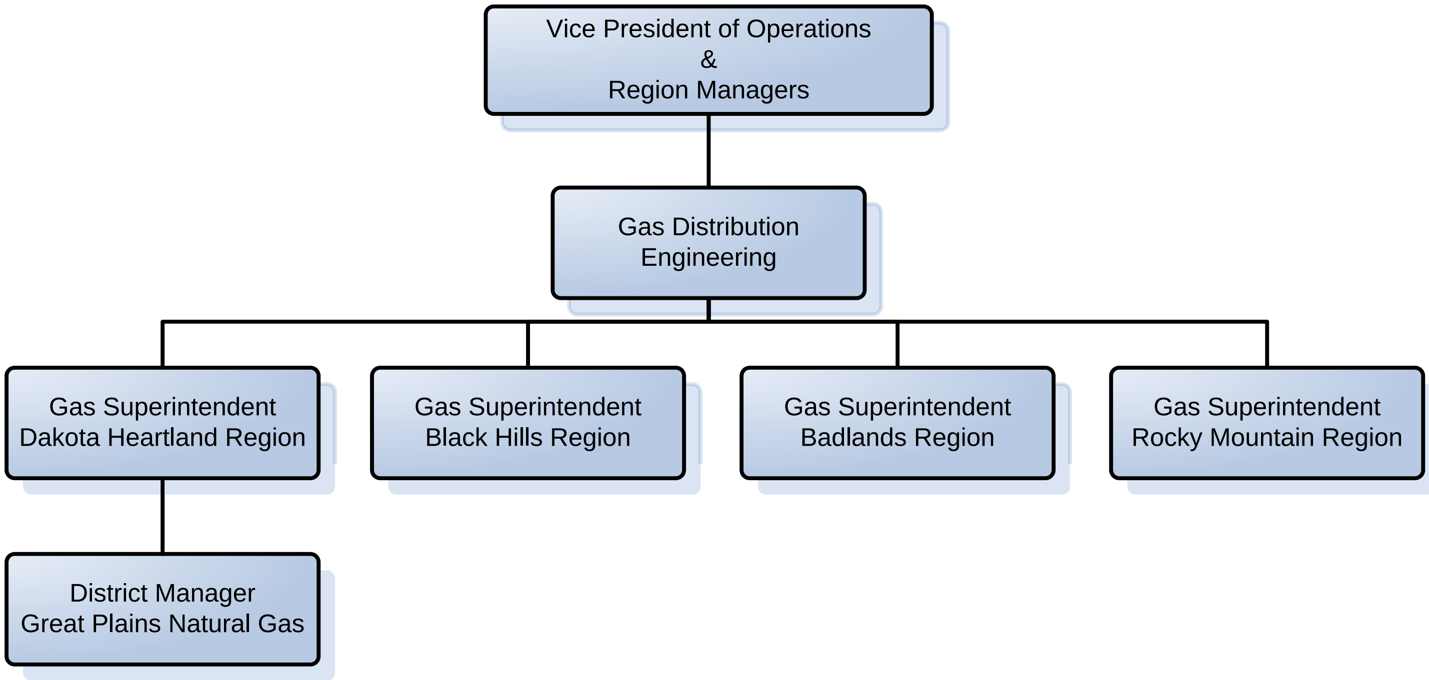


Figure 1.4: MDU Distribution Integrity Management Organization Structure

## 2.0 KNOWLEDGE OF DISTRIBUTION SYSTEM [§192.1007 (A)]

### 2.1 Overview

The purpose of this section is to demonstrate the Company's methodology for providing an understanding of its distribution system facilities.

In order to determine threats and assess risks on the distribution system, the Company begins by collecting appropriate information specific to the facilities within the distribution system. The information is found in two general categories: the physical make up of system components and the operating and maintenance history of those components.

The Company demonstrates knowledge of the system by considering the information outlined in Section 2.2 to the extent it currently exists in at least one of the Company record systems (e.g., maps, paper forms, cards, electronic data bases or files, photographs) or in the knowledge and experience of operations and maintenance personnel.

Appendix B – *Knowledge of System* will summarize the data and records collected by the Company in order to demonstrate the requirements of this section. Information included in the Appendix B may include:

- Record (Form #)
- Record Type (paper/electronic/database/GIS)
- Brief Summary of Data Collected
- Location of Record
- Is the Information used in risk model (Y/N)

### 2.2 Physical Infrastructure

Below is a list of distribution system characteristics that should be considered, at a minimum, when demonstrating system knowledge and identifying threats to the Company's distribution system.

#### 2.2.1 Pipe Material

##### *2.2.1.1 Plastic*

- Plastic Polyethylene (PE)
- Poly Vinyl Chloride (PVC)
- Aldyl-A
- Others [either old or new]

##### *2.2.1.2 Steel*

- Grade
- Seam Type

#### 2.2.2 Pipe Specifications

- Nominal Diameter

#### 2.2.3 Construction

- Year Installed

- Location
- Casing size
- Highway/road crossing

#### 2.2.4 Corrosion

- Below ground coating type

#### 2.2.5 Valves

- Location
- Material or construction
- Year manufactured/installed

#### 2.2.6 Environmental

- Water crossings
- Landslides
- Soil Characteristics
- Flood Zones
- Seismic zones

### 2.3 Historical Information

Below is a list of historical maintenance records that should be considered, at a minimum, when determining relevant knowledge to the integrity of the Company's distribution system.

#### 2.3.1 Documentation of Leaks and Other Maintenance

- Repairs (categorized by cause)
- Leaks (categorized by cause)
- Exposed Pipe Inspection Reports
- Pipeline Patrol Records
- Corrosion Control Records
- Valve Maintenance Records

#### 2.3.2 Excavation Activity

- Number of underground locate requests received

#### 2.3.3 Operating Pressure

- Normal Operating Pressure

### 2.4 Outside Source Data

The Company may use data from outside sources to gain knowledge about facilities and identify threats. Such information may include flood zones, population data, wild fire zones, etc. When data from an outside source is used, the following information must be collected and retained in Appendix B – *Knowledge of System*.

- Description of Data
- Geographic Coverage
- Data Source/Agency
- Source Format/File Type
- Source URL (if applicable)

## 2.5 Newly Installed Facilities

When new facilities are installed, facility information must include, at a minimum, the location and material of which it is constructed. A summary of current information collected on newly installed facilities will be listed in Appendix B – *Knowledge of System* and should include the following:

- Record
- Data Collected
- Format (Paper, Field Automation Database, GIS, etc.)

## 2.6 Information Evaluation

All data used in the risk model is reviewed for completeness and data accuracy through QA/QC efforts by GIS staff. The Company will continuously update and validate facility information during routine operational activities such as maintenance, construction and repairs.

### 2.6.1 Insufficient Data

General Office Engineering will review and evaluate the aggregated data to identify areas where data is insufficient or missing. When incomplete records and/or knowledge is identified, it will be summarized in Appendix B – *Knowledge of System* by including the following information:

- Record
- Date Identified
- Extent of Record
- Plan to Acquire Data
- Anticipated Completion Date
- Department Responsible

### 2.6.2 Developing Additional Information

When analysis and threat assessment indicate that additional infrastructure information may be useful or necessary, the Company will determine what additional information should be collected. Such determination may be triggered by (1) the desire to perform a more focused threat and risk analysis, (2) an indication that a different grouping would provide better understanding of risk, (3) indications that more information is required to evaluate future potential threats or (4) other currently unforeseen reasons.

Except in unusual cases, the additional information will be gathered through normal activities. In order to accomplish this, one or more of the following steps may be implemented:

- Forms or other methods used to collect information related to the physical attributes and/or operating and maintenance activities of distribution pipeline facilities are appropriately modified
- Personnel are trained to properly collect and record the expanded information and use the modified forms or data collection format
- Recordkeeping procedures and/or data management systems are updated to accept new data points
- Newly collected information is integrated into all other records
- Interviews with SMEs

### 2.7 Subject Matter Expert Involvement

In addition to distribution knowledge gained from company records, knowledge will be acquired from operating staff that are familiar with construction and maintenance practices, operating systems and history, and prior and present industry trends. SMEs will also be consulted to fill in operational record gaps. When SMEs are consulted for input, documentation will follow Section 1.6: Subject Matter Expert Involvement.

# 3.0 THREAT IDENTIFICATION [§192.1007 (B)]

## 3.1 Overview

This section's objective is to describe how the Company identifies relevant threats which could affect the integrity of the Company's distribution facilities. After gathering and evaluating the information outlined in Section 2, the Company will determine which threats, if any, could affect the current or future integrity of a particular facility segment. Primary threats for each facility segment will be categorized into the following:

- Corrosion
- Natural Forces
- Excavation Damage
- Other Outside Force Damage
- Material, Weld or Joint Failure
- Equipment Failure
- Incorrect Operation
- Missing Data
- Other – Forces unique to a particular area on the system

If data used for threat identification and categorization are insufficient or suspect, each threat covered by the missing or insufficient data is assumed to apply to the segment being evaluated until the process described in Section 2.6.1 is implemented and begins to produce adequate information. Unavailability of information is not justification for exclusion of a threat. Where data is missing or insufficient, conservative assumptions may be used in the risk assessment based on SME conversations and engineering decisions. Such assumptions will be documented in the Appendix D – *Risk Input*.

## 3.2 THREATS

This section provides threat definitions consistent with PHSMA F7100 Leak Classification definitions.

### 3.2.1 Corrosion

Corrosion results on pipe or other components due to galvanic, bacterial, chemical, stray current or other corrosion action. All metallic pipe and components are subject to the threat of external corrosion. The threat of internal corrosion will be identified only where the expectation of liquid water being present due to a documented event in the facility segment exists or when an internal pipe inspection has shown corrosion to be present on the inside surface of the facility. The Company does not transport corrosive gas in its distribution system therefore internal corrosion is unlikely. Atmospheric corrosion is a subset of external corrosion that will occur only on pipe and components that are not buried. For exposed pipe in areas where only a light surface oxide forms that does not affect the safe operation of the facility (§192.479), the threat of atmospheric corrosion will not be identified.

### 3.2.2 Natural Forces

The threat of natural forces result from earth movements, earthquakes, landslides, subsidence, lightning, heavy rains/floods, washouts, flotation, mudslide, scouring, temperature, frost heave, frozen components, high winds or similar natural causes. While Company facilities experience a wide range of atmospheric temperatures, the range is within the design limits of the materials of construction.

### 3.2.3 Excavation Damage

Excavation damage is damage to pipeline facilities caused by earth moving or other equipment, tools, or vehicles, including damage done by operator's personnel, contractor, or people not associated with the operator. All buried facilities in the Company's distribution system face the threat of being damaged by excavation activities. Consideration is given to piping within protective casings, inside underground structures such as basins or vaults which may be shielded or protected from excavation damage. Excavation damage can also be due to previous unknown damage on pipelines that were not repaired and result in corrosion.

### 3.2.4 Other Outside Force Damage

Other outside force damages are a result from fire or explosion, deliberate or willful acts, such as vandalism and vehicular damage. Only aboveground facilities are considered when determining if this threat is present. The primary concern is areas where gas piping is close enough to vehicular traffic such as automobiles, trucks, forklifts, snow plows, construction equipment, etc., where it may be reasonably expected that damage from vehicle movement could occur. Facilities in locations known to be subject to vandalism, destruction, wreckage, sabotage, or other harm (e.g., unauthorized adjustment or valve movement) may carry the other outside force damage threat.

### 3.2.5 Material, Weld or Joint Failure

This threat is identified by the Company when it is known or anticipated that potential defects in pipe, fittings, components and joints that were introduced during the manufacturing process may be present. Longitudinal pipe seams made by low frequency ERW before 1970, electric flash welding, lap welding, hammer welding, or butt welding and fittings or components fabricated by welding may pose a weld-related material threat. Defects within fittings and components from the manufacturing process are material threats. Certain plastic piping materials (e.g., Century Utility Products pipe, Low-ductile inner wall Aldyl A pipe manufactured before 1973, PE3306 pipe, PVC pipe and fittings, CAB pipe material) are subject to this threat. This threat also includes the failure of original sound material from force applied during construction that causes a dent, gouge, excessive stress or other defect. This includes faulty wrinkle bends, faulty field welds and damage sustained in transportation to the construction or fabrication site.

### 3.2.6 Equipment Failure

Equipment failure resulting from the malfunction of control/relief equipment including valves, regulators, or other instrumentation; stripped threads or broken pipe couplings on nipples, valves or mechanical couplings; or seal failures on gaskets, O-rings, seal/pump packing or similar failures. The Company will consider items of equipment exhibiting possible systemic problems as vulnerable to the equipment malfunction threat. Such items may include regulator or relief valves (e.g., failing to perform the intended task or operating outside of the manufacturer's specified tolerances), repeated history of failed flange gaskets, repeated history of failed O-rings, repeated history of broken pipe or stripped threads, and equipment with a history of problems.

### 3.2.7 Incorrect Operation

The threat of incorrect operation may be applicable to either operating (e.g., start up or shut down of a pipeline, purging) or maintenance activities (e.g., ignition of escaping gas). This threat is associated with internal or external personnel. It does not include the designed operation of a device. Poor workmanship or outdated methods during the construction or installation process that constitutes a failure to follow current procedures or inadequate procedures or safety practices are considered within this threat category. Knowledge of instances where personnel have not followed approved procedures (e.g., modification of a mechanical coupling contrary to the manufacturer's recommendation, failure to install a stiffener) could lead to identification of an incorrect operation threat.

### 3.2.8 Other

The Company will determine if other threats are present around its distribution system that are not covered in the threats described above. Such threats will likely be attributable to special circumstances in specific locations on the system. Accelerated material deterioration not resulting from a material defect or corrosion could come under this threat category.

### 3.2.9 Missing Data

The Company considers missing data a threat to the distribution system. Missing data considered in this category applies to data necessary to identify threats on the system through use of the Company risk model (e.g. installation date, material type, leak cause).

## 3.3 Subdividing Threats

To further refine risk in threat categories, existing and potential threats may be subdivided within the primary threat categories. Decisions for subdividing threats will be based on data analysis, regional trends, industry trends, potential threat identification, Gas Piping Technology Committee (GPTC) Guidance, and SME input. Subdivided threat categories will be included with the risk model calculations documentation in Appendix D – *Risk Input* which should include the following information:

- Threat
- Subdivision Category
- Reason for Subdividing Threat
- Risk Breakdown of Subdivision

## 3.4 Potential Threats

This section describes how potential threats are identified, documented and added to the risk model. Potential threats are threats where the operator has not experienced a leak though conditions conducive to the threat exist. Potential threats are threats identified as having the possibility of affecting the integrity of the distribution system but have not yet been added to the risk model. Potential threats shall be company specific and a table of potential threats will be listed in Appendix C - *Threat Identification*. Prior to annual risk model runs GO Engineering will review the list of potential threats to determine if these threats are applicable to the risk model. Potential threats will be considered from external and internal sources.

### 3.4.1 External Sources

To stay informed of potential new threats to distribution systems, industry and regulatory recommendations will be routinely monitored from external sources including but not limited to:

- Industry and Trade Publications
- Nation Transportation Safety Board (NTSB) Reports and Recommendations
- Pipeline and Hazardous Materials Safety Administration (PHMSA) Recommendations
- State Pipeline Safety Recommendations
- Membership in American Gas Association (AGA), Northwest Operating Group (NWOG), Western Energy Institute (WEI), Gas Technology Institute (GTI), Gas Piping Technology Committee (GPTC), National Association of Corrosion Engineers ( NACE)

### 3.4.2 Internal Sources

Concerns identified by SMEs within the operating company will also be reviewed to determine if it could be a potential threat. Isolated SME concerns brought to GO Engineering's attention following Section 1.6: Subject Matter Expert Involvement shall be summarized in Appendix G – *Subject Matter Expert,* summarizing:

- Concern
- District
- SME Name and Title
- Date Concerned Addressed to Engineering

Tracking isolated concerns in specific districts and towns will allow GO Engineering to see trending and be proactive towards emerging threats that may be affecting the entire distribution system.

### 3.4.3 Potential Threat Assessment

As GO Engineering identifies new potential threats they will determine if these threats are applicable to the Company distribution systems. The applicability of threats to an operator's distribution system may be identified by reviewing applicable operations and maintenance records, considering knowledge of operational personnel and evaluating relevant information.

If a threat is determined to affect the current or future integrity of the distribution system the threat will be added to the risk model and further documented in Appendix D – *Risk Input*. If additional data collection is required to effectively assign risk, Section 2.6.2 will be used to gather the information and until the data is robust enough to accurately reflect risk in the risk model, incomplete data shall be summarized as described in Section 2.6.1.

It is reasonable that some threats might not apply to the Company's system. When threats are considered but excluded from the Company's distribution system risk assessment, reasonable justification will be documented in Appendix C – *Threat Identification.*

# 4.0 RISK EVALUATION AND RANKING [§192.1007 (C)]

## 4.1 Overview

This section describes how the Company evaluates and ranks risks associated with the Company's distribution system. The Company approaches risk assessment through determining the relative risk of facilities grouped by mains and services of similar attributes and/or experiencing similar problems. The magnitude of the relative risk determination will lead to ranking of groups for the application of risk management measures. Relative risk is Company specific and only indicates a comparative value relative to other Company facilities.

All risk model weighting factors, including consequence and likelihood factors, as well as past and future considerations can be found in Appendix D – *Risk Input*.

## 4.2 Risk Model

The Company uses a GIS based risk model known as ESRI® Arc GIS ModelBuilder to calculate relative risk scores for facilities. The risk model is broken down into a series of sub-models that represents each threat category. Each sub-model is designed to use applicable facility data collected in Section 2 to calculate risk for facilities grouped by mains and services. Specific risk model information for each threat is outlined in Appendix D – *Risk Input*.

### 4.2.1 Responsibilities

GO Engineering is responsible for identifying and updating all factors and inputs that are used in the risk model and communicating any changes to the Company GIS department. Changes to the models as wells as generating the results will be completed by the GIS department when directed by GO Engineering. The Company GIS Department will execute risk model calculations when directed by General Office Engineering. The Risk Model will be run annually not to exceed 15 months from the date of the last run. Each model run will be stored and archived by the GIS Department.

### 4.2.2 Determination of Risk Weighting Factors

GO Engineering determines appropriate likelihood (category scores) and consequence factors (impact score) through the use of employees who are knowledgeable in the operation, maintenance, design and construction of its distribution system (i.e. SME Panel). All SME Panel decisions concerning risk weighting factors shall be documented following the process outlined in Section 1.6.2. Operational history and maintenance records will also be used when determining risk factors. Outside consultants and trade associations or other operators with expertise in gas distribution industry trends or historical methods are used when it is determined to be necessary.

Adjustment of weighting factors is allowable, appropriate and expected. One reason may be a validation of risk calculation results with actual field experience as described in Section 4.2.5. Weighting factors may also be adjusted for each operational area as opposed to applying global numbers to all Company facilities when deemed necessary by GO Engineering. Improvement of the distribution system and the Plan over time is expected and will likely require modification to some of the weighting factors. All revisions to the model weight factors will be documented in Appendix I – Periodic Evaluation using the following information:

- Date

- What was changed
- Reason for change

### 4.2.3 Likelihood Factors

Likelihood factors represent the possibly of a specific threat occurring on the distribution system. Numerical weightings of likelihood factors are determined as a result of facility attributes represented by the group. A zero to ten scale on one tenth intervals is used with the following levels of severity:

- 7 – 10 = High Likelihood of Failure
- 3 – 6.9 = Medium Likelihood of Failure
- 0 – 2.9 = Low Likelihood of Failure

### 4.2.4 Consequence Factors

Company assigns numerical weighting factors to represent consequences that may be anticipated in case of an integrity issue involving the facility groups.

Consequence factors are based on the location of the facility in relation to population density as well as the amount of gas that could potentially be released. Additional consideration may be given to "Critical Infrastructures" as defined in the Homeland Security Act (P.L. 107-56) depending on the availability and accuracy of the data. The consequence factors are generally assigned into three categories:

1) Population density and location
2) Potential Energy of Pipeline based on the operating pressure and pipe size
3) Critical infrastructure size and location

A higher number represents a greater relative consequence that could result from a failure. The numbers from the three categories are then added to create an overall consequence factor.

### 4.2.5 Factors for Missing Data

In the case that facility attributes are missing or unknown as identified through the process outlined in Section 2.6 within a group feature, factors will be determined for "unknown" data where it is used by the risk model. The generally accepted risk approach to "unknown" data is that because of the uncertainty it should add risk to the overall risk calculation. The Company may choose to assign higher numerical weights or likelihood factors to data fields directly used in the risk model calculations. The Company will identify and evaluate these gaps in the data and use the processes indicated in Section 2.6.2 to determine and gather the missing data over time.

#### 4.2.6 Relative Risk Calculation

Risk is the product of the likelihood of an event occurring multiplied by the consequence of the event. In equation form:

***Risk*** = ***Likelihood*** (category score) **x** ***Consequence*** (impact score)

The risk model sums the assigned likelihood scores for each threat to calculate a total likelihood factor within a 50 foot grid (raster). The same summing calculation is also done for each of the assigned consequence factors within the same 50 foot grid. The total Likelihood is then multiplied by the total consequence factor to establish a total relative risk score for the grid.

In order to obtain better processing and risk analysis, the final rasters are overlaid on facility poly lines and the risk is assigned at the line segment level within the GIS database. This is repeated for each segment to determine the relative facility segment risk ranking within each group in the Company distribution system.

After the relative risk is calculated for all threats for all groups, comparison of the relative risk numbers leads to those groups of the system where risk management practices should be implemented in order to improve the overall safety of the distribution system based on performance metric trending.

### 4.3 Risk Ranking

Using the risk results from the model run, GO Engineering will rank each threat by state. A summary of the current risk ranking will be included in Appendix E - *Risk Analysis* and should include the following information:

- Primary Threat Total Risk Scores
- Primary Threat Total Risk Scores by State
- Primary Threat Total Risk Scores by District

### 4.4 Risk Model Validation

The purpose of model validation is to confirm that the risk output from the model accurately reflects what is known about the Company's system in order to identify and prioritize known risks. Risk model validation will be led by GO Engineering with SME Panel consultation following Section 1.6.2. A model validation summary will be summarized in Appendix E – *Risk Analysis* and will include:

- Model Run Date
- Date of Model Validation
- Summary of Validation Results

Prior to the SME Panel meeting, GO Engineering will compile applicable model results, performance metrics and operational data trending, including leak reports, to assist and facilitate SME Panel with model validation.

If model changes and results are of no consequence from year to year GO Engineering may decide that model validation by the SME Panel is unnecessary. If model validation is decided to be unnecessary, GO Engineering shall document that no model validation is required in the Model Validation Summary in Appendix E – *Risk Analysis*. Statistics showing inconsequential data from last model validation can be incorporated for reference.

If the SME Panel does not agree with the results of the model, the SME Panel may assist with making model calculation, threat subdivision and weighting factor adjustments to refine/calibrate the model. All model refinements shall be documented in the Appendix I – *Periodic Evaluation*, similar to Section 4.2.2. Once adjustments are complete the model will be rerun and the Model Validation process will be reiterated until model results are validated by the SME Panel.

# 5.0 SELECT AND IMPLEMENT RISK MANAGEMENT ACTIONS [§192.1007 (D)]

## 5.1 Overview

This section describes the existing and proposed measures to address the threats and associated risk to the Company's distribution system as outlined in Sections 3.0: Threat Identification and 4.0: Risk Evaluation and Ranking.

Risk management is accomplished by taking actions to reduce the likelihood of an occurrence, by alleviating the consequences of an occurrence or both. Appropriate actions are dependent on the group being addressed, the associated threat, whether the threat is current or potential in the future and the viability of the actions in managing the relevant risk factors.

## 5.2 Existing Programs Addressing Risk Management

This section summarizes existing plans and programs implemented by the Company that are currently in place to manage risks. Each established program contributes to the management and mitigation of risk to the distribution system. Details for each program are contained in Company Operations and Maintenance procedures and are available upon request.

### 5.2.1 Damage Prevention

The prevention of damage to natural gas distribution facilities by excavation is one of the most effective ways of increasing the integrity of the gas system and improving public safety relative to natural gas. The Company has implemented and maintains a Damage Prevention program that meets the following criteria:

- Meets or exceeds the requirements of §192.614 – Damage Prevention Program
- Participates in one-call programs within service territory
- Supports the Common Ground Alliance (CGA) efforts to reduce excavation damage through the publication and dissemination of best practices

### 5.2.2 Leak Management

The Company recognizes that managing leaks from its distribution system is an important part of addressing the integrity of the system and reducing risk by reducing the potential consequences of a leak. The Company has and effective leak management program that includes the following elements.

#### *5.2.2.1 Locate*

Leaks are located through routine and specially scheduled leakage surveys with leak detection equipment. Additionally, all leak and gas odor complaints are responded to and investigated to locate leaks that occur which are not present at the time of a leakage survey.

Leakage surveys are performed with flame ionization and/or optical methane detector equipment in locations outside of buildings. Intrinsically safe gas detection instruments may be used indoors as a screening tool for detection of the actual leak location.

#### *5.2.2.2 Evaluate*

The Company evaluates each leak detected in accordance with company leak survey procedures. Leaks are located, confirmed and classified when a sustained reading is obtained on a combustible gas indicator.

Based on the classification of the leak, additional actions may be required per company leak survey procedures. For the purpose of reporting under Section 9.1 of this Plan, the company uses the following criteria to define a hazardous leak:

- Leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous (§192.1001)

#### *5.2.2.3 Act*

Take appropriate action to mitigate these hazardous leaks. Confirmed leaks are repaired or monitored as specified in company leak survey procedures. All leaks classified as hazardous leaks are repaired or eliminated before company personnel leave the scene. Leaks considered non-hazardous may be immediately repaired, scheduled for repair or monitored depending on perceived potential of becoming more severe.

#### *5.2.2.4 Keep records*

Every confirmed leak is given a unique identifier and is tracked until it is repaired and subsequently cleared. Leak locations are tied to an address and are initially "assigned" to a main, service pipe or other unit such as a district regulating station or meter number. Leak records, including repair action and clearing confirmations, are retained at the local operating area. All leak records are retained for the life of the affected facility**.**

#### *5.2.2.5 Self-assess*

The Company determines if additional actions are necessary to keep people and property safe. Appropriate District Operations personnel routinely review leak survey, classification and repair results to ensure that all leaks discovered receive proper response. The Company reviews and trends the overall results of the leak management program per Section 6 of the Plan. When appropriate implementation of additional risk control practices or modifications to the leak management program are evaluated.

### 5.2.3 Maintenance Programs

Annual maintenance ensures critical system components are adequately maintained and operational as designed. Annual maintenance is performed on all regulator stations, compressor stations, and critical valves to ensure no adverse operating conditions are present. Regulator stations are checked to ensure set points are correct to achieve regulator lockup and relief set pressures are confirmed that the relief will open at desired set pressures to protect MAOP. Valves are checked annually to ensure the valve is able to open/close and lubricated/greased if needed and/or applicable.

### 5.2.4 Public Awareness

The awareness of the public of pipelines in their vicinity and the public's understanding of how pipelines are operated contributes to the continued safe operation of those pipelines. The knowledge that pipelines may exist in close proximity and the hazards that may result from uninformed activities nearby reduces the likelihood factor of risk. The familiarity with being able to recognize a leak and knowing how to report such an event lessens the consequences of a potential emergency condition.

The Company's Public Awareness Program contains provisions consistent with Table 2-2 in the API Recommended Practice 1162, Public Awareness Programs for Pipeline Operators. The overall Public Awareness Program meets or exceeds all requirements of §192.616 and API RP 1162.

### 5.2.5 Operator Qualification Program

The Operator Qualification (OQ) Program developed and administered by the Company ensures that personnel performing covered tasks on distribution pipeline facilities have the necessary knowledge, skills and abilities to safely perform those tasks with a minimum possibility of human error.

The evaluation and qualification of personnel reduces both the likelihood and consequences of a pipeline incident caused by human error. The Operator Qualification Program meets or exceeds the requirements of Part 192, Subpart N for such programs. The intervention of knowledgeable and skilled personnel in an impending or actual pipeline failure can reduce the consequence segment of the risk equation.

### 5.2.6 Drug and Alcohol Misuse Prevention Plan

The Company recognizes that the use of controlled substances and the misuse of alcohol may be contributing factors to human error. The reduction of an individual's normal capabilities while under the influence of drugs or alcohol can cause inferior performance of covered functions that affect both the likelihood and consequences factors in the risk equation. The Company's drug and alcohol control plans are in full compliance with Part 199 and Part 40 requirements.

## 5.3 Additional or Accelerated Actions

Additional or Accelerated (A/A) actions are implemented when existing compliance activities and procedures need to be supplemented to address risk identified to the integrity of the Company's distribution system. A/A actions that may be implemented to mitigate risk are included, but not limited to those listed in Table 5.1.

**Table 5.1: Additional or Accelerated Actions**

| Threats: Primary | Threats: Subcategory | Possible A/A Actions |
|---|---|---|
| Corrosion | External Corrosion | • Increase frequency of leak surveys<br>• Pipeline replacement<br>• Provide additional cathodic protection devices (e.g. anodes, rectifiers, etc.)<br>• Correct cathodic protection deficiencies |
| | Internal Corrosion | • Increase frequency of leak surveys<br>• Pipeline replacement<br>• Install liquid collection components (e.g. drips, strainers, etc.)<br>• Install pipe liners<br>• Evaluate gas quality at supply inputs, take corrective action with supplier |
| | Atmospheric Corrosion | • Increase frequency of atmospheric corrosion surveys<br>• Pipeline/component replacement<br>• Apply/refurbish coating<br>• Relocate |
| Natural Forces | • Outside Force<br>• Weather<br>• Flooding<br>• Extreme Temperatures<br>• Land Movement | • Relocate pipe from high risk location<br>• Replace pipe in high risk location<br>• Install slip or expansion joints to allow for movement<br>• Install and monitor strain gauges on pipe<br>• Install automatic shut-off component (e.g. excess flow valve)<br>• Conduct leak survey after earth movement events (e.g. earthquake, flood, etc. |
| Excavation Damage | • Third-party damage<br>• Operator Damage | • Conduct enhanced awareness education<br>• Request regulatory intervention (e.g. implement fines for occurrences)<br>• Inspect targeted excavation and backfill activities<br>• Inspect for facility support<br>• Improve accuracy of locating<br>• Participate in pre-construction meetings with project engineers and contractors in high-risk areas<br>• Use warning tape<br>• Expand the use of excess flow valves<br>• Improve system map accuracy and availability<br>• Recruit support of public safety officials (e.g. fire department)<br>• Install additional pipeline markers |

<table>
<tr><th colspan="2">Threats</th><th rowspan="2">Possible A/A Actions</th></tr>
<tr><th>Primary</th><th>Subcategory</th></tr>
<tr><td rowspan="5">Other Outside Force Damage</td><td>Fire/Explosion</td><td>• Provide first responder training<br>• Install curb valves<br>• Improve response capability<br>• Expand the use of excess flow valves</td></tr>
<tr><td>Vehicular</td><td>• Expand policy on when and how to install protection<br>• Increase frequency of patrols/inspections of high-risk facilities<br>• Evaluate the need to relocate hard-to-protect facilities<br>• Expand the use of excess flow valves</td></tr>
<tr><td>Leakage<br>(previous damage)</td><td>• Inspect exposed pipe prior to backfill<br>• Increase frequency of leak surveys</td></tr>
<tr><td>Vandalism</td><td>• Install or improve fences/enclosures<br>• Increased surveillance<br>• Relocate hard-to-protect or critical facilities</td></tr>
<tr><td>Blasting</td><td>• Perform leak survey after blasting<br>• Relocate away from frequent blast areas (e.g. mines)<br>• Re-establish MAOP after blasting (e.g. pressure test)</td></tr>
<tr><td>Material Weld or Weld Failure</td><td>• Manufacturing Defects<br>• Construction/Workmanship defects<br>• Mechanical Damage:<br>➢ Pipe Material<br>Pipe Component</td><td>• Increase frequency of leak surveys<br>• Replace or repair<br>• Revise construction procedures<br>• Revise material standards<br>• Track/trend material failures</td></tr>
<tr><td>Equipment Malfunction</td><td>• Malfunction of System Equipment<br>• Obsolete equipment</td><td>• Replace or repair<br>• Increase frequency of inspection/monitoring<br>• Investigate if equipment being used is appropriate for the situation/location<br>• Improve installation procedures<br>• Track/trend equipment failure</td></tr>
<tr><td>In-Appropriate Operation</td><td>• Inadequate procedures<br>• Inadequate safety practices<br>• Failure to follow procedures</td><td>• Improve procedures<br>• Improve training<br>• Evaluate other locations where inadequate practices may have been used<br>• Perform internal audits or inspections</td></tr>
<tr><td>Other</td><td>Odorant issues<br>Missing or unknown data</td><td>• Increase frequency of leakage survey<br>• Increase odorant levels<br>• Increase frequency of odorant testing<br>• Improve locations for odorant testing<br>• Perform pipe or facility exposure to collect missing or unknown data</td></tr>
<tr><td>Missing Values</td><td>• Missing facility information<br>• Inaccurate Leak Classification</td><td>• Create QA/QC Tracking</td></tr>
</table>

#### *5.3.1.1 Additional or Accelerated Action Implementation*

When A/A actions are implemented to address identified integrity threats, they shall be documented using Form 21760 – *Additional or Accelerated Action Implementation*. Documentation will at a minimum contain the following information:

- Description of A/A action being implemented
- Threat(s) that the A/A action addresses
- Description of the location where the A/A action is being implemented
- Date that the A/A action is to be implemented
- Date the A/A action is completed (if applicable)

Completed Additional or Accelerated Action forms will be stored in Appendix F – *Accelerated Actions.*

### 5.3.2 Additional or Accelerated Action Documentation

A summary of all active/implemented A/A actions shall be stored in Appendix F – *Accelerated Actions* and will include the following information:

- A/A Title
- Implementation Date
- Threat A/A Addresses
- Performance Metric
- Operating Region/District
- Assigned By

# 6.0 MEASURE PERFORMANCE, MONITOR RESULTS AND EVALUATE EFFECTIVENESS [§192.1007 (E)]

## 6.1 Overview

The Company uses performance measures to provide a means to measure, communicate and improve the Program over time. The measures will provide a basis for implementing improvement efforts, including the actions described in Section 5, to support the Program goal of maintaining the integrity of the Company's distribution system.

All Performance metric statistics will be documented in Appendix H - *Performance Measures*. Performance metrics will be compiled by GO Engineering on annual model runs by March 31. Performance metrics will be compiled using Excel spreadsheet templates and all data trending techniques will be documented in the appendix.

## 6.2 Required Performance Measures

The required measures below are collected annually for each state and Company.

- Number of hazardous leaks (as defined in Section 5.2.2.2) either eliminated or repaired, categorized by cause (cause categories will match those of the annual distribution report)
- Number of excavation damages
- Number of excavation notification tickets received from Company service territory one call centers by state (see Table 9.1)
- Total number of leaks either eliminated or repaired, categorized by cause
- Number of hazardous leaks (as defined in Section 5.2.2.2) either eliminated or repaired by material

The baseline statistics used for the above metrics will be the trend over the previous five (5) years from the effective date of this Plan.

## 6.3 Additional Performance Measures

Performance measures the Company will collect in addition to those described in Section 6.2 are listed in table 6.1. Baseline statistics for additional performance may vary shall be identified in Appendix H.

**Table 6.1: Additional Performance Measures**

| Metric Description | | Reporting Frequency |
|---|---|---|
| Company Total Relative Risk of Mains by state | | Annual |
| Company Total Relative Risk of Services by state | | Annual |
| Risk by Threat Category | • Corrosion<br>• Equipment Failure<br>• Excavation Damage<br>• Incorrect Operation<br>• Material Failure<br>• Natural Forces<br>• Outside Forces<br>• Weld or Joint Failure<br>• Other | Annual |
| Risk added due to missing or unknown data | | Annual |

| Company Excavation Damages per 1000 locates by State | Annual |
|---|---|

Additional performance measures are not limited to those listed in Table 6.1. The Company may choose to collect, track and trend other measures based on the results of activities required by this Plan. When information is collected to track and trend the results of implemented A/A actions, it should be collected on a schedule commensurate with the performance activity being measured.

## 6.4 Information Gathering

GO Engineering will use the GIS as the primary means for gathering information pertinent to the performance measures listed in Sections 6.2 and 6.3. If the information is not available in the GIS, paper documents and/or other electronic sources may be used to collect the necessary information. Once the information is gathered, it shall be kept in a central electronic location (e.g. Excel, Access, etc,) where the statistical data can be trended over time. The gathered information shall be available upon request from GO Engineering.

## 6.5 Monitoring Results to Evaluate Effectiveness

Results of the performance measures are analyzed to determine if the goals of the Program and A/A actions are being achieved. The Company has established the baseline for comparison as the beginning of the effective date of this Plan. Subsequent data will be collected annually prior to March 31.

Trends are monitored over time by GO Engineering to ensure they are moving in the appropriate direction based on the measure being evaluated.

### 6.5.1 Performance Metric Effectiveness Review and Trending Criteria

Performance metrics trending will be reviewed by GO Engineering to determine if implementation of an A/A action is necessary to mitigate increasing risk. This review will be summarized in the Performance Metric Trending Summary in Appendix H – *Performance Measures* and a table will consist of:

- Performance Metric
- Past Metric Values For Trending
- Data Obtained in Trending Process
- Is A/A action review necessary for performance metric? (Y/N)

A performance metric will require A/A action implementation when company specific trending criteria are triggered. Trending criteria are found in Appendix H – *Performance Measures*. When A/A action implementation is required based on performance metric trending, GO Engineering will perform an investigation and assign an A/A action to mitigate increasing integrity risks to the Company's distribution systems.

In addition to trending criteria that can trigger implementation of an A/A action, GO Engineering can also initiate an A/A action regardless of trending in an attempt to be proactive at addressing risk in operating system.

Performance metric trending will be completed by GO Engineering in conjunction with compiling the metrics and will be completed annually prior to March 31.

### 6.5.2 Additional or Accelerated Action Effectiveness Review and Criteria

Performance measures for implemented A/A actions will be trended and evaluated for effectiveness. GO Engineering will be responsible to trend data annually in collaboration with Performance metric compilation by March 31. This trending will be documented in Appendix F - *Accelerated Actions* in the Implemented A/A Action Trending Table and will contain:

- A/A Action Title
- A/A Action Performance Metric
- A/A Action Performance Metric Trending Values
- A/A Action Current Year Performance Metric
- Data Obtained in Trending Process
- Is A/A Action being effective at reducing risk (Y/N)

For an implemented A/A action to be considered effective at reducing risk the A/A action performance metric analyzed for a given year must meet company specific criteria which can be found in Appendix F – *Accelerated Action.* If an implemented A/A action is deemed ineffective at reducing risk in a specific year, increased efforts must be made and documented in Appendix F – *Accelerated Action* to reduce risk. Analysis of A/A performance metrics will be summarized in Appendix F – *Accelerated Action* with the following information:

- A/A Action Title
- A/A Action Performance Metric
- Company Specific Trending Data
- Can A/A action be discontinued?

Even though an A/A action can be discontinued due to meeting trending requirements, GO Engineering may decide to keep an A/A action active. Performance metric trending can be A/A action specific and will only need to be collected while the action is still ongoing.

# 7.0 PERIODIC EVALUATION AND IMPROVEMENT OF THE PROGRAM [§192.1007 (F)]

## 7.1 Review of Written Plan

GO Engineering will review the Plan in its entirety and make updates or revisions as needed a minimum of every five years. The initial review will be completed prior to August 1, 2016 and subsequent reviews shall not exceed five years from the previous review. GO Engineering personnel from each of the operating companies under this plan will conduct the periodic review and the process will be documented using Form 21761 – *DIMP Review Summary*. Form 21761 and related documentation shall be retained in Appendix I - *Periodic Evaluation*.

### 7.1.1 Review of Appendices

Appendices in the Plan contain information specific to the Company and shall be reviewed by GO Engineering annually, prior to March 31.

## 7.2 Revisions to the Written Plan

If changes or modifications to the Plan document are made, with the exception of appendices, a record of that change or modification will be noted on the revision control sheet and documented on Form 21761 - *DIMP Review Summary*. The revision number will only change if a revision takes place.

Changes made to the Plan will be relayed to the appropriate field personnel for dissemination to their staff for implementation. If required, the local State regulating authority will be notified and/or furnished with an updated version of the Plan document.

### 7.2.1 Revisions to Appendices

Revisions made to appendices do not require a new written plan revision. When changes or modifications are necessary, the revision information shall be contained within the appendix being updated or modified.

## 7.3 Program Improvement

Improvement of the Plan is made based primarily on the results of the risk management technique or practice. During the review, data that supports the performance of these actions should be collected and analyzed. Analysis may range from simple side-by-side comparisons to sophisticated statistical data processing. The frequency of this review is not pre-set but will be within five years of the prior results evaluation or revision. The frequency depends on an appropriate time frame for which meaningful results can be recorded. For example damage prevention methods may show results within a season where corrosion control enhancements may not provide measurable improvement for many years.

These reviews will also be used to determine if additional information about the distribution system is needed or would help identify areas for improvement. When such needs are identified, the Company will design and institute enhanced information collection activities as described in Section 2.6.2.

Program improvements may include modification of facility groups, adjustment of likelihood or consequence factors, selection of different A/A actions, or determination of additional or alternative performance measures. Overall effectiveness of integrity management in reducing risks is the governing principle.

# 8.0 MECHANICAL COUPLING FAILURE REPORTING [§192.1009]

## 8.1 Overview

The Company reports failures resulting in hazardous leaks (as defined in Section 5.2.2.2) of mechanical couplings that are in service in its distribution system at the time of the failure. Detailed information is listed in Appendix J – *Mechanical Coupling Failures*.

## 8.2 Reporting

All failures of any in-service mechanical coupling are reported to GO Engineering. When it can be done through normal repair or replacement procedures, the failed mechanical coupling is collected and retained for examination. At the time of the coupling failure, as much of the information listed in Section 8.2.1 is recorded and sent along with the specimen. Required information not collected during the time of failure shall be obtained by GO Engineering through further investigation.

### 8.2.1 Minimum Required Reportable Information

The following information is required at a minimum for mechanical fitting failures:

- Location of the failure in the system
- Nominal pipe size
- Material type (of coupling body)
- Nature of failure including contribution of local pipeline environment [soil type, contaminants]
- Coupling manufacturer
- Model number
- Lot number
- Decade of manufacture
- Other information that can be found in markings on the failed coupling

### 8.2.2 Additional Failure Information

Additional information collected for a mechanical fitting failure may include but is not limited to the following:

- Location of failure on the specimen (e.g., body, gasket, threads or bolts)
- Date of installation
- MAOP
- Operating pressure at time of failure
- Normal annual operating pressure range

### 8.3 Failure Analysis

The information listed in Sections 8.2.1 and 8.2.2 is reviewed by GO Engineering and collected by calendar year for inclusion in the Mechanical Fitting Failure annual report to PHMSA. At the end of reporting period, GO Engineering analyzes the data for the year, determines the number of similar failures for each failure reported and includes that information on the annual report. A "similar failure" is identified when one or more of the Minimum Required Reportable Information items as required in Section 8.2.1 is the same and applies only to the current calendar year data. A copy of the annual report is sent to the pipeline safety office of the State in which the failure occurred.

Except for isolated cases, the Company uses the results of the analysis as a factor in its periodic updates of threat and risk analysis. When higher or shifted relative risk is determined, the appropriate sections of the Plan are implemented.

# 9.0 PERIODIC REPORTS TO GOVERNMENT AGENCIES [§192.1007 (E)]

## 9.1 Federal AGENCY(S)

The Company reports the following information to the Pipeline and PHMSA annually by March 15th of each year. These data represent occurrences within the previous calendar year and are part of the annual report submitted by the Company to PHMSA. Statistics are recorded separately by state and Company to facilitate reporting under Section 9.2 of this Plan. For operating Companies that have facilities in multiple states, one annual report will be submitted to PHMSA covering all Company facilities. Appendix K- *Reports to Government Agencies* may be used to store completed annual reports.

- Number of hazardous leaks (as defined in Section 5.2.2.2) either eliminated or repaired, categorized by cause
- Number of excavation damages
- Number of excavation notification tickets received from all operation state's one call centers listed in Table 9.1

**Table 9.1: Company One Call Centers**

| State | Locate Ticket Center | Contact Information |
|---|---|---|
| Idaho | Dig Line, Inc. | Office: (208) 342-1585 |
| Minnesota | Korpartner, Inc. | Office: (952) 368-1911 |
| Montana | One Call Concepts, Inc. | Office: (503) 232-1987<br>Fax: (503) 234-7254 |
| Oregon | One Call Concepts, Inc. | Office: (503) 232-1987<br>Fax: (503) 234-7254 |
| North Dakota | One Call Concepts, Inc. | Office: (503) 232-1987<br>Fax: (503) 234-7254 |
| South Dakota | Korpartner, Inc. | Office: (952) 368-1911 |
| Washington | One Call Concepts, Inc. | Office: (503) 232-1987<br>Fax: (503) 234-7254 |
| Wyoming | Password, Inc. | Office: (509) 624-5235 |

- Total number of leaks either eliminated or repaired, categorized by cause. This total number does not include leaks that are being monitored pending future action.
- Mechanical fitting failure data

## 9.2 Submitting Reports

Reports will be submitted by one of the following methods:

- Via the internet to the PHMSA on-line reporting system which is accessible through the PHMSA home page at:

  http://phmsa.dot.gov

  or

- By facsimile to:

  202-493-2311

  or

- Through US mail to:

  Pipeline and Hazardous Materials Safety Administration
  Information Resource Manager
  US Department of Transportation-East Building
  1200 New Jersey Avenue, SE
  Washington, DC 20590

## 9.3 State Agency(s)

Annual counts of reportable items listed in Section 9.1 for the appropriate state are sent annually by March 15th of each year to the states of South Dakota, Minnesota, North Dakota, Wyoming, Washington, Idaho, Oregon and Montana regulatory agency.

**Table 9.2: State Agency Contact Information**

| State | State Agency Website Address | Contact Information |
|---|---|---|
| Idaho | http://www.puc.state.id.us/ | 1-208-334-0300 |
| Minnesota | http://www.puc.state.mt.us/puc | 1-800-422-0798 |
| Montana | http://psc.mt.gov | 1-406-444-6199 |
| Oregon | http://www.oregon.gov/PUC/ | 1-503-373-7394 |
| North Dakota | http://www.psc.nd.gov | 1-701-328-2400 |
| South Dakota | http://www.puc.sd.gov | 1-605-773-3201 |
| Washington | http://www.utc.wa.gov | 1-360-664-1234 |
| Wyoming | http://psc.state.wy.us | 1-307-777-7427 |

# 10.0 RECORDKEEPING [§192.1011]

## 10.1 Overview

The Company maintains records sufficient to display compliance with CFR 49, Part 192 Subpart P. Such records are retained for a minimum of ten (10) calendar years from the year in which they are produced. GO Engineering is responsible for the retention and availability of the following records:

- Written Plan
  - Current version of the Plan
  - Past revisions of the Plan
  - Description of significant changes between versions
  - Reason each significant change was made
- Likelihood and consequence factors
  - Any supporting documentation used to determine the factors (e.g. construction and maintenance records, SME input, industry data, etc.)
- Outside source data and related information in Appendix B
- Risk management activities implemented as a result of the Program
- Performance measure results and analysis
- Appropriate documentation produced if deviations from required periodic inspections are requested
- Other applicable reports to PHMSA or local State regulatory agency

# 11.0 DEVIATIONS FROM PART 192-MANDATED PERIODIC INSPECTIONS [§192.1013)]

## 11.1 Overview

The Company reviews the risk evaluation results and the effects of implemented risk management practices for positive influences toward the reduction of risk on its distribution system. Improvements may encourage the Company to decide that a reduction in the frequency of one or more inspections or tests required by Part 192, when accompanied by appropriate actions under this Plan, will provide an equal or greater overall level of safety of its distribution system.

In such a case, an analysis is made that includes a description of safety improvement afforded by applicable risk management measure(s), the reason(s) why a particular inspection or test is selected for a reduced frequency of performance, how the available resources are used to mitigate risk in other areas and a demonstration through risk evaluation as described in Section 6.0 of the Plan that risk values are not compromised.

## 11.2 Documentation

A proposal similar in format to a waiver request will be submitted to the pipeline safety authority of the state in which the proposal is requested. Appropriate follow-up data are provided when requested.

The Company reviews any conditions or limitations that are associated with acceptance of the proposal. If they are acceptable, the Company begins implementation of the revised frequency schedules through the following:

- Company Management of Change Process
- Revision of appropriate O & M procedures
- Notification and training of affected personnel and/or contractors
- If necessary under its OQ plan, revising evaluations for Operator Qualification for those tasks
- Performing re-evaluations when required
- Monitoring distribution integrity management performance measures

# Appendix A – Forms

## 1.0 OVERVIEW OF FORMS APPENDIX

This appendix is used to keep blank copies of the forms that are used in the DIMP Plan.

### 1.1 Plan References

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 5.3.1.1 A/A Action Implementation | Form 21760 | N/A |
| 7.1 Review of Written Plan | Form 21761 | N/A |
| 7.2 Revisions to the Written Plan | Form 21761 | N/A |

## 2.0 APPENDIX REVISION SUMMARY

### 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table A2.1: Appendix A Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised BY |
|---|---|---|---|
| 3/15/2013 | Creation | New appendix created to store forms used by the DIMP plan. | Renie Sorensen & Kathleen Chirgwin |
| | | | |
| | | | |

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# FORM 21760: ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

**Operating Company:**______________________________ **Completed By:**___________________________

**Operating Region/District:**________________________ **Completed Date:**_________________________

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** ____________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

**Threat(s) A/A Addresses**:________________________________________________________________

**Reason for A/A Action:**__________________________________________________________________

______________________________________________________________________________

**Description of locations that A/A will be implemented:** ___________________________________________

______________________________________________________________________________

**A/A Implementation Date:**_______________________________________________________________

**List A/A Performance Metric to determine A/A Effectiveness and when A/A can be discontinued:**

______________________________________________________________________________

**Does A/A Action require added A/A performance metrics?** ☐ YES ☐ NO

**If yes, describe new metric(s) and collection schedule:**

______________________________________________________________________________

______________________________________________________________________________

**Supporting Documentation:**_______________________________________________________________

**Additional Comments:**___________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

# FORM 21761: DIMP REVIEW SUMMARY

**Date Started:**________________________________________

**Review Completion Date:**______________________________

**Review Completed By:**________________________________

**Reason/s for Program review:** ________________________________________________________

____________________________________________________________________________

____________________________________________________________________________

____________________________________________________________________________

**Changes to the Written Plan required?** ☐ YES ☐ NO **If Yes, complete the Change Summary Table and approval is required**

**Changes to Risk Model required?** ☐ YES ☐ NO **If Yes, include a summary of recommended changes and approval is required**

---

**Summary of recommended changes:** __________________________________________________

____________________________________________________________________________

____________________________________________________________________________

____________________________________________________________________________

____________________________________________________________________________

____________________________________________________________________________

## Written Plan: Change Summary

| Plan Section | Reason For Change | From | To |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

**New Plan Revision Number Required?** ☐ YES ☐ NO **If Yes, Revision number to be updated:**__________________

---

**VP –Operations (CNGC):** ____________________________________________ **Date:** ____/____/____

**VP –Operations (IGC):** ______________________________________________ **Date:** ____/____/____

**VP – Operations (MDU/GPNG):**______________________________________ **Date:** ____/____/____

---

**Changes Implemented By:**________________________________ **Date Implemented:**_______________

# FORM 21762: SUBJECT MATTER EXPERT INTERVIEW/INPUT

**Person(s) Conducting the Interview:**______________________________ **Interview Date:**__________________________

**Purpose of SME Interview**: ________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

## SME Information:

SME Name:______________________________ SME Job Title:______________________________

Operating Company:______________________________ Years of Experience:______________________________

Operating Region:______________________________

Other relevant information:________________________________________________________________________________

## Audit Results and Conclusions:

**Summary of interview results:** ________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

**Are Changes Required to the Program?** ☐ YES ☐ NO **If yes, changes to:** ☐ Risk Model ☐ Plan ☐ GIS ☐ Other (Describe)

**Describe Changes:** ________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

________________________________________________________________________________

**Interviewer:** ______________________________________________ **Date:** ____/____/____

**SME:** ______________________________________________ **Date:** ____/____/____

# Form 21764: SME Panel Decisions

**Person(s) Conducting the Panel Meeting:**________________________ **Panel Date:**____________________________

**Purpose of SME Panel Meeting**:

☐ Risk Model Calculation Changes ☐ Model validation ☐ Risk Mitigation ☐ Risk Model Performance ☐ Other (explain)

______________________________________________________________________________

______________________________________________________________________________

**Meeting was conducted using**:

☐ In Person ☐ Web/Conference Call ☐ In Person & Web/Conference Call ☐ Other (explain)

______________________________________________________________________________

## Summary of Panel Decisions:

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

**Are Changes Required to the Program?** ☐ Yes ☐ No

**If yes, changes to:** ☐ Risk Model ☐ Plan ☐ GIS ☐ Performance Metrics ☐ Other (Describe)

**Describe Changes (include implementation plan/schedule):**

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

______________________________________________________________________________

## SME Panel Members (if more than 7, include another page)

1) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

2) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

3) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

4) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

5) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

6) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

7) SME Name:____________________ SME Job Title:____________________
Operating Company:____________________ Years of Experience:____________________
Operating Region:____________________
Other relevant information:________________________________________

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**Signatures (if more than 7 SME's, include another page):**

**Interviewer:** ________________________________________ **Date:** ____/____/____

1) **SME:**________________________________________ **Date:** ____/____/____

2) **SME:**________________________________________ **Date:** ____/____/____

3) **SME:**________________________________________ **Date:** ____/____/____

4) **SME:**________________________________________ **Date:** ____/____/____

5) **SME:**________________________________________ **Date:** ____/____/____

6) **SME:**________________________________________ **Date:** ____/____/____

7) **SME:**________________________________________ **Date:** ____/____/____

# Appendix B - Knowledge of Distribution System

**Table of Contents**

# 1.0 SUMMARY OF DISTRIBUTION SYSTEM KNOWLEDGE

## 1.1 Overview

The purpose of this appendix is to provide a summary of CNG's knowledge of the distribution system. The following sections are created from past and present construction as-builds, daily operations, and maintenance documents to demonstrate CNG's knowledge of the distribution system. In addition a summary of the company's missing or incomplete data is present to show where continuous improvement is possible.

## 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 2.1 Overview | 3.0 Operational Data | B3.1 |
| 2.4 Outside Source Data | 4.0 Outside Source Data | B4.1 |
| 2.5 Newly Installed Facilities | 5.0 Newly Installed Facilities | B5.1 |
| 2.6.1 Insufficient Data | 6.0 Insufficient/Missing Data | B6.1 |

# 2.0 APPENDIX REVISION SUMMARY

## 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table B2.1: Appendix B Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | New appendix created to summaries the company's knowledge of the distribution system. | Renie Sorensen & Kathleen Chirgwin |
| 3/17/2015 | Update | Updated outside source table | Renie Sorensen |
| 9/26/2017 | Update | Added Section 3.2 on record retention | Kathleen Chirgwin |

# 3.0 OPERATIONAL DATA

### 3.1 Overview

This section gives a summary of the operational information that is collected during normal pipeline operation including: continuing surveillance records, maintenance records, and new construction records. All listed records have been considered for use within the DIMP model by GO engineering. For the records that not currently being used in the risk model, GO engineering has reviewed and determined that the currently do not provide useful data toward the risk model, but will be reconsidered for future enhancements to the model.

**Table B3.1: Operational Data**

| Record (form) | Record Type (Paper/ electronic/ database/ GIS) | Summary | Record Location | Used in Risk Model |
|---|---|---|---|---|
| Geographic Information System (GIS) | Electronic/GIS | All company information used in the risk model is stored in GIS. | Company Server | Yes |
| As-Built/ Construction Drawing Records | Paper/ Electronic | Plans and design drawings showing: material, date of installation, location, pipe size, construction method, MAOP, pressure test information, | Paper-GO Archives/ electronic-electronic archives | Yes |
| Leak Investigation/ Leak Record (CNG 293A, B, C) | Electronic | This form provides information on the leak location, leak cause and if the leak is repaired or monitored. | Electronic Archives, SharePoint | Yes |
| Exposed Pipe Report (CNG 625) | Paper/ Electronic | Provides a snapshot of the coating and pipe condition. Also provides source to collect missing or unknown data. | Paper- GO Archives/ Electronic-SharePoint | No |
| Material and Component Failure Report (21713) | Electronic | Provides information on location and root cause of the failure. Includes Mechanical Fitting Failures | SharePoint | No |
| Continuing System Surveillance and system Patrol (CNG 286, 297) | Paper/ Electronic | Surveillance occurs during: Periodic maintenance, quarterly patrols and inspections, cathodic protection checks and leak surveys.<br>Records: construction activity, exposed pipe condition, pipeline markers, | Paper- GO Archives/ Electronic-SharePoint | No |

| Record (form) | Record Type (Paper/ electronic/ database/ GIS) | Summary | Record Location | Used in Risk Model |
|---|---|---|---|---|
| | | presence of erosion, condition of ROW, new high occupancy structures, and identifies any AOCs present on the pipeline. | | |
| Leak Survey | Paper/ Electronic | Records areas that have been surveyed and the presence of any leaks | Paper- GO Archives/ Electronic- SharePoint | No |
| Pressure Log (CNG 347) | Paper/ Database | Records High and low pressures at select points in the distribution system | Paper- GO Archives/ Database- SharePoint | No |
| Regulator/ Valve Maintenance (CNG 287A, B) | Paper/ Electronic | Records the condition of the Regulator and valve stations and ensures they are at their proper operating settings. | Paper- GO Archives/ Electronic- SharePoint | No |
| Distribution Line Reports (CNG 336) | Electronic | Records the location, date of installation, materials used, pipe size, construction method, MAOP, and pressure test of distribution mains installed. | Electronic Archives | Yes |
| Facility Installation Diagram (CNG 315) | Electronic | Records the location, date of installation, materials used, pipe size, construction method, MAOP, and pressure test of services installed. | Electronic Archives | Yes |
| PHMSA Annual Report | Electronic | Records and tracks excavation damage, locate tickets, and leaks repaired by cause. | PHMSA.dot.go v | No |
| Sub-Damage Report (CNG 293, Subdam Report) | Paper/ Electronic | Records the location and cause of excavation damage sustained by the distribution system, and tracks the number of locate tickets for a given area | Paper- GO Archives/ Electronic- SharePoint | Yes |
| One Call Tickets | Electronic | Records the location of excavation tickets for use in the model | SharePoint | Yes |
| Pipeline Lowering | Paper | Documentation on all pipeline lowering projects | G.O Engineering Archive | No |

| Record (form) | Record Type (Paper/ electronic/ database/ GIS) | Summary | Record Location | Used in Risk Model |
|---|---|---|---|---|
| Pressure Increase Plans | Paper | Documentation on all pressure increase plans. | G.O Engineering Archive | No |
| Uprating Plans | Paper/Electronic | Documentation on all pressure uprating plans. | G.O Engineering Archive | No |
| Cathodic Protection Annual Survey | Electronic | Documents CP readings at selected points around the system to verify adequate CP protection on distribution system | SharePoint | No |
| MAOP Review | Electronic | Record of System MAOPs. Pressure recording devices or electronic pressure monitoring used to monitor system pressure at specific points in the system based on HI/LOW set points given to Gas Control from Engineering. | SharePoint | Yes |
| MAOP Validation Records | Electronic | All high pressure line records have been reviewed and summarized in a spreadsheet. Grade, wall thickness, pressure test, etc. is included. | Sharepoint | No |

### 3.2 Records Retention

Records retention for records in Table B3.1: Operational Data is specified in the applicable company procedure under Section 5: Record Retention.

## 4.0 OUTSIDE SOURCE DATA

### 4.1 Overview

Outside source data provides additional data that is applicable to identifying risk within the distribution system.

**Table B4.1: Outside Source**

| Data | Geographic Coverage | Source Agency | Source Type | Source Format | Source/URL |
|---|---|---|---|---|---|
| Line Locates | Oregon/Washington | One Call | PCAD | Excel Spread Sheet | Oregon/Washington Utility Notification Center |

| | | | | | |
|---|---|---|---|---|---|
| Flood Zones | By County/Oregon | University of Oregon | Digital Q3 Flood Data | DLG, ARC/INFO, MapInfo | http://libweb.uoregon.edu/map/gis_data/fema.html |
| Flood Zones | By County/Washington | Washington Dept. of Ecology | DFIRMS, Digital Q3 Flood Data | zip file/shape file | http://www.ecy.wa.gov/services/gis/data/flood/flood.htm |
| Oceans/Lakes/Rivers/Creeks | Oregon/Washington | BLM | Hydrography Publication Dataset | zip file/gdb | http://www.blm.gov/or/gis/data.php |
| Wild Fires | Nationwide | USDA Forest Service | MODIS Fire Detection Data | zip file/shape file | http://activefiremaps.fs.fed.us/gisdata.php |
| Landslides | Nationwide | ESRI | USA Landslide Susceptibility | ESRI data Layer | http://www.arcgis.com/home/item.html?id=cc5e9da58860460188705c545e86c871 |
| Railroad Network | Nationwide | ESRI | Federal Railroad Administration | ESRI data layer | ESRI Data & Maps DVD |
| Street Data | Nationwide | TomTom North America, Inc., ESRI | Street Map North America | shape file, MapInfo | ESRI Data & Maps |
| Census Block Population Data | Nationwide | ESRI | 2012 U.S. Census Block Group Data Set | ESRI data layer | ESRI Data & Maps DVD |
| Schools | Nationwide | Institute of Education Sciences | National Center for Education Statistics | Excel Spread Sheet | ELSI - Elementary and Secondary Information System |
| Hospitals | Nationwide | ESRI | Annual Survey Database | ESRI data layer | ESRI Data & Maps DVD |
| Soil Data | Nationwide | National Resources Conservation Service (NRCS) | Soil Survey Geographic Database (SSURGO) | ESRI shape file, Access database | http://soildatamart.nrcs.usda.gov |
| Precipitation Data | Nationwide | National Resources Conservation Service (NRCS) | NRCS PRISM Dataset | ASCII raster grid | http://www.prism.oregonstate.edu/ |
| Shorelines | Nationwide | NOAA's Ocean Service, Office of Coast Survey (OCS) | U.S. Vector Shoreline Data | ESRI shape file | http://www.nauticalcharts.noaa.gov/csdl/ctp/cm_vs.htm |
| Marine Shorelines | Washington | Washington State Department of Ecology | Washington State Marine Shorelines | ESRI shape file | http://www.ecy.wa.gov/services/gis/data/shore/shore.htm |

## 5.0 NEWLY INSTALLED FACILITYES

### 5.1 Overview

This section provides a summary of the information collected during the installation of new pipeline facilities.

**Table B5.1: New Facilities Data**

| Record | Summary of data Collected | Format |
|---|---|---|
| As-Built/ Construction Drawing Records | Plans and design drawings showing: material, grades, date of installation, location, pipe size, construction method, MAOP, design pressure, pressure test information, joining method | Paper/Electronic/GIS |
| Distribution Line Reports (CNG 336) | Records the location, date of installation, materials used, pipe size, construction method, MAOP, and pressure test of distribution mains installed. | Paper/Electronic/GIS |
| Facility Installation Diagram (CNG 315) | Records the location, date of installation, materials used, pipe size, construction method, MAOP, and pressure test of services installed | Paper/Electronic/GIS |
| | | |

## 6.0 INSUFFICIENT/MISSING DATA

### 6.1 Overview

This section summarizes the additional information in regards to the knowledge of the distribution system that can be used to assess applicable threats and risk to the system. As well as describing current plans to collect/find this information.

**Table B6.1: Insufficient/Missing Data**

| Record | Date Identified | Extent of Record | Plan to Acquire Data | Anticipated Completion Date | Responsible Department |
|---|---|---|---|---|---|
| 625 Pipeline Integrity Reports | 1/1/2013 | All paper records (2011-2017 Scanned on SharePoint) | Paper records will be digitized and mapped spatially in GIS and assigned risk for poor and fair condition pipe. | 6/30/2018 | Engineering/ GIS Department |
| Sewer Cross Bores | 1/1/2013 | CNGC has no data available on sewer cross bore incidents. District have had isolated sewer cross bore incidents discovered. | Collect sewer cross bore data, analyze data, and start identifying risk in model. | 12/31/2018 | G.O. Engineering/Operations. |
| Shorted Casings | 1/1/2013 | Location of casing in GIS. | Casing information is now mapped in GIS in Gas Pipe Casing, casing risk will be added to 2018 model run. | 12/31/2017 | Engineering/ GIS Department |
| Vault Locations | 2/12/2013 | Regulator and valves in vaults were not in GIS data. | Information is in GIS in Regulator Station feature class, this is planned to be added to 2018 risk model. | 12/31/2017 | Engineering/ GIS Department |
| MAOP Validation Records on High Pressure Mains. | 3/26/2015 | MAOP Validation information on High Pressure mains. | High Pressure Line MAOP validation records will be mapped in GIS and risk will be assigned for unknown/missing data required for MAOP Validation. Required MAOP validation data needs to be added | 12/31/2018 | Engineering/ GIS Department |

| Record | Date Identified | Extent of Record | Plan to Acquire Data | Anticipated Completion Date | Responsible Department |
|---|---|---|---|---|---|
| | | | to the risk model calculations. | | |
| Service line valves | 1/21/2016 | Service valves are mapped in GIS in Gas Valve Feature Class. | Setup coding in 2017 model run to reduce consequence risk on service lines with service line valves installed. | 12/31/2017 | Engineering/ GIS Department |
| Leak Classification on 293's. | 3/20/2016 | 293 forms, mapped 293 in GIS, and PHSMA reporting numbers. | Retrain on F7100 leak classification definitions on 293's. Currently from leak classification review leaks are being commonly misclassified causing inconsistencies in the leak data and risk assignment. | 12/31/2018 | Operations/Training Department |
| Valid MAOP records on WA HP mains | 4/31/2016 | MAOP Validation documents on SharePoint and Settlement Agreement with WUTC. | Engineering will be following Settlement agreement to acquire valid MAOP record on all HP Main. Will consist of replacement, pressure testing, and exposing fittings to validate MAOP. Model calculations will be updated to include risk on non-validated segments until lines are validated. | 50% complete by 12/31/2018 and 100% complete by 12/31/2021 | Engineering/GIS Department |
| Normalized Risk by WO Number | 12/15/2016 | Model output risk is by segment in the 50x50 grid. | Add model output of normalized risk by WO to compare WO risk. | 12/31/2017 | Engineering/GIS Department |

| Record | Date Identified | Extent of Record | Plan to Acquire Data | Anticipated Completion Date | Responsible Department |
|---|---|---|---|---|---|
| Non Standard Pipe Size | 3/1/2017 | Pipe Size is in main and service feature class. Kennewick district had a leak this year on 7 inch pipe which they did not have fittings to stop 7 inch pipe. | Add consequence risk to non-standard size main and services. | 12/31/2017 | Engineering/GIS Department |
| Risk on shallow pipe that does not meet depth requirements | 3/1/2017 | Districts have identified several known areas that do not meet our depth requirements. | Identify, assess and prioritize excavation risk on shallow pipe (or come up with measures to protect pipe). | 12/31/2018 | Engineering/GIS Department |
| Above ground leaks reported on the annual report | 3-15-2017 | Above ground leaks are being counted and classified by the districts from P-CAD reports and 295 notes. All P-CAD leaks are being counted as other. Some districts are also classifying the leaks and we have no documentation to review | Create documentation and classification guidance on Above ground leaks. | 12/31/2018 | Compliance |

| Record | Date Identified | Extent of Record | Plan to Acquire Data | Anticipated Completion Date | Responsible Department |
|---|---|---|---|---|---|
| | | to determine what is causing the annual report trending to increase by category. | | | |

# Appendix C - Threat Identification

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## 1.0 SUMMARY OF THREAT IDENTIFICATION

### 1.1 Overview

The purpose of this appendix is to record potential threats that have been identified within CNG's system. It also provides a location to document information that was excluded from the risk model with a justification for their exclusion.

### 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 3.4 Potential Threats | 4.0 Potential Threats | C4.1 |
| 3.4.3 Potential Threat Assessment | 5.0 Records/Threats not Included in Risk Model | C5.1 |

## 2.0 APPENDIX REVISION SUMMARY

### 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

Table C2.1: Appendix C Revision Summary

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | New appendix created to summaries threats to the distribution system. | Renie Sorensen & Kathleen Chirgwin |
| 3/24/2017 | Update | Added reference in Section 4.2 to Compliance's industry bulletins/notice tracking spreadsheets. | Kathleen Chirgwin |
| | | | |

## 3.0 THREAT AND SUB-THREAT

### 3.1 Overview

Primary and sub-threats are not provided in this appendix. Primary threats were identified in the plan body in section 3.2. Sub-Threat divisions are shown in Appendix D Table D2.1 and include a brief explanation. Weighting of these sub-threats, within the model, is also identified in Table D2.1 of Appendix D.

# 4.0 POTENTIAL THREATS

## 4.1 Overview

The potential threat section provides a location for the monitor and recording of external sources that identify potential threats that could affect the distribution system. Advisory bulletins and notices applicable to industry are tracked by compliance and located on the Compliance SharePoint site for review.

Table C4.1: Potential Threat

| Potential Threat | Source | Date of Review | Applicable to CNGC | Currently in Risk Model |
|---|---|---|---|---|
| Driscopipe 8000 pipe | PHMSA Docket # PHMSA-2012-0044 | 3/9/2012 | Yes | No |
| Failure of Mechanical Fittings | PHSMA Docket # 2012-0079 | 12/31/2012 | Yes | No |
| Polykan Wrap | SME Panel weighting Review | 2/12/2013 | Yes | No |
| Flooding Vaults- ability to access | SME Panel weighting Review | 2/12/2013 | Yes | No |
| Powder Coated meter bar Corrosion(Received between xx-xx) | SME Panel weighting Review. More information needed on Date range | 2/12/2013 | Yes | No |
| Future utility/road improvement projects | WUTC | 2/14/2013 | Yes | No |
| Customer Built structures over existing pipelines | WUTC | 2/14/2013 | Yes | No |
| Access to pipeline in water Areas | Field Knowledge (Steve Kessie) | 2/14/2013 | Yes | No |
| Trenchless Technologies (Sewer Cross Bores) | WUTC/ Industry | 2/14/2013 | Yes | No |
| Facilities in Tsunami Zones | State Tsunami Designation Zones (Steve Kessie) | 2/14/2013 | Yes | No |
| MAOP Validation Records on HP Pipe (Traceable, Verifiable, Complete) | WUTC Settlement Agreement/ Pending IMP proposed rulemaking/ADB 12-06 | 2014/2015 WA district Audit Inspections | Yes | No |
| Equipment failure leaks on 1960's fittings due to yellow pipe dope and 1960's | Equipment failure leak review on 1960's auto perf tees and 2in bottom | 6/15/2017 | Yes | No |

| | | | | |
|---|---|---|---|---|
| construction practices. | in/out/termination and extension stop fittings and SME discussion with fab shop. | | | |

## 5.0 RECORDS/THREATS NOT INCLUDED IN RISK MODEL

### 5.1 Overview

This section provides a location to identify records/threats that are unused or do not apply to the risk model and give a justification as to why the exclusion from the model was made. The exclusion from the model does not mean the information was not considered or reviewed, but that the information is unavailable at this time to include in the model.

Table C5.1: Non-Applicable Threats/Unused Records

| Threat/ Records | Justification for Exclusion From Model |
|---|---|
| Aldyl-A Pipe | Not found in CNGC's distribution system |
| Cast Iron Pipe | Not found in CNGC's distribution system |
| Material Failure Reports | Material failure reports are reviewed by Director of Operation Services following Company Procedure 722, Director of Operator Services is responsible to bring material/component failure to resolution and ensure all responsible parties are notified as a result of the investigation. All material failure report investigations will be assessed for potential threats on the integrity of distribution system and assigned risk if applicable. |
| Continuing Surveillance Records | Per Cascade Procedures all abnormal operating conditions are reported on AOC forms to district management and are resolved at district level and do not represent long term risk to system integrity concerns for Cascade. |
| Regulator/Valve Maintenance Records | Records are not mapped and thus cannot be added to risk model. These forms are reviewed by District Management and Engineering and immediate action is taken to resolve operating issues. |
| Pipeline Lowering Records | Currently CNGC does not map Areas that have been Lowered. Engineering is responsible to prepare all Lowering plans following CNGC Procedure 622and all HP mains /services lowered are supervised by Construction Services. Lowering pipelines pose no integrity risk to Cascade distribution systems. |
| MAOP Uprating records and Pressure Increase Plans | Currently CNGC does not map Areas that have had a MAOP Uprate. Uprates plan are completed by Engineering following CNGC Procedure 620 and all Uprates are approved by State Pipeline Commissions. Uprates pose no integrity risk to Cascade distribution systems. |
| Cathodic Protection Records | Cathodic Protection records are reviewed by Corrosion Manager. All cathodic protection issues are resolved by Corrosion Manager, posing |

| Threat/ Records | Justification for Exclusion From Model |
| --- | --- |
| | no long term risk to CNCG distribution systems. |
| Pressure Log Charts | MAOP of pipeline are used in risk calculation for consequence, pressure charts are used to monitor daily pressure fluctuations to evaluate growth potential and monitor low pressure areas for necessary reinforcements, low pressure concerns have no effect on pipeline integrity. |
| PHMSA Annual Reports | Information from the PHMSA Annual Report is used to trend leaks by cause. This information is pulled into the risk model from other sources. |
| System Over Pressurizations | All over pressurizations and abnormal operating conditions are reported to engineering and engineering determines immediate corrective action. After corrective action is taken no long term risk is applicable to system integrity. |
| Pipelines experiencing an Earthquake event | Currently Cascade is setting up an MOC for pipeline patrols and leak survey in areas affected by an earthquake for damage to above ground facilities and land subsidence. Engineering is currently identifying areas based on operating pressure, earth quake influence area maps from USGS, and areas susceptible to landslides in the DIMP model run data. All issues discovered during patrols and leak survey will be addressed immediately and pose no long term risk. |
| Potential Damage to Pipeline facilities Caused by Flooding, River Scour, and River Channel Migrations. | Any issue due to flooding, river scour, and river channel migrations will be addressed as discovered in Cascade's Pipeline patrols, leak survey, general operation activities, and annual maintenance on facilities. No long term risk. |
| Ice buildup on regulator stations and potential for frost heave | Cascade is addressing icing as discovered, Engineering currently tracks icing at regulator stations and is addressing icing with heaters and reducing pressure cuts. No long term risk posed to icing since it is being addressed by engineering. |

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# Appendix D - Risk Input

**Table of Contents**

# 1.0 SUMMARY OF RISK INPUT

## 1.1 Overview

The purpose of this appendix is to summarize the risk factors that CNG applies to the risk model.

## 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 3.1 Overview | 3.0 Summary of Risk Model Weighing factors | Table D3.1 |
| 3.3 Subdividing Threats | 3.0 Summary of Risk Model Weighing factors | Table D3.1 |
| 3.4.3 Potential Threat Assessment | 3.0 Summary of Risk Model Weighing factors | Table D3.1 |
| 4.1 Overview | 3.0 Summary of Risk Model Weighing factors | Table D3.1 |
| 4.2 Risk Model | 3.0 Summary of Risk Model Weighing factors | Table D3.1 |
| | | |

# 2.0 APPENDIX REVISION SUMMARY

## 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table D2.1: Appendix D Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | Creation of new appendix to hold company specific information about risk input information including: Weighting factors, and VB Script text for the model. | Renie Sorensen & Kathleen Chirgwin |
| 2/24/2014 | 2014 Updates | Updates to model code logic and minor changes to weighting factors. | Kathleen Chirgwin |
| 3/17/2015 | 2015 Updates | Updated to model code logic. | Renie Sorensen |

# 3.0 SUMMARY OF RISK MODEL WEIGHTING FACTORS

## 3.1 Overview

This section of Appendix D includes a summary of the DIMP risk model weightings for each of the threat categories and their subcategories. A summary of revisions to the risk model, including weighting factors, are included in Section 3.0 of Appendix I – *Periodic Evaluation*.

Risk Likelihood of Failure (LOF) factors are assigned based on three levels of severity

1. High LOF factor = 7 - 10
2. Medium LOF factor = 3 - 6.9
3. Low LOF factor = 0.1 - 2.9
4. No LOF = 0
5. Reduces LOF < 0

All assigned LOF factors from this document are multiplied by 10 in the model in order to avoid using decimals in ESRI Model Builder.

All facilities are ‘active’. No analysis was performed on abandoned Mains or Services. All Leaks are considered to have been repaired or are monitored until repair.

The data available in our system extends back to the mid 1950s. Some information such as categorized leak causes has changed over time and is expected change into the future as new threats and causes come into view.

In an effort to shorten the 'run-time' of the DIMP model, the queries listed in each category are run against a pre-selected set of features. This eliminates the need to assign a high score to potentially missing data within each model. The model assigns elevated risk to missing data in a separate ‘Missing Values’ category.

All external data used in the DIMP model is listed in a Appendix B, Table B4.1

**Table D3.1: Current Weight Factors**

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| Corrosion | Previous Leaks (All) | Monitored Leak | 10 | Leak and repair data was taken to the extent it is available in the GIS with thought that the corrosion cause has always been defined the same. Facilities that have experienced corrosion in the past influence the probability of a failure happening in the future. Leaks or repairs that have a repair date prior to the installation date of the main or service will be excluded. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 4 | |
| | Exposed Pipe Inspections | Poor | 5 | Pipe inspections are added to the GIS and indicate the condition of the coating as observed by onsite personnel. Poor and fair coating conditions pose additional risk of corrosion. Model is currently coded to leak report data on external pipe condition, internal pipe condition, and coating condition. |
| | | Fair | 2.5 | |
| | | Good | 0 | |
| | Atmospheric Corrosion | Above ground Regulator Stations, Odorizer Stations, and valve sets within 1 mile of salt water bodies (oceans, estuaries, rivers under tidal influence) | 1 | Salt in atmosphere is highly corrosive to above ground steel piping. |
| | | Above Ground Facilities experiencing high annual rainfall levels (30 in/yr or greater) | 1 | Wet conditions on Westside of WA accelerate corrosion rates on above ground facilities. Cascade operates systems in two very different climates, the Westside experiences heavy rainfall conditions while the eastside experiences arid desert conditions with very low rainfall |
| | | Steel Pipe on bridges | 1 | Bridge crossing lack pipe coating and cathodic protection posing corrosion risk. |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Corrosion (Continued)** | Material Age (Steel Pipe Only) | PRE-CNG or FISH OR Pipe Installed prior to 1958 (over 20 years of no CP in pipe life) | 3 | Cathodic protection mandated federally in 1970 and all of Cascade's distribution systems were fully protected by 1978, pipe is assigned risk based on the number of decades in its operating life it lacked CP, which poses corrosion risk. Xtru pipe coat came to Cascade in 1967, so all steel pipe prior to 1979 is coal tar wrap. Risk is given to steel pipe prior to 1979 due to lack of cathodic protection and coal tar wrap which can become fragile and disbonded from pipe allowing pipe to be exposed from moisture and rocks causing corrosion. Coal tar wrapped steel also takes higher CP Voltages to adequately protect than Xtru Coat. Corrosion is time and condition independent, a pipe lacking CP can be unprotected for one year and experience the same amount of corrosion as a piece of pipe lacking CP protection for 20 years. |
| | | Pipe Installed from 1958 to 1968 . (10- 20 years of no CP in pipe life) | 1 | |
| | | Pipe Installed from 1968 to 1978 . (less than 10 years of no CP in pipe life) | 0.5 | |
| | Ability to provide Cathodic Protection in Arid Climates | Below ground steel pipe in Arid Climates (annual rainfall <= 15 in/yr) | 0.2 | Steel pipe in arid climates is difficult to protect with Cathodic protection due to very dry soil conditions in rocky/sandy soils. |
| | Bare Steel | Bare Steel | 4 | CNGC has two methods to protect pipe from corrosion, pipe wrap and CP protection. Since bare steel pipe lacks one of CNGCs two corrosion protection measures, bare steel is assigned additional corrosion risk. Bare steel also takes significant more CP voltage to protect than coal tar wrap or Xtru coat. |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Natural Forces** | Previous Leak (10 years) | Monitored Leak | 10 | Leak and repair data was taken to the extent it is available in the GIS with thought that the Natural Forces cause has always been defined the same. Facilities that have experienced a failure due to a natural force in the past influence the probability of a failure happening in the future. Leaks or repairs that have a repair date prior to the installation date of the main or service will be excluded |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |
| | Flooding – Regulator Stations and Valves | Base Flood (Floodway) | 1 | Risk is added to regulator stations based on Federal Emergency Manual Agency (FEMA) Flood hazard zone designations. These designations are used to assign risk to facilities in flood zones where flood insurance purchase is mandatory. See FEMA flood hazard zone designations shown on a Flood Insurance Rate Map (FIRM): FEMA DFIRMs |
| | | Base Flood (Non-Floodway) | 0.5 | |
| | | Base Flood (Floodway) w/ BFE Zone | 1 | |
| | | Base Flood (Non-Floodway) w/ BFE Zone | 0.5 | |
| | | Base Flood w/ Sheet-flow Shallow Flooding | 0 | |
| | | Base Flood w/ Water-Surface Elevation (ponding 1-3 ft) | 0 | |
| | Flooding – Mains and Services | Base Flood (Floodway) | 0.5 | Risk is added to regulator stations based on Federal Emergency Manual Agency (FEMA) Flood hazard zone designations. These designations are used to assign risk to facilities in flood zones where flood insurance purchase is mandatory. See FEMA flood hazard zone designations shown on a Flood Insurance Rate Map (FIRM): FEMA DFIRMs |
| | | Base Flood (Non-Floodway) | 0.3 | |
| | | Base Flood (Floodway) w/ BFE Zone | 0.5 | |
| | | Base Flood (Non-Floodway) w/ BFE Zone | 0.3 | |
| | | Base Flood w/ Sheet-flow Shallow Flooding | 0 | |
| | | Base Flood w/ Water-Surface Elevation (ponding 1-3 ft) | 0 | |

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| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Natural Forces (Continued)** | Water Crossing | Yes | 1 | All segments crossing significant waterways such as lakes, rivers, streams and canals are given added risk. The National Hydrography dataset is the external data source used to identify the location of such waterways. |
| | Frost Upheaval – Mains and Services | Service – “High” Susceptibility to Frost Upheaval - Bare Steel, Coated Steel, Unknown Material | 0.5 | CNG has had several failures due to frost upheaval, the threat does exist and an element of risk is given to facilities with soil attribute data specific to having a higher susceptibility to frost upheaval. CNG uses soil attribute data supplied by the National Resources Conservation (NRCS). Services are given a slightly higher score as they are generally shallower than main. |
| | | Service – “High” Susceptibility to Frost Upheaval - Plastic Material | 0.3 | |
| | | Main – “High” Susceptibility to Frost Upheaval- Bare Steel, Coated Steel, Unknown Material | 0.3 | |
| | | Main – “High” Susceptibility to Frost Upheaval- Plastic Material | 0.2 | |
| | Wild Fires | Moderate Chance | 0.5 | Wild fires pose a significant threat to above ground facilities. The Northwestern United States ranks high on the list for potential wildfires. Wild Fire data used for analysis in the DIMP model is based on US Forest Service regional fire maps of the past 10 years. Areas are identified by kernel density of wild fires in CNG’s operating region. The resulting regions are intersected with regulator stations and risk scores are assigned based on likelihood of wild fires at those locations. |
| | | High Chance | 1 | |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Natural Forces (Continued)** | Landslides | High Incidence (>15% Area) | 2 | Gas pipelines are often threatened by impact and displacement from landslides. Landslide hazard areas used for analysis in the DIMP model are obtained from the digital compilation of the USGS National Landslide Overview Map. Areas which are defined by susceptibility of landslides are intersected with mains and service lines. Risk scores are assigned based on likelihood of landslides occurring at those locations. |
| | | Moderate Incidence (1.5-15% Area) | 1 | |
| | | High Susceptibility & Moderate Incidence | 1.5 | |
| | | High Susceptibility & Low Incidence | 0.5 | |
| | | Moderate susceptibility & Low Incidence | 0.3 | |
| **Excavation Damage** | Previous Leaks (10 years) | Monitored Leak | 10 | Historical excavation damages are not necessarily indicative of future events. This is why historical leaks and repairs are given a lower score when compared to other leaks such as corrosion. Leaks or repairs that have a repair date prior to the installation date of the main or service will be excluded. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |
| | Line Locate Activity | Line Locate within 50 ft radius | 2 (Per Ticket) | Currently all pipe that falls within a 50 foot radius of a Line Locate Ticket location is given an added risk. The risk score remains assigned to the pipe for a period of six months after the completion date of the ticket. In the Line Locate data is provided by One Call. |
| | District Damages/1000 Locate Tickets | Damages/1000 Locates >10 | 3 | Added risk is given to facilities based on the ratio of excavation damages per 1,000 locate tickets from the previous Calendar Year. The assigned risk will be based on the Common Ground Alliance national average as of 2011. The national average from the 2011 CGA report is 5.10 damages per 1,000 locate tickets. |
| | | Damages/1000 Locates >5.1 & <=10 | 2 | |
| | | Damages/1000 Locates >3 & <=5.1 | 1 | |
| | | Damages/1000 Locates >1.5 & <=3 | 0.5 | |
| | | Damages/1000 Locates <1.5 | 0 | |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| Excavation Damage (Continued) | Cased Pipe | Yes | -1 | Risk is reduced for pipe that is installed in a casing as the carrier pipe has a reduced risk for Excavation Damage |
| | Recent Install Date on Main | Installed within 1 year | 2 | A comparison of Excavation Damage and Install Date on Mains and Services reveals that excavation damage occurs predominantly during the first few years after installation. |
| | | Installed within 2 year | 0.5 | |
| | | Installed within 4 year | 0.5 | |
| | | Installed within 6 year | 0 | |
| | Recent Install Date on Service | Installed within 1 year | 2 | |
| | | Installed within 2 year | 1 | |
| | | Installed within 4 year | 0.3 | |
| | Ability to Locate PE Mains/Services | PE Installed Prior to 1995 | 4 | When Cascade first started installing PE mains and services in until 1995 they had a poor tracer wire installation procedure with poor splice kits, which have the potential of being disconnected which adds excavation risk to these early PE systems. Several district in CNGC have expressed this concern since they have experienced these conditions where PE mains and services are very difficult to locate which could lead to poor locates leading to excavation damage incidents. |
| Other Outside Force Damage | Previous Leaks (10 Years) | Monitored Leak | 10 | The Company will use the previous ten years of leak history in order to reflect current risk on the distribution system. Leaks and repairs are remediated when found, or monitored until remediated, and those that have a repair date prior to the installation date of the main or service will be excluded. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |
| | Major Road Crossing | Main | 0.5 | Significant road crossings add an element of Outside Force risk to facilities due to weight and vibration. Risk is added to segments that cross roads designated as highways or interstates using Navteq center line data. |
| | | Service | 0.5 | |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Other Outside Force Damage (Continued)** | Vehicular Damage | Riser (25 ft) | 0.5 | Above ground facilities have a higher susceptibility to vehicle damage. Risers, Rural Taps (High Pressure Service Sets) and Regulator Stations within 25 feet of a road right of way will get added risk. |
| | | Regulator Stations (25 ft) | 1 | |
| | | High Pressure Service Set (25 ft) | 1 | |
| | Casing | Steel Casing < 50 years Old | -2 | While casings are not desired for corrosion related reasons, they due add an element of protection to the outside force threat. Because casings are not protected for corrosion, they can break down over time. For this reason, casings less than 25 years old will have a reduced risk while casings older than 50 years will be assumed to have no added outside force protection. This was based on an average corrosion rate of 3 mills per year with a casing wall thickness of 0.188". |
| **Material Failure** | Previous Leaks (10 Years) | Monitored Leak | 10 | The Company will use the previous ten years of leak history in order to reflect current risk on the distribution system. Leaks and repairs are remediated when found, or monitored until remediated, and those that have a repair date prior to the installation date of the main or service will be excluded. Historically, CNG used the Material and Welds failure cause code in GIS to identify failures that groups Material failures with weld/joint failures. For this reason, leaks and repairs with Facility Types as Girth Weld or Longitudinal Weld are excluded. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Weld or Joint Failure** | Previous Leaks (10 Years) | Monitored Leak | 10 | The Company will use the previous ten years of leak history in order to reflect current risk on the distribution system. Leaks and repairs are remediated when found, or monitored until remediated, and those that have a repair date prior to the installation date of the main or service will be excluded. Historically, CNG used the Material and Welds failure cause code in GIS to identify failures that groups Material failures with weld/joint failures. For this reason, leaks and repairs with Facility Types as Girth Weld or Longitudinal Weld are used for this category. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 4 | |
| | Weld Standards | Steel pipe installed prior to 1980 | 1 | In 1980 Cascade significantly increased weld standards and welder qualifications. |
| | Non Controllable Fitting | Coupling, Elbow, End Cap, Expansion Joint, Flange, Reducer, Full Open Tee, Transition, Insulted Coupling | 0.3 | The non-controllable fittings increases the number of welds and thus increases the likelihood of failure |
| **Equipment** | Previous Leaks (10 Years) | Monitored Leak | 10 | The Company will use the previous ten years of leak history in order to reflect current risk on the distribution system. Leaks and repairs are remediated when found, or monitored until remediated, and those that have a repair date that is prior to the installation date of the main or service will be excluded. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |
| | Age of Valve | FISH or PRE-CNGC | 3 | Risk is added to the Equipment failure on valves based on the age due to the increased likelihood failure. Risk is only added to steel valves or valves on unknown material, no risk is added to plastic valves. |
| | | >= 60 years | 2 | |
| | | >= 40 years & <60 years | 1 | |
| | | >= 30 years & <40 years | 0.5 | |
| | | >= 20 years & <30 years | 0 | |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Equipment (Continued** | High Pressure Service Set Present | Yes | 2 | High Pressure Service Sets (Farm Taps/ Rural Taps) are not on regular maintenance schedule like District Regulator Stations (annual) so piping with a HPSS point feature will receive added risk. |
| **Incorrect Operation** | Previous Leaks (10 Years) | Monitored Leak | 10 | The Company will use the previous ten years of leak history in order to reflect current risk on the distribution system. Leaks and repairs are remediated when found, or monitored until remediated, and those that have a repair date that is prior to the installation date of the main or service will be excluded. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |
| **Other** | Previous Leaks (10 Years) | Monitored Leak | 10 | The Company will use the previous ten years of leak history in order to reflect current risk on the distribution system. Leaks and repairs are remediated when found, or monitored until remediated, and those that have a repair date prior to the installation date of the main or service will be excluded. Repairs for this category are given less risk when compared to other threat categories. The thought behind this is because repairs categorized as Other are generally used for maintenance activities such as installing anodes and lowing pipe. |
| | | Repaired Leak | 8 | |
| | | Maintenance Repair | 2 | |

<table>
<tr><th>Primary Threat</th><th>Sub-threat</th><th>Factor</th><th>Weighting</th><th>Comments</th></tr>
<tr><td rowspan="9">Missing Values</td><td rowspan="4">Leak Information</td><td>Leak Type</td><td>8</td><td rowspan="5">If required information on leaks and repairs used in the risk model is missing, added risk will be assigned.</td></tr>
<tr><td>Repaired</td><td>2</td></tr>
<tr><td>MDU Leak Number</td><td>4</td></tr>
<tr><td>Repair Date</td><td>1</td></tr>
<tr><td>Repair Information</td><td>Leak Type</td><td>4</td></tr>
<tr><td rowspan="2">Install Information</td><td>Date Installed</td><td>4</td><td rowspan="2">If required information on newly installed mains and services used in the risk model is missing, added risk will be assigned.</td></tr>
<tr><td>Material Type-'SubtypeCD'</td><td>4</td></tr>
<tr><td rowspan="2">Valve Information</td><td>Valve Material</td><td>3</td><td rowspan="2">If required information on newly installed valves used in the risk model is missing, added risk will be assigned.</td></tr>
<tr><td>Installation Date</td><td>3</td></tr>
</table>

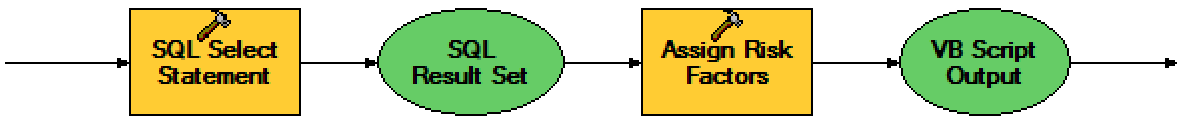
| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| Consequence | Population Density | Square Mile <100 | 0 | The Census Block Group data is included with the ESRI Data & Maps media kit and contains estimated population per square mile value. This value is used as a measure to calculate the impact of a gas system failure on the user community adjacent to the gas system. |
| | | Square Mile >=100 & <500 | 0.5 | |
| | | Square Mile >=500 & <1000 | 1 | |
| | | Square Mile >=1000 & <2000 | 2 | |
| | | Square Mile >=2000 & <5000 | 3 | |
| | | Square Mile >=5000 & <10000 | 4 | |
| | | Square Mile >=10000 | 5 | |
| | Pressure and Diameter | Diameter^2 * Pressure Class <240 | 1 | The Main and Service Pressure Class and Nominal Pipe Size represent a measure of the potential severity of a gas system failure. Relative risk was calculated based on potential severity of a gas release with PE = D^2 * P. Where *D* is the nominal diameter and P is the MAOP. If PE comes out to be 0, a score of 5 is assigned as the worst case scenario. |
| | | Diameter^2 * Pressure>=240 & <4,000 | 2 | |
| | | Diameter^2 * Pressure>=4,000 & <16,000 | 3 | |
| | | Diameter^2 * Pressure>=16,000 & <32,000 | 4 | |
| | | Diameter^2 * Pressure >= 32,000 | 5 | |

| Primary Threat | Sub-threat | Factor | Weighting | Comments |
|---|---|---|---|---|
| **Consequence (Continued)** | Steel Tapping Ability | Steel IP D>4 in<br>AND<br>All HP Mains | 2 | All CNGC districts can stop and tap IP steel mains 4 in and less in nominal pipe size. When incidences occur inserting linestoppers are necessary to stop the flow of blowing gas and repair incidence outside of gas envelope, risk is added to steel IP 6" and greater and all High pressure mains since Division must respond with correct tapping equipment which adds time to response. No risk is assigned to PE or steel IP pipe 4 inches or less in nominal diameter since all districts have the ability to make a squeeze or pinch in emergency response. |
| | Critical Infrastructure | Near Critical Infrastructure | 1 | A Critical Infrastructure is defined in the Homeland Security Act and includes public health and emergency services among others. Hospitals and schools are identified within the CNG's operating region and a buffer zone is created for each. The buffer is a circle 1000 feet in diameter around the point feature. |
| | Service Line EFV | EVF on Service Line | -3 | Excess flow valves (EFVs) respond to an excessive flow of gas such as may occur as a result of a leak by automatically closing and restricting the gas flow. This in turn reduces the consequence of a failure where EFV's are installed. The company complies with Current federal regulation requirements and a reduced consequence is given to segments where EFV's are installed. |

# 4.0 MODEL CALCULATIONS

## 4.1 Overview

This section includes the Visual Basic (VB) scripts specific to each threat. The script identifies the correct ESRI Model Builder language used to assign the risk factors listed in Section 1 of this appendix. In each case the script is preceded by a relevant SQL Select Statement. The Select Statement extracts a certain set of records from the database that fulfill a specific criterion. The string of geoprocessing tools shown below is typical of the workflow used in the DIMP model to assign risk factors. A Company GIS Analyst performs all necessary updates and changes to the scripts and all historical scripts will be archived on the Engineering SharePoint page.




## 4.2 Corrosion

### 4.2.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE LEAKTYPE='COR'

Dim Score
If [SUBTYPECD] > 0 then            'leak report
  If [REPAIRED] = "MON" then           'monitored leak
    Score = 10
  Else                                 'repaired leak
    Score = 8
  End If
Else                                'maintenance repair
  Score = 4
End if
Risk = Score
```

### 4.2.2 Exposed Pipe Inspections

```
SELECT *
FROM LeaksAndRepairs
WHERE INTERNALCONDITION='F' OR INTERNALCONDITION='P' OR
EXTERNALCONDITION='F' OR EXTERNALCONDITION='P' OR COATCOND='F' OR
COATCOND='P'

Dim Score
If ([INTERNALCONDITION] = "P" OR [EXTERNALCONDITION] = "P" OR [COATCOND]
="P") then      'poor
    Score = 5
```

```
ElseIf ([INTERNALCONDITION] = "F" OR [EXTERNALCONDITION] = "F" OR [COATCOND] =
"F") then      'fair
   Score = 2.5
Else
   Score = 0
End If
Risk = Score
```

### 4.2.3 Atmospheric Corrosion

#### *4.2.3.1 Above Ground Facilities within 1 mile of Marine Shoreline*

```
SELECT *
FROM AboveGroundFacilities, MarineShoreLine
WHERE ST_Intersects(AboveGroundFacilities.Shape,
ST_Buffer(MarineShoreLine.Shape, 5280))  = 1

Risk = 1
```

#### *4.2.3.2 Above Ground Facilities in High Annual Rainfall Areas*

```
SELECT *
FROM AboveGroundFacilities, HighAnnualRainfallArea
WHERE ST_Intersects(AboveGroundFacilities.Shape, HighAnnualRainfallArea.Shape)  =
1

Risk = 1
```

#### *4.2.3.3 Steel Pipe on Bridges*

```
SELECT *
FROM Main, hyd_pub_Merg
WHERE (SUBTYPECD=1 OR SUBTYPECD=3) AND ST_Intersects(Main.Shape,
ST_Buffer(hyd_pub_Merg.Shape, 10))  = 1

Risk = 1
```

### 4.2.4 Bare Steel

```
SELECT *
FROM Main
WHERE SUBTYPECD = 1

Risk = 4
```

### 4.2.5 Material Age (Steel Pipe Only)

```
SELECT *
FROM Main
WHERE SUBTYPECD <> 5

Dim Score
If ([WORKORDERID] = "PRE-CNG" OR [WORKORDERID] = "FISH") then
  Score = 3
```

```
ElseIf [DATEINSTALLED] >= #01-01-1948# AND [DATEINSTALLED] < #01-01-1958# then
 Score = 3
ElseIf [DATEINSTALLED] >= #01-01-1958# AND [DATEINSTALLED] < #01-01-1968# then
 Score = 1
ElseIf [DATEINSTALLED] >= #01-01-1968# AND [DATEINSTALLED] < #01-01-1978# then
 Score = 0.5
Else
 Score = 0
End If
Risk = Score
```

#### 4.2.6 Lack of Cathodic Protection in Arid Climate

```
SELECT *
FROM Main
WHERE SUBTYPECD <> 5 AND ST_Intersects(Main.Shape, LowAnnualRainfallArea.Shape) = 1

Risk = 0.2
```

### 4.3 Equipment Failure

#### 4.3.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE LEAKTYPE='EQ' AND (CUTOFFDATE - REPAIRDATE) >= 0 AND (CUTOFFDATE -
REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then              'leak report
 If [REPAIRED] = "MON" then             'monitored leak
  Score = 10
 Else                                   'repaired leak
  Score = 8
 End If
Else                                 'maintenance repair
 Score = 2
End if
Risk = Score
```

#### 4.3.2 Age of Valve

```
SELECT *
FROM GasValve

Dim Score
Dim Age
Age = DateDiff ( "yyyy", [INSTALLATIONDATE] , Date)
If ([WORKORDERID] = "PRE-CNG" OR [WORKORDERID] = "FISH") then
 Score = 3
ElseIf Age >= 60 then
 Score = 2
```

```
ElseIf ( Age >= 40 AND Age < 60) then
  Score = 1
ElseIf ( Age >= 30 AND Age < 40) then
  Score = 0.5
ElseIf ( Age >= 20 AND Age < 30) then
  Score = 0
ElseIf Age < 20 then
  Score = 0
Else
  Score = 0
End If
Risk = Score
```

### 4.3.3 Rural Tap

```
SELECT *
FROM RuralTap

Risk = 2
```

## 4.4 Excavation Damage

### 4.4.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE LEAKTYPE='EQ' AND (CUTOFFDATE - REPAIRDATE) >= 0 AND (CUTOFFDATE -
REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then             'leak report
  If [REPAIRED] = "MON" then          'monitored leak
    Score = 10
  Else                                'repaired leak
    Score = 8
  End If
Else                                'maintenance repair
  Score = 2
End if
Risk = Score
```

### 4.4.2 Line Locate Activity

```
SELECT *
FROM Main, CNG_OneCall
WHERE ST_Intersects(Main.Shape, ST_Buffer(CNG_OneCall.Shape, 50)) = 1

Risk = 2
```

### 4.4.3 District Damages per 1,000 Locate Tickets

```
SELECT *
FROM Main, MainExcavationLeaks_Districts
WHERE ST_Intersects(Main.Shape, MainExcavationLeaks_Districts.Shape) = 1
```

```
Dim Score
If [EXCDAMAGES_PER1000LOC] > 10.0 then
  Score = 3
ElseIf ( [EXCDAMAGES_PER1000LOC] > 5.1 AND [EXCDAMAGES_PER1000LOC] <= 10.0 )
then
  Score = 2
ElseIf ( [EXCDAMAGES_PER1000LOC] > 3.0 AND [EXCDAMAGES_PER1000LOC] <= 5.1 )
then
  Score = 1
ElseIf ( [EXCDAMAGES_PER1000LOC] > 1.5 AND [EXCDAMAGES_PER1000LOC] <= 3.0 )
then
  Score = 0.5
Else
  Score = 0
End If
Risk = Score
```

### 4.4.4 Cased Pipe (includes Inserts & Sleeves)

```
SELECT *
FROM GasPipeCasing

Risk = -1
```

### 4.4.5 Recent Install Date

#### *4.4.5.1 Main*

```
SELECT *
FROM Main
WHERE (Current_Date - DATEINSTALLED) < 365.0 * 6.0

Dim Score
Dim Age
Age = DateDiff ("yyyy", [DATEINSTALLED] , Date)
If Age <= 1 then              '1 year since install
  Score = 2
ElseIf (Age > 1 AND Age <= 2) then    '2 years since install
  Score = 0.5
ElseIf (Age > 2 AND Age <= 4) then    'btw 3 & 4 years since install
  Score = 0.5
Else
  Score = 0
End If
Risk = Score
```

#### *4.4.5.2 Service*

```
SELECT *
FROM Service
WHERE (Current_Date - DATEINSTALLED) < 365.0 * 6.0
```

```
Dim Score
Dim Age
Age = DateDiff ("yyyy", [DATEINSTALLED] , Date)
If Age <= 1 then            '1 year since install
  Score = 2
ElseIf (Age > 1 AND Age <= 2) then    '2 years since install
  Score = 1
ElseIf (Age > 2 AND Age <= 4) then    'btw 3 & 4 years since install
  Score = 0.3
Else
  Score = 0
End If
Risk = Score
```

### 4.4.6 Ability to locate PE

```
SELECT *
FROM Main
WHERE SUBTYPECD = 5 AND DATEINSTALLED < date '1995-01-01'

Risk = 4
```

## 4.5 Incorrect Operation

### 4.5.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE (LEAKTYPE='OP' OR LEAKTYPE='CD') AND (CUTOFFDATE - REPAIRDATE) >= 0
AND (CUTOFFDATE - REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then              'leak report
  If [REPAIRED] = "MON" then             'monitored leak
    Score = 10
  Else                                   'repaired leak
    Score = 8
  End If
Else                                 'maintenance repair
  Score = 2
End if
Risk = Score
```

## 4.6 Material Failure

### 4.6.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE ((LEAKTYPE='MAT' AND (LEAKDESCRIPTION NOT LIKE '%WELD%' AND
LEAKDESCRIPTION NOT LIKE '%SEAM%')) OR  (LEAKTYPE='MAT' AND LEAKDESCRIPTION
IS NULL)) AND (CUTOFFDATE - REPAIRDATE) >= 0 AND (CUTOFFDATE - REPAIRDATE) <=
365.0 * 10.0
```

```
Dim Score
If [SUBTYPECD] > 0 then            'leak report
  If [REPAIRED] = "MON" then         'monitored leak
    Score = 10
  Else                               'repaired leak
    Score = 8
  End If
Else                               'maintenance repair
  Score = 2
End if
Risk = Score
```

## 4.7 Natural Forces

### 4.7.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE LEAKTYPE='NF' AND (CUTOFFDATE - REPAIRDATE) >= 0 AND (CUTOFFDATE -
REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then            'leak report
  If [REPAIRED] = "MON" then         'monitored leak
    Score = 10
  Else                               'repaired leak
    Score = 8
  End If
Else                               'maintenance repair
  Score = 2
End if
Risk = Score
```

### 4.7.2 Flooding – Regulator Stations and Valves

```
SELECT *
FROM RegulatorStation, WA_OR_Floodzone
WHERE ST_Intersects(RegulatorStation.Shape, WA_OR_Floodzone.Shape) = 1

Dim Score
If ( [ZONE] = "A" AND [FLOODWAY] = "FW" ) then          'base flood (floodway)
  Score = 1
ElseIf ( [ZONE] = "A" AND [FLOODWAY] <> "FW" ) then        'base flood (non-
floodway)
  Score = 0.5
ElseIf ( [ZONE] = "AE" AND [FLOODWAY] = "FW" ) then          'base flood (floodway)
w. BFE zones
  Score = 1
ElseIf ( [ZONE] = "AE" AND [FLOODWAY] <> "FW" ) then         'base flood (non-
floodway) w. BFE zones
  Score = 0.5
```

```
ElseIf [ZONE] = "AO" then            'base flood w. sheet-flow shallow flooding
 Score = 0
ElseIf [ZONE] = "AH" then           'base flood w. constant water-surface elevation
(ponding)
 Score = 0
Else
 Score = 0
End If
Risk = Score
```

### 4.7.3 Flooding – Mains and Services

```
SELECT *
FROM Main, WA_OR_Floodzone
WHERE ST_Intersects(Main.Shape, WA_OR_Floodzone.Shape) = 1

Dim Score
If ( [ZONE] = "A" AND [FLOODWAY] = "FW" ) then           'base flood (floodway)
 Score = 0.5
ElseIf ( [ZONE] = "A" AND [FLOODWAY] <> "FW" ) then         'base flood (non-
floodway)
 Score = 0.3
ElseIf ( [ZONE] = "AE" AND [FLOODWAY] = "FW" ) then           'base flood (floodway)
w. BFE zones
 Score = 0.5
ElseIf ( [ZONE] = "AE" AND [FLOODWAY] <> "FW" ) then          'base flood (non-
floodway) w. BFE zones
 Score = 0.3
ElseIf [ZONE] = "AO" then            'base flood w. sheet-flow shallow flooding
 Score = 0
ElseIf [ZONE] = "AH" then           'base flood w. constant water-surface elevation
(ponding)
 Score = 0
Else
 Score = 0
End If
Risk = Score
```

### 4.7.4 Water Crossings

```
SELECT *
FROM Main, hyd_pub_Merg
WHERE ST_Intersects(Main.Shape, hyd_pub_Merg.Shape) = 1

Risk = 1
```

### 4.7.5 Frost Upheaval

#### *4.7.5.1 Steel Mains*

```
SELECT *
FROM Main, soilmu_a_frost
WHERE ST_Intersects(Main.Shape, soilmu_a_frost.Shape) = 1
```

```
Dim Score
Select CASE [SUBTYPECD]
 CASE 1          'Bare Steel Main
     Score = 0.3
 CASE 3          'Coated Steel Main
     Score = 0.3
 CASE 5          'Plastic Main
     Score = 0.2
 CASE 7          'Unknown
     Score = 0.3
 CASE ELSE
     Score = 0
 End Select
Risk = Score
```

#### *4.7.5.2 Services*

```
SELECT *
FROM Service, soilmu_a_frost
WHERE ST_Intersects(Service.Shape, soilmu_a_frost.Shape) = 1

Dim Score
Select CASE [SUBTYPECD]
 CASE 1          'Bare Steel Service
     Score = 0.5
 CASE 3          'Coated Steel Service
     Score = 0.5
 CASE 5          'Plastic Service
     Score = 0.3
 CASE 7          'Unknown
     Score = 0.5
 CASE ELSE
     Score = 0
 End Select
Risk = Score
```

### 4.7.6 Wild Fires

```
SELECT *
FROM RegulatorStation, MODIS_WildFires
WHERE ST_Intersects(RegulatorStation.Shape, MODIS_WildFires.Shape) = 1

Dim Score
Select CASE [GRIDCODE]
 CASE 1          'moderate chance of wild fire
  Score = 0.5
 CASE 2          'high chance of wild fire
  Score = 1
End Select
Risk = Score
```

#### 4.7.7 Landslides

```
SELECT *
FROM Main, LandSlides
WHERE ST_Intersects(Main.Shape, LandSlides.Shape) = 1

Dim Score
If [INC_SUS] = "high" then          'high landslide incidence (>15% of area involved)
  Score = 2
ElseIf [INC_SUS] = "mod" then       'moderate landslide incidence (1.5 - 15% of area
involved)
  Score = 1
ElseIf [INC_SUS] = "combo-hi" then       'high susceptibility and moderate incidence
  Score = 1.5
ElseIf [INC_SUS] = "sus-high" then       'high susceptibility and low incidence
  Score = 0.5
ElseIf [INC_SUS] = "sus-mod" then        'moderate susceptibility and low incidence
  Score = 0.3
Else
  Score = 0
End If
Risk = Score
```

### 4.8 Other Outside Force

#### 4.8.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE LEAKTYPE='OUT' AND (CUTOFFDATE - REPAIRDATE) >= 0 AND (CUTOFFDATE -
REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then              'leak report
  If [REPAIRED] = "MON" then            'monitored leak
    Score = 10
  Else                                  'repaired leak
    Score = 8
  End If
Else                                 'maintenance repair
  Score = 2
End if
Risk = Score
```

#### 4.8.2 Major Road Crossing

```
SELECT *
FROM Main, ESRIStreets_ORWA
WHERE ST_Intersects(Main.Shape, ST_Buffer(ESRIStreets_ORWA.Shape, 35)) = 1

Risk = 0.5
```

### 4.8.3 Vehicular Damage

#### *4.8.3.1 Regulator Station*

```
SELECT *
FROM RegulatorStation, RightOfWay
WHERE ST_Intersects(RegulatorStation.Shape, ST_Buffer(RightOfWay.Shape, 25)) = 1

Risk = 1
```

#### *4.8.3.2 Farm Tap*

```
SELECT *
FROM RuralTap, RightOfWay
WHERE ST_Intersects(RuralTap.Shape, ST_Buffer(RightOfWay.Shape, 25)) = 1

Risk = 1
```

#### *4.8.3.3 Riser*

```
SELECT *
FROM GasServicePoint, RightOfWay
WHERE ST_Intersects(GasServicePoint.Shape, ST_Buffer(RightOfWay.Shape, 25)) = 1

Risk = 0.5
```

### 4.8.4 Casings (includes Inserts and Sleeves)

```
SELECT *
FROM GasPipeCasing
WHERE (Current_Date - INSTALLATIONDATE) < 365.0 * 50.0

Dim Score
Select CASE [MATERIAL]
 CASE "ST"          'steel
  Score = -2
 CASE ELSE
  Score = 0
End Select
Risk = Score
```

## 4.9 Weld or Joint Failure

### 4.9.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE (LEAKTYPE='MAT' AND (LEAKDESCRIPTION LIKE '%WELD%' OR
LEAKDESCRIPTION LIKE '%SEAM%')) AND (CUTOFFDATE - REPAIRDATE) >= 0 AND
(CUTOFFDATE - REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then              'leak report
 If [REPAIRED] = "MON" then            'monitored leak
  Score = 10
```

```
  Else                                'repaired leak
    Score = 8
  End If
Else                                'maintenance repair
  Score = 4
End if
Risk = Score
```

### 4.9.2 Non Controllable Fitting

```
SELECT *
FROM NonControllableFitting

Risk = 0.3
```

### 4.9.3 Controllable Fitting (Extension Stoppers)

```
SELECT *
FROM ControllableFitting
WHERE SUBTYPECD = 1

Risk = 0.3
```

### 4.9.4 Weld Standards

```
SELECT *
FROM Main
WHERE SUBTYPECD <> 5

Dim Score
If [DATEINSTALLED] < #01-01-1980# then
  Score = 1
Else
  Score = 0
End If
Risk = Score
```

## 4.10 Other

### 4.10.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE LEAKTYPE='OTH' AND (CUTOFFDATE - REPAIRDATE) >= 0 AND (CUTOFFDATE -
REPAIRDATE) <= 365.0 * 10.0

Dim Score
If [SUBTYPECD] > 0 then             'leak report
  If [REPAIRED] = "MON" then          'monitored leak
    Score = 10
  Else                                'repaired leak
    Score = 8
  End If
```

```
Else                              'maintenance repair
 Score = 2
End if
Risk = Score
```

## 4.11 Missing Values

### 4.11.1 Leaks and Repairs

```
SELECT *
FROM LeaksAndRepairs
WHERE MDULEAKNO IS NULL OR REPAIRED IS NULL OR LEAKTYPE IS NULL OR
REPAIRDATE IS NULL

Dim Mdulk
Dim Rprdt
Dim Reprd
Dim Lktyp
If [SUBTYPECD] > 0 then           'leak report
 If IsNull( [MDULEAKNO] ) then
  Mdulk = 4
 Else
  Mdulk = 0
 End If
 If IsNull( [REPAIRDATE] ) then
  Rprdt = 1
 Else
  Rprdt = 0
 End If
 If IsNull( [REPAIRED] ) then
  Reprd = 2
 Else
  Reprd = 0
 End If
 If IsNull( [LEAKTYPE] ) then
  Lktyp = 8
 Else
  Lktyp = 0
 End If
Else                              'maintenance repair
 If IsNull( [LEAKTYPE] ) then
  Lktyp = 4
 Else
  Lktyp = 0
 End If
End if
Risk = Mdulk + Rprdt + Reprd + Lktyp
```

### 4.11.2 Mains and Services

```
SELECT *
FROM Main
```

```
WHERE SUBTYPECD = 7 OR DATEINSTALLED IS NULL OR DATEINSTALLED >
Current_Date

Dim DateIns
Dim PressCl
Dim WOID
Dim Subtyp
If IsNull( [DATEINSTALLED] ) then
   DateIns = 4
ElseIf DateDiff("d", [DATEINSTALLED], Date) < 0 then
   DateIns = 4
Else
   DateIns = 0
End If
If [SUBTYPECD] = 7 then
   Subtyp = 1
Else
   Subtyp = 0
End If
Risk = DateIns+Subtyp
```

### 4.11.3 Valves

```
SELECT *
FROM GasValve
WHERE MATERIAL IS NULL OR INSTALLATIONDATE IS NULL

Dim Mat
Dim InsDate
Dim WOID
If IsNull( [MATERIAL] ) then
   Mat = 3
Else
   Mat = 0
End If
If IsNull( [INSTALLATIONDATE] ) then
   InsDate = 3
Else
   InsDate = 0
End If
Risk = Mat+ InsDate
```

## 4.12 Consequence Factors

### 4.12.1 Population Density

```
SELECT *
FROM WA_OR_CensusBlk
WHERE STCOFIPS IN ( '41001', '41009', '41013', '41017', '41031', '41035', '41045',
'41049', '41059', '53001', '53005', '53007', '53011', '53015', '53017', '53021', '53025',
'53027', '53029', '53035', '53045', '53057', '53061', '53071', '53073', '53077')
```

```
Dim Score
If [POP10_SQMI] < 100 then
  Score = 0
ElseIf [POP10_SQMI] >= 100 AND [POP10_SQMI] < 500 then
  Score = 0.5
ElseIf [POP10_SQMI] >= 500 AND [POP10_SQMI] < 1000 then
  Score = 1
ElseIf [POP10_SQMI] >= 1000 AND [POP10_SQMI] < 2000 then
  Score = 2
ElseIf [POP10_SQMI] >= 2000 AND [POP10_SQMI] < 5000 then
  Score = 3
ElseIf [POP10_SQMI] >= 5000 AND [POP10_SQMI] < 10000 then
  Score = 4
ElseIf [POP10_SQMI] >= 10000 then
  Score = 5
Else
  Score = 0
End If
Risk = Score
```

### 4.12.2 Pressure and Diameter

#### *4.12.2.1 Potential Energy Calculation (Main)*

```
SELECT *
FROM Main
WHERE [POTENTIAL_ENERGY] = [PIPESIZE]^2 * Pressure

Static Pressure as variant
Dim PS
If [MAOP] > 0 Then
  PS = [MAOP]
Else
  PS = 0
End If
Pressure= PS
```

#### *4.12.2.2 Potential Energy Calculation (Service)*

```
SELECT *
FROM Service
WHERE [POTENTIAL_ENERGY] =[PIPESIZE]^2 * Pressure

Static Pressure as variant
Dim PS as Integer
Select CASE [PRESSURECLASS]
  CASE "LP"      'Low Pressure
  PS = 1
  CASE "DP"      'Distribution Pressure
  PS = 60
  CASE "IP"      'Intermediate Pressure
  PS = 250
```

```
 CASE "HP"       'High Pressure
 PS = 500
 CASE ELSE
 PS = 60
End Select
Pressure= PS
```

#### *4.12.2.3 Risk Calculation*

```
SELECT *
FROM Main

Dim Score
If [POTENTIAL_ENERGY] > 0 AND [POTENTIAL_ENERGY] < 240 then
 Score = 1
ElseIf [POTENTIAL_ENERGY] >= 240 AND [POTENTIAL_ENERGY] < 4000 then
 Score = 2
ElseIf [POTENTIAL_ENERGY] >= 4000 AND [POTENTIAL_ENERGY] < 16000 then
 Score = 3
ElseIf [POTENTIAL_ENERGY] >= 16000 AND [POTENTIAL_ENERGY] < 32000 then
 Score = 4
ElseIf [POTENTIAL_ENERGY] >= 32000 then
 Score = 5
Else
 Score = 5
End If
Risk = Score
```

### 4.12.3 Steel Tapping Ability

```
SELECT *
FROM Main
WHERE (SUBTYPECD =1 OR SUBTYPECD =3 OR SUBTYPECD =7) AND (PRESSURECLASS = 'IP' OR
PRESSURECLASS = ‘HP’)

Dim Score
If [PIPESIZE] > 4 then
 Score = 2
Else
 Score = 0
End If
Risk = Score
```

### 4.12.4 Critical Infrastructure

#### *4.12.4.1 Schools*

```
SELECT *
FROM Main, Schools
WHERE ST_Intersects(Main.Shape, ST_Buffer(Schools.Shape, 100)) = 1

Risk = 1
```

#### *4.12.4.2 Hospitals*

```
SELECT *
FROM Main, Hospitals
WHERE ST_Intersects(Main.Shape, ST_Buffer(Hospitals.Shape, 100))= 1
```

Risk = 1

### 4.12.5 Excess Flow Valves

```
SELECT *
FROM ExcessFlowValve
```

Risk = -3

# Appendix E - Risk Analysis

## Table of Contents

# 1.0 SUMMARY OF RISK ANALYSIS

## 1.1 Overview

The purpose of this appendix is to summarize the risk rankings determined from the results generated by the risk model.

## 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 4.3 Risk Ranking | 3.0 Risk Ranking | Table E3.1, E3.2 |
| 4.4 Risk Model Validation | 4.0 Model Validation Summary | Table E4.1 |

# 2.0 APPENDIX REVISION SUMMARY

## 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table E2.1: Appendix E Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | Creation of new appendix to summaries risk rankings and record model validation. | Renie Sorensen & Kathleen Chirgwin |
| 2/25/2014 | Addition | Added Standard Deviation Analysis on Total Risk (Section 5) and Added Time Dependent and Time Independent Risk Evaluation (Section 6) | Kathleen Chirgwin |
| 3/22/2016 | Clarification | Added process clarification to 3.1 and 4.1. | Kathleen Chirgwin |
| 3/24/2017 | Addition | Added reference in 6.1 to model review and validation documentation stored on SharePoint in the DIMP plan. | Kathleen Chirgwin |

# 3.0 RISK RANKING

## 3.1 Overview

This ranking is taken directly from the risk model. CNG has specified the rankings for the complete system and divided the system into the different operating states and districts. These scores and rankings will be updated after each model run. All risk in table is combination of mains and services. This data is pulled from the performance metric state report for mains and services, the risk per foot for each category is multiplied by the pipe footage total for each category for mains and services and then summed.

**Table E3.1: Company Risk Score and Ranking**

| Threat | Total Score | Ranking |
|---|---|---|
| Corrosion | 146,206,609 | 2 |
| Natural Forces | 69,979,346 | 5 |
| Excavation Damage | 384,631,797 | 1 |
| Other Outside Force | 3,057,330 | 6 |
| Material | 558,517 | 8 |
| Weld/Joint | 82,522,413 | 4 |
| Equipment | 1,835,886 | 7 |
| Incorrect Operations | 22,669 | 10 |
| Other | 97,693 | 9 |
| Missing Value | 127,586,932 | 3 |
| Total Length | 52,853,633 | n/a |
| Total Risk | 869,352,824 | n/a |

**Table E3.2: Risk Score and Ranking by State**

| Threat | Washington | | Oregon | |
|---|---|---|---|---|
| | Total Score | Ranking | Total Score | Ranking |
| Corrosion | 125,997,971 | 2 | 20,208,638 | 2 |
| Natural Forces | 61,563,480 | 5 | 8,415,866 | 5 |
| Excavation Damage | 295,271,289 | 1 | 89,360,508 | 1 |
| Other Outside Force | 2,145,602 | 6 | 911,728 | 6 |
| Material | 377,050 | 8 | 181,467 | 8 |
| Weld/Joint | 68,602,529 | 4 | 13,919,884 | 4 |
| Equipment | 1,386,932 | 7 | 448,954 | 7 |
| Incorrect Operations | 21,101 | 10 | 1,568 | 10 |
| Other | 79,264 | 9 | 18,428 | 9 |
| Missing Value | 108,642,430 | 3 | 18,944,502 | 3 |
| Total Length | 39,635,756 | n/a | 13,217,877 | n/a |
| Total Risk | 664,087,649 | n/a | 152,411,543 | n/a |

Table E3.3: Risk Score/Foot and Ranking by District Western Region

| Threat | Aberdeen | | Bellingham | | Bremerton | | Longview | | Mt. Vernon | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Total Score | Ranking | Total Score | Ranking | Total Score | Ranking | Total Score | Ranking | Total Score | Ranking |
| Corrosion | 3.072 | 3 | 2.023 | 2 | 1.915 | 3 | 6.257 | 1 | 2.056 | 3 |
| Natural Forces | 0.890 | 5 | 0.601 | 5 | 4.737 | 2 | 0.256 | 5 | 0.544 | 5 |
| Excavation Damage | 5.284 | 1 | 5.709 | 1 | 7.610 | 1 | 1.703 | 3 | 5.206 | 1 |
| Other Outside Force | 0.111 | 6 | 0.051 | 6 | 0.028 | 7 | 0.065 | 6 | 0.052 | 6 |
| Material | 0.000 | 8 | 0.013 | 8 | 0.003 | 8 | 0.002 | 9 | 0.006 | 8 |
| Weld/Joint | 1.570 | 4 | 1.228 | 4 | 1.351 | 4 | 0.938 | 4 | 1.155 | 4 |
| Equipment | 0.021 | 7 | 0.027 | 7 | 0.029 | 6 | 0.023 | 7 | 0.025 | 7 |
| Incorrect Operations | 0.000 | 8 | 0.002 | 10 | 0.001 | 10 | 0.000 | 10 | 0.000 | 10 |
| Other | 0.000 | 8 | 0.003 | 9 | 0.002 | 9 | 0.002 | 8 | 0.003 | 9 |
| Missing Value | 5.129 | 2 | 1.969 | 3 | 0.612 | 5 | 4.813 | 2 | 2.376 | 2 |
| Total Risk | 16.077 | | 11.624 | | 16.288 | | 14.059 | | 11.425 | |

Table E3.4: Risk Score/Foot and Ranking by District Central Region

| Threat | Kennewick | | Walla Walla | | Wenatchee | | Yakima | |
|---|---|---|---|---|---|---|---|---|
| | Total Score | Ranking | Total Score | Ranking | Total Score | Ranking | Total Score | Ranking |
| Corrosion | 2.224 | 2 | 2.962 | 2 | 5.584 | 2 | 3.928 | 1 |
| Natural Forces | 1.162 | 4 | 0.550 | 5 | 0.774 | 5 | 1.521 | 5 |
| Excavation Damage | 9.507 | 1 | 5.299 | 1 | 5.138 | 3 | 3.570 | 2 |
| Other Outside Force | 0.009 | 7 | 0.013 | 7 | 0.017 | 7 | 0.015 | 7 |
| Material | 0.000 | 8 | 0.001 | 8 | 0.009 | 8 | 0.001 | 8 |
| Weld/Joint | 1.068 | 5 | 2.373 | 3 | 2.432 | 4 | 2.108 | 4 |
| Equipment | 0.017 | 6 | 0.040 | 6 | 0.050 | 6 | 0.027 | 6 |
| Incorrect Operations | 0.000 | 10 | 0.001 | 8 | 0.000 | 10 | 0.000 | 10 |
| Other | 0.000 | 9 | 0.001 | 10 | 0.001 | 9 | 0.001 | 9 |
| Missing Value | 1.656 | 3 | 0.586 | 4 | 5.748 | 1 | 3.271 | 3 |
| Total Risk | 15.643 | | 11.826 | | 19.752 | | 14.442 | |

Table E3.5: Risk Score/Foot and Ranking by District Southern Region

| Threat | Bend | | Eastern Oregon | | Pendleton | |
|---|---|---|---|---|---|---|
| | Total Score | Ranking | Total Score | Ranking | Total Score | Ranking |
| Corrosion | 0.956 | 3 | 2.569 | 2 | 2.506 | 2 |
| Natural Forces | 0.616 | 5 | 0.606 | 5 | 0.715 | 5 |
| Excavation Damage | 9.009 | 1 | 1.029 | 4 | 3.966 | 1 |
| Other Outside Force | 0.002 | 8 | 0.160 | 6 | 0.090 | 6 |
| Material | 0.019 | 7 | 0.007 | 8 | 0.004 | 8 |
| Weld/Joint | 0.856 | 4 | 1.331 | 3 | 1.441 | 3 |
| Equipment | 0.037 | 6 | 0.016 | 7 | 0.037 | 7 |
| Incorrect Operations | 0.000 | 10 | 0.000 | 9 | 0.001 | 10 |
| Other | 0.002 | 8 | 0.000 | 10 | 0.002 | 9 |
| Missing Value | 1.058 | 2 | 3.254 | 1 | 1.348 | 4 |
| Total Risk | 12.595 | | 8.973 | | 10.109 | |

# 4.0 STANDARD DEVIATION ANALYSIS ON TOTAL RISK MAINS

## 4.1 Overview

This section provides the standard deviation results for the Company for each model run. The Standard deviations are colored by severity in the model to evaluate and prioritize risk, green is used for low risk and red is used for high risk with color escalation from green to red. This analysis allows us to see how the standard deviation has changed between model runs and compare results. It also allows for uniform coloring for risk comparison. Standard deviation is calculated in GIS using the symbology coloring by quantities using a 1/3 standard deviation and making sure the sample size is using all the risk data.

**Table E4.1: Standard Deviation Ranges**

| Standard Deviation | Coloring | 2013 Model Run | 2014 Model Run | 2015 Model Run | 2016 Model Run |
|---|---|---|---|---|---|
| < -0.5 | green | 0.0– 6.33 | 0.0 - 8.20 | 0.0 – 7.95 | 0.0 – 8.07 |
| -0.5 to -0.17 | Light green | 6.33 – 12.16 | 8.20 - 14.01 | 7.95 - 13.85 | 8.07 - 13.8 |
| -0.17 to .17 | Green-yellow | 12.16 – 18.0 | 14.01 - 19.82 | 13.85 -19.75 | 13.8 -19.5 |
| 0.17 to 0.50 | yellow | 18.0 - 23.84 | 19.82 - 25.63 | 19.75- 25.66 | 19.5- 25.27 |
| 0.50 to 0.83 | Yellow-orange | 23.84 - 29.64 | 25.63 - 31.43 | 25.66 -31.56 | 25.27 -31.00 |
| 0.83 to 1.2 | Bronze/gold | 29.64 - 35.5 | 31.43 - 37.24 | 31.56- 37.46 | 31.00- 36.7 |
| 1.2 to 1.5 | Light orange | 35.5 - 41.36 | 37.24 - 43.05 | 37.46 – 43.4 | 36.7 – 42.47 |
| 1.5 to 1.8 | orange | 41.36 – 47.2 | 43.05 - 48.86 | 43.4 – 49.3 | 42.47– 48.2 |
| 1.8 to 2.2 | Dark orange | 47.2 – 53.0 | 48.86 - 54.66 | 49.3 – 55.2 | 48.2 – 53.9 |
| 2.2 to 2.5 | Orange-red | 53.0 – 58.9 | 54.66 - 60.47 | 55.2 – 61.07 | 53.9 – 59.67 |
| > 2.5 | red | 58.9 - 321 | 60.47 -326.4 | 61.07 -326.4 | 59.67 -326.4 |

## 5.0 TIME DEPENDANT AND TIME INDEPENDENT RISK EVALUATION

### 5.1 Overview

This section provides the primary threat categories that fall into time dependent and time independent risk.

**Table E5.1: Time Dependency Risk Categories**

| Time Dependent Risk | Time Independent Risk |
|---|---|
| Corrosion | Outside Force |
| Equipment Failure | Excavation Damage |
| Incorrect Operation | |
| Material | |
| Natural Force | |
| Weld/Joint Failure | |
| Other | |
| Missing Values | |

## 6.0 MODEL VALIDATION SUMMARY

### 6.1 Overview

This section provides a summary of the model validations that have taken place. For additional information on the personnel involved in the validation see Appendix J – *Subject Matter Expert* . For additional information on the model run review and validation, see the Model Validation folder on SharePoint with the DIMP documents. Detailed model run review and validation documentation started in 2016.

**Table E4.1: Model Validation Summary**

| Date of Model Run | Is Validation Needed (Yes/No) | Date of Model Validation | Comments |
|---|---|---|---|
| 3-11-2013 | Yes | 3-25-2013 | Model Validated by comparing model risk category scoring weighting to CNGC leak history trending. |

| | | | |
|---|---|---|---|
| 3-1-2014 | No | N/A | No major changes to risk inputs beside Missing value, determined that no validation was needed. |
| 3-4-2015 | No | N/A | No major changes to risk inputs, no validation needed. |
| 3-16-2016 | No | N/A | No major changes to risk inputs, no validation needed. |
| 5-30-2016 | No | N/A | No major changes to risk inputs, no validation needed. Engineering did a detailed model calculation review on the 2016 model re-run due to the consequence coding error discovered in the steel tapping ability. The re-run was accepted by engineering and the total risk rankings and total risk compared to 2013 model run did not justify a model validation. |
| 3-15-2017 | No | N/A | No major changes to risk inputs, no validation needed. Detailed model calculation review and trending did not justify a model validation. |

# Appendix F – Accelerated Action

**Table of Contents**

# 1.0 SUMMARY OF ACCELERATED ACTION

## 1.1 Overview

## 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 5.3.1.1 A/A Action Implementation | 6.0 Completed Additional or Accelerated Action Forms | N/A |
| 5.3.2 Accelerated Action Documentation | 3.0 Additional or Accelerated Action | F3.1 |
| 6.5.2 Accelerated Action Effectiveness Review and Criteria | 4.0 Performance Measures Specific to A/A's<br>5.0 Additional or Accelerated Action Review | F4.1<br><br>F5.1, F5.2 |

# 2.0 APPENDIX REVISION SUMMARY

## 2.1 Overview

Revisions to this appendix will be recorded and summarized in the following table. Annual data updating does not need to be recorded here.

**Table F2.1: Appendix F Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised BY |
|---|---|---|---|
| 3/15/2013 | Creation | Creation of new appendix for AA Summary and Effectiveness tracking includes: AA summaries, effective summery, AA specific performance measures, and storage for active AA forms. | Renie Sorensen & Kathleen Chirgwin |
| 2/25/2014 | Updates | Added discontinue criteria of trending down 25% in one year to Section 5.3. Added WA excavation damage Accelerated Action implemented. | Kathleen Chirgwin |
| 3/30/2015 | Updates | Added column to table F4.1 to track baseline model | Renie Sorensen |

# 3.0 ADDITIONAL OR ACCELERATED ACTION

## 3.1 Overview

This section contains a summary of all implemented Accelerated Actions currently in effect at CNG.

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve

**Table F3.1: Accelerated Action Summary**

| Accelerated Action | Implementation Date | Threat | Performance Metric | Operating Region/District | Assigned By |
|---|---|---|---|---|---|
| Anacortes Pipe Replacement | Jan 10, 2012 | Corrosion | Corrosion risk score in Anacortes | NW Region/Mt. Vernon | Renie Sorensen |
| Bend Pipe Replacement | Mar 5, 2012 | Corrosion | Corrosion Risk score in Bend | Southern Region/Bend | Kathleen Chirgwin |
| Longview Pipe Replacement | Jan 10,2012 | Corrosion | Corrosion risk score in Longview | NW Region/Longview | Renie Sorensen |
| GIS Cleanup | Nov 2011 | Missing Values | Total Missing Values Risk Score | System Wide | Kathleen Chirgwin |
| Pilot Rock Testing | May 18, 2012 | Investigation only | Investigation only | Southern Region, Pendleton | Kathleen Chirgwin |
| Shelton Pipe Replacement | Feb, 1 2013 | Corrosion | Corrosion Risk score in Shelton | NW Region/ Aberdeen | Renie Sorensen |
| WA Excavation Damage Outreach | June 15, 2013 | Excavation Damage | Excavation Risk in WA | Western and Central Region | Kathleen Chirgwin & Renie Sorensen |
| OR Excavation Damage Outreach | Aug 1, 2015 | Excavation Damage | Excavation Risk in OR | Southern Region | Kathleen Chirgwin & Renie Sorenson |
| Pendleton Pipe Replacement | Jan 1, 2017 | Corrosion | Corrosion risk score in Pendleton | Southern Region | Kathleen Chirgwin |

## 4.0 PERFORMANCE MEASURES SPECIFIC TO A/A'S

### 4.1 Overview

Some Accelerated Actions cannot be evaluated using the standard set of performance measures, thus it becomes necessary to temporarily gather and trend additional data. A summary of this collected data is provided in this section. Trending Baseline will either be an average of the previous 5 years of data or the baseline established from the August 2011 data using current model calculations, depending on type of metric chosen.

Percent Change= (Current yr-Trending Baseline)/Trending Baseline*100

**Table F4.1 A/A Performance Measure Trending**

| Metric | Associated Accelerated Action | Baseline Model | Current Trending Baseline | Current metric Value | % Change Baseline | % Change Previous year | Trending Observations |
|---|---|---|---|---|---|---|---|
| Corrosion Risk/ foot in Anacortes | Anacortes Pipe Replacement | Aug 2011 | 2.719 | 2.20 | -19% | -6% | Trending down form Baseline. Seeing effects of 4 years of pipe replacement. |
| Corrosion Risk/ foot in Longview | Longview Pipe Replacement | Aug 2011 | 10.674 | 6.01 | -44% | -24% | Trending down from Baseline. Seeing effects of 5 years of pipe replacement. |
| Corrosion Risk/ foot in Bend | Bend Pipe Replacement | Aug 2011 | 1.224 | 0.90 | -26% | -4% | Trending down from Baseline and previous year. Seeing effects of 5 years of pipe replacement. |
| Corrosion Risk/ foot in Shelton | Shelton Pipe Replacement | March 2017 | 4.36 | 4.36 | N/A | N/A | No pipe replacement has been started in Shelton, scheduled to start in 2017. |
| Missing Value Risk in Company | GIS Cleanup | March 2014 | 126,856,530 | 127,586,932 | 1% | -7% | GIS Cleanup is ongoing. |
| Excavation Risk in WA | WA Excavation Damage Outreach | March 2013 | 5,771.720 | 6,497.217 | 13% | 6% | Excavation risk in the model in WA is still increasing gradually. |
| Excavation Risk in OR | OR Excavation Damage Outreach | March 2014 | 4,605.83 | 7,485.613 | 63% | 0% | Significant increase from Baseline. For the last three years OR has increased by 58%, |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | 62% and 63% of the baseline. |
| Corrosion Risk/ foot in Pendleton | Pendleton Pipe Replacement | March 2017 | 3.77 | 3.77 | N/A | N/A | No pipe replacement has been started in Pendleton, scheduled to start in 2017. |

## 5.0 ADDITIONAL OR ACCELERATED ACTION REVIEW

### 5.1 Overview

This section provides a location to record the annual review of accelerated actions and record.

### 5.2 Effectiveness Criteria

For an implemented A/A to be considered effective at reducing or maintaining risk the A/A performance metric analyzed for a given year cannot have a percent change greater than 10%.

**Table F5.1: Implemented Accelerated Action Effectiveness Review**

| Accelerated Action | Performance Metric | Effective at Risk Reduction (Yes/No) | Previous Year Trending/ Comments | Reviewed By |
|---|---|---|---|---|
| Bend Pipe Replacement | Corrosion Risk In Bend | Yes | Bend is trending down from Baseline and previous year. | Kathleen Chirgwin |
| Longview Pipe Replacement | Corrosion risk in Longview | Yes | Longview is trending down from Baseline and previous year. | Kathleen Chirgwin |
| Anacortes Pipe Replacement | Corrosion risk in Anacortes | Yes | Anacortes is trending down from Baseline and previous year. | Kathleen Chirgwin |
| GIS Cleanup | Missing Value Risk Score | Yes | We are trending up slightly from Baseline but previous year comparison is trending down. | Kathleen Chirgwin |
| Shelton Pipe Replacement | Corrosion Risk in Shelton | TBD | Shelton pipe replacement is planned to start in 2017. | Kathleen Chirgwin |
| Excavation Risk in WA | WA Excavation Damage Outreach | No | More efforts, trending up by more than 10% of the baseline. | Kathleen Chirgwin |
| Excavation Risk in OR | OR Excavation Damage Outreach | No | More efforts, trending significantly higher than the baseline for the last three years. | Kathleen Chirgwin |
| Pendleton Pipe Replacement | Corrosion risk in Pendleton | TBD | Pendleton pipe replacement is planned to start in 2017. | Kathleen Chirgwin |

### 5.3 Discontinue A/A Criteria

For an A/A to be discontinued and considered effective at addressing risk, the A/A performance metric percent change compared to the established baseline must trend down at least 5% for three consecutive years or trend down 25% in single year.

**Table F5.2: A/A Discontinue Trending**

| Accelerated Action | Performance Metric | Can A/A Be Discontinued (Yes/No) | 3 Years Baseline Trending Results compared to previous run | | | Reviewed By |
|---|---|---|---|---|---|---|
| | | | 2014 | 2015 | 2016 | |
| Bend Pipe Replacement | Corrosion Risk In Bend | No | 2.2% | -6% | -4% | Kathleen Chirgwin |
| Longview Pipe Replacement | Corrosion risk in Longview | No | -11.5% | 1% | -24% | Kathleen Chirgwin |
| Anacortes Pipe Replacement | Corrosion risk in Anacortes | No | 14.6% | 3% | -6% | Kathleen Chirgwin |
| GIS Cleanup | Missing Value Risk Score | No | -7.1% | 16% | -7% | Kathleen Chirgwin |
| Shelton Pipe Replacements | Corrosion Risk in Shelton | N/A | N/A | N/A | N/A | Kathleen Chirgwin |
| Excavation Risk in WA | WA Excavation Damage Outreach | No | 15% | 1% | 0% | Kathleen Chirgwin |
| Excavation Risk in WA | OR Excavation Damage Outreach | No | 58% | 3% | 0% | Kathleen Chirgwin |
| Pendleton Pipe Replacement | Corrosion Risk in Pendleton | N/A | N/A | N/A | N/A | Kathleen Chirgwin |

## 6.0 COMPLETED ADDITIONAL OR ACCELERATED ACTION FORMS

### 6.1 Overview

This section is for the storage of active Additional or Accelerated Action forms. Discontinued Additional or Accelerated Action forms will be archived on Engineering SharePoint.

# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas Corporation

**Operating Region/District:** Southern Region/Bend District

**Completed By:** Kathleen Chirgwin

**Completed Date:** March 5, 2012

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** Replacement of pre-manufactured gas system installed in 1930's in downtown Bend. This vintage coal tar wrapped steel pipe will be replaced with new plastic system with PE mains and services.

**Threat(s) A/A Addresses**: Corrosion. Material and Missing Value risk.

**Reason for A/A Action:** This pipe has extensive corrosion due to the vintage of pipe and has been potholed to find wall loss in excess of 70% and is commonly referred to as "swiss cheese" by district and Cascade employees who have worked on this system. In SME interviews Downtown Bend pipe has been identified as one of Cascade's riskiest systems due to vintage of pipe, leaks, and severe corrosion concerns. Downtown Bend Pre-CNG pipe is also identified in model as high risk and it is predominate in the Top 100 OR Main risk, Top 50 OR Service Risk, and Top 25 OR Corrosion Risk.

**Description of locations that A/A will be implemented:** Replacement of pre-cng pipe located in downtown Bend with new PE system.

**A/A Implementation Date:** 1/1/2012______________

**Duration:** Until manageable risk level is obtained for Downtown Bend.

**Does A/A Action require added performance metrics?** ☐ YES ☒ NO **If yes, describe new metric(s) and collection schedule:**

Effects of this replacement will be tracked in pre-cng statistics (as we replace pre-cng pipe pre-cng pipe totals will be driven down), overall risk scoring for Bend district and town of Bend will be reduced (specifically material failure risk, corrosion risk, and missing value risk), it is anticipated that Bend district leaks will be reduced over time with this replacement since this pre-cng pipe in downtown bend is where majority of leaks are found in Bend district, and as replacement phases are complete it will be eliminated from Top 100 OR main risk, Top 50 OR Service Risk, and Top 25 OR Corrosion risk evaluation.

gas system in downtown Bend. With this A/A since replacement will happen over multiple year's executive summary, cost estimate and map of replacement for each phase completed will be included.

**Additional Comments:** This pre-cng manufactured gas system in Bend sums to approximately 25 miles of main. Challenges to this replacement project include construction in downtown infrastructure, construction within a highly populated and heavily visited tourist area, solid rock construction, and meeting all of City of Bends requirements and specifications**.** As this replacement continues and condition/integrity is assessed it will allow for greater knowledge concerning severity, which will allow Cascade to further validate the model on risk assessment and determine aggressiveness of pipe replacement.

# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas Corporation **Completed By:** Kathleen Chirgwin

**Operating Region/District:** Entire Company_________ **Completed Date:** November 2011__________

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** GIS Data Entry/Cleanup.

**Threat(s) A/A Addresses**: Missing Values___________

**Reason for A/A Action:**

Cascade is making extensive efforts on data cleanup, data scrubbing, and data entry in GIS mapping records which drives Cascade's DIMP model. This A/A will be ongoing since the more system data we can collect on our operating system the more accurate Cascade can asses and analyze system risk. In Cascade's current DIMP model we assign risk to mains, leak reports, services, and valves which are missing critical system information like pipe material, install date, work order id, leak information, etc. After analyzing Cascade's top risk identified by March 2012 model run, the majority of Cascade's highest risk is due to missing values in attribute data, which is not accurate to SME/Company knowledge of Cascade's system. Cascade also wants to use this A/A to track GIS cleanup efforts which is heavily driven and been accelerated by our DIMP model.

**Description of locations that A/A will be implemented:** This A/A will be implemented throughout all districts in Cascade.

**A/A Implementation Date:** October 2011__________ **Duration:** Until Satisfied with GIS Data Cleanup______________________________________

**Does A/A Action require added performance metrics?** ☐ YES ☒ NO **If yes, describe new metric(s) and collection schedule:**

As data is inputted to GIS Data records, missing value risk in DIMP model will be driven down over time. As missing value risk is cleaned up in GIS data you will see missing value risk in DIMP model be driven down, specifically in OR/WA Top 100 Main and Top 50 Service Risk Analysis. As the missing value risk is filled in it will allow for more accurate model runs and system risk analysis.

**Supporting Documentation**: Model risk for missing value risk per 1000 ft in district and towns and Missing data numbers in mains and service records model data breakdown.

**Additional Comments:**

Over the past few years Cascade has transitioned from CAD mapping to GIS mapping. In 2010 Cascade went live with full GIS Mapping. The GIS mapping conversion consisted of digitizing all of Cascade's paper leak and asbuilt records and building attribute databases. Cascade is still making extensive efforts on data cleanup, including data entry and data scrubbing on unknown install dates, asbuilt records, and pipe material. As part of this cleanup effort GIS employees are currently traveling from district to district to capture missing data, digitize old paper maps, and provide additional training on asbuilt mapping.

# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas Corp
**Operating Region/District:** Pendleton, OR

**Completed By:** Kathleen Chirgwin
**Completed Date:** May 18, 2012

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:**

Cascade completed a DIMP investigation into the 6" Pilot Rock Line due to Pendleton District corrosion and integrity concerns. This investigation consisted of gathering all company knowledge available on the integrity of this line. To gather this information all asbuilt information was researched, all leak history documentation was reviewed, all 625 Integrity Management Dig Report was reviewed, the DIMP model scores were assessed, and several Cascade employees with SME on this line were interviewed. The overall goal of this investigation is to identify areas of concern on the Pilot Rock Line and address how to investigate and assess risk for pipelines with areas of concern for Cascade's Distribution Integrity Management Program.

**Threat(s) A/A Addresses**:

Corrosion concerns due to lack of Cathodic Protection on 6" HP Pilot Rock Line.

**Reason for A/A Action:**

Engineering's recommendation is to confirm the corrosion concern with further testing in the identified areas of concern. To confirm the condition of the pipe engineering recommends pipeline exposures by potholing and documenting with 625: Integrity Management Dig Reports or ECDA Current Mapping by a consultant to pinpoint anomalies and then expose anomalies with potholing. Engineering recommendations on potholing is to pothole every 300-400 feet in the area of concern and assess pipe condition by removing 2ft of pipe coating. Once further testing is complete Engineering will review and make a recommendation on how to proceed.

**Description of locations that A/A will be implemented:**

The two areas on Pilot Rock line with "suspect" pipe totals approximately 6000 ft of pipe. The first area of concern is 3000 ft north and 1000 ft south of 2010 Plidko Clamp repair and the second is 1000 ft North and 1000 ft south of the 2005 1500 ft replacement near the Gun Club.

**A/A Implementation Date:** May 18, 2012

**Duration:** Until further testing and evaluation is complete by Cascade Engineering.

**Does A/A Action require added performance metrics?** ☐YES ☒NO **If yes, describe new metric(s) and collection schedule:**

**Supporting Documentation:**

Pilot Rock Analysis Summary, Subject Matter Expert Interviews, Map of Area of Concern, and further testing to determine integrity of Pilot Rock HP Line in identified areas of concern.

**Additional Comments:**

Once further testing on area of concern on Pilot Rock is complete, engineering will review and make a recommendation on how to restore integrity to this line if necessary and or coordinate further investigation.

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# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas

**Completed By:** Renie Sorensen

**Operating Region/District:** Northwest Region/Mount Vernon District

**Completed Date:** January 10, 2012

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** Replacement of bare steel and Pre-CNGC manufactured gas pipe in Anacortes, WA, with new PE pipe (Approximately 75,000 feet of main).

**Threat(s) A/A Addresses**: Corrosion, and Unknown data.

**Reason for A/A Action:** This area has a history of corrosion leaks, and pipe that is known to be in poor condition, presence of corrosion, threaded fittings, buried flanged fittings. Due to the age of this pipe there is a lack of information causing a high missing value risk. Pipe also has an MAOP of 10 psi which causes some deliverability issues during the winter months.

**Description of locations that A/A will be implemented:** City of Anacortes, WA, on Pre-CNGC/FISH pipe portion of the system. Northern and eastern ends of the city.

**A/A Implementation Date:** January 1, 2012

**Duration:** Until risk has reached a manageable level in the Anacortes replacement area.

**Does A/A Action require added performance metrics?** ☐ YES ☒ NO **If yes, describe new metric(s) and collection schedule:** This AA will be tracked using Corrosion risk score for the City of Anacortes.

**Supporting Documentation:** See SME interviews from Mount Vernon District, executive summaries, cost estimates, map of project area.

**Additional Comments:** This project was originally brought to light prior to DIMP implementation by district personnel. Information gathered from DIMP points more at Mount Vernon as having a larger risk. District personnel have identified this area as the area of greater concern. This supports the replacement of the Pre-CNGC pipe in Anacortes.

# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas

**Completed By:** Renie Sorensen

**Operating Region/District:** Northwest Region/Longview District

**Completed Date:** January 10, 2012

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** Replacement of bare steel and Pre-CNGC pipe in Longview and Kelso, WA with new PE pipe.

**Threat(s) A/A Addresses**: Corrosion, and Unknown data.

**Reason for A/A Action:** This area has a history of leaks, and pipe that is known to be in poor condition. Due to the age of this pipe information is unavailable causing high risk from missing values. The area is known to be bare pipe and prone to corrosion.

**Description of locations that A/A will be implemented:** Cities of Longview and Kelso, WA, on bare pipe portion of the system.

**A/A Implementation Date:** January 1, 2012

**Duration:** Until risk has reached manageable levels in cities of Longview and Kelso

**Does A/A Action require added performance metrics?** ☐ YES ☒ NO **If yes, describe new metric(s) and collection schedule:** This AA will be tracked corrosion risk score for the City of Longview.

**Supporting Documentation:** See SME interviews from Longview District. Executive summaries, cost estimates, area maps.

**Additional Comments:** This project was originally brought to light prior to DIMP implementation. Information gathered from DIMP supports the replacement of the bare steel in the Longview/Kelso area. SME interviews also point to this area as an area of high concern.

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# FORM 21760: ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

**Operating Company:** Cascade Natural Gas

**Completed By:** Renie Sorensen

**Operating Region/District:** NW Region/Aberdeen

**Completed Date:** 2/13/13

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** **Replacement of Pre-CNGC and bare pipe in the City of Shelton, WA.**

**Threat(s) A/A Addresses:** Corrosion and equipment failures (Buried valves)

**Reason for A/A Action:** **Shelton Ranks high in our risk model. City of Shelton is also doing major road work and the opportunity to replace pipe is ideal.**

**Description of locations that A/A will be implemented:** **Replacement of Pre-CNGC pipe in the City of Shelton prior to road construction**

**A/A Implementation Date:** **Project was implemented February 1, 1013**

**List A/A Performance Metric to determine A/A Effectiveness and when A/A can be discontinued:**

**Corrosion Risk for the City of Shelton**

**Does A/A Action require added A/A performance metrics?** ☒ YES ☐ NO

**If yes, describe new metric(s) and collection schedule:**

**Corrosion Risk for the City of Shelton WA**

**Supporting Documentation:** **See SME Forms 2012 Aberdeen District**

**Additional Comments:** **Shelton was identified as an area of the system with high risk by both the model and SMEs in the area. The timing is a bonus with the road construction that the city is performing currently.**

# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas Corporation

**Completed By:** Kathleen Chirgwin

**Operating Region/District:** State of Washington

**Completed Date:** June 15, 2013

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** Setup a conference with every professional contractor that has damaged Cascade facilities in the past year. Discussion will be documented on a public awareness form by selected Washington districts.

**Threat(s) A/A Addresses**: Excavation Damage

**Reason for A/A Action:** 35 percent change increase in main risk per 1000 ft for excavation risk in the State of Washington.

**Description of locations that A/A will be implemented:**

Each year this accelerated action will be implemented in select Washington districts based on Damages per 1000 locates statistics to target the districts with the highest excavation damages.

2013 Districts

| District | Region | 2012 Damages per 1000 locates |
|---|---|---|
| Walla Walla | Central | 10.3 |
| Aberdeen | Western | 7.4 |
| Yakima | Central | 6.5 |
| Mt Vernon | Western | 5.3 |

**A/A Implementation Date:** 6/15/2013____________________

**Duration:** See Discontinue A/A Criteria in Appendix F – Acceleration Actions

**Does A/A Action require added performance metrics?** ☐ YES ☒ NO **If yes, describe new metric(s) and collection schedule:**

**Supporting Documentation:** This A/A documentation can be found on Sharepoint in the Public Awareness Folder in the Excavator folder for the applicable year for the selected districts..

**Additional Comments:** None.

Intermountain Gas Company Montana-Dakota
Utilities Co.

# ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

21760(7-11)

**Operating Company:** Cascade Natural Gas Corporation **Completed By:** Kathleen Chirgwin

**Operating Region/District:** State of Oregon **Completed Date:** March 28, 2016

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** Increase public awareness community involvement and advertising via media campaigns to inform public on 811 and safe digging.

**Threat(s) A/A Addresses**: Excavation Damage

**Reason for A/A Action:** In the State of Oregon for 2014 Excavation leaks repaired by Cause and Excavation damage risk for mains increased significantly.

**Description of locations that A/A will be implemented:**

Each year this accelerated action will be implemented in select Oregon districts based on Damages per 1000 locates statistics to target the districts with the highest excavation damages.

| District | Region | 2014 Damages per 1000 locates |
|---|---|---|
| Bend | Southern | 8.18 |
| Eastern OR | Southern | 0.73 |
| Pendleton | Southern | 4.21 |

For 2015 we started this A/A with increased public awareness media campaign throughout the Bend district.

**A/A Implementation Date:** 6/15/2015 **Duration:** See Discontinue A/A Criteria in Appendix F – Acceleration Actions

**Does A/A Action require added performance metrics?** ☐YES ☒NO **If yes, describe new metric(s) and collection schedule:**

**Supporting Documentation:** This A/A documentation can be found on SharePoint in the Public Awareness Folder for the applicable year for the selected districts for public awareness meeting/event documentation or contact Cascade's Public Awareness coordinator for additional information.

**Additional Comments:**

The increased public awareness for Bend started in August of 2015 and continued through the end of the year.

This AA was identified in 2015 and started but the paperwork was not completed until the 2016 appendix update.

# FORM 21760: ADDITIONAL OR ACCELERATED ACTION IMPLEMENTATION

**Operating Company:** Cascade Natural Gas
**Completed By:** Kathleen Chirgwin
**Operating Region/District:** Southern Region/Pendleton
**Completed Date:** 3/24/2017

## Additional or Accelerated (A/A) Action Plan

**Description of A/A Action implemented:** Replacement of Pre-CNG pipe in the City of Pendleton, OR.

**Threat(s) A/A Addresses:** Corrosion

**Reason for A/A Action:** Pendleton ranks high in our risk model due to PRE-CNG pipe. District also has concerns on corrosion pitting on this pipe due to poor cathodic protection in the 1970's due to rocky conditions. Pendleton has been a challenging system for cathodic protection.

**Description of locations that A/A will be implemented:** Replacement of Pre-CNG pipe in downtown and on the North Hill.

**A/A Implementation Date:** Project was implemented with approval of the 2017 capital budget.

**List A/A Performance Metric to determine A/A Effectiveness and when A/A can be discontinued:**
Corrosion Risk for the town of Pendleton. A/A discontinuation criteria is defined in Section 5.3 of Appendix F.

**Does A/A Action require added A/A performance metrics?** ☒ YES ☐ NO
**If yes, describe new metric(s) and collection schedule:**
Corrosion Risk for the town of Pendleton.

**Supporting Documentation:** See SME forms 2012 Pendleton District.

**Additional Comments:** Pendleton was identified as an area of the system with high risk by both the model and SMEs in the area.

# Appendix G – Subject Matter Expert

**Table of Contents**

## 1.0 SUMMARY OF SUBJECT MATTER EXPERT

### 1.1 Overview

The objective of this appendix is to summarize results of SME panel discussions and validations. It also provides a location to summarize and document Individual SME concerns.

### 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 1.6 Subject Matter Expert Involvement | All sections | All Tables |
| 1.6.2 Subject Matter Expert Panel | 3.1 SME Panel | G3.1 |
| 3.4.2 Internal Source | 3.2 Individual SME Concerns | G3.2 |

## 2.0 APPENDIX REVISION SUMMARY

### 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table G2.1: Appendix G Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | Creation of new appendix to summaries SME involvement and for storage of completed SME forms | Renie Sorensen & Kathleen Chirgwin |
| 5/9/2013 | Content Revision | Removed content from appendix that was not needed. | Renie Sorensen |
| | | | |

## 3.0 SUBJECT MATTER EXPERT SUMMARY

### 3.1 SME Panel

The SME panel members are used to validate the risk model, and in scoring and weighting used in the risk model.

**Table G3.1: SME Panel Meeting Summary**

| Date | Purpose | Summary of Results |
|---|---|---|
| 2/12/2013 | Model Calculation Validation | Modifications were made to several model calculations. All other calculations were confirmed. Also included discussion of other potential threats to the system. Please see meeting notes in section 4.1.1 under Model Calculation Validation 2/12/2013 for full detail of changes. |
| 2/25/2012 | Model Validation | Panel shown 2012 model results and were in agreement that the model is an accurate representation of CNGC's risk. Please see meeting notes in section 4.1.1 under Model Validation 3/25/2013 for full detail. |
| | | |
| | | |

### 3.2 Individual SME Concerns

When concerns are communicated to engineering through an SME interview they are summarized in this section where they can be examined and determine if the concern is a threat or potential threat to the distribution system. Concerns deemed to be threats will be added to the risk model, and those deemed to be potential threats will be moved to the potential threat table in Appendix C.

**Table G3.2: Individual SME Concern Summary**

| Concern | District where Concern was Identified | SME Name and Title | Date Concern Addressed to Engineering |
|---|---|---|---|
| Braised Service Tees | Wenatchee | Steve Knutson | 7/12/2012 |
| Rocky Backfill | Yakima | Richard Nave | 7/11/2012 |
| Non operating flange Valves (buried) | Aberdeen | Kevin Berner | 7/20/2012 |
| Pipe Depth | Aberdeen | Kelly Campbell | 7/20/2012 |
| Double Service lines | Shelton | Jesse Middleton | 7/20/2012 |
| Poor Weld Concerns | Mount Vernon | John Rodriguez Jr. | 7/19/2012 |
| Idle Service Stubs | Moses Lake | Lori Shimek | 7/12/2012 |
| | | | |
| | | | |
| | | | |

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# 4.0 SME FORMS STORAGE

## 4.1 Overview

SME forms 21764 for SME Panel will be stored here for Ten years. All older forms will be archived and available upon request only.

### 4.1.1 SME Panel Storage

Model Calculation Validation 2/12/2013

Model Validation 3/25/2013

# Appendix H - Performance Measures

Table of Contents

# 1.0 SUMMARY OF PERFORMANCE MEASURES

## 1.1 OVERVIEW

This Appendix's purpose is to provide a central location to display and monitor the results gathered from the annual model run.

## 1.2 PLAN REFERENCES

Sections of the Written Plan that reference this Appendix are as Follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 6.1 Overview | 3.3.1 Trending<br>3.4.1 Trending | All tables in section<br>All tables in section |
| 6.5.1 Performance Metric Effectiveness Review | 3.3.1 Trending<br>3.4.1 Trending | All tables in section<br>All tables in section |
| | | |

# 2.0 APPENDIX REVISION SUMMARY

## 2.1 OVERVIEW

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

Table H2.1: Appendix H Revision Summary

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | Appendix created to summaries results generated by the annual model run and to record the trending results. | Renie Sorensen & Kathleen Chirgwin |
| 3/14/2014 | Table Modification | Added column in selected tables to compare the percent change to previous year results | Renie Sorensen |
| 3/16/2015 | New Table for Baseline | Added Table H3.11 to establish which Model Run is used for the baseline for each measure. | Renie Sorensen |
| 3/21/2017 | Needed additional table to meet 192.1007 (e) (i) and 192.1007 (iv) requirements | Added table to track hazardous leaks eliminated or repaired separately from total leaks eliminated or repaired as reported on annual report. Shifted table numbers. | Kathleen Chirgwin |
| 3/21/2017 | Additional insight into leak classification | Added table to track mapped 293B (below ground leaks repaired). | Kathleen Chirgwin |

| | | | |
|---|---|---|---|
| | trending. This table will also allow us to trend the revised leak classifications that have been changed after leak review. | | |

## 3.0 PERFORMANCE MEASURES

### 3.1 OVERVIEW

The complete performance measures are located in an Excel file on the Engineering SharePoint page and will be available from General Office Engineering upon request. Displayed here are the most recent year results, the trending baseline, and trend results. To trend CNG is using percent change from the current year and trending baseline. Percent change is calculated with the following formula

Percent Change= (Current yr-Trending Baseline)/Trending Baseline*100

Triggers for A/A Review
A performance metric will require A/A Review if the performance metric for the given year has a percent change greater than 25% of the trending baseline or increases by 15% of the trending baseline for 3 consecutive years.

### 3.2 REQUIRED PERFORMANCE MEASURES

These performance measures are required to be recorded and reported as part of the annual report.

Table H3.1: WA Total/Hazardous Leaks Repaired by Cause as reported on annual report

| Leak Cause | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Corrosion | 0 | 3 | 1 | 9 | 10 | 9.5 | 4 | -58% | No |
| Natural Forces | 0 | 1 | 0 | 2 | 4 | 3 | 0 | -100% | No |
| Excavation Damage | 0 | 48 | 21 | 90 | 95 | 92.5 | 138 | 49% | Yes |
| Other Outside Force Damage | 0 | 14 | 1 | 9 | 11 | 10 | 13 | 30% | Yes |
| Material or Weld | 0 | 1 | 3 | 1 | 8 | 4.5 | 4 | -11% | No |
| Equipment | 0 | 1 | 0 | 3 | 1 | 2 | 0 | -100% | No |
| Incorrect Operations | 0 | 0 | 0 | 2 | 1 | 1.5 | 4 | 167% | Yes |
| Other | 0 | 1 | 1 | 6 | 97* | 51.5 | 57 | 11% | No |

*Numbers different from previous plans because all data was changed to match annual reports as filed. In the past plans we did not report hazardous and total separately, we had been combining them. Also In the past we had been changing leak classifications based on required AA review leak reviews. Going forward we will be trending 293 leak classification with cleanup separately and consider 293 reviewed classifications trending on A/A review.

*Note in 2014 we started including above ground P-CAD leaks and above ground leaks discovered on 295 forms. This feature was added to P-CAD in mid-2014, so 2014 does not include a complete year of consistent records. Previous to 2014 we were only reporting below ground leaks.

*Note previous to 2012 we were not reporting any hazardous leaks, after 2012 we started reporting hazardous as grade 1 leaks.

Table H3.2: OR Hazardous Leaks Repaired by Cause as reported on annual report

| Leak Cause | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Corrosion | 0 | 3 | 1 | 2 | 1 | 1.5 | 1 | -33.3% | No |
| Natural Forces | 0 | 1 | 0 | 1 | 1 | 1 | 1 | 0.0% | No |
| Excavation Damage | 0 | 47 | 21 | 51 | 57 | 54 | 73 | 35.2% | Yes |
| Other Outside Force Damage | 0 | 5 | 1 | 5 | 9 | 7 | 9 | 28.6% | Yes |
| Material or Weld | 0 | 7 | 3 | 6 | 2 | 4 | 3 | -25.0% | No |
| Equipment | 0 | 0 | 0 | 2 | 1 | 1.5 | 4 | 166.7% | Yes |
| Incorrect Operations | 0 | 0 | 0 | 0 | 2 | 1 | 3 | 200.0% | Yes |
| Other | 0 | 12 | 1 | 3 | 1 | 2 | 52* | 2500.0% | Yes |

*Numbers different from previous plans because all data was changed to match annual reports as filed. In the past plans we did not report hazardous and total separately, we had been combining them. Also In the past we had been changing leak classifications based on required AA review leak reviews. Going forward we will be trending 293 leak classification with cleanup separately and consider 293 reviewed classifications trending on A/A review.

*Note in 2014 we started including above ground P-CAD leaks and above ground leaks discovered on 295 forms. This feature was added to P-CAD in mid-2014, so 2014 does not include a complete year of consistent records. Previous to 2014 we were only reporting below ground leaks.

*Note previous to 2012 we were not reporting any hazardous leaks, after 2012 we started reporting hazardous as grade 1 leaks.

Table H3.3: WA Total Leaks Eliminated or Repaired by Cause as reported on annual report

| Leak Cause | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Corrosion | 8 | 28 | 20 | 31 | 29 | 30 | 23 | -23% | No |
| Natural Forces | 0 | 3 | 0 | 2 | 5 | 3.5 | 2 | -43% | No |
| Excavation Damage-Main | 14 | 22 | 18 | 27 | 30 | 28.5 | 49 | 72% | Yes |
| Excavation Damage-Service | 24 | 75 | 53 | 68 | 107 | 87.5 | 102 | 17% | No |
| Other Outside Force Damage | 8 | 28 | 1 | 11 | 17 | 14 | 22 | 57% | Yes |
| Material or Weld | 12 | 17 | 14 | 23 | 72 | 47.5 | 25 | -47% | No |
| Equipment | 2 | 20 | 14 | 13 | 43 | 28 | 74 | 164% | Yes |
| Incorrect Operations | 0 | 0 | 0 | 6 | 92 | 49 | 4 | -92% | No |
| Other | 32 | 8 | 17 | 1034* | 1714 | 1374 | 1616 | 18% | No |
| Total leaks eliminated or repaired | 100 | 201 | 137 | 1215* | 2109 | 1662 | 1917 | 15% | No |
| Known leaks scheduled for repair | 65 | 92 | 69 | 273** | 294 | 283.5 | 538 | 90% | Yes |

*In 2014 all P-Cad above ground leaks repaired where thrown into Other when this field was available in mid-2014. Note in 2014 we started including above ground P-CAD leaks and above ground leaks discovered on 295 forms. This feature was added to P-CAD in mid-2014, so 2014 does not include a complete year of consistent records. Previous to 2014 we were only reporting below ground leaks.

**In 2014 we started counting known above ground leaks into leaks scheduled for repair, in previous years we had only been reporting below ground leaks scheduled for repair that were being monitored.

Table H3.4: OR Total Leaks Eliminated or Repaired by Cause as reported on annual report

| Leak Cause | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Corrosion | 3 | 7 | 2 | 11 | 3 | 7 | 11 | 57% | Yes |
| Natural Forces | 0 | 1 | 1 | 2 | 1 | 1.5 | 1 | -33% | No |
| Excavation Damage-Main | 7 | 13 | 6 | 12 | 18 | 15 | 14 | -7% | No |
| Excavation Damage-Service | 13 | 39 | 15 | 42 | 46 | 44 | 73 | 66% | Yes |
| Other Outside Force Damage | 3 | 6 | 5 | 7 | 9 | 8 | 15 | 88% | Yes |
| Material or Weld | 18 | 21 | 17 | 38 | 22 | 30 | 26 | -13% | No |
| Equipment | 3 | 9 | 2 | 23 | 22 | 22.5 | 109 | 384% | Yes |
| Incorrect Operations | 0 | 1 | 0 | 0 | 2 | 1 | 3 | 200% | Yes |
| Other | 41 | 21 | 2 | 648* | 962 | 805 | 529 | -34% | No |
| Total leaks eliminated or repaired | 88 | 118 | 50 | 783* | 1085 | 934 | 781 | -16% | No |
| Known leaks scheduled for repair | 8 | 47 | 52 | 611** | 446 | 528.5 | 337 | -36% | No |

*In 2014 all P-Cad above ground leaks repaired where thrown into Other when this field was available in mid-2014. Note in 2014 we started including above ground P-CAD leaks and above ground leaks discovered on 295 forms. This feature was added to P-CAD in mid-2014, so 2014 does not include a complete year of consistent records. Previous to 2014 we were only reporting below ground leaks.

**In 2014 we started counting known above ground leaks into leaks scheduled for repair, in previous years we had only been reporting below ground leaks scheduled for repair that were being monitored.

Table H3.5: WA Total Leaks Eliminated or Repaired by Cause as reported on 293 B form and mapped

| Leak Cause | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Corrosion | 20 | 25 | 26 | 23 | 23 | 23.4 | 20 | -15% | No |
| Natural Forces | 1 | 2 | 1 | 0 | 1 | 1 | 0 | -100% | No |
| Excavation Damage | 66 | 97 | 70 | 66 | 105 | 80.8 | 115 | 42% | Yes |
| Other Outside Force Damage | 9 | 25 | 2 | 9 | 17 | 12.4 | 13 | 5% | No |
| Material or Weld | 15 | 23 | 21 | 18 | 23 | 20 | 23 | 15% | No |
| Equipment | 27 | 16 | 26 | 7 | 18 | 18.8 | 24 | 28% | Yes |
| Incorrect Operations | 2 | 1 | 1 | 2 | 0 | 1.2 | 2 | 67% | Yes |
| Other | 14 | 7 | 2 | 35 | 9 | 13.4 | 16 | 19% | No |
| Total leaks eliminated or repaired | 154 | 196 | 149 | 160 | 196 | 171 | 213 | 25% | No |

*This table is updated if leaks are reviewed and changed to a different leak cause.

*2016 incorrect operations and equipment failure leaks have been reviewed.

Table H3.6: OR Total Leaks Eliminated or Repaired by Cause as reported on 293 B form and mapped

| Leak Cause | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Corrosion | 4 | 3 | 5 | 12 | 3 | 5.4 | 9 | 67% | Yes |
| Natural Forces | 1 | 0 | 3 | 2 | 1 | 1.4 | 1 | -29% | No |
| Excavation Damage | 24 | 53 | 31 | 57 | 58 | 44.6 | 81 | 82% | Yes |
| Other Outside Force Damage | 11 | 6 | 3 | 7 | 9 | 7.2 | 8 | 11% | No |
| Material or Weld | 11 | 13 | 25 | 30 | 20 | 19.8 | 19 | -4% | No |
| Equipment | 22 | 11 | 23 | 22 | 21 | 19.8 | 35 | 77% | Yes |
| Incorrect Operations | 1 | 0 | 0 | 1 | 1 | 0.6 | 1 | 67% | Yes |
| Other | 3 | 2 | 3 | 9 | 3 | 4 | 3 | -25% | No |
| Total leaks eliminated or repaired | 77 | 88 | 93 | 140 | 116 | 102.8 | 157 | 53% | Yes |

*This table is updated if leaks are reviewed and changed to a different leak cause.

*2016 incorrect operations, other outside force, equipment, corrosion, and material/weld leaks have been reviewed.

Table H3.7: WA Leaks Repaired by Material

Numbers are pulled from GIS snapshot of mapped 293's joined to mains and services.

| Leak Material | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Pre 1980 Steel | 69 | 110 | 65 | 46 | 65 | 71 | 60 | -15% | No |
| Post 1980 Steel | 15 | 30 | 15 | 12 | 19 | 18.2 | 22 | 21% | No |
| Polyethylene (PE) Plastic | 67 | 87 | 68 | 58 | 90 | 74 | 90 | 22% | No |
| | | | | | | | | | |

Table H3.8: OR Leaks Repaired by Material

Numbers are pulled from GIS snapshot of mapped 293's joined to mains and services.

| Leak Material | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Pre 1980 Steel | 31 | 28 | 16 | 52 | 29 | 31.2 | 63 | 102% | Yes |
| Post 1980 Steel | 13 | 15 | 8 | 11 | 12 | 11.8 | 30 | 154% | Yes |
| Polyethylene (PE) Plastic | 25 | 44 | 25 | 49 | 51 | 38.8 | 81 | 109% | Yes |
| | | | | | | | | | |

Table H3.9: WA Excavation Metrics as reported on annual report

| Metric | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Number of Excavation Damages | 161 | 157 | 139 | 152 | 173 | 156.4 | 187 | 20% | No |
| Number of Locate Tickets | 41953 | 41958 | 40778 | 41489 | 43292 | 41894 | 46819 | 12% | N/A |
| Damages/1000 Locate Tickets | 3.84 | 3.74 | 3.41 | 3.75 | 4.00 | 3.75 | 3.99 | 7% | No |

Table H3.10: OR Excavation Metrics as reported on annual report

| Metric | Previous years Values | | | | | Baseline | Current year (2016) | % change | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2013 | 2014 | 2015 | | | | |
| Number of Excavation Damages | 65 | 50 | 85 | 89 | 109 | 79.6 | 101 | 27% | Yes |
| Number of Locate Tickets | 11144 | 12463 | 14461 | 14939 | 17394 | 14080.2 | 19236 | 37% | N/A |
| Damages/1000 Locate Tickets | 5.83 | 4.01 | 5.88 | 5.96 | 6.27 | 5.59 | 5.25 | -6% | No |

### 3.3 ADDITIONAL PERFORMANCE MEASURES

The following performance measures are in addition to the required measures and were selected to evaluate the effectiveness of the Plan. Trending Baseline is the risk values established from the Model Runs in Table H3.11.

Table H3.7: WA Additional Measures Mains Risk/1000 Ft

| Metric | Baseline Value | Current year(2016) | % change Baseline | % Change Previous Year | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|
| Total Risk Mains | 14,302.30 | 16159.596 | 13.0% | -0.6% | No |
| Corrosion Risk | 3,070.17 | 3143.278 | 2.4% | -3.6% | No |

| | | | | | |
|---|---|---|---|---|---|
| Natural Forces Risk | 1,259.33 | 1492.019 | 18.5% | 10.3% | No |
| Excavation Damage Risk | 5,706.03 | 6497.217 | 13.9% | 0.2% | No |
| Other Outside Force Damage Risk | 177.83 | 30.142 | -83.1% | -0.2% | No |
| Material Risk | 7.66 | 7.405 | -3.3% | -11.8% | No |
| Joint Risk | 1,507.72 | 1634.499 | 8.4% | -1.2% | No |
| Equipment Risk | 20.55 | 23.929 | 16.4% | -2.9% | No |
| Incorrect Operations Risk | 0.29 | 0.199 | -32.4% | -15.2% | No |
| Other Risk | 1.32 | 1.360 | 3.4% | -37.8% | No |
| Risk for Missing/Unknown Data | 2,551.39 | 3329.548 | 30.5% | -3.0% | Yes |
| | | | | | |

Table H3.8: OR Additional Measures Mains Risk/1000 Ft

| Metric | Baseline Value | Current year(2016) | % change Baseline | % Change Previous Year | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|
| Total Risk Mains | 11,036.07 | 13168.637 | 19.3% | -2.6% | No |
| Corrosion Risk | 1,899.08 | 1932.040 | 1.7% | -0.9% | No |
| Natural Forces Risk | 663.56 | 663.498 | 0.0% | -1.5% | No |
| Excavation Damage Risk | 5,533.87 | 7485.613 | 35.3% | 0.3% | Yes |
| Other Outside Force Damage Risk | 166.31 | 84.212 | -49.4% | -12.9% | No |
| Material Risk | 17.94 | 21.416 | 19.4% | -0.5% | No |
| Joint Risk | 1,066.29 | 1208.436 | 13.3% | 11.0% | No |
| Equipment Risk | 18.88 | 36.421 | 92.9% | 46.2% | Yes |
| Incorrect Operations Risk | 0.04 | 0.000 | -100.0% | -100.0% | No |
| Other Risk | 1.60 | 0.765 | -52.0% | -44.9% | No |
| Risk for Missing/Unknown Data | 1,668.50 | 1736.235 | 4.1% | -20.9% | No |
| | | | | | |

Table H3.9: WA Additional Measures Services Risk/1000 Ft

| Metric | Baseline Value | Current year(2015) | % change Baseline | % Change Previous Year | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|
| Total Risk Services | 11,573.61 | 10436.048 | -9.8% | -0.7% | No |
| Corrosion Risk | 2,634.23 | 2168.776 | -17.7% | -1.1% | No |
| Natural Forces Risk | 1,342.77 | 1285.034 | -4.3% | 22.0% | No |
| Excavation Damage Risk | 5,288.34 | 4844.448 | -8.4% | -4.7% | No |
| Other Outside Force Damage Risk | 98.75 | 46.157 | -53.3% | -1.3% | No |
| Material Risk | 3.70 | 1.068 | -71.1% | 19.3% | No |
| Joint Risk | 1,451.40 | 1217.995 | -16.1% | -2.1% | No |
| Equipment Risk | 42.72 | 32.646 | -23.6% | 0.3% | No |
| Incorrect Operations Risk | 0.77 | 1.068 | 39.5% | 19.3% | Yes |
| Other Risk | 3.18 | 2.605 | -18.2% | -23.5% | No |
| Risk for Missing/Unknown Data | 707.77 | 836.251 | 18.2% | -1.8% | No |
| | | | | | |

Table H3.10: OR Additional Measures Services Risk/1000 Ft

| Metric | Baseline Value | Current year(2016) | % change Baseline | % Change Previous Year | A/A Review Needed(Y/N) |
|---|---|---|---|---|---|
| Total Risk Services | 8,783.66 | 8674.875 | -1.2% | 1.5% | No |
| Corrosion Risk | 1,016.92 | 825.960 | -18.8% | 3.9% | No |
| Natural Forces Risk | 747.86 | 589.986 | -21.1% | 6.1% | No |
| Excavation Damage Risk | 5,060.95 | 5496.431 | 8.6% | 0.3% | No |
| Other Outside Force Damage Risk | 70.33 | 42.413 | -39.7% | 4.0% | No |
| Material Risk | 3.31 | 0.325 | -90.2% | 20.2% | No |

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| | | | | | |
|---|---|---|---|---|---|
| Joint Risk | 945.68 | 782.289 | -17.3% | 4.6% | No |
| Equipment Risk | 30.63 | 29.685 | -3.1% | 28.5% | No |
| Incorrect Operations Risk | 0.12 | 0.325 | 166.6% | 20.2% | Yes |
| Other Risk | 3.26 | 2.491 | -23.7% | 11.6% | No |
| Risk for Missing/Unknown Data | 904.59 | 904.969 | 0.0% | 0.4% | No |
| | | | | | |

Table H3.11: Additional Measures Baseline

| Metric | Baseline | Comment/Reason for change |
|---|---|---|
| Total Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Corrosion Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Natural Forces Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Excavation Damage Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Other Outside Force Damage Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Material Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Joint Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Equipment Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Incorrect Operations Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Other Risk | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes to risk data over time. |
| Risk for Missing/ Unknown Data | 5 year model run average | Five years of model run data, several risk categories data changes yearly so five year average accounts for changes |

| | | |
|---|---|---|
| | | to risk data over time. |

### 3.4 OTHER PERFORMANCE MEASURES

Performance measures that are specific to an accelerated action that are only collected while that accelerated action is active will be stored in Appendix F – *Accelerated Action*.

### 3.5 A/A PERFORMANCE MEASURE REVIEW SUMMARY

Below is a summary of performance metrics with increasing risk that require A/A review. A/A review shall be completed by June 15.

| State | Performance Measure Description | Review Completed By | Review Completion Date | Summary of Review |
|---|---|---|---|---|
| WA | Hazardous Leaks on annual report – Excavation Damage | Kathleen Chirgwin | 6/6/17 | WA Excavation Damage Repaired Leaks on 293 B : 115<br>WA Total Hazardous Excavation Damage Repaired Leaks: 138<br>WA Total Excavation Damage Repaired Leaks: 151<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>Continue Implemented WA Excavation A/A, more efforts are needed. |
| WA | Hazardous Leaks on annual report – Other Outside Force Damage | Kathleen Chirgwin | 6/6/17 | WA Other Outside Force Damage Repaired Leaks on 293B: 13<br>WA Total Hazardous Outside Force Damage Repaired Leaks: 13<br>WA Total Outside Force Damage Repaired Leaks: 22<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data |

| | | | | |
|---|---|---|---|---|
| | | | | shift is also affecting the baseline.<br><br>From 293 B outside force damage trending, leaks due to outside force damage have not increased by more than 25%. No action is necessary. |
| WA | Hazardous Leaks on annual report – Incorrect Operations | Kathleen Chirgwin | 6/6/17 | WA Incorrect Operations Repaired Leaks on 293B: 2<br>WA Total Hazardous Incorrect Operations Repaired Leaks: 4<br>WA Total Incorrect Operations Damage Repaired Leaks: 4<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>Reviewed 293 B incorrect operations leaks and trending, after review 2 leaks were correctly classified as incorrect operations. Incorrect operations leaks per year have a low occurrence per year and a change from 1 to 2 leaks per year is not a significant increase. |
| OR | Hazardous Leaks on annual report – Excavation Damage | Kathleen Chirgwin | 6/6/17 | OR Excavation Damage Repaired Leaks on 293B: 81<br>WA Total Hazardous Excavation Damage Repaired Leaks: 73<br>WA Total Excavation Damage Repaired Leaks: 87<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>Continue Implemented OR Excavation A/A, more efforts are needed. |
| OR | Hazardous Leaks on annual report – Other | Kathleen Chirgwin | 6/6/17 | OR Other Outside Force Damage Repaired Leaks on 293B: 8 |

| | | | | |
|---|---|---|---|---|
| | Outside Force Damage | | | OR Total Hazardous Outside Force Damage Repaired Leaks: 13<br>OR Total Outside Force Damage Repaired Leaks: 15<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>Reviewed 293 B outside force damage leaks and trending, after review 8 of 13 leaks were correctly classified as outside force damage. 293 B leaks are not trending up by more than 25%, no action is required. |
| OR | Hazardous Leaks on annual report – Equipment | Kathleen Chirgwin | 6/6/17 | OR Equipment Repaired Leaks on 293B: 35<br>OR Total Hazardous Equipment Repaired Leaks: 4<br>OR Total Equipment Repaired Leaks: 109<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>293 B Equipment leaks have been reviewed and equipment leaks have increased above 25% for first time in all three categories. Reviewed all equipment failure leaks and pulled parts numbers of leaking fittings. In 2015 and 2016 we saw a lot of equipment failure leaks on 1960 ¾ in autoperf service tees and bottom in/out/termination/extension fitting caps. Discussed these leaking fittings in an SME interview with construction services, see SME interview on 6-7-17 for full details. After discussion, we came up with some guidance and recommendations to provide to the field and update the leak CP and leak classification. Leaking autoperf tees requiring re-crimping will |

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|---|---|---|---|---|
| | | | | be classified as incorrect operations and not equipment failure since if the autoperf tee was not crimped (or crimped correctly with the crimping tool) and the completion plug was not checked for leaks at installation it was not installed per the manufacturer recommendation.<br><br>From the number of above ground equipment leaks without documentation to review, more guidance needs to be provided to the field on how to classify and document these leaks. I suspect some districts are classifying above ground leaks as equipment failure and others are putting all above ground leaks into the other category. Identified in Table B6.1: Insufficient/Missing data.<br><br>Continue to monitor hazardous equipment failure leaks until baseline is established and or documentation and guidance is improved on above ground leaks. |
| OR | Hazardous Leaks on annual report – Incorrect Operations | Kathleen Chirgwin | 6/6/17 | OR Incorrect Operations Repaired Leaks on 293B: 1<br>OR Total Hazardous Incorrect Operations Repaired Leaks: 3<br>WA Total Incorrect Operations Damage Repaired Leaks: 3<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>Reviewed 293 B incorrect operations leaks and trending. Incorrect operations leaks per year have a low occurrence per year and 1 leak per year is not a significant increase. |
| OR | Hazardous Leaks on annual report – Other | Kathleen Chirgwin | 6/6/17 | OR Other Repaired Leaks on 293B: 3<br>OR Total Hazardous Incorrect Operations Repaired Leaks: 52<br>WA Total Incorrect Operations Damage |

| | | | | |
|---|---|---|---|---|
| | | | | Repaired Leaks: 529<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>OR 293 B leaks categorized as other is decreasing, compliance needs to improve processes to allow P-CAD above ground leaks to be correctly classified and not dumped into the other category. Identified in Table B6.1: Insufficient/Missing data. |
| WA | Total leaks eliminated or repaired on annual report - Excavation Damage Main | Kathleen Chirgwin | 6/6/17 | WA Excavation Damage Repaired Leaks on 293 B : 115 (42% increase)<br>WA Total Hazardous Excavation Damage Repaired Leaks: 138 (29% increase)<br>WA Total Excavation Damage Repaired Leaks on Main : 42 (72% increase)<br><br>Continue Implemented WA Excavation A/A, more efforts are needed. |
| WA | Total leaks eliminated or repaired on annual report - Other Outside Force Damage | Kathleen Chirgwin | 6/6/17 | WA Other Outside Force Damage Repaired Leaks on 293B: 13 (5% increase)<br>WA Total Hazardous Outside Force Damage Repaired Leaks: 13<br>WA Total Outside Force Damage Repaired Leaks: 22<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>From 293 B outside force damage trending, leaks due to outside force damage have not increased by more than 25%. No action is necessary. |
| WA | Total leaks eliminated or repaired on annual report - Equipment | Kathleen Chirgwin | 6/6/2017 | OR Equipment Repaired Leaks on 293B: 35<br>OR Total Hazardous Equipment Repaired Leaks: 4<br>OR Total Equipment Repaired Leaks: 109<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014. |

| | | | | |
|---|---|---|---|---|
| | | | | Previous to 2012 we did not report any hazardous leaks in the annual report, this data shift is also affecting the baseline.<br><br>Reviewed all 293 B equipment failure leaks and pulled parts numbers of leaking fittings. In 2015 and 2016 we saw a lot of equipment failure leaks on 1960 ¾ in autoperf service tees and bottom in/out/termination/extension fitting caps. Discussed these leaking fittings in an SME interview with construction services, see SME interview on 6-7-17 for full details. After discussion, we came up with some guidance and recommendations to provide to the field and update the leak CP and leak classification. Leaking autoperf tees requiring re-crimping will be classified as incorrect operations and not equipment failure since if the autoperf tee was not crimped (or crimped correctly with the crimping tool) and the completion plug was not checked for leaks at installation it was not installed per the manufacturer recommendation.<br><br>From the number of above ground equipment leaks without documentation to review, more guidance needs to be provided to the field on how to classify and document these leaks. I suspect some districts are classifying above ground leaks as equipment failure and others are putting all above ground leaks into the other category. Identified in Table B6.1: Insufficient/Missing data.<br><br>Continue to monitor equipment failure leaks until baseline is established and or documentation and guidance is improved on above ground leaks. |
| WA | Known Leaks Scheduled for repair on annual report | Kathleen Chirgwin | 6/6/2017 | The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Due to the data shift we are seeing more WA |

| | | | | |
|---|---|---|---|---|
| | | | | leaks eliminated or repaired on the annual report but WA's total leaks as reported on 293B is not above the 25% increase threshold, we are seeing more leaks scheduled for repair on the annual report due to the shift in data of including above ground leaks scheduled for repair which has affected the trending, no action is needed. Monitor leaks scheduled for repair numbers until baseline is established and or above and below ground leaks scheduled for repair can be separated. |
| OR | Total leaks eliminated or repaired on annual report – Corrosion | Kathleen Chirgwin | 6/9/17 | OR Corrosion Repaired Leaks on 293B: 9<br>OR Total Hazardous Corrosion Repaired Leaks: 1<br>OR Total Corrosion Repaired Leaks: 11<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Reviewed OR 293 B corrosion leaks and all 9 were correctly classified as corrosion. We are seeing a slight increase comparted to the baseline this year in corrosion leaks on the annual report, however in 2014 we also had 11 corrosion leaks on the annual report. The baseline is low due to a small number of corrosion leaks in 2011, 2013, and 2015. Continue to monitor corrosion leaks in OR. |
| OR | Total leaks eliminated or repaired on annual report – Excavation Damage Service | Kathleen Chirgwin | 6/9/17 | OR Excavation Damage Repaired Leaks on 293B: 81 (81% increase)<br>OR Total Hazardous Excavation Damage Repaired Leaks: 73<br>OR Total Excavation Damage Service Repaired Leaks: 73<br><br>The five-year baseline used for trending is using inconsistent data due to the addition of above ground leaks in mid-2014.<br><br>Continue Implemented OR Excavation A/A, more efforts are needed. Recommend more efforts with homeowners since we are seeing the majority of excavation damage leaks on services lines. |
| OR | Total leaks eliminated | Kathleen | 6/9/17 | See summary of review to OR Hazardous Leaks |

| | | | | |
|---|---|---|---|---|
| | or repaired on annual report – Other Outside Force Damage | Chirgwin | | on annual report- Other Outside Force Damage. |
| OR | Total leaks eliminated or repaired on annual report - Equipment | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Equipment. |
| OR | Total leaks eliminated or repaired on annual report – Incorrect Operations | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Incorrect Operations. |
| WA | Total leaks eliminated or repaired reported on 293 – Excavation Damage | Kathleen Chirgwin | 3/23/2017 | Continue Implemented WA Excavation A/A, more efforts are needed. |
| WA | Total leaks eliminated or repaired reported on 293 – Incorrect Operations | Kathleen Chirgwin | 6/9/17 | See summary of review to WA Hazardous Leaks on annual report- Incorrect Operations. |
| OR | Total leaks eliminated or repaired reported on 293 – Corrosion | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Total leaks eliminated or repaired on annual report – Corrosion |
| OR | Total leaks eliminated or repaired reported on 293 – Excavation Damage | Kathleen Chirgwin | 6/9/17 | Continue Implemented WA Excavation A/A, more efforts are needed. |
| OR | Total leaks eliminated or repaired reported on 293 – Other Outside Force Damage | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Other Outside Force Damage. |
| OR | Total leaks eliminated or repaired reported on 293 – Material/Weld | Kathleen Chirgwin | 6/9/17 | Reviewed 2016 leaks reported on 293 classified as material/weld. After review 9 of 26 were incorrectly classified, after these leaks were reclassified the trending dropped below the 25% criteria, no action is required. |
| OR | Total leaks eliminated or repaired reported on 293 – Equipment | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Equipment. |
| OR | Total leaks eliminated or repaired reported on 293 – Incorrect Operations | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Incorrect Operations. |
| OR | Total leaks eliminated or repaired reported on 293 | Kathleen Chirgwin | 6/15/2017 | Oregon is seeing a large increase (56%) in total repaired leaks for 2016 which is affecting all categories. After discussing this with the Bend district we are not seeing an increase in leaks |

| | | | | |
|---|---|---|---|---|
| | | | | are seeing a backlog of monitored leaks being repaired. The district has had a culture shift of no longer monitoring leaks and instead is attempting to keep their monitoring leak numbers down. Bill Walker mentioned that when we became the district operations manager for the Bend district in 2014 that he came in with 276 open leaks and the district has been addressing these leaks and now only has 36 open leaks that are being monitored.<br><br>Monitor OR total repaired leak numbers. Recommend we look at tracking monitored leaks and leaks discovered for the year by the district to better understand repaired leaks as reported on the annual report. |
| OR | Leaks repaired by material: Pre-1980 Steel | Kathleen Chirgwin | 6/15/2017 | See summary of review for Total leaks eliminated or repaired reported on 293 for OR. |
| OR | Leaks repaired by material: Post-1980 Steel | Kathleen Chirgwin | 6/15/2017 | See summary of review for Total leaks eliminated or repaired reported on 293 for OR. |
| OR | Leaks repaired by material: PE pipe | Kathleen Chirgwin | 6/15/2017 | See summary of review for Total leaks eliminated or repaired reported on 293 for OR. |
| OR | Excavation Damages | Kathleen Chirgwin | 3/24/2017 | Continue implemented OR Excavation A/A, more efforts are needed. |
| WA | Other Risk Main | Kathleen Chirgwin | 3/24/2017 | Continue implemented Missing Value Risk A/A, more efforts may be needed, recommend we target cleanup efforts on highest missing value risk in DIMP. The majority of the high missing value risk is due to incomplete/missing data entry that could be reviewed and inputted by GIS. I would also recommend QA/QC on new data being inputted by GIS to ensure all required fields are being completed. |
| OR | Excavation Damage Risk Main | Kathleen Chirgwin | 3/24/2017 | Continue implemented OR Excavation A/A, more efforts may be needed. |
| OR | Equipment Risk Main | Kathleen Chirgwin | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Equipment.<br><br>With the increase in equipment failure leaks we are also seeing an increase in equipment failure risk on main. |
| WA | Incorrect Operations Risk Services | Kathleen Chirgwin | 6/9/17 | See summary of review to WA Hazardous Leaks on annual report- Incorrect Operations. |

| | | | | |
|---|---|---|---|---|
| | | | | Incorrect operations risk per 1000 ft is a very low number causing it to be sensitive to leaks and trending. This small increase requires no action. |
| OR | Incorrect Operations Risk Services | Kathleen | 6/9/17 | See summary of review to OR Hazardous Leaks on annual report- Incorrect Operations.<br><br>Incorrect operations risk per 1000 ft is a very low number causing it to be sensitive to leaks and trending. This small increase requires no action. |
| WA | Total leaks eliminated or repaired reported on 293 – Equipment | Kathleen Chirgwin | 6/9/17 | After 293B 2016 leak review revised trending trended above 25% requiring review.<br>See summary of review to WA Total Hazardous Leaks as reported on annual report.<br><br>Continue to review equipment failure leak trending. |
| | | | | |

# Appendix I – Periodic Evaluation

**Table of Contents**

## 1.0 SUMMARY OF PERIODIC EVALUATION

### 1.1 Overview

The purpose of this appendix is to store all DIMP Review Summary forms. It also provides a location to document any changes in the model calculations found in Appendix D – *Risk Evaluation and Ranking*

### 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 4.2.2 Determining Risk Weighting Factors | 3.0 risk Model Revisions | I3.1 |
| 4.4 Risk Model Validation | 3.0 risk Model Revisions | I3.1 |
| 7.1 Review of Written Plan | 4.0 Plan Review Summary | N/A |
| | | |

## 2.0 APPENDIX REVISION SUMMARY

### 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table I2.1: Appendix I Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | Created appendix to summaries changes to the written plan and Model. | Renie Sorensen & Kathleen Chirgwin |
| 7/15/2013 | Revision 2 doc | Added documentation for 2nd plan revision | Renie Sorensen |
| 8/3/2016 | Revision 3 doc | Added documentation for 3rd plan revision | Kathleen Chirgwin |

## 3.0 RISK MODEL REVISIONS

### 3.1 Overview

All revisions to the risk model and/or model calculations will be summarized in this section to provide a history of how the model has changed and improved over time. Previous versions of model calculations can be found in the yearly editions of the plan.

**Table I3.1: Model Revision Summary**

| Effective Date of Change | Reason for Change | Summary of Changes |
|---|---|---|
| 2/14/2013 | Model Overhaul after DIMP Audit | Change scoring to 0 to 10 with one decimal point. Updated sub-threats to correct threat category. Added additional sub-threats to: Corrosion, Equipment failure, Excavation Damage, and Consequence. |
| 3/31/2014 | Additional Damages/1000 locate risk category | Added additional category to excavation damages sub threat district damages/1000 locates. District damages/1000 locate tickets less than 1.5 are not assigned excavation damage risk. |
| 3/31/2014 | Missing Value Risk was inconsistent with sub threat risk that uses missing value data to assign risk. | Missing value risk weighting was reassigned to match risk in threat categories to be consistent with worst case risk scenario of not having the data available to code the risk correctly for the potential threat. |
| 3/31/2016 | 4 in IP steel tapping ability in districts. | Steel tapping ability risk was removed on 4 in IP steel pipe since the districts now have equipment to tap 4 in IP steel without Division's assistance. |
| 3/31/2016 | Inconsistencies in School and Hospital consequence Buffers | School and hospital consequence buffer was changed to a 1000 feet radius, previously we used an equation to calculate the radius based on population but we had concerns on this data due to inconsistencies in the data available. |
| 3/31/2016 | MAOP data added to mains in GIS | In consequence for pressure and diameter consideration we changed the pressure data from pressure class to the MAOP of the main. The MAOP for all mains were added to our GIS data which allows for more accurate pressure and diameter calculations and consequence scoring. |
| | | |
| | | |

## 4.0 PLAN REVIEW SUMMARY

### 4.1 Overview

The following section is for the storage of all DIMP Review Summary forms and any additional revision control information to support the summary form.

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## FORM 21761: DIMP REVIEW SUMMARY

**Date Started:** 7/21/2016
**Review Completion Date:** 7/29/2016
**Review Completed By:** Kathleen Chirgwin (CNGC), Matt Klingenstein (MDU/GPNG), Tyler Muzzana (IGC)

**Reason/s for Program review:** Review required per Section 7.1 of the written plan (Revision 2) and Part 192.1007 (f). Plan and specific company appendices are reviewed annually by GO staff per Section 7.1.1 of the written plan. Any revisions made during this review will require a new plan revision number and approval signatures from VP, Operations personnel. In order meet PHMSA requirement for this review, FAQ C.4.f.2 listed under PHMSA's Distribution Integrity Management web page was referenced, FAQ attached.

**Changes to the Written Plan required?** ☒Yes ☐No **If Yes, complete the Change Summary Table and approval is required**

**Changes to Risk Model required?** ☐Yes ☒No **If Yes, include a summary of recommended changes and approval is required**

**Summary of recommended changes:** Minor verbiage changes required due to code language listed under Subpart P. Required changes are included in the Written Plan: Change Summary Table listed below. All three parties agreed that annual review done by each operating companies includes verifying general information, incorporating new system information, re-evaluating threats and risk, reviewing performance metrics to reduce risk, reviewing effectiveness of measures to reduce risk, reviewing measures implemented to reduce risk to refine/improve as needed and reviewing performance measures for effectiveness. A review by each company was completed in March of 2016 and appendices were updated as necessary to meet the intent of the 5 year review required under 192.1007 (f). Other minor grammatical changes not affecting the content of the Plan were also included with this review.

**Written Plan: Change Summary**

| Plan Section | Reason For Change | From | To |
|---|---|---|---|
| 4.4 | Joint discussion with review group. No need to require approval in this instance. | Approval from GO Director, Engineering Services | Approval not required when no validation is necessary |
| Table 5.1 | Added Missing Values | No Missing Value threat | Missing Value threat with associated possible A/A items. |
| Table 6.1 | Baseline metrics are accounted for in Appendix H, not needed in Table | Baseline metrics included with table 6.1 | Removed baseline metric column |
| 7.1 | Part 192.1007 (f) code language | 4 year review requirement | 5 year view requirement |

**New Plan Revision Number Required?** ☒Yes ☐No **If Yes, Revision number to be updated:** Revision #3

**VP – Operations (CNGC):** [signature] **Date:** 8/1/16
**VP – Operations (IGC):** [signature] **Date:** 7/29/16
**VP – Operations (MDU/GPNG):** Pat Darras **Date:** 8/2/16

**Changes Implemented By:** Kathleen Chirgwin **Date Implemented:** 8/3/2016

Cascade Natural Gas Corporation — Great Plains Natural Gas Co. (A Division of MDU Resources Group, Inc. In the Community to Serve®) — Intermountain Gas Company (A Subsidiary of MDU Resources Group, Inc.) — Montana-Dakota Utilities Co. (A Division of MDU Resources Group, Inc. In the Community to Serve®)

Cascade Natural Gas Corporation
Intermountain Gas Company

Great Plains Natural Gas Co.
Montana-Dakota Utilities Co.

## DIMP REVIEW SUMMARY

21761(7-11)

**Date Started:** July 3, 2013
**Review Completion Date:** July 5, 2013
**Review Completed By:** Daryl Anderson (MDU)

**Reason/s for Program review:**

Reviewed Plan for changes to Corporate decision not to proceed to new Integrated Standards and Procedures Along with new standards numbering system.

**Changes to the Written Plan required?** ☒ Yes ☐ No **If Yes, complete the Change Summary Table and approval is required**

**Changes to Risk Model required?** ☐ Yes ☒ No **If Yes, include a summary of recommended changes and approval is required**

**Summary of recommended changes:**

Change Plan to reflect Standards Procedure Numbering remaining generic to each company

**Written Plan: Change Summary**

| Plan Section | Reason For Change | From | To |
|---|---|---|---|
| Title Page | Remove reference to Integrated Procedure Numbers | Removed Numbers | No Numbers |
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

**New Plan Revision Number Required?** ☒ Yes ☐ No **If Yes, Revision number to be updated:** Revison 2

**VP – Operations (CNG):** [signature] **Date:** 7 / 11 / 13

**VP – Operations (IGC):** [signature] **Date:** 7 / 11 / 2013

**VP – Operations (MDU):** [signature] **Date:** 7 / 8 / 2013

**Changes Implemented By:** ______ **Date Implemented:** ______

Cascade Natural Gas Corporation
Intermountain Gas Company

Great Plains Natural Gas Co.
Montana-Dakota Utilities Co.

# DIMP REVIEW SUMMARY

21761(7-11)

**Date Started:** 8/24/2012
**Review Completion Date:** 3/15/2013
**Review Completed By:** TYLER MUZZANA, KATHLEEN CHIRGWIN, RENIE SORENSEN

**Reason/s for Program review:** Respond to Idaho, Washington and Oregon DIMP audits conducted August 21-22 2012. Copies of the audit results are available from CNGC and IGC Engineering. Revisions to the written plan and risk model were required to be implemented prior to March 31, 2013. The new version of the DIMP written plan and related appendices will be on the Integration SharePoint Site and will be available from GO engineering.

**Changes to the Written Plan required?** X YES NO **If Yes, complete the Change Summary Table and approval is required**

**Changes to Risk Model required?** X YES NO **If Yes, include a summary of recommended changes and approval is required**

**Summary of recommended changes:** The most significant changes to the plan included the creation of multiple appendices that each operating company will retain and update. The appendices will have more detailed information specific to each company in order to better address DIMP requirements. Other written plan additions included more detail with regards to Subject Matter Experts and how they will be used during DIMP processes. A more detailed description of changes is listed in the attached spreadsheet. A "tracked changes" version of the original document is on the Operations Integration SharePoint (DIMP) page for reference.

## Written Plan: Change Summary

| Plan Section | Reason For Change | From | To |
|---|---|---|---|
| | See attached spreadsheet - | | |
| | | | |
| | | | |

**New Plan Revision Number Required?** X YES NO **If Yes, Revision number to be updated:** 1

**VP –Operations (CNGC):** [signature] **Date:** 3 / 19 / 13
**VP –Operations (IGC):** [signature] **Date:** 3 / 18 / 13
**VP – Operations (MDU/GPNG):** [signature] **Date:** 3 / 19 / 13

**Changes Implemented By:** Kathleen Chirgwin **Date to be Implemented:** March 31, 2013
Tyler Muzzana
Renie Sorensen

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## Written Plan: Revision 1

### Change Summary

| Section | Paragraph | Description of changes. |
|---|---|---|
| 1.5 | Plan Appendices | Added section to describe how Appendices will be used to capture company specific data |
| 1.6 | SME Involvement | Added section to describe how SMEs will be used in the plan |
| 1.6.1/1.6.2 | Isolated/Panel SMEs | Added sections to describe the use of isolated SMEs vs. the SME Panel |
| 1.7 | Definitions | Added SME definition |
| 1.8.1.5 | Figure 1.3 | Change CNGC org structure, Northwestern Region was combined with Western Region |
| 2.1 | Overview | Reworded to section to detail how knowledge of distribution system is demonstrated. Appendix B information added |
| 2.2 | Physical Infrastructure | Added verbiage to describe section, added more characteristics to sub sections: Steel Grade, Seam Type, Environmental characteristics, Surface Conditions, etc. |
| 2.3 | Historical Information | Added verbiage to describe section, added more examples of data used |
| 2.4 | Outside Source Data | Added verbiage and changed appendix where information is retained |
| 2.5 | Newly Installed Facilities | Moved location in plan, added verbiage to describe section and define minimum storage requirements |
| 2.6 | Information Evaluation | Rewrote section to describe QA/QC and continuous updating. (old 2.5.5) |
| 2.6.1 | Insufficient Data | Section rewrite addition of reference to appendix B for summarization of missing information |
| 2.6.2 | Developing Additional Information | Move section to subsection of 2.6 added additional activity to gather information |
| 2.7 | SME Involvement | Added section to describe how SMEs will be used in gaining knowledge of system |
| OLD 2.5.2.2 | Tracking and Trending | Removed section described in section 6.5.1 |
| 3.1 | Overview | Added verbiage to describe objective of section and added missing Data as threat category |
| 3.2 | Threats | Added or removed verbiage to threat descriptions to better reflect PHSMA leak definitions for each threat |
| 3.2.9 | Missing Data | Added description of missing data threat |
| 3.3 | Subdividing Threats | Added section to describe how sub threats are used to refine risk threat categories |
| 3.4 | Potential Threats | Added section to describe potential threats and how they are identified, stored and assessed within the distribution System. Included reference to new Appendix C |
| 4.1 | Overview | Added verbiage to describe purpose of section, referenced new Appendix D |
| 4.2 | Risk Model | Added verbiage to describe function of risk model |
| 4.2.1 | Responsibilities | Added section to describe responsible parties with respect to annual model run |
| 4.2.2 | Determination of Risk Weighting Factors | Added and removed verbiage to clarify process of developing Risk Weighting factors |
| 4.2.3 | Likelihood Factors | Changed Scale of weighting factors 0-10 added likelihood range breakdown |
| 4.2.5 | Factors for Missing Data | Added verbiage to clarify process |
| 4.2.6 | Relative Risk Calculation | Added verbiage and example to second paragraph describing how model calculates risk |
| 4.3 | Risk Ranking | Split risk ranking and model validation, Describe process for Ranking Risk |
| 4.4 | Risk Model Validation | Split risk ranking and model validation, rewrote section to describe validation process |
| 5.1 | Overview | Added verbiage to describe purpose of section |
| 5.2.3 | Maintenance Programs | Added Section to describe purpose of annual Maintenance programs |
| 5.3 | Additional or Accelerated Actions | Rewrote section to describe how and when A/As are used |
| 5.3 | Table 5.1 | Updated table |
| 5.3.1.1 | A/A action implementation | Reworded section to clarify. Updated location for form storage. |
| 5.3.2 | Accelerated Action Documentation | Section added to describe documentation required with A/As |

| Section | Paragraph | Description of changes. |
|---|---|---|
| 6.1 | Overview | Rewrote section to describe objective of this section |
| 6.4 | Information Gathering | Added verbiage to first paragraph detailing who is responsible. |
| 6.5 | Monitoring Results | Section removed and put into sub sections 6.5.1 and 6.5.2 |
| 6.5.1 | Performance Metric Effectiveness and Trending | Subsection created to add detail to trending needs and evaluation of effectiveness of Performance Measures |
| 6.5.2 | A/A Effectiveness Review and criteria | Subsection created to add detail to trending needs and evaluation of effectiveness of A/As |
| 7.1 | Review of Written Plan | Added verbiage to first paragraph detail extent of annual review. Changed storage location for review documentation |
| 7.1.1 | Review of Appendices | Added Section to describe review of Appendices |
| 7.2 | Revisions to the Written Plan | Added verbiage to describe revision process |
| 7.2.1 | Revisions to Appendices | Section added to describe how Revisions to appendices will be handled |
| 7.3 | Program improvement | Section reference update |
| Form 21764 | SME Panel Form | Creation of SME Panel Form |
| Form 21761 | DIMP Review Summary | Add signature line for VP- Operations CNGC |
| Appendices | Appendix A - K | Revised existing and added new appendices to the plan. Each appendix is specific to each operating company to allow for further detail/process information. The appendices are referenced throughout the entire document |

# Appendix J – Mechanical Coupling Failures

# 1.0 MECHANICAL COUPLING FAILURES

## 1.1 Overview

This appendix serves the purpose of recording and storing information in relation to mechanical coupling failures. The process that the gathered information goes through is established in CNG CP 722.

## 1.2 Plan References

Sections of the Written Plan that reference this Appendix are as follows:

| Plan Section | Appendix Section | Table number |
|---|---|---|
| 8.1 Overview | 1.1 Mechanical Coupling Failure Reporting Overview | J3.1 |
| | | |

# 2.0 APPENDIX REVISION SUMMARY

## 2.1 Overview

Revisions to this appendix will be recorded/summarized in the following table. Annual data updating does not need to be recorded here.

**Table J2.1: Appendix J Revision Summary**

| Date of Revision | Reason For Revision | Summary of Changes | Revised By |
|---|---|---|---|
| 3/15/2013 | Creation | Creation of appendix to record Mechanical coupling failures for tracking purposes | Renie Sorensen & Kathleen Chirgwin |
| 3/24/2017 | Addition | Added Section 4.0 to store submitted Mechanical Fitting Failure Reports. | Kathleen Chirgwin |

## 3.0 MECHANICAL COUPLING FAILURE SUMMARY

### 3.1 Overview

All mechanical fittings that fail are summarized in the following table to help track any issues that could create a threat to the system.

**Table J3.1 Mechanical Coupling Failure Summary**

| Date of Failure | Location | Part Number | Root Cause of Failure |
|---|---|---|---|
| As per district managers contacted on 2/13/13 no failures have occurred for 2011 or 2012 | | | |
| Per district management and Leak Review No Mechanical failures occurred that caused a hazardous leak in 2013 and 2014 | | | |
| Per compliance on 3-29-2016, no mechanical failures occurred that caused a hazardous leak in 2015. | | | |
| 12/19/2016 | Mt Vernon, Washington | CPLG 3259-52-1014-00<br>Lot Number: 471413-000<br>Year Manufactured: 2011 | Incorrect Operations |

## 4.0 MECHANICAL FITTING FAILURE REPORTS

### 4.1 Overview

This section provides a location to store mechanical fitting failures reported.

| | | |
|---|---|---|
| NOTICE: This report is required by 49 CFR Part 192.1009. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | | OMB NO: 2137-0522<br>EXPIRATION DATE: 10/31/2017 |
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Submitted Date:** | 03/14/2017 |
| | **Form Type:** | INITIAL |
| | **Submitted Date:** | |

## MECHANICAL FITTING FAILURE REPORT FOR CALENDAR YEAR 2016 FOR DISTRIBUTION OPERATORS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 1 hour per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

| PART A – OPERATOR INFORMATION | (DOT use only) | 20161219212866483-66041 |
|---|---|---|

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK,US |
| 4c. State | WA |
| 4d. Zip Code | 99336 |

## PART B – PREPARER AND AUTHORIZED SIGNATURE

| | |
|---|---|
| Mike Eutsey,agent<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| mike.eutsey@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |
| PREPARER'S ADDRESS: | |
| Number and Street | 8113 W GRANDRIDGE BLVD |
| City and County | KENNEWICK |
| State | WA |
| Zip Code | 99336 |

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| PART C – MECHANICAL FITTING FAILURE DATA | | |
|---|---|---|
| 1. STATE IN WHICH FITTING FAILED: | WA | |
| 2. DATE OF FAILURE: | 12/19/2016 | |
| 3. SPECIFY THE MECHANICAL FITTING: | Stab | |
| 4. SPECIFY THE TYPE OF MECHANICAL FITTING: | Service or Main Tee | |
| 5. LEAK LOCATION: | a)Belowground<br>b)Outside<br>c)Service-to-Service | |
| 6. YEAR INSTALLED: | 2016 | |
| 7. YEAR MANUFACTURED: | 2011 | |
| 8. IF YEAR MANUFACTURED OR YEAR INSTALLED IS NOT KNOWN THEN, DECADE INSTALLED: | | |
| 9. MANUFACTURER: | CONTINENTAL (CONTINENTAL INDUSTRIES) | |
| 10. PORT OR MODEL NUMBER: | CPLG 3259-52-1014-00 | |
| 11. LOT NUMBER: | 471413-000 | |
| 12. OTHER ATTRIBUTES: | NA | |
| 13. FITTING MATERIAL: | Plastic | |
| 14. SPECIFY THE TWO MATERIALS BEING JOINED | | |
| A) FIRST PIPE | | |
| -NORMAL SIZE: | 1" | |
| -UNIT: | IPS | |
| -MATERIAL: | Plastic | |
| -IF PLASTIC, SPECIFY: | Polyethylene (PE) | |
| B) SECOND PIPE | | |
| -NORMAL SIZE: | 1" | |
| -UNIT: | IPS | |
| -MATERIAL: | Plastic | |
| -IF PLASTIC, SPECIFY: | Polyethylene (PE) | |
| 15. APPARENT CAUSE OF LEAK:<br><br>Reports submitted during 2011 and 2012 with a cause of "Material or Weld" and leak due to "Construction/Installation Defect" have been changed by PHMSA to a cause of "Incorrect Operation". | Incorrect Operation | |
| 16. HOW DID THE LEAK OCCUR? | Leak Through Seal | |
| 17. OPERATOR'S INTERNAL MECHANICAL FITTING FAILURE TRACKING NUMBER (OPTIONAL): | NA | |

# Appendix K – Reports to Government Agencies

## 1.0 REPORTS TO GOVERNMENT AGENCIES

### 1.1 Overview

This appendix provides a location to store PHMSA Anural Distribution Report.

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| | | |
|---|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | | OMB NO: 2137-0629<br>EXPIRATION DATE: 5/31/2018 |
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Date Submitted:** | 03/14/2017 |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR CALENDAR YEAR 2016 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0629. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at* http://www.phmsa.dot.gov/pipeline/library/forms.

| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | **20177117-31874** |
|---|---|---|

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W GRANDRIDGE BLVD |
| 2b. City and County | KENNEWICK |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |
| 6. **THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP** *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)* | |
| Natural Gas | |
| 7. **THIS REPORT PERTAINS TO THE FOLLOWING TYPE OF OPERATOR** *(Select Type of Operator based on the structure of the company included in this OPID for which this report is being submitted.):* | |
| Investor Owned | |

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | RECONDITIONED CAST IRON | SYSTEM TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | | |
| | BARE | COATED | BARE | COATED | | | | | | | |
| MILES OF MAIN | 0 | 0 | 2.73 | 2777.68 | 1895.89 | 0 | 0 | 0 | 129.07 | 0 | 4805.37 |
| NO. OF SERVICES | 0 | 0 | 84 | 106701 | 106423 | 0 | 0 | 0 | 1759 | 0 | 214967 |

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| 2.MILES OF MAINS IN SYSTEM AT END OF YEAR | | | | | | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | SYSTEM TOTALS |
| STEEL | 0 | 1745.84 | 487.49 | 427.64 | 60.70 | 58.74 | 2780.41 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 0 | 1541.61 | 319.06 | 35.22 | 0 | 0 | 1895.89 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 0 | 95.40 | 29.30 | 4.37 | 0 | 0 | 129.07 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 0 | 3382.85 | 835.85 | 467.23 | 60.7 | 58.74 | 4805.37 |
| Describe Other Material: | | Unknown | | | | | |

| 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | | | | | AVERAGE SERVICE LENGTH: 142 | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | SYSTEM TOTALS |
| STEEL | 174 | 102906 | 3534 | 150 | 17 | 4 | 106785 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 182 | 104228 | 1893 | 115 | 5 | 0 | 106423 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 420 | 1274 | 60 | 3 | 2 | 0 | 1759 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 776 | 208408 | 5487 | 268 | 24 | 4 | 214967 |
| Describe Other Material: | | Unknown | | | | | |

| 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 662.83 | 0 | .82 | 136.30 | 866.70 | 505.60 | 447.90 | 1069.70 | 838.50 | 277.02 | 4805.37 |
| NUMBER OF SERVICES | 4132 | 16 | 7 | 6070 | 30113 | 19702 | 21467 | 64621 | 49695 | 19144 | 214967 |

## PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION FAILURE | 15 | 0 | 8 | 4 |
| NATURAL FORCE DAMAGE | 0 | 0 | 2 | 0 |
| EXCAVATION DAMAGE | 49 | 43 | 102 | 95 |
| OTHER OUTSIDE FORCE DAMAGE | 4 | 4 | 18 | 9 |
| PIPE, WELD OR JOINT FAILURE | 12 | 0 | 13 | 4 |
| EQUIPMENT FAILURE | 13 | 0 | 61 | 0 |
| INCORRECT OPERATIONS | 1 | 1 | 3 | 3 |
| OTHER CAUSE | 31 | 2 | 1585 | 55 |
| NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 538 | | | | |

## PART D - EXCAVATION DAMAGE

1. TOTAL NUMBER OF EXCAVATION DAMAGES BY APPARENT ROOT CAUSE: 187

a. One-Call Notification Practices Not Sufficient: 78

b. Locating Practices Not Sufficient: 27

c. Excavation Practices Not Sufficient: 70

d. Other: 12

2. NUMBER OF EXCAVATION TICKETS : 46819

## PART E-EXCESS FLOW VALUE(EFV) DATA

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 2616

ESTIMATED NUMBER OF EFV'S IN THE SYSTEM AT THE END OF YEAR: 18526

## PART F - LEAKS ON FEDERAL LAND

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 2

## PART G-PERCENT OF UNACCOUNTED FOR GAS

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .37%

## PART H - ADDITIONAL INFORMATION

## PART I - PREPARER

| | |
|---|---|
| | |
| Chris Grissom,Mgr, Standards & Compliance<br>(Preparer's Name and Title) | (509) 531-6427<br>(Area Code and Telephone Number) |
| | |
| christopher.grissom@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

| | | |
|---|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | | OMB NO: 2137-0629<br>EXPIRATION DATE: 5/31/2018 |
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Date Submitted:** | 03/14/2017 |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR CALENDAR YEAR 2016 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0629. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at [http://www.phmsa.dot.gov/pipeline/library/forms](http://www.phmsa.dot.gov/pipeline/library/forms).*

| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | **20177118-31875** |
|---|---|---|
| 1. Name of Operator | | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | | |
| 2a. Street Address | | 8113 W GRANDRIDGE BLVD |
| 2b. City and County | | KENNEWICK |
| 2c. State | | WA |
| 2d. Zip Code | | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | | |
| 4a. Street Address | | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | | KENNEWICK |
| 4c. State | | WA |
| 4d. Zip Code | | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | | OR |

6. **THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP** *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

Natural Gas

7. **THIS REPORT PERTAINS TO THE FOLLOWING TYPE OF OPERATOR** *(Select Type of Operator based on the structure of the company included in this OPID for which this report is being submitted.)***:**

Investor Owned

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | RECONDITIONED CAST IRON | SYSTEM TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | | |
| | BARE | COATED | BARE | COATED | | | | | | | |
| MILES OF MAIN | 0 | 0 | .70 | 821.44 | 783.56 | 0 | 0 | 0 | 21.70 | 0 | 1627.4 |
| NO. OF SERVICES | 0 | 0 | 22 | 28798 | 42482 | 0 | 0 | 0 | 166 | 0 | 71468 |

| 2.MILES OF MAINS IN SYSTEM AT END OF YEAR | | | | | | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | SYSTEM TOTALS |
| STEEL | .70 | 545.35 | 152.14 | 113.32 | 10.63 | 0 | 822.14 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 0 | 665.46 | 108.84 | 9.26 | 0 | 0 | 783.56 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 0 | 15.4 | 5 | 1.3 | 0 | 0 | 21.7 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | .7 | 1226.21 | 265.98 | 123.88 | 10.63 | 0 | 1627.4 |
| Describe Other Material: | | Unknown | | | | | |

| 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | | | | | AVERAGE SERVICE LENGTH: 118 | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | SYSTEM TOTALS |
| STEEL | 60 | 27468 | 1252 | 35 | 4 | 1 | 28820 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 109 | 41439 | 892 | 40 | 2 | 0 | 42482 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 29 | 120 | 17 | 0 | 0 | 0 | 166 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 198 | 69027 | 2161 | 75 | 6 | 1 | 71468 |
| Describe Other Material: | | Unknown | | | | | |

| 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 136.22 | .14 | 0 | 36.40 | 245 | 126.24 | 179.4 | 385 | 447 | 72 | 1627.4 |
| NUMBER OF SERVICES | 1121 | 4 | 7 | 1605 | 8130 | 5781 | 5271 | 19030 | 22228 | 8291 | 71468 |

**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION FAILURE | 2 | 0 | 9 | 1 |
| NATURAL FORCE DAMAGE | 0 | 0 | 1 | 1 |
| EXCAVATION DAMAGE | 14 | 10 | 73 | 63 |
| OTHER OUTSIDE FORCE DAMAGE | 0 | 0 | 15 | 9 |
| PIPE, WELD OR JOINT FAILURE | 5 | 2 | 21 | 1 |
| EQUIPMENT FAILURE | 2 | 2 | 107 | 2 |
| INCORRECT OPERATIONS | 0 | 0 | 3 | 3 |
| OTHER CAUSE | 1 | 0 | 528 | 52 |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 337

**PART D - EXCAVATION DAMAGE**

1. TOTAL NUMBER OF EXCAVATION DAMAGES BY APPARENT ROOT CAUSE: 101

a. One-Call Notification Practices Not Sufficient: 50

b. Locating Practices Not Sufficient: 5

c. Excavation Practices Not Sufficient: 35

d. Other: 11

2. NUMBER OF EXCAVATION TICKETS : 19236

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1506

ESTIMATED NUMBER OF EFV'S IN THE SYSTEM AT THE END OF YEAR: 8169

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .45%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER**

| | |
|---|---|
| | |
| Chris Grissom,Mgr, Standards & Compliance<br>(Preparer's Name and Title) | (509) 531-6427<br>(Area Code and Telephone Number) |
| | |
| christopher.grissom@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

| | | |
|---|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | | OMB NO: 2137-0629<br>EXPIRATION DATE: 5/31/2018 |
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Date Submitted:** | 03/15/2016 |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR CALENDAR YEAR 2015 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0629. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | **20165835-28614** |
|---|---|---|

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W GRANDRIDGE BLVD |
| 2b. City and County | KENNEWICK |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |

6. **THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP** *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)*

Natural Gas

7. **THIS REPORT PERTAINS TO THE FOLLOWING TYPE OF OPERATOR** *(Select Type of Operator based on the structure of the company included in this OPID for which this report is being submitted.)***:**

Investor Owned

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | RECONDITIONED CAST IRON | SYSTEM TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | | |
| | BARE | COATED | BARE | COATED | | | | | | | |
| MILES OF MAIN | | | 3 | 2780 | 1833 | | | | 128 | | 4744 |
| NO. OF SERVICES | | | 85 | 107562 | 102550 | | | | 1854 | | 212051 |

| 2.MILES OF MAINS IN SYSTEM AT END OF YEAR | | | | | | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | SYSTEM TOTALS |
| STEEL | 0 | 1750 | 490 | 427 | 57 | 59 | 2783 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 0 | 1496 | 312 | 25 | 0 | 0 | 1833 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 0 | 97 | 27 | 4 | 0 | 0 | 128 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 0 | 3343 | 829 | 456 | 57 | 59 | 4744 |
| Describe Other Material: | | Unknown | | | | | |

| 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | | | | | AVERAGE SERVICE LENGTH: 151 | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | SYSTEM TOTALS |
| STEEL | 197 | 103731 | 3551 | 147 | 17 | 4 | 107647 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 221 | 100400 | 1815 | 110 | 4 | 0 | 102550 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 647 | 1136 | 65 | 4 | 2 | 0 | 1854 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 1065 | 205267 | 5431 | 261 | 23 | 4 | 212051 |
| Describe Other Material: | | Unknown | | | | | |

| 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 674 | 0 | 1 | 138 | 868 | 507 | 448 | 1071 | 835 | 202 | 4744 |
| NUMBER OF SERVICES | 4152 | 16 | 7 | 6205 | 30511 | 19893 | 21537 | 64790 | 49674 | 15266 | 212051 |

**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION FAILURE | 13 | 1 | 16 | 9 |
| NATURAL FORCE DAMAGE | 0 | 0 | 5 | 4 |
| EXCAVATION DAMAGE | 30 | 24 | 107 | 71 |
| OTHER OUTSIDE FORCE DAMAGE | 6 | 1 | 11 | 10 |
| PIPE, WELD OR JOINT FAILURE | 14 | 3 | 58 | 5 |
| EQUIPMENT FAILURE | 10 | 0 | 33 | 1 |
| INCORRECT OPERATIONS | 0 | 0 | 92 | 1 |
| OTHER CAUSE | 23 | 4 | 1691 | 93 |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 294

**PART D - EXCAVATION DAMAGE**

1. TOTAL NUMBER OF EXCAVATION DAMAGES BY APPARENT ROOT CAUSE: 173

a. One-Call Notification Practices Not Sufficient: 80

b. Locating Practices Not Sufficient: 5

c. Excavation Practices Not Sufficient: 71

d. Other: 17

2. NUMBER OF EXCAVATION TICKETS : 43292

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1742

ESTIMATED NUMBER OF EFV'S IN THE SYSTEM AT THE END OF YEAR: 15223

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 4

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .34%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER**

CASCADE NATURAL GAS CORPORATION — GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® — INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. — MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

| | | |
|---|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | | OMB NO: 2137-0629<br>EXPIRATION DATE: 5/31/2018 |
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Date Submitted:** | 03/15/2016 |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR CALENDAR YEAR 2015 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0629. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

***Important:*** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | **20165837-28616** |
|---|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP | |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | | |
| 2a. Street Address | 8113 W GRANDRIDGE BLVD | |
| 2b. City and County | KENNEWICK | |
| 2c. State | WA | |
| 2d. Zip Code | 99336 | |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 | |
| 4. HEADQUARTERS NAME & ADDRESS | | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD | |
| 4b. City and County | KENNEWICK | |
| 4c. State | WA | |
| 4d. Zip Code | 99336 | |
| 5. STATE IN WHICH SYSTEM OPERATES | OR | |
| 6. **THIS REPORT PERTAINS TO THE FOLLOWING COMMODITY GROUP** *(Select Commodity Group based on the predominant gas carried and complete the report for that Commodity Group. File a separate report for each Commodity Group included in this OPID.)* | | |
| Natural Gas | | |
| 7. **THIS REPORT PERTAINS TO THE FOLLOWING TYPE OF OPERATOR** *(Select Type of Operator based on the structure of the company included in this OPID for which this report is being submitted.)*: | | |
| Investor Owned | | |

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | RECONDITIONED CAST IRON | SYSTEM TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | | |
| | BARE | COATED | BARE | COATED | | | | | | | |
| MILES OF MAIN | | | 1 | 822 | 758 | | | | 23 | | 1604 |
| NO. OF SERVICES | | | 17 | 29135 | 40245 | | | | 289 | | 69686 |

| 2.MILES OF MAINS IN SYSTEM AT END OF YEAR | | | | | | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | SYSTEM TOTALS |
| STEEL | 0 | 554 | 145 | 113 | 11 | 0 | 823 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 0 | 646 | 103 | 9 | 0 | 0 | 758 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 0 | 17 | 5 | 1 | 0 | 0 | 23 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 0 | 1217 | 253 | 123 | 11 | 0 | 1604 |
| Describe Other Material: | | Unknown | | | | | |

| 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | | | | | AVERAGE SERVICE LENGTH: 113 | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | SYSTEM TOTALS |
| STEEL | 67 | 27790 | 1253 | 37 | 4 | 1 | 29152 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 117 | 39268 | 824 | 34 | 2 | 0 | 40245 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 53 | 208 | 28 | 0 | 0 | 0 | 289 |
| RECONDITIONED CAST IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 237 | 67266 | 2105 | 71 | 6 | 1 | 69686 |
| Describe Other Material: | | Unknown | | | | | |

| 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |

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| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 168 | 0 | 0 | 15 | 242 | 126 | 174 | 386 | 447 | 46 | 1604 |
| NUMBER OF SERVICES | 1139 | 4 | 8 | 1614 | 8221 | 5828 | 5309 | 19072 | 22245 | 6246 | 69686 |

**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION FAILURE | 2 | 0 | 1 | 1 |
| NATURAL FORCE DAMAGE | 0 | 0 | 1 | 1 |
| EXCAVATION DAMAGE | 18 | 14 | 46 | 43 |
| OTHER OUTSIDE FORCE DAMAGE | 1 | 1 | 8 | 8 |
| PIPE, WELD OR JOINT FAILURE | 14 | 2 | 8 | 0 |
| EQUIPMENT FAILURE | 17 | 1 | 5 | 0 |
| INCORRECT OPERATIONS | 1 | 1 | 1 | 1 |
| OTHER CAUSE | 3 | 0 | 959 | 1 |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 446

**PART D - EXCAVATION DAMAGE**

1. TOTAL NUMBER OF EXCAVATION DAMAGES BY APPARENT ROOT CAUSE: 109

a. One-Call Notification Practices Not Sufficient: 39

b. Locating Practices Not Sufficient: 10

c. Excavation Practices Not Sufficient: 38

d. Other: 22

2. NUMBER OF EXCAVATION TICKETS : 17394

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1146

ESTIMATED NUMBER OF EFV'S IN THE SYSTEM AT THE END OF YEAR: 6366

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .31%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER**

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 10/31/2016 |

| | | |
|---|---|---|
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Date Submitted:** | |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR CALENDAR YEAR 2014 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | - |
|---|---|---|

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge |
| 2b. City and County | Kennewick |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | OR |

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | SYSTEM TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | | | | | | |
| MILES OF MAIN | | 0 | .69 | 821.99 | 741.15 | 0 | 0 | 0 | 28.92 | 1592.75 |
| NO. OF SERVICES | | 0 | 15 | 29367 | 38635 | 0 | 0 | 0 | 183 | 68200 |

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**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | SYSTEM TOTALS |
|---|---|---|---|---|---|---|---|
| STEEL | 0 | 552.90 | 146.21 | 113. | 10.57 | 0 | 822.68 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| PLASTIC PE | 0 | 633.07 | 99.99 | 8.09 | 0 | 0 | 741.15 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| OTHER | 0 | 16.88 | 10.70 | 1.34 | 0 | 0 | 28.92 |
| TOTAL | 0.00 | 1,202.85 | 256.90 | 122.43 | 10.57 | 0.00 | 1,592.75 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** — **AVERAGE SERVICE LENGTH: 0**

| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | SYSTEM TOTALS |
|---|---|---|---|---|---|---|---|
| STEEL | 69 | 28003 | 1268 | 37 | 4 | 1 | 29382 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 121 | 37690 | 792 | 30 | 2 | 0 | 38635 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 56 | 106 | 21 | 0 | 0 | 0 | 183 |
| TOTAL | 246 | 65799 | 2081 | 67 | 6 | 1 | 68200 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 171.36 | .29 | 0 | 15.35 | 243.36 | 126.90 | 175.35 | 384.90 | 446.74 | 28.50 | 1592.75 |
| NUMBER OF SERVICES | 1189 | 4 | 8 | 1628 | 8299 | 5915 | 5340 | 19130 | 22263 | 4424 | 68200 |

| PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR | | | | |
|---|---|---|---|---|
| CAUSE OF LEAK | MAINS | | SERVICES | |
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 6 | 0 | 5 | 2 |
| NATURAL FORCES | 0 | 0 | 2 | 1 |
| EXCAVATION DAMAGE | 12 | 9 | 42 | 42 |
| OTHER OUTSIDE FORCE DAMAGE | 3 | 3 | 4 | 2 |
| MATERIAL OR WELDS | 23 | 1 | 15 | 5 |
| EQUIPMENT | 14 | 0 | 9 | 2 |
| INCORRECT OPERATIONS | 0 | 0 | 0 | 0 |
| OTHER | 0 | 0 | 648 | 3 |
| NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 611 | | | | |

| PART D - EXCAVATION DAMAGE | PART E-EXCESS FLOW VALUE(EFV) DATA |
|---|---|
| NUMBER OF EXCAVATION DAMAGES: 89 | NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 821 |
| NUMBER OF EXCAVATION TICKETS : 14939 | ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 4731 |

| PART F - LEAKS ON FEDERAL LAND | PART G-PERCENT OF UNACCOUNTED FOR GAS |
|---|---|
| TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0 | UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.<br>INPUT FOR YEAR ENDING 6/30: 0% |

| PART H - ADDITIONAL INFORMATION |
|---|
| |

| PART I - PREPARER AND AUTHORIZED SIGNATURE | |
|---|---|
| Mike Eutsey,Mgr, Standards & Compliance<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| mike.eutsey@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 10/31/2016 |
|---|---|

| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | | |
|---|---|---|
| | **Initial Date Submitted:** | |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR
## CALENDAR YEAR 2014
## GAS DISTRIBUTION SYSTEM



| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | - |
|---|---|---|

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge |
| 2b. City and County | Kennewick |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | SYSTEM TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | | | | | | |
| MILES OF MAIN | 0 | 0 | 3.18 | 2780.16 | 1790.49 | 0 | 0 | 0 | 131.38 | 4705.21 |
| NO. OF SERVICES | 0 | 0 | 87 | 108478 | 99518 | 0 | 0 | 0 | 1826 | 209909 |

| 2.MILES OF MAINS IN SYSTEM AT END OF YEAR | | | | | | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | SYSTEM TOTALS |
| STEEL | 0 | 1757. | 486. | 424.34 | 57. | 59. | 2,783.34 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| PLASTIC PE | 0 | 1462.19 | 304.30 | 24. | 0 | 0 | 1,790.49 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 |
| OTHER | 0 | 97 | 30.38 | 4. | 0 | 0 | 131.38 |
| TOTAL | 0.00 | 3,316.19 | 820.68 | 452.34 | 57.00 | 59.00 | 4,705.21 |

| 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR | | | | | AVERAGE SERVICE LENGTH: 0 | | |
|---|---|---|---|---|---|---|---|
| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | SYSTEM TOTALS |
| STEEL | 199 | 104601 | 3596 | 148 | 17 | 4 | 108565 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 224 | 97509 | 1682 | 99 | 4 | 0 | 99518 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 653 | 1101 | 66 | 4 | 2 | 0 | 1826 |
| TOTAL | 1076 | 203211 | 5344 | 251 | 23 | 4 | 209909 |

| 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
| MILES OF MAIN | 678.67 | .01 | 1.13 | 138.40 | 870.5 | 507.98 | 448.67 | 1071.10 | 834.35 | 154.40 | 4705.21 |
| NUMBER OF SERVICES | 4191 | 16 | 7 | 6289 | 30844 | 20014 | 21648 | 64960 | 49674 | 12266 | 209909 |

**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 18 | 5 | 13 | 4 |
| NATURAL FORCES | 1 | 1 | 1 | 1 |
| EXCAVATION DAMAGE | 27 | 23 | 68 | 67 |
| OTHER OUTSIDE FORCE DAMAGE | 4 | 2 | 7 | 7 |
| MATERIAL OR WELDS | 11 | 1 | 12 | 0 |
| EQUIPMENT | 6 | 0 | 7 | 3 |
| INCORRECT OPERATIONS | 3 | 1 | 3 | 1 |
| OTHER | 12 | 1 | 1022 | 5 |

**NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR** : 273

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 152

NUMBER OF EXCAVATION TICKETS : 41489

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1216

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 12761

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 2

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: 0%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

Mike Eutsey,Mgr. Standards & Compliance
(Preparer's Name and Title)

(509) 734-4576
(Area Code and Telephone Number)

mike.eutsey@cngc.com
(Preparer's email address)

(Area Code and Facsimile Number)

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| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |

| | | |
|---|---|---|
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Initial Date Submitted:** | 03/14/2014 |
| | **Form Type:** | INITIAL |
| | **Date Submitted:** | |

## ANNUAL REPORT FOR CALENDAR YEAR 2013 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

| **PART A - OPERATOR INFORMATION** | **(DOT use only)** | **20142729-21771** |
|---|---|---|

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge |
| 2b. City and County | Kennewick |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | OR |

**PART B - SYSTEM DESCRIPTION**

**1.GENERAL**

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | DUCTILE IRON | COPPER | CAST/ WROUGHT IRON | PLASTIC | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 1.000 | 803.000 | 0.000 | 0.000 | 0.000 | 731.000 | 29.000 | 1564.000 |
| N0. OF SERVICES | 0.000 | 0.000 | 20.000 | 30073.000 | 0.000 | 0.000 | 0.000 | 37711.000 | 331.000 | 68135.000 |

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**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2' OR LESS | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' THRU 12' | OVER 12' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 553.000 | 147.000 | 98.000 | 6.000 | 0.000 | 804.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 626.000 | 97.000 | 8.000 | 0.000 | 0.000 | 731.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 17.000 | 11.000 | 1.000 | 0.000 | 0.000 | 29.000 |
| TOTAL | 0.000 | 1196.000 | 255.000 | 107.000 | 6.000 | 0.000 | 1564.000 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** — **AVERAGE SERVICE LENGTH: 0**

| MATERIAL | UNKNOWN | 1' OR LESS | OVER 1' THRU 2' | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 74.000 | 28680.000 | 1296.000 | 38.000 | 4.000 | 1.000 | 30093.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 132.000 | 36786.000 | 766.000 | 25.000 | 2.000 | 0.000 | 37711.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 266.000 | 37.000 | 28.000 | 0.000 | 0.000 | 0.000 | 331.000 |
| TOTAL | 472.000 | 65503.000 | 2090.000 | 63.000 | 6.000 | 1.000 | 68135.000 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 165.000 | 0.000 | 0.000 | 15.000 | 244.000 | 127.000 | 169.000 | 379.000 | 446.500 | 18.500 | 1564.000 |
| NUMBER OF SERVICES | 1505.000 | 5.000 | 7.000 | 1565.000 | 8173.000 | 5955.000 | 5430.000 | 19285.000 | 22710.000 | 3500.000 | 68135.000 |

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**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 2 | 1 | 0 | 0 |
| NATURAL FORCES | 0 | 0 | 1 | 0 |
| EXCAVATION DAMAGE | 6 | 6 | 15 | 15 |
| OTHER OUTSIDE FORCE DAMAGE | 1 | 0 | 4 | 1 |
| MATERIAL OR WELDS | 8 | 0 | 9 | 3 |
| EQUIPMENT | 1 | 0 | 1 | 0 |
| INCORRECT OPERATIONS | 0 | 0 | 0 | 0 |
| OTHER | 1 | 0 | 1 | 1 |

**NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR** : 52

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 85

NUMBER OF EXCAVATION TICKETS : 14461

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1128

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 3710

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: 0%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

| | |
|---|---|
| Tina Beach,agent<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |

U.S Department of Transportation
Pipeline and Hazardous Materials Safety Administration

| | |
|---|---|
| **Initial Date Submitted:** | 03/14/2014 |
| **Form Type:** | INITIAL |
| **Date Submitted:** | |

# ANNUAL REPORT FOR CALENDAR YEAR 2013 GAS DISTRIBUTION SYSTEM



## PART A - OPERATOR INFORMATION | (DOT use only) | 20142728-21770

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge |
| 2b. City and County | Kennewick |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City and County | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |

## PART B - SYSTEM DESCRIPTION

**1.GENERAL**

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | DUCTILE IRON | COPPER | CAST/ WROUGHT IRON | PLASTIC | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 4.700 | 2653.740 | 0.000 | 0.000 | 0.000 | 1752.810 | 169.560 | 4580.810 |
| NO. OF SERVICES | 0.000 | 0.000 | 92.000 | 109539.000 | 0.000 | 0.000 | 0.000 | 98832.000 | 2028.000 | 210491.000 |

CASCADE NATURAL GAS CORPORATION
GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve®
INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc.
MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2' OR LESS | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' THRU 12' | OVER 12' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.010 | 1735.520 | 480.240 | 385.450 | 54.960 | 2.260 | 2658.440 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.070 | 1434.740 | 299.410 | 18.590 | 0.000 | 0.000 | 1752.810 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 124.610 | 40.290 | 4.660 | 0.000 | 0.000 | 169.560 |
| TOTAL | 0.080 | 3294.870 | 819.940 | 408.700 | 54.960 | 2.260 | 4580.810 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** **AVERAGE SERVICE LENGTH: 0**

| MATERIAL | UNKNOWN | 1' OR LESS | OVER 1' THRU 2' | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 207.000 | 105608.000 | 3644.000 | 152.000 | 16.000 | 4.000 | 109631.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 236.000 | 96864.000 | 1629.000 | 99.000 | 4.000 | 0.000 | 98832.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 1111.000 | 839.000 | 72.000 | 4.000 | 2.000 | 0.000 | 2028.000 |
| TOTAL | 1554.000 | 203311.000 | 5345.000 | 255.000 | 22.000 | 4.000 | 210491.000 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 651.280 | 0.100 | 1.130 | 136.920 | 869.990 | 477.440 | 434.800 | 1054.450 | 832.770 | 121.930 | 4580.810 |
| NUMBER OF SERVICES | 4988.000 | 15.000 | 7.000 | 6061.000 | 29998.000 | 20033.000 | 21936.000 | 65617.000 | 50888.000 | 10948.000 | 210491.000 |

| PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR | | | | |
|---|---|---|---|---|
| CAUSE OF LEAK | MAINS | | SERVICES | |
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 15 | 3 | 5 | 0 |
| NATURAL FORCES | 0 | 0 | 0 | 0 |
| EXCAVATION DAMAGE | 18 | 9 | 53 | 27 |
| OTHER OUTSIDE FORCE DAMAGE | 0 | 0 | 1 | 3 |
| MATERIAL OR WELDS | 6 | 0 | 8 | 3 |
| EQUIPMENT | 6 | 1 | 8 | 2 |
| INCORRECT OPERATIONS | 0 | 0 | 0 | 0 |
| OTHER | 6 | 1 | 11 | 2 |

**NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 69**

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 139

NUMBER OF EXCAVATION TICKETS : 40778

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1810

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 11309

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: 0%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

| | |
|---|---|
| Tina Beach,agent<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |

U.S Department of Transportation
Pipeline and Hazardous Materials Safety Administration

| | |
|---|---|
| **Form Type:** | INITIAL |
| **Date Submitted:** | 04/10/2013 |
| **(DOT use only)** | 20131407-18837 |

## ANNUAL REPORT FOR CALENDAR YEAR 2012 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

### PART A - OPERATOR INFORMATION

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge |
| 2b. City | Kennewick |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | OR |

### PART B - SYSTEM DESCRIPTION

**1.GENERAL**

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | DUCTILE IRON | COPPER | CAST/ WROUGHT IRON | PLASTIC | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 814.000 | 0.000 | 0.000 | 0.000 | 670.000 | 0.000 | 1484.000 |
| NO. OF SERVICES | 0 | 0 | 0 | 30121 | 0 | 0 | 0 | 35828 | 0 | 65949 |

**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2' OR LESS | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' THRU 12' | OVER 12' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 558.000 | 158.000 | 92.000 | 6.000 | 0.000 | 814.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 575.000 | 89.000 | 6.000 | 0.000 | 0.000 | 670.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 1133.000 | 247.000 | 98.000 | 6.000 | 0.000 | 1484.000 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** **AVERAGE SERVICE LENGTH: 72**

| MATERIAL | UNKNOWN | 1' OR LESS | OVER 1' THRU 2' | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0 | 28770 | 1319 | 29 | 3 | 0 | 30121 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 0 | 35132 | 612 | 83 | 1 | 0 | 35828 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 0 | 63902 | 1931 | 112 | 4 | 0 | 65949 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 62.000 | 320.000 | 134.000 | 168.000 | 367.000 | 424.000 | 9.000 | 1484.000 |
| NUMBER OF SERVICES | 0 | 0 | 0 | 0 | 9652 | 6513 | 5119 | 18378 | 23857 | 2430 | 65949 |

| PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR | | | | |
|---|---|---|---|---|
| CAUSE OF LEAK | MAINS | | SERVICES | |
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 3 | 1 | 4 | 2 |
| NATURAL FORCES | 0 | 0 | 1 | 1 |
| EXCAVATION DAMAGE | 13 | 8 | 39 | 39 |
| OTHER OUTSIDE FORCE DAMAGE | 3 | 3 | 3 | 2 |
| MATERIAL OR WELDS | 7 | 2 | 14 | 5 |
| EQUIPMENT | 5 | 0 | 4 | 0 |
| INCORRECT OPERATIONS | 0 | 0 | 1 | 0 |
| OTHER | 4 | 1 | 17 | 11 |

**NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR** : 47

| PART D - EXCAVATION DAMAGE | PART E-EXCESS FLOW VALUE(EFV) DATA |
|---|---|
| NUMBER OF EXCAVATION DAMAGES: 50 | NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 621 |
| NUMBER OF EXCAVATION TICKETS : 12463 | ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 2583 |

| PART F - LEAKS ON FEDERAL LAND | PART G-PERCENT OF UNACCOUNTED FOR GAS |
|---|---|
| TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0 | UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.<br>INPUT FOR YEAR ENDING 6/30: 0% |

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

| | |
|---|---|
| Tina Beach,agent<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |

| | | |
|---|---|---|
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Form Type:** | INITIAL |
| | **Date Submitted:** | 04/10/2013 |
| | **(DOT use only)** | 20131406-18836 |

## ANNUAL REPORT FOR CALENDAR YEAR 2012 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

### PART A - OPERATOR INFORMATION

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge |
| 2b. City | Kennewick |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. GRANDRIDGE BLVD |
| 4b. City | KENNEWICK |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |

### PART B - SYSTEM DESCRIPTION

**1.GENERAL**

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | DUCTILE IRON | COPPER | CAST/ WROUGHT IRON | PLASTIC | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 2772.000 | 0.000 | 0.000 | 0.000 | 1594.000 | 0.000 | 4366.000 |
| N0. OF SERVICES | 0 | 0 | 0 | 114944 | 0 | 0 | 0 | 95358 | 0 | 210302 |

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**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2' OR LESS | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' THRU 12' | OVER 12' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 1887.000 | 482.000 | 316.000 | 42.000 | 45.000 | 2772.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 1315.000 | 265.000 | 14.000 | 0.000 | 0.000 | 1594.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 3202.000 | 747.000 | 330.000 | 42.000 | 45.000 | 4366.000 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** — **AVERAGE SERVICE LENGTH: 75**

| MATERIAL | UNKNOWN | 1' OR LESS | OVER 1' THRU 2' | OVER 2' THRU 4' | OVER 4' THRU 8' | OVER 8' | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0 | 111094 | 3679 | 159 | 12 | 0 | 114944 |
| DUCTILE IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| COPPER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CAST/WROUGHT IRON | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PVC | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC PE | 0 | 94640 | 693 | 25 | 0 | 0 | 95358 |
| PLASTIC ABS | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PLASTIC OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OTHER | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL | 0 | 205734 | 4372 | 184 | 12 | 0 | 210302 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 423.000 | 993.000 | 579.000 | 418.000 | 1040.000 | 827.000 | 86.000 | 4366.000 |
| NUMBER OF SERVICES | 0 | 0 | 0 | 1723 | 31955 | 24926 | 20600 | 61736 | 60158 | 9204 | 210302 |

| PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR | | | | |
|---|---|---|---|---|
| CAUSE OF LEAK | MAINS | | SERVICES | |
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 10 | 0 | 18 | 3 |
| NATURAL FORCES | 1 | 0 | 2 | 1 |
| EXCAVATION DAMAGE | 22 | 11 | 75 | 37 |
| OTHER OUTSIDE FORCE DAMAGE | 3 | 0 | 25 | 14 |
| MATERIAL OR WELDS | 7 | 1 | 10 | 0 |
| EQUIPMENT | 3 | 0 | 17 | 1 |
| INCORRECT OPERATIONS | 0 | 0 | 0 | 0 |
| OTHER | 3 | 1 | 5 | 0 |

**NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 92**

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 157

NUMBER OF EXCAVATION TICKETS : 41958

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 1639

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 9062

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: 0%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

| | |
|---|---|
| Tina Beach,agent<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |

| | | |
|---|---|---|
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Form Type:** | INITIAL |
| | **ID:** | 11746 |
| | **(DOT use only)** | 20120666-15717 |

# ANNUAL REPORT FOR CALENDAR YEAR 2011 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

## PART A - OPERATOR INFORMATION

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge Blvd |
| 2b. City and County | Kennewick,Benton |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. Grandridge Blvd |
| 4b. City and County | Kennewick,Benton |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | OR |

## PART B - SYSTEM DESCRIPTION

**1.GENERAL**

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 814.980 | 667.250 | 0.000 | 0.000 | 0.000 | 0.000 | 1482.230 |
| N0. OF SERVICES | 0.000 | 0.000 | 0.000 | 30243.000 | 35353.000 | 0.000 | 0.000 | 0.000 | 0.000 | 65596.000 |

CASCADE NATURAL GAS CORPORATION
GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve®
INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc.
MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

## 2.MILES OF MAINS IN SYSTEM AT END OF YEAR

| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 558.580 | 158.350 | 92.010 | 6.040 | 0.000 | 814.980 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 573.730 | 88.190 | 5.330 | 0.000 | 0.000 | 667.250 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 1132.310 | 246.540 | 97.340 | 6.040 | 0.000 | 1482.230 |

## 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR

**AVERAGE SERVICE LENGTH: 72**

| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 28884.000 | 1327.000 | 29.000 | 3.000 | 0.000 | 30243.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 34670.000 | 600.000 | 83.000 | 0.000 | 0.000 | 35353.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 63554.000 | 1927.000 | 112.000 | 3.000 | 0.000 | 65596.000 |

## 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 62.410 | 320.520 | 134.110 | 168.120 | 367.440 | 423.560 | 6.070 | 1482.230 |
| NUMBER OF SERVICES | 0.000 | 0.000 | 0.000 | 0.000 | 9765.000 | 6520.000 | 5125.000 | 18388.000 | 23857.000 | 1941.000 | 65596.000 |

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**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 0 | 0 | ~~0~~ 3 | 0 |
| NATURAL FORCES | 0 | 0 | 0 | 0 |
| EXCAVATION DAMAGE | ~~0~~ 7 | 0 | ~~12~~ 13 | 0 |
| OTHER OUTSIDE FORCE DAMAGE | 0 | 0 | ~~0~~ 3 | 0 |
| MATERIAL OR WELDS | ~~0~~ 6 | 0 | ~~0~~ 12 | 0 |
| EQUIPMENT | ~~0~~ 2 | 0 | ~~0~~ 1 | 0 |
| INCORRECT OPERATIONS | 0 | 0 | ~~30~~ 0 | 0 |
| OTHER | ~~0~~ 15 | 0 | ~~14~~ 26 | 0 |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 8

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 65

NUMBER OF EXCAVATION TICKETS : 11144

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 571

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 2547

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .34%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

| | |
|---|---|
| Tina Beach,Manager of Standards and Compl<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (Area Code and Facsimile Number) |

3-20-2017 replaced 2011 OR report with revised report found on Sharepoint.

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| | | |
|---|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | **Form Type:** | INITIAL |
| | **ID:** | 11642 |
| | **(DOT use only)** | 20120667-15718 |

# ANNUAL REPORT FOR CALENDAR YEAR 2011 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

## PART A - OPERATOR INFORMATION

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge Blvd. |
| 2b. City and County | Kennewick,Benton |
| 2c. State | WA |
| 2d. Zip Code | 99336-7166 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. Grandridge Blvd |
| 4b. City and County | Kennewick,Benton |
| 4c. State | WA |
| 4d. Zip Code | 99336-7166 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |

## PART B - SYSTEM DESCRIPTION

### 1.GENERAL

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 9.000 | 2774.530 | 1574.800 | 0.000 | 0.000 | 0.000 | 0.000 | 4358.330 |
| N0. OF SERVICES | 0.000 | 0.000 | 0.000 | 115553.000 | 90298.000 | 0.000 | 0.000 | 0.000 | 0.000 | 205851.00 0 |

Cascade Natural Gas Corporation | Great Plains Natural Gas Co. A Division of MDU Resources Group, Inc. In the Community to Serve® | Intermountain Gas Company A Subsidiary of MDU Resources Group, Inc. | Montana-Dakota Utilities Co. A Division of MDU Resources Group, Inc. In the Community to Serve®

## 2.MILES OF MAINS IN SYSTEM AT END OF YEAR

| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 9.000 | 1886.350 | 482.840 | 317.320 | 43.400 | 44.620 | 2783.530 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 1301.580 | 259.900 | 13.320 | 0.000 | 0.000 | 1574.800 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 9.000 | 3187.930 | 742.740 | 330.640 | 43.400 | 44.620 | 4358.330 |

## 3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR

AVERAGE SERVICE LENGTH: 75

| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 111559.000 | 3693.000 | 289.000 | 12.000 | 0.000 | 115553.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 89647.000 | 626.000 | 25.000 | 0.000 | 0.000 | 90298.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 201206.000 | 4319.000 | 314.000 | 12.000 | 0.000 | 205851.000 |

## 4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 9.000 | 0.000 | 0.000 | 424.300 | 998.230 | 578.710 | 418.640 | 1040.430 | 827.490 | 61.530 | 4358.330 |
| NUMBER OF SERVICES | 0.000 | 0.000 | 0.000 | 1729.000 | 32412.000 | 24944.000 | 19747.000 | 61307.000 | 60162.000 | 5550.000 | 205851.000 |

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**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 2 | 0 | 6 | 0 |
| NATURAL FORCES | 0 | 0 | 0 | 0 |
| EXCAVATION DAMAGE | 14 | 0 | 24 | 0 |
| OTHER OUTSIDE FORCE DAMAGE | 0 | 0 | 8 | 0 |
| MATERIAL OR WELDS | 6 | 0 | 6 | 0 |
| EQUIPMENT | 0 | 0 | 2 | 0 |
| INCORRECT OPERATIONS | 0 | 0 | 0 | 0 |
| OTHER | 14 | 0 | 18 | 0 |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 65

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 161

NUMBER OF EXCAVATION TICKETS : 41953

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 750

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 6922

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .06%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

Tina Beach,Manager of Standards and Compl
(Preparer's Name and Title)

(509) 734-4576
(Area Code and Telephone Number)

tina.beach@cngc.com
(Preparer's email address)

(Area Code and Facsimile Number)

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

| | |
|---|---|
| NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122. | OMB NO: 2137-0522<br>EXPIRATION DATE: 01/31/2014 |

| | | |
|---|---|---|
| U.S Department of Transportation<br>Pipeline and Hazardous Materials Safety Administration | Form Type: | ORIGINAL |
| | ID: | 3615 |
| | (DOT use only) | 20111195-16297 |

# ANNUAL REPORT FOR CALENDAR YEAR 2010 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

## PART A - OPERATOR INFORMATION

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge Blvd |
| 2b. City and County | Kennewick,Benton |
| 2c. State | WA |
| 2d. Zip Code | 99336 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. Grandridge Blvd |
| 4b. City and County | Kennewick,Benton |
| 4c. State | WA |
| 4d. Zip Code | 99336 |
| 5. STATE IN WHICH SYSTEM OPERATES | OR |

## PART B - SYSTEM DESCRIPTION

1.GENERAL

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 823.510 | 665.210 | 0.000 | 0.000 | 0.000 | 0.000 | 1488.720 |
| NO. OF SERVICES | 0.000 | 0.000 | 0.000 | 30337.000 | 34215.000 | 0.000 | 0.000 | 0.000 | 0.000 | 64552.000 |

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**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 558.580 | 158.440 | 106.490 | 0.000 | 0.000 | 823.510 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 571.870 | 88.010 | 5.330 | 0.000 | 0.000 | 665.210 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 1130.450 | 246.450 | 111.820 | 0.000 | 0.000 | 1488.720 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** — **AVERAGE SERVICE LENGTH: 72**

| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 28968.000 | 1337.000 | 29.000 | 3.000 | 0.000 | 30337.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 33618.000 | 576.000 | 21.000 | 0.000 | 0.000 | 34215.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 62586.000 | 1913.000 | 50.000 | 3.000 | 0.000 | 64552.000 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 62.430 | 320.750 | 134.110 | 183.200 | 372.590 | 412.620 | 3.020 | 1488.720 |
| NUMBER OF SERVICES | 0.000 | 0.000 | 0.000 | 0.000 | 9849.000 | 6527.000 | 5130.000 | 18395.000 | 23857.000 | 794.000 | 64552.000 |

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve

**PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR**

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 5 | | 12 | |
| NATURAL FORCES | 0 | | 1 | |
| EXCAVATION DAMAGE | 8 | | 17 | |
| OTHER OUTSIDE FORCE DAMAGE | 0 | | 8 | |
| MATERIAL OR WELDS | 24 | | 21 | |
| EQUIPMENT | 0 | | 0 | |
| INCORRECT OPERATIONS | 0 | | 0 | |
| OTHER | 2 | | 3 | |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 5

**PART D - EXCAVATION DAMAGE**

NUMBER OF EXCAVATION DAMAGES: 49

NUMBER OF EXCAVATION TICKETS : 9268

**PART E-EXCESS FLOW VALUE(EFV) DATA**

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 776

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 1976

**PART F - LEAKS ON FEDERAL LAND**

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

**PART G-PERCENT OF UNACCOUNTED FOR GAS**

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .34%

**PART H - ADDITIONAL INFORMATION**

**PART I - PREPARER AND AUTHORIZED SIGNATURE**

| | |
|---|---|
| Tina Beach,Manager of Standards and Comp<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (509) 737-9803<br>(Area Code and Facsimile Number) |

CASCADE NATURAL GAS CORPORATION | GREAT PLAINS NATURAL GAS CO. A Division of MDU Resources Group, Inc. In the Community to Serve® | INTERMOUNTAIN GAS COMPANY A Subsidiary of MDU Resources Group, Inc. | MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc. In the Community to Serve®

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OMB NO: 2137-0522
EXPIRATION DATE: 01/31/2014

U.S Department of Transportation
Pipeline and Hazardous Materials Safety Administration

| | |
|---|---|
| Form Type: | ORIGINAL |
| ID: | 3572 |
| (DOT use only) | 20111180-16296 |

## ANNUAL REPORT FOR CALENDAR YEAR 2010 GAS DISTRIBUTION SYSTEM

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0522. Public reporting for this collection of information is estimated to be approximately 16 hours per response, including the time for reviewing instructions, gathering the data needed, and completing and reviewing the collection of information. All responses to this collection of information are mandatory. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

### PART A - OPERATOR INFORMATION

| | |
|---|---|
| 1. Name of Operator | CASCADE NATURAL GAS CORP |
| 2. LOCATION OF OFFICE (WHERE ADDITIONAL INFORMATION MAY BE OBTAINED) | |
| 2a. Street Address | 8113 W. Grandridge Blvd. |
| 2b. City and County | Kennewick,Benton |
| 2c. State | WA |
| 2d. Zip Code | 99336-7166 |
| 3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER | 2128 |
| 4. HEADQUARTERS NAME & ADDRESS | |
| 4a. Street Address | 8113 W. Grandridge Blvd |
| 4b. City and County | Kennewick,Benton |
| 4c. State | WA |
| 4d. Zip Code | 99336-7166 |
| 5. STATE IN WHICH SYSTEM OPERATES | WA |

### PART B - SYSTEM DESCRIPTION

1.GENERAL

| | STEEL | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | UNPROTECTED | | CATHODICALLY PROTECTED | | | | | | | |
| | BARE | COATED | BARE | COATED | PLASTIC | CAST/ WROUGHT IRON | DUCTILE IRON | COPPER | OTHER | TOTAL |
| MILES OF MAIN | 0.000 | 0.000 | 9.000 | 2743.690 | 1547.960 | 0.000 | 0.000 | 0.000 | 0.000 | 4300.650 |
| NO. OF SERVICES | 0.000 | 0.000 | 0.000 | 115798.000 | 89090.000 | 0.000 | 0.000 | 0.000 | 0.000 | 204888.00 0 |

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**2.MILES OF MAINS IN SYSTEM AT END OF YEAR**

| MATERIAL | UNKNOWN | 2" OR LESS | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" THRU 12" | OVER 12" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 9.000 | 1887.120 | 469.670 | 300.160 | 42.120 | 44.620 | 2752.690 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 1278.080 | 256.560 | 13.320 | 0.000 | 0.000 | 1547.960 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 9.000 | 3165.200 | 726.230 | 313.480 | 42.120 | 44.620 | 4300.650 |

**3.NUMBER OF SERVICES IN SYSTEM AT END OF YEAR** | **AVERAGE SERVICE LENGTH: 75**

| MATERIAL | UNKNOWN | 1" OR LESS | OVER 1" THRU 2" | OVER 2" THRU 4" | OVER 4" THRU 8" | OVER 8" | TOTAL |
|---|---|---|---|---|---|---|---|
| STEEL | 0.000 | 111903.000 | 3721.000 | 162.000 | 12.000 | 0.000 | 115798.000 |
| DUCTILE IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| COPPER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| CAST/WROUGHT IRON | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PVC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| PLASTIC PE | 0.000 | 88482.000 | 584.000 | 24.000 | 0.000 | 0.000 | 89090.000 |
| PLASTIC ABS | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER PLASTIC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| OTHER | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| TOTAL | 0.000 | 200385.000 | 4305.000 | 186.000 | 12.000 | 0.000 | 204888.000 |

**4.MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION**

| | UNKNOWN | PRE-1940 | 1940-1949 | 1950-1959 | 1960-1969 | 1970-1979 | 1980-1989 | 1990-1999 | 2000-2009 | 2010-2019 | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|
| MILES OF MAIN | 0.000 | 0.000 | 0.000 | 403.000 | 1059.000 | 566.000 | 413.000 | 1024.000 | 828.000 | 7.650 | 4300.650 |
| NUMBER OF SERVICES | 0.000 | 0.000 | 0.000 | 1732.000 | 32744.000 | 24976.000 | 20837.000 | 61920.000 | 60169.000 | 2510.000 | 204888.000 |

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## PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING THE YEAR

| CAUSE OF LEAK | MAINS | | SERVICES | |
|---|---|---|---|---|
| | TOTAL | HAZARDOUS | TOTAL | HAZARDOUS |
| CORROSION | 6 | | 8 | |
| NATURAL FORCES | 0 | | 2 | |
| EXCAVATION DAMAGE | 41 | | 90 | |
| OTHER OUTSIDE FORCE DAMAGE | 2 | | 10 | |
| MATERIAL OR WELDS | 11 | | 17 | |
| EQUIPMENT | 1 | | 1 | |
| INCORRECT OPERATIONS | 1 | | 0 | |
| OTHER | 8 | | 6 | |

NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR : 43

## PART D - EXCAVATION DAMAGE

NUMBER OF EXCAVATION DAMAGES: 108

NUMBER OF EXCAVATION TICKETS : 38267

## PART E-EXCESS FLOW VALUE(EFV) DATA

NUMBER OF EFV'S INSTALLED THIS CALENDER YEAR ON SINGLE FAMILY RESIDENTIAL SERVICES: 2464

ESTIMATED NUMBER OF EFV'S IN SYSTEM AT THE END OF YEAR: 6172

## PART F - LEAKS ON FEDERAL LAND

TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED TO REPAIR: 0

## PART G-PERCENT OF UNACCOUNTED FOR GAS

UNACCOUUNTED FOR GAS AS A PERCENT OF TOTAL INPUT FOR THE 12 MONTHS ENDING JUNE 30 OF THE REPORTING YEAR.

INPUT FOR YEAR ENDING 6/30: .08%

## PART H - ADDITIONAL INFORMATION

## PART I - PREPARER AND AUTHORIZED SIGNATURE

| | |
|---|---|
| Tina Beach,Manager of Standards and Compl<br>(Preparer's Name and Title) | (509) 734-4576<br>(Area Code and Telephone Number) |
| tina.beach@cngc.com<br>(Preparer's email address) | (509) 737-9803<br>(Area Code and Facsimile Number) |

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Ryan Privratsky and Michael P. Parvinen

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# Depreciation Expense on 2018 Retirements
# Exhibit CNGC/903

**October 2018**

# Cascade Natural Gas Corporation
# Depreciation Expense on 2018 Retirements

## State Of Oregon

| | FERC Account | 2015 | 2016 | 2017 | Total | Average |
|---|---|---|---|---|---|---|
| 1 | 874 | 1,073,812.37 | 1,113,616.31 | 1,223,950.10 | | |
| 2 | Deferral | | | 507,240.93 | | |
| 3 | Total | 1,073,812.37 | 1,113,616.31 | 1,731,191.03 | 3,918,619.71 | 1,306,206.57 |
| 4 | Adjustment | | | | | 82,256.47 |
| 5 | Company Original proposed Adj | | | | | 116,724.36 |
| 6 | Change from Test Year | | | | | **($34,467.89)** |

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Stephanie Barth and Michael P. Parvinen

# EXHIBIT 1000
# (REDACTED)

October 2018

**EXHIBIT 1000 – REPLY TESTIMONY**

TABLE OF CONTENTS

## I. INTRODUCTION

**Q. Please state your names.**

A. Our names are Michael P. Parvinen and Stephanie Barth.

**Q. Ms. Barth, please state your title and business address, and summarize your education and professional experience.**

A. I am the Vice President, Chief Accounting Officer and Controller for MDU Resources Group, Inc. (MDU Resources). My business address is 1200 West Century Avenue, Bismarck, North Dakota 58503. I hold a bachelor of accountancy degree from the University of North Dakota and am a registered CPA in the state of North Dakota. I have worked at MDU Resources Group, Inc. or one if its subsidiaries for the past 22 years, holding positions of increasing responsibility over those years. I am currently the Vice President, Chief Accounting Officer and Controller of MDU Resources Group.

**Q. Mr. Parvinen, have you previously filed testimony in this case?**

A. Yes. I filed Direct Testimony in this case, CNGC/200, on May 31, 2018. In addition, contemporaneous with this testimony, I am also filing additional response testimony, CNGC/800 and CNGC/900.

**Q. Why are you jointly sponsoring this testimony?**

A. We are jointly sponsoring this testimony because the questions raised by the parties regarding the income taxes included in this case implicate both ratemaking policy, which is Mr. Parvinen's area of expertise, and tax law and policy, which is within Ms. Barth's area of expertise. We decided to file this testimony jointly to avoid splitting up the discussion of taxes between two pieces of testimony.

## II. SCOPE AND SUMMARY OF TESTIMONY

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

A. The purpose of our testimony is to respond to the tax-related issues raised in the response testimony of Public Utility Commission of Oregon Staff (Staff) witness John Fox,[1] Oregon Citizens' Utility Board (CUB) witness William Gehrke,[2] and Alliance of Western Energy Consumers (AWEC) witness Bradley Mullins.[3]

**Q. Please summarize your testimony.**

A. Our testimony summarizes the way in which Cascade Natural Gas Company (Cascade or Company) reflected the impact of the Tax Cuts and Jobs Act (TCJA) in this case, and responds to certain adjustments to that treatment proposed by the parties. In particular, our testimony supports the Company's proposals to (a) pass back to customers non-plant related excess deferred income taxes (EDIT) resulting from the new tax law over a ten year amortization period; (b) calculate plant-related EDIT using the average rate assumption methodology (ARAM) consistent with its filing; and (c) consider the tax benefits of the TCJA received from January 1, 2018 until the rate effective date in this case (Interim Period Benefit) in the Company's normal earnings review. In addition, our testimony addresses AWEC's concerns about actual taxes paid by Cascade's parent, MDU Resources, and supports the Company's use of an Oregon-specific state income tax rate to calculate Oregon customers' rates. Finally, our testimony proposes to accept an adjustment proposed by CUB regarding the Oregon state income tax rate.

## III. TAX CUTS AND JOBS ACT

**Q. Please explain how Cascade reflected the impact of the TCJA in this case.**

A. The Company included the four components of TCJA impacts in this case:

[1] Staff/200.
[2] CUB/100.
[3] AWEC/100.

- First, the Company made an adjustment to Base Year expense to reflect the new corporate tax rate, converting the federal income tax expense from 35 percent to the new rate of 21 percent.[4]
- Second, the Company calculated and included in the revenue requirement a return of EDIT resulting from the tax change.[5] Plant-related EDIT is calculated using ARAM. The Company proposes to return non-plant EDIT over a ten-year amortization period.[6]
- Third, the Company made an adjustment to the relevant conversion factors for individual costs to reflect the 21 percent tax rate.[7]
- Finally, the Company proposed a treatment for the tax benefits realized by the Company during the Interim Period, which are currently being deferred pursuant to the Company's petition filed in UM 1927.[8] Specifically, the Company proposed to include the deferred balance in the annual earnings review, so that any benefits in excess of the Company's authorized return on equity would be passed back to Cascade's customers consistent with the application of that mechanism.[9]

**Adjustment to Base Year Expense for New Tax Rates**

**Q. Do any parties take issue with the Company's adjustment to reflect the current 21 percent tax rate into test year rates?**

[4] CNGC/200, Parvinen/11.
[5] CNGC/200, Parvinen/11.
[6] CNGC/200, Parvinen/11.
[7] CNGC/200, Parvinen/11.
[8] CNGC/200, Parvinen/12.
[9] CNGC/200, Parvinen/13.

A. No. Staff specifically states that it is not proposing to modify the Company's reduction of base year taxes from 35 percent to 21 percent.[10] Neither CUB or AWEC propose an adjustment.

**Calculation of EDIT**

**Q. Please summarize the Company's approach to adjusting EDIT to reflect the impact of the TCJA.**

A. As discussed in Mr. Parvinen's Direct Testimony, EDIT results from the implementation of the new federal tax rate in the TCJA to the underlying booked tax differences that produce deferred taxes.[11] The EDIT is comprised of two components: plant and non-plant.[12] Plant-related EDIT is "protected" and must be calculated and passed back to customers using specified methodologies, and in Cascade's case, the required methodology is ARAM.[13] For the non-plant EDIT, the Company is not required to pass back the benefit to customers over a specific time period, however, the Company is proposing a ten-year amortization, to reflect the characteristics of the items giving rise to the EDIT.[14]

**Non-Plant Related EDIT**

**Q. What is the amount for non-plant EDIT the Company proposes to pass back to customers on an annual basis, using the proposed ten-year amortization?**

A. The Company proposes to pass back to customers an annual amount of $177,710, over ten years.[15]

**Q. Why did the Company propose to pass back the non-plant EDIT to customers over ten years?**

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[10] Staff/200, Fox/7.
[11] CNGC/200, Parvinen/13.
[12] CNGC/200, Parvinen/12.
[13] CNGC/200, Parvinen/12.
[14] CNGC/200, Parvinen/13.
[15] CNGC/203, Parvinen/1.

A. The primary reason was an attempt to match the amortization with the deferral period on the underlying items being taxed—which averages approximately ten years. This was also the amortization period adopted by the Washington Commission for the non-plant EDIT.[16]

**Q. Do any parties disagree with this approach?**

A. Yes. Staff proposes that non-plant related EDIT be amortized and returned to customers over five years instead of ten years.[17] This would reduce tax expense by an additional ($177,710).[18] AWEC proposes that the non-plant related EDIT be amortized and passed back to customers over a two-year period.[19] This proposal would decrease tax expense by ($710,840).

**Q. What reasons does Staff give for recommending a five-year amortization?**

A. Staff provides two reasons. First, Staff explains why it would not be appropriate to order Cascade to immediately refund the entire amount.[20] Staff explains that requiring an immediate refund would be unduly harsh—negating a large portion of the requested rate increase and causing cash-flow problems.[21] However, Staff reasons that the Company should be able to absorb an increased refund of $177,710 "fairly easily."[22] Staff also points out that the Company has requested a Safety Cost Recovery Mechanism (SCRM) in this case and, if granted, Cascade is likely to come in for rate cases less frequently—meaning that the Commission will not have the opportunity to

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16 *Wash. Utils. and Transp. Comm'n v. Cascade Nat. Gas Corp.*, Docket UG-170929, Order 06 at ¶ 54 (Jul. 20, 2018).
17 Staff/200, Fox/9.
18 Staff/200, Fox/9.
19 AWEC/100, Mullins/18.
20 Staff/200, Fox/10.
21 Staff/200, Fox/10.
22 Staff/200, Fox/10.

reset the amount of the amortization for some time.[23] Staff concludes that therefore it benefits customers to accelerate the return of the tax benefit.[24]

**Q. What reason does Mr. Mullins given for his recommendation?**

A. Mr. Mullins argues that it is appropriate to return the EDIT benefit to customers over Cascade's "typical general rate case cycle."[25] Mr. Mullins also points out that PGE agreed to pass back non-plant related EDIT in two years.[26]

**Q. Do you agree with Staff's or AWEC's reasoning?**

A. In part. We certainly agree with Staff's view that it would be unreasonable to require the Company to return the EDIT to customers immediately, because to do so could create a cash flow problem for Cascade. However, we do not agree with the other arguments offered by these parties. First, neither Staff or AWEC even attempt to address or refute the inherent reasonableness of passing back the excess deferred taxes over the same time period as the deferred tax giving rise to the EDIT. Moreover, we believe that concerns about the timing of rate cases suggests that a longer amortization period is appropriate, not a shorter one.

**Q. Please explain.**

A. If the Company does not time the effective date of a future rate case to exactly match the end of the amortization period, the Company will either over- or under-refund the balance. However, if the Commission accepts the Company's proposal to use a ten-year amortization period, the amount in rates is smaller, and the consequences of an over- or under-refund will be relatively less significant.

**Q. Is there another approach that could be used to mitigate this concern regarding rate case timing?**

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[23] Staff/200, Fox/10.
[24] Staff/200, Fox/10.
[25] AWEC/100, Mullins/26.
[26] AWEC/100, Mullins/26.

A. Yes. The amount can be treated as a separate tariff, refunding the specific amount until a specific date rather than including the amount in base rates.

**Q. What do you conclude about the appropriate amortization of non-plant EDIT?**

A. We conclude that the Company's proposal to pass back the non-plant deferred tax benefit over 10 years is reasonable, supportable, and should be accepted.

**Q. Please explain why the Company used the ARAM approach to calculating plant-related EDIT.**

A. Cascade used the ARAM methodology as is required under the TCJA. That law requires that utilities normalize plant-related EDIT, and refund to customers at the same rate at which the book and tax temporary differences reverse over the remaining life of the plant giving rise to the EDIT or else face a tax penalty.[27] Any utility that has sufficient asset vintage records to perform the calculation using the ARAM approach is required to do so. Cascade does possess the required vintage records and therefore used ARAM.

**Q. What positions do the parties take regarding the Company's calculation of plant-related EDIT, using the ARAM methodology?**

A. Staff supports the Company's use of the ARAM methodology to calculate plant-related EDIT, and also considers both the percentage rate of return and method to allocate Oregon benefits to be reasonable.[28] However, AWEC disagrees with the Company's approach.[29]

**Q. Please summarize AWEC's argument regarding the Company's calculation of plant-related EDIT.**

[27] 3 Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, § 1561(d), 131 Stat. 2054, 2099 (2017).
[28] Staff/200, Fox/8-9.
[29] AWEC/100, Mullins/21-22.

A. Mr. Mullins makes two primary criticisms of the Company's calculation of plant-related EDIT—which he refers to as excess deferred federal income tax, or EDFIT. First, Mr. Mullins claims that Cascade has not provided the data necessary to support its ARAM calculation.[30] And second, Mr. Mullins argues that the Company should not use the ARAM method at all to calculate EDIT and instead should use the Reverse South Georgia Method (RSGM)—which Mr. Mullins refers to as the Alternative Method.[31]

**Q. Please respond to Mr. Mullins' argument that the Company has not provided the data necessary to support its ARAM calculation.**

A. This argument is without merit. First, AWEC has not requested any data on this topic and provides no basis for its assertion that Cascade does not have the data to support its ARAM calculation. Specifically, Cascade uses the PowerPlan Power Tax Module to calculate its tax basis, tax depreciation, and ARAM amortization of its utility plant assets, consistent with industry practice.

**Q. Please summarize Mr. Mullins' argument that Cascade should calculate plant-related EDIT using the RSGM.**

A. Mr. Mullins claims that the RSGM is preferable because it does not vary from year to year and further that under the ARAM approach it is possible for significant amounts to be lost through the timing of rate cases and varying levels of amortization that occur from year to year.[32] Mr. Mullins also claims that the IRS explicitly allows the RSGM for utilities that use composite depreciation rates.[33]

**Q. Does Mr. Mullins use RSGM to produce his own calculation of Cascade's plant-related EDIT?**

[30] AWEC/100, Mullins/22.
[31] AWEC/100, Mullins/21.
[32] AWEC/100, Mullins/23.
[33] AWEC/100, Mullins/23.

A. Yes. Using a 3.04 percent composite depreciation rate from Cascade's 2015 depreciation study, Mr. Mullins produces annual plant-related EDIT amortization of $282,372.[34]

**Q. What is your response?**

A. Mr. Mullins' recommendation should be rejected. Mr. Mullins' recommendation assumes that Cascade is free to select either the ARAM approach or the RSGM, but this is incorrect. As discussed above, IRS guidance provides that if a utility possesses the vintage data necessary to perform the ARAM method then it is required to use the ARAM method. Because Cascade clearly has the data necessary to prepare the ARAM schedule, the Company must use ARAM. Using a method other than ARAM when the data is available could result in a normalization violation. Most importantly, however, Mr. Mullins' arguments on this point seem to be entirely gratuitous, given that the adjustment would be in the Company's favor.[35]

**Interim Period Tax Savings**

**Q. Please explain the Company's proposal for addressing the benefit received by the Company from the impact of the TCJA, for the Interim Period.**

A. The benefits of the TCJA are currently being tracked by the Company in a deferral account, pursuant to Cascade's application filed in UM 1927.[36] That application will need to be renewed prior to the end of 2018, so that Cascade can continue to track those benefits into 2019. At the end of the Interim Period, Cascade proposes to include those benefits in the Company's normal earnings review, such that benefits

[34] AWEC/100, Mullins/23.
[35] Mr. Mullins' calculation of plant-related EDIT amortization using the RSGM is $282,372, as compared to the $382,556 calculated by Cascade using the ARAM methodology. In other words, if the Commission were to order the Company to use the RSGM, as Mr. Mullins insists is correct, customers would pay more in rates for taxes.
[36] *In the Matter of Cascade Nat. Gas Corp. Application for Deferral of 2018 Net Benefits Associated with the US Tax Cuts and Jobs Act*, Docket No. UM 1927, Application (Dec. 29, 2017).

that cause the Company to earn above its authorized ROE will be returned to customers subject to the sharing mechanism adopted by the Commission.[37]

**Q. How have the parties responded to the Company's proposal?**

A. Staff has generally indicated that it is open to including the Interim Period benefits (Interim Benefit) in rates in this case, in the interest of accelerating the return of the benefits to ratepayers.[38] However, Staff does not make a specific proposal for how the benefit should be calculated, or the time period over which the benefit should be returned.[39] Mr. Mullins, on the other hand, offers a specific methodology for estimating the Interim Benefit and argues that it should be returned to customers through rates adopted in this case over a two-year amortization period.[40]

**Q. Please respond to the general proposal that the Interim Benefit be returned to customers through the rates adopted in this case.**

A. Cascade disagrees with this approach. First, Mr. Mullins's proposal would violate the deferral statute, which requires that an earnings review be performed before deferred amounts can be amortized.[41] Cascade will be unable to determine its earnings for 2018 until approximately April of 2019.[42] So as a practical matter, the correct amount to be returned to customers cannot be determined in this rate case. Moreover, any approach that returns the deferred benefits to customers without regard to the Company's actual earnings would constitute single issue ratemaking, which should be avoided if possible. Cascade's rates were last set in the 2015 rate case, at which time they were judged to be fair and reasonable.[43] During the rate effective period, while

[37] CNGC/200, Parvinen/13.
[38] Staff/200, Fox/7.
[39] Staff/200, Fox/7.
[40] AWEC/100, Mullins/26.
[41] ORS 757.259.
[42] CNGC/200, Parvinen/13.
[43] *In the Matter of Cascade Nat. Gas Corp. Request for a Gen. Rate Revision*, Docket No. UG 305, Order No. 16-477 at 5-6 (Dec. 12, 2016).

the tax rate decreased for 2018, it is also fair to assume that others have increased. Cascade's approach recognizes that this is the case by requiring a refund only if the Interim Benefit causes the Company to earn above its authorized ROE. On the other hand, Mr. Mullins' approach would require the Company to make a refund, even if the net effect of increased costs results in underearning, which could be harmful to the Company.

**Q. What approach does Mr. Mullins recommend for calculating the Interim Period benefit?**

A. Mr. Mullins uses what he calls "the rate base approach" which he claims will determine the amount of revenues necessary to provide the utility with the same return on equity as if the tax rate had not been enacted.[44] Specifically, Mr. Mullins estimates the Interim Benefit by taking Cascade's authorized ROE and calculating the revenue requirement amount based on the rate base.[45]

**Q. Do you agree that Mr. Mullins' approach is valid?**

A. No. Mr. Mullins' approach is flawed because he incorrectly assumes that Cascade has and is earning its full rate of return based on end-of-period, 2017, rate base, which is incorrect. The rate base figure Mr. Mullins uses can be found in Exhibit 301, Row 27, which is the per books results of operation for 2017. Also, as shown in the same exhibit, the actual rate of return earned by the Company for 2017 was only 5.66—not the authorized return of 7.284.

**Q. How do you respond to Mr. Mullins' proposal that the Interim Period benefit be returned to customers over a two-year amortization period?**

A. We disagree with that proposal. As we explained above, Cascade believes that the Interim Benefit should be returned to customers to the extent that it causes the

[44] AWEC/100, Mullins/25-26.
[45] AWEC/100, Mullins/26.

Company to earn above its authorized ROE. Cascade also believes that the Company's Oregon earnings for 2018 are such that over-earning is unlikely. However, if the Commission were to order the return of the interim benefit, it should be done through a separate tariff in order to be able to terminate the refund at the appropriate time and not through base rates where the timing of a new rate case becomes a critical factor.

## IV. OTHER FEDERAL AND STATE TAX ISSUES

**MDU Resources Consolidated Tax Return**

**Q. Please describe Mr. Mullins' concern regarding Cascade's 2015 and 2016 federal income taxes.**

A. Mr. Mullins points out that, in 2015 and 2016, Cascade did not pay any amounts in federal income taxes. In addition, Mr. Mullins notes that Cascade paid [redacted] in state income taxes.[46] Although Mr. Mullins does not propose an adjustment based on these facts, he claims that the situation is "not fair."[47] In particular, he points out that Cascade's customers' rates include amounts for state and federal taxes, and he argues that "if nothing is being remitted to the federal government, then ratepayers are paying something but getting nothing in return."[48]

**Q. Is it correct to say that Cascade [redacted] in 2015 and 2016?**

A. Not precisely. Cascade files its state and federal income tax returns as part of the consolidated group under its corporate parent, MDU Resources. That is, MDU Resources is the taxpaying entity, which is responsible for paying any taxes due on Cascade's behalf. As a result, it is more accurate to say that MDU Resources paid no federal income taxes in those years.

[46] AWEC/100, Mullins/17.
[47] AWEC/100, Mullins/39.
[48] AWEC/100, Mullins/17.

[redacted]

**Q. How is it that Cascade's customers pay rates for utility service that include amounts for state and federal taxes for years when Cascade's corporate parent [redacted] on behalf of Cascade for 2015 and 2016?**

A. This apparent "discrepancy" can occur because the taxes included in Cascade's rates are calculated on a stand-alone basis, whereas the Cascade's parent pays taxes for a consolidated group of subsidiaries.

**Q Please explain.**

A Most public utility commissions, including the Oregon commission, use the traditional "stand-alone" method for calculating the amount of income taxes to be incorporated into a regulated utility's rates. This method calculates taxes based on the regulated revenues and operating costs of the utility itself, without regard to the utility's unregulated activities or the operations of its parent and other affiliated companies. The "stand-alone" calculation is used so that the taxes in utility rates are based on the costs of providing the regulated utility service.

On the other hand, federal and state tax laws require a corporate holding company to file consolidated tax returns reflecting its full span of regulated and unregulated operations. Losses in some corporate operations can offset profits in others for the purpose of determining corporate tax liability. When this occurs, the amount collected for taxes in a utility's rates can exceed the income taxes the corporate parent actually pays to the taxing authorities. [redacted]

[redacted]—losses at one of the affiliate companies offset the profits earned by other companies, including Cascade, in the corporate group.

**Q. Do you agree with Mr. Mullins that this outcome is "unfair" to Cascade's utility customers?**

A. No, we do not. Not only is this result consistent with Oregon, law, it is also consistent with sound public policy considerations. ORS 757.269—which governs the setting of income taxes in utility rates—establishes the standalone method as the state's primary approach. That statute provides as follows:

> [A]mounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.[49]

That statute provides that the Commission may "adjust" the estimated tax expense where the utility pays taxes as part of an affiliated group, based in part on whether the utility's affiliated group has a "history" of paying state or federal income taxes that are less than the taxes calculated on the standalone basis, or any other consideration necessary to protect the public interest.[50] However, as a matter of policy, the Commission has relied solely on the standalone approach.[51]

This approach is consistent with foundational ratemaking principles that protect utility customers from cross-subsidization, including the negative impacts associated with losses at non-regulated affiliates. As explained in Accounting for Public Utilities:

> It is not uncommon for a regulated utility to have subsidiary operations that produce tax losses which, on a consolidated tax return, offset taxable income from utility operations. . . The only approach that is consistent with standard ratemaking principles that prohibit cross subsidization between utility and non-utility activities is to put the regulated operations on a 'stand-alone' basis

[49] ORS 757.269(1).
[50] ORS 757.269(3).
[51] Note that an exemption to this policy applied between 2005-2011, after the Oregon legislature passed SB 408; that statute required an "actual taxes paid" approach to utility ratemaking. *See* former OAR 860-022-0041(8)(a) (implementing SB 408). That law was repealed in 2011.

> and to assign the full tax burden to the taxable gain source and a tax benefit to the tax loss source. The basic theory is that the regulated costs should not be affected by the results from the non-regulated operations.[52]

**Q Does Mr. Mullins suggest that the Company should depart from its general policy of calculating utility taxes on a stand-alone basis?**

A No. Indeed, it is not clear as to why Mr. Mullins is raising the issue, other than possibly encouraging the Commission to resolve any other disagreements regarding taxes in AWEC's favor. However, given the sound reasons for using the stand-alone methodology, AWEC's concerns are not well-taken.

**Oregon State Income Taxes**

**Q. What precisely is Mr. Mullins' concern with the effective tax rate used by the Company to calculate Oregon state income taxes?**

A. Mr. Mullins points out that Cascade uses an effective state tax rate of 7.4 percent to calculate the effects of state taxes on the revenue requirement, but that the effective state tax rate that Cascade uses in preparing its audited financial statements was just 1.8049 percent (before considering the effects of the federal benefit associated with the state tax deduction).[53] Mr. Mullins recommends that the state taxes in the revenue requirement should be based on the actual effective state tax rate Cascade uses for financial accounting purposes.[54]

**Q. Is Mr. Mullins correct that Cascade used a 7.4 percent tax rate to calculate state taxes in Oregon, when its effective rate for the entire company is approximately 1.8 percent?**

A. Yes.

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[52] *Accounting for Public Utilities*, Matthew Bender & Company, Section 7.08[3] (Oct. 2017).
[53] AWEC/100, Mullins/18.
[54] AWEC/100, Mullins/19.

**Q. Why is it appropriate then for the rates paid by Oregon customers to reflect a state tax rate that is higher than the effective tax rate?**

A. Since Cascade operates in both the states of Washington and Oregon, the effective state rate that it uses for financial reporting purposes becomes a blended rate of the two states in which it operates, based on the apportionment of each state. However, as a matter of ratemaking, the taxes imposed by Oregon are included in Oregon customer rates, while the taxes imposed by Washington are included in Washington customer rates. Importantly, Washington has no state income tax while Cascade's corporate rate for Oregon income taxes is 7.6 percent. Given that Washington accounts for approximately three quarters of Cascade's revenues,[55] Cascade's effective state income tax rate is quite low. But nevertheless, it is appropriate for Oregon customers to bear the full amount of the Oregon state tax rate.

**Q. Have you prepared a figure that helps illustrate the apportionment of Cascade's state income taxes for Washington and Oregon?**

A. Yes, that table is included as Exhibit 1001.

**Q. Please explain the adjustment for Oregon state taxes proposed by CUB.**

A. As explained above, in Cascade's initial filing, the Company assumed an Oregon corporate income tax rate of 7.6 percent. However, CUB has pointed out that the state of Oregon imposes a 6.6 percent corporate income tax on the first $1 million of income related to Oregon sales, and a 7.6 percent tax rate for income above $1 million.[56] For this reason, CUB proposes an adjustment of $10,000—which represents 1 percent of 1,000,000.[57]

**Q. Do you agree with CUB's adjustment?**

[55] Washington revenues account for approximately 76 percent of Cascade's total revenues, with Oregon accounting for the remaining 24 percent.
[56] CUB/100, Gehrke/6.
[57] CUB/100, Gehrke/7.

A. Yes. Cascade agrees that, for ratemaking purposes, Oregon customers should receive the benefit of the 6.6 percent tax rate for the first $1 million of income related to Oregon sales.

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

A. Yes.

CNGC/1001
Barth-Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Stephanie Barth and Michael Parvinen

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**Confidential State Income Taxes**
**Exhibit CNGC/1001**

**REDACTED**

**October 2018**

THIS DOCUMENT CONTAINS PROTECTED INFORMATION.

ALL QUALIFIED PERSONS AS DEFINED IN

ORDER 18-172 WILL RECEIVE THE DOCUMENT VIA U.S. MAIL.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Linda L. Murray

# EXHIBIT 1100

October 2018

# EXHIBIT 1100 – REPLY TESTIMONY

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# I. INTRODUCTION

**Q. Would you please state your name and business address?**

A. Yes, my name is Linda L. Murray. My business address is 8113 Grandridge Blvd., Kennewick, WA 99336.

**Q. What is your position with MDU Resources Group, Inc.?**

A. I am the Director of Human Resources.

**Q. What are your duties and responsibilities?**

A. I am responsible for the strategic direction and administration of all disciplines in the Human Resources (HR) department for Cascade Natural Gas Corporation (Cascade or Company) and Intermountain Gas Company (Intermountain) including compensation and benefits, talent acquisition and development, labor and employee relations, and governmental compliance involving employment and employee relations for Cascade and Intermountain.

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

A. I have worked in the Human Resources field for more than 30 years. For the past 10 years, I have been employed by MDU Resources Group, Inc., as the Director of Human Resources, working at its subsidiaries, Cascade and Intermountain. Prior to joining the MDU Resources Group, Inc., I worked in a variety of human resource positions including as Compensation and Benefits Manager. I hold senior professional certifications from the Human Resource Certification Institute and the Society for Human Resource Management.

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

A. My testimony explains the Company's process for setting total compensation for its employees, including both base pay and incentive compensation (also known as "at-risk compensation"). In addition, my testimony responds to proposals made by Staff that would systematically under-forecast the Company's base pay, and that would disallow portions of the Company's incentive compensation.

**Q. Please summarize your testimony.**

A. My testimony explains that Cascade's wage and salary costs accurately and verifiably reflect Cascade's 2018 Test Year expenses, that at-risk pay was appropriately included for recovery because it is a vital means of attracting and retaining a competent, motivated workforce, and that Cascade's wage and salary figures were appropriately adjusted for new employees added during the 2018 Test Year.

## II. WAGE & SALARY

**Q. Please describe Cascade's general approach to setting total compensation for employees.**

A. There are three basic principles underlying Cascade's approach to employee compensation—all designed to minimize costs while allowing the Company to attract and retain the qualified employees required to deliver safe and reliable service.

***First,*** Cascade has adopted a Total Rewards philosophy, which provides our employees with both total cash compensation and benefits. The two key components of total cash compensation are base pay and incentive compensation.

***Second,*** Cascade makes every attempt to compare its base pay and at-risk compensation with those figures available in the relevant labor market, and to set total cash compensation at the market average for comparable jobs. We are finding that the market for employees with the skills and experience we require is very competitive in the areas where we do business. For that reason, the two components of cash compensation we offer must—taken together—provide the same general pay levels and benefits as are included in the packages provided by Cascade's competitors for labor.

***Third*****,** the Company believes that, in order to encourage employee engagement and to help employees better understand the importance of operating our business effectively, a certain percentage of each employee's market compensation should be placed "at risk." Accordingly, under Cascade's incentive plan and subject to an initial earnings hurdle, each employee has the opportunity to receive total cash compensation and benefits at the market average, so long as the employee performs at an acceptable level. However, employees earn less than the average remuneration when performance is less than acceptable and, conversely, earn more than the average remuneration when performance is consistently exceptional. Importantly, however, our program is structured such that total compensation to all employees is aligned with the market average.

**Q. Please explain how the Company determines the market average for the base pay and pay-at-risk components of total cash compensation.**

A. Cascade uses market data to help establish both components of employee compensation. This data is sourced from a variety of industry salary surveys, including the American Gas Association, Mercer, EAP Data Information Solutions, Willis, Towers, Watson, World at Work, and Kenexa Compensation Analyst, among others. We then analyze the median base pay and target incentive compensation data to determine a market average for each component and for total compensation.

**Q. Do you have additional processes in place to ensure that the Company is not paying more than necessary to attract and retain a qualified workforce?**

A. Yes. Periodically the Company contracts with an outside independent consultant to review compensation programs and practices, to confirm that Cascade's base pay, incentive pay, and benefits are generally at market and are sufficient to attract and retain the talent required to provide safe and reliable gas service to our customers. For instance, this year the Company contracted with Pearl Meyer to provide a third-party review of base compensation and incentive compensation. The report that Pearl Meyer prepared is included as Confidential Exhibit CNGC/1101.

**Q. What was the result of the 2018 Pearl Meyer review of Cascade's total compensation program?**

A. The Pearl Meyer review indicated that Cascade's compensation programs, including incentive programs, are somewhat conservative compared with other industry and utility entities that compete for the same employees.[1] Base pay in particular was reported as generally lower than comparable industry and utility entities, reflecting Cascade's reliance on pay-at-risk in its efforts to provide a competitive total cash compensation necessary to attract and retain a capable workforce.[2]

**1. <u>Base Pay</u>**

**Q. How does the Company determine annual base pay increases?**

A. To determine an overall amount for annual base pay increases, we rely on the compensation survey data described above. Based on these resources, we set our overall compensation structure. Individual increases are based on performance, placement within the compensation structure, and a review of equity to others within the same compensation tier. While some employees may receive a lower or higher increase, overall compensation is always set at market. Importantly, a part of our conservative approach to base pay is that our salary grades for non-bargain unit employees start at 80 percent of market and, over time, an employee achieves market.

**Q. How did Cascade arrive at the base pay for its 2018 Test Year in this case?**

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[1] Confidential Exhibit CNGC/1101 at 20.
[2] Confidential Exhibit CNGC/1101 at 21.

A. For its union employees, the Company arrived at 2018 base pay using actual contracted- for wages for 2018. For non-union employees, Cascade used actual 2017 salary data, which was then adjusted using actual non-union wage increases that became effective on January 1, 2018.[3]

**Q. Does any party criticize or rebut Cascade's general methodology for determining base pay?**

A. No. No party criticizes the studies used by Cascade, nor does any party assert that the Company misapplied the studies or that our general approach is flawed.

**Q. Does Staff nonetheless propose adjustments?**

A. Yes. Staff proposes reducing base year salaries and wages by $718,552 (allocated as $553,285).[4]

**Q. How does Staff propose arriving at base pay?**

A. Ms. Gardner explains that it is Staff's policy to start with actual wage and salary levels from three years prior to the test year, and then to apply an inflation index to project the proposed base pay amount.[5] In this case, Staff relies on 2015 wage and salary data, which Staff then escalates using the All-Urban CPI to create a proposed value for base pay in 2018.[6]

**Q. Does Staff explain why it relies on its wage and salary model, or otherwise explain why it believes that its approach results in fair and reasonable rates?**

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[3] CNGC/300, Peters/5; *see also* CNGC/200, Parvinen/22 ("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.").
[4] Staff/100, Gardner/18.
[5] Staff/100, Gardner/15.
[6] Staff/100, Gardner/15.

A. No. While Staff explains that the three-year model is what it typically applies, Staff does not otherwise justify the model's use or explain why Staff believes that the three-year model results in fair and reasonable rates.[7]

**Q. Does Staff's three-year model reliably forecast base pay?**

A. No, for four reasons. First, Staff's approach is entirely theoretical and not reasonably calculated to produce sound results. Second, Staff's methodology is unbalanced in its application. Third, Staff's approach wrongly assumes that inflation is the only factor resulting in wage increases. Finally, and most importantly, the application of Staff's approach is entirely inappropriate in Cascade's case because Cascade's test year wages are based on actual wage increases granted.

**Q. Why do you say that Staff's model is entirely theoretical and not reasonably calculated to produce sound results?**

A. Staff's approach makes no attempt to determine whether the wages produced by the model actually reflect market wages and therefore does not accurately determine the expenses the Company will incur to provide safe, reliable gas service at fair and reasonable rates. While a model can provide some useful information, it is no substitute for a comprehensive assessment of market wages, such as that relied upon by Cascade in setting employee pay.

**Q. Please explain why you say that Staff's model is unbalanced in its application.**

A. Staff's methodology is structured so that it can produce only downward adjustments in wages, but never an upward adjustment, regardless of the circumstances. Staff characterizes its approach as allowing for either upward or downward adjustments within "a 10 percent band around Staff's calculated projection."[8] This is simply incorrect.

[7] Staff/100, Gardner/15.
[8] Staff/100, Gardner/17.

Based on Staff's method, as applied in its workpapers, if wages are too low, it will produce *no* adjustment. This is demonstrated by the fact that Staff's model forecasts officer salaries at a level higher than that requested by Cascade in this case, but *nonetheless proposes no upward adjustment*.[9]

Indeed, Staff's formula calculating the wage adjustment only applies "if" Staff's amount is *lower* than the Company's forecasted costs. As a result, if Staff's amount is *higher* than the Company's forecasted cost (as occurred here for officer salaries), no adjustment occurs. This understanding is borne out by the consistent results: Staff's method has, so far as I have been able to determine, *always* yielded either a downward adjustment or no adjustment to wages and salaries—never an upward adjustment. As a result, it does not appear that Staff's approach is a balanced test to reasonably predict likely salary estimates, but is instead used to routinely under-forecast wages and salaries.

**Q. Please explain your statement that Staff's model wrongly assumes that inflation is the only factor resulting in wage increases.**

A. As explained above, Staff's model starts with historical wages and then escalates those wages for inflation. However, when determining wage increases, employers need to consider factors other than inflation—the most significant of which are performance and merit increases. The failure to consider these additional factors will always result in an underestimate.

**Q. Please explain your statement that application of Staff's model is especially inappropriate in Cascade's case.**

[9] See Staff electronic workpaper, CNG UG 347 Exh 100 Issue 3 Wage & Salary model CONF wp Gardner.xlsx (sheet 100-3.1 PUC 3-year W&S total).

A. Staff's approach is especially inappropriate in Cascade's case because Cascade's test year wages are based on the actual wage increases granted for the test year. In this respect, Cascade is differently situated than other Oregon utilities, whose future test years are farther out than those selected by Cascade. Given that Cascade's test year wages reflect actual wages, there is no reason for Staff to rely on a theoretical model approach. On the contrary, once the Company has demonstrated the actual wages it is paying in the test year, and has provided evidence that those wages are set to market, Staff should not propose a disallowance without even attempting to confirm the soundness of Cascade's wage request, particularly when the Company pays third-party salary vendors to provide independent analysis.

**Q. What do you conclude about Staff's adjustment based on its three-year model?**

A. Staff's model suffers from several flaws. To the extent that Staff's approach may yield some useful information when forecasts are needed, it is wholly inappropriate where actual data from the test year is available.

**2. <u>Incentive Pay</u>**

**Q. Please provide a high-level description of Cascade's incentive pay plan for employees.**

A**.** Cascade's incentive plan is referred to as the Employee Incentive Plan (Plan). The Plan is made available to all non-bargaining unit employees who are regular full-time or part-time.

The Plan provides incentive compensation to employees that perform adequately across multiple measures, including managing costs, providing high-quality customer service, and developing a quality workforce. In 2018, the separate goal of employee development was removed. Going forward, beginning in 2019, the Plan's goals are tied to managing O&M costs, achieving high-quality customer service, and ensuring cyber security.

After the total payout under the Plan is determined for each year, employees are awarded a portion of this total payout based on individual performance, as laid out in the plan documents.[10] This total payout approach ensures that Cascade maintains competitive market compensation overall, while encouraging optimal performance.

**Q. How is the total payout amount determined?**

A. The total payout amount has historically been determined based on the Company's achievement of three major goals: (1) the Financial Goal, which is based on the Company's earnings; (2) the Operations and Maintenance (O&M) Expense Goal, which depends on the Company meeting an expense target; and (3) the Customer Service Satisfaction Goal, which is determined according to the results of the JD Powers and Associates survey. Through 2017, these goals were weighted with 45 percent tied to the Financial Goal, 45 percent tied to the O&M Expense Goal, and 10 percent tied to the Customer Service Satisfaction Goal. In 2018, the Plan includes only two goals, with 50 percent tied to the O&M Expense Goal and 50 percent tied to the Customer Service Satisfaction Goal.[11]

**Q. Please describe the rationale for each goal.**

A. The Financial Goal is designed to encourage employees to spend dollars wisely, increase efficiencies in work processes, eliminate redundancies, and suggest and justify capital projects that will return more than the cost of capital over the life of the project. The O&M Goal is similarly designed to encourage employees to seek efficiencies where reasonably possible, while ensuring safe and reliable service. The Customer Service

[10] The Plan document is included as Confidential Exhibit CNGC/1102.
[11] Confidential Exhibit CNGC/1102 at 5.

Goal is designed to heighten employees' awareness of the customer experience—whether or not a particular employee's job involves direct customer contact. By ensuring comprehensive accountability for customer service, Cascade is best able to provide both high-quality *and* cost-effective service to our customers.

**Q. How do you assess whether incentive compensation remains consistent with industry standards?**

A. We routinely monitor industry trends concerning incentive compensation. According to a 2017 American Gas Association Compensation Survey, for instance, the majority of participating utilities provided incentive compensation or pay-at-risk to all levels of employees. In 2014, the World at Work incentive pay practices survey (which included 350 publicly-traded companies) indicated that 99 percent of those surveyed had short-term incentives. Based on this ongoing research, it appears that placing some compensation at-risk continues to be a well-established tool in the workplace.[12] We will continue to watch these programs, as we do base pay, to ensure that we continue to provide competitive incentives.

**Q. Does the Company have separate incentive plans for executives?**

A. Yes. We have two additional incentives made available to our MDU Resources Group executives—the Executive Incentive Compensation Plan (Executive Incentive Plan) and the Long-Term Performance-Based Incentive Plan (LTP Plan). Awards made under these plans are tied primarily to financial goals for the Company.

**Q. Is Cascade including executive incentive pay in its request for recovery?**

A. No. Cascade excluded 100 percent of its executives' incentive payments.[13]

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[12] Confidential Exhibit CNGC/1101 at 29.
[13] CNGC/200, Parvinen/22.

**Q. Please state the amount of non-executive incentive payments included in the Company's test year revenue requirement.**

A. $561,994. Cascade included 100 percent of its non-executive pay-at-risk in this rate case.[14]

**Q. Does Staff state that Cascade's incentive payments are excessive or out of line with market expectations?**

A. No. Indeed, Staff appears to agree that Cascade's incentive amounts "appear to be appropriate as compared to the peer data."[15]

**Q. Does Staff nonetheless propose adjustments?**

A. Yes. Staff proposes reducing Cascade's test year incentives by $333 thousand.[16]

**Q. Why does Staff propose excluding these portions of Cascade's compensation package?**

A. Staff states that, previously, "the Commission has included only a portion of employees' incentives in rates."[17] Staff states that whether compensation is reasonable is "a distinct issue from whether customers should pay for incentives in rates."[18] Staff states that "the metrics, goals, and targets" of an incentive plan may "give rise to the disallowance."[19] Quoting a Commission order, Staff explains that if a utility's employee incentive plans "would benefit both ratepayers and shareholders," the Commission will include the incentive payments in rates.[20]

**Q. Does Staff state that Cascade's incentive payments fail to benefit ratepayers?**

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[14] CNGC/200, Parvinen/21-22.
[15] Staff/100, Gardner/20.
[16] Staff/100, Gardner/25.
[17] Staff/100, Gardner/22.
[18] Staff/100, Gardner/22.
[19] Staff/100, Gardner/22.
[20] Staff/100, Gardner/23 (quoting Order No. 97-171).

A. No. Ms. Gardner notes that previous incentive plans have been partially disallowed because "customers and shareholders benefit in different proportions to the plan," but does not address why non-officer incentives should be excluded in this case.[21]

**Q. Do you believe that Staff's testimony accurately characterizes Commission policy?**

A. No. While I agree that Staff has repeatedly applied a formula for disallowance, the underlying Commission principle is based on who benefits from incentives—not on a particular formula. Indeed, Staff's statements appear to acknowledge that the central Commission policy is to allow recovery of pay-at-risk if such incentive payments benefit utility customers: "it is the metrics, goals, and targets the plan is based upon that give rise to the disallowance."[22]

**Q. Do Cascade's customers benefit from the use of pay-at-risk?**

A. Yes. Placing a portion of employees' pay at-risk benefits Cascade's customers by motivating employees to focus on controlling costs while at the same time increasing customer satisfaction. These factors provide critical customer benefits, in addition to ensuring that Cascade is attracting and retaining qualified, responsible, and highly-skilled employees. By providing a safe, reliable, efficient, and responsive utility, pay-at-risk substantially benefits Cascade's customers. Where, as here, the amounts are reasonably necessary and justifiable, pay-at-risk for employees should be wholly recoverable.

## III. NEW EMPLOYEES

**Q. Please provide a high-level description of how new employees were used in setting Cascade's costs for wages and salaries in the 2018 Test Year.**

[21] Staff/100, Gardner/24.
[22] Staff/100, Gardner/22.

A. Cascade determined 2018 Test Year wages and salaries by first looking to the most recently-available actual compensation data from Base Year 2017. Using this data, Cascade identified the Oregon-allocated wages paid for the Base Year. Then the Company adjusted the Base Year wages by adding Oregon-allocated wages associated with any new positions that were to be hired during the 2018 Test Year to create a very practical, fact-based adjustment to the Base Year revenue requirement.

**Q. What was Cascade's anticipated number of new employee positions to be added during the 2018 Test Year, as described in opening testimony?**

A. In opening testimony, Cascade indicated that we anticipated a net increase of 7 employee positions in 2018 on a *system basis*.[23]

**Q. Do you have a correction to the characterization of new employee positions added during the 2018 Test Year?**

A. Yes. To clarify, the Company had anticipated adding 15 new positions in 2018 *on a total system basis*.[24] However, only 7 of these new positions were to be either partially or entirely allocated to *Oregon*.[25] These different numbers were reflected in Cascade's response to Staff DR 264, which listed 7 employees to be added in 2018, while the accompanying attachments described a total of 15 employees to be added to Cascade's system as a whole.[26] Only the 7 positions that were partially or wholly assigned to Oregon were included for recovery. The other positions were Washington-assigned.

**Q. Do you have a further correction to the number of new employee positions added during the 2018 Test Year?**

[23] CNGC/300, Peters/5.
[24] *See* Staff DR No. 264 (attachments).
[25] *See* Staff DR No. 264.
[26] *See* Staff DR No. 264 (and accompanying attachments).

A. Yes. While Cascade anticipated adding 7 new Oregon-allocated positions, only 6 of these positions have been filled.[27] As a result, Cascade has removed the unfilled supervisory position from its revenue requirement request. Of these 6 remaining positions, 3 are fully assigned to Cascade's office in Bend, Oregon, while the final 3 new positions are shared between Washington and Oregon. The 3 shared employee positions were allocated between the two states, resulting in 25.15 percent of these positions being allocated to Oregon, with the remaining share of these employees' costs allocated to Washington.

These 6 Oregon-allocated positions are largely for crew to support maintenance and construction of our natural gas operations, with one new Engineer position.[28] The Engineer position was created as part of Cascade's new Integrity Management department, and will provide continued reliability and project execution.[29]

**Q. Have you confirmed that each of these 6 new positions been filled?**

A. Yes. Included with this testimony as Confidential Exhibit CNGC/1103 is confirmation of hire documentation, such as signed offer letters, corresponding with each position filled.

**Q. What is the financial impact of these new positions?**

A. These new positions involve an increase in Cascade's revenue requirement over the Base Year of $250,144.[30] This is $13,824 less than the initial revenue requirement estimate, to account for the removal of the unfilled position.

**Q. What are Staff's concerns with respect to Cascade's new positions?**

[27] *See* Confidential Exhibit CNGC/1103.
[28] Staff DR No. 264 (FICA Resources Proposal and CS Organization and Structure attachments). Note, while one additional employee (a second Engineer position) of the total 15 was assigned to Oregon and Washington, this position was almost exclusively dedicated to Washington work and so was not included in Cascade's request for recovery.
[29] Staff DR No. 264 (Additional System Integrity attachment).
[30] CNGC/300, Peters/5-6.

A. Staff understands that 35—rather than 6—new positions are being added in this rate case.[31] Staff derived this number from Cascade's response to Staff DR No. 92, in which Staff requested Cascade's FTE count for 2015 through 2018.[32] The difference between FTE count provided for 2017 and for 2018 was 35.

**Q. Is there a problem with Staff's reliance on FTE count?**

A. Yes. Unlike Staff, Cascade's accounting system does not use FTEs as a standard form of measurement. As a result, when Staff asked Cascade to provide FTE information, Cascade was able to do so only for *fully-assigned* Cascade employees.[33] Nor could Cascade provide Oregon-specific FTE information; DR No. 92 reflected Cascade-assigned FTEs only.[34] Thus, the number of FTEs provided for each year reflected fully Cascade-assigned FTEs, and did not include those employees that are shared or allocated and whose salaries are only partially Cascade-assigned. This clarification was included in the Company's response to DR No. 92.[35]

**Q. What is the impact of Staff's reliance on FTEs?**

A. By relying on FTE counts, which do not fully reflect Cascade's employee population, Staff incorrectly assumes that changes in FTEs reflect a changing number of Cascade employees. Indeed, Staff's reliance on FTEs reinforces the problem with Staff's approach to determining wage and salary requirements for the 2018 Test Year—it is fundamentally inconsistent with Cascade's accounting system, which does not track partially allocated FTEs.

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[31] Staff/100, Gardner/18.
[32] Staff/100, Gardner/18; *see also* Staff DR No. 92.
[33] Staff DR No. 92 at 1-3.
[34] Staff DR No. 92 at 1.
[35] Staff DR No. 92 at 1 (noting that "FTE calculations for shared/allocated employees are not included in these figures (CNG direct only)").

**Q. Please explain why Cascade's approach results in a more accurate 2018 Test Year assessment for wage and salary figures.**

A. Cascade's approach is more accurate because it relies on actual 2017 wage and salary figures, which are then escalated for known new hires.[36] Unlike Staff's multi-step formula, Cascade's approach is clear, concrete, and readily verifiable.

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

A. Yes, it does.

[36] CNGC/200, Parvinen/22.

CNGC/1101
Murray

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Linda L. Murray

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**Confidential Pearl Meyer**
**Exhibit CNGC/1101**

**REDACTED**

**October 2018**

THIS DOCUMENT CONTAINS PROTECTED INFORMATION.

ALL QUALIFIED PERSONS AS DEFINED IN

ORDER 18-172 WILL RECEIVE THE DOCUMENT VIA U.S. MAIL.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

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Cascade Natural Gas Corporation

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**Employee Incentive Plan**
**Exhibit CNGC/1102**

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**Confidential New Positions**
**Exhibit CNGC/1103**

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**October 2018**

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Tammy Nygard

# EXHIBIT 1200

October 2018

**EXHIBIT 1200 – REPLY TESTIMONY**

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## I. INTRODUCTION AND SUMMARY

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

A. My name is Tammy Nygard and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

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

A. I am the Controller for the MDU Utilities Group which provides leadership and services for the four utility brands associated with MDU Resources Group, Inc. (MDU Resources): Cascade Natural Gas Corporation (Cascade or the Company), Intermountain Gas Company (Intermountain), Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co. (Great Plains).

**Q. What are your duties and responsibilities with the MDU Utilities Group?**

A. I am responsible for management of the accounting and the financial forecasting/planning functions, including the analysis and reporting of all financial transactions for Cascade, Intermountain, Montana-Dakota, and Great Plains. Please describe your educational and professional background. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 15 years of experience in the utility industry. During my tenure with the MDU Utilities Group, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and now as MDU Utilities Group Controller.

**Q. Did you provide direct testimony in this proceeding?**

A. No.

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

A. My reply testimony addresses the corporate cost allocation adjustment recommended by the Alliance of Wester Energy Consumers ("AWEC") witness Mr. Bradley G. Mullins.

**Q. Please summarize your reply testimony.**

A. My testimony demonstrates that the company's corporate cost allocation methodology is reasonable. Cascade's methodology adheres to the commitments made when MDU Resources acquired Cascade in 2007. Cascade's overall administrative and general ("A&G") expenses resulting from the allocation methodology have been consistently lower than they would have been if Cascade had remained a stand-alone utility.

Cascade's allocation methodology is also the same approach used in prior rate cases. When Staff expressed concerns over the allocation methodology in the last case, Cascade agreed to hold a workshop on the issue to provide additional information to the parties regarding how corporate costs are allocated to Cascade. No party proposed an alternative allocation methodology at the workshop, or even asked Cascade to explore alternative methodologies. And in this case, AWEC is the only party to challenge the allocation methodology.

Despite not raising any concerns in the last case, or the workshop, AWEC now proposes a dramatic change in the methodology that would substantially decrease the corporate overhead costs allocated to Cascade. AWEC's adjustment has virtually no analytic support, and AWEC concedes that aspects of it are unprecedented. Most importantly, the predicate for AWEC's adjustment—its claim that Cascades rates are higher because of the allocation of corporate overhead costs—is contradicted by the facts, which AWEC simply ignores.

**Q. Did you prepare any exhibits in support of your testimony?**

A. Yes. I prepared the following exhibits:

- Exhibit CNGC/1201 - Organizational Chart;
- Exhibit CNGC/1202 - Cascade Administrative and General Study;
- Exhibit CNGC/1203 - Cascade Administrative and General Benchmark Analysis;
- Exhibit CNGC/1204 - AWEC Response to DR No. 9

## II. CORPORATE STRUCTURE OF MDU RESOURCES

**Q. What is the Company's relationship to MDU Resources?**

A. Cascade is a wholly-owned subsidiary of MDU Resources. MDU Resources is located in Bismarck, North Dakota.

**Q. Please briefly describe the corporate structure of MDU Resources.**

A. MDU Resources is the parent company of Cascade and Intermountain, as well as its unregulated subsidiaries (WBI Holdings, Knife River, Construction Services, and FutureSource). Montana-Dakota and Great Plains are divisions of MDU Resources.[1] The MDU Utilities Group is an operating division of MDU Resources, which provides leadership and services to MDU Resources' utility brands. Please see my Exhibit CNGC/1201 for an organizational chart depicting the corporate structure of MDU Resources.

**Q. Please describe each utility brand.**

A. The four utility brands include Cascade, Intermountain, Montana-Dakota, and Great Plains. The following is a high-level overview of each brand:

- Cascade provides natural gas service in Oregon and Washington. As of December 31, 2017, Cascade served 73,582 retail customers in Oregon and 213,948 retail customers in Washington.

[1] The corporate structure is anticipated to change on January 1, 2019, when Montana-Dakota and Great Plains are expected to become subsidiaries of MDU Resources.

- As of December 31, 2017, Intermountain provided natural gas service in Idaho to 354,833 retail customers.
- Montana-Dakota provides both natural gas and electric service in Montana, Wyoming, North Dakota, and South Dakota. As of December 31, 2017, Montana-Dakota served 194,222 natural gas-only retail customers, 64,467 electric-only retail customers, and 78,434 combined natural gas and electric retail customers.
- Great Plains provides natural gas service in Minnesota and North Dakota. Great Plains serves 21,806 customers in Minnesota and 2,280 customers in North Dakota.

## III. BACKGROUND ON CASCADE'S CORPORATE COST ALLOCATION

**Q. What is the basis for the methodology used to allocate costs to Cascade?**

A. As a condition of the acquisition of Cascade by MDU Resources, Cascade made several commitments related to the inter-company cost allocation used for setting rates in Oregon.

First, Commitment 10 addressed shared corporate costs and stated: "for Oregon regulatory purposes, that commencing with the closing of the Transaction and through December 31, 2012, the allocated shared corporate costs, as well as its allocated and assigned utility division costs, will not exceed the costs the Cascade customers would otherwise have paid absent the acquisition, as adjusted for changes in the Consumer Price Index."[2]

Second, Commitment 12 further stated that "[a]ny corporate cost allocation used for rate setting, and subsequent changes thereto, will be submitted to the Commission for review" and that "[a]ny proposed cost allocation methodology for the

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[2] *In the Matter of MDU Resources Group, Inc. Application for Authorization to Acquire Cascade Natural Gas Corporation*, Docket No. UM 1283, Order No. 07-221, Appendix A at 16 (June 5, 2007).

allocation of corporate and affiliate . . . overheads, required by law or rule to be submitted to the Commission for review or approval, will comply with the following principles:

a. For services rendered to Cascade or each cost category subject to allocation to Cascade by MDU Resources or any of its affiliates, Cascade must be able to demonstrate that such service or cost category is necessary to Cascade for the performance of its regulated operations, is not duplicative of services already being performed within Cascade, and is reasonable and prudent.

b. Cost allocations to Cascade and its subsidiaries will be based on generally accepted accounting standards; that is, in general, direct costs will be charged to Cascade and its subsidiaries whenever possible and shared or indirect costs will be allocated based upon the primary cost-driving factors.

c. MDU Resources and its divisions will have in place an allocation or reporting system adequate to support the allocation and assignment of costs of executives and other relevant personnel to Cascade.

d. An audit trail will be maintained such that all costs subject to allocation can be specifically identified, particularly with respect to their origin. In addition, the audit trail must be adequately supported. Failure to adequately support any allocated cost may result in denial of its recovery in rates.

e. Costs which would have been denied recovery in rates had they been incurred by Cascade regulated operations will likewise be denied recovery whether they are allocated directly or indirectly through MDU Resources. Cascade shall include in any rate case filing a confirmation of this provision or a proposed implementing ratemaking adjustment if necessary."[3]

**Q. Has the Cascade satisfied these commitments?**

A. Yes. As described in more detail below, Cascade made the necessary compliance filings to demonstrate compliance with Commitment 10 and the cost allocation methodology used to set Oregon rates meets the requirements of Commitment 12.

**Q. Has the Commission ever found Cascade in violation of Commitment 10 or 12?**

A. No.

**Q. Did parties to Cascade's last general rate case raise any issues related to the allocation of corporate costs to Cascade?**

[3] *Id.* at 17.

A Yes. In the Company's 2016 general rate case (docket UG 305), Staff proposed several adjustments related to charges allocated to (and from) Cascade by MDU Resources and affiliates, including a specific adjustment related to general overhead allocations.

In response to Staff's testimony, the Company filed detailed reply testimony demonstrating the reasonableness of its overall A&G expenses, and justifying the methodology used to allocate general overhead costs to Cascade, among other allocation issues.

**Q. How were the cost allocation issues resolved in docket UG 305?**

A. Ultimately, the 2016 rate case was resolved by a comprehensive all-party stipulation. The stipulation included no specific adjustment related to the allocation of general overhead expenses to Cascade (although the stipulation did include adjustment related to other cost allocation issues).[4]

In addition, to address concerns raised by Staff, Cascade agreed to evaluate its cost allocation methodology and hold a workshop to provide an opportunity to work constructively with the parties outside of a contested case to resolve concerns over its allocation methodology.[5]

**Q. Did Cascade agree to address any specific issues at the post-rate case workshop?**

A. Yes. Cascade committed to the following for the allocations workshop:

- Reviewing MDU Resources' corporate structure;
- Reviewing its current processes for allocating labor-related costs performed by employees of MDU Resources and MDU Utilities who are responsible for customer

[4] *In the Matter of Cascade Natural Gas Corporation, Request for a General Rate Revision*, Docket No. UG 305, Stipulation ¶ 1; UG 305, Stipulating Parties/100, Parvinen-Gardner-Jenks-Gorman/18-19.
[5] Docket No. UG 305, Stipulation ¶ 5; UG 305, Stipulating Parties/100, Parvinen-Gardner-Jenks-Gorman/18-19.

service functions, and proposing changes to ensure that such costs are allocated based on objective factors;

- Explaining any proposed changes to Cascade's allocations methodologies to be implemented in 2017;
- Evaluating the treatment of combination gas and electric customers and presenting its findings as part of the allocations workshop;
- Providing detailed explanations as to how allocated costs are treated and coded using the applicable software to ensure that all allocated costs can be identified and traced in the system;
- Providing a spreadsheet demonstrating several examples of costs allocated, directly assigned, or otherwise charged to Cascade from affiliates, with journal descriptions of the original charge, the amount of the original charge, and the basis for the amount charged to Cascade;
- If any charges to Cascade are based on time, Cascade will provide several examples of time-based allocations and Cascade will provide supporting documentation;
- If any charges to Cascade result from discretionary choices by affiliate employees or management, Cascade will provide several examples for such allocations and Cascade will provide supporting documentation; and
- Explaining the MDU Resources and affiliates' capitalization.[6]

**Q. Did parties have the opportunity to submit written comments before the workshop?**

A. Yes. To allow for a meaningful workshop, the stipulation allowed Staff and parties to provide written comments to Cascade prior to the workshop, including suggestions for modifications to the Company's allocation methodologies.[7] Cascade agreed to consider any proposed modifications to its allocation methodologies, but was not obligated to implement such modifications.[8]

**Q. Did the testimony supporting the stipulation explain why the parties agreed to the workshop framework?**

[6] Docket No. UG 305, Stipulation ¶ 5.
[7] Docket No. UG 305, Stipulation ¶ 5.
[8] Docket No. UG 305, Stipulation ¶ 5.

A. Yes. The joint testimony explained that the purpose of the workshop:

> The Stipulating Parties' agreement for Cascade to hold a workshop will provide Staff and other parties with additional information and transparency regarding MDU Resources' corporate structure and Cascade's inter-company allocations methodologies and accounting systems. The inclusion of an opportunity for comments on the allocation methodologies will provide Cascade with an opportunity to consider whether revisions to its allocations methodologies may be appropriate. The Stipulating Parties agree that this workshop is a crucial component of a reasonable resolution of the issues raised by Staff regarding allocations.[9]

**Q. Did Cascade hold a workshop?**

A. Yes. Cascade held the workshop on April 26, 2017. Five Cascade representatives travelled to Salem for the workshop, including the VP of Regulatory Affairs and Customer Service, Controller, Director of Regulatory Affairs, Director of Finance and Accounting Systems, and the Accounting and Finance Manager. During the workshop, Cascade addressed each of the issues identified in the docket UG 305 stipulation, as described in the written materials used during the workshop. The workshop was attended by several members of Commission Staff, and the Department of Justice, as well as representatives from AWEC. Staff led a robust discussion and all parties were given the opportunity to pose questions to the Cascade attendees.

**Q. Did AWEC provide Cascade with any written comments before or after the workshop?**

A. No. AWEC's testimony in this case is the first time it expressed concerns over the allocation of corporate overhead costs. AWEC did not raise this issue during the last rate case nor during the post-rate case workshop.

## IV. CORPORATE COST ALLOCATION

**Q. What are general overhead costs?**

[9] Docket No. UG 305, Stipulating Parties/100, Parvinen-Gardner-Jenks-Gorman/26.

A. General overhead costs are costs incurred by the holding company that are not directly assignable to a particular operating company. General overhead costs include, for example, the costs of MDU Resource's legal and tax departments, information technology costs for the holding company, as well as communications, human resources, internal audit, investor relations, travel, Securities and Exchange Commission reporting and treasury.

**Q. How does MDU Resources allocate corporate overhead?**

A. MDU Resources allocates corporate overhead based on each of its business unit's corporate allocation factor. The corporate allocation factor is determined by the relative capitalization of each business unit as a percentage of overall capitalization of MDU Resources. Cascade's corporate allocation factor—which reflects the Company's capitalization relative to MDU Resources' other business units—is 10.4 percent. The MDU Utilities Group accounts for 35.8 percent of overall capitalization. When costs are allocated to the MDU Utilities Group, Cascade's share of those allocated costs is 29.1 percent based on its capitalization relative to MDU Resources' other utility brands. Taken together, Cascade's share of the allocated overhead costs is 13.85 percent.

**Q. Is this the same methodology that was used in the Company's last general rate case?**

A. Yes.

**Q. Does MDU Resources use the same allocation methodology in each state where it provides retail utility service?**

A. Yes.

## V. <u>REPLY TO AWEC'S ADJUSTMENT</u>

**Q. Please describe AWEC's proposed adjustment.**

A. AWEC proposes an adjustment to how general corporate overhead costs incurred by MDU Resources are allocated among its operating companies, including Cascade. Cascade's allocation methodology assigns 13.85 percent of corporate overhead costs to the Company. AWEC recommends reducing that figure by 67 percent to 4.58 percent. By modifying the methodology used to allocate general overhead expenses, AWEC recommends a reduction to Cascade's revenue requirement of $655,147.[10]

**Q. What is the basis for AWEC's recommendation?**

A. AWEC first justifies its adjustment by implying that customers have been harmed by MDU Resources' acquisition of Cascade because, according to AWEC, Cascade has instituted "aggressive corporate cost allocation policies that actually serve to increase the costs allocated to Oregon's ratepayers" relative to the costs that would have been allocated to Oregon's ratepayers without the acquisition by MDU Resources.[11]

**Q. Did AWEC provide any evidence supporting its claim that MDU Resources is unreasonably "dumping" costs onto Cascade?**

A. No. AWEC's claims on this point are entirely unsupported and, more importantly, entirely untrue. AWEC fails to identify any inter-company cross-charge that was improperly assigned to Cascade in violation of the acquisition commitments discussed above. AWEC also fails to provide any evidence that Cascade's A&G expense (which is where costs allocated from MDU Resources are generally found), or rates generally, are higher now because of the acquisition by MDU Resources.

**Q. Has the Company conducted any analysis of how its A&G expense was affected by the acquisition by MDU Resources?**

A. Yes. In August 2016, Cascade completed a study regarding Cascade's A&G

[10] AWEC/100, Mullins/3.
[11] AWEC/100, Mullins/5.

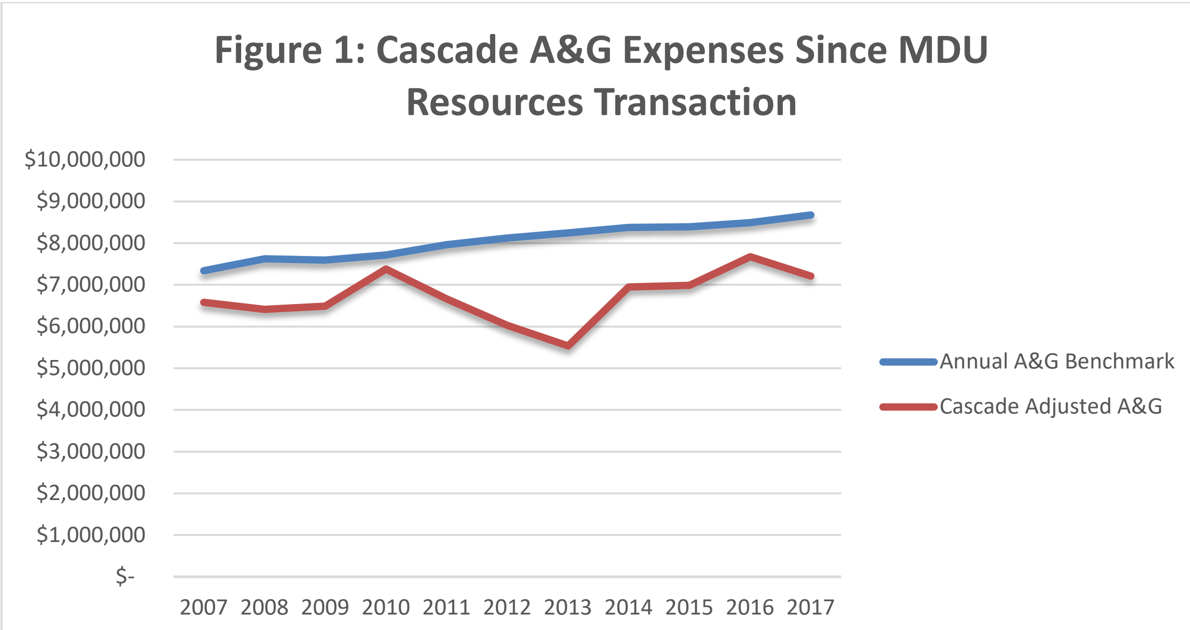
expenses. The results of the study demonstrate that Cascade has maintained a relatively low A&G expense per customer compared with other gas utilities in the region and across the country. Specifically, Cascade's 2014 A&G expense was $84.86 per customer, which is lower than both the mean and median A&G per customer for gas utilities in the west and nationwide.[12] The Company provided the results of this analysis in its testimony in docket UG 305.

**Q. Is Cascade's A&G expense as a subsidiary of MDU Resources less than it would be for Cascade as a standalone utility?**

A. Yes. As discussed above, as a condition of the acquisition of Cascade by MDU Resources, Cascade committed that "for Oregon regulatory purposes, that commencing with the closing of the Transaction and through December 31, 2012, the allocated shared corporate costs, as well as its allocated and assigned utility division costs, will not exceed the costs the Cascade customers would otherwise have paid absent the acquisition, as adjusted for changes in the Consumer Price Index."[13] As provided in section (a) of Commitment 10, compliance is determined through comparison with a 2005 Benchmark adjusted annually by the increase in the Consumer Price Index (CPI). Through December 31, 2012, Cascade filed an annual earnings report with the Public Utility Commission of Oregon (Commission) showing the calculation of actual A&G expense compared to the 2005 benchmark as adjusted for CPI and demonstrating that the Company has stayed under the threshold for A&G costs as adjusted for changes in CPI. Although Cascade no longer files the comparison to the 2005 A&G benchmark with the Commission, Cascade still performs this analysis. As shown in Exhibit CNGC/1203, Cascade's 2017 A&G expense is still

[12] *See* Exhibit CNGC/1202, Nygard/1 and Nygard/4.
[13] Docket No. UM 1283, Order No. 07-221, Appendix A at 16 (June 5, 2007).

below the 2005 benchmark as adjusted for CPI. Figure 1 below shows how Cascade's actual A&G expense has compared to the pre-acquisition benchmark.




**Q. Did AWEC's testimony acknowledge or rebut any of this evidence, which was provided in annual compliance filings through 2012 and included in the record of Cascade's last general rate case?**

A. No. AWEC fails to acknowledge or rebut the evidence that the acquisition by MDU Resources has actually *lowered* Cascade's A&G expense. AWEC did not dispute any of this analysis or conclusions in its testimony here, even though AWEC makes contrary claims.

AWEC's unsupported claim that the benefits of the MDU Resource acquisition have not materialized is simply wrong. Therefore, the premise underlying AWEC's adjustment—that Cascade is improperly bearing overhead costs that should be attributed to other operating companies or MDU Resources—lacks evidentiary support.

**Q. Is AWEC's criticism of the acquisition by MDU Resources here consistent with prior testimony?**

A. No. When NW Natural requested Commission approval to form a holding company corporate structure, AWEC's predecessor (the Northwest Industrial Gas Users Association, or "NWIGU") expressed a concern over how costs would be allocated between the holding company and affiliates and the utility. AWEC recommended that "NW Natural should be required to provide annual cost allocation reports that contain the methodologies and details used to allocate HoldCo or any affiliate-related costs to NW Natural."[14] AWEC then noted that the Commission imposed similar requirements on Cascade and argued that the Commission should impose the same requirements on NW Natural:

> As part of the Commission's order approving MDU Resources Group's acquisition of Cascade Natural Gas Corporation, the Commission imposed several conditions of approval regarding cost allocation. Those conditions included requirements to report changes to corporate cost allocation for rate setting, accounting standards to be used for that purpose, and a requirement to implement a reporting system . . . I urge the Commission to implement those kinds of commitments as conditions of approval.[15]

[14] *In the Matter of NW Natural, Application for Approval of Corporate Reorganization to Create a Holding Co.*, Docket No. UM 1804, NWIGU/100, Finklea/9 (June 14, 2017) ("Q. Do you have concerns about how costs will be allocated between NW Natural and HoldCo and future affiliates? A. Yes. Anytime you have a corporate structure or business that includes regulated and nonregulated operations, the allocation of costs between the operations can become difficult to track. NW Natural should be required to provide annual cost allocation reports that contain the methodologies and details used to allocate HoldCo or any affiliate-related costs to NW Natural. And, as a condition of approval, there should be no cross-subsidization by NW Natural customers of unregulated activities. Q. Has the Commission required cost allocation reports before as a condition of approval? A. Yes. As part of the Commission's order approving MDU Resources Group's acquisition of Cascade Natural Gas Corporation, the Commission imposed several conditions of approval regarding cost allocation. Those conditions included requirements to report changes to corporate cost allocation for rate setting, accounting standards to be used for that purpose, and a requirement to implement a reporting system. I recognize that the Company has proposed similar commitments in its application and I urge the Commission to implement those kinds of commitments as conditions of approval if it determines it will approve NW Natural's application.").

[15] Docket No. UM 1804, NWIGU/100, Finklea/9 (June 14, 2017).

At that time, AWEC said nothing in its testimony about how Cascade's allocation methodology had supposedly caused harm to customers. If Cascade's allocation commitments were ineffective at protecting customers, as AWEC now claims, presumably AWEC would not have recommended that the Commission impose the same conditions on NW Natural. The fact that just last year AWEC testified favorably about Cascade undermines the credibility of its testimony here.

**Q. AWEC next argues that it is unreasonable to use the relative capitalization of each operating company to establish the allocation percentage for corporate overhead costs.[16] Instead, AWEC recommends using other factors besides capitalization to allocate corporate overhead costs.[17] What factors does AWEC recommend?**

A. Instead of using capitalization, AWEC recommends using four factors: (1) rate base; (2) wages; (3) employee count; and (4) gross revenues. AWEC equally weights each of these four factors when calculating the allocation percentage for each operating company.[18]

**Q. Are AWEC's proposed factors reasonable?**

A. No. The corporate overhead allocation factor based on invested capital is consistent with MDU Resources' long-standing cost allocation policy, which has been accepted in many rate filings both here and in the other states where MDU Resources' operating companies provide retail service.

The use of invested capital to allocate costs among MDU Resources' operating companies is also appropriate for the particular mix of companies, which includes several non-regulated, non-utility businesses.

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[16] AWEC/100, Mullins/8-9.
[17] AWEC/100, Mullins/9.
[18] AWEC/100, Mullins/11.

**Q. Would the use of AWEC's proposed four-factor methodology be problematic for Cascade?**

A. Yes. The use of AWEC's proposed four-factor approach is likely to introduce much more volatility into the corporate allocation calculation because of the nature of the MDU Resources business mix. Certain of MDU Resources' operating companies are engaged in cyclical industries, such as construction, that in a downturn could have significantly lower revenue and labor (both wage and employee count), which account for three of the four factors AWEC proposes. Using AWEC's approach, such a downturn would cause higher allocation of corporate overhead costs to Cascade, even though the downturn would be unlikely to materially lower the affected operating companies' share of corporate overhead costs. Because of this cyclical nature of some MDU Resources' business units, labor and revenue do not have a direct relationship with equitable corporate cost sharing. An allocation based on invested capital is less volatile and follows where the capital dollars are spent, which aligns with where much of the MDU Resources' management activities are directed.

**Q. Have you conducted any analysis to verify the reasonableness of using capitalization way to allocate costs?**

A. Yes. To account for the non-utility operating companies within the MDU Resources' holding company structure, I conducted a two-step allocation method. First, I allocated all corporate overhead costs using the capitalization method to all of the operating companies. Then, I used a three-factor method (capitalization, revenues, and labor) to allocate the overhead costs among the three utility operating companies. This methodology appropriately recognizes the differences between utility and non-utility operating companies and responds to AWEC's concern that using only capitalization is too limited.

**Q. What were the results of your verification analysis?**

A. When capitalization is used in the first step, 57 percent of the overhead costs are allocated to the utilities. Cascade's share of the allocated utility overhead costs, based on the three-factor methodology, is 24.6 percent. Thus, the multi-step three-factor method allocates 14 percent of MDU Resources' corporate overhead costs to Cascade, compared to 13.85 percent under the straight capitalization methodology Cascade recommends.

**Q. AWEC recommends that if capitalization is considered, it should be based on rate base values, not net book values.[19] How do you respond to that recommendation?**

A. The Company would not be able to use rate base as a measure because other MDU Resources companies are not regulated utilities, and therefore do not have a utility rate base structure to their balance sheets.

**Q. AWEC claims that it is reasonable to double-count labor costs by including the number of employees as one of the four allocation factors because "employees are a key driver of overhead costs."[20] Do you agree?**

A. No. It is not reasonable or fair to double count labor costs in this fashion. Labor costs have a direct relationship to the number of employees within the Company's utility operations, the amount of medical and other benefits costs, and the level of administrative activities related to the size of the work force. Adding another labor-related allocation factor is redundant and therefore overstates the impact of labor-related activities on overhead costs.

[19] AWEC/100, Mullins/11.
[20] AWEC/100, Mullins/11.

**Q. Did AWEC provide any evidence that "employees are a key driver of overhead costs?"**

A. No. AWEC provided no quantitative analysis supporting this statement. Indeed, the only support AWEC provides for this statement is a citation to a NARUC manual describing how to perform cost-of-service studies.[21] However, the page cited by AWEC says nothing about how employees are a key driver of overhead costs and the manual does not even address the allocation of holding company corporate overhead costs among operating companies. Without support for this broad statement, there is no basis to double-count labor factors, as AWEC recommends.

Notably, if AWEC did not double-count labor, its proposed allocation factor for corporate overhead would increase from 4.6 percent to 5.3 percent, an increase of roughly 17 percent.[22]

**Q. AWEC also recommends that 25 percent of the corporate overhead costs should be assigned to the holding company.[23] Is that reasonable?**

A. No. AWEC claims that the holding company is a business that incurs costs to benefit itself, not the operating companies, and therefore should be assigned a portion of the overhead costs. This claim, however, is unfounded. The holding company exists solely for the benefit of the operating companies, *i.e.*, without the operating companies there would be no holding company. Because MDU Resources provides management oversight and other administrative functions for all of its business units, it is therefore unreasonable to assign costs to the holding company as if it were an independent operating company.

[21] AWEC/100, Mullins/9, n. 1.
[22] This calculation is based on AWEC's Table 2 and is the average of AWEC's A2, B1, and C factors, with no other changes.
[23] AWEC/100, Mullins/9-10.

**Q. What types of activities does AWEC claim benefit the holding company but not the operating companies?**

A. AWEC identifies only two activities—neither of which justifies assigning overhead costs to the holding company.

First, AWEC claims that the holding company "consider[s] strategic reorganizations" that benefit the holding company itself.[24] But it is hard to imagine how a potential strategic reorganization could be deemed to benefit the holding company but not the operating companies. To the extent that MDU Resources analyzes potential reorganizations, it would only do so to benefit the operating companies.

Second, AWEC claims that the holding company "seek[s] out new mergers and acquisitions," which AWEC claims would benefit the holding company not the operating companies.[25] This too is incorrect and misunderstands how Cascade treats merger and acquisition costs.

**Q. How would costs be allocated if MDU Resources were pursuing a merger or acquisition?**

A. MDU Resources is not looking to expand its current line of business. Therefore, if there was a potential merger or acquisition considered by the holding company, the costs of that transaction would be directly assignable to the specific operating company that would merge with or acquire the new company. And if the merger or acquisition was related to one of the utility operating companies, the transaction costs would be incurred below-the-line, so they would never be included in customer rates.

[24] AWEC/100, Mullins/10.
[25] AWEC/100, Mullins/10.

Thus, there is no basis to assign overhead costs to the holding company for merger and acquisition activity.

**Q. How does AWEC justify its 25 percent allocation to the holding company?**

A. AWEC provides no quantitative analysis demonstrating that any operating costs should be allocated to the holding company, let alone 25 percent. Instead, AWEC's witness admits that the 25 percent allocation is a result of his "judgmental weighting," without any explanation for how he arrived at his chosen allocation.[26] In a data response, AWEC could not identify a single utility that used a 25 percent allocation factor.[27]

**Q. Even if it were reasonable to assign some portion of overhead costs to the holding company, is 25 percent a reasonable figure?**

A. No. Even if one assumes that the holding company studied strategic reorganizations or sought out new mergers and acquisitions *for the benefit of itself* (which is untrue), it is unreasonable to assume that these two activities account for 25 percent of the holding company's activities.

**Q. Are costs effectively allocated to MDU Resources through the ratemaking process?**

A. Yes. For example, all below-the-line expenses are borne by MDU Resources, including shared expenses like meals and entertainment, membership and dues, and director and officers insurance.

**Q. If AWEC's unsupported 25 percent allocation to MDU Resources is removed, how does that impact its adjustment?**

[26] AWEC/100, Mullins/10.
[27] Exhibit CNGC/1204 (AWEC Response to DR No. 9).

A. Removing the 25 percent allocation to MDU Resources, without changing any other aspect of AWEC's adjustment, increases the overhead allocation to Cascade from 4.6 percent to 6.1 percent, which decreases the adjustment from roughly $655,000 to roughly $550,000. And if labor is not double-counted, the removal of the 25 percent allocation to MDU Resources increases the allocation to Cascade to 7.1 percent, which decreases AWEC's adjustment to $475,000.

**Q. AWEC also criticizes how overhead costs are allocated among the utility group.[28] Please describe AWEC's argument.**

A. When allocating overhead costs among MDU Resources' three utility operating companies, each utility's customer count is used as an allocation factor. Because Montana Dakota serves both gas and electric customers, that utility's customer count is multiplied by 1.25 to reflect the dual service provided to those customers. AWEC argues that a customer that receives both gas and electric service should be treated as two customers for purposes of overhead allocation.

**Q. Is AWEC's recommendation reasonable?**

A. No. Treating combination customers as if they were two customers completely misrepresents the customer service costs they are responsible for causing. In fact, for most purposes, these combination customers cause the same costs as single service customers.

**Q. Please explain.**

A. For example, it only takes a single call to set up both the natural gas and electric service, make account changes, or set up payment arrangements. In addition, the combination customers receive a single bill and remit a single payment and any other correspondence is consolidated and sent as a single notification. Also, field service

[28] AWEC/100, Mullins/12-13.

calls are handled by a combination technician, so any scheduling is handled as a single transaction. These activities make up the vast majority of customer service costs imposed by our customers. In fact, the only area in which a combined customer might impose more costs on the system than a single service customer would be outage and other service complaint-type calls, which are relatively infrequent.

**Q. If combination customers typically cause the same costs as single service customers, why does Cascade use a 1.25 allocation adjustment?**

A. Cascade recognizes that there are going to be some instances where a combination customer will cause a utility to incur greater costs than a single service customer, although such instances are rare. To account for these rare instances, Cascade conservatively uses a multiplier of 1.25 to allocate costs to Montana Dakota in recognition of the additional costs caused by combination customers.

**Q. AWEC also recommends an adjustment to remove incentive compensation provided to employees of entities other than Cascade.[29] How do you respond to this recommendation?**

A. This issue is addressed in the reply testimony of Michael Parvinen.

**Q. AWEC also recommends an adjustment to remove certain dues and subscriptions from Oregon rates. What is the basis for AWEC's recommendation?**

A. AWEC argues that certain costs are incurred by other entities and that the cost allocation manual does not provide an allocation policy for these costs.[30] AWEC further claims that some of the charges provide no benefit to Oregon customers. AWEC also claims that some costs are not properly situs assigned.

[29] AWEC/100, Mullins/14.
[30] AWEC/100, Mullins/15.

**Q. How do you respond to AWEC's adjustment?**

A. As Cascade is a subsidiary of MDU Resources, these costs benefit all the subsidiaries of the corporation. AWEC states that Cascade undertakes a process to situs assign certain categories for these costs to Oregon, but does not undertake a similar process of directly assigning costs to Washington, before allocating costs between the two states. This is untrue. Cascade's process is the same for both Washington and Oregon. There are costs that are direct assigned to Washington, and Oregon is not asked to bear any of those costs; those costs are therefore not part of this filing.

**Q. AWEC also claims that the cost allocation manual has no provision for allocating taxes other than income taxes.[31] Is this true?**

A. Taxes other than income consists primarily of property tax, payroll tax, franchise tax, and gross revenue tax. Property tax, franchise tax and gross revenue tax are direct assigned. Payroll tax would follow the employees standard labor distribution and is therefore covered in the manual.

**Q. Can you please provide a closing summary?**

A. Yes. Cascade's corporate administrative cost allocation method is appropriate for the business mix of MDU Resources, particularly given that not all of the operating companies are regulated utilities. Cascade's method has proven to be within the bounds of prior Commission directives and performance measures and should remain unchanged. AWEC's claims reflect nothing more than their witness's personal opinions, are unfounded and unsupported by any evidentiary basis.

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

A. Yes, it does.

[31] AWEC/100, Mullins/16.

CNGC/1201
Nygard

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Tammy J. Nygard

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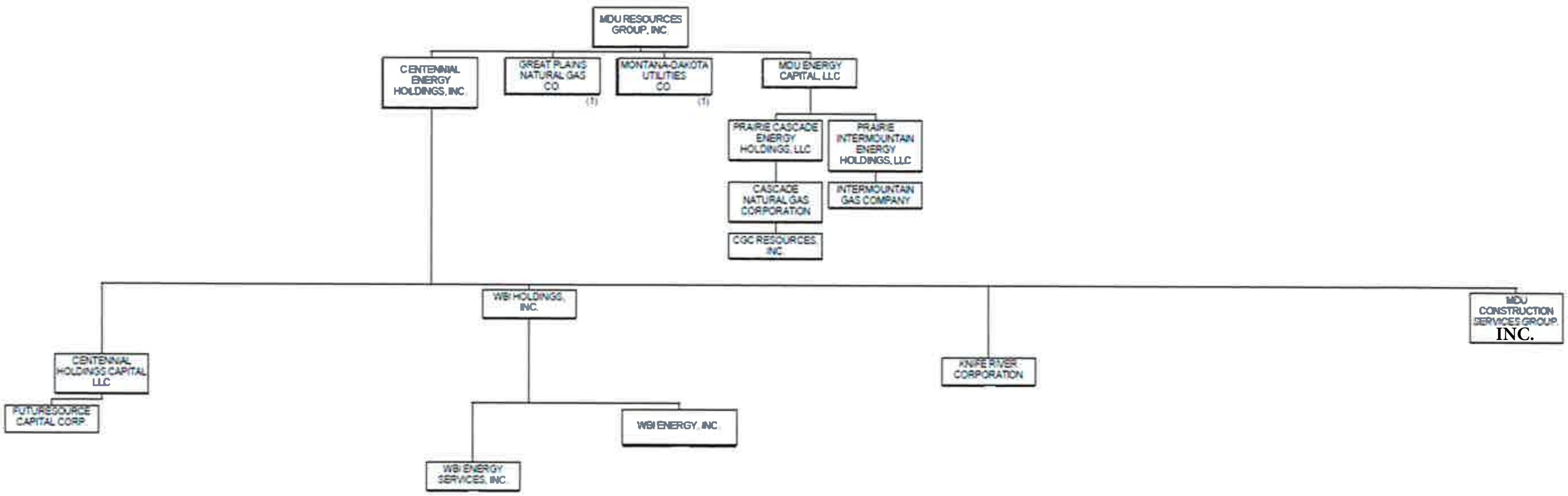
**Organizational Chart**
**Exhibit CNGC/1201**

**October 2018**

# MDU Resources Group, Inc. Organizational Chart



CNGC/1202
Nygard

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Tammy J. Nygard

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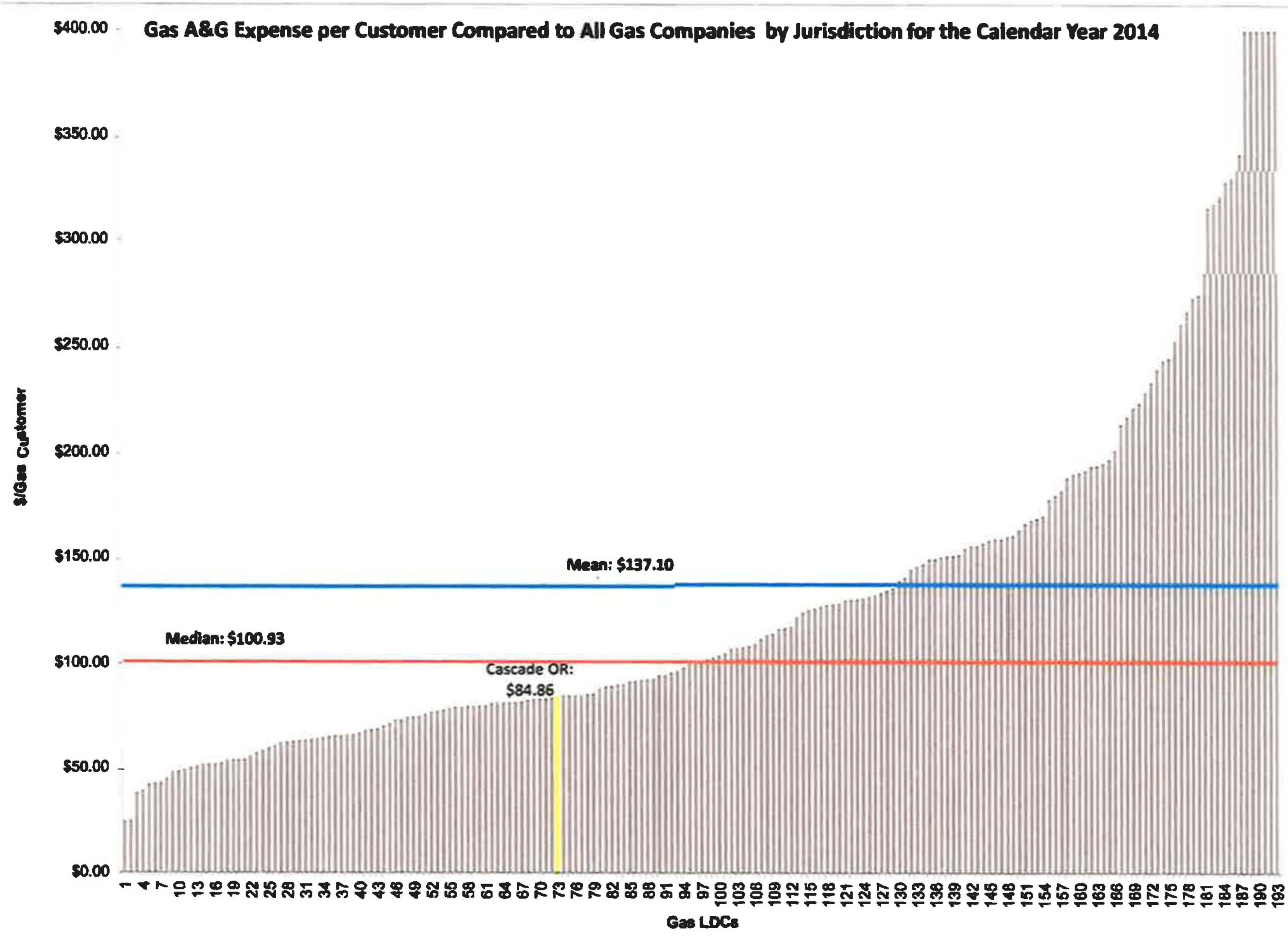
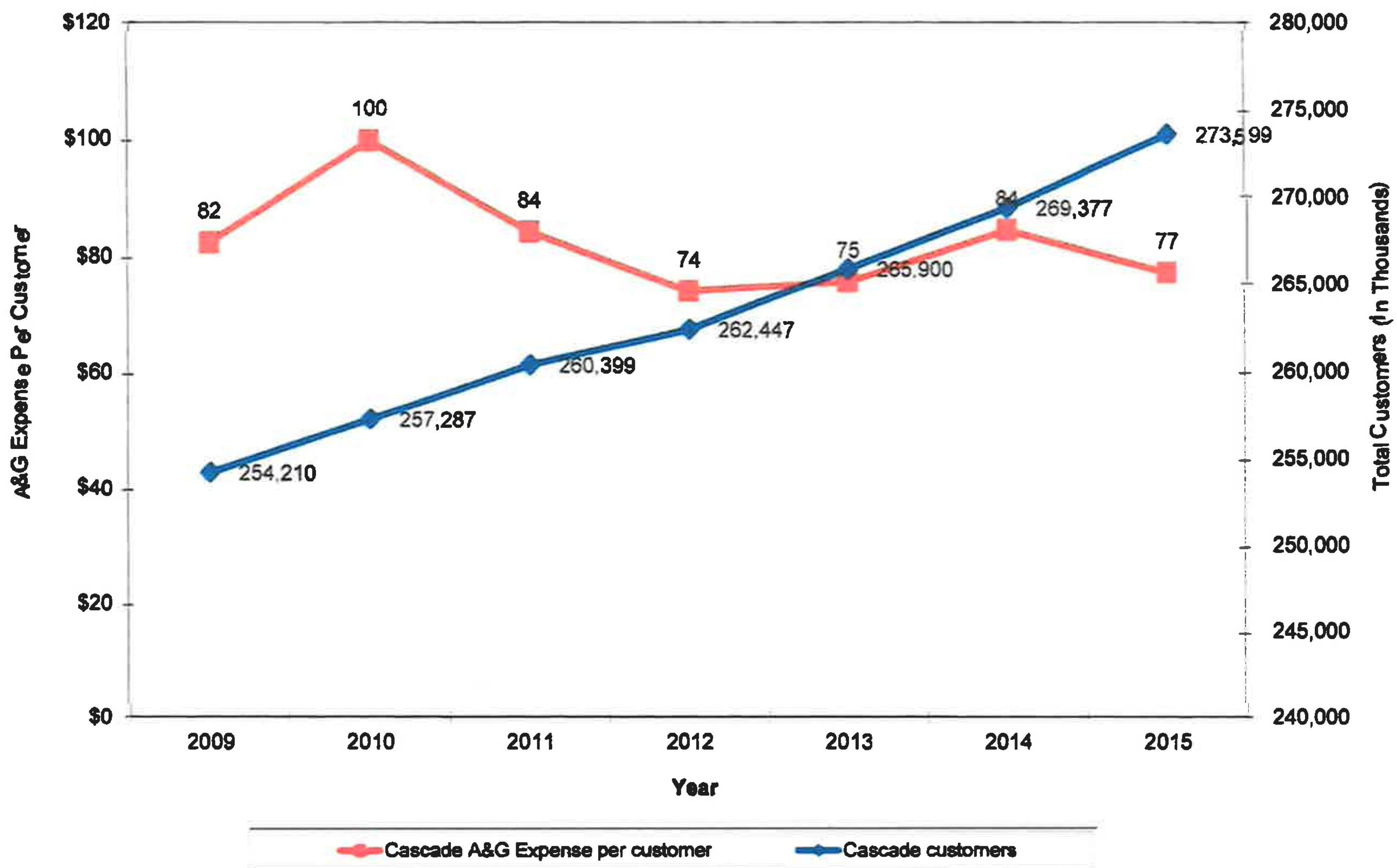
**Cascade Administrative and General Study**
**Exhibit CNGC/1202**

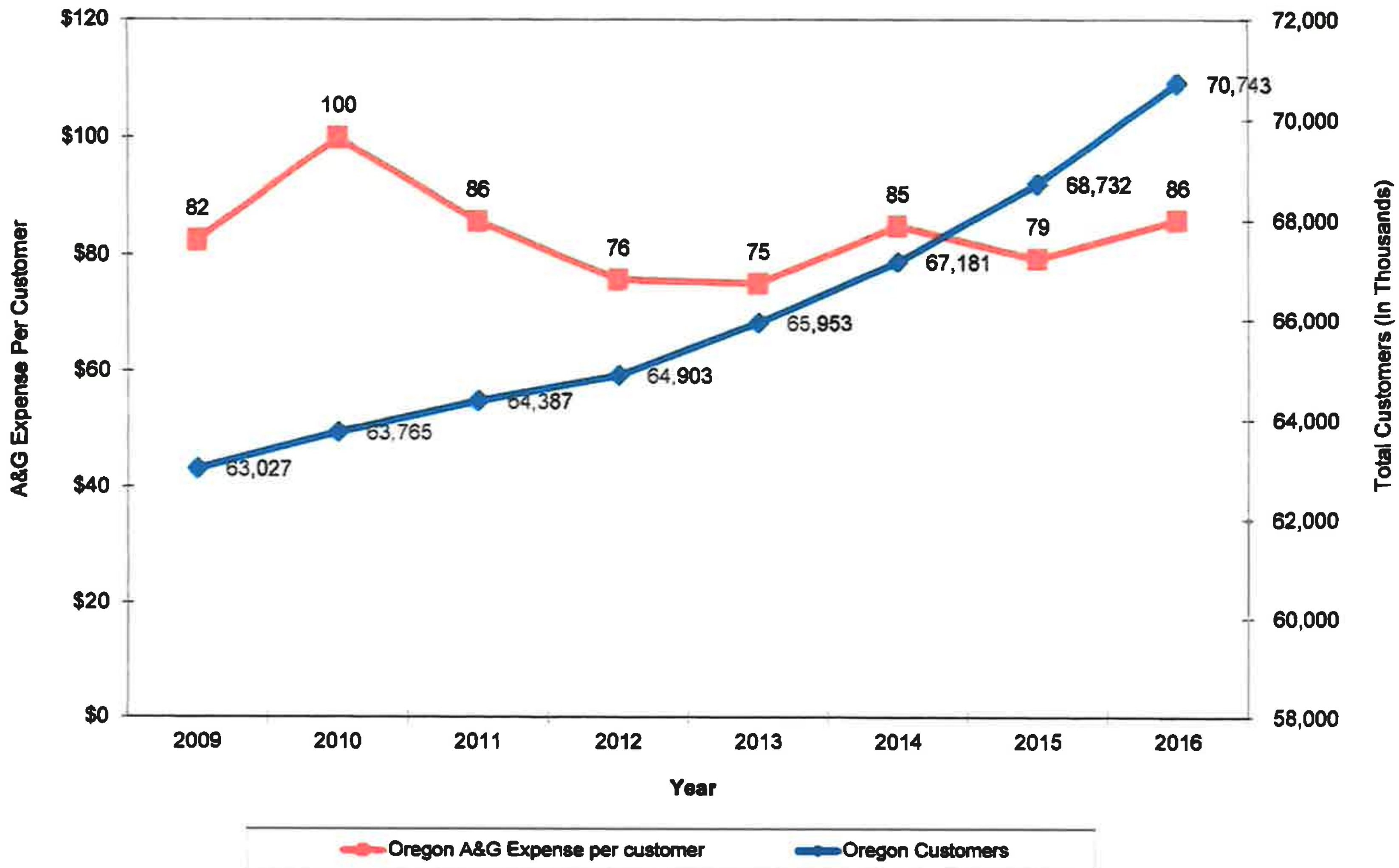
**October 2018**

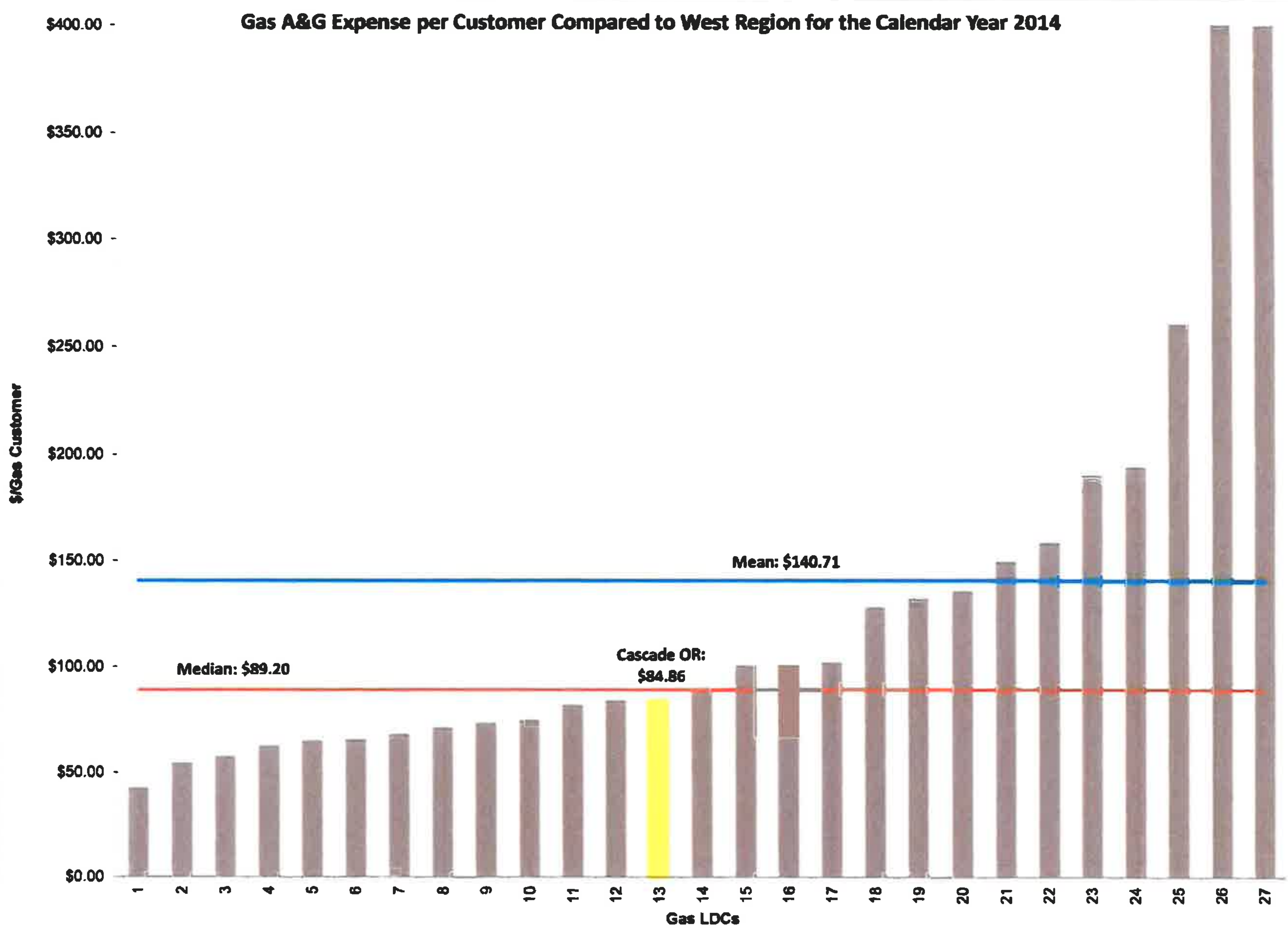

Gas A&G Expense per Customer Compared to All Gas Companies by Jurisdiction for the Calendar Year 2014
$/Gas Customer
$400.00
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
Mean: $137.10
Median: $100.93
Cascade OR:
$84.86
Gas LDCs

**Cascade Natural Gas Corporation**
**A&G Expense Per Customer and Customer Count Trends**
**For the Calendar Years 2009 - 2015**



**Cascade Natural Gas Corporation - Oregon**
**A&G Expense Per Customer and Customer Count Trends**
**For the Calendar Years 2009 - Test Year 2016**




Gas A&G Expense per Customer Compared to West Region for the Calendar Year 2014
$/Gas Customer
$400.00
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
Mean: $140.71
Median: $89.20
Cascade OR:
$84.86
1
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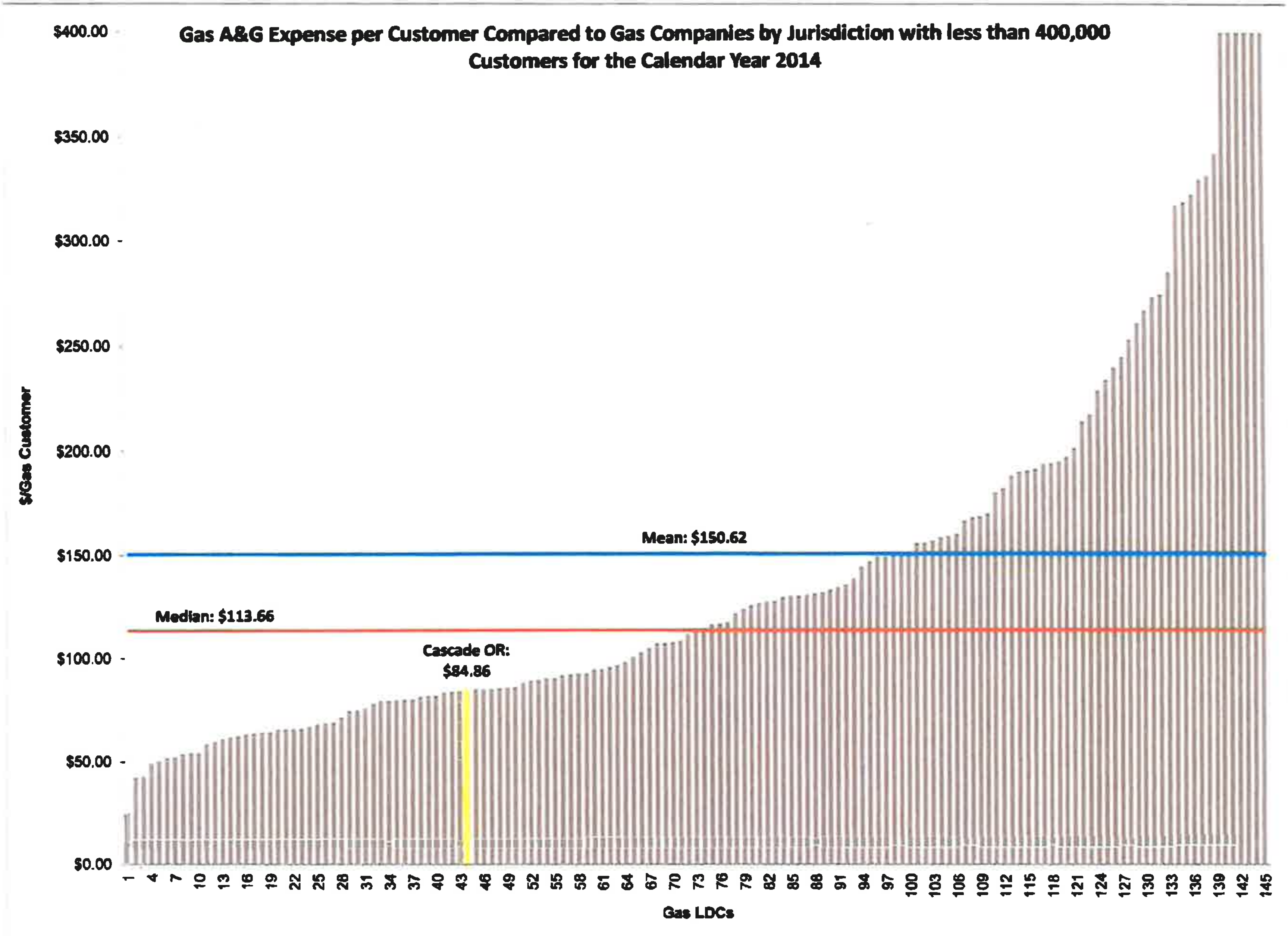
Gas LDCs


Gas A&G Expense per Customer Compared to Gas Companies by Jurisdiction with less than 400,000 Customers for the Calendar Year 2014
$/Gas Customer
$400.00
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$0.00
Mean: $150.62
Median: $113.66
Cascade OR: $84.86
Gas LDCs
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70 73 76 79 82 85 88 91 94 97 100 103 106 109 112 115 118 121 124 127 130 133 136 139 142 145

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Tammy J. Nygard

# Cascade Administrative and General Benchmark Analysis
# Exhibit CNGC/1203

**October 2018**

# Cascade Natural Gas Corporation
## UM 1283 A&G Expense Adjustment
### State of Oregon

| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2005 A&G Benchmark (per UM-1283) | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 | $ 6,848,545 |
| CPI Increase | 7.15% | 11.26% | 10.87% | 12.69% | 16.24% | 18.65% | 20.38% | 22.34% | 22.51% | 24.03% | 26.67% |
| Annual A&G Benchmark | $ 7,338,154 | $ 7,619,691 | $ 7,592,780 | $ 7,717,305 | $ 7,960,749 | $ 8,125,600 | $ 8,244,620 | $ 8,378,364 | $ 8,390,152 | $ 8,494,134 | $ 8,675,068 |
| | | | | | | | | | | | |
| Cascade Actual A&G Expense | $ 7,349,106 | $ 6,522,058 | $ 6,606,891 | $ 7,494,560 | $ 6,672,809 | $ 6,236,397 | $ 5,311,406 | $ 6,940,669 | $ 7,006,212 | $ 7,691,564 | $ 7,903,808 |
| A&G Type 1 adjustments | $ (769,091) | $ (112,175) | $ (117,570) | $ (114,513) | $ (5,906) | $ (209,722) | $ 223,129 | $ 4,360 | $ (18,672) | $ (18,081) | $ (698,165) |
| Cascade Adjusted A&G Expense | $ 6,580,015 | $ 6,409,884 | $ 6,489,321 | $ 7,380,047 | $ 6,666,903 | $ 6,026,674 | $ 5,534,534 | $ 6,945,029 | $ 6,987,540 | $ 7,673,483 | $ 7,205,642 |
| | | | | | | | | | | | |
| Below Threshold (Yes/No) | YES | YES | YES | YES | YES | YES | YES | YES | YES | YES | YES |
| | | | | | | | | | | | |
| A&G Adjustment (if below threshold then no adjustment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

CNGC/1204
Nygard

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Tammy J. Nygard

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**AWEC Response to DR No. 9**
**Exhibit CNGC/1204**

**October 2018**

# ALLIANCE OF WESTERN ENERGY CONSUMERS' RESPONSE TO CASCADE DATA REQUESTS

**CASCADE DR TO AWEC NO. 9**

Refer to AWEC/100, Mullins/10, lines 11-12. Is Mr. Mullins aware of any other utility that uses a 25 percent allocation factor to assign overhead costs to the holding company? If so, please provide all supporting documentation.

(a) Is Mr. Mullins aware of any other state or federal commission that has required or approved the use of a 25 percent allocation factor to assign overhead costs to the holding company? If so, please provide all supporting documentation.

**AWEC RESPONSE**

a) AWEC objects to this request on the basis that it requests a legal opinion. Notwithstanding, AWEC responds as follows.

Mr. Mullins has not conducted the requested comprehensive review of all state and federal legal proceedings that have discussed the issue of corporate cost allocation.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Brian Robertson

# EXHIBIT 1300

October 2018

## I. INTRODUCTION

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

A. My name is Brian Robertson. My business address is 8113 W. Grandridge Blvd., Kennewick, Washington 99336-7166.

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

A. I am employed by Cascade Natural Gas Corporation (Cascade or Company) as a Gas Supply Senior Resource Planning Analyst.

**Q. Please describe your educational and relevant employment background.**

A. I am a graduate of Central Washington University with a Bachelor of Science in Actuarial Science. I first joined Cascade as a Regulatory Analyst in February of 2014. I joined the Gas Supply Department in March of 2015 as a Resource Planning Analyst II and was promoted to a Gas Supply Senior Resource Planning Analyst in July of 2016.

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

A. My testimony responds to Staff's suggestions for further improvements to the Company's load forecasting, as presented by Scott Gibbens.[1] While Staff does not propose any adjustments related to Cascade's load forecasting, Staff does suggest that future load forecast modeling include revisions to weather normalization and the model selection process.[2] Staff also suggests using residential new construction as a forecast driver for increases in customer counts.[3]

**Q. Please summarize your testimony.**

A. My testimony briefly explains Cascade's approach to developing customer load forecasts, and responds to Staff's suggested modifications for future forecasting, including incorporating non-linear weather effects, automated modeling, and new residential

[1] Staff/400.
[2] Staff/400, Gibbens/7-8.
[3] Staff/400, Gibbens/7.

construction data. Cascade generally supports each of Staff's suggestions, as explained below.

## II. LOAD FORECASTING

**Q. Please briefly summarize Cascade's approach to load forecasting.**

A. Cascade load forecasting considers changes to two customer classes separately: (1) "core" load, which includes residential, commercial and industrial customers, and (2) "non-core" load, which includes certain large customer loads. Cascade models changes in core load using a load forecasting model. Cascade models non-core customer load growth using annual surveys of these large volume customers, and through in-person meetings with the largest volume accounts.

**Q. Do any parties propose changes to Cascade's method of forecasting large customer load growth?**

A. No. The only suggestions for changes concern Cascade's core load forecast modeling.[4]

**Q. Please expand on how Cascade modeled its core load forecast in this case.**

A. In this case, the Company used Autoregressive Integrated Moving Average (ARIMA) models to create distinct customer growth and demand growth forecasts.[5] These models forecast use-per-customer and number of customers separately, at which point the values can be multiplied to produce the load forecast totals.[6] The models use both economic and weather variables to establish each component of total load.[7]

**Q. How is the weather variable used to forecast load?**

A. Because weather changes substantially impact gas consumption, it serves as the most important factor in establishing use-per-customer. The Company uses the most recent 30

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[4] Staff/400, Gibbens/6-7.
[5] Staff/402, Gibbens/6.
[6] Staff/402, Gibbens/7.
[7] Staff/402, Gibbens/6-7.

years of weather data from seven different weather stations in Cascade's service territory to establish its weather variable. This weather data is normalized to establish a "typical" weather pattern and its corresponding impact on customer usage—known as "weather normalization."

**Q. How is the economic variable used to forecast load?**

A. Economic variables include population and employment levels. Because this data corresponds to the likely increase in Cascade's number of core customers, it serves as the key component of Cascade's customer growth forecasting. While Cascade uses both population and employment levels in its modeling, we occasionally drop one or the other of these factors when the additional data does not provide additional statistical significance (and would thus not impact the forecast).

**Q. Please summarize Staff's response to Cascade's load forecasting.**

A. Staff does not object to Cascade's load forecasting in this case.[8] However, Staff proposes three modifications for Cascade to consider incorporating into future load forecasting analyses, which are as follows:

1. Allow for non-linear weather effects on natural gas usage.
2. Standardize the model selection process using a computer algorithm available in SAS.
3. Explore using Oregon residential new construction as a forecast driver for number of customers.[9]

**Q. Please expand on Staff's proposal to allow non-linear weather effects.**

A. Staff proposes to shift from a linear model of weather effects to a non-linear approach.[10] In this rate case, Cascade used a linear model which assumes a one-for-one relationship

[8] Staff/400, Gibbens/8.
[9] Staff/400, Gibbens/6-7.
[10] Staff/400, Gibbens/7.

between weather changes and increased customer gas consumption. That is, a linear relationship assumes that a steady decrease in temperature will result in a steady increase in gas consumption. By comparison, a non-linear approach reflects the fact that the actual relationship between weather and consumption is not necessarily linear, and in fact customer consumption can change dramatically depending on the type and amount of temperature change. By more accurately modeling the relationship between weather changes and gas use, utilities are able to more effectively forecast load.

**Q. Does Cascade support Staff's proposal to use non-linear weather effects in load forecasting?**

A. Yes. Cascade has been in the process of exploring how to incorporate non-linear weather analysis in recent years. Indeed, Cascade's most recent Integrated Resource Plan filing in Washington employed non-linear weather modeling to improve its load forecasting.

**Q. Please explain how Cascade has begun employing non-linear forecasting.**

A. Cascade now models weather effects using two non-linear variables—temperature and wind. Temperature is first tracked on a daily basis in a linear fashion. Then, this daily data is modeled using the ARIMA model, with each month given a coefficient that provides the most statistically accurate match to historical gas consumption. Wind is similarly tracked, with monthly linear relationships modeled using a regression analysis to provide non-linear annual windchill impacts. Together, these weather impacts are added to forecast non-linear weather impacts on total load. Cascade believes that this new modeling, consistent with Staff's recommendation, will continue to improve the Company's load forecasting.

**Q. Please expand on Staff's proposal to standardize the model selection process.[11]**

[11] Staff/400, Gibbens/7.

A. In the ARIMA model, a user can manually select which autoregressive and moving average terms apply. Staff suggests using a statistical package, such as SAS, that automatically optimizes these settings using a built-in algorithm.[12] Staff prefers automated model selection in part to "make the process consistent and efficient for the Company."[13]

**Q. Please respond to Staff's proposal.**

A. Cascade supports Staff's suggestion to incorporate automated modeling. While Cascade no longer uses SAS, we are exploring automated ARIMA functionalities in R and would be willing to work with Staff to create an approach that is both consistent and efficient.

**Q. Please expand on Staff's proposal to use Oregon residential new construction in load forecasting.**

A. Staff proposes to use available data on new residential buildings in Oregon to help anticipate increased customer population in Cascade's service territory.[14] Staff suggests that this data would be more reliable because it more directly corresponds to the number of anticipated *new* customers—as opposed to population and employment level more generally, which does not adjust for changing household levels or anticipate ongoing growth.[15]

**Q. What residential new construction data does Staff suggest that Cascade use in its load forecasting?**

A. Staff points to three options for residential new construction data: First, Staff suggests using publicly available data found in the U.S. Census Bureau's regional data.[16] Second, Staff suggests using pending data from the Oregon Population Research Center (OPRC) at Portland State University, which Staff indicates is in the process of performing a housing

[12] Staff/400, Gibbens/7.
[13] CNGC DR No. 01 at 1.
[14] Staff/400, Gibbens/7.
[15] Staff/400, Gibbens/7-8.
[16] CNGC DR No. 02 at 1.

development survey, and whose final report may become publicly available.[17] Third, Staff suggests that the OPRC may have useful data on building permit reports, though Staff has not reviewed the data as a paid subscription is required.[18]

**Q. Please respond to Staff's proposal.**

A. Cascade intends to explore the data provided by the OPRC to determine whether it provides useful forward-looking data that may improve the Company's core load forecasting. Unfortunately, U.S. Census Bureau regional data does not provide useful information both because the data is regional, and thus not reflective of Cascade's relative rural service area, and because the U.S. Census Bureau only publishes new population projections for Oregon counties every ten years. By comparison, current data Cascade uses for population forecasting is from Woods & Poole, which publishes new projections annually.

**Q. Please summarize your response to Staff's proposals.**

A. Cascade appreciates Staff's support of Cascade's load forecasting in this case, and intends to continue to incorporate Staff's suggested modifications to its future load forecasting, where possible.

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

A. Yes, it does.

[17] CNGC DR No. 02 at 1.
[18] CNGC DR No. 02 at 1.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Del Herner

# EXHIBIT 1400

October 2018

## I. INTRODUCTION

**Q. Would you please state your name and business address?**

A. Yes, my name is Del Herner. My business address is 555 South Cole Road, Boise, Idaho 83709.

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

A. I am the Director of Customer Services for Cascade Natural Gas Corporation (Cascade or Company) and Intermountain Gas Company (Intermountain), subsidiaries of MDU Resources Group, Inc. (MDU Resources). I am also the Director of Customer Services for Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Company (Great Plains), Divisions of MDU Resources. Collectively, these four utilities are sometimes referred to within the Company as the Utilities Group.

**Q. What are your duties and responsibilities?**

A. I am responsible for the Customer Services department of the Utilities Group. My duties and responsibilities include providing strategic leadership on all matters pertaining to the Customer Service Departments located in Bismarck, ND and Meridian, ID.

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

A. I have over 35 years of Call Center Management experience in a number of industries including computer service and repair, healthcare, hardware and software support, corporate travel, and utilities. For the last 15 years I have worked in the utility industry as the Manager of Customer Service, Manager of Credit and Collections, and for the last 4.5 years as the Director of Customer Services at the Utilities Group. I hold a Master of Business Administration degree and a Master of Business Management degree from the University of Mary.

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

A. My testimony responds to the proposal of the Oregon Citizens' Utility Board (CUB) to cease collecting residential customer security deposits for a two-year period.[1] Cascade believes that CUB's proposal would lead to more uncollectibles that would lead to higher rates for Cascade's remaining customers.

## II. SECURITY DEPOSITS

**Q. Please describe Cascade's general policy concerning security deposits.**

A. Security deposits are designed to protect against the risk of customers' non-payment and to prevent shifting the costs of unpaid bills onto other paying customers. Cascade only requires security deposits when certain key risk factors are identified, including an inability to establish credit, the existence of previous unpaid balances, or a record of prior service terminations for theft, tampering, or diverting of service.

**Q. How many of Cascade's Oregon customers pay security deposits annually?**

A. Of our 74,000 Oregon customers,[2] 2,030—or roughly 2.7 percent—required security deposits in 2017.[3]

**Q. How long does Cascade hold security deposits?**

A. Generally, twelve months. The only circumstances in which the security deposit would not be returned in that time would be if either (1) the customer was disconnected for nonpayment, or (2) the customer received three or more disconnection notices during that twelve-month period (in which case, the security deposit would be held for an additional twelve months).

**Q. Can deposits be returned earlier?**

A. Yes, if the customer establishes satisfactory credit, the security deposit (plus any interest) would be returned.

**Q. How much does Cascade charge for security deposits?**

[1] CUB/100, Gehrke/16.
[2] CNGC/100, Kivisto/2.
[3] See Exhibit 1401.

A. Average security deposits in 2017 were $85.89. These amounts reflect approximately two months' worth of usage. Cascade uses customer-specific values to ensure that the security deposit accurately reflects the potential risk of non-payment, without over-charging.

**Q. Is the security deposit amount collected all at once?**

A. No. The security deposit is collected over three pay periods to minimize its impact on customers' bills.

**Q. Can the payment period be extended further?**

A. Yes. If a customer indicates that they cannot make a deposit over the course of three payment periods, then a customer could be allocated up to six payment periods to make the deposit.

**Q. Are you aware of customers needing to use this relief from security deposit payments?**

A. No. Having discussed the issue with my customer service team, I am not aware of customers requesting to extend the deposit payment period. This suggests to me that the security deposit is not imposing an unreasonable burden on customers.

**Q. Please briefly describe CUB's proposal with respect to Cascade's security deposits and why CUB proposes the new approach.**

A. CUB proposes that Cascade cease requiring residential security deposits for a two-year period. CUB believes that, because low-income households are more likely to need to provide a security deposit, equity considerations require that Cascade's use of security deposits be "abandoned."[4] CUB predicts that foregoing security deposits will not have a significant impact, but offers that Cascade could establish a balancing account to redistribute any impacts of the program after two years.[5]

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[4] CUB/100, Gehrke/18.
[5] CUB/100, Gehrke/18.

**Q. Do you agree with CUB that foregoing security deposits will not have a significant impact on Cascade's uncollectibles?**

A. No. Cascade relies on its security deposits to shield other customers from the impacts of non-paying customers, yet nonetheless experiences substantial uncollectible debts where non-payment balances have exceeded the security deposit amounts—for instance, totaling $345,554 in 2017. Therefore, it is logical to believe that, absent the payment of security deposits, the quantity of uncollectibles would increase.

**Q. Do you support CUB's proposal to stop requiring security deposits?**

A. No. I do not believe that CUB's approach is either equitable or fair because it would likely result in more uncollectibles that would lead to higher rates for Cascade's other customers. While I understand and agree with CUB that low-income customers may be more likely to be required to pay security deposits due to inability to demonstrate adequate credit or employment history, CUB's proposal would actually serve to redistribute the costs incurred by non-paying customers to other customers—many of whom are also low-income customers.

**Q. Please explain why you believe that CUB's proposal would be inequitable.**

A. CUB's approach would require the rest of Cascade's customers to shoulder the cost of non-paying customers. Cascade's Oregon service territory is located in relatively rural, low-income areas—namely, Baker, Crook, Deschutes, Jefferson, Klamath, Malheur, Morrow, and Umatilla counties. According to my review of recent U.S. Census data, all but one of these counties have poverty rates higher than the national level (12.3 percent). In Malheur County, for instance, 22.9 percent of individuals were below the poverty level in 2017; Klamath County's poverty rate is 19 percent.[6]

[6] *See* Exhibit 1402.

In sum, CUB's approach to the difficulties faced by a sub-set of low-income customers would actually place additional burdens on Cascade's other low-income customers. This approach strikes me as highly inequitable.

**Q. CUB points out that Avista has recently agreed to a two-year pilot program similar to CUB's proposal in this case, and suggests that Cascade should do the same. What is your response?**

A. Cascade is interested in the outcome of that pilot program and whether it will bear out Cascade's prediction that uncollectibles will increase in the absence of security deposits. However, that pilot has not yet been implemented and so it seems prudent to wait to see the results. If CUB is correct and uncollectibles do not increase, then Cascade would be happy to discuss whether a similar program might work for Cascade.

**Q. Does Cascade provide alternative means of supporting low-income customers?**

A. Yes, Cascade facilitates a number of programs intended to benefit low-income Oregon customers, including Winter Help, the Energy Assistance Fund, and the Low-Income Home Energy Assistance Program (LIHEAP).

**Q. Please describe the Winter Help program.**

A. The Winter Help program is used to support low-income customers at risk of disconnection and can be provided annually to customers in need. The program began in 1989, and is funded with charitable contributions and matching funds from Cascade. We have been able to help more than 10,000 families through this program since it began.

**Q. Please describe the Energy Assistance Fund.**

A. The Energy Assistance Fund allocates revenues to support low-income utility bill assistance, as well as conservation and renewable energy projects and low-income weatherization. The program is administered through local Community Action agencies located in the regions that Cascade serves.

**Q. Please describe the LIHEAP.**

A. This is a federal program that provides regular assistance to low-income households by covering part of their energy bills. This program is similarly administered through local Community Action agencies.

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

A. Yes, it does.

CNGC/1401
Herner

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Del Herner

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**Security Deposits**
**Exhibit CNGC/1401**

**October 2018**

| Row Labels | Nbr Deposits | Avg Deposit Amt |
|---|---|---|
| **CNGOR** | | |
| **2016** | | |
| DEPOSIT - RESIDENTIAL | | |
| 1-UNCONFIRMED | 984 | 81.51 |
| 2-RISK | 579 | 84.37 |
| 3-RISK NPAY | 720 | 87.13 |
| **2016 Total** | **2283** | **84.01** |
| **2017** | | |
| DEPOSIT - RESIDENTIAL | | |
| 1-UNCONFIRMED | 962 | 84.31 |
| 2-RISK | 404 | 89.16 |
| 3-RISK NPAY | 664 | 86.20 |
| **2017 Total** | **2030** | **85.89** |
| **2018** | | |
| DEPOSIT - RESIDENTIAL | | |
| 1-UNCONFIRMED | 862 | 79.02 |
| 2-RISK | 206 | 86.13 |
| 3-RISK NPAY | 307 | 84.45 |
| **2018 Total** | **1375** | **81.30** |

CNGC/1402
Herner

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Del Herner

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**U.S. Census Data**
**Exhibit CNGC/1402**

**October 2018**

Persons in poverty, percent by county
Source: 2017 American Community Survey 1-Year Estimates, www.census.gov

| (red = CNG service area) | Individuals Below Poverty Level |
|---|---|
| Baker County | 17.60% |
| Benton County | 18.40% |
| Clackamas County | 8.70% |
| Clatsop County | 12.90% |
| Columbia County | 11% |
| Coos County | 17.50% |
| Crook County | 14.20% |
| Curry County | 14.10% |
| Deschutes County | 10.60% |
| Douglas County | 15.60% |
| Gilliam County | 12.20% |
| Grant County | 16% |
| Harney County | 16.40% |
| Hood River County | 10.70% |
| Jackson County | 14.60% |
| Jefferson County | 17.30% |
| Josephine County | 18% |
| Klamath County | 19% |
| Lake County | 15.20% |
| Lane County | 18.30% |
| Lincoln County | 19.60% |
| Linn County | 13.10% |
| Malheur County | 22.90% |
| Marion County | 13.60% |
| Morrow County | 14.80% |
| Multnomah County | 14.20% |
| Polk County | 12.10% |
| Sherman County | 12.20% |
| Tillamook County | 12.90% |
| Umatilla County | 15.70% |
| Union County | 16% |
| Wallowa County | 14.60% |
| Wasco County | 14.20% |
| Washington County | 9% |
| Wheeler County | 19.60% |
| Yamhill County | 11.70% |

Source(s): U.S. Census Bureau, 2016 Small Area Income and Poverty Estimates (SAIPE)
Powered by the U.S. Census Bureau
Data may contain sampling error. Sampling error and margin of errormay render some of the differences between geographies statistically insignificant.An 'X' entry indicates that either no sample observations or too few sample observations were available to compute an estimate.Note that an 'X' entry in other US Census Bureau tables could indicate a different issue.
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Persons in poverty, percent by county
Source: 2017 American Community Survey 1-Year Estimates, www.census.gov

| **(red = CNG service area)** | **Individuals Below Poverty Level** |
|---|---|
| Malheur County | 22.90% |
| Lincoln County | 19.60% |
| Wheeler County | 19.60% |
| Klamath County | 19% |
| Benton County | 18.40% |
| Lane County | 18.30% |
| Josephine County | 18% |
| Baker County | 17.60% |
| Coos County | 17.50% |
| Jefferson County | 17.30% |
| Harney County | 16.40% |
| Grant County | 16% |
| Union County | 16% |
| Umatilla County | 15.70% |
| Douglas County | 15.60% |
| Lake County | 15.20% |
| Morrow County | 14.80% |
| Jackson County | 14.60% |
| Wallowa County | 14.60% |
| Crook County | 14.20% |
| Multnomah County | 14.20% |
| Wasco County | 14.20% |
| Curry County | 14.10% |
| Marion County | 13.60% |
| Linn County | 13.10% |
| Clatsop County | 12.90% |
| Tillamook County | 12.90% |
| Gilliam County | 12.20% |
| Sherman County | 12.20% |
| Polk County | 12.10% |
| Yamhill County | 11.70% |
| Columbia County | 11% |
| Hood River County | 10.70% |
| Deschutes County | 10.60% |
| Washington County | 9% |
| Clackamas County | 8.70% |

Source(s): U.S. Census Bureau, 2016 Small Area Income and Poverty Estimates (SAIPE)
Powered by the U.S. Census Bureau
Data may contain sampling error. Sampling error and margin of errormay render some of the differences between geographies statistically insignificant.An 'X' entry indicates that either no sample observations or too few sample observations were available to compute an estimate.Note that an 'X' entry in other US Census Bureau tables could indicate a different issue.
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**UG 347**

# Cascade Natural Gas Corporation

# Reply Testimony of Pamela J. Archer

# EXHIBIT 1500

October 2018

**EXHIBIT 1500 – REPLY TESTIMONY**

TABLE OF CONTENTS

## I. INTRODUCTION

**Q. Are you the same Pamela J. Archer who filed direct testimony in this proceeding on behalf of Cascade Natural Gas Corporation (Cascade or Company)?**

A. Yes.

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

A. The purpose of my testimony is to respond to the Oregon Citizens' Utility Board's (CUB) discussion of Cascade's proposed increases to its field visit charge and returned payment charge, as presented in the Testimony of William Gehrke.[1]

## II. FIELD VISITS

**Q. Please briefly explain Cascade's policy regarding a field visit charge.**

A. A field visit charge covers the costs associated with a visit to a customer to either disconnect or reconnect service but where, due to the customer's action, Cascade is unable to complete the disconnection or reconnection.[2] The field visit charge is imposed to ensure that the costs associated with such a visit are not passed on to other customers.

**Q. What is Cascade's proposal concerning the field visit charge?**

A. Cascade proposes increasing the field visit charge from $10 to $20.[3]

**Q. When was the last time that Cascade increased the field visit charge?**

A. This fee has not been updated for more than thirty years.[4] The fee appears to have been last changed sometime between 1972 and 1988.[5]

**Q. What was the basis for increasing the fee to $20?**

A. Given the many years since the fee was updated, the Company felt it was reasonable to

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[1] CUB/100.
[2] CNGC/501.
[3] CNGC/500, Archer/6.
[4] CNGC/500, Archer/6.
[5] CNGC/500, Archer/6, n.1.

consider the comparable charges used by similar utilities to help establish a proxy value.[6] The costs for other Oregon regulated utilities' field visit charges are all $20.[7]

**Q. Please briefly explain CUB's objection to the Company's increase of this charge.**

A. CUB argues that Cascade's increased field visit charge should be rejected because the Company has been unable to track the annual cost of field visits for Oregon customers.[8] CUB therefore opposes any increase in this charge.[9]

**Q. Have you performed any additional analysis since CUB filed its testimony and what were the results of that analysis?**

A. Yes. In light of CUB's comments, I performed additional high-level analysis to verify the reasonableness of the proposed field visit charge. Relevant cost components fall into two general categories: vehicle use and labor.

**Q. Please explain the vehicle use costs incorporated into the field visit charge.**

A. Vehicle use costs account for the expenses associated with use of Cascade's fleet vehicles, which entail routine, predictable expenses (such as fuel, wear-and-tear, and maintenance needs) associated with travel time. These costs translate to $7.07 per hour for vehicle use. Having reviewed Oregon records for field visits, an average visit entails 0.28 hours, which translates to $2.00 in vehicle use costs per field visit.[10]

**Q. Please explain the labor costs associated with the field visit charge.**

A. Labor costs are the most significant component of the field visit charge, and reflect an average service mechanic's wage and benefit costs of $52.60 per hour. With an average visit requiring 0.28 hours of time, this translates to $14.73 in labor costs per field visit.[11]

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[6] CNGC/500, Archer/6-7.
[7] CNGC/500, Archer/7.
[8] CUB/100, Gehrke/3-4.
[9] CUB/100, Gehrke/4.
[10] Exhibit Archer/1501.
[11] Exhibit Archer/1501.

**Q. Are there any additional costs associated with field visits?**

A. Yes. I did not specifically account for additional overhead, incidental supervisory oversight, and clerical scheduling costs.

**Q. Does this additional analysis support Cascade's request for a $20 field visit charge?**

A. Yes. This additional high-level analysis verifies the reasonableness of Cascade's proposed $20 field visit charge.

## III. RETURNED PAYMENT CHARGE

**Q. Please briefly explain Cascade's policy regarding a returned payment charge.**

A. A returned payment charge covers the costs associated with a returned payment, including the cost of processing such a return.

**Q. What is Cascade's proposal with respect to a returned payment charge in this case?**

A. Cascade proposes increasing the charge from $10 to $25.[12] Cascade felt that its increase was appropriate in this case for two reasons: First, Cascade's costs—and most particularly labor costs—have increased significantly over the past decades. Second, given the many years since the charge was last updated, Cascade believed that it was reasonable to look to other utility returned payment charges as a useful proxy.[13] The Commission has approved charges of between $15 and $25 for other Oregon regulated utilities.[14]

**Q. Please briefly explain CUB's objection to the increased returned payment charge.**

A. CUB argues that no increase to the returned payment charge is appropriate because the underlying *bank charges* have not increased.[15] As a result, CUB states that Cascade "has failed to provide requisite evidence to support its request."[16]

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[12] CNGC/500, Archer/6.
[13] CNGC/500, Archer/6-7.
[14] CNGC/500, Archer/7.
[15] CUB/100, Gehrke/5.
[16] CUB/100, Gehrke/5.

**Q. Please respond to CUB's objection.**

A. CUB's objection appears to rest on a point of confusion related to Cascade's response to a CUB DR. CUB relies on CUB DR 6 to conclude that the costs associated with processing a returned payment include only the underlying bank charge.[17] In CUB DR 6, CUB asked Cascade to provide the costs associated with returned payments over the past several years.[18] Cascade's response provided what was, at the time, the only available concrete component of Cascade's costs to process a returned payment—bank fees.[19] As CUB correctly noted, this discrete component of Cascade's costs to process returned payments has not increased since the Company's last rate case. However, what was not made adequately clear in this response was that bank fees comprise only *one component* of the costs associated with processing returned payments.

**Q. What are the other cost components for Cascade to process a returned payment?**

A. The most critical costs associated with processing returned payments are associated with labor.

**Q. Have you performed additional analysis to confirm the labor costs associated with returned payment processing?**

A. Yes. In light of comments from CUB, I performed additional high-level analysis to verify the reasonableness of the proposed returned payment charge. In particular, I quantified the labor costs associated with returned payment processing. Two Cascade employees are responsible for processing Oregon returned payment charges, spending approximately one-half hour and two-thirds of an hour processing returned payments each day, respectively.[20]

[17] CUB/100, Gehrke/4-5.
[18] CUB DR 6.
[19] CUB DR 6.
[20] Exhibit Archer/1502.

To determine the labor costs per returned payment charge, I multiplied this estimated time spent by each employee's wage and benefit costs to create an average monthly total. I then divided this average monthly total cost by the average number of Oregon returned payment charges. Together, this resulted in an average of $19.79 in labor costs for each returned payment charge. This cost is in addition to the $3.62 bank fee.[21]

**Q. Are there other relevant costs that you did not include in your analysis?**

A. Yes. I did not specifically account for overhead or supervisory costs, which would further increase the costs associated with returned payment processing.

**Q. Does this supplemental analysis support Cascade's request for a $25 returned payment charge?**

A. Yes. This supplemental, high-level analysis verifies the reasonableness of Cascade's proposed $25 returned payment charge.

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

A. Yes, it does.

[21] Exhibit/Archer 1502.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Pamela J. Archer

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**Field Visit**
**Exhibit CNGC/1501**

**October 2018**

**Cascade Natural Gas Corporation**
**UG-347**
**Costs For Field Visit Charge**
**State of Oregon**

| | A | B | |
|---|---|---|---|
| Ln. | | | |
| 1 | Labor Costs | $ | 14.73 |
| 2 | Vehicle Use | $ | 1.97 |
| 3 | Total | $ | 16.70 |

CNGC/1502
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Pamela J. Archer

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**Returned Payment**
**Exhibit CNGC/1502**

**October 2018**

**Cascade Natural Gas Corporation**
**UG-347**
**Costs For Returned Payment Charge**
**State of Oregon**

Employee # 1 Wages and Benefits (annual)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41.89 | / hr | x | 0.66 | hrs/day | x | 22 | days/mon | x | 12 | mons/yr | = | $ 7,298.91 |

Employee # 2 Wages and Benefits (annual)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 38.24 | / hr | x | 0.5 | hrs/day | x | 22 | days/mon | x | 12 | mons/yr | = | $ 5,047.68 |

| | | |
|---|---|---|
| Total annual labor costs: | | $ 7,298.91 |
| | + | $ 5,047.68 |
| | | $ 12,346.59 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $ 12,346.59 | / | 156 | * | 4 | = | $ 19.79 | per transaction |
| | | | | | + | 3.62 | bank fee |
| | | | | | | $ 23.41 | |

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

**DOCKET NO. UG 347**

Cascade Natural Gas Corporation

**Reply Testimony of Ronald J. Amen**

**LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN EXHIBIT CNGC/1600**

October 31, 2018

# REPLY TESTIMONY – LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

## Contents





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

## I. INTRODUCTION OF WITNESS

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

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

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

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

**Q. Did you provide direct testimony in this proceeding?**

A. Yes. I previously sponsored the following direct testimony and exhibits:

- Exhibit CNG/601 Summary of LRIC
- Exhibit CNG/602 Functional Revenue Requirement
- Exhibit CNG/603 Incremental Plant Carrying Costs
- Exhibit CNG/604 Incremental O&M Costs
- Exhibit CNG/605 Summary of Revenue by Rate Class
- Exhibit CNG/606 Analysis of Revenue by Detailed Rate Schedule
- Exhibit CNG/607 Residential Impact by Month
- Exhibit CNG/608 Impact of Recommended Rate Changes
- Exhibit CNG/609 Ronald J. Amen Statement of Qualifications

## II. PURPOSE OF TESTIMONY

**Q. What is the purpose of your reply testimony in this proceeding?**



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A. My reply testimony addresses the alterations to the Long-Run Incremental Cost ("LRIC") Study recommended by the Alliance of Western Energy Consumers ("AWEC") witness Mr. Bradley G. Mullins.

**Q. Do you have exhibits supporting your rebuttal testimony.**

A. No.

## III. CASCADE'S LRIC STUDY

### A. General Transportation – Schedule 163

**Q. Please summarize the LRIC results for Schedule 163 as presented in your direct testimony.**

A. Exhibit CNG/601 from my direct testimony presented the total LRIC-based revenue requirement for each of Cascade's rate schedules.[1] By comparing the revenue requirement to test year revenues by rate schedule under Cascade's current rates[2], one can see the extent to which Cascade's current rates and non-gas revenues are reflective of LRIC. Revenue-to-cost ratios portray the relative difference between these two revenue amounts for each rate schedule. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the individual rate schedule are below its indicated LRIC. The LRIC results for Rate Schedule 163 show a revenue-to-cost ratio of 0.83.[3]

### B. Opening Testimony of AWEC

[1] UG 347 CNG/601/Line 38.
[2] UG 347 CNG/601/Line 33.
[3] UG 347 CNG/601/Line 39.



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**Q. Please summarize the conclusion expressed by AWEC witness Mullins regarding Schedule 163 and his underlying rationale.**

A. Mr. Mullins concludes that because Cascade modified the structure of Rate Schedule 163 by adding an additional rate block to accommodate the potential transition of the Schedule 902-2 customer, thereby "treating the Schedule 902-2 customer as a cost of service customer, and then separating that customer from the cost of service study makes the results of the study inviable."[4] Mr. Mullins supports his conclusion by including the Schedule 902-2 customer's costs and forecasted revenues with Schedule 163 in a modification of the Company's LRIC study. The revenue-to-cost results under this scenario shows the revised Schedule 163 transportation revenues are above the indicated revenue requirement by 22%.[5]

Mr. Mullins further states Cascade's study allocates commodity investment costs of $19,247,882 to transportation customers, but not special contract customers, which if corrected further increases the parity ratio of Schedule 163 customers.[6]

## C. Cascade's Reply Position

**Q. Is it appropriate to combine the Special Contract customer served under Schedule 902-2 with Schedule 163 customers in the LRIC at this time?**

A. No. Cascade did not include the Schedule 902-2 customer with Schedule 163 in the LRIC because the Schedule 902-2 customer was not a current Schedule 163 customer during the test year and is, at present, still served under its Special Contract, which

[4] UG 347/AWEC/Mullins/32.
[5] UG 347/AWEC/108.
[6] UG 347/AWEC/Mullins/32.



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expires on March 31, 2019. As discussed in my Direct Testimony, under the Notice provisions of the Special Contract 902-2, Cascade informed the customer one year prior to the expiration of the Special Contract that it would not be renewed under its current price structure. Cascade offered to serve the Schedule 902-2 customer under Schedule 163 at the conclusion of its Special Contract and therefore provided a modified Schedule 163 rate structure proposal in its direct case that was designed to have a negligible impact on the customer and revenue neutral for Cascade.[7] Since that time, discussions between Cascade and the Schedule 902-2 customer have led to the withdrawal of the termination notice by the Company. Cascade and the customer have agreed to proceed with negotiations over the course of this next year toward a new Special Contract by September 2019.

**Q. Please comment on AWEC witness Mullins' assertion that the "Commodity investment" allocation of $19,247,882 be removed from Schedule 163 in the LRIC?**

A. Mr. Mullins is referring to the allocation of System Replacement capital investment costs.[8] The Special Contract customers do not receive an allocation of these costs for two reasons. First, the Special Contract customers have individually been given a direct assignment of the distribution main extension investment costs incurred to serve them either from their point of service back to the nearest system town border station, interstate pipeline interconnect, or the nearest high pressure, transmission level main with a direct path to the town border station. The Schedule 163 customers are dispersed throughout the distribution system and have only received a direct assignment

[7] UG 347/CNG/606.
[8] UG 347/CNG/603/Amen/2.



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of the distribution main extension investment costs associated with the main to which their individual service lines are connected.

Second, the rates and charges, terms and conditions of service for the Special Contract customers are governed by their individual contracts, which originated as an anti-bypass measure based on the alternative service available to each of the customers at that time. This contrasts with the firm transportation tariff service available to qualifying Schedule 163 customers. Therefore, the Special Contract customers should not receive an allocation of the System Replacement investment costs under the LRIC.

## IV. CONCLUSIONS

**Q. Please summarize the conclusions of your reply testimony.**

A. First, the Commission should rely upon the Company's LRIC study because it best reflects the long run incremental costs incurred to serve the Company's customers. Second, for the reasons stated above, the Commission should reject the assertions made by AWEC witness Mr. Mullins that the LRIC results for General Transportation Schedule 163 customers, which show the class to below parity (0.83), is incorrect; and further, that Cascade's cost of service study is flawed, inconsistent with how it proposes to set rates and should be rejected.[9] Finally, the Company's proposed revenue changes to the various rate classes that reflect the results of the Company's LRIC should be adopted for purposes of adjusting the rate components of the respective rate schedules.

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

A. Yes.

[9] UG 347 AWEC/Mullins/31, 17-31.



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