Exhibit No. __ (NAK-1T)
Docket No. UG-19____
Witness: Nicole A. Kivisto

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-19______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF NICOLE A. KIVISTO

March 29, 2019

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I. INTRODUCTION

Q. Please state your name and business address.

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

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

A. I am the President and Chief Executive Officer ("CEO") of Cascade Natural Gas Corporation ("Cascade" or "Company"), Intermountain Gas Company, Montana-Dakota Utilities Co. ("Montana-Dakota"), and Great Plains Natural Gas Co. ("Great Plains"). After restructuring, all of these companies are now subsidiaries of MDU Resources Group, Inc. ("MDU Resources"), located in Bismarck, North Dakota. Together, these four utilities comprise the Montana Dakota Utilities Group (MDUG or Utilities Group). Cascade became a wholly-owned subsidiary of MDU Resources in 2007.

Q. Please describe your duties and responsibilities.

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

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

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

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

Q. Have you previously written or presented testimony on behalf of Cascade before the Washington Utilities and Transportation Commission ("Commission") or any other commission?

A. Yes, I have previously testified before this Commission in Cascade's most recent Washington rate cases, Docket No. UG-170929 and Docket No. UG-152286. I have also testified before the Public Utility Commission of Oregon in Cascade's most recent Oregon rate cases, Docket No. UG 347 and Docket No. UG 305.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony covers numerous subject areas, including an overview of Cascade's corporate profile, a brief summary of the Company's rate request, and a description of the primary drivers leading to this request for rate relief. I also provide background on Cascade's increased spending on system improvements and describe measures the Company has taken to control costs and increase operating efficiencies, allowing it to reduce the impact of this request. Finally, I provide the Commission an update on Cascade's work to design and implement a load study that would verify system usage by class and help inform the allocation of costs between customer classes.

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

A. Cascade's cost of doing business in Washington is increasing despite the Company's efforts to control costs and increase efficiency. Since 2008, the Company has invested over $406.6 million to improve the safety and reliability of its distribution system in

Washington. While much progress was made over this period, Cascade believes it necessary to maintain its focus on system improvements and estimates it will invest more than $282 million to ensure system safety and reliability between 2019 and 2023. Further, the Company continues to experience increases in labor and personnel costs, general inflation across its business lines, and to some degree customer growth.

Cascade's rate base growth and increased operating expenses since its last filed rate case require it to request an overall rate of increase of $12,708,529 million or 5.6 percent. The Company's demonstrated increase is based on an overall rate of return of 7.728 percent based on a weighted capital structure of 50 percent common equity, 50 percent long-term debt, and a return on equity of 10.3 percent.

The Company's filing uses a historical test year based on the twelve-month period that ended December 31, 2018. The 2018 test year was selected as the most recent, appropriate, and supportable to represent the period in which rates will be in effect. In addition, certain capital projects expected to be complete and in service by the end of 2019 have also been pro formed into the Company's requested rate base. Company witness Maryalice Peters provides further discussion of the test period in her testimony.

As to rate spread and rate design, the Company's proposed tariffs reflect its application of an equal percent of margin increase or decrease to each rate class, except for Special Contracts. This proposed rate treatment is consistent with the Commission's order in the Company's last rate case. No changes to rate design are proposed by Cascade, including the customer charge. Again, this treatment is consistent with the Commission's order in the last rate case.

Cascade's rate filing will result in a bill increase of $2.83 per month for the average residential customer using 57 therms per month. As a result, the average customer's bill will increase from $46.01 per month to $48.85.

III. OVERVIEW OF CASCADE

Q. Please briefly provide an overview of the Company.

A. Cascade was originally formed in 1953 to serve smaller and predominantly rural communities in the Pacific Northwest. Cascade now provides natural gas distribution service in 96 communities in Washington and Oregon, serving 294,462 customers, of which 218,540 are in Washington. Cascade's headquarters are located in Kennewick, Washington. Although Cascade serves 68 communities in Washington, most of the communities are quite small. The largest of the communities served by Cascade in Washington are Bellingham, Mt. Vernon, Bremerton, Tri-Cities, and Yakima. Cascade serves a non-contiguous service territory with 268 dedicated employees.

IV. REASONS FOR RATE INCREASE REQUEST

Q. Please describe the factors influencing Cascade's decision to seek a rate increase at this time.

A. As I express earlier in my testimony, there are several factors that have contributed to the Company's decision to file a general rate case. When examined as a whole, the combination of significant rate base investments, increased pressures on operating and maintenance ("O&M") expenditures, and the progressive and deleterious impact of regulatory lag on cost recovery, and consequently earnings, require the Company to file this rate case and sequential rate cases in future years.

Q, Please explain how regulatory lag creates a progressive and deleterious drain on the Company's finances.

A. First, I believe it is necessary to put the Company's circumstances in context. Cascade is in the middle of a needed campaign to improve the safety and reliability of its distribution system. In 2016 and 2017, the Company's invested capital in Washington exceeded $31.1 million and $42.4 million, respectively. In the 2018 test year, the Company's capital investment in Washington increased to $93.5 million and is projected to exceed $86.6 million in 2019. As noted earlier in my testimony, Cascade will continue to make significant capital investments in Washington through 2023 and has budgeted more than $195 million to achieve its reliability objectives.

Cascade's investment history and future objectives demonstrate the Company's clear commitment to improve its Washington properties for the benefit of its customers and the public. However, the Company's commitment to invest in and improve its system will continue to negatively impact Cascade's earnings unless the progressive impacts of regulatory lag can be reliably mitigated.

As necessary background, please recall that the 2017 filing was based upon a historical test year that ended on December 31, 2016.[1] Therefore, the capital investments made by Cascade since then and not included in the Commission-approved pipeline replacement cost recovery mechanism have not been included in rate base until this filing – a period exceeding two years for the capital projects completed in early 2017. As a result,

[1] The use of the Average of Monthly Averages methodology for determining plant allowed into rate base results in the exclusion of a percentage of plant put into service during the test year.

Cascade incurred approximately $56 million of unrecovered capital costs during this period.

Expressed nominally, the unrecovered return *of* and *on* the investments not included in the 2016 test year and made in 2017 is estimated to be $4.6 million. By the end of 2018, the cumulative total of 2016, 2017, and 2018 unrecovered return *of* and *on* invested capital is estimated to be $13.7 million. At the same time, the Company has incurred and booked a cumulative total of $2.29 million in unrecovered depreciation expense over these periods. Even though the Commission may approve the Company's in-service investments made in 2016, 2017 and 2018 in this rate case, Cascade will never recover the return *of* and *on* these investments from their in-service date to the start of new rates approved by the Commission's final order in this docket. This is the essence of the regulatory lag affecting Cascade during this period of extraordinary capital investment—progressive regulatory lag resulting in accumulating carrying costs and earnings below its authorized return. Mr. Parvinen also provides similar calculations of the impact of regulatory lag in Exhibits__(MPP-3) and (MPP-4).

The accumulation of these deleterious financial impacts can be mitigated but not eliminated by annual rate cases designed to timely capture all in-service capital investments made by the Company. However, unless an end of period adjustment is allowed by the Commission, the Company will not capture the full value of projects put into service in 2018, requiring it to carry portions of these projects into the next rate case. As these unrecognized capital investments accumulate, the incentive to file a new rate case early in

2020 intensifies, thus exacerbating the back-to-back rate case cycle.

Until its capital investments can be recognized for rate treatment without having to file a general rate case, Cascade will have no choice but to file annual rate cases over the next five years. To be clear, Cascade would like to avoid the cost and efforts devoted to annual rate case filings but believes it to be the only available option until more timely cost recovery opportunities are approved by the Commission.

Q. Does the Company believe the regulatory outcomes in Washington influenced the recent downgrade of the Company's financial ratings?

A. Yes. On August 1, 2018, Fitch Ratings downgraded Cascade's Issuer Default Rating from "A-" to "BBB+." In addition, the agency downgraded the Company's Unsecured debt rating from "A" to "A-." To support its downgrade decision, Fitch expressly noted the Company's "challenging" regulatory environment in Washington, the limited recovery of rate base included in the last rate filing, and Cascade's inability to earn its "authorized return for several years."[2] While regulatory lag was not expressly called out in the Fitch report, there is no question that under-recovery of invested capital has negatively impacted earnings.

Q. Has Cascade made all reasonable efforts to control costs in order to avoid the need to file a new rate case?

A. Yes. Cascade's management takes seriously the need for efficiency and cost-effectiveness when making decisions on new investments or operational expenses. As examples, Cascade has found synergy savings since its acquisition by MDU Resources. These savings

[2] FitchRatings, "Fitch Affirms MDU Resources, Centennial Energy; Downgrades Cascade; Outlook Stable", August 1, 2018, https://www.fitchratings.com/site/pr/10040135.

have been produced by streamlining senior management, forming both a unified customer service center and a joint billing facility, restructuring processes to create efficiencies, and investing in uniform accounting and customer information system software.

The Utilities Group also seeks to maximize synergies and create efficiencies. To this end, we have approved the acquisition of a new Gas Management System and centralized other operations and functions. The Company also takes seriously its obligation to deliver safe, reliable, and efficient service to its customers, and I can assure the Commission that Cascade has and will continue to take the steps necessary to fulfill this obligation.

V. CUSTOMER SUPPORT PROGRAMS

Q. How does Cascade support customers that have difficulty paying for the natural gas service provided to them by the Company?

A. With the support of the Commission, Cascade currently provides its customers with a number of bill assistance and conservation programs designed to assist customers in meeting their energy bill obligations.

Regarding bill assistance, Cascade's Washington Energy Assistance Fund ("WEAF") and its Winter Help programs provide needed bill assistance to low-income customers. Cascade also offers its customers a program called the Budget Payment Plan, which serves to reduce bill volatility associated with seasonal fluctuations in usage.

The WEAF program has been very successful and was recently updated to better serve low-income customers. To this end, the Commission approved the Company's request to increase the program's spending cap. As a result, the program's 2018-2019 funding was set at $1,329,400 and it is projected to grow to $1,467,400 by program year

2020-2021. In addition, the program is allowed an incremental 5% soft cap should additional funds be needed.

Cascade also offers a Budget Payment Plan for customers that allows those that opt in to make a flat payment for a period of time, thus flattening or leveling their monthly bill. Cascade has found that this plan makes it easier for customers to budget their payments. As of December 31, 2018, there were 21,243 Washington customers participating in the Budget Payment Plan, comprising 9.7% percent of Cascade's customer base.

Cascade also provides conservation programs for all customers, as well as conservation programs through community action agencies specifically designed for low-income customers. The Company's conservation program budgets have seen a marked increase in the past few years. Through 2017 the Company's program expenses annually had not exceeded $3.6 million. In 2018, however, Cascade's energy efficiency budget increased to meet higher therm savings goals to approximately $5.1 million with 2019's budget set at approximately $6.1 million, which includes program delivery costs, the incentives offered to customers, and work with regional partner, the Northwest Energy Efficiency Alliance.

Q. Have customers responded positively to the programs and services offered by the Company?

A. Yes. I am proud to inform the Commission that Cascade finished first in J.D. Power's 2018 Gas Utility Residential Customer Satisfaction Survey for mid-size gas utilities. The Company's outstanding achievement was due to the exceptional work of our employees and Cascade's focus on providing safe, reliable and efficient service to our customers.

VI. UPDATE ON CUSTOMER CLASS LOAD STUDY

Q. Please describe Cascade's agreement to conduct a load study for the purpose of determining commodity usage by core customer classes.

A. As part of the settlement of UG-170929, the Company agreed to design and conduct a study that would allow it to more accurately assess commodity usage among its core customer classes. Upon implementation, the study will be used to verify system usage by class and help inform the allocation of costs between the classes. For purposes of this case, the Company has spread the proposed increase on an equal percent of margin to each class except for Special Contracts, as called for in the settlement.

Q. Did the Commission establish a deadline for completion of the study?

A. No, it did not. The Commission's final order observed that the parties' settlement contained no deadline for the study's completion and it approved the settlement terms, as written. It did, however, comment on the rate spread restrictions noted above, stating that the agreement imposed "appropriate parameters and restrictions on the allocation of future rate increases until such time as a load study or detailed load analysis is complete."[3] The Commission's willingness to allow Cascade the time necessary to make what it believes to be the best decision for it and its customers is much appreciated.

Q. Please explain the Company's philosophy regarding the parameters of its load study.

A. From the Company's perspective, an acceptable load study should be designed to balance the study's objectives with its overall cost, including necessary system and back office

[3] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Order 06 at ¶ 72 (July 20, 2018).

modifications. To this end, the flexibility provided by the Commission's order has allowed Cascade the opportunity to consider its options, weigh expected costs, and assess the range of benefits.

Q. Has Cascade settled on a study design consistent with these principles?

A. Yes, the Company has examined its options and based on its preliminary analysis, believes the load study can be completed in less time and at a lower cost using newly installed equipment and existing personnel.

Q. Please explain.

A. Cascade's goal is to arrive at a reasonable result using the technologies and personnel at hand. We are scoping the use of newly installed Encoder Receiver Transmitters ("ERT") in combination with reprogramming Mobile Meter Reading ("MMR") equipment to take the readings necessary to effectively determine customer class usage over a designated period. By using the combination of ERT and MMR equipment, the Company believes it can minimize the study's costs and maximize its benefits. Importantly, the Company also believes it can produce comparable and useful results over a reasonable period.

Q. What is the Company's expected timeline for completion of the load study?

A. Cascade hopes to begin data collection over the next heating season, assuming the final study design and anticipated equipment modifications can be completed over the summer. I must caution, however, that the study's completion will be weather dependent.

An important cost allocation factor is the determination of peak day usage by class. Obtaining the peak usage data requires the existence of a peak day or even better, a number of peak or near peak days, to produce statistically meaningful data points. Therefore, the load study could take more than one heating season to complete should peak day temperatures and loads fail to occur.

Q. Will the Company share its data collection strategy with the Commission prior to implementation?

A. Yes, that is the Company's intent. When the final draft of the load study has been prepared, the Company will present it to the Commission, interested parties, and stakeholders for review and comment.

Q. Cascade considered building out of a Fixed Area Network to enhance the collection of customer usage data and improve system operations, is this option still being considered?

Yes, construction of a Fixed Area Network ("FAN") remains a key objective for Cascade. At this time, the Company is scoping the network's design and required technologies. Once this work is completed, it will then turn to finalizing the project's capital budgets and timeline for construction. If a FAN is determined to be cost-effective and technologically feasible, Cascade anticipates that its construction could be complete by 2024.

VII. OTHER COMPANY WITNESSES

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

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

Ms. Tammy Nygard, Controller, will address the Company's capital structure, the proposed cost of embedded debt, and the overall rate of return.

Ms. Ann E. Bulkley, Senior Vice President – Concentric Energy Advisors, will discuss the requested overall return on equity for Cascade.

Mr. Michael Parvinen, Director – Regulatory Affairs, discusses the impact of regulatory lag on the Company and describes the Company's proposals to mitigate regulatory lag. He also addresses the Company's calculation of working capital. Further, he discusses the Company's conservation targets and whether they are appropriate.

Ms. Pamela Archer, Supervisor, Regulatory Analysis, will discuss the proposed tariff changes.

Ms. Maryalice Peters, Regulatory Analyst, discusses the Company's proposed revenue requirements and supporting calculations.

Mr. Isaac Myhrum, Regulatory Analyst, performs the summary of revenues by customer class and the revenue analysis for the Cost Recovery Mechanism and the Company's unbilled revenue. He also performs the baseline analysis for Cascade's Decoupling program. The Company's proposed rate spread is also covered by Mr. Myhrum's testimony.

Mr. Brian Robertson, Senior Resource Planning Analyst, will discuss the weather normalization adjustment and method behind the calculation.

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

A. Yes.

Exhibit No. __ (TJN-1T)
Docket No. UG-19____
Witness: Tammy J. Nygard

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF TAMMY J. NYGARD

March 29, 2019

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I. OVERVIEW

Q. Would you please state your name, business address and position?

A. Yes. My name is Tammy J. Nygard and my business address is 400 North Fourth Street, Bismarck, ND 58501. I am the Controller for Cascade Natural Gas Corporation ("Cascade" or "Company"), a wholly-owned subsidiary company of MDU Resources Group, Inc. ("MDU Resources"). I am also the Controller of Montana-Dakota Utilities Co. ("Montana-Dakota"), Great Plains Natural Gas Co. ("Great Plains"), and Intermountain Gas Company ("Intermountain"), subsidiaries of MDU Resources Group.

Q. Would you please describe your duties?

A. As Controller, I am responsible for providing leadership and management of the accounting and the financial forecasting/planning functions, including analysis and reporting of all financial transactions for Cascade, Intermountain, Montana-Dakota and Great Plains.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Mary with a Bachelor of Science degree in Accounting and Computer Information Systems. I have over 17 years of experience in the utility industry. During my tenure with the Company, I have held positions of increasing responsibility, including Financial Analyst for Montana-Dakota, Director of Accounting and Finance for Cascade, and my current position, Controller.

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

A. My testimony supports the Company's overall cost of capital recommendation in this case. To that end, I explain and support the Company's recommended cost of debt, capital structure and rate of return.

Q. What is the Company's overall recommended cost of capital for this case?

A. Cascade proposes an overall rate of return ("ROR") of 7.728 percent, which provides a reasonable return for Cascade's investors at a fair cost to Cascade's customers. The recommended ROR is based on a 50.0 percent common equity ratio with a return on equity of 10.3 percent and a debt cost of 5.155 percent.

II. COST OF DEBT, CAPITAL STRUCTURE, AND RATE OF RETURN

Q. How does Cascade finance its regulated utility operations?

A. Cascade finances its regulated utility operations with a mix of debt and common equity capital.

Q. How much debt is currently held at Cascade and what are the maturity dates of the existing debt?

A. Confidential Exhibit No. __ (TJN-2C) details Cascade's currently outstanding debt and the associated maturity dates. Total outstanding debt as of December 31, 2018, was valued at $214,361,000 with maturity dates beginning in 2020. All the debt is unsecured term notes with tenors ranging from twelve years to forty years. Each issuance of debt requires either semi-annual or quarterly interest payments.

Q. What is the average annualized interest rate of Cascade's debt and how is this calculated?

A. The average annualized cost of debt of 5.308 percent is calculated based on the weighted average outstanding debt at December 31, 2018, inclusive of the annual amortization of the costs associated with the financing of the debt. The associated amortization has been computed on a straight-line basis over the remaining life of the issues. Cascade uses the same methodology for book accounting purposes. In 2019, the Company plans to issue $50 million of additional long-term debt, which reduces the cost of debt in this case to 5.155 percent. Since 2006, the Company has been able to reduce its average annualized cost of debt from approximately 7.58 percent to 5.155 percent.

Q. Will any of the debt included in this filing come due within the next five years?

A. Yes. As shown in the attached confidential Exhibit No. __ (TJN-2C), one long-term note will mature in September 2020 in the amount of $15,000,000. The Company anticipates this amount will be replaced through a new long-term debt offering.

Q. Does Cascade plan to issue any other debt in the next five years?

A. Any long-term debt issuances planned for the next five years are provided in confidential Exhibit No. __ (TJN-3C).

Q. What is the overall ROR and capital structure that Cascade is requesting in this case?

A. The Company is requesting an ROR of 7.728 percent, which is based on a capital structure of 50 percent equity and 50 percent debt. The components and calculation of the proposed rate of return are shown in the following table:

Table 1. Proposed Rate of Return

Proposed Rate of Return			
	Capital Structure	Cost	Component
Common Equity	50%	10.300%[1]	5.150%
Total Debt	50%	5.155%	2.578%
	100%		7.728%

[1] *See*, Exh. No.__(AEB-1T)

Q. The Company is proposing a capital structure of 50 percent equity and 50 percent debt. Please explain.

A. The Company's requested capital structure is based upon Cascade's actual (and targeted) average capital structure for the last two years, adjusting 2018 for an unanticipated $17.5 million short-term debt increase from higher gas costs in November and December resulting from the Enbridge incident.[2] As a regulated public utility, Cascade has the responsibility to provide safe and reliable service to customers across its service territory. This requires on-going investment in new plant for mains, services, meters, and other support facilities. As part of the planning process, Cascade determines the amount of new financing needed to support the capital expenditure program with a target of 50 percent debt and 50 percent equity. The Company is committed to maintaining a healthy capital ratio, which Cascade believes is in the best interests of its shareholders and customers, and reduces financial risk for Cascade's debt obligations. The following Table 2 provides a summary of Cascade's actual capital structure supporting the requested capital structure of 50 percent equity and 50 percent debt.

Table 2. Cascade's Actual Capital Structure

Capital Structure				
	12/31/2017	12/31/2018	Adjusted 12/31/2018	Average
Total Debt	50.8%	50.9%	49.2%	50.0%
Common Equity	49.2%	49.1%	50.8%	50.0%

[2] The Company received $30 million of equity in September 2018, which was anticipated to result in a 50 percent equity ratio at December 31, 2018. However, due to the Enbridge incident, which caused increased gas costs in November and December 2018, and therefore higher unrecovered purchased gas costs, the Company incurred higher short-term debt costs than anticipated, which resulted in year-end equity percentage of slightly over 49 percent.

Q. Why is the Company proposing a 10.3 percent return on equity?

A. Ms. Ann E. Bulkley calculated a range for the cost of common equity capital for Cascade's Washington natural gas distribution operations based on multiple analytical methods, including the Discounted Cash Flow model, the Capital Asset Pricing Model, the Risk Premium Approach, and the Expected Earnings Analysis.[3] Ms. Bulkley then compared the range of results produced by these methods with the returns on equity for a group of proxy companies that have risks similar to those of Cascade's Washington gas distribution operations.[4] Finally, Ms. Bulkley considered the impact of current capital market conditions on the results produced by the various analytical tools, using this review to further inform her opinion. In the end, Ms. Bulkley's multi-faceted and balanced approach produced the Company's requested 10.3 percent return on equity. Ms. Bulkley's comprehensive cost of capital analysis is detailed in her testimony.[5] The Company agrees with the information presented and conclusion reached by Ms. Bulkley that a 10.3 percent ROE represents a fair return for both the Company and its customers.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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[3] *See*, Exh. No.__AEB-1T at 3, lines 5-16.
[4] *Id.* at 8, lines 1-9.
[5] *Id.*

Redacted Exhibit No. __ (TJN-2C)
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Witness: Tammy J. Nygard

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CASCADE NATURAL GAS CORPORATION

EXHIBIT OF TAMMY J. NYGARD

CASCADE'S CURRENTLY OUTSTANDING DEBT

March 29, 2019

Redacted Version

Shaded information is designated as confidential per WAC 480-07-160

Cascade Natural Gas Corporation
Schedule of Outstanding Long-Term Debt
December 31, 2018

Description	Term in Years	Rate	Balance

Redacted Exhibit No. __ (TJN-3C)
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CASCADE NATURAL GAS CORPORATION

EXHIBIT OF TAMMY J. NYGARD

LONG-TERM DEBT

March 29, 2019

Redacted Version

Shaded information is designated as confidential per WAC 480-07-160

Cascade Natural Gas Corporation
Summary of Forecasted Debt and Equity Issuances and Retirements

	2019	2020	2021	2022	2023
Equity Infusion					-
Debt Retirement					-
Debt Issuance					-
Total Additional Capitalization					-

Exhibit No. __ (PJA-1T)
Docket No. UG-19____
Witness: Pamela J. Archer

BEFORE THE
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CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF PAMELA J. ARCHER

March 29, 2019

I. INTRODUCTION

Q. Please state your name, business address, and present position with Cascade Natural Gas Corporation ("Cascade" or "Company").

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

Q. Would you briefly describe your duties?

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

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

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

Q. Have you previously testified before the Washington Utilities and Transportation Commission ("Commission")?

A. Yes. I have testified before the Commission in Cascade's 2015 general rate case in Docket UG-152286.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to introduce all proposed changes to Cascade's current rate schedules. The proposed tariff, as well as all legislative tariffs containing the changes in red-lined, strike-out text is included in this filing as attachments A and B to the cover letter accompanying Cascade's general rate case filing, respectively. The proposed tariff is also introduced into the record under my testimony as Exhibit No.__ (PJA-2).

Q. Would you please explain what is contained in Exhibit No. __(PJA-2)?

A. Yes. Exhibit No. __ (PJA-2) contains a copy of the Company's proposed tariff sheets that are being presented in this case

Q. Did you rely on data or information provided by other witnesses to prepare the tariff sheets?

A. Yes. I relied on testimony and exhibits provided by Mr. Isaac D. Myhrum and Ms. Maryalice C. Peters.

Q. What substantive changes is the Company making to its Tariff?

A. The Company is filing the following revised Sheets:

- Fifth Revision Sheet No. 25
- Sixty-First Revision Sheet No. 503
- Forty-Fifth Revision Sheet No. 504
- Forty-Fourth Revision Sheet No. 505
- Sixty-First Revision Sheet No. 511

- Fifty-Fifth Revision Sheet No. 570
- Nineteenth Revision Sheet No. 663

Q. Please explain the changes that are non-housekeeping in nature.

A. Cascade proposes revising Schedule Nos. 503, 504, 505, 511, 570, and 663 to include changes to rates, as discussed in the testimony of Company witnesses Mr. Myhrum and Ms. Peters. In addition, I am updating Rule 21, Decoupling Mechanism, also discussed in Mr. Myhrum's testimony.

Q. Are you proposing any other revisions to the rates or values reflected in the Tariff?

A. Yes. The Company proposes that the Gross Revenue Fee in Rate Schedule 663 decrease from 4.431 percent to 4.362 percent, consistent with the changes to the percentage applied to bills to cover the costs for uncollectibles, state Business and Operating ("B&O") tax and Commission fees, as shown in Ms. Peters' Exhibit No. __ MCP-4.

The Company also proposes an update to the lost and unaccounted for percentage in Rate Schedule 663, increasing the percentage from 0.1615 percent to .2479 percent.

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. __ (PJA-2)
Docket No. UG-19____
Witness: Pamela J. Archer

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF PAMELA J. ARCHER

PROPOSED TARIFFS

March 29, 2019

RULE 21
DECOUPLING MECHANISM

PURPOSE:
This Rule describes the revenue-per-Customer Decoupling Mechanism which annually applies a per therm credit or debit under Schedule 594, "Decoupling Mechanism Adjustment" to applicable Customers' bills for the purpose of truing up the annual difference between Margin Revenues and the Authorized Margin Revenues per Customer served as herein defined.

APPLICABILITY:
This Rule is applicable to all Customers served on Schedules 503, 504, 505, 511, and 570.

MARGIN REVENUES
Margin Revenue is the amount of Margin billed in a billing month, adjusted for unbilled margin revenues. Margin Revenue does not include amounts billed for the Basic Customer Charge, or adjustment schedules, such as Schedules 500, 581, 582, 583, 593, 594, 595, 596, 597, and 598.

AUTHORIZED MARGIN REVENUE PER CUSTOMER
The Authorized Margin per month per customer is established in the tables below. Table 1 shows January through June, and Table 2 shows July through December.

Table 1	Jan	Feb	March	April	May	June	
503	$37.86	$29.65	$24.14	$16.59	$9.94	$6.34	(C)
504	$155.03	$129.13	$94.02	$70.84	$40.33	$35.53	
505	$587.00	$468.28	$519.22	$407.72	$295.90	$219.80	
511	$3540.56	$2447.12	$2877.25	$2422.21	$1848.70	$1319.17	
570	$1857.62	$1791.39	$1743.13	$1729.61	$1440.99	$1040.34	
Table 2	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	
503	$4.87	$2.39	$6.88	$14.75	$29.47	$37.70	
504	$29.51	$16.50	$40.36	$71.05	$116.08	$154.23	
505	$194.48	$206.31	$236.37	$378.49	$360.66	$535.57	
511	$1142.91	$1154.89	$1088.53	$1838.26	$1693.73	$2928.63	
570	$834.40	$892.65	$756.29	$960.80	$1601.33	$1762.85	(C)

(Continued)

RESIDENTIAL SERVICE RATE
SCHEDULE NO. 503

AVAILABILITY:

This schedule is available to residential customers throughout the territory served by the Company under the tariff of which this schedule is a part for natural gas supplied for all purposes provided adequate capacity and supply exist in the Company's system. Service under this schedule shall be through one or more meters, billed separately.

RATE:

	Margin	WACOG	Total		
Basic Service Charge			$ 5.00	per month	
All Gas Used Per Month	$0.32160	$ 0.49569	$0.81729	per therm	(I)

RATE ADJUSTMENT:

Service under this schedule is subject to various adjustments as specified in Schedules 581, 582, 583, 590, 593, 594, 595, 596, and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington Utilities and Transportation Commission. (C) (T)

MINIMUM CHARGE:

Basic Service Charge: $ 5.00 per month

TERMS OF PAYMENT:

Above rates are net. Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition. Past due balances will be subject to a late payment charge.

RECONNECTION CHARGE:

A reconnection charge of twenty-four dollars ($24.00) during regular business hours or sixty dollars ($60.00) during non-business hours may be made for restoration of service when service has been turned off for nonpayment of any bill due, seasonal turnoff, or for other reasons arising through the action of the customer.

TAX ADDITIONS:

The rates named herein are subject to increases as set forth in Schedule No. 500, entitled "Tax Additions".

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate schedule is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Washington Utilities and Transportation Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

CNG/W19-03-02 Effective for Service on and after
Issued March 29, 2019 May 1, 2019

Issued by CASCADE NATURAL GAS CORPORATION

By: Michael Parvinen Director, Regulatory Affairs

GENERAL COMMERCIAL SERVICE RATE
SCHEDULE NO. 504

AVAILABILITY:
This schedule is available to commercial customers throughout the territory served by the Company under the tariff of which this schedule is a part for natural gas supplied for all purposes provided adequate capacity and supply exist in the Company's system. Service under this schedule may be through one or more meters, billed separately.

RATE:

	Margin	WACOG	Total		
Basic Service Charge			$13.00	per month	
All Therms Used	$0.27357	$0.49304	$0.76661	per therm	(I)

RATE ADJUSTMENT:
Service under this schedule is subject to various adjustments as specified in Schedules 581, 582, 583, 590, 593, 594, 595, 596, and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington Utilities and Transportation Commission. (C) (T)

MINIMUM CHARGE:
Basic Service Charge $13.00

TERMS OF PAYMENT:
Above rates are net. Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition. Past due balances will be subject to a late payment charge.
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RECONNECTION CHARGE:
A reconnection charge of twenty-four dollars ($24.00) during regular business hours or sixty dollars ($60.00) during non-business hours may be made for restoration of service may be made for restoration of service when service has been turned off for nonpayment of any bill due, seasonal turnoff, or for other reasons arising through the action of the customer.

TAX ADDITIONS:
The rates named herein are subject to increases as set forth in Schedule No. 500, entitled "Tax Additions".

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate schedule is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Washington Utilities and Transportation Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

GENERAL INDUSTRIAL SERVICE RATE
SCHEDULE NO. 505

AVAILABILITY:
This schedule is available to industrial customers throughout the territory served by the Company under the tariff of which this schedule is a part for natural gas supplied for all purposes provided adequate capacity and supply exist in the Company's system. Service under this schedule shall be through one or more meters, billed separately.

RATE:

	Margin	WACOG	Total		
Basic Service Charge			$60.00	per month	
First 500 therms/month	$0.21103	$0.47993	$0.69096	per therm	(I)
Next 3,500 therms/month	$0.17090	$0.47993	$0.65083	per therm	(I)
All over 4,000 therms/month	$0.16484	$0.47993	$0.64477	per therm	(I)

RATE ADJUSTMENT:
Service under this schedule is subject to various adjustments as specified in Schedules 581, 582, 583, 590, 593, 594, (C)
595, 596, and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington (T)
Utilities and Transportation Commission.

MINIMUM CHARGE:
Basic Service Charge $60.00

TERMS OF PAYMENT:
Above rates are net. Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition. Past due balances will be subject to a late payment charge.

RECONNECTION CHARGE:
A reconnection charge of twenty-four dollars ($24.00) during regular business hours or sixty dollars ($60.00) during non-business hours may be made for restoration of service when service has been turned off for nonpayment of any bill due, seasonal turnoff, or for other reasons arising through the action of the customer.

TAX ADDITIONS:
The rates names herein are subject to increases as set forth in Schedule No. 500 entitled "Tax Additions".

SPECIAL TERMS AND CONDITIONS:

1. The application of this rate schedule is subject to the General Rules and Regulations of the Company as they may be in effect from time to time and as approved by the Washington Utilities and Transportation Commission.

2. Gas purchased under this schedule shall not be submetered or resold to others without special permission from the Company.

SCHEDULE 511
LARGE VOLUME GENERAL SERVICE

AVAILABILITY:
This schedule is available to customers throughout the territory served by the Company under the tariff of which this schedule is a part provided adequate capacity and supply exist in the Company's system. Service under this schedule shall be for natural gas supplied for all purposes to customers having an annual fuel requirement of not less than 50,000 therms.

RATE:

	Margin	WACOG	Total	
Basic Service Charge			$125.00 per month	
First 20,000 therms/month	$0.16940	$0.47993	$0.64933 per therm	(I)
Next 80,000 therms/month	$0.12985	$0.47993	$0.60978 per therm	(I)
All over 100,000 therms/month	$0.03202	$0.47993	$0.51195 per therm	(I)

RATE ADJUSTMENT:
Service under this schedule is subject to various adjustments as specified in Schedules 581, 582, 583, 590, 593, 594, (C)
595, 596, and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington (T)
Utilities and Transportation Commission.

SERVICE AGREEMENT:
Customers receiving service under this rate schedule shall execute a service agreement for an Annual Minimum Quantity of 50,000 therms a year.

ANNUAL DEFICIENCY BILL:
In the event customer purchases less than the Annual Minimum Quantity as stated in the service agreement, customer shall be charged an Annual Deficiency Bill. The annual Deficiency Bill shall be calculated as the difference between the Annual Minimum Quantity and the actual purchase or transport therms times per therm rates in this schedule except WACOG plus all per therm rates for all adjustment schedules that would apply to service procured under this rate schedule.

TERMS OF PAYMENT:
Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition. Past due balances will be subject to a late payment charge.

TAX ADDITIONS:
The rates named herein are subject to increases as set forth in Schedule No. 500, Municipal Taxes.

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

SCHEDULE. 570
INTERRUPTIBLE SERVICE

AVAILABILITY:
This schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part provided adequate capacity and supply exist in Company's system. Service under this schedule shall be for natural gas delivered for all purposes to customers having an annual fuel requirement of not less than 50,000 therms per year, which shall include all firm gas delivered, if any, and where customer agrees to maintain standby fuel burning facilities and an adequate supply of standby fuel to replace the entire supply of natural gas delivered hereunder. Service under this schedule shall be subject to curtailment by the Company when, in the judgment of the Company, such curtailment or interruption of service is necessary. Company shall not be liable for damages for, or because of, any curtailment of natural gas deliveries hereunder.

RATE:

	Margin	WACOG	Total		
Basic Service Charge			$163.00	per month	
First 30,000 therms/month	$0.09333	$0.46687	$0.56020	per therm	(I)
All over 30,000 therms/month	$0.02657	$0.46687	$0.49344	per therm	(I)

RATE ADJUSTMENT:
Service under this schedule is subject to various adjustments as specified in Schedules 581, 582, 583, 590, 593, 594, 595, 596, (C)
and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington Utilities and (T)
Transportation Commission.

ANNUAL DEFICIENCY BILL:
In the event customer purchases less than the Annual Minimum Quantity as stated in the service agreement, customer shall be charged an Annual Deficiency Bill. Annual Deficiency Bill shall be calculated as the difference between the Annual Minimum Quantity and the actual purchase or transport therms times per therm rates in this schedule except WACOG plus all per therm rates for all adjustment schedules that would apply to service procured under this rate schedule.

SERVICE AGREEMENT:
Customers receiving service under this rate schedule shall execute a service agreement for an Annual Minimum Quantity of 50,000 therms a year.

TERMS OF PAYMENT:
Each monthly bill shall be due and payable within fifteen (15) days from the date of rendition. Past due balances will be subject to a late payment charge.

TAX ADDITIONS:
The rates named herein are subject to increases as set forth in Schedule No. 500, Municipal Taxes.

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

(M) text was previously found on Sheet 570-A.

SCHEDULE 663
DISTRIBUTION SYSTEM TRANSPORTATION SERVICE

(Continued from Previous Page)

Rates (continued):

D. Delivery Charge for all therms delivered per month

	Margin
First 100,000	$0.06302
100,001-200,000	$0.02299
200,001-500,000	$0.01397
>500,000	$0.00664

(I)
(I)
(I)
(I)

E. Gross Revenue Fee:
The total of all charges shall be subject to a Gross Revenue Fee of 4. 362% to cover state utility tax and other governmental levies imposed upon the Company. (R)

F. Fuel Use Requirements:
Customers served on Schedule 663 shall provide the Company with in-kind fuel for lost and unaccounted for gas on the Company's distribution system. The fuel use factor is 0.2479%. (I)

All other terms and conditions of service shall be pursuant to the rules and regulations set forth in this Tariff.

RATE ADJUSTMENTS:
Service under this schedule is subject to various adjustments including Schedules 581, 582, 583, 593, 594, 595, 596 and 597.

TAX ADDITIONS:
The rates named herein are subject to increases as set forth in Schedule 500, Municipal Taxes.

(continued)

(M) refers to language on Sheet No. 663-A that was previously on Sheet No. 663.

Exhibit No.___(AEB-1T)
Docket No. UG-19____
Witness: Ann E. Bulkley

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-19______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF ANN E. BULKLEY

March 29, 2019

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. What is your position with Concentric Energy Advisors, Inc. ("Concentric")?

A. I am employed by Concentric as a Senior Vice President.

Q. On whose behalf are you submitting this Direct Testimony?

A. I am submitting this Direct Testimony before the Washington Utilities and Transportation Commission ("Commission") on behalf of Cascade Natural Gas Corporation ("Cascade" or the "Company"), which is a wholly-owned subsidiary of MDU Resources Group, Inc. ("MDU Resources").

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with more than 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Exhibit No.___(AEB-3) to this testimony.

Q. Please describe Concentric's activities in energy and utility engagements.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q. Have you testified before any regulatory authorities?

A. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit No.___(AEB-3) to this testimony.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the appropriate Return on Equity ("ROE")[1] for the Company's natural gas utility operations in Washington and to provide an assessment of its proposed capital structure to be used for ratemaking purposes. My analyses and recommendations are supported by the data presented in Exhibit No.___(AEB-2), Schedules 1 through 12, which were prepared by me or under my direction.

[1] Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "cost of equity".

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. As discussed in more detail in Section VII, I applied the Constant Growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Risk Premium Approach and the Expected Earnings Analysis. My recommendation also takes into consideration: (1) the Company's small size; (2) Flotation Cost; (3) the Company's customer concentration; (4) the Company's capital expenditure requirements; (5) the regulatory environment in which the Company operates; and (6) the Company's adjustment mechanisms. Finally, I considered the Company's proposed capital structure as compared to the capital structures of the proxy companies.[2] While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

Q. How is the remainder of your Direct Testimony organized?

A. Section III provides a summary of my analyses and conclusions. Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital. Section V discusses current and projected capital market conditions and the effect of those conditions on Cascade's cost of equity in Washington. Section VI explains my selection of a proxy group of natural gas utilities. Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE

[2] The selection and purpose of developing a group of comparable companies will be discussed in detail in Section VI of my Direct Testimony.

for Cascade. Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for Cascade in this case. Section IX assesses the proposed capital structure of Cascade as compared with the capital structures of the utility operating subsidiaries of the proxy group companies. Section X presents my conclusions and recommendations for the market cost of equity.

III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[3] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that result must lead to just and reasonable rates.
- The effect of current and projected capital market conditions on investors' return requirements.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE for Cascade.

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[3] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

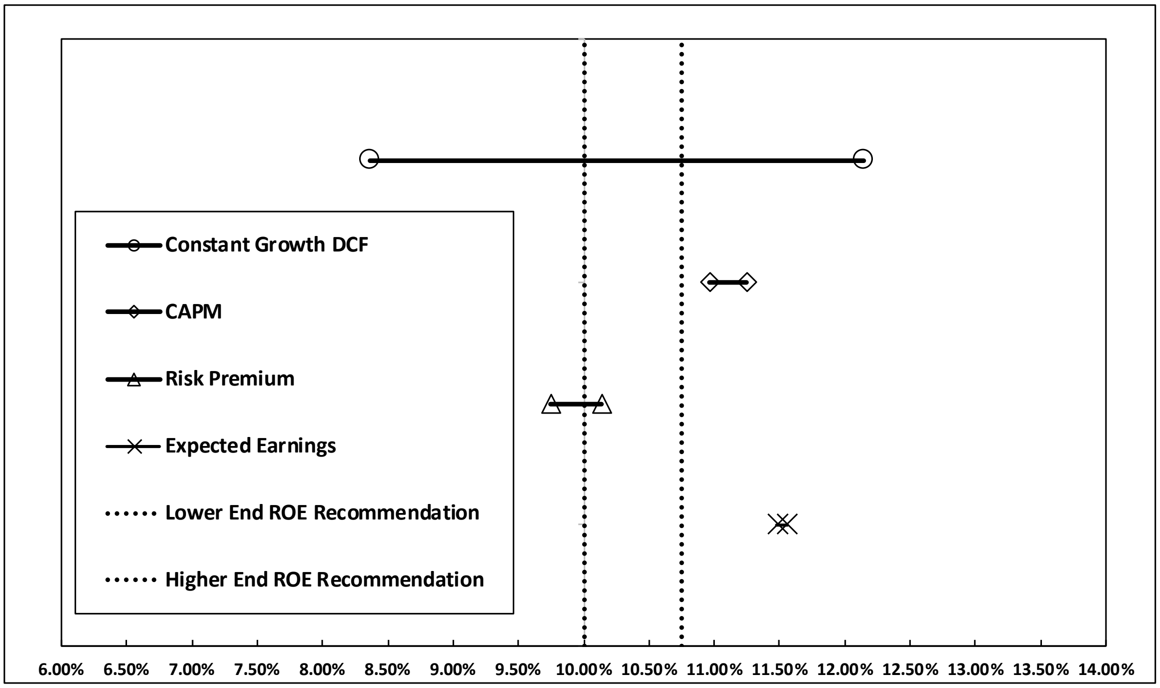
Q. Please explain how you considered those factors.

A. I have relied on several analytical approaches to estimate the Company's cost of equity based on a proxy group of publicly traded companies. As shown in Figure 1, those ROE estimation models produce a wide range of results. My conclusion as to where within that range of results Cascade's ROE falls is based on the Company's business and financial risk relative to the proxy group. Although the companies in my proxy group are generally comparable to Cascade, each company is unique, and no two companies have the exact business and financial risk profiles. Accordingly, we settle on a proxy group with similar, but not the same risk profiles; and adjust the results of our analysis either upwards or downwards within the reasonable range of results to account for any residual differences in risk.

Q. Please summarize the ROE estimation models that you considered to establish the range of ROEs for Cascade.

A. I considered the results of the Constant Growth DCF model using current dividends, earnings growth rates and stock prices. In addition, I considered two risk premium approaches, the CAPM and a Bond Yield Plus Risk Premium methodology, as well as an Expected Earnings analysis. Figure 1 summarizes the range of results established using each of these estimation methodologies.

Figure 1: Summary of Cost of Equity Analytical results[4]



As shown on Figure 1 (and in Exhibit No.___(AEB-2), Schedule 1), the range of the DCF model results is wide, particularly in relation to the results of the other methodologies. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results is wide.

The requested ROE is for the future rate period; therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (e.g., projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high valuations of utility stocks and the market's expectation for higher interest rates. The use of historical inputs and assumptions would tend to understate the required ROE for Cascade, when considering current and projected conditions in

[4] The analytical results reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7.00 percent.

capital markets.

As discussed in more detail in Sections V and VII, the DCF models are influenced by current market conditions that are not projected to be sustained in the long-term. Those conditions result in lower estimates of the ROE using the DCF model. For example, the median low Constant Growth DCF[5] results (prior to exclusions for outliers) for the proxy group, ranging from 7.81 to 7.90 percent for the 30-, 90-, and 180-day assumption, are below an acceptable range of returns for a natural gas utility and are below any authorized ROE for an electric utility or natural gas utility in the U.S. since at least 1980.[6] Based on prospective capital market conditions, and the inverse relationship between the market risk premium and interest rates, I conclude that the median low DCF results do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of Cascade.

Due to these concerns about the results produced by the DCF model, my ROE recommendation considers the median and median-high results of the DCF model, a forward-looking CAPM analysis, a Bond Yield plus Risk Premium analysis, and an Expected Earnings analysis. I also consider company-specific risk factors and current and prospective capital market conditions.

Q. What is your recommended ROE for Cascade?

A. In addition to the analytical results presented in Figure 1, I also considered the level

[5] My DCF models generated a median low, median, and median high result. The median low result is the median of the proxy group DCF results calculated using the lowest earnings growth rate for each company from Value Line, Yahoo! Finance or Zacks.

[6] Source: Regulatory Research Associates, Rate Case History, January 1, 1980 – January 31, 2019.

of regulatory, business, and financial risk faced by Cascade's natural gas operations in Washington relative to the proxy group to establish the range of reasonable returns. Considering these factors, I believe a range from 10.00 to 10.75 percent is reasonable. This recommendation reflects the range of results for the proxy group companies, the relative risk of Cascade's natural gas operations in Washington as compared to the proxy group, and current capital market conditions. Within that range, a return of 10.30 percent is reasonable.

Q. Please summarize the analysis you conducted in determining that Cascade's requested capital structure is reasonable and appropriate.

A. Based on the analysis presented in Section IX of my testimony, I conclude that Cascade's proposed 50.00 percent common equity is reasonable. To determine if Cascade's requested capital structure was reasonable, I reviewed the capital structures of the utility subsidiaries of the proxy companies. As shown in Exhibit No.___(AEB-2), Schedule 12, the results of that analysis demonstrate that the average equity ratios for the utility operating companies of the proxy group range from 51.32 percent to 63.18 percent with an average of 57.07 percent. Cascade's proposed equity ratio of 50.00 percent is below the range of equity ratios for the utility operating subsidiaries of the proxy group companies and is therefore reasonable. However, it is important to note that the difference in capitalization between Cascade and the proxy group is significant and should be considered in setting the appropriate ROE for the Company, especially considering that Federal tax reform legislation has had a negative effect on the cash flows and credit metrics of regulated utilities.

Furthermore, a fundamental aspect of the financial regulation of utilities is assuring that the subject utility has a reasonable opportunity to earn a return on capital consistent with the return available on investments of similar risk. While this principle is most often discussed in terms of the allowed ROE, it is equally applicable to all aspects of overall Rate of Return ("ROR"). The equity return, the product of the ROE and the equity ratio, (i.e., the Weighted Return on Equity ("WROE")), ultimately defines the return to shareholders and the product of the cost of debt and the debt ratio ensures that a company's debt obligations are met. Therefore, it is necessary to consider both the rates that are applied to debt and equity and the composition of the capital structure to determine the reasonableness of the ROR. As discussed in greater detail in Section IX, the Company's proposed common equity ratio of 50.00 percent is below the range of the equity ratios of the companies in my proxy group. Taken together, the Company's proposed common equity ratio of 50.00 percent and the Company's requested ROE of 10.30 percent, results in a WROE of 5.15 percent. This reasonably balances the interests of customers and shareholders by enabling Cascade to maintain its financial integrity and therefore its ability to attract capital at reasonable terms and conditions under a variety of economic and financial market conditions.

IV.REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[7]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes, it has. In Docket Nos. UE-170485 and UG-170486, Avista Corporation's 2017 rate case, the Commission stated that:

> The Commission's final determination of an acceptable ROE recognizes fully the guiding principles of regulatory ratemaking that require us to reach an end result that yields fair, just, reasonable, and sufficient rates.[8]

My view accords with this guidance that an allowed ROR must be sufficient to enable regulated companies, like Cascade, the ability to attract capital on reasonable terms.

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable natural gas service while maintaining its financial integrity. To the extent the Company is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

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[7] *Hope*, 320 U.S. 591 (1944); *Bluefield*, 262 U.S. 679 (1923).
[8] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket Nos. UE-170485 and UG-170486, Order 07, ¶ 59 (April 26, 2018) (hereinafter "Avista Order 07").

Q. Is a utility's ability to attract capital also affected by the ROEs that are authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other natural gas and electric utilities. Therefore, the ROE awarded to a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have an incentive to direct their capital to those investments. Thus, an authorized ROE significantly below authorized ROEs for other natural gas and electric utilities can inhibit the utility's ability to attract capital for investment in Washington.

Likewise, because Cascade is a subsidiary of MDU Resources, Cascade competes with the other MDU Resources subsidiaries for investment capital. In determining how to allocate its finite capital resources, it would be reasonable for MDU Resources to consider the authorized ROE of each of its subsidiaries.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions; doing so balances the long-term interests of the utility and its ratepayers.

The financial community carefully monitors the current and expected financial condition of utility companies, and the regulatory framework in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Commission's order in this proceeding, therefore, should establish rates that provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms under a variety of economic and financial market conditions; (2) sufficient to ensure good financial management and firm integrity; and (3) commensurate with returns on investments in enterprises with similar risk. To the extent Cascade is authorized the opportunity to earn its market-based cost of capital, the proper balance is achieved between customers' and shareholders' interests.

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates in the ROE estimation models to estimate the required return for the subject company.

As discussed in the remainder of this section, analysts and regulatory commissions have concluded that current market conditions have affected the results of the ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) the current low interest rate environment and the corresponding effect on valuations and dividend yields of utility stocks relative to historical levels; (2) the market's expectation for higher interest rates; and (3) recent Federal tax reform. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

A. The Effect of Market Conditions on Valuations

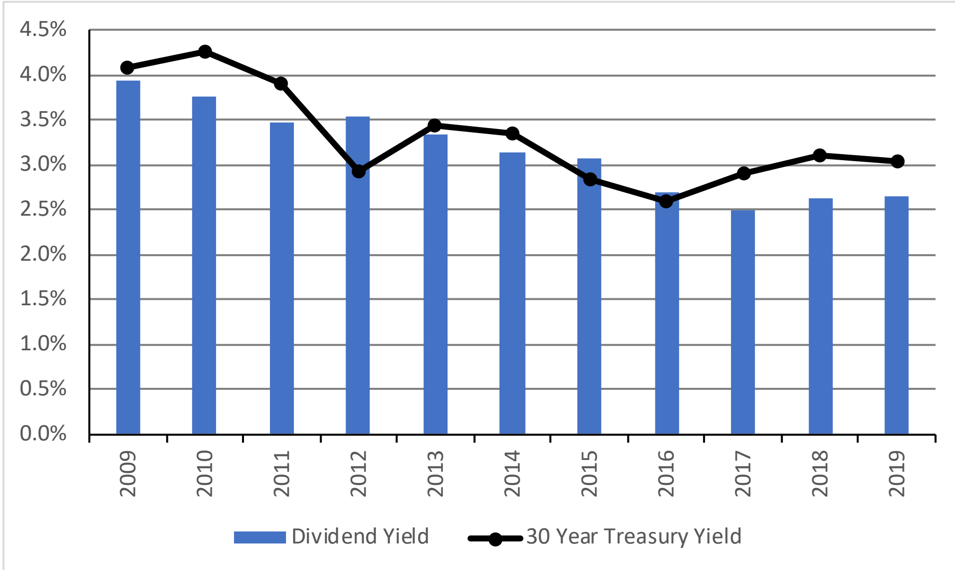
Q. How has the Federal Reserve's monetary policy affected capital markets in recent years?

A. Extraordinary and persistent federal intervention in capital markets artificially lowered government bond yields after the Great Recession of 2008-2009, as the Federal Open Market Committee ("FOMC") used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage-backed securities) to stimulate the U.S. economy. As a result of very low or zero returns on short-term government bonds, yield-seeking investors have been forced into longer-term instruments, bidding up prices and reducing yields on those investments. As investors have moved along the risk spectrum in search of yields that meet their return requirements, there has been increased demand for dividend-paying equities, such as natural gas and electric utility stocks.

Q. How has the period of abnormally low interest rates affected the valuations and dividend yields of utility shares?

A. The Federal Reserve's accommodative monetary policy has caused investors to seek alternatives to the historically low interest rates available on Treasury bonds. A result of this search for higher yield is that the share prices for many common stocks, especially dividend-paying stocks such as utilities, have been driven higher while the dividend yields (which are computed by dividing the dividend payment by the stock price) have decreased to levels well below the historical average. As shown in Figure 2, over the period from 2009 through 2017, since the Federal Reserve intervened to stabilize financial markets and support the economic recovery after the Great Recession of 2008-09, Treasury bond yields and utility dividend yields declined. Specifically, Treasury bond yields declined by approximately 118 basis points, and natural gas utility dividend yields have decreased by about 144 basis points over this same period.

Figure 2: Dividend Yields for Natural Gas Utility Stocks



Note: Figure includes 2019 data through January 31, 2019.
Source: Bloomberg Professional

Q. How have higher stock valuations and lower dividend yields for utility companies affected the results of the DCF model?

A. During periods of general economic and capital market stability, the DCF model may adequately reflect market conditions and investor expectations. However, in the current market environment, the DCF model results are distorted by the historically low level of interest rates and the higher valuation of utility stocks. Value Line recently commented on the high valuations of electric utilities:

> Even after a pullback in late 2018, most stocks in the Electric Utility Industry are still priced expensively, in our view. Many of the equities are still trading within our 2021-2023 Target Price Range. The industry's average dividend yield is 3.5%, and some stocks have yields that aren't significantly higher than the median of all stocks under our coverage. For the 3- to 5-year period, the group's average total return potential is just 5%.[9]

This is further supported by a recent Edward Jones report on the utility

[9] Value Line Investment Survey, Electric Utility (West) Industry, January 25, 2019, at 2217.

sector:

> Utility valuations have come down as 10-year Treasury bond rates have climbed back over 3%. On a price-to-earnings basis, they do remain significantly above their historical average, but have declined to less unreasonable levels. We have seen utility valuations moving in line with interest rate movements, although there have been exceptions to this. Overall, however, we believe the low-interest rate environment has been the biggest factor in pushing utilities higher since many investors buy them for their dividend yield.
>
> Utilities have declined from their all-time highs reached late in 2017, but are still trading significantly above their average price-to-earnings ratio over the past decade. The premium valuation continues to reflect not only the low interest rate environment, but also the stable and predominantly regulated earnings growth we foresee.[10]

As noted by Value Line and Edward Jones, over the last few years, utility stocks have experienced high valuations and low dividend yields; driven by investors moving into dividend paying stocks from bonds due to the low interest rates in the bond market, however, those dynamics are changing. Value Line and Edward Jones recognize that as interest rates increase, bonds become a substitute for utility stocks. As utility stock prices decline, the dividend yields will increase. This change in market conditions implies that the ROE calculated using historical market data in the DCF model may understate the forward-looking cost of equity.

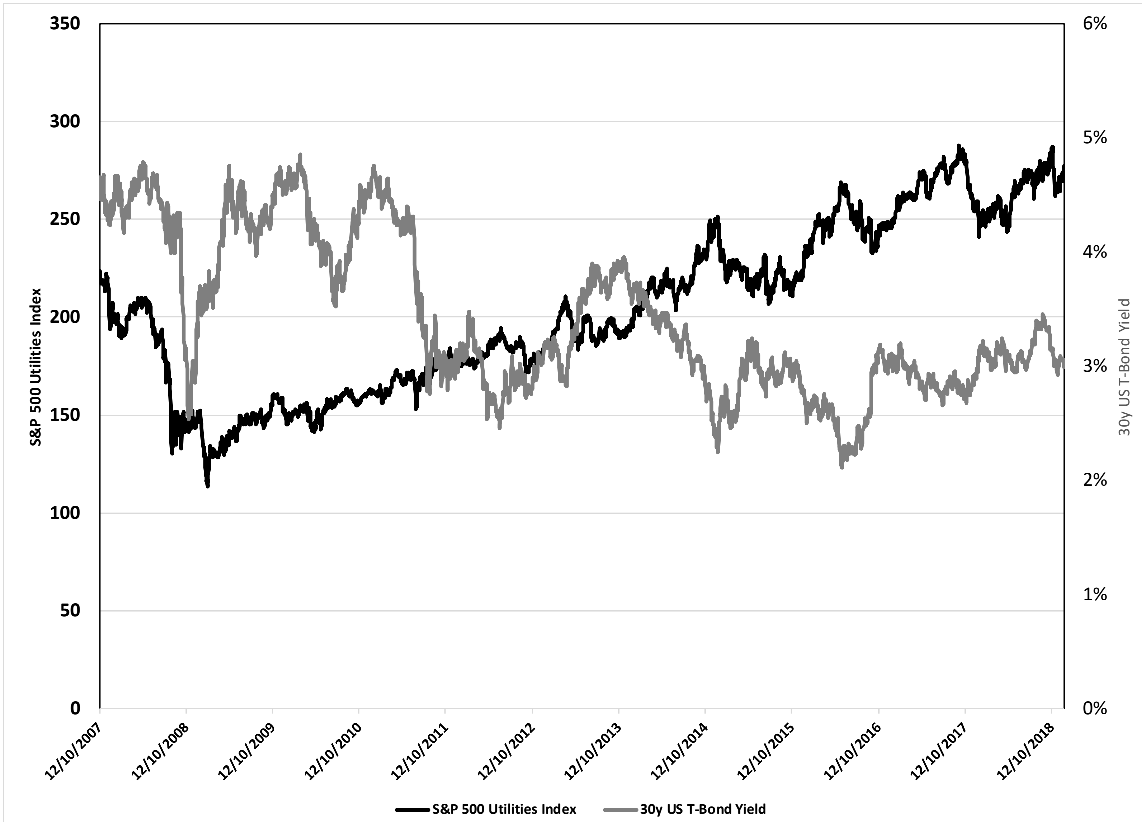
Q. How did the Standard & Poor's ("S&P") Utilities Index respond to the market conditions that existed following the Great Recession of 2008-2009?

A. Figure 3, demonstrates market conditions from 2007-2019 as measured by the S&P Utilities index and the yield on 30-year Treasury bonds. As shown in Figure 3, the

[10] Andy Pusateri and Andy Smith. Edward Jones, Utilities Sector Outlook (January 16, 2019), at 2-3.

S&P Utilities index increased steadily from the beginning of 2009 through early November 2017, as yields on 30-year Treasury bonds declined in response to accommodative federal monetary policy.

Figure 3: S&P Utilities Index and U.S. Treasury Bond Yields (2007-2019)



Source: Bloomberg Professional

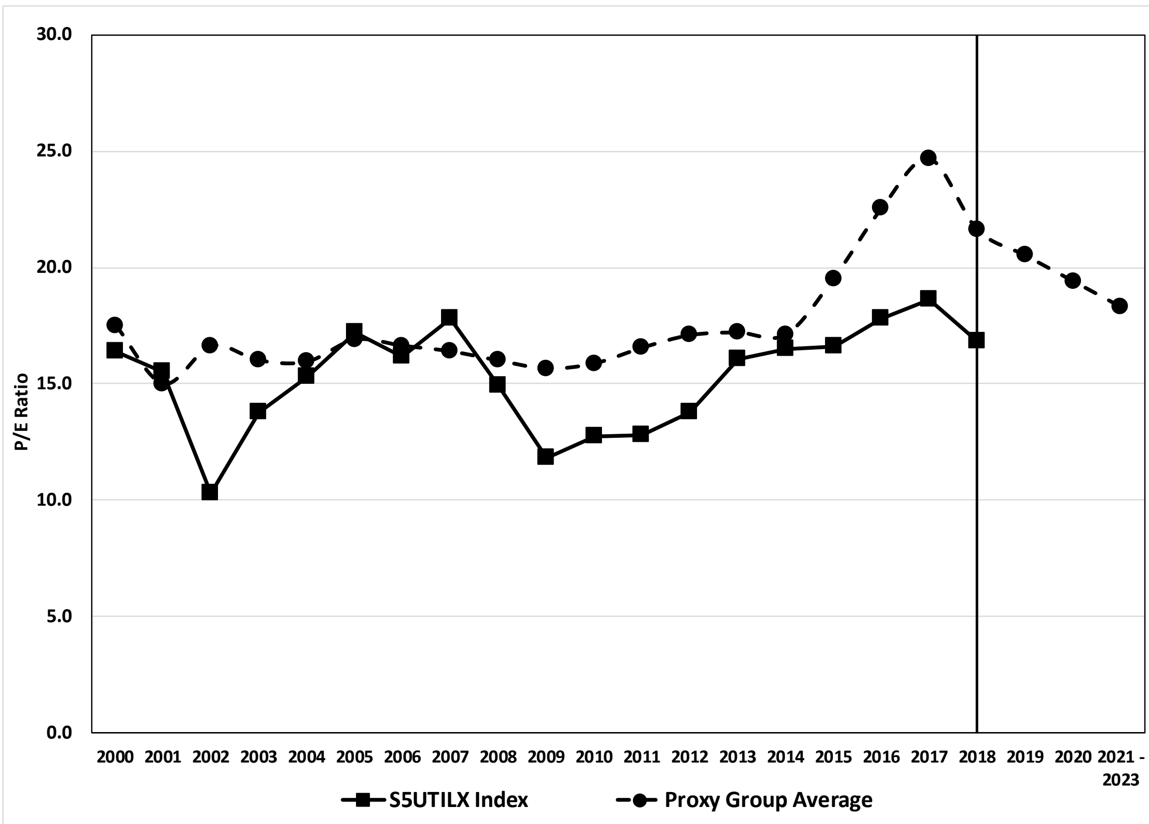
Q. How do the valuations of public utilities compare to the historical average?

A. Figure 4 summarizes the average historical and projected P/E ratios for the proxy companies calculated using data from Bloomberg Professional and Value Line.[11] As shown in Figure 4, the average P/E ratio for the proxy companies was higher in 2017 than at any other time in the last seventeen years and is significantly higher than the average projected P/E ratio for the group for the period from 2021-2023.

[11] Selection of the Proxy Companies is discussed in detail in Section VI of my Direct Testimony.

In 2018 however, the average P/E ratio for the proxy companies has decreased slightly to 21.61 from the high in 2017 of 24.64. All else equal, if P/E ratios for the proxy companies continue to decline, as Value Line projects, the ROE results from the DCF model would be higher. Therefore, the DCF model using historical market data is likely understating the forward-looking cost of equity for the proxy group companies.

Figure 4: Average Historical Proxy Group P/E Ratios[12]



Q. How do equity investors view the utilities sector based on these recent market conditions?

A. Investment advisors have suggested that utility stocks may underperform as a result of market conditions. Barron's recently published its seventh annual review of

[12] Figure includes data through January 31, 2019. *Source: Bloomberg Professional.*

income-producing investments in which Barron's ranked eleven different sectors based on projected performance in 2019. The utility sector ranked ninth out of the eleven sectors with Barron's noting that:

> Utilities, however, aren't cheap; they are valued at an average of 17 times projected 2019 earnings, a premium to the S&P 500, at about 14. That may make it hard for utilities to best the index in 2019, barring a market collapse. Earnings growth is running at a mid-single-digits yearly pace.[13]

Similarly, a recent report on the market outlook for 2019 from J.P. Morgan Asset Management noted that due to higher volatility the Fed may pause increasing the federal funds rate; however, they are not recommending rotation into the utility sector:

> As prospects for slower economic growth become clearer in the middle of next year, the Fed may signal it will pause. Such a signal, or a trade agreement with China, could lead multiples to expand, pushing the stock market higher and potentially adding years to this already old bull market. However, even if the bull market does end in the next few years, it is important to remember that late-cycle returns have typically been quite strong.
>
> This leaves investors in a tough spot – should they focus on a fundamental story that is softening, or invest with an expectation that multiples will expand as the bull market runs its course? The best answer is probably a little bit of each. We are comfortable holding stocks as long as earnings growth is positive, but do not want to be over-exposed given an expectation for higher volatility. As such, higher-income sectors like financials and energy look more attractive than technology and consumer discretionary, and we would lump the new communication services sector in with the latter names, rather than the former. However, given our expectation of still some further interest rate increases, it does not yet seem appropriate to fully rotate into defensive sectors like utilities and consumer staples. Rather, a focus on cyclical

[13] Bary, Andrew. "Best Income Investments for 2019." Barron's, 4 Jan. 2019, https://www.barrons.com/articles/the-best-income-ideas-for-2019-51546632171.

> value should allow investors to optimize their upside/downside capture as this bull market continues to age.[14]

This view was further supported by UBS who underweights utilities:

> Our underweight views on consumer staples and utilities sectors reflect our preference for sectors that are more leveraged to continued favorable economic growth than these two defensive sectors. In addition, consumer staples are contending with sluggish organic growth. High dividend yields for the utilities sector makes it most negatively exposed to higher interest rates. Our industrials underweight is a bit of a hedge against a potential increase in trade frictions.[15]

Q. Have regulators recently responded to the historically low dividend yields for utility companies and the corresponding effect on the DCF model?

A. Yes. The FERC recently proposed a methodology that reflects their current view that investors rely on multiple ROE estimation models. The proposed methodology includes an equal weighting of the DCF, CAPM, Expected Earnings and Risk Premium models to better reflect investor behavior and capital market conditions.[16]

In addition, the Illinois Commerce Commission ("ICC"), the Pennsylvania Public Utility Commission ("PPUC") and the Missouri Public Service Commission ("Missouri PSC") have all considered the effect of low dividend yields on the DCF results in recent decisions. I discuss the response of these regulators to historically low dividend yields and the impact on the DCF model in detail later in my testimony.

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[14] J.P. Morgan Asset Management, "The investment outlook for 2019: Late-cycle risks and opportunities", November 30, 2018, at 5.
[15] UBS, "2019 outlook: Aging gracefully", December 5, 2018, at 7.
[16] Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs at para. 32 (October 16, 2018).

B. The Current and Expected Interest Rate Environment

Q. Please provide a brief summary of the recent monetary policy actions of the Federal Reserve.

A. Based on stronger conditions in employment markets, a relatively stable inflation rate, steady economic growth, and increased household spending, the Federal Reserve raised the short-term borrowing rate by 25 basis points on four occasions in 2018. Since December 2015, the Federal Reserve has increased interest rates nine times, bringing the federal funds rate to the range of 2.25 percent to 2.50 percent. However, the Federal Reserve recently indicated at the March 2019 meeting that going forward it will be patient in determining future adjustments to the federal funds rate due to recent global economic and financial developments and low inflationary pressures.[17]

Additionally, in October 2017, the FOMC started reducing the size of the Federal Reserve's $4.5 trillion bond portfolio by no longer reinvesting the proceeds of the bonds it holds. In response to the Great Recession, the Federal Reserve pursued a policy known as "Quantitative Easing," in which it systematically purchased mortgage-backed securities and long-term Treasury bonds to provide liquidity in financial markets and drive down yields on long-term government bonds. Although the Federal Reserve discontinued the Quantitative Easing program in October 2014, it continued to reinvest the proceeds from the bonds it holds. Under the initial balance sheet normalization policy, the FOMC gradually

[17] FOMC, Federal Reserve press release, March 20, 2019.

reduced the Federal Reserve's securities holdings by $10 billion per month initially, ramping up to $50 billion per month by the end of the first twelve months.[18] However, at the March 2019 meeting, the FOMC announced that it intends to slow the reduction of its holdings of Treasury Securities starting in May 2019 and ultimately conclude the program in September 2019.[19]

Q. How does the recent change in the Federal Reserve's policy affect the yields on long-term government bonds?

A. While the Federal Reserve has recently indicated to that will it will be patient in determining future adjustments the federal funds rate, this is not unusual as monetary policy has a lagged effect on the economy. As Federal Reserve Bank of San Francisco notes:

> It can take a fairly long time for a monetary policy action to affect the economy and inflation. And the lags can vary a lot, too. For example, the major effects on output can take anywhere from three months to two years. And the effects on inflation tend to involve even longer lags, perhaps one to three years, or more.[20]

Since December 2015, the Federal Reserves has increased the federal funds rate nine times, four of which occurred in 2018 and three in 2017. Therefore, given recent market volatility and lagged effect that monetary policy has on the economy, it is reasonable to expect the Federal Reserve to be patient with future increases. However, it is important to note, that the Federal Reserve is continuing to reduce

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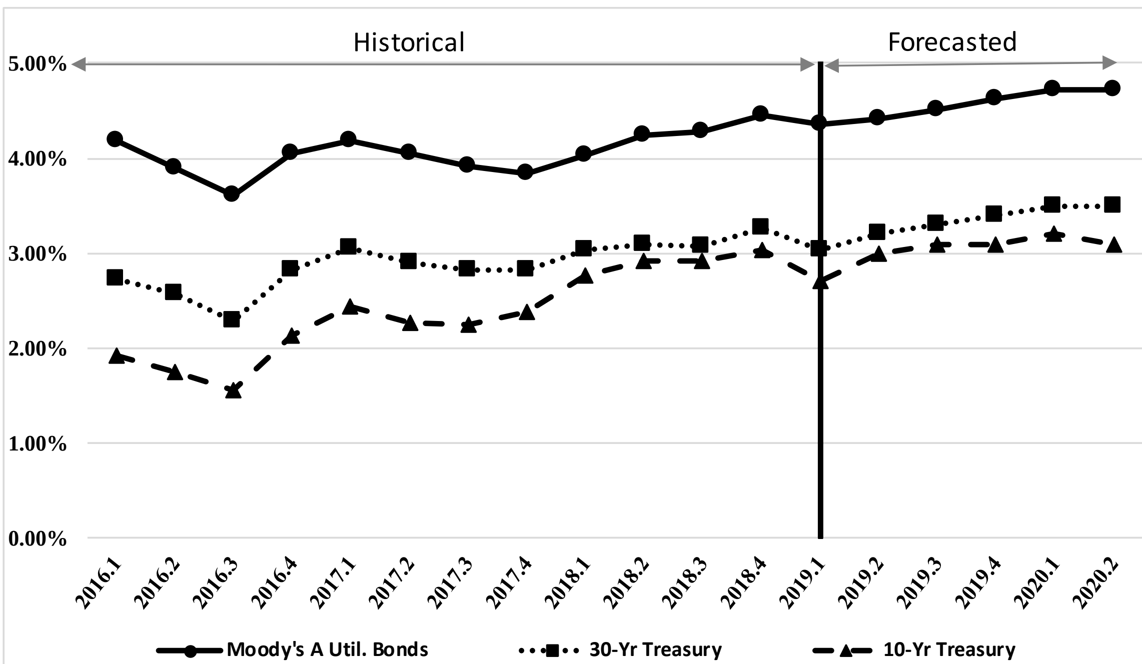
[18] Federal Reserve press release, Addendum to the Policy Normalization Principles and Plans, June 14, 2017, implemented at FOMC meeting, September 20, 2017.

[19] Federal Reserve press release, Balance Sheet Normalization Principles and Plans, March 20, 2019.

[20] Federal Reserve Bank of San Francisco, "U.S. Monetary Policy: An Introduction - How does monetary policy affect the U.S. economy?", February 6, 2004. https://www.frbsf.org/education/teacher-resources/us-monetary-policy-introduction/real-interest-rates-economy/

the size of its balance sheet by no longer reinvesting the proceeds of the bonds it holds over the near-term. This policy in conjunction with the lagged effect of past increases in the federal funds rate suggests that the yields on long-term government bonds should continue to increase over the near-term which is consistent with investors' expectations. As shown in Figure 5, investors are expecting continued increases in interest rates on both government and corporate/utility bonds over the next few years.

Figure 5: Interest Rate Conditions[21]



Q. Have you examined the effect of the Federal Reserve's monetary policy on the yields of long-term government bonds over the past few years?

A. Yes. As shown in Figure 5, yields on long-term government bonds have increased since the Federal Reserve started to raise the federal funds rate in 2016. However,

[21] Source: Historical data from Bloomberg Professional. Forecast data from Blue Chip Financial Forecasts, Volume. 38, No. 2, February 1, 2019, at 2.

the increase in long-term government bond yields has not been as pronounced as the rise in short-term interest rates. This is due to a shift in the supply and demand of long-term government bonds that has occurred since 2009. For example, since the Great Recession of 2008-2009, federal debt has increased significantly which has resulted in an increase in the supply of Treasury bonds in the market. In general, an increase in supply should result in a decrease in the price of Treasury bonds and an increase in yield. However, long-term government bonds yields have not increased as fast as expected given the increase in supply. This is because the demand for Treasury bonds has also increased since 2009. As noted in a recent article published by the St. Louis Federal Reserve, the demand for government bonds increased for a number of reasons some of which included increased holdings by foreign governments as countries in Europe and Asia faced their own economic uncertainty, and increased holdings from commercial banks due to new regulations that required banks to hold a larger portion of high-quality liquid assets.[22] This has resulted in a more gradual increase in the yields on long-term government bonds over the past few years.

Q. Is the demand for long-term government bonds currently increasing?

A. No, it is not. As noted in the Federal Reserve article:

> Some evidence suggests that the growth in demand for Treasuries has already begun to soften. Returning to Figures 1 and 2, foreign holdings have remained more or less constant since 2014, largely because of declining holdings in Japan and China. Likewise, regulation and policy changes such as the Dodd-Frank Act and new rules for prime money market funds may have only transitory effects on the demand for Treasuries.

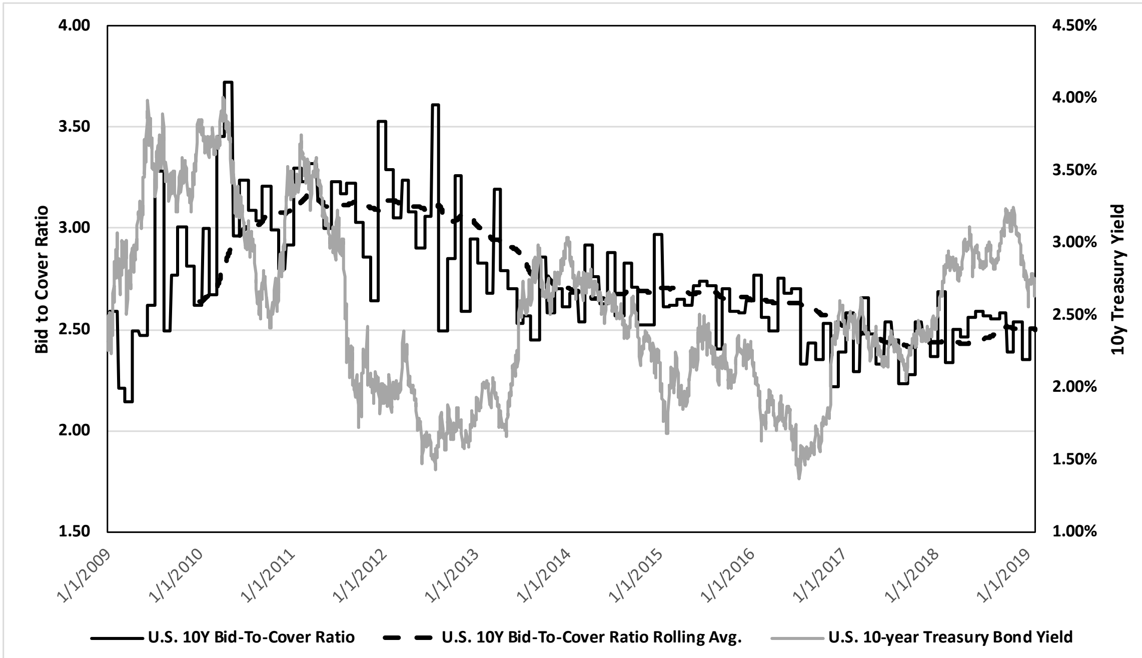
[22] David Andolfatto and Andrew Spewak, Federal Reserve Bank of St. Louis, "On the Supply of, and Demand for, U.S. Treasury Debt," Economic Synopses, No. 5, 2018. https://doi.org/10.20955/es.2018.5.

> For example, the pace of growth of the ratio of commercial bank Treasury security holdings to private loans has slowed since 2014 (see Figure 3), as has the growth of investment in government money market funds since 2017 (Figure 4).[23]

Furthermore, another indicator of the demand for Treasury bonds is the bid-to-cover ratio, which represents the dollar amount of bids received versus the dollar amount sold in a Treasury security auction. Therefore, a higher bid-to-cover ratio is indicative of an increase in the demand for government bonds. As shown in Figure 6, the bid-to-cover ratio for the 10-year U.S. Treasury bond is currently at its lowest point since 2009, which indicates that the demand for long-term government bonds has declined. The decline in demand is occurring at a time when the supply of Treasury bonds is expected to increase as the Federal Reserve continues its balance sheet unwind over the near-term and the federal government issues bonds to offset the reduced tax revenue associated with the implementation of the TCJA. As a result, yields on long-term government bonds are expected to continue to increase over the near-term which is consistent with investors' expectations shown in Figure 5.

[23] *Id.*

Figure 6: U.S. 10-year Treasury Bond Bid-to-Cover-Ratio



Q. What effect do rising interest rates have on the cost of equity?

A. As interest rates continue to increase, the cost of equity for the proxy companies using the DCF model is likely to be an overly conservative estimate of investors' required returns because the proxy group average dividend yield reflects the increase in stock prices that resulted from substantially lower interest rates. As such, rising interest rates support the selection of a return toward the upper end of a reasonable range of ROE estimates resulting from the DCF analysis. Alternatively, my CAPM and Bond Yield Plus Risk Premium analyses include estimated returns based on near-term projected interest rates, reflecting investors' expectations of market conditions over the period that the rates that are determined in this case will be set.

C. Effect of Tax Reform on the ROE and Capital Structure

Q. Are there other factors that should be considered in determining the cost of equity for Cascade?

A. Yes. The effect of the TCJA should also be considered in the determination of the cost of equity. The credit rating agencies have commented on the effect of the TCJA on regulated utilities. In summary, the TCJA is expected to reduce utility revenues due to the lower federal income taxes and the requirement to return excess accumulated deferred income taxes. This change in revenue is expected to reduce Funds From Operations ("FFO") metrics across the sector, and absent regulatory mitigation strategies, is expected to lead to weaker credit metrics and negative ratings actions for some utilities.[24]

Q. Have credit or equity analysts commented on the effect of the TCJA on utilities?

A. Yes. Moody's Investors Services ("Moody's") indicated that while the TCJA was credit positive for many sectors, it has an overall negative credit impact on regulated operating companies of utilities and their holding companies due to the reduction in cash flow metrics that results from the change in the federal tax rate and the loss of bonus depreciation.

Moody's noted that the rates that regulators allow utilities to charge customers is based on a cost-plus model, with tax expense being one of the pass-through items. Utilities will collect less taxes at the lower rate, reducing revenue.

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[24] FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.

While the taxes are ultimately paid out as an expense, under the new law utilities lose the timing benefit, reducing cash that may have been carried over a number of years. The lower tax rate combined with the loss of bonus depreciation will have a negative effect on utility cash flows and will ultimately negatively impact the utilities' ability to fund ongoing operations and capital improvement programs.

Q. How has Moody's responded to the increased risk for utilities resulting from the TCJA?

A. In January 2018, Moody's issued a report changing the rating outlook for several regulated utilities from Stable to Negative.[25] At that time, Moody's noted that the rating change affected companies with limited cushion in their ratings for deterioration in financial performance. In June 2018, Moody's issued a report in which the rating agency downgraded the outlook for the entire regulated utility industry from Stable to Negative for the first time ever. Moody's cites ongoing concerns about the negative effect of the TCJA on cash flows of regulated utilities. While noting that "[r]egulatory commissions and utility management teams are taking important first steps"[26] and that "we have seen some credit positive developments in some states in response to tax reform,"[27] Moody's concludes that "we believe that it will take longer than 12-18 months for the majority of the sector to show any material financial improvement from such efforts."[28]

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[25] Moody's Investor Service, Global Credit Research, Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform, January 19, 2018.
[26] Moody's Investors Service, "Regulated utilities – US: 2019 outlook shifts to negative due to weaker cash flows, continued high leverage", June 18, 2018, at 3.
[27] *Id*.
[28] *Id*.

Q. Has Moody's changed its outlook for utilities in 2019?

A. No. Consistent with the prior reports issued by Moody's in January and June of 2018, Moody's is maintaining its negative outlook for regulated utilities in 2019 as a result of continued concerns over the effect of the TCJA on cash flows as well as increasing debt.[29] Moody's notes that "[t]he combination of financial pressures is expected to keep the sector's ratio of FFO to debt down around 15% in the year ahead." [30]

Q. What does it mean for Moody's to downgrade a credit outlook?

A. A Moody's rating outlook is an opinion regarding the likely rating direction over what it refers to as "the medium term." A Stable outlook indicates a low likelihood of a rating change in the medium term. A Negative outlook indicates a higher likelihood of a rating change over the medium term. While Moody's indicates that the time period for changing a rating subsequent to a change in the outlook from Stable will vary, on average Moody's indicates that a rating change will follow within a year of a change in outlook.[31]

Q. Has the Company experienced a downgrade related to cash flow metrics resulting from tax reform?

A. No, although, S&P issued a ratings report on September 27, 2018 where it affirmed the BBB+ credit rating of the Company but downgraded the stand-alone credit profile ("SACP") of Cascade from bbb+ to bbb. Specifically, S&P noted the following:

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[29] Moody's Investors Service, Research Announcement: Moody's: US regulated utilities sector outlook for 2019 remains negative, November 8, 2018.
[30] *Id.*
[31] Moody's Investors Service, Rating Symbols and Definitions, July 2017, at 27.

> Our revised assessment of Cascade's SACP reflects our expectations of sustained weaker financial measures, reflecting the lower end of the range for the company's financial risk profile, including adjusted FFO to debt of about 13%-16%. This largely reflects the company's increased capital spending plan and the adverse cash flow effects from tax reform.[32]

Q. Have any utilities experienced a downgrade related to cash flow metrics resulting from the TCJA?

A. Yes. Figure 7 summarizes credit rating downgrades for utilities that have resulted from tax reform.

Figure 7: Credit Rating Downgrades Resulting from TCJA

Utility	Rating Agency	Credit Rating before TCJA	Credit Rating after TCJA	Downgrade Date
Brooklyn Union Gas Company	Moody’s	A2	A3	2/22/2019
Avista Corp.	Moody’s	Baa1	Baa2	12/30/2018
Consolidated Edison Company of New York	Moody's	A2	A3	10/30/2018
Consolidated Edison, Inc.	Moody's	A3	Baa1	10/30/2018
Orange and Rockland Utilities	Moody's	A3	Baa1	10/30/2018
Southwestern Public Service Company	Moody's	Baa1	Baa2	10/19/2018
Dominion Energy Gas Holdings	Moody's	A2	A3	9/20/2018
Piedmont Natural Gas Company, Inc.	Moody's	A2	A3	8/1/2018
WEC Energy Group, Inc.	Moody's	A3	Baa1	7/12/2018
Integrys Holdings Inc.	Moody's	A3	Baa1	7/12/2018
OGE Energy Corp.	Moody's	A3	Baa1	7/5/2018
Oklahoma Gas & Electric Company	Moody's	A1	A2	7/5/2018

Q. Have other rating agencies commented on the effect of the TCJA on ratings?

A. Yes. S&P and Fitch have also commented on the implications of the TCJA on utilities. S&P published a report on January 24, 2018, entitled “U.S. Tax Reform: For Utilities’ Credit Quality, Challenges Abound” in which S&P concludes:

[32] Standard and Poor’s Global Ratings, “Research Update: Cascade Natural Gas Corp. ‘BBB+’ Ratings Affirmed; Stand-Alone Credit Profile Revised to ‘bbb’; Outlook Stable”, September 27, 2018.

The impact of tax reform on utilities is likely to be negative to varying degrees depending on a company's tax position going into 2018, how its regulators react, and how the company reacts in return. It is negative for credit quality because the combination of a lower tax rate and the loss of stimulus provisions related to bonus depreciation or full expensing of capital spending will create headwinds in operating cash-flow generation capabilities as customer rates are lowered in response to the new tax code. The impact could be sharpened or softened by regulators depending on how much they want to lower utility rates immediately instead of using some of the lower revenue requirement from tax reform to allow the utility to retain the cash for infrastructure investment or other expenses. Regulators must also recognize that tax reform is a strain on utility credit quality, and we expect companies to request stronger capital structures and other means to offset some of the negative impact.

Finally, if the regulatory response does not adequately compensate for the lower cash flows, we will look to the issuers, especially at the holding company level, to take steps to protect credit metrics if necessary. Some deterioration in the ability to deduct interest expense could occur at the parent, making debt there relatively more expensive. More equity may make sense and be necessary to protect ratings if financial metrics are already under pressure and regulators are aggressive in lowering customer rates. It will probably take the remainder of this year to fully assess the financial impact on each issuer from the change in tax liabilities, the regulatory response, and the company's ultimate response. We have already witnessed differing responses. We revised our outlook to negative on PNM Resources Inc. and its subsidiaries on Jan. 16 after a Public Service Co. of New Mexico rate case decision incorporated tax savings with no offsetting measures taken to alleviate the weaker cash flows. It remains to be seen whether PNM will eventually do so, especially as it is facing other regulatory headwinds. On the other hand, FirstEnergy Corp. issued $1.62 billion of mandatory convertible stock and $850 million of common equity on Jan. 22 and explicitly referenced the need to support its credit metrics in the face of the new tax code in announcing the move. That is exactly the kind of proactive financial management that we will be looking for to fortify credit quality and promote ratings stability.[33]

[33] Standard and Poor's Global Ratings, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound", January 24, 2018.

In S&P's 2019 trends report, the rating agency notes that the utility industry's financial measures weakened in 2018 and attributed that to tax reform, capital spending and negative load growth. In addition, S&P expects that weaker credit metrics will continue into 2019 for those utilities operating with minimal financial cushion. S&P further expects that these utilities will look to offset the revenue reductions from tax reform with equity issuances. The rating agency reported that in 2018 regulated utilities issued nearly $35 billion in equity, which is more than twice the equity issuances in 2016 and 2017.[34]

Finally, FitchRatings recognized the implications of tax reform but indicated that any ratings actions will be guided by the response of regulators and the management of the utilities. Fitch notes that the solution will depend on the ability of utility management to manage the cash flow implications of the TCJA. Fitch offers several solutions to provide rate stability and to moderate changes to cash flow in the near term, including increasing the authorized ROE and/or equity ratio as measures that can be implemented.[35]

Q. Has the Commission recognized that the TCJA has had an adverse impact on utility cash flows?

A. Yes. In Avista's 2017 rate case, the Commission "note[d] the TCJA will increase stress on the Company's balance sheet and credit metrics as short-term cash flows are impacted by customer refunds."[36]

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[34] Standard & Poor's Ratings, "Industry Top Trends 2019, North America Regulated Utilities", November 8, 2019.
[35] FitchRatings, Special Report, What Investors Want to Know, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector", January 24, 2018.
[36] Avista Order 07, ¶ 72.

Q. Has the Company recently experienced a credit rating downgrade?

A. Yes. In August of 2018, FitchRatings downgraded Cascade from A- to BBB+. In its ratings review, Fitch noted that Cascade was downgraded due to a much weaker financial profile that resulted from the recent rate case decision in the Company's Washington rate case and an elevated capital expenditure program that is expected to increase leverage over the near-term.[37] With respect to the rate case decision in Washington, Fitch viewed unfavorably "the below-average 9.4 % authorized ROE and 49% equity ratio" and the Commission's decision to disallow Cascade from retaining the excess taxes collected between the period that the TCJA went into effect (January 1, 2018) and the date that Cascade's new rates would go in effect (August 1, 2018).[38] Fitch believes that the Commission's decision will impact Cascade's ability to earn it authorized ROE and notes that the Company has been underearning its authorized return for a few years.[39] Thus, Fitch's downgrade of Cascade highlights the importance of authorizing an ROE in this proceeding that is sufficient to maintain the credit quality of the Company while continuing to allow Cascade the ability to attract capital at reasonable terms which will be important over the near term given the Company's significant capital expenditure plan.

Q. What conclusions do you draw from your analysis of capital market conditions?

A. The important conclusions resulting from capital market conditions are:

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[37] FitchRatings, Fitch Affirms MDU Resources, Centennial Energy; Downgrades Cascade; Outlook Stable, August 1, 2018.
[38] *Id.*
[39] *Id.*

- The assumptions used in the ROE estimation models have been affected by recent historical market conditions.

- Recent market conditions are not expected to persist as yields on long-term bonds are expected to increase. As a result, the recent historical market conditions are not reflective of the market conditions that will be present when the rates for Cascade will be in effect.

- It is important to consider the results of a variety of ROE estimation models, using forward-looking assumptions to estimate the cost of equity.

- Without adequate regulatory support, the TCJA will have a negative effect on utility cash flows, which increases investor risk expectations for utilities.

VI. PROXY GROUP SELECTION

Q. Why have you used a group of proxy companies to estimate the cost of equity for Cascade?

A. In this proceeding, we are focused on estimating the cost of equity for a natural gas utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and given that Cascade's natural gas operations in Washington do not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to Cascade in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if Cascade was a publicly-traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for Cascade.

Q. Please provide a brief profile of Cascade.

A. Cascade is a natural gas distribution company that is a wholly-owned subsidiary of MDU Resources. The Company distributes natural gas to approximately 282,000 residential, commercial and industrial customers in approximately 96 communities in Washington and Oregon.[40] In Washington, Cascade distributes natural gas to approximately 218,540 residential, commercial and industrial customers in several non-contiguous service territories in western and central Washington.[41] Cascade serves approximately 68 communities in Washington, the largest of which are Yakima, Bellingham, the Tri-Cities, Marysville, Bremerton, Longview, and Mt. Vernon.[42] As of December 31, 2018, Cascade's net utility plant in Washington was approximately $435.75 million.[43] In addition, Cascade had total natural gas sales in Washington in 2018 of approximately 93 million Dths, made up of 12.77 percent residential, 10.27 percent firm commercial, 1.90 percent firm industrial and 75.06 percent transportation.[44] For Cascade's parent company, MDU Resources, Washington accounted for 26.00 percent of the natural gas distribution operating sales revenues in 2017, while Idaho (33.00 percent), North Dakota (13.00 percent), Montana (9.00 percent), Oregon (8.00 percent), South Dakota (6.00 percent),

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[40] Cascade Natural Gas Corporation website, https://www.cngc.com/.
[41] Data provided by Cascade Natural Gas Corporation.
[42] Cascade Natural Gas Corporation website, https://www.cngc.com/.
[43] Data provided by Cascade Natural Gas Corporation.
[44] EIA FORM 176 - Electric Power (i.e., Gas used as fuel in the electric power sector).

Minnesota (3.00 percent) and Wyoming (2.00 percent) accounted for the other 74.00 percent of retail gas distribution operating sales revenues.[45] Cascade currently has an investment grade long-term rating of BBB+ (Outlook: Stable) from S&P and A- (Outlook: Stable) from Fitch.[46]

Q. How did you select the companies included in your proxy group?

A. I began with the group of 10 companies that Value Line classifies as Natural Gas Distribution Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- are covered by at least two utility industry analysts;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are in rate base;
- derive more than 70.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and
- were not parties to a merger or transformative transaction during the analytical periods relied on.

[45] MDU Resources Group, 2017 SEC Form 10-K, at 13.
[46] SNL Financial, February 15, 2019.

Q. Did you eliminate any other companies that otherwise met your screening criteria?

A. Yes. On September 13, 2018, Columbia Gas of Massachusetts, a wholly-owned subsidiary of NiSource Inc. ("NiSource") experienced a significant event as a result of over pressured lines on their system. The incident resulted in immediate financial ramifications for NiSource. In fact, NiSource's stock price fell approximately 12.00 percent immediately following the incident. Given the impact the incident had on the stock price of NiSource, and the potential effect on the company's financial performance, it is appropriate to exclude NiSource from my proxy group.

Q. What is the composition of your proxy group?

A. The screening criteria discussed above is shown in Exhibit No.___(AEB-2), Schedule 2 and resulted in a proxy group consisting of the companies shown in Figure 8 below.

Figure 8: Proxy Group

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire, Inc.	SR

VII.COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall ROR for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to determine Cascade's ROE?

A. I considered the results of the Constant Growth DCF model, the CAPM model, the Bond Yield Plus Risk Premium methodology and an Expected Earnings analysis. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q. Why is it important to use more than one analytical approach?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[47] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[48] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches.

Q. Is it important given the current market conditions to use more than one analytical approach?

A. Yes. As discussed in Section V above, the U.S. economy is beginning to emerge from an unprecedented period of low interest rates. Low interest rates, and the effects of the investor "flight to quality" can be seen in high utility share valuations, relative to historical levels and relative to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity

[47] Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed. (New York: McKinsey & Company, Inc., 2000), at 214.

[48] Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed. (Orlando: Dryden Press, 1994), at 341.

estimates from a DCF analysis. Low interest rates also impact the CAPM in two ways: (1) the risk-free rate is lower, and (2) because the market risk premium is a function of interest rates, (i.e., it is the return on the broad stock market less the risk-free interest rate), the risk premium should move higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the impact that the current low interest rate environment is having on the ROE estimates for the proxy group and, where possible, consider using projected market data in the models to estimate the return for the forward-looking period.

Q. Are you aware of any regulatory commissions who have recognized that recent conditions in capital markets are causing ROE recommendations based on DCF models to be unreasonable?

A. Yes, several regulatory commissions have addressed the effect of capital market conditions on the DCF model, including FERC, the ICC, the PPUC and the Missouri PSC.

Q. Please summarize how the FERC has responded to the effect of market conditions on the DCF.

A. Understanding the important role that dividend yields play in the DCF model, the FERC determined that capital market conditions have caused the DCF model to understate equity costs for regulated utilities. In Opinion No. 531, the FERC noted:

> There is 'model risk' associated with the excessive reliance or mechanical application of a model when the surrounding conditions are outside of the normal range. 'Model risk' is the risk that a theoretical model that is used to value real world

> transactions fails to predict or represent the real phenomenon that is being modeled.[49]

In Opinion No. 531, the FERC noted that the low interest rates and bond yields that persisted throughout the analytical period that was relied on (study period) had affected the results of the DCF model and recognized the need to move away from the midpoint of the DCF analysis. In that case, the FERC relied on the CAPM and other risk premium methodologies to inform its judgment to set the return above the midpoint of the DCF results.

In Opinion No. 551, issued in September 2016, the FERC recognized that those same market conditions continued into the study period, and again concluded that it was necessary to rely on ROE estimation methodologies other than the DCF model to set the appropriate ROE:

> Though the Commission noted certain economic conditions in Opinion No. 531, the principle argument was based on low interest rates and bond yields, conditions that persisted throughout the study period. Consequently, we find that capital market conditions are still anomalous as described above…[50]
>
> ****
>
> Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with *Hope* and *Bluefield*.[51]
>
> ****
>
> As the Commission found in Opinion No. 531, under these circumstances, we have less confidence that the midpoint of

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[49] FERC Docket No. EL11-66-001, Opinion No. 531 (June 19, 2014), fn 286.
[50] FERC Docket No. EL14-12-002, Opinion No. 551, at para. 121.
[51] *Id*., at para. 122.

> the zone of reasonableness in this proceeding accurately reflects the equity returns necessary to meet the Hope and Bluefield capital attraction standards. We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies…[52]

Finally, in October 2018, the FERC issued an Order in response to the remand from the U.S. Court of Appeals for the District of Columbia indicating plans to establish ROEs based on an equal weighting of the results of four financial models: the DCF, CAPM, Expected Earnings and Risk Premium. FERC explains its reasons for moving away from sole reliance on the DCF model as follows:

> Our decision to rely on multiple methodologies in these four complaint proceedings is based on our conclusion that the DCF methodology may no longer singularly reflect how investors make their decisions. We believe that, since we adopted the DCF methodology as our sole method for determining utility ROEs in the 1980s, investors have increasingly used a diverse set of data sources and models to inform their investment decisions. Investors appear to base their decisions on numerous data points and models, including the DCF, CAPM, Risk Premium, and Expected Earnings methodologies. As demonstrated in Figure 2 below, which shows the ROE results from the four models over the four test periods at issue in this proceeding, these models do not correlate such that the DCF methodology captures the other methodologies. In fact, in some instances, their cost of equity estimates may move in opposite directions over time. Although we recognize the greater administrative burden on parties and the Commission to evaluate multiple models, we believe that the DCF methodology alone no longer captures how investors view utility returns because investors do not rely on the DCF alone and the other methods used by investors do not necessarily produce the same results as the DCF. Consequently, it is appropriate for our analysis to consider a combination of the DCF, CAPM, Risk Premium, and Expected Earnings approaches.[53]

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[52] *Id.*

[53] Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, issued October 16, 2018, at para. 40. [Figure 2 was omitted]

Q. How have the PPUC, the ICC and the Missouri PSC addressed the effect of market conditions on the DCF?

A. In a 2012 decision for PPL Electric Utilities, while noting that the PPUC has traditionally relied primarily on the DCF method to estimate the cost of equity for regulated utilities, the PPUC recognized that market conditions were causing the DCF model to produce results that were much lower than other models such as the CAPM and Bond Yield Plus Risk Premium. The PPUC's Order explained:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[54]

The PPUC ultimately concluded:

> As such, where evidence based on the CAPM and RP methods suggest that the DCF-only results may understate the utility's current cost of equity capital, we will give consideration to those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[55]

In a recent ICC case, Docket No. 16-0093, Staff relied on a DCF analysis that resulted in average returns for their proxy groups of 7.24 percent to 7.51 percent. The company demonstrated that these results were uncharacteristically too low, by comparing the results of Staff's models to recently authorized ROEs for regulated utilities and the return on the S&P 500.[56] In Order No. 16-0093, the ICC

[54] Pennsylvania Public Utility Commission, PPL Electric Utilities, R-2012-2290597, meeting held December 5, 2012, at 80.
[55] *Id.*, at 81.
[56] State of Illinois Commerce Commission, Docket No. 16-0093, Illinois-American Water Company Initial Brief, August 31, 2016, at 10.

agreed with the Company that Staff's proposed ROE of 8.04 percent was anomalous and recognized that a return that is not competitive will deter investment in Illinois.[57] In setting the return in this proceeding the ICC recognized that it was necessary to consider other factors beyond the outputs of the financial models, particularly whether or not the return is sufficient to attract capital, maintain financial integrity, and is commensurate with returns for companies of comparable risk, while balancing the interests of customers and shareholders.[58]

Finally, in February 2018, the Missouri PSC issued a decision in Spire's 2017 gas rate case, in which the allowed ROE was set at 9.80 percent. In explaining the rationale for its decision, the Commission cited the importance of considering multiple methodologies to estimate the cost of equity and the need for the authorized ROE to be consistent with returns in other jurisdictions and to reflect the growing economy and investor expectations for higher interest rates.

> Based on the competent and substantial evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.8 percent is a fair and reasonable return on equity for Spire Missouri. That rate is nearly the midpoint of all the experts' recommendations and is consistent with the national average, the growing economy, and the anticipated increasing interest rates. The Commission finds that this rate of return will allow Spire Missouri to compete in the capital market for the funds needed to maintain its financial health.[59]

[57] Illinois Staff's analysis and recommendation in that proceeding were based on its application of the multi-stage DCF model and the CAPM to a proxy group of water utilities.
[58] State of Illinois Commerce Commission Decision, Docket No. 16-0093, Illinois-American Water Company, 2016 WL 7325212 (2016), at 55.
[59] File No. GR-2017-0215 and File No. GR-2017-0216, Missouri Public Service Commission, Report and Order, Issue Date February 21, 2018, at 34.

Q. Has the Commission made similar findings regarding the reliance on multiple models given current market conditions?

A. Yes. It is my understanding that the Commission has repeatedly emphasized that it "places value on each of the methodologies used to calculate the cost of equity and does not find it appropriate to select a single method as being the most accurate or instructive."[60] The Commission has explained that "[f]inancial circumstances are constantly shifting and changing, and we welcome a robust and diverse record of evidence based on a variety of analytics and cost of capital methodologies."[61]

Q. What are your conclusions about the results of the DCF and CAPM models?

A. Recent market data that is used as the basis for the assumptions for both models have been affected by market conditions. As a result, relying exclusively on historical assumptions in these models, without considering whether these assumptions are consistent with investors' future expectations, will underestimate the cost of equity that investors would require over the period that the rates in this case are to be in effect. In this instance, relying on the historical average of abnormally high stock prices results in low dividend yields that are not expected to continue over the period that the new rates will be in effect. This, in turn, underestimates the ROE for the rate period.

The use of recent historical Treasury bond yields in the CAPM also tends to underestimate the projected cost of equity. Recent experience indicates that interest rates are increasing. The expectation that bond yields will not remain at

[60] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, n. 89 (Dec. 4, 2013).
[61] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06, ¶ 91 (March 25, 2011).

currently low levels means that the expected cost of equity would be higher than is suggested by the CAPM using historical average yields. The use of projected yields on Treasury bonds results in CAPM estimates that are more reflective of the market conditions that investors expect during the period that the Company's rates will be in effect.

B. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

Where P_0 represents the current stock price, D1…D∞ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio;

(3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended January 31, 2019.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. In my Constant Growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. However, the averaging periods that I use rely on historical data that is not consistent with the forward-looking expectation that interest rates will increase. Therefore, the results of my Constant Growth DCF model using historical data may underestimate the forward-looking cost of equity. As a result, I place more weight on the median to median-high results produced by my Constant Growth DCF model.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Thomson First Call (provided by Yahoo!Finance); and (3) Value Line Investment Survey.

C. Discounted Cash Flow Model Results

Q. How did you calculate the range of results for the Constant Growth DCF Model?

A. I calculated the low result for my DCF models using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all sources.

Q. Have you excluded any of the Constant Growth DCF results for individual companies in your proxy group?

A. Yes, I have. It is appropriate to exclude Constant Growth DCF results below a specified threshold at which equity investors would consider such returns to provide an insufficient return increment above long-term debt costs. The average credit rating for the companies in my proxy group is A-/A3. The average yield on Moody's A-rated utility bonds for the 30 trading days ending January 31, 2019, was 4.34 percent.[62] As shown on Exhibit No.___(AEB-2), Schedule 3, I have eliminated Constant Growth DCF results lower than 7.00% because such returns would provide equity investors a risk premium only 266 basis points above A-rated utility bonds.

Q. What were the results of your DCF analyses?

A. Figure 9 summarizes the results of my DCF analyses. As shown in Figure 9, the median DCF results range from 9.63 percent to 9.72 percent and the median high results are in the range of 12.12 percent to 12.17 percent. While I also summarize the median low DCF results, I do not believe that the low DCF results provide a reasonable spread over the expected yields on Treasury bonds to compensate

[62] Source: Bloomberg Professional.

investors for the incremental risk related to an equity investment.

Figure 9: Discounted Cash Flow Results

	Median Low	Median	Median High
Constant Growth DCF[63]			
30-Day Average	8.24%	9.69%	12.16%
90-Day Average	8.58%	9.63%	12.12%
180-Day Average	8.26%	9.72%	12.17%

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the DCF models is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. To the extent that utility valuations are high and may not be sustainable, it is important to consider the results of the DCF models with caution. As I indicated previously, this is due to the high utility equity valuations that occurred in the lower interest rate environment as investors have sought higher returns. With the expectation of rising interest rates, such levels are not expected to be sustained in the upcoming years. Because the low dividend yields may result in the DCF model understating investors' expected return, I have given primary weight to the median and high-end DCF results. My overall recommendation also relies on the results of other ROE estimation models.

D. CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. This second

[63] *See* Exhibit No.___(AEB-2), Schedule 3.

component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta\left(r_m - r_f\right) \quad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market.

In this specification, the term (rm – rf) represents the market risk premium. According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (i.e., Variance (r_m)) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (i.e., Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds of 3.03 percent;[64] (2) the average projected 30-year U.S. Treasury bond yield for Q2 2019 through Q2 2020 of 3.38 percent;[65] and (3) the average projected 30-year U.S. Treasury bond yield for 2020 through 2024 of 3.90 percent.[66]

Q. Would you place more weight on one of these scenarios?

A. Yes. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. As discussed in Section V of my Direct Testimony, leading economists surveyed by Blue Chip are expecting an increase in long-term interest rates over the next five years. This is an important consideration for equity investors as they assess their return requirements. While I have included the results of a CAPM analysis that relies on the current average risk-free rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown on Exhibit No.___(AEB-2), Schedule 4, I used the average Beta coefficients for the proxy group companies as reported by Value Line. Value Line's calculation is based on five years of weekly returns relative to the New York

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[64] Bloomberg Professional, as of January 31, 2019.
[65] Blue Chip Financial Forecasts, Vol. 38, No. 2, February 1, 2019, at 2.
[66] Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14.

Stock Exchange Composite Index. My average Beta coefficient for the proxy group was 0.671.

Q. How did you estimate the market risk premium in the CAPM?

A. I estimated the market risk premium based on the expected return on S&P 500 Index less the yield on the 30-year Treasury bond. I calculate the expected return on the S&P 500 Index companies for which dividend yields and long-term earnings projections are available using the Constant Growth DCF model discussed earlier in my Direct Testimony. Based on an estimated market capitalization-weighted dividend yield of 2.08 percent and a weighted long-term growth rate of 12.64 percent, the estimated required market return for the S&P 500 Index is 14.85 percent. As shown in Exhibit No.___(AEB-2), Schedule 5, the implied market risk premium over the current 30-day average of the 30-year U.S. Treasury bond yield, and projected yields on the 30-year U.S. Treasury bond, range from 10.95 percent to 11.81 percent.

Q. Have other regulators endorsed the use of a forward-looking market risk premium?

A. Yes. In Opinion No. 531-B, the FERC specifically endorsed a method that is similar to the method I have used to calculate the forward-looking market risk premium (i.e., applying a Constant Growth DCF analysis to the S&P 500 and using the 30-year Treasury bond yields).[67]

In response to arguments against this methodology, the FERC stated:

> We are also unpersuaded that the growth rate projection in the NETOs' CAPM study was skewed by the NETOs' reliance on

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[67] 150 FERC ¶ 61,165, Docket Nos. EL11-66-002, Opinion No. 531-B (March 3, 2015), at para. 109-111.

> analysts' projections of non-utility companies' medium-term earnings growth, or that the study failed to consider that those analysts' estimates reflect unsustainable short-term stock repurchase programs and are not long-term projections. As explained above, the NETOs based their growth rate input on data from IBES, which the Commission has found to be a reliable source of such data. Thus, the time periods used for the growth rate projections in the NETOs' CAPM study are the time periods over which IBES forecasts earnings growth. Petitioners' arguments against the time period on which the NETOs' CAPM analysis is based are, in effect, arguments that IBES data are insufficient in a CAPM study. [68]
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> ***
>
> While an individual company cannot be expected to sustain high short term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable.[69]

Additionally, the Staff in Maine has also endorsed the use of a forward-looking market risk premium. In the Bench Analysis in Docket No. 2017-00198 for Emera Maine and Docket No. 2017-00065 for Northern Utilities, Staff accepted the approach proposed by the companies for calculating the market return.[70] In each case, the market return was the expected return for the S&P 500 which was calculated using a Constant Growth DCF model. In Docket No. 2017-00198, Staff noted the following:

> Staff has no issue with the methodology used by Mr. Perkins in calculating market parameters based on the S&P 500 and

[68] *Id.*, at para. 112.
[69] *Id.*, at para. 113.
[70] *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2017-00198, Bench Analysis at 71-72 (December 21, 2017); *Northern Utilities, Inc. d/b/a UNITIL, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Bench Analysis, at 15-16 (October 6, 2017).

used the model provided by Mr. Perkins with the revised risk free rate to re-calculate the market risk premiums.[71]

Furthermore, the Maine Public Utilities Commission ("Maine PUC") in Docket No. 2017-0198 used the CAPM results calculated by Staff and Emera Maine as a check on the reasonableness of the DCF results in the case and did not dispute the use of the forward-looking market risk premium by the parties (i.e., Staff and Emera Maine).[72]

Q. What are the results of your CAPM analyses?

A. As shown in Figure 10 (*see* also Exhibit No.___(AEB-2), Schedule 5), my CAPM analysis produces a range of returns from 10.97 percent to 11.25 percent.

Figure 10: CAPM Results

	CAPM Results
Current Risk-Free Rate (3.03%)	10.97%
Q2 2019-Q2 2020 Projected Risk-Free Rate (3.38%)	11.08%
2020-2024 Projected Risk-Free Rate (3.90%)	11.25%
Mean Result	**11.10%**

E. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders,

[71] *Emera Maine, Request for Approval of a Proposed Rate Increase,* Docket No. 2017-00198, Bench Analysis, at 71-72 (December 21, 2017).
[72] *Emera Maine, Request for Approval of Proposed Rate Increase,* Docket No. 2017-00198, June 28, 2018, at 41

equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for natural gas utility companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for natural gas utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[73]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider

[73] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 11 below, from 1992 through January 2019, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [5]$$

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

a = intercept term

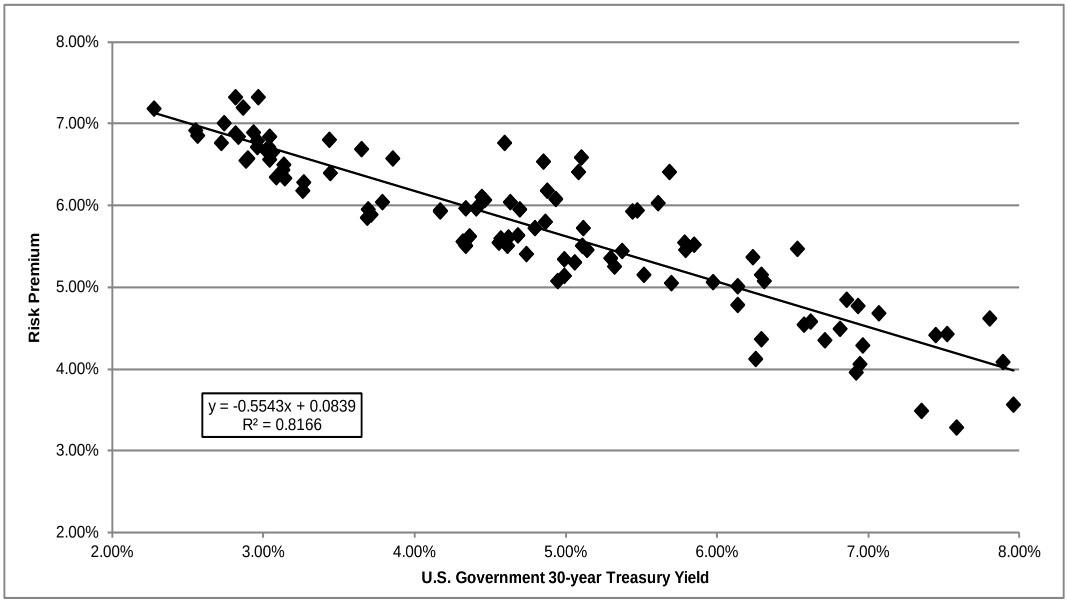
b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 613 natural gas utility rate cases from 1992 through January 2019 as reported by Regulatory Research Associates ("RRA").[74] This equation's coefficients were statistically significant at the 99.00 percent level.

[74] This analysis began with a total of 956 cases and was screened to eliminate limited issue rider cases, transmission-only cases, and cases that were silent with respect to the authorized ROE. After applying those screening criteria, the analysis was based on data for 613 cases.

Figure 11: Risk Premium Results



As shown on Exhibit No.___(AEB-2), Schedule 6, based on the current 30-day average of the 30-year U.S. Treasury bond yield (i.e., 3.03 percent), the risk premium would be 6.71 percent, resulting in an estimated ROE of 9.74 percent. Based on the near-term (Q2 2019 – Q2 2020) projections of the 30-year U.S. Treasury bond yield (i.e., 3.38 percent), the risk premium would be 6.52 percent, resulting in an estimated ROE of 9.90 percent. Based on longer-term (2020-2024) projections of the 30-year U.S. Treasury bond yield (i.e., 3.90 percent), the risk premium would be 6.23 percent, resulting in an estimated ROE of 10.13 percent.

Q. How did the results of the Bond Yield Risk Premium inform your recommended ROE for Cascade?

A. I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for Cascade. The results of both my CAPM and Bond Yield Risk Premium analyses provide support for my view that the DCF model is understating investors' return requirements under current market conditions. Also, as noted above, investors will consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium analysis takes into account this comparison by estimating the return expectations of investors based on the current and past ROE awards of gas utilities across the US.

F. Expected Earnings Analysis

Q. Have you considered any additional analysis to estimate the cost of equity for Cascade?

A. Yes. I have considered an Expected Earnings analysis based on the projected ROEs for each of the proxy group companies.

Q. What is an Expected Earnings Analysis?

A. The Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock. The expected earnings analysis is a forward-looking estimate of investors' expected returns. The use of an Expected Earnings approach based on the proxy companies provides a range of the expected returns on a group of risk comparable companies to the subject company. This range is useful in helping to determine the opportunity cost of investing in the subject company, which is relevant in determining a company's ROE.

Q. Have regulators endorsed the use of an Expected Earnings Analysis?

A. Yes. As discussed above, the FERC issued an Order in October 2018 indicating plans to establish ROEs based on an equal weighting of the results of four financial models: the DCF, CAPM, Expected Earnings and Risk Premium. In regard to the expected earnings analysis, FERC noted the following:

> A comparable earnings analysis is a method of calculating the earnings an investor expects to receive on the book value of a particular stock. The analysis can be either backward looking using the company's historical earnings on book value, as reflected on the company's accounting statements, or forward-looking using estimates of earnings on book value, as reflected in analysts' earnings forecasts for the company. The latter approach is often referred to as an "Expected Earnings analysis." The returns on book equity that investors expect to receive from a group of companies with risks comparable to those of a particular utility are relevant to determining that utility's cost of equity, because those returns on book equity help investors determine the opportunity cost of investing in that particular utility instead of other companies of comparable risk. Because investors rely on Expected Earnings analyses to help estimate the opportunity cost of investing in a particular utility, we find this type of analysis useful in determining a utility's ROE.[75]

Q. Has the Commission considered the use of an Expected Earnings Analysis?

A. Yes. In its order in Dockets UE-170485 and UG-170486, the Commission considered the results of the Comparable Earnings analysis[76] in establishing the authorized ROE for Avista Corporation. The Commission noted that it tends to place more weight on the results of the DCF, CAPM and Risk Premium analyses; however, given the wide range of CAPM results presented by the ROE witnesses in the case, the Commission decided to apply weight to the results of the Comparable Earnings analysis.[77] Specifically, the Commission stated the following:

> Finally, as additional data points for our consideration of establishing Avista's ROE, we note that two witness, Mr.

[75] Federal Energy Regulatory Commission, Docket No. EL 11-66-001, et al., Order Directing Briefs, issued October 16, 2018, at 42.
[76] The Expected Earnings analysis is a form of the Comparable Earnings analysis that relies exclusively on forward-looking projections.
[77] Avista Order 07, ¶ 65.

> McKenzie for Avista and Mr. Parcell for Staff, employ the CE approach to two proxy groups of companies. The respective mid-points of each witnesses' CE analysis are 10.5 and 9.5 percent, respectively, with an average of 10.0 percent. Although we generally do not apply material weight to the CE method, having stronger reliance on the DCF, CAPM and RP methods, we are inclined to include the CE method here given the anomalous CAPM results described previously.[78]

Q. How did you develop the Expected Earnings Approach?

A. I relied primarily on the projected ROE capital for the proxy companies as reported by Value Line for the period from 2021-2023. However, I adjusted those projected ROEs to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the period. This adjustment is consistent with FERC's methodology for the Expected Earnings analysis that was included in its October 2018 order. As shown in Exhibit No.___(AEB-2), Schedule 7, the Expected Earnings analysis results in a mean of 11.56 percent and a median of 11.48 percent.

VIII.REGULATORY AND BUSINESS RISKS

Q. Do the median DCF and mean CAPM, Risk Premium and Expected Earnings results for the proxy groups, taken alone, provide an appropriate estimate of the cost of equity for Cascade?

A. No. These results provide only a range of the appropriate estimate of the Company's cost of equity. There are several additional factors that must be taken into consideration when determining where the Company's cost of equity falls

[78] *Id.*

within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Small Size Risk

Q. Please explain the risk associated with small size.

A. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect." While empirical evidence of the size effect often is based on studies of industries other than regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[79]

Q. How does the smaller size of a utility affect its business risk?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for

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[79] Michael Annin, Equity and the Small-Stock Effect, Public Utilities Fortnightly, October 15, 1995.

smaller companies.

Q. How does Cascade's natural gas distribution operations in Washington compare in size to the proxy group companies?

A. Cascade's natural gas distribution operations in Washington are substantially smaller than the median for the proxy group companies in terms of market capitalization. Exhibit No.___(AEB-2), Schedule 8 provides the actual market capitalization for the proxy group companies and estimates the implied market capitalization for Cascade (i.e., the implied market capitalization if Cascade's natural gas distribution operations in Washington were a stand-alone publicly-traded entity). To estimate the size of the Company's market capitalization relative to the proxy group, I calculated Cascade's proposed capital structure equity component of $202.50 million by multiplying Cascade's test year rate base of $405.00 million by Cascade's test year common equity ratio of 50.00 percent. I then applied the median market-to-book ratio for the proxy group of 2.07 to Cascade's implied common equity balance and arrived at an implied market capitalization of approximately $420.18 million, or 10.30 percent of the median market capitalization for the proxy group.

Q. How did you estimate the size premium for Cascade?

A. Given this relative size information, it is possible to estimate the impact of size on the ROE for Cascade using Duff and Phelps data that estimates the stock risk premia based on the size of a company's market capitalization. As shown in Exhibit No.___(AEB-2), Schedule 8, the median market capitalization of the proxy group of approximately $4.08 billion corresponds to the fifth decile of the Duff and Phelps market capitalization data. Based on Duff and Phelps' analysis, that decile corresponds to a size premium of 1.28 percent (i.e., 128 basis points). Cascade's implied market capitalization of approximately $420.18 million falls within the ninth decile, which comprises market capitalization levels up to $727.843 million and corresponds to a size premium of 2.46 percent (i.e., 246 basis points). The difference between those size premia is 118 basis points (i.e., 2.46 percent minus 1.28 percent).

Q. Have regulators in other jurisdictions made a specific risk adjustment to the ROE results based on a company's small size?

A. Yes, other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the British Colombia Utilities Commission's ("BCUC") Generic Cost of Capital decision for Stage 2 stated that small size relative to the benchmark utility was a business risk factor considered when awarding an equity risk premium to the following utilities:

- FortisBC Electric - awarded a total equity risk premium of 40 basis points;[80]
- FortisBC Whistler - awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size;"[81] and
- PNG-Tumbler Ridge- awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things.[82]

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[80] BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014, at iv.
[81] *Id.*, at iii.
[82] *Id.*, at iv.

In addition, the Yukon Utilities Board, in Board Order 2017-01, concluded "that small size is the most significant factor to be considered in determining a risk premium for ATCO Electric Yukon ("AEY")."[83] The Board noted the 25 basis point premium awarded for small size in the BCUC decision which the Board deemed an acceptable premium for the additional risk associated with AEY's small size. Therefore, the Board awarded AEY an ROE that was equal to the ROE determined for the BCUC benchmark utility plus a 25 basis point premium for size.[84]

In Order No. 15, the Regulatory Commission of Alaska ("RCA") concluded that Alaska Electric Light and Power Company ("AEL&P") was riskier than the proxy group companies due to small size as well as other business risks. The RCA did "not believe that adopting the upper end of the range of ROE analyses in this case, without an explicit adjustment, would adequately compensate AEL&P for its greater risk."[85] Thus, the RCA awarded AEL&P an ROE of 12.875 percent which was 108 basis points above the highest return on equity estimate from any model presented in the case.[86] Similarly, in Order No. 19, the RCA noted that small size as well as other business risks such as structural regulatory lag, weather risk, alternative rate mechanisms, gas supply risk, geographic isolation and economic conditions increased the risk of ENSTAR Natural Gas Company.[87] Ultimately, the

[83] YUB Appendix A to Board Order 2017-01: Reasons for Decision, April 27, 2017, at 44.
[84] *Id*.
[85] *In the Matter of the Revenue Requirement and Cost of Service Study Designated as TA381-1 Filed by Alaska Electric Light and Power Company*, Docket No. U-10-29, Order No. 15 at 37 (Sept. 2, 2011).
[86] *Id.* at 32 and 37.
[87] *In the Matter of the Tariff Revision Designated as TA285-4 Filed by ENSTAR Natural Gas Company, A Division of Semco Energy, Inc.*, Docket No. U-16-066, Order No. 19 at 50-52 (Sept. 22, 2017).

RCA concluded that:

> Although we agree that the risk factors identified by ENSTAR increase its risk, we do not attempt to quantify the amount of that increase. Rather, we take the factors into consideration when evaluating the remainder of the record and the recommendations presented by the parties. After applying our reasoned judgment to the record, we find that 11.875% represents a fair ROE for ENSTAR.[88]

Q. How have you considered the smaller size of Cascade in your recommendation?

A. While I have estimated the effect of Cascade's small size on the ROE, I am not proposing a specific adjustment for this risk factor. Rather, I believe it is important to consider the small size of Cascade's natural gas distribution operations in Washington in the determination of where, within the range of analytical results, the Company's required ROE falls. Therefore, the additional risk associated with small size indicates that the Company's ROE should be established above the mean results for the proxy group companies.

B. Flotation Cost

Q. What are flotation costs?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs.

Q. Why is it important to consider flotation costs in the allowed ROE?

A. A regulated utility must have the opportunity to earn an ROE that is both competitive and compensatory to attract and retain new investors. To the extent

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[88] *Id.*

that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diluting equity share value.

Q. Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Rather, like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, whether an issuance occurs during the test year, or is planned for the test year, is irrelevant, because failure to allow recovery of past flotation costs may deny Cascade the opportunity to earn its required ROR in the future.

Q. Please provide an example of why a flotation cost adjustment is necessary to compensate investors for the capital they have invested.

A. Suppose MDU Resources issues stock with a value of $100, and an equity investor invests $100 in MDU Resources in exchange for that stock. Further suppose that, after paying the flotation costs associated with the equity issuance, which include fees paid to underwriters and attorneys, among others, MDU Resources ends up with only $97 of issuance proceeds, rather than the $100 the investor contributed. MDU Resources invests that $97 in plant used to serve its customers, which becomes part of rate base. Absent a flotation cost adjustment, the investor will thereafter earn a return on only the $97 invested in rate base, even though she contributed $100. Making a small flotation cost adjustment gives the investor a reasonable opportunity to earn the authorized return, rather than the lower return that results when the authorized return is applied to an amount less than what the investor contributed.

Q. Is the date of MDU Resources last issued common equity important in the determination of flotation costs?

A. No. As shown in Exhibit No.___(AEB-2), Schedule 9, MDU Resources closed on equity issuances of approximately $58 million and $54 million (for a total of 4.7 million shares of common stock) in November 2002 and February 2004, respectively. The vintage of the issuance, however, is not particularly important because the investor suffers a shortfall in every year that he should have a reasonable opportunity to earn a return on the full amount of capital that he has contributed. Returning to my earlier example, the investor who contributed $100 is entitled to a reasonable opportunity to earn a return on $100 not only in the first year after the investment, but in every subsequent year in which he has the $100 invested. Leaving aside depreciation, which is dealt with separately, there is no basis to conclude that the investor is entitled to earn a return on $100 in the first year after issuance, but thereafter is entitled to earn a return on only $97. As long as the $100 is invested, the investor should have a reasonable opportunity to earn a return on the entire amount.

Q. Is the need to consider flotation costs recognized by the academic and financial communities?

A. Yes. The need to reimburse shareholders for the lost returns associated with equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. This treatment is consistent with the philosophy of a fair ROR. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[89]

Q. How did you calculate the flotation costs for Cascade?

A. My flotation cost calculation is based on the costs of issuing equity that were incurred by MDU Resources in its two most recent common equity issuances. Those issuance costs were applied to my proxy group. Based on the issuance costs provided in Exhibit No.___(AEB-2), Schedule 9, flotation costs for Cascade are approximately 0.09 percent (i.e., 9 basis points) for the proxy group.

Q. Do your final results include an adjustment for flotation cost recovery?

A. No. I did not make an explicit adjustment for flotation costs to any of my quantitative analyses. Rather, I provide the above result for consideration in my

[89] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

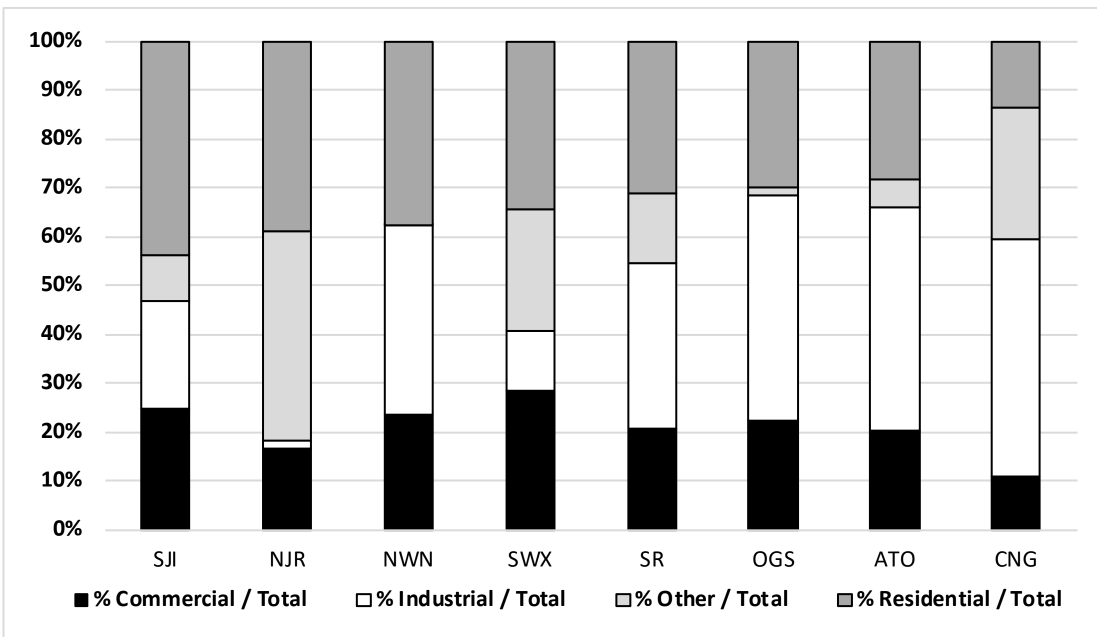
recommended ROE, which reflects the range of results from my Constant Growth DCF, CAPM, Risk Premium and Expected Earnings analyses.

C. Customer Concentration

Q. Please summarize Cascade's customer concentration risk.

A. Approximately 49.00 percent of Cascade's 2017 total company utility gas sales in Washington were derived from industrial customers. As shown in Figure 12, Cascade's industrial and electric power[90] sales volume as a percentage of total utility gas sales was 76.00 percent, higher than each of the proxy group companies.

Figure 12: Customer Concentration[91]



Q. How does customer concentration affect business risk?

A. A relatively high concentration of commercial and industrial customers results in higher business risk. Because the customers are large, they can represent a

[90] Labeled as other sales in Figure 12.
[91] EIA FORM 176 - Other sales includes Electric Power (i.e., Gas used as fuel in the electric power sector) and Vehicle Fuel Volume (i.e., The quantity of fuel used by vehicles).

significant portion of a company's sales which could be lost if a customer goes out of business or switches suppliers. As noted by Dhaliwal, Judd, Serfling and Shaikh in their article, *Customer Concentration Risk and the Cost of Equity Capital*:

> Depending on a major customer for a large portion of sales can be risky for a supplier for two primary reasons. First, a supplier faces the risk of losing substantial future sales if a major customer becomes financially distressed or declares bankruptcy, switches to a different supplier, or decides to develop products internally. Consistent with this notion, Hertzel et al. (2008) and Kolay et al. (2015) document negative supplier abnormal stock returns to the announcement that a major customer declares bankruptcy. Further, a customer's weak financial condition or actions could signal inherent problems about the supplier's viability to its remaining customers and lead to compounding losses in sales. Second, a supplier faces the risk of losing anticipated cash flows from being unable to collect outstanding receivables if the customer goes bankrupt. This assertion is consistent with the finding that suppliers offering customers more trade credit experience larger negative abnormal stock returns around the announcement of a customer filing for Chapter 11 bankruptcy (Jorion and Zhang, 2009; Kolay et al., 2015).[92]

Therefore, a company that has a high degree of customer concentration will be inherently riskier than a company that derived income from a larger customer base. Furthermore, as Dhaliwal, Judd, Serfling and Shaik detail in the article, the increased risk associated with a more concentrated customer base will have the effect of increasing a company's cost of equity.[93]

Q. Please describe how changes in economic conditions and Cascade's high degree of customer concentration can affect its business risks.

A. While Cascade does not depend on any one major customer, the Company has a

[92] Dhaliwal, Dan S., J. Scott Judd, Matthew A. Serfling, and Sarah Shaikh. "Customer Concentration Risk and the Cost of Equity Capital." SSRN Electronic Journal (2016): 1-2. Web.
[93] *Id.,* at 4.

high concentration of industrial customers in Washington. Cascade's major industrial customers are engaged in manufacturing products for industries such as food processing, primary metals, stone/clay/glass, petroleum, paper and printing, and wood and lumber products.[94] The manufacturing industry is dependent on economic conditions and the business cycle.

Q. How has manufacturing employment faired in recent economic conditions?

A. As shown in Figure 13, total manufacturing employment in Washington decreased 13.44 percent from the beginning of 2008 to the end of 2009 before beginning to gradually increase in 2010 as the U.S. entered the economic recovery phase of the business cycle. However, as of November 2018, manufacturing employment in Washington had just achieved pre-recession levels. As a result, manufacturing employment is very susceptible to fluctuations in the business cycle. It is also directly impacted by the global economy as U.S. firms face growing competition from firms in other countries whose goods are imported into the U.S.

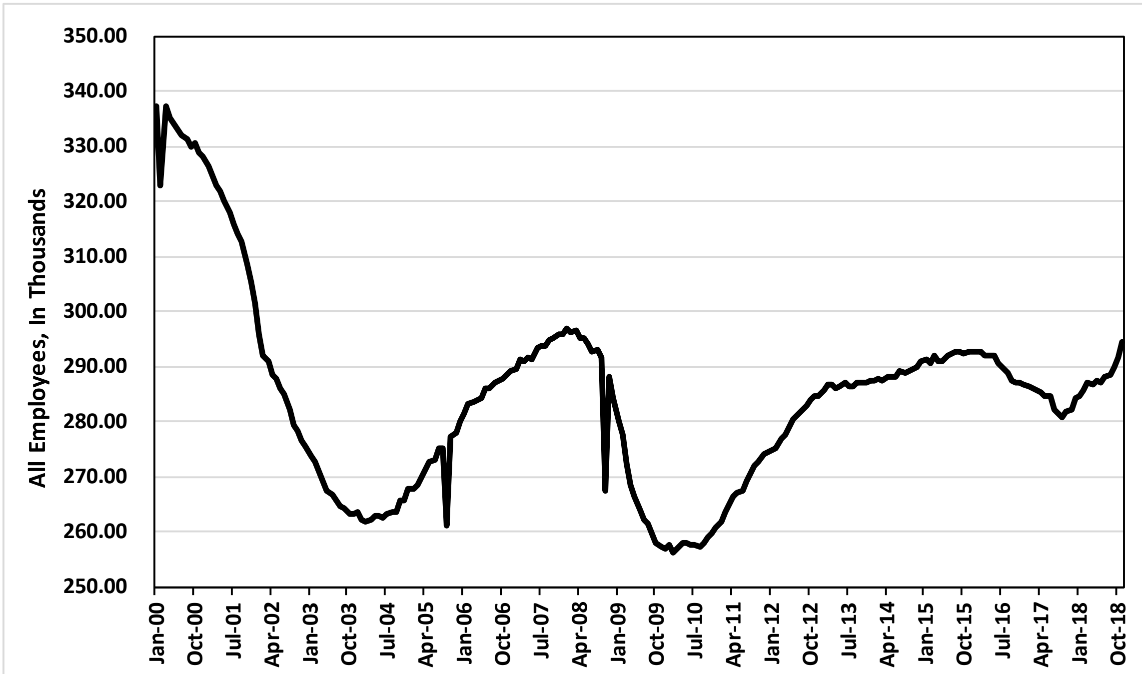
Q. Is Cascade's natural gas delivery volume dependent on the manufacturing industry?

A. Yes. As discussed above, 49.00 percent of Cascade's 2017 total company utility gas sales in Washington were derived from industrial customers, a large portion of which are engaged in manufacturing. Therefore, fluctuations in the business cycle could have a large impact on the natural gas sales of Cascade. Furthermore, if manufacturing firms reduce output due to weak economic conditions, the effect could be compounded if local employment declined, reducing the sales volume for

[94] Cascade Natural Gas Corporation, 2018 Integrated Resource Plan, December 14, 2018, at 7-15.

Cascade.

Figure 13: Washington Manufacturing Employment (Thous.)



Q. Are you aware of other risk factors that could affect Cascade's business operations?

A. Cascade is also in direct competition with other sources of energy such as electricity, diesel, solar and wind, among others. Therefore, depending on how competitive the price of gas is to other sources of energy, there is the risk that customers in the commercial and industrial classes could switch to an alternative energy source. Furthermore, as discussed above, a large portion of Cascade's distribution load is derived from electric power sales. Natural gas generation in Washington has historically been in direct competition with hydroelectric power, which is the state's largest source of electricity.[95] However, natural gas generation

[95] Source: EIA – Annual Generation by State.

could now also face increased competition in the near and long-term from renewable generation such as wind and solar due to various subsidies and mandates for renewable generating technologies. For example, in 2006, Initiative 937 passed, which requires electric utilities who serve more than 25,000 customers to obtain 15.00 percent of their electric load from new renewable resources by 2020.[96] Thus, Cascade's reliance on a large percentage of industrial and electric power load results in an increased risk of volatility with respect to sales, earnings, and cash flow.

Q. How does Cascade's revenue decoupling mechanisms affect the Company's customer concentration risk?

A. In Docket No. UG-152286, the Commission approved a revenue decoupling mechanism ("RDM") for Cascade.[97] The RDM is a revenue per customer mechanism with a deferral account established to track the difference between the authorized margin revenue per customer and the actual margin revenue per customer. The Company is then able to file rates each year that will either collect or refund the amount in the deferral account from the prior year. The authorized margin revenue per customer will be determined by rate class for the residential, commercial and industrial sales customers.[98] Transportation customers are not included in the RDM. Cascade is allowed to recover any under-collection subject to an annual rate adjustment cap of 3.00 percent. Any amount that exceeds the 3.00

[96] Source: Database of State Incentives for Renewables and Efficiency ("DSIRE"). http://programs.dsireusa.org/system/program/detail/2350.
[97] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket No. UG-152286, Order 04, ¶ 8 (July 7, 2016).
[98] *Id.*

percent cap will be deferred for recovery in a subsequent year. Over-collections are refunded to customers and there is no cap on the amount that can be refunded in a given year. Additionally, the RDM is subject to an earnings test that would adjust the amount collected or refunded if earnings were to exceed a given level.[99]

The approval of the RDM for Cascade has the effect of mitigating the financial impact of customer concentration risk by providing the Company the opportunity to recover the authorized margin revenue per customer for each rate class included in the RDM. Therefore, the under-recovery of revenue as a result of a sales large customer switching to an alternative energy source or reducing output due to economic conditions can be recovered by the Company in a subsequent year. However, the RDM does not eliminate the effect of customer concentration risk. For example, the RDM does not include transportation customers. Therefore, if a large transportation customer were to switch to an alternative energy source or reduce output due to economic conditions, the Company would not be able to recover the revenue reduction associated with the customer. Furthermore, if the under-collected amount is significantly above the 3.00 percent cap there could be a long lag between when the revenue shortfall occurred and when it is recovered by the Company.

Q. Does the Company's revenue decoupling mechanism reduce the customer concentration risk of the Company as compared to the proxy group?

A. No. While Cascade does have an RDM to mitigate the impact of customer concentration risk, this does not imply that the Company has less customer

[99] *Id.*

concentration risk than the proxy group. As shown in Exhibit No.___(AEB-2), Schedule 11 and discussed in more detail below, 89.00 percent of the operating companies held by the proxy group have some form of a decoupling mechanism. Since the proxy group companies have already implemented similar risk mitigation measures, Cascade would not have less risk than the benchmark group as a result of its RDM.

Q. What is your conclusion regarding the Company's customer concentration and its effect on the cost of equity for Cascade?

A. Cascade is heavily reliant on sales to industrial and electric power customers in Washington. As noted above, 76.00 percent of Cascade's total natural gas sales were to industrial and electric power customers, and 49.00 percent of sales were to industrial customers. This industrial concentration is higher than all of the proxy group companies. A high degree of customer concentration increases the Company's risk related to customer migration, economic conditions or competition. Increased customer diversity decreases the effect that any one customer can have on a company's sales. Furthermore, while Cascade has an RDM, the RDM does not eliminate the risk posed by customer concentration. In addition, similar to the Company, most of the companies in the proxy group have some form of an RDM. Thus, the Company's heavy customer concentration in a small number of industrial and electric power customers implies that Cascade has an above average risk profile when compared to the companies in the proxy group.

D. Capital Expenditures

Q. Please summarize the Company's capital expenditure requirements.

A. The Company's current projections for 2019 through 2023 include approximately $282.11 million in capital investments for the period.[100] Based on the Company's net utility plant of approximately $383.75 million as of December 31, 2017,[101] the 282.11 million anticipated capital expenditures are approximately 73.51 percent of Cascade's net utility plant as of December 31, 2017.

Q. How is the Company's risk profile affected by their substantial capital expenditure requirements?

A. As with any utility faced with substantial capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project

[100] Data provided by Cascade Natural Gas Corporation for Capital Expenditures 2019-2023.
[101] Data provided by Cascade Natural Gas Corporation.

> represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[102]

Therefore, to the extent that Cascade's rates do not permit the opportunity to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. How do Cascade's capital expenditure requirements compare to those of the proxy group companies?

A. As shown in Exhibit No.___(AEB-2), Schedule 10, I calculated the ratio of expected capital expenditures to net utility plant for Cascade and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2019-2023 by its total net utility plant as of December 31, 2017. As shown in Exhibit No.___(AEB-2), Schedule 10 (*see* also Figure 14 below), Cascade's ratio of capital expenditures as a percentage of net utility plant of 73.51 percent is approximately 1.01 times the median for the proxy group companies of 72.94 percent. This result indicates slightly greater risk relative to the companies in the proxy group.

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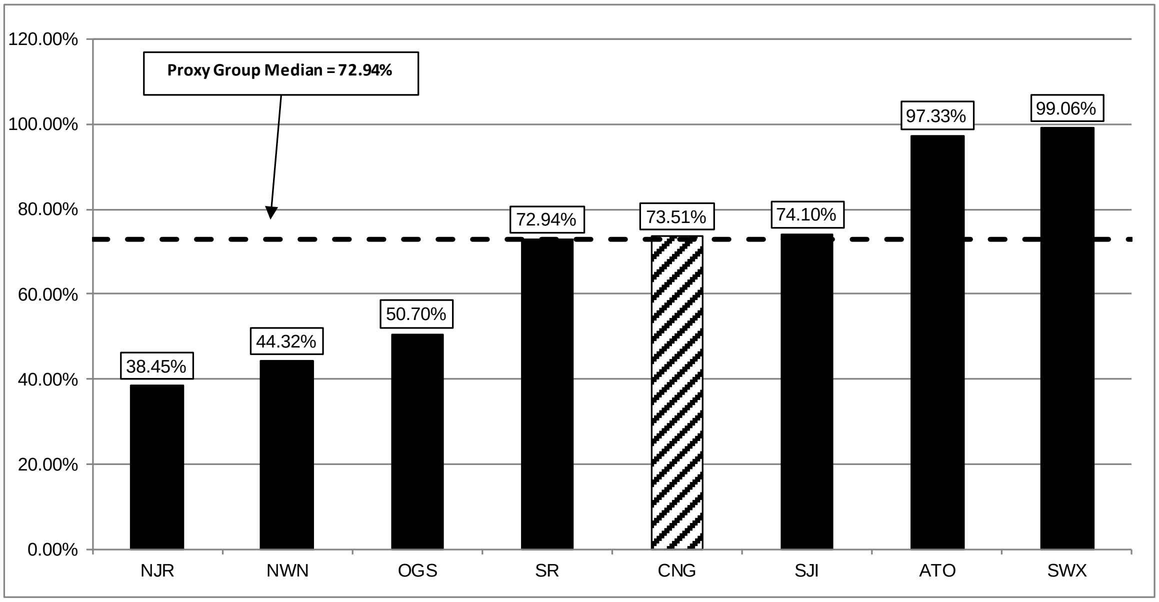
[102] S&P Global Ratings, "Assessing U.S. Investor-Owned Utility Regulatory Environments," August 10, 2016, at 7.

Figure 14: Comparison of Capital Expenditures – Proxy Group Companies



Q. Does Cascade have a capital tracking mechanism to recover the costs associated with its capital expenditures plan between rate cases?

A. Yes. Currently, Cascade has an annual pipeline Cost Recovery Mechanism ("CRM"), which allows Cascade to recover the costs associated with qualifying gas infrastructure investments that improve safety and reliability. However, it is important to note that the majority of the costs included in Cascade's capital expenditures plan do not qualify for cost recovery through the CRM. In fact, the CRM represents only approximately 18 percent of total projected capital expenditures for 2019. As a result, Cascade would still depend on rate case filings for capital cost recovery.

Additionally, as shown in Exhibit No.___(AEB-2), Schedule 11, 67.00 percent of the proxy group utilities recover costs through capital tracking mechanisms. While Cascade does recover capital expenditures through a capital tracking mechanism, Cascade does still rely on rate case filings for a large portion of the Company's capital costs.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. The Company's capital expenditure requirements as a percentage of net utility plant are significant and will continue over the next few years. Additionally, similar to a number of the operating subsidiaries of the proxy group, Cascade does have a capital tracking mechanism to recover the Company's projected capital expenditures. However, a large portion of Cascade's capital expenditure plan does not qualify for recovery through the CRM; therefore, the Company is still dependent on rate case filings to recover capital expenditures. As a result, Cascade's significant capital expenditure plan, only part of which qualifies for timely cost recovery, results in a risk profile that is greater than that of the proxy group and supports an ROE toward the higher end of the reasonable range of ROEs.

E. Regulatory Risk

Q. Please explain how the regulatory environment affects investors' risk assessments.

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. Cascade is no exception. They must finance their operations and require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet their near-term financial obligations, make the capital investments needed to maintain and expand their systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profiles must be adequate on a relative basis to ensure their ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1)

regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[103]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[104] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[105]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility

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[103] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 4.

[104] Standard & Poor's Global Ratings, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, June 25, 2018, at 2.

[105] *Id.*, at 1.

adapts to that environment are the most important credit considerations."[106] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "[b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[107]

Q. Have you conducted any analysis of the regulatory framework in Washington relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Washington on four factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These are: 1) test year convention (i.e., forecast vs. historical); 2) method for determining rate base (i.e., average vs. year-end); 3) use of revenue decoupling mechanisms or other clauses that mitigate volumetric risk; and 4) prevalence of capital cost recovery between rate cases. The results of this regulatory risk assessment are shown in Exhibit No.___(AEB-2), Schedule 11 and are summarized below.

Test year convention: Cascade uses a modified historical test year adjusted for known and measurable changes in Washington, while 39.00 percent of the operating companies held by the proxy group provide service in jurisdictions that use a fully or partially forecast test year.

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[106] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, at 6.
[107] *Id.*

Rate Base: The Company's rate base in Washington is determined based on average rate base. However, the majority (i.e., 61.00 percent) of the operating subsidiaries held by the proxy group are allowed to use year-end rate base, meaning that the rate base includes capital additions that occurred in the second half of the test year and is more reflective of net utility plant going forward.

Volumetric Risk: Cascade does have protection against volumetric risk in Washington, through a revenue decoupling mechanism that was approved in 2016. This is consistent with the companies in the proxy group where 89.00 percent of the operating companies held by the proxy group have some form of protection against volumetric risk.

Capital Cost Recovery: Cascade does have a capital tracking mechanism to recover a limited range of capital investment costs between rate cases. However, it is important note that the capital cost recovery mechanism only accounts for approximately 18 percent of total projected capital expenditures for 2019. As discussed above, 67.00 percent of the operating companies held by the proxy group have some form of capital cost recovery mechanism in place.

Q. Has RRA provided recent commentary regarding its regulatory ranking for Cascade?

A. Yes. In May 2017, RRA updated its evaluation of the regulatory environment in Washington and noted the following:

> The regulatory environment in Washington is, on balance, somewhat more restrictive than average from an investor viewpoint. The state's electric utilities remain vertically integrated and are regulated under a traditional regulatory paradigm. Rate case activity has been fairly robust, and authorized equity returns, some of which were approved

> following settlements, have been below prevailing industry averages when established. In addition, while there have been limited exceptions, the commission has primarily relied upon average rate base valuations and historical test years, each of which can exacerbate regulatory lag and render it difficult for the utility to earn the authorized return. On a more constructive note, the WUTC has approved the implementation of revenue decoupling mechanisms for most of the state's electric and gas utilities, and for one utility, has adopted a rate plan that provides for annual increases in allowed revenue per customer for the duration of the rate-plan period. Power-cost adjustment mechanisms, in effect for all of the state's electric utilities, contain dead-bands and sharing mechanisms that, while allowing the company an opportunity to retain a benefit, also limit the costs that may be recovered from ratepayers. In addition, for one utility operating in the state, recent rulings have disallowed purchased power costs from qualifying facilities located outside the state. In May 2017, RRA performed a comprehensive audit of its regulatory rankings. The ranking accorded Washington did not change as a result of this process. RRA continues to accord Washington an Average/3 ranking.[108]

Q. How do the returns that have been authorized in Washington since May 2017 compare with the authorized returns in other jurisdictions?

A. As noted in RRA's evaluation above, the authorized ROEs for electric and natural gas utilities in Washington, while partially the result of settlement agreements approved by the Commission, have been below the average authorized ROEs for electric and natural gas utilities across the U.S. As shown in Figure 15, the Commission has issued orders in three natural gas utility rate cases since RRA completed its evaluation of the regulatory jurisdiction in Washington in May 2017. In each rate case, the ROE authorized was below the average authorized ROE for electric and natural gas utilities for 2017 through 2019 of 9.70 percent by a range

[108] Regulatory Research Associates, Profile of Washington Utilities and Transportation Commission, accessed February 26, 2019.

of 20 basis points to 30 basis points.[109] Therefore, the ROEs authorized in Washington continue to be below the prevailing national average.

Figure 15: Washington Authorized Returns – 2017– 2019[110]

Company	Docket	Service	Commission Decision	
			Date	Authorized ROE
Cascade Natural Gas Corp.	UG-170929	Natural Gas	7/20/2018	9.40%
Avista Corp.	UE-170485	Electric	4/26/2018	9.50%
Avista Corp.	UG-170486	Natural Gas	4/26/2018	9.50%
Puget Sound Energy Inc.	UE-170033	Electric	12/5/2017	9.50%
Puget Sound Energy Inc.	UG-170034	Natural Gas	12/5/2017	9.50%

Q. Have any credit rating agencies commented on the regulatory environment in Washington?

A. Yes. As discussed in Section V above, FitchRatings downgraded Cascade from A- to BBB+ for reasons that included the less than favorable outcome in the Company's last rate case in Washington. Specifically, Fitch viewed the "below-average 9.4% authorized ROE and 49% equity ratio" as well as the Commission's decision to disallow Cascade from retaining the excess taxes collected between the period that the TCJA went into effect (January 1, 2018) and the date that Cascade's new rates would go in effect (August 1, 2018) as unfavorable.[111] Ultimately, Fitch noted that it "believes the likelihood of a material improvement in Washington's regulatory environment that would lead to more constructive rate outcomes is

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[109] The average authorized ROE of 9.70 percent excludes rate cases in New York since the ROE determinations are based on a formulaic approach that has generally resulted in the lowest returns for any state regulatory jurisdiction for electric and natural gas distribution companies. Similarly, the average excludes electric rate cases in Illinois since the authorized ROEs are also based on a formulaic approach which produces results well below 9.00 percent.

[110] Figure 15 excludes the expedited rate filing of Puget Sound Energy Inc. in 2018 (Docket Nos. UE-180899 and UG-180900) as the case was settled and reflected the equity ratio and return on equity established in Docket Nos. UE-170033 and UG-170034.

[111] FitchRatings, "Fitch Affirms MDU Resources, Centennial Energy; Downgrades Cascade; Outlook Stable", August 1, 2018, https://www.fitchratings.com/site/pr/10040135.

questionable in the near-to-intermediate term."[112]

Q. What are your conclusions regarding the perceived risks related to the Washington regulatory environment?

A. As discussed throughout this section of my testimony, both Moody's, S&P and Fitch have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have timely cost recovery through forecasted test years, year-end rate base, cost recovery trackers and revenue stabilization mechanisms. While Cascade has a decoupling mechanism, a large portion of the Company's capital expenditure plan is not recovered through Cascade's capital cost tracker. Additionally, authorized ROEs in Washington have been below the average authorized ROEs for electric and gas utilities across the U.S. For these reasons, I conclude that the authorized ROE for Cascade should be higher than the proxy group mean.

IX. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes, it is. Assuming other factors equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher

[112] *Id.*

interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders. Common shareholders are the residual claimants on the cash flow of the Company. Therefore, the greater the debt service requirement, the less cash flow available for common equity holders.

Q. What is Cascade's proposed capital structure?

A. The Company's proposal is to establish a capital structure consisting of 50.00 percent common equity, and 50.00 percent long-term debt.

Q. Did you conduct any analysis to determine if this requested equity ratio was reasonable?

A. Yes, I did. I reviewed the Company's historical actual capital structure and the capital structures of the utility operating subsidiaries of the proxy companies. Because the ROE is set based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the proxy group average capital structure to benchmark the equity ratio for the Company.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. I calculated the mean proportions of common equity, long-term debt, and preferred equity for the most recent year for each of the companies in the proxy group at the operating subsidiary level.[113] My analysis of the capital structures of the proxy group companies is provided in Exhibit No.___(AEB-2), Schedule 12. As shown in Exhibit No.___(AEB-2), Schedule 12, the equity ratios for the proxy group at the operating utility company level ranged from 51.32 percent to 63.18 percent with

[113] Source: SNL Financial and FERC Form 1 and FERC Form 2 annual reports.

an average of 57.07 percent. Cascade's proposed equity ratio of 50.00 percent is below the range of equity ratios for the utility operating subsidiaries of the proxy group companies and is therefore reasonable.

Q. Are there other factors to be considered in setting the Company's capital structure?

A. Yes. The credit rating agencies' response to the TCJA must also be considered when determining the equity ratio. As discussed previously in my testimony, all three rating agencies have noted that the TCJA has negative implications for utility cash flows. S&P and FitchRatings have specifically identified increasing the equity ratio as one approach to ensure that utilities have sufficient cash flows following the tax cuts and the loss of bonus depreciation. Furthermore, Moody's unprecedented downgrade of the rating outlook for the entire utilities sector in June 2018 stresses the importance of maintaining adequate cash flow metrics for the industry as a whole and Cascade in the context of this proceeding. Finally, in a recent credit opinion, S&P downgraded the SACP of Cascade from bbb+ to bbb due partially to the impact on cash flows of tax reform.[114]

Q. Is there a relationship between the equity ratio and the authorized ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility such as Cascade. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

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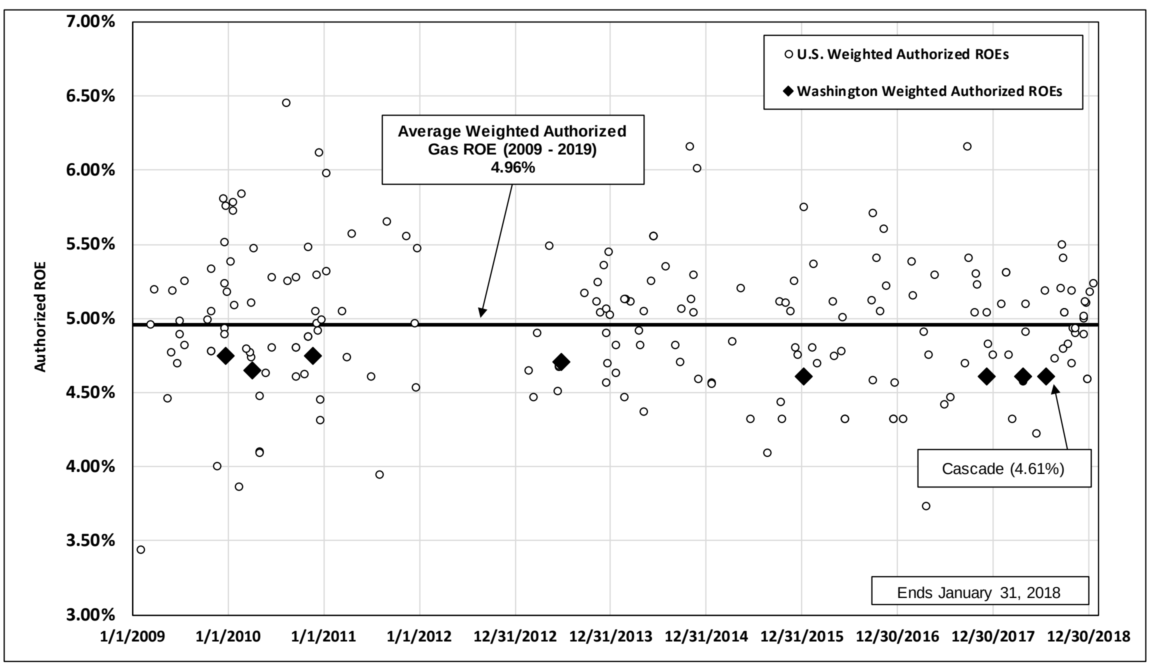
[114] Standard and Poor's Global Ratings, "Research Update: Cascade Natural Gas Corp. 'BBB+' Ratings Affirmed; Stand-Alone Credit Profile Revised to 'bbb'; Outlook Stable", September 27, 2018.

Q. Have you conducted an analysis to examine how the Commission's recent authorized Equity Ratios and authorized ROEs compare to those authorized in other jurisdictions?

A. Yes. As shown in Figure 16 below, I compared the authorized WROEs (i.e., authorized ROE times the authorized equity ratio) for natural gas utilities in Washington to the authorized WROEs in other jurisdictions since January 2009. As shown in Figure 16, the authorized WROEs for natural gas utilities in Washington have been at the bottom of the range of WROEs authorized by state jurisdictions.

Figure 16: Comparison of Washington and U.S. Authorized Weighted Equity Ratios for Natural Gas Utilities[115]



Q. Is it appropriate to consider the WROE that has been authorized in other

[115] Rate cases in Arkansas, Florida, Indiana, and Michigan have been excluded from Figure 16 since the authorized capital structure approved in the cases includes deferred taxes and other credits at zero or low cost. The additional items have the effect of reducing both the equity and debt ratios used to establish the rate of return which, in turn, produces results that are not comparable to allowed equity ratios in other states.

jurisdictions when considering the appropriate equity ratio for Washington?

A. Yes. One of the most important principles in determining the ROE for a company is to ensure the company has the opportunity to earn a reasonable return on capital that is consistent with the returns available on investments of comparable risk. While it is referenced most often in the discussion of the appropriate ROE, it is equally as important to consider the equity ratio. It is the combination of the equity ratio and the authorized ROE that define the return to investors. Therefore, as discussed above, the Commission must consider the equity ratio as well as the authorized ROE in establishing a risk-comparable return.

Q. What is your conclusion regarding an appropriate capital structure for Cascade?

A. Considering the actual capital structures of the operating companies in the proxy group, Cascade's proposed common equity ratio of 50.00 percent is slightly below the range established by the capital structures of the utility operating subsidiaries of the proxy group companies. This difference in capitalization is significant, especially considering the cash flow concerns raised by credit rating agencies as a result of the TCJA, and thus should be considered in setting the appropriate ROE at the higher end of the range of reasonable equity returns. As a result, the proposed equity ratio in combination with my recommended ROE are reasonable and would be adequate to support capital attraction on reasonable terms.

X. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for Cascade?

A. Based on the quantitative and qualitative analyses presented in my Direct

Testimony, and in light of the business and financial risks of Cascade compared to the proxy group, and the effects of Federal tax reform on the cash flow metrics of utilities, it is my view that an ROE of 10.30 is reasonable and would fairly balance the interests of customers and shareholders. This ROE would enable the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable and affordable natural gas utility service to customers in Washington.

Figure 17: Summary of Analytical Results[116]

Constant Growth DCF			
	Median Low	Median	Median High
30-Day Average Price	8.24%	9.69%	12.16%
90-Day Average Price	8.58%	9.63%	12.12%
180-Day Average Price	8.26%	9.72%	12.17%
Capital Asset Pricing Model			
	Current Risk-Free Rate (3.03%)	Q2 2019 – Q2 2020 Projected Risk-Free Rate (3.38%)	2020-2024 Projected Risk-Free Rate (3.90%)
CAPM Results	10.97%	11.08%	11.25%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate (3.03%)	Q2 2019 – Q2 2020 Projected Risk-Free Rate (3.38%)	2020-2024 Projected Risk-Free Rate (3.90%)
Risk Premium Results	9.74%	9.90%	10.13%
Expected Earnings Analysis			
	Mean		Median
Expected Earnings Results	11.56%		11.48%

[116] The analytical results included in Figure 17 reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7.00 percent.

Q. What is your conclusion with respect to Cascade's proposed capital structure?

A. My conclusion is that Cascade's proposal to establish a capital structure consisting of 50.00 percent common equity, and 50.00 percent long-term debt is reasonable when compared to the capital structures of the companies in the proxy group and taking in consideration the impact of the TCJA on the cash flows and therefore should be adopted.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit No. __ (AEB-2)
General Economic Statistics
Witness: Ann E. Bulkley

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF ANN E. BULKLEY

GENERAL ECONOMIC STATISTICS

March 29, 2019

SUMMARY OF ROE ANALYSES RESULTS[1]

Constant Growth DCF			
	Median Low	Median	Median High
30-Day Average	8.24%	9.69%	12.16%
90-Day Average	8.58%	9.63%	12.12%
180-Day Average	8.26%	9.72%	12.17%
Constant Growth Average	8.36%	9.68%	12.15%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
CAPM	10.97%	11.08%	11.25%
CAPM Mean Result	11.10%		
Treasury Yield Plus Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Analysis	9.74%	9.90%	10.13%
Risk Premium Mean Result	9.92%		
Expected Earnings Analysis			
	Mean		Median
Expected Earnings Result	11.56%		11.48%

Notes:

[1] The analytical results included in the table reflect the results of the Constant Growth DCF analysis excluding the results for individual companies that did not meet the minimum threshold of 7 percent.

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Company		Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Postive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	% Regulated Operating Income > 70%	% Regulated Natural Gas Operating Income > 60%	Announced Merger
Atmos Energy Corporation	ATO	YES	A	Yes	Yes	100.00%	68.59%	No
New Jersey Resources Corporation	NJR	YES	BBB+	Yes	Yes	96.45%	88.91%	No
Northwest Natural Gas Company	NWN	YES	A+	Yes	Yes	99.50%	96.47%	No
One Gas Inc.	OGS	YES	A	Yes	Yes	100.00%	100.00%	No
South Jersey Industries, Inc.	SJI	YES	BBB	Yes	Yes	80.31%	100.00%	No
Southwest Gas Corporation	SWX	YES	BBB+	Yes	Yes	82.19%	100.00%	No
Spire Inc.	SR	YES	A-	Yes	Yes	99.77%	100.00%	No

Notes:
[1] Source: SNL Financial
[2] Source: SNL Financial
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] to [6] Source: Form 10-Ks for 2017, 2016 & 2015
[7] SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF -- CASCADE NATURAL GAS PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	All Proxy Group [9]	[10]	[11]	With Exclusions [12]	[13]	[14]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.10	$93.27	2.25%	2.33%	7.50%	6.45%	6.50%	6.82%	8.77%	9.14%	9.84%	8.77%	9.14%	9.84%
New Jersey Resources Corporation	NJR	$1.17	$46.09	2.54%	2.63%	9.50%	6.00%	7.00%	7.50%	8.61%	10.13%	12.16%	8.61%	10.13%	12.16%
Northwest Natural Gas Company	NWN	$1.90	$60.49	3.14%	3.34%	30.50%	4.00%	4.30%	12.93%	7.20%	16.28%	34.12%	7.20%	16.28%	34.12%
One Gas Inc.	OGS	$1.84	$79.77	2.31%	2.39%	10.50%	5.50%	5.90%	7.30%	7.87%	9.69%	12.93%	7.87%	9.69%	12.93%
South Jersey Industries, Inc.	SJI	$1.15	$28.87	3.98%	4.21%	9.50%	12.70%	12.50%	11.57%	13.67%	15.78%	16.94%	13.67%	15.78%	16.94%
Southwest Gas Corporation	SWX	$2.08	$77.00	2.70%	2.79%	9.00%	6.20%	5.00%	6.73%	7.77%	9.53%	11.82%	7.77%	9.53%	11.82%
Spire, Inc.	SR	$2.37	$75.12	3.15%	3.22%	6.50%	2.70%	4.00%	4.40%	5.90%	7.62%	9.76%		7.62%	9.76%
MEDIAN				2.70%	2.79%	9.50%	6.00%	5.90%	7.30%	7.87%	9.69%	12.16%	8.24%	9.69%	12.16%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of January 31, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

90-DAY CONSTANT GROWTH DCF -- CASCADE NATURAL GAS PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.10	$94.96	2.21%	2.29%	7.50%	6.45%	6.50%	6.82%	8.73%	9.10%	9.79%	8.73%	9.10%	9.79%
New Jersey Resources Corporation	NJR	$1.17	$46.79	2.50%	2.59%	9.50%	6.00%	7.00%	7.50%	8.58%	10.09%	12.12%	8.58%	10.09%	12.12%
Northwest Natural Gas Company	NWN	$1.90	$65.33	2.91%	3.10%	30.50%	4.00%	4.30%	12.93%	6.97%	16.03%	33.85%		16.03%	33.85%
One Gas, Inc.	OGS	$1.84	$81.74	2.25%	2.33%	10.50%	5.50%	5.90%	7.30%	7.81%	9.63%	12.87%	7.81%	9.63%	12.87%
South Jersey Industries, Inc.	SJI	$1.15	$31.32	3.67%	3.88%	9.50%	12.70%	12.50%	11.57%	13.35%	15.45%	16.60%	13.35%	15.45%	16.60%
Southwest Gas Corporation	SWX	$2.08	$79.34	2.62%	2.71%	9.00%	6.20%	5.00%	6.73%	7.69%	9.44%	11.74%	7.69%	9.44%	11.74%
Spire, Inc.	SR	$2.37	$75.43	3.14%	3.21%	6.50%	2.70%	4.00%	4.40%	5.88%	7.61%	9.74%		7.61%	9.74%
MEDIAN				2.62%	2.71%	9.50%	6.00%	5.90%	7.30%	7.81%	9.63%	12.12%	8.58%	9.63%	12.12%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of January 31, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

180-DAY CONSTANT GROWTH DCF -- CASCADE NATURAL GAS PROXY GROUP

										All Proxy Group			With Exclusions		
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth	Low ROE	Mean ROE	High ROE	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	$2.10	$92.68	2.27%	2.34%	7.50%	6.45%	6.50%	6.82%	8.79%	9.16%	9.85%	8.79%	9.16%	9.85%
New Jersey Resources Corporation	NJR	$1.17	$45.92	2.55%	2.64%	9.50%	6.00%	7.00%	7.50%	8.62%	10.14%	12.17%	8.62%	10.14%	12.17%
Northwest Natural Gas Company	NWN	$1.90	$64.28	2.96%	3.15%	30.50%	4.00%	4.30%	12.93%	7.02%	16.08%	33.91%	7.02%	16.08%	33.91%
One Gas, Inc.	OGS	$1.84	$78.88	2.33%	2.42%	10.50%	5.50%	5.90%	7.30%	7.90%	9.72%	12.96%	7.90%	9.72%	12.96%
South Jersey Industries, Inc.	SJI	$1.15	$32.28	3.56%	3.77%	9.50%	12.70%	12.50%	11.57%	13.23%	15.34%	16.49%	13.23%	15.34%	16.49%
Southwest Gas Corporation	SWX	$2.08	$78.39	2.65%	2.74%	9.00%	6.20%	5.00%	6.73%	7.72%	9.48%	11.77%	7.72%	9.48%	11.77%
Spire, Inc.	SR	$2.37	$73.89	3.21%	3.28%	6.50%	2.70%	4.00%	4.40%	5.95%	7.68%	9.81%		7.68%	9.81%
MEDIAN				2.65%	2.74%	9.50%	6.00%	5.90%	7.30%	7.90%	9.72%	12.17%	8.26%	9.72%	12.17%

Notes
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of January 31, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line Investment Survey
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])
[12] Equals [9] if greater than 7.00%
[13] Equals [10] if greater than 7.00%
[14] Equals [11] if greater than 7.00%

BETA
AS OF JANUARY 31, 2019

Proxy Group	Ticker	[1] Value Line
Atmos Energy Corporation	ATO	0.60
New Jersey Resources Corporation	NJR	0.70
Northwest Natural Gas Company	NWN	0.60
ONE Gas, Inc.	OGS	0.65
South Jersey Industries, Inc.	SJI	0.80
Southwest Gas Corporation	SWX	0.70
Spire, Inc.	SR	0.65
MEAN		0.671

Notes:
[1] Source: Value Line; November 30, 2018

CAPITAL ASSET PRICING MODEL

	[4]	[5]	[6]	[7]	[8]
	Risk-Free Rate *(Rf)*	Beta *(β)*	Market Return *(Rm)*	Market Risk Premium *(Rm − Rf)*	ROE *(K)*
Proxy Group Average Value Line Beta					
Current 30-day average of 30-year U.S. Treasury bond yield [1]	3.03%	0.671	14.85%	11.81%	10.97%
Near-term projected 30-year U.S. Treasury bond yield (Q2 2019 - Q2 2020) [2]	3.38%	0.671	14.85%	11.47%	11.08%
Projected 30-year U.S. Treasury bond yield (2020 - 2024) [3]	3.90%	0.671	14.85%	10.95%	11.25%
				MEAN	11.10%

Notes:
[1] Source: Bloomberg Professional, 30-day average as of January 31, 2019
[2] Source: Blue Chip Financial Forecasts, Vol. 38, No. 2, February 1, 2019, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14
[4] See Notes [1], [2] and [3]
[5] Source: Schedule-4
[6] Source: Schedule-5, p.2
[7] Equals [6] - [4]
[8] Equals [4] + ([5] x [7])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[9] Estimated Weighted Average Dividend Yield	2.08%		
[10] Estimated Weighted Average Long-Term Growth Rate	12.64%		
[11] S&P 500 Estimated Required Market Return	14.85%		
[12] Risk-Free Rate	3.03%	3.38%	3.90%
[13] Implied Market Risk Premium	11.81%	11.47%	10.95%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	0.14%	4.60%	0.01%	8.20%	0.01%
American Express Co	AXP	0.37%	1.52%	0.01%	14.99%	0.06%
Verizon Communications Inc	VZ	0.97%	4.38%	0.04%	2.30%	0.02%
Broadcom Inc	AVGO	0.46%	3.95%	0.02%	14.32%	0.07%
Boeing Co/The	BA	0.93%	2.13%	0.02%	16.70%	0.16%
Caterpillar Inc	CAT	0.33%	2.58%	0.01%	13.35%	0.04%
JPMorgan Chase & Co	JPM	1.46%	3.09%	0.05%	9.33%	0.14%
Chevron Corp	CVX	0.93%	4.15%	0.04%	7.17%	0.07%
Coca-Cola Co/The	KO	0.87%	3.24%	0.03%	7.49%	0.07%
AbbVie Inc	ABBV	0.51%	5.33%	0.03%	8.81%	0.05%
Walt Disney Co/The	DIS	0.71%	1.58%	0.01%	12.98%	0.09%
FleetCor Technologies Inc	FLT	0.08%	n/a	n/a	16.50%	0.01%
Extra Space Storage Inc	EXR	0.05%	3.49%	0.00%	5.34%	0.00%
Exxon Mobil Corp	XOM	1.32%	4.48%	0.06%	11.59%	0.15%
Phillips 66	PSX	0.19%	3.35%	0.01%	5.70%	0.01%
General Electric Co	GE	0.38%	0.39%	0.00%	1.60%	0.01%
HP Inc	HPQ	0.15%	2.91%	0.00%	6.06%	0.01%
Home Depot Inc/The	HD	0.88%	2.24%	0.02%	13.01%	0.11%
International Business Machines Corp	IBM	0.52%	4.67%	0.02%	3.59%	0.02%
Concho Resources Inc	CXO	0.10%	n/a	n/a	31.00%	0.03%
Johnson & Johnson	JNJ	1.52%	2.71%	0.04%	7.26%	0.11%
McDonald's Corp	MCD	0.59%	2.60%	0.02%	8.92%	0.05%
Merck & Co Inc	MRK	0.82%	2.96%	0.02%	8.46%	0.07%
3M Co	MMM	0.50%	2.72%	0.01%	7.70%	0.04%
American Water Works Co Inc	AWK	0.07%	1.90%	0.00%	8.45%	0.01%
Bank of America Corp	BAC	1.17%	2.11%	0.02%	9.70%	0.11%
Brighthouse Financial Inc	BHF	0.02%	n/a	n/a	8.64%	0.00%
Baker Hughes a GE Co	BHGE	0.05%	3.05%	0.00%	40.82%	0.02%
Pfizer Inc	PFE	1.04%	3.39%	0.04%	5.45%	0.06%
Procter & Gamble Co/The	PG	1.02%	2.97%	0.03%	6.60%	0.07%
AT&T Inc	T	0.93%	6.79%	0.06%	5.69%	0.05%
Travelers Cos Inc/The	TRV	0.14%	2.45%	0.00%	17.65%	0.02%
United Technologies Corp	UTX	0.43%	2.49%	0.01%	9.80%	0.04%
Analog Devices Inc	ADI	0.15%	1.94%	0.00%	8.43%	0.01%
Walmart Inc	WMT	1.18%	2.17%	0.03%	5.01%	0.06%
Cisco Systems Inc	CSCO	0.90%	2.79%	0.03%	5.74%	0.05%
Intel Corp	INTC	0.91%	2.67%	0.02%	8.54%	0.08%
General Motors Co	GM	0.23%	3.90%	0.01%	11.08%	0.03%
Microsoft Corp	MSFT	3.40%	1.76%	0.06%	12.16%	0.41%
Dollar General Corp	DG	0.13%	1.00%	0.00%	15.00%	0.02%
Cigna Corp	CI	0.32%	0.02%	0.00%	18.35%	0.06%
Kinder Morgan Inc/DE	KMI	0.17%	4.42%	0.01%	10.00%	0.02%
Citigroup Inc	C	0.67%	2.79%	0.02%	11.07%	0.07%
American International Group Inc	AIG	0.16%	2.96%	0.00%	11.00%	0.02%
Honeywell International Inc	HON	0.45%	2.28%	0.01%	13.55%	0.06%
Altria Group Inc	MO	0.39%	6.48%	0.03%	8.50%	0.03%
HCA Healthcare Inc	HCA	0.20%	1.15%	0.00%	11.56%	0.02%
Under Armour Inc	UAA	0.02%	n/a	n/a	30.02%	0.00%
International Paper Co	IP	0.08%	4.22%	0.00%	6.08%	0.00%
Hewlett Packard Enterprise Co	HPE	0.09%	2.89%	0.00%	4.86%	0.00%
Abbott Laboratories	ABT	0.54%	1.75%	0.01%	11.69%	0.06%
Aflac Inc	AFL	0.15%	2.26%	0.00%	9.28%	0.01%
Air Products & Chemicals Inc	APD	0.15%	2.82%	0.00%	12.30%	0.02%
Royal Caribbean Cruises Ltd	RCL	0.11%	2.33%	0.00%	13.52%	0.01%
American Electric Power Co Inc	AEP	0.17%	3.39%	0.01%	5.96%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
Hess Corp	HES	0.07%	1.85%	0.00%	-9.49%	-0.01%
Anadarko Petroleum Corp	APC	0.10%	2.54%	0.00%	21.38%	0.02%
Aon PLC	AON	0.16%	1.02%	0.00%	11.70%	0.02%
Apache Corp	APA	0.05%	3.05%	0.00%	-3.09%	0.00%
Archer-Daniels-Midland Co	ADM	0.11%	2.98%	0.00%	11.10%	0.01%
Automatic Data Processing Inc	ADP	0.26%	2.26%	0.01%	14.00%	0.04%
Verisk Analytics Inc	VRSK	0.08%	n/a	n/a	12.91%	0.01%
AutoZone Inc	AZO	0.09%	n/a	n/a	12.80%	0.01%
Avery Dennison Corp	AVY	0.04%	1.99%	0.00%	5.75%	0.00%
MSCI Inc	MSCI	0.06%	1.36%	0.00%	13.10%	0.01%
Ball Corp	BLL	0.08%	0.77%	0.00%	6.50%	0.00%
Bank of New York Mellon Corp/The	BK	0.21%	2.14%	0.00%	7.33%	0.02%
Baxter International Inc	BAX	0.16%	1.05%	0.00%	12.20%	0.02%
Becton Dickinson and Co	BDX	0.29%	1.23%	0.00%	13.29%	0.04%
Berkshire Hathaway Inc	BRK/B	1.19%	n/a	n/a	-5.60%	-0.07%
Best Buy Co Inc	BBY	0.07%	3.04%	0.00%	11.10%	0.01%
H&R Block Inc	HRB	0.02%	4.24%	0.00%	10.00%	0.00%
Boston Scientific Corp	BSX	0.22%	n/a	n/a	38.58%	0.09%
Bristol-Myers Squibb Co	BMY	0.34%	3.32%	0.01%	12.78%	0.04%
Fortune Brands Home & Security Inc	FBHS	0.03%	1.94%	0.00%	11.16%	0.00%
Brown-Forman Corp	BF/B	0.06%	1.41%	0.00%	9.86%	0.01%
Cabot Oil & Gas Corp	COG	0.05%	1.12%	0.00%	33.27%	0.02%
Campbell Soup Co	CPB	0.05%	3.95%	0.00%	3.05%	0.00%
Kansas City Southern	KSU	0.05%	1.36%	0.00%	8.97%	0.00%
Hilton Worldwide Holdings Inc	HLT	0.09%	0.81%	0.00%	9.53%	0.01%
Carnival Corp	CCL	0.13%	3.47%	0.00%	11.76%	0.02%
Qorvo Inc	QRVO	0.03%	n/a	n/a	11.42%	0.00%
CenturyLink Inc	CTL	0.07%	14.10%	0.01%	-21.81%	-0.02%
UDR Inc	UDR	0.05%	2.95%	0.00%	5.68%	0.00%
Clorox Co/The	CLX	0.08%	2.59%	0.00%	4.95%	0.00%
CMS Energy Corp	CMS	0.06%	2.93%	0.00%	6.93%	0.00%
Newell Brands Inc	NWL	0.04%	4.34%	0.00%	1.98%	0.00%
Colgate-Palmolive Co	CL	0.24%	2.60%	0.01%	6.69%	0.02%
Comerica Inc	CMA	0.05%	3.40%	0.00%	16.41%	0.01%
IPG Photonics Corp	IPGP	0.03%	n/a	n/a	9.24%	0.00%
Conagra Brands Inc	CAG	0.04%	3.93%	0.00%	8.50%	0.00%
Consolidated Edison Inc	ED	0.11%	3.81%	0.00%	3.73%	0.00%
SL Green Realty Corp	SLG	0.03%	3.68%	0.00%	-0.59%	0.00%
Corning Inc	GLW	0.11%	2.16%	0.00%	10.39%	0.01%
Cummins Inc	CMI	0.10%	3.10%	0.00%	10.64%	0.01%
Danaher Corp	DHR	0.33%	0.58%	0.00%	10.95%	0.04%
Target Corp	TGT	0.16%	3.51%	0.01%	6.44%	0.01%
Deere & Co	DE	0.22%	1.85%	0.00%	10.83%	0.02%
Dominion Energy Inc	D	0.24%	5.22%	0.01%	6.03%	0.01%
Dover Corp	DOV	0.05%	2.19%	0.00%	10.97%	0.01%
Alliant Energy Corp	LNT	0.05%	3.19%	0.00%	6.49%	0.00%
Duke Energy Corp	DUK	0.27%	4.23%	0.01%	5.00%	0.01%
Regency Centers Corp	REG	0.05%	3.42%	0.00%	6.04%	0.00%
Eaton Corp PLC	ETN	0.14%	3.46%	0.00%	9.83%	0.01%
Ecolab Inc	ECL	0.19%	1.16%	0.00%	13.00%	0.03%
PerkinElmer Inc	PKI	0.04%	0.31%	0.00%	15.49%	0.01%
Emerson Electric Co	EMR	0.17%	2.99%	0.01%	8.93%	0.02%
EOG Resources Inc	EOG	0.24%	0.89%	0.00%	11.06%	0.03%
Entergy Corp	ETR	0.07%	4.08%	0.00%	-0.73%	0.00%
Equifax Inc	EFX	0.05%	1.46%	0.00%	6.60%	0.00%
IQVIA Holdings Inc	IQV	0.11%	n/a	n/a	15.23%	0.02%
Gartner Inc	IT	0.05%	n/a	n/a	14.47%	0.01%
FedEx Corp	FDX	0.20%	1.46%	0.00%	14.30%	0.03%
Macy's Inc	M	0.03%	5.74%	0.00%	0.60%	0.00%
FMC Corp	FMC	0.05%	2.01%	0.00%	17.07%	0.01%
Ford Motor Co	F	0.15%	6.82%	0.01%	-4.80%	-0.01%
NextEra Energy Inc	NEE	0.36%	2.48%	0.01%	8.40%	0.03%
Franklin Resources Inc	BEN	0.06%	3.51%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	0.07%	1.72%	0.00%	-12.55%	-0.01%
Gap Inc/The	GPS	0.04%	3.81%	0.00%	8.63%	0.00%
General Dynamics Corp	GD	0.22%	2.17%	0.00%	10.09%	0.02%
General Mills Inc	GIS	0.11%	4.41%	0.00%	5.90%	0.01%
Genuine Parts Co	GPC	0.06%	2.89%	0.00%	5.62%	0.00%
WW Grainger Inc	GWW	0.07%	1.84%	0.00%	12.47%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
Halliburton Co	HAL	0.12%	2.30%	0.00%	30.08%	0.04%
Harley-Davidson Inc	HOG	0.03%	4.02%	0.00%	8.97%	0.00%
Harris Corp	HRS	0.08%	1.79%	0.00%	7.00%	0.01%
HCP Inc	HCP	0.06%	4.69%	0.00%	2.29%	0.00%
Helmerich & Payne Inc	HP	0.03%	5.07%	0.00%	96.36%	0.03%
Fortive Corp	FTV	0.11%	0.37%	0.00%	12.69%	0.01%
Hershey Co/The	HSY	0.07%	2.72%	0.00%	7.28%	0.00%
Synchrony Financial	SYF	0.09%	2.80%	0.00%	6.20%	0.01%
Hormel Foods Corp	HRL	0.10%	1.98%	0.00%	5.80%	0.01%
Arthur J Gallagher & Co	AJG	0.06%	2.30%	0.00%	10.91%	0.01%
Mondelez International Inc	MDLZ	0.29%	2.25%	0.01%	7.33%	0.02%
CenterPoint Energy Inc	CNP	0.07%	3.72%	0.00%	6.90%	0.00%
Humana Inc	HUM	0.18%	0.65%	0.00%	14.26%	0.03%
Willis Towers Watson PLC	WLTW	0.09%	1.47%	0.00%	14.13%	0.01%
Illinois Tool Works Inc	ITW	0.19%	2.91%	0.01%	9.51%	0.02%
Ingersoll-Rand PLC	IR	0.10%	2.12%	0.00%	10.69%	0.01%
Foot Locker Inc	FL	0.03%	2.47%	0.00%	6.24%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.04%	3.69%	0.00%	8.53%	0.00%
International Flavors & Fragrances Inc	IFF	0.06%	2.06%	0.00%	9.00%	0.01%
Jacobs Engineering Group Inc	JEC	0.04%	1.05%	0.00%	13.25%	0.01%
Hanesbrands Inc	HBI	0.02%	4.00%	0.00%	1.83%	0.00%
Kellogg Co	K	0.09%	3.80%	0.00%	4.91%	0.00%
Broadridge Financial Solutions Inc	BR	0.05%	1.92%	0.00%	10.00%	0.00%
Perrigo Co PLC	PRGO	0.03%	1.64%	0.00%	1.17%	0.00%
Kimberly-Clark Corp	KMB	0.16%	3.70%	0.01%	6.34%	0.01%
Kimco Realty Corp	KIM	0.03%	6.58%	0.00%	3.54%	0.00%
Kohl's Corp	KSS	0.05%	3.55%	0.00%	16.00%	0.01%
Oracle Corp	ORCL	0.77%	1.51%	0.01%	7.35%	0.06%
Kroger Co/The	KR	0.10%	1.98%	0.00%	6.43%	0.01%
Leggett & Platt Inc	LEG	0.02%	3.71%	0.00%	10.00%	0.00%
Lennar Corp	LEN	0.06%	0.34%	0.00%	12.74%	0.01%
Jefferies Financial Group Inc	JEF	0.03%	2.40%	0.00%	n/a	n/a
Eli Lilly & Co	LLY	0.54%	2.15%	0.01%	12.86%	0.07%
L Brands Inc	LB	0.03%	8.62%	0.00%	10.72%	0.00%
Charter Communications Inc	CHTR	0.32%	n/a	n/a	47.90%	0.15%
Lincoln National Corp	LNC	0.05%	2.53%	0.00%	n/a	n/a
Loews Corp	L	0.06%	0.52%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.33%	2.00%	0.01%	15.17%	0.05%
Host Hotels & Resorts Inc	HST	0.06%	4.43%	0.00%	4.57%	0.00%
Marsh & McLennan Cos Inc	MMC	0.19%	1.88%	0.00%	11.80%	0.02%
Masco Corp	MAS	0.04%	1.48%	0.00%	15.46%	0.01%
Mattel Inc	MAT	0.02%	n/a	n/a	10.00%	0.00%
S&P Global Inc	SPGI	0.20%	1.19%	0.00%	12.10%	0.02%
Medtronic PLC	MDT	0.50%	2.26%	0.01%	7.94%	0.04%
CVS Health Corp	CVS	0.36%	3.05%	0.01%	11.30%	0.04%
DowDuPont Inc	DWDP	0.52%	2.82%	0.01%	6.17%	0.03%
Micron Technology Inc	MU	0.18%	n/a	n/a	-3.30%	-0.01%
Motorola Solutions Inc	MSI	0.08%	1.95%	0.00%	6.30%	0.01%
Cboe Global Markets Inc	CBOE	0.04%	1.33%	0.00%	13.10%	0.01%
Mylan NV	MYL	0.07%	n/a	n/a	6.67%	0.00%
Laboratory Corp of America Holdings	LH	0.06%	n/a	n/a	8.78%	0.01%
Newmont Mining Corp	NEM	0.08%	1.64%	0.00%	-3.00%	0.00%
Twenty-First Century Fox Inc	FOXA	0.22%	0.73%	0.00%	9.22%	0.02%
NIKE Inc	NKE	0.44%	1.07%	0.00%	13.35%	0.06%
NiSource Inc	NI	0.04%	2.86%	0.00%	5.79%	0.00%
Noble Energy Inc	NBL	0.05%	1.97%	0.00%	25.55%	0.01%
Norfolk Southern Corp	NSC	0.19%	2.05%	0.00%	8.64%	0.02%
Principal Financial Group Inc	PFG	0.06%	4.31%	0.00%	5.88%	0.00%
Eversource Energy	ES	0.09%	2.91%	0.00%	5.62%	0.01%
Northrop Grumman Corp	NOC	0.20%	1.74%	0.00%	12.71%	0.03%
Wells Fargo & Co	WFC	0.95%	3.68%	0.04%	11.26%	0.11%
Nucor Corp	NUE	0.08%	2.61%	0.00%	0.85%	0.00%
PVH Corp	PVH	0.04%	0.14%	0.00%	11.03%	0.00%
Occidental Petroleum Corp	OXY	0.21%	4.67%	0.01%	13.85%	0.03%
Omnicom Group Inc	OMC	0.07%	3.08%	0.00%	6.64%	0.00%
ONEOK Inc	OKE	0.11%	5.36%	0.01%	23.23%	0.03%
Raymond James Financial Inc	RJF	0.05%	1.69%	0.00%	12.30%	0.01%
Parker-Hannifin Corp	PH	0.09%	1.84%	0.00%	9.52%	0.01%
Rollins Inc	ROL	0.05%	1.13%	0.00%	10.00%	0.01%

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Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
PPL Corp	PPL	0.10%	5.24%	0.01%	6.17%	0.01%
Exelon Corp	EXC	0.20%	2.89%	0.01%	4.94%	0.01%
ConocoPhillips	COP	0.33%	1.80%	0.01%	6.00%	0.02%
PulteGroup Inc	PHM	0.03%	1.58%	0.00%	7.17%	0.00%
Pinnacle West Capital Corp	PNW	0.04%	3.35%	0.00%	4.99%	0.00%
PNC Financial Services Group Inc/The	PNC	0.24%	3.10%	0.01%	7.37%	0.02%
PPG Industries Inc	PPG	0.11%	1.82%	0.00%	7.49%	0.01%
Progressive Corp/The	PGR	0.17%	3.74%	0.01%	9.80%	0.02%
Public Service Enterprise Group Inc	PEG	0.12%	3.30%	0.00%	6.64%	0.01%
Raytheon Co	RTN	0.20%	2.11%	0.00%	12.28%	0.02%
Robert Half International Inc	RHI	0.03%	1.74%	0.00%	13.20%	0.00%
Edison International	EIX	0.08%	4.30%	0.00%	5.84%	0.00%
Schlumberger Ltd	SLB	0.26%	4.52%	0.01%	33.69%	0.09%
Charles Schwab Corp/The	SCHW	0.27%	1.45%	0.00%	19.78%	0.05%
Sherwin-Williams Co/The	SHW	0.17%	0.82%	0.00%	10.92%	0.02%
JM Smucker Co/The	SJM	0.05%	3.24%	0.00%	3.41%	0.00%
Snap-on Inc	SNA	0.04%	2.29%	0.00%	8.23%	0.00%
AMETEK Inc	AME	0.07%	0.77%	0.00%	10.44%	0.01%
Southern Co/The	SO	0.21%	4.94%	0.01%	3.38%	0.01%
BB&T Corp	BBT	0.16%	3.32%	0.01%	10.93%	0.02%
Southwest Airlines Co	LUV	0.14%	1.13%	0.00%	10.67%	0.01%
Stanley Black & Decker Inc	SWK	0.08%	2.09%	0.00%	10.50%	0.01%
Public Storage	PSA	0.16%	3.76%	0.01%	4.45%	0.01%
Arista Networks Inc	ANET	0.07%	n/a	n/a	27.64%	0.02%
SunTrust Banks Inc	STI	0.11%	3.37%	0.00%	9.18%	0.01%
Sysco Corp	SYY	0.14%	2.44%	0.00%	12.53%	0.02%
Texas Instruments Inc	TXN	0.41%	3.06%	0.01%	10.48%	0.04%
Textron Inc	TXT	0.05%	0.15%	0.00%	12.56%	0.01%
Thermo Fisher Scientific Inc	TMO	0.42%	0.28%	0.00%	11.00%	0.05%
Tiffany & Co	TIF	0.05%	2.48%	0.00%	12.54%	0.01%
TJX Cos Inc/The	TJX	0.26%	1.57%	0.00%	11.18%	0.03%
Torchmark Corp	TMK	0.04%	0.76%	0.00%	13.70%	0.01%
Total System Services Inc	TSS	0.07%	0.58%	0.00%	14.15%	0.01%
Johnson Controls International plc	JCI	0.13%	3.08%	0.00%	6.90%	0.01%
Ulta Beauty Inc	ULTA	0.07%	n/a	n/a	19.00%	0.01%
Union Pacific Corp	UNP	0.50%	2.01%	0.01%	10.86%	0.05%
Keysight Technologies Inc	KEYS	0.06%	n/a	n/a	17.00%	0.01%
UnitedHealth Group Inc	UNH	1.10%	1.33%	0.01%	13.73%	0.15%
Unum Group	UNM	0.03%	2.99%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.06%	1.27%	0.00%	5.00%	0.00%
Varian Medical Systems Inc	VAR	0.05%	n/a	n/a	16.10%	0.01%
Ventas Inc	VTR	0.10%	4.92%	0.00%	2.29%	0.00%
VF Corp	VFC	0.14%	2.42%	0.00%	-16.64%	-0.02%
Vornado Realty Trust	VNO	0.06%	3.78%	0.00%	3.70%	0.00%
Vulcan Materials Co	VMC	0.06%	1.10%	0.00%	16.04%	0.01%
Weyerhaeuser Co	WY	0.08%	5.18%	0.00%	10.50%	0.01%
Whirlpool Corp	WHR	0.04%	3.46%	0.00%	5.75%	0.00%
Williams Cos Inc/The	WMB	0.14%	5.05%	0.01%	3.90%	0.01%
WEC Energy Group Inc	WEC	0.10%	3.23%	0.00%	4.89%	0.00%
Xerox Corp	XRX	0.03%	3.54%	0.00%	0.20%	0.00%
Adobe Inc	ADBE	0.51%	n/a	n/a	16.75%	0.09%
AES Corp/VA	AES	0.05%	3.33%	0.00%	8.66%	0.00%
Amgen Inc	AMGN	0.50%	3.10%	0.02%	6.16%	0.03%
Apple Inc	AAPL	3.33%	1.75%	0.06%	9.40%	0.31%
Autodesk Inc	ADSK	0.14%	n/a	n/a	54.78%	0.07%
Cintas Corp	CTAS	0.08%	1.09%	0.00%	12.11%	0.01%
Comcast Corp	CMCSA	0.70%	2.30%	0.02%	11.34%	0.08%
Molson Coors Brewing Co	TAP	0.06%	2.46%	0.00%	0.00%	0.00%
KLA-Tencor Corp	KLAC	0.07%	2.82%	0.00%	7.15%	0.00%
Marriott International Inc/MD	MAR	0.17%	1.43%	0.00%	12.10%	0.02%
McCormick & Co Inc/MD	MKC	0.06%	1.84%	0.00%	6.10%	0.00%
Nordstrom Inc	JWN	0.03%	3.19%	0.00%	9.00%	0.00%
PACCAR Inc	PCAR	0.10%	1.95%	0.00%	6.10%	0.01%
Costco Wholesale Corp	COST	0.40%	1.06%	0.00%	10.58%	0.04%
First Republic Bank/CA	FRC	0.07%	0.75%	0.00%	11.82%	0.01%
Stryker Corp	SYK	0.28%	1.17%	0.00%	8.64%	0.02%
Tyson Foods Inc	TSN	0.08%	2.42%	0.00%	-5.00%	0.00%
Lamb Weston Holdings Inc	LW	0.04%	1.11%	0.00%	11.02%	0.00%
Applied Materials Inc	AMAT	0.16%	2.05%	0.00%	7.34%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
American Airlines Group Inc	AAL	0.07%	1.12%	0.00%	15.20%	0.01%
Cardinal Health Inc	CAH	0.06%	3.81%	0.00%	18.34%	0.01%
Celgene Corp	CELG	0.26%	n/a	n/a	20.70%	0.05%
Cerner Corp	CERN	0.08%	n/a	n/a	12.47%	0.01%
Cincinnati Financial Corp	CINF	0.06%	2.61%	0.00%	n/a	n/a
DR Horton Inc	DHI	0.06%	1.56%	0.00%	11.80%	0.01%
Flowserve Corp	FLS	0.02%	1.73%	0.00%	20.07%	0.00%
Electronic Arts Inc	EA	0.12%	n/a	n/a	12.63%	0.01%
Expeditors International of Washington Inc	EXPD	0.05%	1.30%	0.00%	9.60%	0.00%
Fastenal Co	FAST	0.07%	2.84%	0.00%	14.85%	0.01%
M&T Bank Corp	MTB	0.10%	2.43%	0.00%	10.45%	0.01%
Xcel Energy Inc	XEL	0.12%	2.90%	0.00%	5.98%	0.01%
Fiserv Inc	FISV	0.14%	n/a	n/a	7.40%	0.01%
Fifth Third Bancorp	FITB	0.07%	3.28%	0.00%	3.95%	0.00%
Gilead Sciences Inc	GILD	0.38%	3.26%	0.01%	5.45%	0.02%
Hasbro Inc	HAS	0.05%	2.78%	0.00%	9.73%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.06%	4.23%	0.00%	8.20%	0.00%
Welltower Inc	WELL	0.12%	4.49%	0.01%	7.21%	0.01%
Biogen Inc	BIIB	0.29%	n/a	n/a	5.81%	0.02%
Northern Trust Corp	NTRS	0.08%	2.71%	0.00%	12.82%	0.01%
Packaging Corp of America	PKG	0.04%	3.35%	0.00%	8.25%	0.00%
Paychex Inc	PAYX	0.11%	3.16%	0.00%	9.25%	0.01%
People's United Financial Inc	PBCT	0.03%	4.27%	0.00%	2.00%	0.00%
QUALCOMM Inc	QCOM	0.25%	5.01%	0.01%	11.71%	0.03%
Roper Technologies Inc	ROP	0.12%	0.65%	0.00%	9.20%	0.01%
Ross Stores Inc	ROST	0.14%	0.98%	0.00%	10.50%	0.02%
IDEXX Laboratories Inc	IDXX	0.08%	n/a	n/a	16.33%	0.01%
Starbucks Corp	SBUX	0.36%	2.11%	0.01%	13.12%	0.05%
KeyCorp	KEY	0.07%	4.13%	0.00%	13.17%	0.01%
State Street Corp	STT	0.11%	2.65%	0.00%	8.69%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	0.05%	n/a	n/a	19.54%	0.01%
US Bancorp	USB	0.35%	2.89%	0.01%	7.83%	0.03%
AO Smith Corp	AOS	0.03%	1.84%	0.00%	9.33%	0.00%
Symantec Corp	SYMC	0.06%	1.43%	0.00%	7.50%	0.00%
T Rowe Price Group Inc	TROW	0.09%	3.00%	0.00%	6.11%	0.01%
Waste Management Inc	WM	0.17%	1.94%	0.00%	11.78%	0.02%
CBS Corp	CBS	0.07%	1.46%	0.00%	16.37%	0.01%
Allergan PLC	AGN	0.21%	2.06%	0.00%	7.11%	0.01%
Constellation Brands Inc	STZ	0.12%	1.70%	0.00%	8.64%	0.01%
Xilinx Inc	XLNX	0.12%	1.29%	0.00%	8.60%	0.01%
DENTSPLY SIRONA Inc	XRAY	0.04%	0.83%	0.00%	6.90%	0.00%
Zions Bancorp NA	ZION	0.04%	2.52%	0.00%	6.78%	0.00%
Alaska Air Group Inc	ALK	0.03%	2.19%	0.00%	5.60%	0.00%
Invesco Ltd	IVZ	0.03%	6.59%	0.00%	1.84%	0.00%
Linde PLC	LIN	0.38%	2.02%	0.01%	18.10%	0.07%
Intuit Inc	INTU	0.24%	0.87%	0.00%	15.87%	0.04%
Morgan Stanley	MS	0.31%	2.84%	0.01%	13.50%	0.04%
Microchip Technology Inc	MCHP	0.08%	1.81%	0.00%	12.03%	0.01%
Chubb Ltd	CB	0.26%	2.19%	0.01%	10.00%	0.03%
Hologic Inc	HOLX	0.05%	n/a	n/a	3.10%	0.00%
Citizens Financial Group Inc	CFG	0.07%	3.77%	0.00%	16.69%	0.01%
O'Reilly Automotive Inc	ORLY	0.12%	n/a	n/a	15.51%	0.02%
Allstate Corp/The	ALL	0.13%	2.09%	0.00%	9.00%	0.01%
FLIR Systems Inc	FLIR	0.03%	1.31%	0.00%	n/a	n/a
Equity Residential	EQR	0.11%	2.98%	0.00%	6.31%	0.01%
BorgWarner Inc	BWA	0.04%	1.66%	0.00%	6.02%	0.00%
Newfield Exploration Co	NFX	0.02%	n/a	n/a	17.71%	0.00%
Incyte Corp	INCY	0.07%	n/a	n/a	57.27%	0.04%
Simon Property Group Inc	SPG	0.24%	4.39%	0.01%	5.20%	0.01%
Eastman Chemical Co	EMN	0.05%	3.08%	0.00%	7.40%	0.00%
Twitter Inc	TWTR	0.11%	n/a	n/a	56.40%	0.06%
AvalonBay Communities Inc	AVB	0.11%	3.05%	0.00%	5.99%	0.01%
Prudential Financial Inc	PRU	0.16%	3.91%	0.01%	9.00%	0.01%
United Parcel Service Inc	UPS	0.31%	3.45%	0.01%	10.18%	0.03%
Apartment Investment & Management Co	AIV	0.03%	3.07%	0.00%	-2.64%	0.00%
Walgreens Boots Alliance Inc	WBA	0.29%	2.44%	0.01%	9.77%	0.03%
McKesson Corp	MCK	0.10%	1.22%	0.00%	7.95%	0.01%
Lockheed Martin Corp	LMT	0.35%	3.04%	0.01%	9.15%	0.03%
AmerisourceBergen Corp	ABC	0.07%	1.92%	0.00%	8.42%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
Capital One Financial Corp	COF	0.16%	1.99%	0.00%	4.54%	0.01%
Waters Corp	WAT	0.07%	n/a	n/a	11.10%	0.01%
Dollar Tree Inc	DLTR	0.10%	n/a	n/a	9.96%	0.01%
Darden Restaurants Inc	DRI	0.06%	2.86%	0.00%	10.31%	0.01%
NetApp Inc	NTAP	0.07%	2.51%	0.00%	19.39%	0.01%
Citrix Systems Inc	CTXS	0.06%	1.37%	0.00%	11.85%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.02%	3.02%	0.00%	n/a	n/a
DXC Technology Co	DXC	0.08%	1.19%	0.00%	6.44%	0.00%
DaVita Inc	DVA	0.04%	n/a	n/a	18.34%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.07%	2.56%	0.00%	9.50%	0.01%
Iron Mountain Inc	IRM	0.05%	6.57%	0.00%	7.16%	0.00%
Estee Lauder Cos Inc/The	EL	0.13%	1.26%	0.00%	11.52%	0.01%
Cadence Design Systems Inc	CDNS	0.06%	n/a	n/a	10.90%	0.01%
Universal Health Services Inc	UHS	0.05%	0.30%	0.00%	9.82%	0.00%
E*TRADE Financial Corp	ETFC	0.05%	1.20%	0.00%	12.08%	0.01%
Skyworks Solutions Inc	SWKS	0.05%	2.08%	0.00%	8.42%	0.00%
National Oilwell Varco Inc	NOV	0.05%	0.68%	0.00%	86.26%	0.04%
Quest Diagnostics Inc	DGX	0.05%	2.43%	0.00%	7.98%	0.00%
Activision Blizzard Inc	ATVI	0.15%	0.72%	0.00%	10.89%	0.02%
Rockwell Automation Inc	ROK	0.09%	2.29%	0.00%	8.42%	0.01%
Kraft Heinz Co/The	KHC	0.25%	5.20%	0.01%	3.82%	0.01%
American Tower Corp	AMT	0.32%	1.94%	0.01%	15.19%	0.05%
HollyFrontier Corp	HFC	0.04%	2.34%	0.00%	7.07%	0.00%
Regeneron Pharmaceuticals Inc	REGN	0.19%	n/a	n/a	13.78%	0.03%
Amazon.com Inc	AMZN	3.57%	n/a	n/a	49.33%	1.76%
Jack Henry & Associates Inc	JKHY	0.04%	1.11%	0.00%	11.00%	0.00%
Ralph Lauren Corp	RL	0.03%	2.15%	0.00%	6.69%	0.00%
Boston Properties Inc	BXP	0.09%	2.88%	0.00%	6.45%	0.01%
Amphenol Corp	APH	0.11%	1.05%	0.00%	9.75%	0.01%
Arconic Inc	ARNC	0.04%	1.28%	0.00%	11.60%	0.00%
Pioneer Natural Resources Co	PXD	0.10%	0.22%	0.00%	28.80%	0.03%
Valero Energy Corp	VLO	0.16%	4.10%	0.01%	16.26%	0.03%
Synopsys Inc	SNPS	0.06%	n/a	n/a	15.20%	0.01%
L3 Technologies Inc	LLL	0.07%	1.63%	0.00%	10.49%	0.01%
Western Union Co/The	WU	0.03%	4.16%	0.00%	3.19%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.30%	0.00%	10.60%	0.01%
Accenture PLC	ACN	0.42%	1.90%	0.01%	10.27%	0.04%
TransDigm Group Inc	TDG	0.09%	n/a	n/a	14.04%	0.01%
Yum! Brands Inc	YUM	0.12%	1.79%	0.00%	12.97%	0.02%
Prologis Inc	PLD	0.18%	2.78%	0.01%	6.85%	0.01%
FirstEnergy Corp	FE	0.09%	3.88%	0.00%	-0.02%	0.00%
VeriSign Inc	VRSN	0.09%	n/a	n/a	13.40%	0.01%
Quanta Services Inc	PWR	0.02%	0.45%	0.00%	25.00%	0.01%
Henry Schein Inc	HSIC	0.05%	n/a	n/a	9.57%	0.00%
Ameren Corp	AEE	0.07%	2.74%	0.00%	8.30%	0.01%
ANSYS Inc	ANSS	0.06%	n/a	n/a	12.40%	0.01%
NVIDIA Corp	NVDA	0.37%	0.45%	0.00%	10.57%	0.04%
Sealed Air Corp	SEE	0.03%	1.62%	0.00%	3.82%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.17%	1.15%	0.00%	13.20%	0.02%
SVB Financial Group	SIVB	0.05%	n/a	n/a	8.88%	0.00%
Intuitive Surgical Inc	ISRG	0.25%	n/a	n/a	12.95%	0.03%
Affiliated Managers Group Inc	AMG	0.02%	1.14%	0.00%	2.88%	0.00%
Take-Two Interactive Software Inc	TTWO	0.05%	n/a	n/a	12.30%	0.01%
Republic Services Inc	RSG	0.11%	1.96%	0.00%	11.85%	0.01%
eBay Inc	EBAY	0.13%	1.66%	0.00%	10.71%	0.01%
Goldman Sachs Group Inc/The	GS	0.31%	1.62%	0.01%	7.27%	0.02%
SBA Communications Corp	SBAC	0.09%	n/a	n/a	45.90%	0.04%
Sempra Energy	SRE	0.14%	3.06%	0.00%	9.96%	0.01%
Moody's Corp	MCO	0.13%	1.11%	0.00%	12.80%	0.02%
Booking Holdings Inc	BKNG	0.36%	n/a	n/a	15.78%	0.06%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	9.39%	0.00%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	16.57%	0.01%
Devon Energy Corp	DVN	0.05%	1.20%	0.00%	10.92%	0.01%
Alphabet Inc	GOOGL	1.43%	n/a	n/a	17.82%	0.25%
Red Hat Inc	RHT	0.13%	n/a	n/a	18.40%	0.02%
Teleflex Inc	TFX	0.05%	0.50%	0.00%	12.95%	0.01%
Allegion PLC	ALLE	0.03%	0.98%	0.00%	11.97%	0.00%
Netflix Inc	NFLX	0.63%	n/a	n/a	36.80%	0.23%
Agilent Technologies Inc	A	0.10%	0.86%	0.00%	9.50%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
Anthem Inc	ANTM	0.33%	1.06%	0.00%	11.14%	0.04%
CME Group Inc	CME	0.28%	1.54%	0.00%	13.78%	0.04%
Juniper Networks Inc	JNPR	0.04%	2.93%	0.00%	8.07%	0.00%
BlackRock Inc	BLK	0.28%	3.18%	0.01%	9.25%	0.03%
DTE Energy Co	DTE	0.09%	3.21%	0.00%	5.87%	0.01%
Celanese Corp	CE	0.05%	2.26%	0.00%	7.05%	0.00%
Nasdaq Inc	NDAQ	0.06%	2.00%	0.00%	8.16%	0.00%
Philip Morris International Inc	PM	0.51%	5.94%	0.03%	8.77%	0.04%
salesforce.com Inc	CRM	0.49%	n/a	n/a	23.98%	0.12%
Huntington Ingalls Industries Inc	HII	0.04%	1.67%	0.00%	40.00%	0.02%
MetLife Inc	MET	0.19%	3.68%	0.01%	13.36%	0.03%
Under Armour Inc	UA	0.02%	n/a	n/a	37.54%	0.01%
Tapestry Inc	TPR	0.05%	3.49%	0.00%	10.33%	0.00%
Fluor Corp	FLR	0.02%	2.30%	0.00%	19.23%	0.00%
CSX Corp	CSX	0.24%	1.34%	0.00%	10.47%	0.02%
Edwards Lifesciences Corp	EW	0.15%	n/a	n/a	14.00%	0.02%
Ameriprise Financial Inc	AMP	0.07%	2.84%	0.00%	11.80%	0.01%
TechnipFMC PLC	FTI	0.04%	2.26%	0.00%	5.58%	0.00%
Zimmer Biomet Holdings Inc	ZBH	0.09%	0.88%	0.00%	3.85%	0.00%
CBRE Group Inc	CBRE	0.07%	n/a	n/a	11.00%	0.01%
Mastercard Inc	MA	0.91%	0.63%	0.01%	16.68%	0.15%
CarMax Inc	KMX	0.04%	n/a	n/a	12.92%	0.01%
Intercontinental Exchange Inc	ICE	0.19%	1.25%	0.00%	11.57%	0.02%
Fidelity National Information Services Inc	FIS	0.15%	1.34%	0.00%	12.00%	0.02%
Chipotle Mexican Grill Inc	CMG	0.06%	n/a	n/a	21.66%	0.01%
Wynn Resorts Ltd	WYNN	0.06%	2.44%	0.00%	31.10%	0.02%
Assurant Inc	AIZ	0.03%	2.49%	0.00%	n/a	n/a
NRG Energy Inc	NRG	0.05%	0.29%	0.00%	46.03%	0.02%
Monster Beverage Corp	MNST	0.13%	n/a	n/a	15.40%	0.02%
Regions Financial Corp	RF	0.07%	3.69%	0.00%	14.52%	0.01%
Mosaic Co/The	MOS	0.05%	0.31%	0.00%	7.00%	0.00%
Expedia Group Inc	EXPE	0.07%	1.07%	0.00%	17.20%	0.01%
Evergy Inc	EVRG	0.06%	3.31%	0.00%	8.22%	0.01%
Discovery Inc	DISCA	0.02%	n/a	n/a	12.30%	0.00%
CF Industries Holdings Inc	CF	0.04%	2.75%	0.00%	16.65%	0.01%
Viacom Inc	VIAB	0.04%	2.72%	0.00%	3.48%	0.00%
Alphabet Inc	GOOG	1.66%	n/a	n/a	17.82%	0.30%
TE Connectivity Ltd	TEL	0.12%	2.17%	0.00%	10.13%	0.01%
Cooper Cos Inc/The	COO	0.06%	0.02%	0.00%	10.50%	0.01%
Discover Financial Services	DFS	0.09%	2.37%	0.00%	8.80%	0.01%
TripAdvisor Inc	TRIP	0.03%	n/a	n/a	17.25%	0.01%
Visa Inc	V	1.00%	0.74%	0.01%	17.79%	0.18%
Mid-America Apartment Communities Inc	MAA	0.05%	3.79%	0.00%	n/a	n/a
Xylem Inc/NY	XYL	0.05%	1.35%	0.00%	14.57%	0.01%
Marathon Petroleum Corp	MPC	0.19%	3.20%	0.01%	16.14%	0.03%
Advanced Micro Devices Inc	AMD	0.10%	n/a	n/a	15.67%	0.02%
Tractor Supply Co	TSCO	0.04%	1.45%	0.00%	12.76%	0.01%
ResMed Inc	RMD	0.06%	1.56%	0.00%	12.50%	0.01%
Mettler-Toledo International Inc	MTD	0.07%	n/a	n/a	13.01%	0.01%
Copart Inc	CPRT	0.05%	n/a	n/a	10.00%	0.01%
Fortinet Inc	FTNT	0.06%	n/a	n/a	19.22%	0.01%
Albemarle Corp	ALB	0.04%	1.66%	0.00%	9.81%	0.00%
Essex Property Trust Inc	ESS	0.08%	2.74%	0.00%	6.15%	0.00%
Realty Income Corp	O	0.09%	3.94%	0.00%	6.59%	0.01%
Seagate Technology PLC	STX	0.05%	5.69%	0.00%	3.59%	0.00%
Westrock Co	WRK	0.04%	4.47%	0.00%	4.73%	0.00%
IHS Markit Ltd	INFO	0.09%	n/a	n/a	11.21%	0.01%
Western Digital Corp	WDC	0.06%	4.45%	0.00%	2.72%	0.00%
PepsiCo Inc	PEP	0.68%	3.29%	0.02%	6.68%	0.05%
Diamondback Energy Inc	FANG	0.07%	0.48%	0.00%	15.26%	0.01%
Nektar Therapeutics	NKTR	0.03%	n/a	n/a	n/a	n/a
Maxim Integrated Products Inc	MXIM	0.06%	3.39%	0.00%	8.93%	0.01%
Church & Dwight Co Inc	CHD	0.07%	1.35%	0.00%	9.07%	0.01%
Duke Realty Corp	DRE	0.04%	2.94%	0.00%	4.81%	0.00%
Federal Realty Investment Trust	FRT	0.04%	3.08%	0.00%	4.25%	0.00%
MGM Resorts International	MGM	0.07%	1.63%	0.00%	2.26%	0.00%
Twenty-First Century Fox Inc	FOX	0.17%	0.73%	0.00%	9.22%	0.02%
JB Hunt Transport Services Inc	JBHT	0.05%	0.97%	0.00%	18.78%	0.01%
Lam Research Corp	LRCX	0.11%	2.59%	0.00%	-0.42%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[14] Weight in Index	[15] Estimated Dividend Yield	[16] Cap-Weighted Dividend Yield	[17] Long-Term Growth Est.	[18] Cap-Weighted Long-Term Growth Est.
Mohawk Industries Inc	MHK	0.04%	n/a	n/a	4.95%	0.00%
Pentair PLC	PNR	0.03%	1.75%	0.00%	10.22%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.21%	n/a	n/a	46.02%	0.10%
Facebook Inc	FB	1.69%	n/a	n/a	21.88%	0.37%
United Rentals Inc	URI	0.04%	n/a	n/a	17.76%	0.01%
Alexandria Real Estate Equities Inc	ARE	0.06%	2.95%	0.00%	5.64%	0.00%
ABIOMED Inc	ABMD	0.07%	n/a	n/a	29.00%	0.02%
Delta Air Lines Inc	DAL	0.14%	2.83%	0.00%	13.07%	0.02%
United Continental Holdings Inc	UAL	0.10%	n/a	n/a	14.17%	0.01%
News Corp	NWS	0.01%	1.55%	0.00%	18.80%	0.00%
Centene Corp	CNC	0.11%	n/a	n/a	17.51%	0.02%
Macerich Co/The	MAC	0.03%	6.50%	0.00%	2.58%	0.00%
Martin Marietta Materials Inc	MLM	0.05%	1.09%	0.00%	12.23%	0.01%
PayPal Holdings Inc	PYPL	0.44%	n/a	n/a	22.12%	0.10%
Coty Inc	COTY	0.02%	6.44%	0.00%	8.78%	0.00%
DISH Network Corp	DISH	0.03%	n/a	n/a	-20.68%	-0.01%
Alexion Pharmaceuticals Inc	ALXN	0.12%	n/a	n/a	16.41%	0.02%
Everest Re Group Ltd	RE	0.04%	2.56%	0.00%	10.00%	0.00%
WellCare Health Plans Inc	WCG	0.06%	n/a	n/a	18.46%	0.01%
News Corp	NWSA	0.02%	1.56%	0.00%	18.80%	0.00%
Global Payments Inc	GPN	0.08%	0.04%	0.00%	14.67%	0.01%
Crown Castle International Corp	CCI	0.21%	3.84%	0.01%	18.23%	0.04%
Aptiv PLC	APTV	0.09%	1.11%	0.00%	10.39%	0.01%
Advance Auto Parts Inc	AAP	0.05%	0.15%	0.00%	17.37%	0.01%
Capri Holdings Ltd	CPRI	0.03%	n/a	n/a	6.27%	0.00%
Align Technology Inc	ALGN	0.08%	n/a	n/a	23.19%	0.02%
Illumina Inc	ILMN	0.18%	n/a	n/a	25.16%	0.04%
Alliance Data Systems Corp	ADS	0.04%	1.28%	0.00%	12.18%	0.00%
LKQ Corp	LKQ	0.04%	n/a	n/a	13.85%	0.00%
Nielsen Holdings PLC	NLSN	0.04%	5.45%	0.00%	n/a	n/a
Garmin Ltd	GRMN	0.06%	3.06%	0.00%	6.03%	0.00%
Cimarex Energy Co	XEC	0.03%	0.96%	0.00%	63.18%	0.02%
Zoetis Inc	ZTS	0.18%	0.76%	0.00%	16.18%	0.03%
Digital Realty Trust Inc	DLR	0.09%	3.73%	0.00%	17.99%	0.02%
Equinix Inc	EQIX	0.13%	2.31%	0.00%	19.40%	0.03%
Discovery Inc	DISCK	0.04%	n/a	n/a	12.30%	0.01%

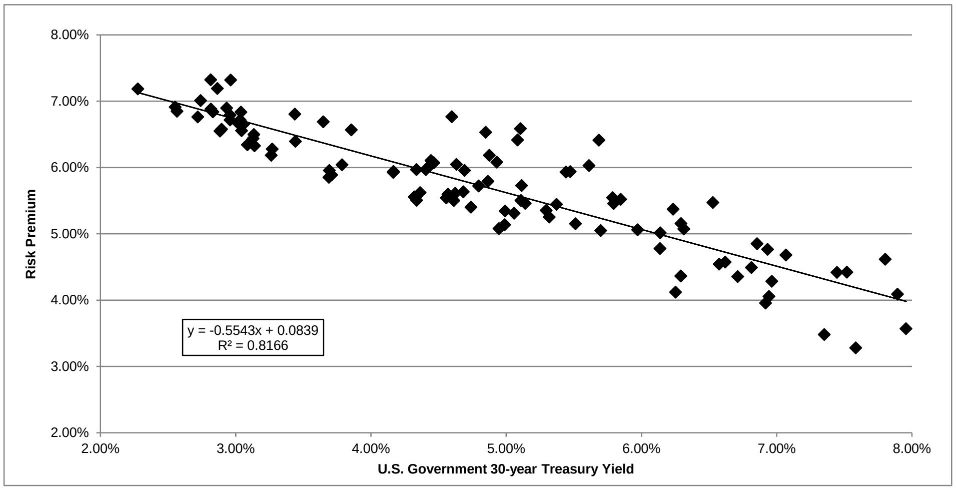
Notes:
[9] Equals sum of Col. [16]
[10] Equals sum of Col. [18]
[11] Equals ([9] x (1 + (0.5 x [10]))) + [10]
[12] Source: Schedule-5, at 1
[13] Equals [11] − [12]
[14] Equals weight in S&P 500 based on market capitalization
[15] Source: Bloomberg Professional, as of January 31, 2019
[16] Equals [14] x [15]
[17] Source: Bloomberg Professional, as of January 31, 2019
[18] Equals [14] x [17]

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.42%	7.80%	4.62%
1992.2	11.98%	7.89%	4.09%
1992.3	11.87%	7.45%	4.42%
1992.4	11.94%	7.52%	4.42%
1993.1	11.75%	7.07%	4.68%
1993.2	11.71%	6.86%	4.85%
1993.3	11.39%	6.31%	5.07%
1993.4	11.16%	6.14%	5.02%
1994.1	11.12%	6.57%	4.55%
1994.2	10.84%	7.35%	3.48%
1994.3	10.87%	7.58%	3.28%
1994.4	11.53%	7.96%	3.57%
1995.2	11.00%	6.94%	4.06%
1995.3	11.07%	6.71%	4.35%
1995.4	11.61%	6.23%	5.37%
1996.1	11.45%	6.29%	5.16%
1996.2	10.88%	6.92%	3.96%
1996.3	11.25%	6.96%	4.29%
1996.4	11.19%	6.62%	4.58%
1997.1	11.31%	6.81%	4.49%
1997.2	11.70%	6.93%	4.77%
1997.3	12.00%	6.53%	5.47%
1997.4	10.92%	6.14%	4.78%
1998.2	11.37%	5.85%	5.52%
1998.3	11.41%	5.47%	5.94%
1998.4	11.69%	5.10%	6.59%
1999.1	10.82%	5.37%	5.44%
1999.2	11.25%	5.79%	5.46%
1999.4	10.38%	6.25%	4.12%
2000.1	10.66%	6.29%	4.36%
2000.2	11.03%	5.97%	5.06%
2000.3	11.33%	5.79%	5.55%
2000.4	12.10%	5.69%	6.41%
2001.1	11.38%	5.44%	5.93%
2001.2	10.75%	5.70%	5.05%
2001.4	10.65%	5.30%	5.35%
2002.1	10.67%	5.51%	5.15%
2002.2	11.64%	5.61%	6.03%
2002.3	11.50%	5.08%	6.42%
2002.4	11.01%	4.93%	6.08%
2003.1	11.38%	4.85%	6.53%
2003.2	11.36%	4.60%	6.76%
2003.3	10.61%	5.11%	5.50%
2003.4	10.84%	5.11%	5.73%
2004.1	11.06%	4.88%	6.18%
2004.2	10.57%	5.32%	5.25%
2004.3	10.37%	5.06%	5.31%
2004.4	10.66%	4.86%	5.79%
2005.1	10.65%	4.69%	5.96%
2005.2	10.54%	4.47%	6.07%
2005.3	10.47%	4.44%	6.03%
2005.4	10.32%	4.68%	5.63%
2006.1	10.68%	4.63%	6.05%
2006.2	10.60%	5.14%	5.46%
2006.3	10.34%	4.99%	5.34%
2006.4	10.14%	4.74%	5.40%
2007.1	10.52%	4.80%	5.72%
2007.2	10.13%	4.99%	5.14%
2007.3	10.03%	4.95%	5.08%
2007.4	10.12%	4.61%	5.50%
2008.1	10.38%	4.41%	5.97%
2008.2	10.17%	4.57%	5.60%
2008.3	10.55%	4.44%	6.11%
2008.4	10.34%	3.65%	6.69%
2009.1	10.24%	3.44%	6.81%
2009.2	10.11%	4.17%	5.94%
2009.3	9.88%	4.32%	5.56%
2009.4	10.31%	4.34%	5.97%
2010.1	10.24%	4.62%	5.61%
2010.2	9.99%	4.36%	5.62%
2010.3	10.43%	3.86%	6.57%
2010.4	10.09%	4.17%	5.93%
2011.1	10.10%	4.56%	5.54%
2011.2	9.85%	4.34%	5.51%
2011.3	9.65%	3.69%	5.96%

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Gas ROE	U.S. Govt. 30-year Treasury	Risk Premium
2011.4	9.88%	3.04%	6.84%
2012.1	9.63%	3.14%	6.50%
2012.2	9.83%	2.93%	6.90%
2012.3	9.75%	2.74%	7.01%
2012.4	10.06%	2.86%	7.19%
2013.1	9.57%	3.13%	6.44%
2013.2	9.47%	3.14%	6.33%
2013.3	9.60%	3.71%	5.89%
2013.4	9.83%	3.79%	6.04%
2014.1	9.54%	3.69%	5.85%
2014.2	9.84%	3.44%	6.39%
2014.3	9.45%	3.26%	6.19%
2014.4	10.28%	2.96%	7.32%
2015.1	9.47%	2.55%	6.91%
2015.2	9.43%	2.88%	6.55%
2015.3	9.75%	2.96%	6.79%
2015.4	9.68%	2.96%	6.72%
2016.1	9.48%	2.72%	6.76%
2016.2	9.42%	2.57%	6.85%
2016.3	9.47%	2.28%	7.19%
2016.4	9.67%	2.83%	6.84%
2017.1	9.60%	3.04%	6.56%
2017.2	9.47%	2.90%	6.58%
2017.3	10.14%	2.82%	7.32%
2017.4	9.70%	2.82%	6.88%
2018.1	9.68%	3.02%	6.66%
2018.2	9.43%	3.09%	6.34%
2018.3	9.71%	3.06%	6.65%
2018.4	9.55%	3.27%	6.28%
2019.1	9.75%	3.03%	6.72%
AVERAGE	10.54%	4.81%	5.72%
MEDIAN	10.47%	4.74%	5.85%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.903661
R Square	0.816602
Adjusted R Square	0.814822
Standard Error	0.003942
Observations	105

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.007127	0.007127	458.621404	0.000000
Residual	103	0.001601	0.000016		
Total	104	0.008727			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0839	0.001303	64.38	0.000000	0.081333	0.086504	0.081333	0.086504
U.S. Govt. 30-year Treasury	(0.5543)	0.025882	(21.42)	0.000000	(0.605614)	(0.502951)	(0.605614)	(0.502951)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-Day Average [4]	3.03%	6.71%	9.74%
Blue Chip Consensus Forecast (Q2 2019 - Q2 2020) [5]	3.38%	6.52%	9.90%
Blue Chip Consensus Forecast (2020-2024) [6]	3.90%	6.23%	10.13%
AVERAGE			9.92%

Notes:
[1] Source: Regulatory Research Associates, accessed February 7, 2019.
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of January 31, 2019
[5] Source: Blue Chip Financial Forecasts, Vol. 38, No. 2, February 1, 2019, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.083919 + (-0.554283 x Column [7])
[9] Equals Column [7] + Column [8]

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line ROE 2021-2023	Value Line Total Capital 2017	Value Line Common Equity Ratio 2017	Total Equity 2017	Value Line Total Capital 2021-2023	Value Line Common Equity Ratio 2021-2023	Total Equity 2021-2023	Compound Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
Atmos Energy Corporation	ATO	11.00%	6,966	56.00%	3,901	11,000	55.00%	6,050	9.17%	1.044	11.48%
New Jersey Resources Corporation	NJR	13.00%	2,234	55.40%	1,237	3,160	62.00%	1,959	9.62%	1.046	13.60%
Northwest Natural Gas Company	NWN	12.00%	1,426	52.10%	743	1,750	53.50%	936	4.73%	1.023	12.28%
One Gas Inc.	OGS	11.00%	3,154	62.20%	1,961	3,850	62.00%	2,387	4.00%	1.020	11.22%
South Jersey Industries, Inc.	SJI	11.50%	2,315	51.50%	1,192	3,700	50.00%	1,850	9.18%	1.044	12.00%
Southwest Gas Corporation	SWX	9.50%	3,613	50.20%	1,814	5,700	52.50%	2,993	10.53%	1.050	9.98%
Spire, Inc.	SR	10.00%	3,986	50.00%	1,993	5,115	55.00%	2,813	7.14%	1.034	10.34%
Mean											11.56%
Median											11.48%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Market Capitalization ($ billions)	[2] Market-to-Book Ratio
Atmos Energy Corporation	ATO	10.93	2.07
New Jersey Resources Corporation	NJR	4.08	2.77
Northwest Natural Gas Company	NWN	1.74	2.37
ONE Gas Inc.	OGS	4.19	2.08
South Jersey Industries, Inc.	SJI	2.54	2.00
Southwest Gas Corporation	SWX	4.08	1.96
Spire, Inc.	SR	3.81	1.67
Average		4.48	2.13
Median		4.08	2.07

Cascade Natural Gas Corp.	
Common Equity ($ millions) [3]	202.50
Implied Market Capitalization [4]	420.18
As a percent of Proxy Group Median Market Capitalization	10.30%

Duff & Phelps Cost of Capital Navigator -- Size Premium

Breakdown of Deciles 1-10	[5] Market Capitalization of Largest Company ($ millions)	[6] Size Premium
1-Largest	1,073,390.57	-0.30%
2	29,022.867	0.52%
3	13,455.802	0.81%
4	7,254.230	0.85%
5	4,503.549	1.28%
6	2,992.251	1.50%
7	1,960.201	1.58%
8	1,292.224	1.80%
9	727.843	2.46%
10-Smallest	321.578	5.22%
Cascade Natural Gas Corp. - Implied Market Capitalization	420	2.46%
Proxy Group Median Market Capitalization	4,081	1.28%
Size Premium [7]		1.18%

Notes:
[1] Source: Bloomberg Professional; equals 30-day average as of January 31, 2019
[2] Source: Bloomberg Professional; equals 30-day average as of January 31, 2019
[3] Data provided by Cascade Natural Gas Corp.
[4] Equals [3] x proxy group median market-to-book ratio
[5] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2018
[6] Duff & Phelps Cost of Capital Navigator - Size Premium: Annual Data as of 12/31/2018
[7] Equals 2.46% − 1.28%

FLOTATION COST ADJUSTMENT -- CASCADE NATURAL GAS PROXY GROUP

Company	Date [i]	Shares Issued (000)	Offering Price	Under-writing Discount [ii]	Offering Expense ($000)	Net Proceeds Per Share	Total Flotation Costs ($000)	Equity Issue Before Costs ($000)	Net Proceeds ($000)	Flotation Cost Percentage
MDU Resources Group	2/4/2004	2,300	$ 23.32	$ 0.7930	$ 350	$ 22.37	$ 2,174	$ 53,636	$ 51,462	4.05%
MDU Resources Group	11/19/2002	2,400	$ 24.00	$ 0.7200	$ 193	$ 23.20	$ 1,921	$ 57,600	$ 55,680	3.33%
							$ 4,094	$ 111,236	$ 107,142	3.68%

Notes:
[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9632, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	ROE	ROE Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$2.10	$93.27	2.25%	2.33%	2.42%	7.50%	6.45%	6.50%	6.82%	9.14%	9.23%
New Jersey Resources Corporation	NJR	$1.17	$46.09	2.54%	2.63%	2.73%	9.50%	6.00%	7.00%	7.50%	10.13%	10.23%
Northwest Natural Gas Company	NWN	$1.90	$60.49	3.14%	3.34%	3.47%	30.50%	4.00%	4.30%	12.93%	16.28%	16.41%
One Gas Inc.	OGS	$1.84	$79.77	2.31%	2.39%	2.48%	10.50%	5.50%	5.90%	7.30%	9.69%	9.78%
South Jersey Industries, Inc.	SJI	$1.15	$28.87	3.98%	4.21%	4.37%	9.50%	12.70%	12.50%	11.57%	15.78%	15.94%
Southwest Gas Corporation	SWX	$2.08	$77.00	2.70%	2.79%	2.90%	9.00%	6.20%	5.00%	6.73%	9.53%	9.63%
Spire, Inc.	SR	$2.37	$75.12	3.15%	3.22%	3.35%	6.50%	2.70%	4.00%	4.40%	7.62%	7.75%
Median											9.69%	9.78%
Flotation Cost Adjustment											[12]	0.09%

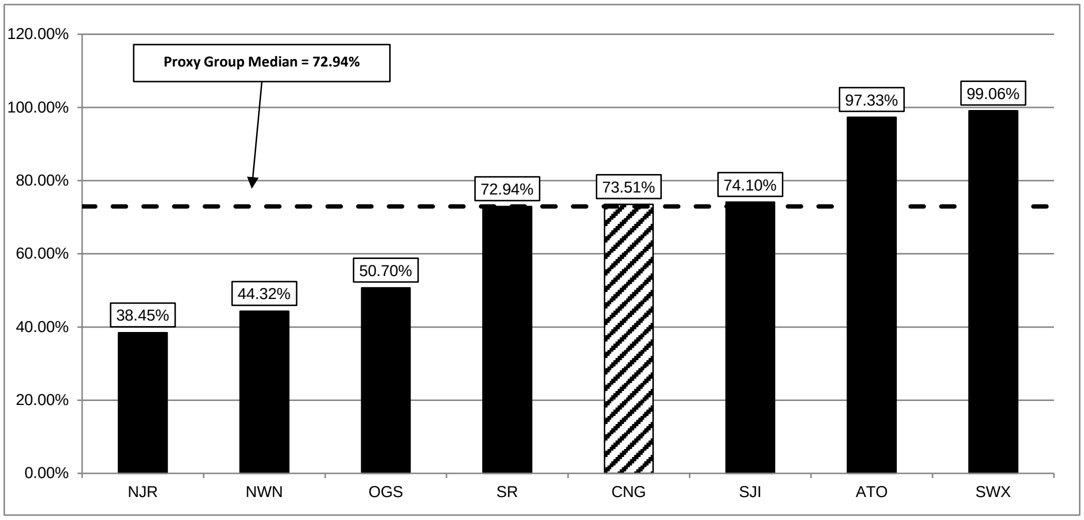
Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of Janaury 31, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Equals [4] / (1 − Flotation Cost)
[6] Source: Value Line
[7] Source: Yahoo! Finance
[8] Source: Zacks
[9] Equals Average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals Average ([11]) − Average ([10])

2019-2023 CAPITAL EXPENDITURES AS A PERCENT OF 2017 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2017	2019	2020	2021	2022	2023	2019-23 Cap. Ex. / 2017 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$14.65	$14.43	$14.20	$14.20	$14.20	
Common Shares Outstanding			116.00	123.00	130.00	130.00	130.00	
Capital Expenditures			$1,699.4	$1,774.3	$1,846.0	$1,846.0	$1,846.0	97.33%
Net Plant		$9,259.2						
New Jersey Resources Corporation	NJR							
Capital Spending per Share			$2.25	$2.30	$2.35	$2.35	$2.35	
Common Shares Outstanding			86.50	86.50	86.50	86.50	86.50	
Capital Expenditures			$194.6	$199.0	$203.3	$203.3	$203.3	38.45%
Net Plant		$2,609.7						
Northwest Natural Gas Company	NWN							
Capital Spending per Share			$6.65	$6.45	$6.25	$6.25	$6.25	
Common Shares Outstanding			30.00	31.00	32.00	32.00	32.00	
Capital Expenditures			$199.5	$200.0	$200.0	$200.0	$200.0	44.32%
Net Plant		$2,255.0						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$7.40	$7.45	$7.50	$7.50	$7.50	
Common Shares Outstanding			53.00	54.00	55.00	55.00	55.00	
Capital Expenditures			$392.2	$402.3	$412.5	$412.5	$412.5	50.70%
Net Plant		$4,007.6						
South Jersey Industries, Inc.	SJI							
Capital Spending per Share			$3.10	$3.93	$4.75	$4.75	$4.75	
Common Shares Outstanding			91.00	93.00	95.00	95.00	95.00	
Capital Expenditures			$282.1	$365.0	$451.3	$451.3	$451.3	74.10%
Net Plant		$2,700.2						
Southwest Gas Corporation	SWX							
Capital Spending per Share			$15.20	$16.23	$17.25	$17.25	$17.25	
Common Shares Outstanding			51.00	53.00	55.00	55.00	55.00	
Capital Expenditures			$775.2	$859.9	$948.8	$948.8	$948.8	99.06%
Net Plant		$4,523.7						
Spire, Inc.	SR							
Capital Spending per Share			$9.60	$9.80	$10.00	$10.00	$10.00	
Common Shares Outstanding			52.00	53.50	55.00	55.00	55.00	
Capital Expenditures			$499.2	$524.3	$550.0	$550.0	$550.0	72.94%
Net Plant		$3,665.2						
Cascade Natural Gas	CNG							
Capital Expenditures [8]			$86.6	$67.6	$46.2	$42.5	$39.1	73.51%
Net Plant in Service [9]		$383.75						
				CNG CapEx Total (2019 - 2023)				$282.11
				CNG CapEx Annual Average				$56.4
				Proxy Group Median				72.9%
				CNG as % Proxy Group Median				1.01

Notes:
[1] - [6] Value Line, November 30, 2018
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] - [9] Data provided by Cascade Natural Gas

2019-2023 CAPITAL EXPENDITURES AS A PERCENT OF 2017 NET PLANT



Projected CAPEX / 2017 Net Plant

Company		2019-2023
New Jersey Resources Corporation	NJR	38.45%
Northwest Natural Gas Company	NWN	44.32%
ONE Gas, Inc.	OGS	50.70%
Spire, Inc.	SR	72.94%
Cascade Natural Gas	CNG	73.51%
South Jersey Industries, Inc.	SJI	74.10%
Atmos Energy Corporation	ATO	97.33%
Southwest Gas Corporation	SWX	99.06%
Proxy Group Median		72.94%
CNG/Proxy Group		1.01

Notes:
Source: Schedule-10 page 1 col. [7]

COMPARISON OF CASCADE NATURAL GAS AND PROXY GROUP COMPANIES
REGULATORY FRAMEWORK - ADJUSTMENT CLAUSES

						Decoupling		New Capital	
Proxy Group Company	Operation State	Operation		Test Year	Rate Base	Full	Partial	Generation Capacity	Generic Infrastructure
Atmos Energy Corporation	Kansas	Gas	1	Historical	Year End		x		x
	Kentucky	Gas	1	Fully Forecast	Year End		x		x
	Louisiana	Gas	1	Historical	Average		x		x
	Mississippi	Gas	1	Fully Forecast	Average		x		x
	Tennessee	Gas	1	Fully Forecast	Average		x		
	Texas RRC	Gas	1	Historical	Year End		x		x
New Jersey Resources Corporation	New Jersey	Gas	1	Partially Forecast	Year End	x			x
Northwest Natural Gas Company	Oregon	Gas	1	Fully Forecast	Average		x		
	Washington	Gas	1	Historical	Average				
ONE Gas, Inc.	Kansas	Gas	1	Historical	Year End		x		x
	Oklahoma	Gas	1	Historical	Year End		x		
	Texas RRC	Gas	1	Historical	Year End		x		x
South Jersey Industries, Inc.	New Jersey	Gas	1	Partially Forecast	Year End	x			x
Southwest Gas Corporation	Arizona	Gas	1	Historical	Year End		x		x
	California	Gas	1	Fully Forecast	Average	x			
	Nevada	Gas	1	Historical	Year End	x			x
Spire, Inc.	Alabama	Gas	1	Historical	Average		x		
	Missouri	Gas	1	Historical	Year End				x
Proxy Companies				Historical: 11 Forecast: 7	Average: 7 Year End: 11	4	12	0	12
Total Jurisdictions	18								
Percent of Jurisdictions				Forecast: 39%	Year End: 61%	22%	67%	0%	67%
Cascade Natural Gas [2]	Washington			Historical	Average	x			x

Notes:
[1] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated September 28, 2018. Operating subsidiaries not covered in this report were excluded from this exhibit.
[2] Data provided by Cascade Natural Gas Corporation

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2017	2016	MRY
Atmos Energy Corporation	ATO	59.63%	61.35%	59.63%
New Jersey Resources Corporation	NJR	62.35%	56.79%	62.35%
Northwest Natural Gas Company	NWN	51.95%	55.38%	51.95%
ONE Gas, Inc.	OGS	63.18%	62.08%	63.18%
South Jersey Industries, Inc.	SJI	54.63%	66.50%	54.63%
Southwest Gas Corporation	SWX	51.32%	54.69%	51.32%
Spire, Inc.	SR	56.45%	64.21%	56.45%
MEAN		57.07%	60.14%	57.07%
LOW		51.32%	54.69%	51.32%
HIGH		63.18%	66.50%	63.18%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2017	2016	MRY
Atmos Energy Corporation	ATO	59.63%	61.35%	59.63%
New Jersey Natural Gas Company	NJR	62.35%	56.79%	62.35%
Northwest Natural Gas Company	NWN	51.95%	55.38%	51.95%
Kansas Gas Service Company	OGS	63.35%	62.01%	63.35%
Oklahoma Natural Gas Company	OGS		62.13%	62.13%
Texas Gas Service Company	OGS	63.01%	62.09%	63.01%
South Jersey Gas Company	SJI	54.63%	66.50%	54.63%
Southwest Gas Corporation	SWX	51.32%	54.69%	51.32%
Spire Alabama Inc.	SR		77.62%	77.62%
Spire Gulf Inc.	SR	41.52%	56.30%	41.52%
Spire Mississippi Inc.	SR	68.02%	53.26%	68.02%
Spire Missouri Inc.	SR	57.13%	56.93%	57.13%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2017	2016	MRY
Atmos Energy Corporation	ATO	40.37%	38.65%	40.37%
New Jersey Resources Corporation	NJR	37.65%	43.21%	37.65%
Northwest Natural Gas Company	NWN	48.05%	44.62%	48.05%
ONE Gas, Inc.	OGS	36.82%	37.92%	36.82%
South Jersey Industries, Inc.	SJI	45.37%	33.50%	45.37%
Southwest Gas Corporation	SWX	48.68%	45.31%	48.68%
Spire, Inc.	SR	43.55%	35.79%	43.55%
MEAN		42.93%	39.86%	42.93%
LOW		36.82%	33.50%	36.82%
HIGH		48.68%	45.31%	48.68%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2017	2016	MRY
Atmos Energy Corporation	ATO	40.37%	38.65%	40.37%
New Jersey Natural Gas Company	NJR	37.65%	43.21%	37.65%
Northwest Natural Gas Company	NWN	48.05%	44.62%	48.05%
Kansas Gas Service Company	OGS	36.65%	37.99%	36.65%
Oklahoma Natural Gas Company	OGS		37.87%	37.87%
Texas Gas Service Company	OGS	36.99%	37.91%	36.99%
South Jersey Gas Company	SJI	45.37%	33.50%	45.37%
Southwest Gas Corporation	SWX	48.68%	45.31%	48.68%
Spire Alabama Inc.	SR		22.38%	22.38%
Spire Gulf Inc.	SR	58.48%	43.70%	58.48%
Spire Mississippi Inc.	SR	31.98%	46.74%	31.98%
Spire Missouri Inc.	SR	42.87%	43.07%	42.87%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

PREFERRED EQUITY RATIO [1]

Proxy Group Company	Ticker	2017	2016	MRY
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%
New Jersey Resources Corporation	NJR	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%
ONE Gas, Inc.	OGS	0.00%	0.00%	0.00%
South Jersey Industries, Inc.	SJI	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%
Spire, Inc.	SR	0.00%	0.00%	0.00%
MEAN		0.00%	0.00%	0.00%
LOW		0.00%	0.00%	0.00%
HIGH		0.00%	0.00%	0.00%

PREFERRED EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2017	2016	MRY
Atmos Energy Corporation	ATO	0.00%	0.00%	0.00%
New Jersey Natural Gas Company	NJR	0.00%	0.00%	0.00%
Northwest Natural Gas Company	NWN	0.00%	0.00%	0.00%
Kansas Gas Service Company	OGS	0.00%	0.00%	0.00%
Oklahoma Natural Gas Company	OGS		0.00%	0.00%
Texas Gas Service Company	OGS	0.00%	0.00%	0.00%
South Jersey Gas Company	SJI	0.00%	0.00%	0.00%
Southwest Gas Corporation	SWX	0.00%	0.00%	0.00%
Spire Alabama Inc.	SR		0.00%	0.00%
Spire Gulf Inc.	SR	0.00%	0.00%	0.00%
Spire Mississippi Inc.	SR	0.00%	0.00%	0.00%
Spire Missouri Inc.	SR	0.00%	0.00%	0.00%

Notes:
[1] Ratios are weighted by actual common capital and long-term debt of Operating Subsidiaries
[2] Natural Gas Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

Exhibit No. __ (AEB-3)
Resume
Witness:Ann E. Bulkley

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF ANN E. BULKLEY

RESUME

3/29/2019

Ann E. Bulkley
Senior Vice President

Ms. Bulkley more than two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has advised clients seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital testimony before several state regulatory commissions. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings over the past seven years. Ms. Bulkley's expert testimony experience includes:

- Northern States Power Company: Before the North Dakota Public Service Commission, provided expert testimony on the cost of capital for the company's North Dakota electric utility operations.
- WE Energies: Before the Michigan Public Service Commission, provided expert testimony in support of the company's cost of capital for its electric utility operations.
- Atmos Energy: Provided expert testimony in support of the company's return on equity and capital structure before the Public Utilities Commission for the State of Colorado.
- UNS Electric: Provided expert testimony in support of the company's return on equity and capital structure before the Arizona Corporation Commission.
- Portland Natural Gas Transmission: Provided testimony strategy as well as analytical support for cost of capital testimony before the Federal Energy Regulatory Commission.

- In addition to the specific cases listed above, Ms. Bulkley has provided testimony strategy as well as analytical support on cost of capital in several cases in the following states: Arizona, Colorado, Connecticut, Massachusetts, Minnesota, New Mexico, New York, North Carolina, South Carolina, South Dakota, Virginia, and Utah.

Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice. In addition, Ms. Bulkley has relied on other simulation based valuation methodologies.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.

- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed, and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Senior Vice President
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

M.A., Economics, Boston University, 1995

B.A., Economics and Finance, Simmons College, 1991

Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Commonwealth of Massachusetts Appellate Tax Board				
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Connecticut Public Utilities Regulatory Authority				
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity
Federal Energy Regulatory Commission				
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Sea Robin Pipeline Company LLC	11/30/18	Sea Robin Pipeline Company LLC	Docket# RP19-___-000	Return on Equity
Indiana Utility Regulatory Commission				
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-00194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
FirstLight Hydro	06/17	FirstLight Hydro		Valuation of generating asset
Massachusetts Department of Public Utilities				
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Michigan Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity
Michigan Tax Tribunal				
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Covert Township	05/18	New Covert Generating Co., LLC.	Docket No. 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/18	New Covert Generating Co., LLC.	Docket No. 16-001888-TT	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-2085 Case No. SR-17-2086	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D0218.9.60	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New Hampshire- Rockingham County Superior Court				
Eversource Energy d/b/a Public Service of New Hampshire	11/18	Eversource Energy d/b/a Public Service of New Hampshire	Docket No 218-2016-CV-00899	Valuation of utility property
Eversource d/b/a Public Service of New Hampshire	12/18	Eversource d/b/a Public Service of New Hampshire	Docket No 218-2016-cv-00917	Valuation of utility property
New Hampshire- Merrimack County Superior Court				
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of utility property
New Jersey Board of Public Utilities				
Public Service Electric & Gas Company	01/18	Public Service Electric & Gas Company	BPU Docket No. GR17070776	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-001398-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company	05/15	New York State Electric and Gas Company	Case No. 15-G-0284	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0059	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. C-17-E-0238	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Gas 17-G-0460 Electric 17-E-0459	Return on Equity
North Dakota Public Service Commission				
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Public Utility Commission of Pennsylvania				
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Public Service Commission of West Virginia				
West Virginia American Water Company	04/18	West Virginia American Water Company		Return on Equity

Exhibit No. __ (IDM-1T)
Docket No. UG-19_____
Witness: Isaac D. Myhrum

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-19______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF ISAAC D. MYHRUM

March 29, 2019

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Isaac D. Myhrum and my business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. My present position is Regulatory Analyst II in the Regulatory Affairs Department.

Q. Would you briefly describe your duties?

A. Yes. I prepare regulatory reports and filings on behalf of the Company for both the Public Utility Commission of Oregon (OPUC or Commission) and Washington Utilities and Transportation Commission (WUTC). I also perform analysis of the regulatory filings submitted by the Company to these commissions and other regulatory agencies.

Q. How long have you been employed by the Company?

A. I have been employed by the Company since August 2016.

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

Yes. I hold a Bachelor of Arts degree in Accounting and Business Administration from Washington State University. I also hold a Bachelor of Science degree in Political Science with an emphasis in Economics from the University of Idaho. I attended New Mexico State University's Center for Public Utilities Rate School in October 2016 and have attended other utility-specific trainings, and conferences. Prior to joining the Company, I worked as a staff accountant for two public accounting firms in the Tri-Cities, Washington area.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to introduce and support several exhibits in this proceeding, including the Company's Summary of Revenues and its related Revenue Adjustments. I will also testify to the Company's revenue distribution methodology, Cost Recovery Mechanism (CRM) revenues, weather normalization adjustments and their impacts on billing determinants, unbilled revenues and related accounting practices, rate spread and rate design, and the filing's impacts on the authorized margin per customer under the Company's decoupling mechanism.

Q. Are you sponsoring any exhibits in this proceeding?

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

Exhibit No. __(IDM-2), Summary of Revenues by Rate Schedule

Exhibit No. __(IDM-3), Revenue Adjustments

Exhibit No. __(IDM-4), Revenue Distribution

Exhibit No. __(IDM-5), Decoupling Mechanism, Authorized Revenue Per Customer

II. SUMMARY OF REVENUES BY RATE SCHEDULE

Q. Would you please describe Exhibit No.___(IDM-2) entitled "Summary of Revenues by Rate Schedule"?

A. Yes. The summary of revenues by rate schedule provides a comparison of revenues at current rates with those the Company expects under proposed rates. Exhibit No.___(IDM-2) presents the Company's Per Books Revenue for the twelve months ending December 31, 2018 listed by rate schedule ("Per Books Revenue" labeled column "(D)"). The Per Books Revenue amounts include all the components of the current rates, including gas costs, non-gas costs, taxes, and billing adjustments for each rate schedule. The Per Books Revenue total matches the 2018 total operating revenues subtotal presented in Company witness Maryalice Peters' testimony.[1]

Q. Would you please describe each column section of the revenue summary exhibit?

A. Yes. The column sections in the exhibit are the following:

- Current Section (labeled "A" through "D")

The section labeled "Current" contains four columns labeled "A" through "D". It contains descriptions of rate schedules, rates schedules utilized by the Company, and revenues received for the period January 1, 2018 through December 31, 2018.

1. Column A "Rate Description" – Lists each rate schedule utilized by the Company in 2018. Descriptions include Basic Service Charges, Delivery Charges, Average Cost of Gas, as well as Non-Gas Revenue items including taxes and other adjustments.
2. Column B "Billing Determinants" – Lists the billing determinant counts of each schedule within the Company in 2018. The billing determinants are customer counts (i.e. "Bills") and volumetric usage calculations (i.e. "Therms"). The billing determinants were calculated by dividing the associated Per Books Revenue figure in column "D" by the associated rate in column "C". This provides an accurate calculation of determinants and ties directly to Per Books Revenue.
3. Column C "Current Rate" - These are the authorized rates that were in effect when the billing determinants were observed and associated revenues were collected in 2018. Notice that there was a change to most

[1] CNGC Exh. No. MCP-2 – ROO Summary Sheet, column (1), Total Operating Revenues.

Basic Service Charges and Delivery Charge rates when new rates and tariffs went into effect on August 1, 2018. These changes were authorized by the final order in the Company's last general rate case.[2]

4. <u>Column D "Per Books Revenue 2018"</u> – This is the Company's per books revenue presented by rate schedule and collected during the calendar year of 2018.

- <u>Schedule Merge Section (labeled "E" through "G")</u>

The columns in Schedule Merge present billing determinants and associated rates and revenues that migrated or merged between rate schedules during the calendar year 2018. Several of the migrations came about due to the discontinuation of schedules authorized in the Company's 2018 general rate case, resulting in the removal of three rate schedules and the migration of affected customers to other schedules:

❖ Rate Schedule 502 (Building Construction Temporary Heating and Dry-Out Service) was discontinued with future dry-out or building construction customers being served on Schedule 503 (Residential Service Rate).

❖ Rate Schedule 512 (Compressed Natural Gas Service) was discontinued and the one customer affected was migrated to Schedule 504 (General Commercial Service Rate).

❖ Rate Schedule 577 (Limited Interruptible Service Rate) was discontinued and the two customers affected were migrated to Schedule

[2] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Order 06, (July 20, 2018).

570 (Interruptible Service Schedule).

The billing determinants associated with Cascade's Schedule 663 Transportation Service-related rate schedules are merged in this exhibit for presentation simplicity purposes and to demonstrate combined revenue impacts. For example, billing determinants and revenues for "Rate Schedule 6631", "Rate Schedule 6632", "Rate Schedule 6633" and "Rate Schedule 6635", are combined into one rate schedule section to better show revenue impacts. These rate schedules are tracked separately in the Company's books but share identical basic services charges and delivery charges.

Billing determinants associated with special contract Rate Schedule 916 are also merged in this exhibit with other rate schedules in 6631 because the customer associated with schedule 916 was transferred to Rate Schedule 6631 in 2018.

The Company's other rate schedules "CNGW04LV" and "CNGW05LV" were merged in this exhibit with Rate Schedules 504 and 505, respectively. The customer on "CNGW04LV" is a large volume customer that pays Rate Schedule 504 rates, while the "CNGW05LV" is a large volume interruptible schedule paying Rate Schedule 505 rates.

The following are descriptions of the three columns in the Schedule Merge section:

1. <u>Column E "Billing Determinants (Therms/Bills)</u> – Presents billing determinants from discontinued or merged schedules to current schedules.
2. <u>Column F "Rate"</u> – Rates and charges associated with merged billing determinants

3. <u>Column G ("Remove/Add")</u> – The figures in column G are the product of discontinued billing determinants (in column "I") multiplied by the associated "Rate" (Margin Rate or Basic Service Charge) in Column F.

- <u>Adjusted Current Section (labeled "H" through "J")</u>

This section presents adjusted billing determinants after the schedule merges and applies current charges to present adjusted Per Books Margin Revenues. The section contains the following three columns:

1. <u>Column H "Adjusted Billing Determinants"</u> – Presents adjusted billing determinants after merged data has been included. It is the sum of labeled Columns "B" and "E".
2. <u>Column I "Rate" –</u> This column presents the current basic services charges and other volumetric rates associated with adjusted current billing determinants.
3. <u>Column J "Adjusted Per Books Margin Revenue"</u> – This column presents Adjusted Per Books revenue by schedule. This is the product of the adjusted billing determinants in column "H" and the associated current rates in column "I".

- <u>End of Period Determinants at Current Rates Section (labeled "K" and "L")</u>

Consistent with and supporting the testimony by Company witness Michael Parvinen, this section presents billing determinants and associated revenues adjusted to End of Period (EOP) test year levels. The section also presents the difference of all Adjusted Per Books Margin Revenues with Adjusted EOP Margin Revenue which is the EOP Revenue Adjustment:

1. Column K "Billing Determinants (Therms/Bills)" – This column presents billing determinants adjusted to calculated EOP customer and volumetric usage levels. I provide more detail on how these calculations were performed on page 11 of this testimony.
2. Column L "Adjusted EOP Margin Revenue" – Presents revenues associated with EOP billing determinants at current rates.
3. Column M "EOP Revenue Adjustment" – This column presents the adjustment/difference between the revenues associated with EOP billing determinants, column "L", and previous revenues presented as Adjusted Per Books Margin Revenue in column "J".

- Cost Recovery Mechanism (CRM) Section (labeled "N" through "P")

This column presents adjustments associated with the Company's CRM adjustment by rate schedule. I provide more detail regarding the CRM revenue and its adjustments on page 12 of this testimony.

1. Column N "Billing Determinants (Therms/Bills)" – This column presents the EOP billing determinants used to calculate CRM revenues per schedule.
2. Column O "Rate" – This column presents the CRM rate associated with each rate schedule.
3. Column P "CRM Revenue" – This column presents the CRM revenue associated with each rate schedule. The revenue is the product of EOP billing determinants in column "N" and the CRM rates presented in column "O".

- Proposed Section (labeled “Q” through “S”)

This section presents the Company’s proposed rates for each schedule in this case and the associated revenue utilizing EOP billing determinants. The section compares revenues at current rates with proposed rates to calculate the “2019 Revenue Adjustment” per schedule.

1. Column Q “Proposed Rates” – This column presents the proposed rates for each of the Company schedules in this case.
2. Column R “Revenue at Proposed Rates” – This column presents the revenue associated with proposed rates utilizing EOP billing determinants. It is the product of Proposed Rates in column “Q” with the EOP Billing Determinants in column “K”.
3. Column S “2019 Revenue Adjustment” – This column presents the difference between the Revenue at Proposed Rates in column “R” with the previous Adjusted EOP Margin Revenue presented in column “L”. The Company’s proposed revenue requirement is presented here by rate schedule.

Q. In the “Adjusted Current” section, can you how describe how the billing determinants “Bills and Therms” are adjusted?

A. Yes. In column “H”, labeled “Adjusted Billing Determinants”, billing determinants that were observed before and after margin and basic service rate revisions are combined. This is done to calculate the annualized number for the billing determinants for each schedule. For most schedules, the tariff revision authorized to take effect on August 1, 2018, in the last general rate case resulted in a change to margin rates and basic service charges.[3]. The annualized billing determinants are then applied to current rates in column "I" and the current adjusted margin revenues are presented in column "J".

Q. In the "Adjusted Current" section, can you please describe the Weather Normalized Volume adjustment for schedules 503 and 504?

A. In column H, the volumetric billing determinants (i.e. "Therms") in the Residential Service Rate Schedule 503 and General Commercial Service Rate Schedule 504 are given an adjustment to gross them up to weather normalized volumes. The adjusted volumes serve as the basis for the adjusted volumetric margin revenues presented in the section.

Q. Please describe generally the Weather Normalization data related to Exhibit No.__(IDM-2)

A. My Exhibit No.__(IDM-2) supports the testimony presented by Company witness Brian Robertson and contains weather normalized data for Schedules 503 and Schedule 504. My workpaper, IDM WP-1.5, labeled "Weather Normalization" contains the actual 2018 monthly volumetric usage for Schedules 503 and 504 with adjustments to normalized values. Weather normalized usage is not applied to other schedules in this rate proceeding.

Q. What is the regulatory basis for Weather Normalization data in this case?

A. As agreed to in the Company's last general rate case, the Company utilizes the weather normalization approach specified in the Company's 2015 general rate case (2015 GRC)

[3] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Order 06, (July 20, 2018).

settlement agreement.[4] The agreement outlines the following approach to produce weather normalization data as follows:[5]

a) Use of 10 years of usage and weather data;

b) Use of National Oceanic and Atmospheric Administration ("NOAA") weather data for both actual temperature and "normal" temperature benchmark;

c) Refined regression models to exclude insignificant monthly heating degree day variables;

d) Inclusion of a trend variable in the regression models when appropriate, and correct common statistical problems such as serial correlations. Staff may provide technical assistance;

e) Identification of outliers by comparing predicted usage with actual usage as well as double-checking data accuracy and re-specifying regression models if necessary; and

f) Use of an alternative way approach to reporting monthly usage if unbilled therms are not trued up monthly: alignment of heating degree days with billing cycles on a monthly basis, rather than using monthly usage data that includes gross estimates of unbilled therms.

A detailed description of the Company's weather normalization methodology, which conforms to the 2015 GRC agreement, is presented in Company witness Brian Robertson's testimony, Exhibit No.___(BLR-1T).

[4] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Dockets UG-170929, Order 06 at ¶ 81 (Jul. 20, 2018).
[5] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Dockets UG-152286, Joint Settlement Agreement at ¶ 44 (May 13, 2016).

Q. Can you please describe how billing determinants are adjusted in the "EOP Billing Determinants at Current Rates" section?

A. Yes. Billing determinants in this section are adjusted to reflect EOP customer counts; specifically, the customer counts as of December 31, 2018. This has an impact on both basic service charge revenues and volumetric margin revenues because the basic assumption is that EOP customer counts have been annualized.

Q. Will you describe in greater detail how the EOP calculations are performed?

A. Certainly. In workpaper IDM WP-1.3 entitled "End of Period Calculations," I demonstrate how volumetric usage would be calculated had EOP customer counts been observed for the entirety of 2018.

The first table of the workpaper labeled, "2018 Monthly Therms - Actual(Normalized) Therms / Ave Use Per Month", shows weather normalized volumes (for Rate Schedules 503 and 504 only) and actual volumes for all core and non-core schedules. This section also calculates a monthly average of therm usage based on actual customer count calculations for each class. In other words, normalized and actual usage is divided by customer counts to determine a baseline average usage per month for each rate schedule.

The second section of the workpaper labeled, "2018 Annualized Usage Using End of Period Customer Counts" calculates monthly average usage using EOP customer counts. This is done by multiplying the average therm usage per month, calculated in the first section, by the end customer counts as of December 31, 2018. The resulting sum of this calculation for all months produces the adjusted EOP therms amount for each rate schedule which is used in Exhibit No.__(IDM-2), column "K" for

EOP therm determinants.

The EOP customer count (i.e. "Bills) in column "K" is calculated by taking the number of customers observed as of December 31, 2018 and multiplying by twelve.

The cumulative revenue impact of these EOP adjustments is presented in Exhibit No.__(IDM-2) column "M", row 745. It is also presented as a key revenue adjustment, in Exhibit No.__(IDM-3), "Revenue Adjustments", labeled R-4.

III. COST RECOVERY MECHANISM (CRM) REVENUE

Q. Can you describe in greater detail the revenues associated with the Cost Recovery Mechanism ("CRM") in Exhibit No.___(IDM-2), Column "P"?

A. Yes. This section annualizes CRM revenues by applying rates that were effective November 1, 2018 to EOP billing determinants. The CRM adjustment is the total of annualized CRM revenues expected from schedules 503, 504, 505, 511, 570 and 663, less the actual CRM revenues from these schedules in 2018. The total CRM adjustment also shown in Exhibit No. __ (IDM-3). "Revenue Adjustments," as the Total Annual CRM Adjustment, R-4.

Q. Will you please describe the purpose of the CRM and why amounts recovered under the mechanism change on an annual basis?

A. Yes. The CRM provides recovery for certain safety-related investments, in particular for replacement of pipeline facilities with elevated risk to the public. Consistent with the Commission's policy statement in Docket No. UG-120715, Cascade provides annual updates to the Commission regarding its capital investments that are recoverable under the CRM. Cascade filed its most recent CRM update on June 1, 2018 in Docket No. UG-180512, and the current rates were approved, effective November 1, 2018.

IV. REVENUE ADJUSTMENTS

Q. Would you please describe Exhibit No.___(IDM-3) entitled "Revenue Adjustments"?

A. Yes. Exhibit No.___(IDM-3) is a summary document of the Restating Revenue adjustments found at the bottom of Exhibit No.___(IDM-2), "Summary of Revenues by Rate Schedule" and also as the Restating Adjustments in Exhibit No.___(MCP-5), "Summary of Proposed Adjustments To Test Year Results," furnished by Company witness Maryalice Peters.

The following are the Restating Revenue adjustments:

- <u>R-1 - Total Annual CRM Adjustment</u>
- <u>R-3 - Total Restate Revenue Adjustment</u>
- <u>R-4 – Total Restate End of Period (EOP) Adjustment</u>

Q. Would you please describe "R-1 Total Annual CRM Adjustment"?

A. Yes. As discussed earlier in this testimony, the CRM adjustment is the total of annualized CRM revenues expected under schedules 503, 504, 505, 511, 570 and 663, less the actual CRM revenues received by the Company under these schedules in 2018. This is essentially the CRM adjustment required to gross up these revenues associated with EOP billing determinants. The adjustment and calculation is shown in Exhibit No.___(IDM-2), "Summary of Revenues by Rate Schedule", column "P", row 745. It is presented as restating Revenue Adjustment (R-1) in Exhibit No.___(MCP-5).

Q. Would you please describe "R-3 Restate Revenue Adjustment"?

A. Yes. In short, the Restate Revenue Adjustment is the amount required to fully annualize revenues at current rates. While the total Column "J" in Exhibit

No.___(IDM-2), shows Adjusted Per Books Margin Revenues of $95,624,401, this amount does not fully capture the effects of revenues effectively booked in Unbilled Margins and Cap Adjustments. The Company also subtracts the 2018 total booked margin from column "D", ($93,428,701) to accurately calculate the total adjustment.

Q. Would you please describe what is meant by "Unbilled Margins" and "Cap Adjustments" in adjustment R-3?

A. Certainly. "Unbilled Margins" describes the netting of December 2018 current unbilled margin revenue with January 2018 previous month margin revenue. Netting these seemingly disparate revenue amounts is important because it captures the effect of net margin revenues that were realized in 2018 but were not fully represented in the Company's books because of timing differences. The resulting positive amount, $1,582,283 is added to the adjustment. The calculation is shown in my workpaper, IDM WP-1.6, entitled "WACAP2018", in column labeled "AK", row "147".

The "Cap Adjustment" is a reference to the total revenues booked in 2018 under the Company's Washington Rule 21, "Decoupling Mechanism". These revenues are netted out of the Restating Revenue Adjustment R-3 because the Company's current margin rates already capture the effects of decoupling and also because the test year billing determinants are already adjusted to weather normalized volumes. Failure to remove these revenues from the Company's current annualized revenue adjustment would have the effect of unduly inflating margin revenues. The resulting amount of all 2018 Cap revenues collected ($1,044,211), is therefore removed from the adjustment.

Q. Would you please describe adjustment R-4 "Total Restate End of Period (EOP) Adjustment"?

A. Yes. The adjustment grosses up Adjusted Per Books Revenue at current rates to EOP test year revenue utilizing EOP customer counts and billing determinants.

V. UNBILLED REVENUE & ACCOUNTING PRACTICES

Q. Will you please provide a brief history of the Company's unbilled revenues and updated accounting practices?

A. Yes. In the Joint Testimony supporting the settlement of the Company's 2015 GRC, the Company agreed to several practices that would apply to the Company's future reporting and general rate case filings.

Specifically, the Joint Testimony stated that "unbilled revenues" must be properly calculated and "identified by revenue type (gas cost revenue, margin revenue, and any other revenue source)."[6] Further, the testimony stipulated that "the Company will use a methodology and accounting for any unbilled revenues in accordance with accepted industry practices in which unbilled revenues are trued-up monthly and verified for reasonableness. Lastly, the Company will identify book revenues for accounting purposes between true gas cost revenue, margin revenue and all other revenue sources."[7]

The Commission's Final Order Accepting Settlement required Cascade to "(1) separate conservation revenues and WEAF revenues from the Weighted Average Cost of Gas for reporting purposes; (2) utilize an accounting procedure for unbilled revenues that are trued-up monthly and verified for reasonableness in accordance with accepted

[6] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-152286, Joint Testimony in Support of Settlement at 25, line 13 (May 27, 2016).
[7] *Id.* at 26, line 2

industry practices; and (3) bifurcate booked revenues for accounting purposes between true gas cost revenue, margin revenue, and all other revenues sources."[8]

In Cascade's subsequent rate case, UG-170929, witness Michael P. Parvinen testified that the Company had addressed the core issues surrounding unbilled revenues:

> "The Company uses an industry accepted approach to calculating its unbilled revenues. The method is based on using actual monthly pipeline data to determine true customer usage and compares the usage to the actual billed usage. The difference between true customer usage and actual billed usage provides the amount of the unbilled revenue. This is a very common approach and has been accepted by the Company's outside auditor."[9]

In the same proceeding the Company provided a detailed data response explaining how unbilled gas sales were estimated and how unbilled gas revenues were internally calculated.[10] In addition, Company witness Maryalice C. Rosales provided testimony, exhibits and workpapers demonstrating the Company had separated conservation revenues and WEAF revenues from the Weighted Average Cost of Gas and had bifurcated booked revenues for accounting purposes between true gas cost revenue, margin revenue, and all other revenues sources, as required by the Commission.[11]

Q. How is the Company addressing the matters of unbilled revenues and related accounting practices in this case?

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[8] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-152286, Order 04 at ¶ 14 (Jul. 7, 2016).
[9] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929 (UG-170929), Direct Testimony of Michael P. Parvinen, Exhibit MPP1T at 16, lines 10-15.
[10] *Cascade 2017 GRC*, Response to WUTC Staff Data Response No. 15.
[11] *Id.*, Direct Testimony of Maryalice C. Rosales Exhibit MCR-1T at 5:15-6:7, MCR-2 and MCR-4.

A. As in Docket No. UG-170929, the Company continues to use the agreed-upon methodologies to calculate unbilled revenues and as directed by the Commission, separates conservation revenues and WEAF revenues from the Weighted Average Cost of Gas for reporting purposes. Regarding the presentation of revenues, in Exhibit No.__(IDM-2), I present Company booked revenues bifurcated for accounting purposes between true gas cost revenue, margin revenue, and all other revenues sources.

VI. RATE SPREAD & RATE DESIGN

Q. What methodology does the Company propose to determine Rate Spread and Rate Design in this case?

A. The Company's proposed rate spread and design methodologies remain the same as those approved by the Commission in Order No. 06 of Docket No. UG-170929. Specifically, as required by the order, the Company has applied an equal percent of margin increase or decrease to each schedule, except for Special Contracts, to determine rate spread.[12] Further the Company's basic service charges for each rate schedule will remain unchanged.

Q. Would you please describe Exhibit No.__(IDM-4) "Revenue Distribution"?

A. Yes. That exhibit demonstrates how the Company has equitably applied it's requested revenue increase across each schedule, excluding special contracts. This is accomplished by taking the Company's Required Revenue increase from Exhibit No.___(MCP-3) and allocating it based on each classes' percentage of overall margin

[12] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Order 06 at ¶ 69 (Jul. 20, 2018).

revenues, excluding special contract revenues. For classes that allow for block usage, the revenue requirement is also allocated based on the block's contribution to overall margin revenues, excluding special contract revenues.

In Exhibit No.__(IDM-4), column "k", the percentage of margin revenue increase per schedule demonstrates that the Company has indeed applied an equal percentage of the margin increase to each schedule and overall. The resulting percentage increase is applied to the "Current Rate(s)" in column "d" to calculate proposed margin rates per customer class and corresponding usage blocks. These proposed rates flow to Exhibit No.__(IDM-2), "Revenue Summary" and their effective recovery of the revenue requirement is demonstrated in the "Proposed" revenue columns of the exhibit. The total revenue requirement distribution by schedule is proven out in Exhibit No.__(IDM-2), column "S", row 745.

As mentioned previously, the Company by order is not permitted to change any basic service charges at this time. Therefore, revenue distribution increases are not applicable to these charges.

VII. DECOUPLING BASELINE CALCULATIONS

Q. Would you please describe Exhibit No.__(IDM-5) entitled "Decoupling Mechanism, Authorized Revenue Per Customer"?

A. Yes. Consistent with the methodology approved in Order No. 04 in UG-152286, Exhibit No.___(IDM-5) presents the authorized margin revenue per customer per month revised to reflect the proposed changes in revenue requirement. This methodology was also reaffirmed in the final order of the Company's last general rate case, UG-170929[13]

Q. How is the authorized margin revenue per customer in Exhibit No.__(IDM-5) calculated?

A. The new monthly authorized margin revenue per customer is derived by dividing the annual proposed Margin Revenue per customer class as shown in Table 1, Column 1, by the EOP test year therms per customer class presented in the exhibit Table 1, Column 2. This produces the rates as shown in Table 1, Column 3.

These rates are then multiplied by the monthly EOP test year therms per customer class shown in Table 2 and then divided by the EOP customer count in Table 1, Column 4, to determine the authorized annual revenue per customer per month, shown in Table 3.

Q. Has the Company submitted proposed tariff changes to reflect the new authorized margin revenues per customer?

A. Yes. The proposed authorized margin revenue per customer from Exhibit No.__(IDM-5) is also presented in the Company's proposed tariff, Fifth Revision Sheet No. 25, Rule 21, "Decoupling Mechanism".

Q. Does this conclude your testimony?

A. Yes.

[13] *Id.*, ¶ 83

Exhibit No. __ (IDM-2)
Docket No. UG-19____
Witness: Isaac D. Myhrum

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS
CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF ISAAC D. MYHRUM

<u>SUMMARY OF REVENUES BY RATE SCHEDULE</u>

March 29, 2019

Cascade Natural Gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
1	**Rate Schedule 502 - Building Construction Rate**				Migrated to 503														
2	Basic Service Charge - Jan-Aug	5,353	$ 14.00	$74,942	-5,353	$14.00	-$74,942.00	-	$14.00	$0.00									
3	Basic Service Charge - Sept-Dec	0	$ -	$0															
4	Delivery Charge - Jan-Aug	370,699	$ 0.09183	$34,041	-370,699	$0.09183	-$34,041.26	-	$0.09183	$0.00									
5	Delivery Charge - Sept - Dec	0	$ -	$0						$0.00									
6	Total Margin			$108,983															
7																			
8	Average Cost of Gas			$169,679															
9																			
10	Non-Gas Revenue																		
11	WA Energy Assistance Fund Program			$1,161															
12	WA Replacement Pipe Cost Recovery			$4,745															
13	WA Decoupling Mechanism			-$596															
14	WA Deferred Gas Costs			$20,653															
15	WA Conservation Cost Recovery			$5,060															
16	City Tax Tier 1			$17,768															
17	City Tax Applied (City Tax < Maximum)			$9															
18	Adjustment Dollars			-$14															
19	Current Month Unbilled +			$0															
20	Previous Month Unbilled -			$0															
21	CAP Adjustment			-$8,304															
22	Deferrals			-$511															
23	Deficiency			$0															
24	Adjustment			$13															
25	Total Non-Gas Revenue			$39,983															
26																			
27	**Total Rate Schedule 502 Revenue**	$0.00	check	$318,645															
28																			
29	**Rate Schedule 503 - Residential Service Rate**				Migrated from 502														
30	Basic Service Charge - Jan-Jul	1,529,647	$4.00	$6,118,588	5,353	$4.00	$21,412	1,535,000											
31	Basic Service Charge - Aug-Dec	762,758	$5.00	$3,813,789				762,758	$5.00	$11,488,788	2,301,790	$11,508,952	$20,164				$5.00	$ 11,508,952	$ -
32																			
33	Delivery Charge - Jan-Jul	84,153,826	$ 0.29484	$24,811,914	370,699	$0.29484	$109,297	84,524,525											
34	Delivery Charge - Aug- Dec	36,966,089	$ 0.27205	$10,056,625				36,966,089	$0.27205	$33,051,522				131,567,022	$ 0.01341	$ 1,764,314			
35	Total Margin			$44,800,915															
36																			
37	Weather Normalized Volume Adjustment							8,595,166	$0.27205	$2,338,315									
38																			
39	Average Cost of Gas			$55,203,865				130,085,781	$0.27205	$35,389,837	131,567,022	$35,792,808	$402,972				$ 0.32160	$ 42,312,386	$ 6,519,577
40										$46,878,625		$47,301,760	$423,135					$ 53,821,337	$ 6,519,577
41	Non-Gas Revenue																		
42	WA Energy Assistance Fund Program			$356,004															
43	WA Replacement Pipe Cost Recovery			$1,439,980															
44	WA Decoupling Mechanism			-$657,530															
45	WA Deferred Gas Costs			$5,784,749															
46	WA Conservation Cost Recovery			$1,927,959															
47	WA Protected-Plus Excess Deferred Income Tax			-$241,134															
48	WA Unprotected Excess Deferred Income Tax			-$113,446															
49	WA Temporary Federal Income Tax Rate Credit			-$214,310															
50	City Tax Tier 1			$5,133,602															
51	City Tax for Cities with Annual Maximum			$19,178															
52	City Tax Applied (City Tax < Maximum)			$2,064															
53	State Utility Tax Credit			-$760															
54	Indian Nation Tribal Charge			$19,156															
55	Adjustment			-$1,316															
56	Current Month Unbilled +			$67,372,865															
57	Previous Month Unbilled -			-$70,535,940															
58	CAP Adjustment			$1,447,891															
59	Deferrals			$325,808															
60	Deficiency			$0															
61	Total Non-Gas Revenue			$12,064,822															
62																			
63	**Total Rate Schedule 503 Revenue**	$0.01	check	$112,069,602															
64																			
65																			
66	**Rate Schedule 504 - General Commercial Service**				Migrated from 512 & add 04LV														
67	Basic Service Charge - Jan-Jul	184,413	$10.00	$1,844,130	14	$10	$140	184,427											
68	Basic Service Charge - Aug-Dec	127,485	$13.00	$1,657,310	$5	$13	$62	127,490	$13.00	$4,054,923	318,953	$4,146,389	$91,466				$ 13.00	$ 4,146,389	$ -
69																			
70	Delivery Charge - Jan-Jul	59,235,944	$ 0.24608	$14,576,781	50,466	$0.24608	$12,419	59,286,410											
71	Delivery Charge - Aug - Dec	27,628,821	$ 0.23142	$6,393,862	6,334	$0.23142	$1,466	27,635,155	$0.23142	$20,115,388				92,551,661	$ 0.00909	$ 841,295			
72	Total Margin			$24,472,082															
73																			
74	Weather Normalized Volume Adjustment							4,930,665	$0.23142	$1,141,054									
75																			
76	Average Cost of Gas			$39,380,976				91,852,229	$0.23142	$21,256,443	92,551,661	$21,418,305	$161,862				$ 0.27357	$ 25,319,600	$ 3,901,295
77										$25,311,366		$25,564,694	$253,329					$ 29,465,989	$ 3,901,295
78	Non-Gas Revenue																		
79	WA Energy Assistance Fund Program			$206,086															
80	WA Replacement Pipe Cost Recovery			$747,372															
81	WA Decoupling Mechanism			-$312,200															
82	WA Deferred Gas Costs			$4,192,484															
83	WA Conservation Cost Recovery			$1,368,810															
84	WA Protected-Plus Excess Deferred Income Tax			-$134,711															
85	WA Unprotected Excess Deferred Income Tax			-$63,494															
86	WA Temporary Federal Income Tax Rate Credit			-$120,413															
87	City Tax Tier 1			$3,762,988															
88	City Tax Tier 2			$2,037															
89	City Tax for Cities with Annual Maximum			$79,561															
90	City Tax Applied (City Tax < Maximum)			$926															
91	State Utility Tax Credit			-$4,945															
92	Indian Nation Tribal Charge			$35,306															
93	Adjustment Dollars			-$159,242															
94	Current Month Unbilled +			$48,907,467															
95	Previous Month Unbilled -			-$50,844,325															
96	CAP Adjustment			$48,789															
97	Deferrals			$149,412															

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
98	Deficiency			$54,452															
99	Adjustment			-$18.32															
100	Total Non-Gas Revenue			$7,916,344															
101																			
102	**Total Rate Schedule 504 Revenue**	$0.00	check	$71,769,402	$0														
103																			
104																			
105	**Rate Schedule 505 - General Industrial Service**				Merge from 05LV														
106	Basic Service Charge - Jan-Jul	3,296	$ 48.00	$ 158,208	7	$ 48.00	$336	3,303											
107	Basic Service Charge - Aug-Dec	2,310	$60.00	$138,618	5	$ 60.00	$288	2,315	$60.00	$337,086	5,760	$345,600	$8,514				$ 60.00	$ 345,600	$ -
108	Margin First 500 Therms (Jan. - Jul.)	1,072,908	$ 0.18843	$202,168	1,135	$ 0.18843	$214	1,074,043											
109	Margin Next 3,500 Therms (Jan. - Jul.)	3,517,606	$ 0.15175	$533,797	767	$ 0.15175	$116	3,518,373											
110	Margin > 4,000 Therms (Jan. - Jul.)	2,693,790	$ 0.14620	$393,832		$ 0.14620	$0	2,693,790											
111	Margin First 500 Therms (Aug. - Dec)	637,312	$ 0.17851	$113,767	631	$ 0.17851	$113	637,943	$0.17851	$305,607	1,733,987	$309,534	$3,927	1,733,987	$ 0.00684	$ 11,860	$ 0.21103	$ 365,915	$ 56,381
112	Margin Next 3,500 Therms (Aug. - Dec.)	2,042,063	$ 0.14457	$295,221	-	$ 0.14457	$0	2,042,063	$0.14457	$803,872	5,632,622	$814,308	$10,436	5,632,622	$ 0.00684	$ 38,527	$ 0.17090	$ 962,633	$ 148,324
113	Margin > 4,000 Therms (Aug. - Dec.)	2,028,587	$ 0.13944	$282,866	-	$ 0.13944	$0	2,028,587	$0.13944	$658,488	4,781,351	$666,712	$8,223	4,781,351	$ 0.00684	$ 32,704	$ 0.16484	$ 788,152	$ 121,440
114	Total Margin			$2,118,477						$2,105,053		$2,136,154	$31,101			$ 83,092		$ 2,462,299	$ 326,145
115																			
116	Average Cost of Gas			$5,279,788															
117																			
118	Non-Gas Revenue																		
119	WA Energy Assistance Fund Program			$17,570															
120	WA Replacement Pipe Cost Recovery			$79,367															
121	WA Decoupling Mechanism			$88,127															
122	WA Deferred Gas Costs			$585,373															
123	WA Conservation Cost Recovery			$187,363															
124	WA Protected-Plus Excess Deferred Income Tax			-$14,061															
125	WA Unprotected Excess Deferred Income Tax			-$6,662															
126	WA Temporary Federal Income Tax Rate Credit			-$12,729															
127	City Tax Tier 1			$320,658															
128	City Tax Tier 2			$1,924															
129	City Tax Applicable to Identified Bus for Tax. Rev Limits			$1,200															
130	City Tax for Cities with Annual Maximum			$1,323															
131	City Tax Applied (City Tax < Maximum)			$452															
132	Indian Nation Tribal Charge			$10,065															
133	Adjustment			-$2,552															
134	Current Month Unbilled +			$0															
135	Previous Month Unbilled -			$0															
136	CAP Adjustment			-$6,965															
137	Deferrals			-$104,031															
138	Deficiency			$0															
139	Total Non-Gas Revenue			$1,146,423															
140	**Total Rate Schedule 505 Revenue**																		
141		$0.00	*check*	$8,544,688															
142																			
143	**Rate Schedule 511 - Large Volume General Service Rate**																		
144	Basic Service Charge - Jan-Jul	603	$ 100.00	$ 60,300				603											
145	Basic Service Charge - Sept-Dec	423	$125.00	$ 52,898				423	$125.00	$128,273	1,032	$ 129,000.00	$727				$ 125.00	$ 129,000	$ -
146	Margin First 20,000 Therms (Jan. -Jul.)	5,709,351	$ 0.14834	$ 846,925				5,709,351											
147	Margin Next 80,000 Therms (Jan. - Jul.)	2,763,232	$ 0.11295	$ 312,107				2,763,232											
148	Margin> 100,000 Therms (Jan. - Jul.)	505,392	$ 0.02541	$ 12,842				505,392											
149	Margin First 20,000 Therms (Aug. - Dec.)	3,049,425	$ 0.14330	$ 436,983				3,049,425	$0.14330	$1,255,133	8,739,571	$ 1,252,380	-$2,752	8,739,571	$ 0.00473	$ 41,338	$ 0.16940	$ 1,480,499	$ 228,118
150	Margin Next 80,000 Therms (Aug. - Dec.)	1,763,020	$ 0.10984	$ 193,650				1,763,020	$0.10984	$497,164	4,503,350	$ 494,648	-$2,516	4,503,350	$ 0.00473	$ 21,301	$ 0.12985	$ 584,747	$ 90,099
151	Margin> 100,000 Therms (Aug. - Dec.)	265,227	$ 0.02709	$ 7,185				265,227	$0.02709	$20,876	771,998	$ 20,913	$37	771,998	$ 0.00473	$ 3,652	$ 0.03202	$ 24,723	$ 3,809
152	Total Margin			$ 1,922,889						$1,901,445		$ 1,896,942	-$4,503			$66,291		$ 2,218,968	$ 322,027
153																			
154	Average Cost of Gas			$6,192,611															
155																			
156	Non-Gas Revenue																		
157	WA Energy Assistance Fund Program			$17,525															
158	WA Replacement Pipe Cost Recovery			$66,152															
159	WA Decoupling Mechanism			-$320,712															
160	WA Deferred Gas Costs			$684,453															
161	WA Conservation Cost Recovery			$219,993															
162	WA Protected-Plus Excess Deferred Income Tax			-$12,522															
163	WA Unprotected Excess Deferred Income Tax			-$5,901															
164	WA Temporary Federal Income Tax Rate Credit			-$11,256															
165	City Tax Tier 1			$341,468															
166	City Tax Tier 2			$6,654															
167	Indian Nation Tribal Charge			$3,128															
168	Adjustment			-$242															
169	City Tax for Cities with Annual Maximum			$12,874															
170	State Utility Tax Credit			-$13,893															
171	Current Month Unbilled +			$0															
172	Previous Month Unbilled -			$0															
173	CAP Adjustment			-$470,920															
174	Deferrals			$282,007															
175	Deficiency			$0															
176	Total Non-Gas Revenue			$798,808															
177	Total Non-Gas Revenue																		
178																			
179	**Total Rate Schedule 511 Revenue**	$0.00	check	$8,914,308															
180																			
181	**Rate Schedule: CNGW04LV**				Merge w 504														
182	Basic Service Charge Jan-Jul	7	$10.00	$70	-7	$10.00	-$70	-	$10.00	$0									
183	Basic Service Charge Aug-Dec	5	$13.00	$62	-5	$13.00	-$62	-	$13.00	$0									
184	Margin Jan-Jul	21187	$ 0.24608	$5,214	-21,187	$0.24608	-$5,214	-	$0.24608	$0									
185	Margin Aug-Dec	6334	$ 0.23142	$1,466	-6,334	$0.23142	-$1,466	-	$0.23142	$0									
186				$6,811			-$6,811			$0									
187																			
188	Average Cost of Gas			$12,508															
189																			
190	WA Energy Assistance Fund Program			$65															
191	WA Replacement Pipe Cost Recovery			$244															
192	WA Decoupling Mechanism			-$75															
193	WA Deferred Gas Costs			$1,367															
194	WA Conservation Cost Recovery			$424															
195	WA Protected-Plus Excess Deferred Income Tax			-$33															

Cascade Natural Gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
196	WA Unprotected Excess Deferred Income Tax			-$15															
197	WA Temporary Federal Income Tax Rate Credit			-$29															
198	City Tax Tier 1			$1,276															
199	Adjustment																		
200	Current Month Unbilled +			$0															
201	Previous Month Unbilled -			$0															
202	CAP Adjustment			-$7,036															
203	Deferrals			$182															
204	Deficiency			$0															
205	Adjustment			$0															
206	-PM CA1501A			-$22,478															
207	+CM CA1501A			$23,650															
208	Total Non-Gas Revenue			-$2,458															
209																			
210	**Total Rate Schedule: CNGW04LV**	$0.00	check	$16,862															
211																			
212	**Rate Schedule 512 - Compressed Natural Gas**				Migrated to 504														
213	Basic Service Charge - Jan - Jul	7	$ 14.00	$98	-7	$ 14.00	-$98	-	$14.00	$0									
214	Basic Service Charge - Aug - Dec	-	0	$0				-	$0.00	$0									
215	Delivery Charge - Jan - Jul	29,279	$ 0.21479	$6,289	-29,279	$0.21479	-$6,289	-	$0.21479	$0									
216	Delivery Charge - Aug - Dec	-	0	$0						$0									
217	Total Margin			$6,387			-$6,387												
218																			
219	Average Cost of Gas			$13,402															
220																			
221	Non-Gas Revenue																		
222	WA Energy Assistance Fund Program			$53															
223	WA Replacement Pipe Cost Recovery			$226															
224	WA Decoupling Mechanism			$12															
225	WA Deferred Gas Costs			$1,631															
226	WA Conservation Cost Recovery			$400															
227	City Tax Tier 1			$1,327															
228	Adjustment																		
229	Current Month Unbilled +			$0															
230	Previous Month Unbilled -			$0															
231	CAP Adjustment			-$481															
232	Deferrals			-$62															
233	Deficiency			$0															
234	Total Non-Gas Revenue			$3,105															
235																			
236	**Total Rate Schedule 512**	$0.00	check	$22,893															
237																			
238	**Rate Schedule: CNGW05LV**				Merge w 505														
239	Basic Service Charge - Jan - Jul	7	$ 48.00	$336	-7	48.00	-$336	-	$48.00000	$0									
240	Basic Service Charge - Aug - Dec	5	$60.00	$288	-5	60.00	-$288	-	$60.00000	$0									
241	Margin First 500 Therms - Jan-Jul	1135	$ 0.18843	$214	-1,135	0.18843	-$214	-	$0.18843	$0									
242	Margin First 500 Therms - Aug-Dec	631	$ 0.17851	$113	-631	0.17851	-$113	-	$0.17851	$0									
243	Margin Next 3,500 Therms - Jan-Jul	767	$ 0.15175	$116	-767	0.15175	-$116	-	$0.15175	$0									
244	Margin Next 3,500 Therms - Aug-Dec	0	$ 0.14457	$0	0	0.14457	$0		$0.14457	$0									
245	Total Margin			$1,067			-1,067			$0									
246																			
247	Average Cost of Gas			1,125															
248																			
249	Non-Gas Revenue																		
250	WA Energy Assistance Fund Program			4															
251	WA Replacement Pipe Cost Recovery			17															
252	WA Decoupling Mechanism			20															
253	WA Deferred Gas Costs			138															
254	WA Conservation Cost Recovery			35															
255	WA Protected-Plus Excess Deferred Income Tax			(2)															
256	WA Unprotected Excess Deferred Income Tax			(1)															
257	WA Temporary Federal Income Tax Rate Credit			(2)															
258	Adjustment																		
259	Current Month Unbilled +			0															
260	Previous Month Unbilled -			0															
261	CAP Adjustment			3,468															
262	Deferrals			(20)															
263	Deficiency			32,815															
264	Ajustment			29															
265	-PM CA1501A			(2,397)															
266	+CM CA1501A			2,160															
267	Total Non-Gas Revenue			36,263															
268																			
269	**Total Rate Schedule: CNGW05LV**	-	check	38,455															
270																			
271	**Rate Schedule 570 - Interruptible Service Schedule**				Migrated from 577														
272	Basic Service Charge - (Jan-Jul)	56	$ 130.00	7,280	16	130.00	2,080	72											
273	Basic Service Charge - (Aug-Dec)	32	$163.00	5,216				32	$163.00	$16,952	96	$15,648	-$1,304				$ 163.00	$ 15,648	$ -
274	Margin First 30,000 Therms (Jan. - Jul.)	674,641	$ 0.08233	55,543	109,321	0.08233	9,000	783,962											
275	Margin > 30,000 Therms (Jan. - Jul.)	674,277	$ 0.02251	15,178				674,277											
276	Margin First 30,000 Therms (Aug-Dec)	473,492	$ 0.07895	37,382				473,492	$0.07895	$99,276	1,159,981	$91,581	-$7,695	1,159,981	$ 0.00340	$ 3,944	$ 0.09333	$ 108,262	$ 16,681
277	Margin > 30,000 Therms (Aug-Dec)	269,738	$ 0.02248	6,064				269,738	$0.02248	$21,221	866,599	$19,481	-$1,740	866,599	$ 0.00340	$ 2,946	$ 0.02657	$ 23,030	$ 3,548
278	Total Margin			126,663						$137,449		$126,710	-$10,740			$ 6,890		$ 146,939	$ 20,230
279																			
280	Average Cost of Gas			895,841															
281																			
282	Non-Gas Revenue																		
283	WA Energy Assistance Fund Program			919															
284	WA Replacement Pipe Cost Recovery			4,510															
285	WA Decoupling Mechanism			(5,324)															
286	WA Deferred Gas Costs			105,896															
287	WA Conservation Cost Recovery			31,529															
288	WA Protected-Plus Excess Deferred Income Tax			(624)															
289	WA Unprotected Excess Deferred Income Tax			(295)															
290	WA Temporary Federal Income Tax Rate Credit			(565)															
291	City Tax Tier 1			15,082															

Cascade Natural Gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
292	Indian Nation Tribal Charge			779															
293	Current Month Unbilled +			0															
294	Previous Month Unbilled -			0															
295	CAP Adjustment			33,487															
296	Deferrals			1,619															
297	Deficiency			0															
298	Adjustment			0															
299	-PM CA1501A			(1,173,493)															
300	+CM CA1501A			1,172,380															
301	Total Non-Gas Revenue			185,900															
302																			
303	**Total Rate Schedule 570 Revenue**	-	*check*	1,208,405															
304																			
305																			
306	**Rate Schedule 577 - Limited Interruptible Serice Rate**				Migrate to 570														
307	Basic Service Charge - Jan-Aug	16	$ 130.00	2,080	-16	130.00	(2,080)	-	$130.00	$0									
308	Basic Service Charge - Aug-Dec	0	0	-	0	-	-	-	$0.00	$0									
309	Margin First 4,000 Therms (Jan. - Jul.)	63334	$ 0.10401	6,587	-63,334	0.104010	(6,587)	-	$0.10401	$0									
310	Margin > 4,000 Therms (Jan. - Jul.)	45987	$ 0.08446	3,884	-45,987	0.08446	(3,884)	-	$0.08446	$0									
311	Margin First 4,000 Therms (Aug. - Dec.)	0	0	-	0	-	-	-	$0.00000	$0									
312	Margin > 4,000 Therms (Aug. - Dec.)	0	0	-	0	-	-	-	$0.00000	$0									
313	Total Margin			12,551			(12,551)			$0									
314																			
315	Average Cost of Gas			47,191															
316																			
317	Non-Gas Revenue																		
318	WA Energy Assistance Fund Program			98															
319	WA Replacement Pipe Cost Recovery			251															
320	WA Decoupling Mechanism			(114)															
321	WA Deferred Gas Costs			6,090															
322	WA Conservation Cost Recovery			1,492															
323	City Tax Tier 1			2,657															
324	Adjustment																		
325	Current Month Unbilled +			-															
326	Previous Month Unbilled -			-															
327	CAP Adjustment			4,282															
328	Deferrals			(2)															
329	Deficiency			-															
330	Adjustment			-															
331	-PM CA1501A			(67,005)															
332	+CM CA1501A			55,044															
333	Total Non-Gas Revenue			2,795															
334																			
335	**Total Rate Schedule 577 Revenue**	-	check	62,537															
336																			

Cascade Natural Gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
337																			
338	**Rate Schedule 6631 - Non-Core Industrial**				From other 663 & 916														
339	Basic Service Charge - Jan-Jul	1,478	$ 500.00	$739,000	38	$500	19,000	1,516											
340	Basic Service Charge - Aug-Dec	742	$625.00	$463,750	16	$625	10,000	758	$625.00	$1,421,250	2,268	$1,417,500	-$3,750				$ 625.00	$ 1,417,500	$ -
341	Contract Demand Charge - Jan-Jul	10,393,155	$ 0.20000	$2,078,631	8,320,000	$0.2000	1,664,000	18,713,155											
342	Contract Demand Charge - Aug-Dec	5,829,900	$ 0.20000	$1,165,980	3,640,000	$0.2000	728,000	9,469,900	$0.20000	$5,636,611	28,183,055	$5,636,611	$0				$ 0.20000	$ 5,636,611	$ -
343	System Balancing Charge - Jan-Jul	242,183,475	$ 0.00040	$96,873	105,762,125	$0.0004	42,305	347,945,600											
344	System Balancing Charge - Aug-Dec	115,783,225	$ 0.00040	$46,313	63,719,675	$0.0004	25,488	179,502,900	$0.00040	$210,979	527,448,500	$210,979	$0				$ 0.00040	$ 210,979	$ -
345	Delivery Charge First 100,000 Therms- Jan-Jul	61,865,362	$ 0.05730	$3,544,885	2,831,760	$0.05730	162,260	64,697,123											
346	Delivery Charge Next 200,000 Therms - Jan-Jul	42,816,219	$ 0.02023	$866,172	4,397,060	$0.02023	88,953	47,213,279											
347	Delivery Charge Next 200,000 Therms - Jan-Jul	21,960,312	$ 0.01187	$260,669	3,846,365	$0.01187	45,656	25,806,676											
348	Delivery Charge > 500,000 Therms - Jan-Jul	115,541,685	$ 0.00508	$586,952	28,159,522	$0.00508	143,050	143,701,207											
349	Delivery Charge First 100,000 Therms - Aug-Dec	32,976,210	$ 0.05331	$1,757,962	938,869	$0.05331	50,051	33,915,079	$0.05331	$5,257,016	98,378,565	$5,244,561	-$12,455	98,378,565	$ 0.00171	$ 168,227	$ 0.06302	$ 6,199,846	$ 955,285
350	Delivery Charge Next 200,000 Therms - Aug-Dec	22,496,950	$ 0.01945	$437,566	1,600,000	$0.01945	31,120	24,096,950	$0.01945	$1,386,984	71,561,496	$1,391,871	$4,887	71,561,496	$ 0.00171	$ 122,370	$ 0.02299	$ 1,645,397	$ 253,526
351	Delivery Charge Next 200,000 Therms - Aug-Dec	10,971,464	$ 0.01182	$129,683	1,600,000	$0.01182	18,912	12,571,464	$0.01182	$453,630	38,711,379	$457,568	$3,939	38,711,379	$ 0.00171	$ 66,196	$ 0.01397	$ 540,914	$ 83,345
352	Delivery Charge > 500,000 Therms - Aug-Dec	49,338,794	$ 0.00562	$277,284	127,569,507	$0.00562	716,941	176,908,301	$0.00562	$1,801,825	319,536,160	$1,795,793	-$6,032	319,536,160	$ 0.00171	$ 546,407	$ 0.00664	$ 2,122,893	$ 327,100
353	Total Margin			$12,451,719.86						$16,168,296		$16,154,885	-$13,411			$ 903,201		$ 17,774,140	$ 1,619,255
354																			
355	Non-Gas Revenue																		
356	WA Protected-Plus Excess Deferred Income Tax			(67,553)															
357	WA Unprotected Excess Deferred Income Tax			(31,781)															
358	WA Temporary Federal Income Tax Rate Credit			(62,523)															
359	WA Energy Assistance Fund Program			96,651															
360	WA Replacement Pipe Cost Recovery			532,601															
361	Contract Charge (applicable only if identified in contract)			15,000															
362	Contract Charge (applicable only if identified in contract)			6,000															
363	Gross Revenue Fee			555,778															
364	City Tax Tier 1			403,016															
365	City Tax Tier 2			1,204															
366	City Tax Applicable to Identified Bus. for Tax Rev Limits			600															
367	City Tax for Cities with Annual Maximum			15,458															
368	City Tax Applied (City Tax < Maximum)			1,193															
369	State Utility Tax Credit			(1,367)															
370	Indian Nation Tribal Charge			8,394															
371	Adjustment			5,114															
372	Current Month Unbilled +			$0															
373	Previous Month Unbilled -			$0															
374	CAP Adjustment			$0															
375	Deferrals			-$94,246															
376	Deficiency			$0															
377	Adjustment			-$15															
378	-PM CA1501A			-$13,808,165															
379	+CM CA1501A			$13,736,588															
380	Total Non-Gas Revenue			$1,311,949															
381																			
382	**Total Rate Schedule 6631 Revenue**	$0.00	check	$13,763,668															
383																			
384																			
385	**Rate Schedule 6632**				Merge 6631														
386	Basic Service Charge - Jan-Jun	6	$500.00	$3,000	-6	$500	-$3,000	-	$ 500.00	$0									
387	Basic Service Charge - Jul-Dec	-	$0	$0	0	$0	$0	-	$0.00000	$0									
388	System Balancing Charge - Jan-Jun	425,975	$ 0.00040	$170	-425,975	$0.0004	-$170	-	$0.00040	$0									
389	System Balancing Charge - Sept-Dec	-	$0	$0	0	$0.0000	$0	-	$0.00000	$0									
390	Delivery Charge First 100,000 Therms- Jan-Aug	425,965	$ 0.05730	$24,408	-425,965	$0.0573	-$24,408	-	$0.05730	$0									
391	Delivery Charge First 100,000 Therms - Sept-Dec	-	0	$0	0	$0	$0	-	$0.00000	$0									
392	Total Margin			$27,578			-$27,578			$0									
393																			
394	Non-Gas Revenue																		
395	WA Energy Assistance Fund Program			$115															
396	WA Replacement Pipe Cost Recovery			$750															
397	Gross Revenue Fee			$1,232															
398	City Tax Tier 1			$890															
399	Current Month Unbilled +			$0															
400	Previous Month Unbilled -			$0															
401	CAP Adjustment			$0															
402	Deferrals			$0															
403	Deficiency			$0															
404	Adjustment			$0															
405	-PM CA1501A			($30,451)															
406	+CM CA1501A			$25,029															
407	Total Non-Gas Revenue			($2,434)															
408																			
409	**Total Rate Schedule 663-2 Revenue**	$0.00	check	$25,144															
410																			
411	**Rate Schedule 906 - Interruptible Transportation**																		
412	Dispatch Service Charge (Jan-Sept)	9	$500.00	$4,500				9											
413	Dispatch Service Charge (Oct-Dec)	3	$625.00	$1,875				3	$625.00	$7,500									
414	Contract Demand Charge (Jan-Jul)	7	$ 13,062.54	$91,438				7											
415	Contract Demand Charge (Aug-Dec)	5	$ 13,219.29	$66,096				5	$13,219	$158,631									
416	DSC Commodity (Jan-Sept)	21,784,250	0.0002	$4,357				21,784,250											
417	DSC Commodity (Oct-Dec)	-		$0				-											
418	System Balancing Rate (Jan-Sept)	-		$0				-											
419	System Balancing Rate (Oct-Dec)	6,857,875	0.0004	$2,743				6,857,875	$0.00040	$11,457									
420	Commodity Charge First 100,000 Therms per day (Jan-Jun)	15,232,404	0.0143688	$218,871				15,232,404											
421	Commodity Charge First 100,000 Therms per day (Jul-Dec)	13,123,029	0.0145412	$190,825				13,123,029	$0.01454	$412,322									
422	Commodity Charge Over 100,000 Therms per day (Jan-Jun)	217,685	0.0186657	$4,063				217,685											
423	Commodity Charge Over 100,000 Therms per day (Jul-Dec)	46,468	0.0188897	$878				46,468	$0.01889	$4,990									
424	Total Margin			$585,646						$594,900									
425																			
426	Non-Gas Revenue																		
427	Gross Revenue Fee			$26,101															
428	Adjustments			$564															
429	-PM CA1501A			-$611,764															
430	+CM CA1501A			$606,434															
431	Total Non-Gas Revenue			-$4,766															
432																			
433	**Total Rate Schedule 906 Revenue**	$0.00	check	$606,981															
434																			

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)
435	**Rate Schedule 909 - Interruptible Transportation**									
436	Dispatch Service Charge (Jan-Sept)	9	$500.00	$4,500				9		
437	Dispatch Service Charge (Oct-Dec)	3	$625.00	$1,875				3	$625.00	$7,500
438	Contract Demand Charge (Jan-Sept)	9	$2,000.00	$18,000				9		
439	Contract Demand Charge (Oct-Dec)	-	$0.00	$0				-		
440	Monthly Facilities Charge (Jan-Sept)	-	$0.00	$0				-		
441	Monthly Facilities Charge (Oct-Dec)	3	$2,000.00	$6,000				3	$2,000.00	$24,000
442	System Balancing Rate (Jan-Sept)	-	$0	$0				-		
443	System Balancing Rate (Oct-Dec)	3,848,125	$ 0.0004	$1,539				3,848,125	$0.00040	$8,941
444	DSC Commodity (Jan-Sept)	18,504,350	$ 0.0002	$3,701				18,504,350		
445	DSC Commodity (Oct-Dec)	-	0	$0						
446	Commodity Charge (Jan-Sept)	18,504,364	$ 0.0155259	$287,297				18,504,364		
447	Commodity Charge (Oct-Dec)	3,753,483	$ 0.0163767	$61,470				3,753,483	$0.01638	$364,510
448	Total Margin			$384,382						$404,951
449										
450	Non-Gas Revenue									
451	Gross Revenue Fee			$17,141						
452	Adjustments			$458						
453	-PM CA1501A			-$401,533						
454	+CM CA1501A			$373,268						
455	Total Non-Gas Revenue			-$27,806						
456										
457	**Total Rate Schedule 909 Revenue**	$0.00	check	$373,716						
458										
459	**Rate Schedule 910 - Interruptible Transportation**									
460	Dispatch Service Charge (Jan-Sept)	9	500	4,500				9		
461	Dispatch Service Charge (Oct-Dec)	3	625	1,875				3	$625.00	$7,500
462	Monthly Facilities Charge (Jan-Sept)	0	$0.00	0				-		
463	Monthly Facilities Charge (Oct - Dec)	3	$2,250.00	6,750				3	$2,250.00	$27,000
464	System Balancing Charge (Jan-Sept)	0	$0.00	0						
465	System Balancing Charge (Oct-Dec)	2,064,625	$0.0004	826				2,064,625	$0.00040	$3,272
466	Contract Demand Charge (Jan-Sept)	9	$2,250.00	20,250				9		
467	Contract Demand Charge (Oct-Dec)	-	$0.00	0						
468	DSC Commodity (Jan-Sept)	6,114,250	$0.0002	1,223				6,114,250		
469	DSC Commodity (Oct-Dec)	-	$0.00	0						
470	Commodity Charge (Jan-Sept)	6,114,191	$0.0112648	68,875				6,114,191		
471	Commodity Charge (Oct-Dec)	2,046,318	$0.0115915	23,720				2,046,318	$0.01159	$94,593
472	Total Margin			128,019						$132,364
473										
474	Non-Gas Revenue									
475	Gross Revenue Fee			5,704						
476	Adjustments			279						
477	-PM CA1501A			(133,727)						
478	+CM CA1501A			134,740						
479	Total Non-Gas Revenue			1,291						
480										
481	**Total Rate Schedule 910 Revenue**	$0.00	check	135,014						
482										
483	**Rate Schedule 911 - Interruptible Transportation**									
484	Dispatch Service Charge (Jan-Sept)	9	$ 500.00	4,500				9		
485	Dispatch Service Charge (Oct - Dec)	3	$ 625.00	1,875				3	$625.00	$7,500
486	Monthly Facilities Charge (Jan-Sept)	0	$ -	-						
487	Monthly Facilities Charge (Oct - Dec)	3	$ 3,950.00	11,850				3	$3,950.00	$47,400
488	System Balancing Charge (Jan-Sept)	0	$ -	-						
489	System Balancing Charge (Oct - Dec)	1,357,175	$ 0.0004	543				1,357,175	$0.00040	$2,090
490	Contract Demand Charge (Jan-Sept)	9	$ 3,950.00	35,550				9		
491	Contract Demand Charge (Oct - Dec)	0	$ -	-						
492	DSC Commodity (Jan-Sept)	3,866,650	$ 0.0002	773				3,866,650		
493	DSC Commodity (Oct-Dec)	0	$ -	-						
494	Commodity Charge (Jan-Sept)	3,866,677	$ 0.0172248	66,603				3,866,677		
495	Commodity Charge (Oct - Dec)	1,347,696	$ 0.0177243	23,887				1,347,696	$0.01772	$92,421
496	Total Margin			145,581						$149,411
497										
498	Non-Gas Revenue									
499	Gross Revenue Fee			6,488						
500	Adjustments			201						
501	-PM CA1501A			(152,072)						
502	+CM CA1501A			149,321						
503	Total Non-Gas Revenue			(2,551)						
504										
505	**Total Rate Schedule 911 Revenue**	$ -	check	149,518						
506										
507	**Rate Schedule 914 - Interruptible Transportation**									
508	Dispatch Service Charge (Jan-Sept)	9	$ 500.00	4,500				9		
509	Dispatch Service Charge (Oct-Dec)	3	$ 625.00	1,875				3	$625.00	$7,500
510	Monthly Facilities Charge (Jan-Sept)	-	0	0						
511	Monthly Facilities Charge (Oct-Dec)	3	$ 6,725.00	20,175				3	$6,725.00	$80,700
512	System Balancing Charge (Jan-Sept)	-	0	0						
513	System Balancing Charge (Oct-Dec)	2,584,425	$ 0.0004	1,034				2,584,425	$0.00040	$4,937
514	Contract Demand Charge (Jan-Sept)	9	$ 6,725.00	60,525				9		
515	Contract Demand Charge (Oct-Dec)	-	0	0						
516	DSC Commodity (Jan-Sept)	9,757,600	$ 0.0002	1,952				9,757,600		
517	DSC Commodity (Oct-Dec)	-	0	0						
518	Commodity Charge (Jan-Sept)	9,757,646	$ 0.0105356	102,803				9,757,646		
519	Commodity Charge (Oct-Dec)	2,553,789	$ 0.0108411	27,686				2,553,789	$0.01084	$133,469
520	Total Margin			220,549						$226,606
521										
522	Non-Gas Revenue									
523	Gross Revenue Fee			9,830						
524	Adjustments			4,508						
525	-PM CA1501A			(230,386)						
526	+CM CA1501A			231,919						
527	Total Non-Gas Revenue			6,041						
528										
529	**Total Rate Schedule 914 Revenue**	$0.00	check	236,420						
530										
531	**Rate Schedule 6631**				Merge 6631					
532	Basic Service Charge (Jan-Aug)	8	$ 500.00	$4,000	-8	$500.00	-$4,000.00	-	$500.00	$0

EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
533	Basic Service Charge (Sept-Dec)	7	$ 625.00	$4,375	-7	$625.00	-$4,375.00	-	$625.00	$0									
534	Contract Demand Charge (Oct-Dec)	1,560,000	$ 0.20000	$312,000	-1,560,000	$0.20	-$312,000.00	-	$0.20000	$0									
535	System Balancing Charge (Oct-Dec)	23,104,000	$ 0.00040	$9,242	-23,104,000	$0.00	-$9,241.60	-	$0.00040	$0									
536	Delivery Charge First 100,000 Therms (Oct-Dec)	276,766	$ 0.05331	$14,754	-276,766	$0.05	-$14,754.40	-	$0.05331	$0									
537	Delivery Charge Next 200,000 Therms (Oct-Dec)	400,000	$ 0.01945	$7,780	-400,000	$0.02	-$7,780.00	-	$0.01945	$0									
538	Delivery Charge Next 200,000 Therms (Oct-Dec)	400,000	$ 0.01182	$4,728	-400,000	$0.01	-$4,728.00	-	$0.01182	$0									
539	Delivery Charge > 500,000 Therms (Oct-Dec)	22,027,226	$ 0.00562	$123,793	-22,027,226	$0.01	-$123,793.01	-	$0.00562	$0									
540	Total Margin			$480,672			-$480,672.01			$0									
541																			
542	Non-Gas Revenue																		
543	WA Protected-Plus Excess Deferred Income Tax (Oct-Dec)			-$13,174															
544	WA Unprotected Excess Deferred Income Tax (Oct-Dec)			-$6,240															
545	WA Temporary Federal Income Tax Rate Credit (Oct-Dec)			-$12,476															
546	WA Energy Assistance Fund Program (Oct-Dec)			$6,238															
547	WA Replacement Pipe Cost Recovery (Oct-Dec)			$16,020															
548	Gross Revenue Fee (Jan-Sept)			$206															
549	Gross Revenue Fee (Oct-Dec)			$21,094															
550	City Tax Applicable to Identified Bus. for Tax Rev Limits (Oct-Dec)			$180															
551	DEFWA revenues			-$43,960															
552	Deficiency Billings			$0															
553	Adjustment			$0															
554	-PM CA1501A			-$486,283															
555	+CM CA1501A			$698,913															
556	Total Non-Gas Revenue			$180,519															
557																			
558	**Total Rate Schedule 6631**	$0.00	check	$661,191															
559																			
560	**Rate Schedule 6633**				Merge 6631														
561	Basic Service Charge - Jan-Aug	8	$ 500.00	$4,000	-8	$500	-$4,000	-	$500.00	$0									
562	Basic Service Charge - Sept-Dec	4	$ 625.00	$2,500	-4	$625	-$2,500	-	$625.00	$0									
563	Contract Demand Charge - Jan-Aug	4,160,000	$ 0.2000	$832,000	-4,160,000	$0.2000	-$832,000	-	$0.20000	$0									
564	Contract Demand Charge - Sept-Dec	2,080,000	$ 0.2000	$416,000	-2,080,000	$0.2000	-$416,000	-	$0.20000	$0									
565	System Balancing Charge - Jan-Aug	25,959,475	$ 0.0004	$10,384	-25,959,475	$0.0004	-$10,384	-	$0.00040	$0									
566	System Balancing Charge - Sept-Dec	31,205,850	$ 0.0004	$12,482	-31,205,850	$0.0004	-$12,482	-	$0.00040	$0									
567	Delivery Charge First 100,000 Therms- Jan-Aug	712,759	$ 0.05730	$40,841	-712,759	$0.0573	-$40,841	-	$0.05730	$0									
568	Delivery Charge Next 200,000 Therms - Jan-Aug	1,400,000	$ 0.02023	$28,322	-1,400,000	$0.0202	-$28,322	-	$0.02023	$0									
569	Delivery Charge Next 200,000 Therms - Jan-Aug	1,227,896	$ 0.01187	$14,575	-1,227,896	$0.0119	-$14,575	-	$0.01187	$0									
570	Delivery Charge > 500,000 Therms - Jan-Aug	22,618,799	$ 0.00508	$114,904	-22,618,799	$0.0051	-$114,904	-	$0.00508	$0									
571	Delivery Charge First 100,000 Therms - Sept-Dec	328,205	$ 0.05331	$17,497	-328,205	$0.0533	-$17,497	-	$0.05331	$0									
572	Delivery Charge Next 200,000 Therms - Sept-Dec	600,000	$ 0.01945	$11,670	-600,000	$0.0195	-$11,670	-	$0.01945	$0									
573	Delivery Charge Next 200,000 Therms - Sept-Dec	600,000	$ 0.01182	$7,092	-600,000	$0.0118	-$7,092	-	$0.01182	$0									
574	Delivery Charge > 500,000 Therms - Sept-Dec	29,677,653	$ 0.00562	$166,788	-29,677,653	$0.0056	-$166,788	-	$0.00562	$0									
575	Total Margin			$1,679,055			-1,679,055			$0									
576																			
577	Non-Gas Revenue																		
578	WA Protected-Plus Excess Deferred Income Tax			($17,789)															
579	WA Unprotected Excess Deferred Income Tax			($8,426)															
580	WA Temporary Federal Income Tax Rate Credit			($16,851)															
581	WA Energy Assistance Fund Program			$15,435															
582	WA Replacement Pipe Cost Recovery			$67,249															
583	Gross Revenue Fee			$74,796															
584	-PM CA1501A			($1,778,106)															
585	+CM CA1501A			$1,764,236															
586	Total Non-Gas Revenue			$100,543															
587																			
588	**Total Rate Schedule 6633**	$0.00	check	$1,779,598															
589																			
590																			
591																			
592	**Rate Schedule 6635**				Merge w 6631														
593	Basic Service Charge (Jan-Aug)	8	$ 500.00	4,000	-8	500.00	(4,000)	-	$500.00	$0									
594	Basic Service Charge (Sept-Dec)	4	$ 625.00	2,500	-4	625.00	(2,500)	-	$625.00	$0									
595	System Balancing Charge (Jan-Aug)	8,364,775	$ 0.0004	3,346	-8,364,775	0.0004	(3,346)	-	$0.00040	$0									
596	System Balancing Charge (Sept-Dec)	9,409,825	$ 0.0004	3,764	-9,409,825	0.0004	(3,764)	-	$0.00040	$0									
597	Delivery Charge First 100,000 Therms (Jan-Aug)	800,000	$ 0.05730	45,840	-800,000	0.0573	(45,840)	-	$0.05730	$0									
598	Delivery Charge First 100,000 Therms (Sept-Dec)	333,898	$ 0.05331	17,800	-333,898	0.0533	(17,800)	-	$0.05331	$0									
599	Delivery Charge Next 200,000 Therms(Jan-Aug)	1,204,771	$ 0.02023	24,373	-1,204,771	0.0202	(24,373)	-	$0.02023	$0									
600	Delivery Charge Next 200,000 Therms (Sept-Dec)	600,000	$ 0.01945	11,670	-600,000	0.0195	(11,670)	-	$0.01945	$0									
601	Delivery Charge Next 200,000 Therms(Jan-Aug)	819,311	$ 0.01187	9,725	-819,311	0.0119	(9,725)	-	$0.01187	$0									
602	Delivery Charge Next 200,000 Therms (Sept-Dec)	600,000	$ 0.01182	7,092	-600,000	0.0118	(7,092)	-	$0.01182	$0									
603	Delivery Charge Over 500,000 Therms(Jan-Aug)	5,540,722	$ 0.00508	28,147	-5,540,722	0.0051	(28,147)	-	$0.00508	$0									
604	Delivery Charge Over 500,000 Therms (Sept-Dec)	7,875,922	$ 0.00562	44,263	-7,875,922	0.0056	(44,263)	-	$0.00562	$0									
605	Total Margin			202,519			(202,519)			$0									
606																			
607	Non-Gas Revenue																		
608	WA Protected-Plus Excess Deferred Income Tax			($5,366)															
609	WA Unprotected Excess Deferred Income Tax			($2,541)															
610	WA Temporary Federal Income Tax Rate Credit			($5,081)															
611	WA Energy Assistance Fund Program			$4,799															
612	WA Replacement Pipe Cost Recovery			$21,249															
613	Utilization Discount First 100,000 Therms			($58,827)															
614	Utilization Discount Next 200,000 Therms			($31,529)															
615	Utilization Discount Next 200,000 Therms			($11,936)															
616	Utilization Discount Next 100,000 Therms			($5,775)															
617	Utilization Discount Next 300,000 Therms			($10,636)															
618	Utilization Discount Next 400,000 Therms			($7,589)															
619	Utilization Discount > 1,300,000 but < 18,700,000 Therms			($28,144)															
620	Facilities Charge			$1,445,820															
621	Compressor Operation			$91,174															
622	Gross Revenue Fee			$70,645															
623	-PM CA1501A			($1,664,035)															
624	+CM CA1501A			$1,647,124															
625	Total Non-Gas Revenue			$1,449,353															
626																			
627	**Total Rate Schedule 6635**	-	check	$1,651,872															
628																			
629	**Rate Schedule 901 - Interruptible Transportation**																		
630	Dispatch Service Charge (Jan-Sept)	9	$ 500.00	$ 4,500				9											

Cascade Natural Gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
631	Dispatch Service Charge (Oct-Dec)	3	$ 625.00	$ 1,875				3	$625.00	$7,500									
632	Monthly Charge (Jan-Aug)	-	0	$ -															
633	Monthly Charge (Sept-Dec)	4	20,468.36	$ 81,873				4	$20,468.36	$245,620									
634	Contract Demand Charge (Jan-Sept)	8	20,215.64	$ 161,725				8											
635	Contract Demand Charge (Oct-Dec)	-	$ -	$ -															
636	Dispatch Service Charge (Jan-Sept)	52,423,150	0.0002	$ 10,485				52,423,150											
637	Dispatch Service Charge (Oct-Dec)	-	0	$ -															
638	System Balancing Charge (Jan-Sept)	-	0	$ -															
639	System Balancing Charge (Oct-Dec)	17,223,525	0.0004	$ 6,889				17,223,525	$0.00040	$27,859									
640	Commodity Charge (Jan-Jul)	42,165,281	0.0148248	$ 625,092				42,165,281											
641	Commodity Charge (Aug-Dec)	27,404,970	0.0150101	$ 411,351				27,404,970	$0.01501	$1,044,256									
642	Total Margin			$ 1,303,791						$1,325,235									
643																			
644	Non-Gas Revenue																		
645	Gross Revenue Fee			$58,110															
646	Adjustments			$980															
647	-PM CA1501A			($1,358,262)															
648	+CM CA1501A			$1,369,363															
649	Total Non-Gas Revenue			$12,081															
650																			
651	**Total Rate Schedule 901 Revenue**	-	check	$1,373,981															
652																			
653	**Rate Schedule 903 - Interruptible Transportation**																		
654	Dispatch Service Charge (Jan-Sept)	9	500.00	4,500				9											
655	Dispatch Service Charge (Oct-Dec)	3	625.00	1,875				3	$ 625.00	$7,500									
656	Monthly Charge (Jan-Sept)	-	-	0															
657	Monthly Charge (Oct-Dec)	5	14,541.22	72,706				5	$14,541.22	$174,495									
658	Contract Demand Charge (Jan-Sept)	7	14,368.80	100,582				7											
659	Contract Demand Charge (Oct-Dec)	-	-	0															
660	Dispatch Service Charge (Jan-Sept)	19,563,650	0.0002	3,913				19,563,650											
661	Dispatch Service Charge (Oct-Dec)	-	-	0															
662	System Balancing Charge (Jan-Sept)	-	-	0															
663	System Balancing Charge (Oct-Dec)	392,300	0.0004	157				392,300	$0.00040	$7,982									
664	Commodity Charge (Jan-Sept)	19,722,652	0.0143688	283,391				19,722,652											
665	Commodity Charge (Oct-Dec)	392,300	0.0145412	5,705				392,300	$0.01454	$292,496									
666	Total Margin			472,828						$482,473									
667																			
668	Non-Gas Revenue																		
669	Gross Revenue Fee			21,069															
670	Adjustments			1,596															
671	City Tax Tier 1			31,525															
672	-PM CA1501A			(525,467)															
673	+CM CA1501A			495,146															
674	Total Non-Gas Revenue			2,800															
675																			
676	**Total Rate Schedule 903 Revenue**	-	check	496,697															
677																			
678	**Rate Schedule 907 - Interruptible Transportation**																		
679	Dispatch Service Charge (Jan-Sept)	9	500	4,500				9	$ 500.00	($4,500)									
680	Dispatch Service Charge (Oct-Dec)	0	0	0				-	$0.00000	$0									
681	Contract Demand Charge (Jan-Sept)	9	62100	558,900				9	$62,100.00	($558,900)									
682	Contract Demand Charge (Oct-Dec)	0	0	0				-	$0.00000	$0									
683	Assignment per 3rd Party Agreement (Jan-Sept)	9	(20,872.50)	(187,853)				9	-$20,872.50	$187,853									
684	Assignment per 3rd Party Agreement (Oct-Dec)	0	0	0															
685	Total Margin			375,548						($375,548)									
686								discontinued											
687	Non-Gas Revenue							Oct. 2018											
688	Gross Revenue Fee			16,767															
689	Adjustments			131															
690	-PM CA1501A			(348,738)															
691	+CM CA1501A			305,146															
692	Total Non-Gas Revenue			(43,462)															
693																			
694	**Total Rate Schedule 907 Revenue**	-	check	348,853															
695																			
696																			
697	**Rate Schedule 908- Interruptible Transportation**																		
698	Dispatch Service Charge (Jan-Sept)	9	500	4,500				9											
699	Dispatch Service Charge (Oct-Dec)	3	625	1,875				3	$ 625.00	$7,500									
700	Dispatch Service Charge (Jan-Sept)	8,557,650	0.0002	1,712				8,557,650											
701	Dispatch Service Charge (Oct-Dec)	-	0	0				-											
702	System Balancing Charge (Jan-Sept)	-	0	0				-											
703	System Balancing Charge (Oct-Dec)	65,375	0.0004	26				65,375	$0.00040	$3,449									
704	Commodity Charge First 22 Million/Year	8,622,981	$ 0.0100000	86,230				8,622,981	$0.01000	$86,230									
705	Minimum Charge per Month	6	$13,900.00	84,596				6	$13,900.00	$84,596									
706	Total Margin			178,939						$181,775									
707																			
708	Non-Gas Revenue																		
709	Gross Revenue Fee			7,975															
710	Adjustments			397															
711	-PM CA1501A			(186,919)															
712	+CM CA1501A			186,990															
713	Total Non-Gas Revenue			8,443															
714																			
715	**Total Rate Schedule 908 Revenue**	-	check	187,381															
716																			
717	**Rate Schedule 916- Interruptible Transportation**				merge 6631														
718	Basic Service Charge (Jan-Aug)	8	500.00	4,000	(8)	$500.00	($4,000.00)	-	$ 500.00	$0									
719	Basic Service Charge (Sept)	1	625.00	625	(1)	$625.00	($625.00)	-	$ 625.00	$0									
720	Contract Demand Charge (Jan-Sept)	9	60,000.00	540,000	(9)	$60,000.00	($540,000.00)	-	$60,000.00	$0									
721	Assignment per 3rd Party Agreement	9	20,872.50	187,853	(9)	$20,872.50	($187,852.50)	-	$20,872.50	$0									
722	System Balancing Charge	71,011,900	0.0004	28,405	(71,011,900)	$0.00040	($28,404.76)	-	$0.00040	$0									
723	Delivery Charge First 100,000 Therms (Jan-Sept)	893,037	0.05730	51,171	(893,037)	$0.05730	($51,171.00)	-	$0.05730	$0									
724	Delivery Charge Next 200,000 Therms (Jan-Sept)	1,792,289	0.02023	36,258	(1,792,289)	$0.02023	($36,258.00)	-	$0.02023	$0									
725	Delivery Charge Next 200,000 Therms (Jan-Sept)	1,799,158	0.01187	21,356	(1,799,158)	$0.01187	($21,356.00)	-	$0.01187	$0									
726	Delivery Charge > 500,000 Therms (Jan-Sept)	67,988,707	0.00508	345,383	(67,988,707)	$0.00508	($345,382.63)	-	$0.00508	$0									
727	Total Margin			1,215,050			($1,215,049.89)			$0									
728								moved to 663											

Cascade Natural gas Corporation
SUMMARY OF REVENUES BY RATE SCHEDULE

		Current			Schedule Merge			Adjusted Current			EOP Determinants at Current Rates			Cost Recovery Mechanism CRM			Proposed		
	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue 2018	Billing Determinants (Therms/Bills)	Rate	Remove/Add	Adjusted Billing Determinants	Rate	Adjusted Per Books Margin Revenue	Billing Determinants (Therms/Bills)	Adjusted EOP Margin Revenue	EOP Revenue Adjustment	Billing Determinants (Therms/Bill)	Rate	CRM Revenue	Proposed Rates	Revenue At Proposed Rates	2019 Revenue Adjustment
	(A)	(B) = (D)/(C)	(C)	(D)	(E)	(F)	(G)	(H) = (B)+(E)	(I)	(J) = (H)*(I)	(K)	(L) = (K)*(I)	(M) = (L)-(J)	(N)	(O)	(P) = (N)*(O)	(Q)	(R) = (Q)*(K)	(S) = (R)-(L)
729	Non-Gas Revenue							520,000	8	4,160,000									
730	WA Protected-Plus Excess Deferred Income Tax			($8,204)				New contract demand terms											
731	WA Unprotected Excess Deferred Income Tax			($3,886)															
732	WA Temporary Federal Income Tax Rate Credit			($7,772)															
733	WA Energy Assistance Fund Program			$19,173															
734	WA Replacement Pipe Cost Recovery			$109,581															
735	Gross Revenue Fee			$54,233															
736	City Tax App. to Iden Bus. for Tax Rev Limits			$540															
737	Adjustment			$0															
738	-PM CA1501A			($1,359,609)															
739	+CM CA1501A			$1,197,187															
740	Total Non-Gas Revenue			$1,243															
741																			
742	**Total Rate Schedule 916 Revenue**	$0.00	check	$1,216,293															
743														Total CRM Proposed Rev	$	3,665,082			
744														Less booked CRM		-$2,980,736			
745	**Total Cascade Margin**			**$93,428,701**						**$95,624,401** #		Total EOP Adj.	**$678,910** #	Total CRM Adjustment	**$**	**684,346**			**$ 12,708,529**
746	**Total Cascade Revenue**			$225,972,125															
747								Less Total Booked Margin		($93,428,701)									
748	**Miscellaneous Service Revenues**			$778,717				Total Cap Adjustments		($1,044,211)									
749	**Rent From Gas Property**			$100				Net Unbilled Margins Booked		$1,582,283									
750	**Interdepartmental Rents**			$85,563				Total Revenue Adjustment		**$2,733,772**									
751	**Other Gas Revenue**			$72,861															
752	**Provision for Rate Refund**			($2,424,725)															
753																			
754	**TOTAL OPERATING REVENUE**			$224,484,641															
755			Check	$0.01															
756																			

Exhibit No. __ (IDM-3)
Docket No. UG-19____
Witness: Isaac D. Myhrum

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF ISAAC D. MYHRUM

REVENUE ADJUSTMENTS

March 29, 2019

Cascade Natural Gas Corporation

Revenue Adjustments

Adjusted current margin revenues using weather normalized volumes at current margin rates (Per Myhrum Exh. IDM-2, column "J", row "745")	$95,624,401
Less Total Booked Margin (Per Exh. IDM-2, column "D", row "745")	($93,428,701)
Less Total Cap Adjustments (Per Exh. IDM-2, column "J", row "748")	($1,044,211)
Plus Unbilled Margins Booked (Per Exh. IDM-2, column "J", row "749")	$1,582,283
Total Restate Revenue Adjustment (Per Exh. IDM-2, column "J", row "750") (Per Exh. MCP-5, R-3 Adjustment)	**$2,733,772**
Total Restate End of Period (EOP) Adjustment (Per Exh. IDM-2, column "M", row "745") (Per Exh. MCP-5, R-4 Adjustment)	**$678,910**
Total CRM Proposed Revenue (Per Exh. IDM-2, column "P", row "743")	$3,665,082
Less Booked CRM Revenue (Per Exh. IDM-2, column "P", row "744")	($2,980,736)
Total Annual CRM Adjustment (Per Exh. IDM-2, column "P", row "745") (Per Exh. MCP-5, R-1 Adjustment)	**$684,346**

Exhibit No. __ (IDM-4)
Docket No. UG-19____
Witness: Isaac D. Myhrum

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF ISAAC D. MYHRUM

<u>REVENUE DISTRIBUTION</u>

March 29, 2019

Cascade Natural Gas Corporation
Revenue Distribution

Line No.	Description	Rate Schedule	Block Descriptions	Current Rate	Proposed Rate	Test Year Adjusted Sales @ 12/31/2018	Test Year Revenue @ Current Rates	Margin Revenue @ Proposed Rates	Revenue Percentage by class @ 12/31/2018	Proposed Revenue Increase	Total Revenue % Increase
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Residential										
1	Optional Service	503		0.27205	0.32160	131,567,022	$ 35,792,808	42,312,386			
2	Total					131,567,022	$ 35,792,808	42,312,386	0.513008	**6,519,577**	18.21%
3											
4	**Commercial**										
5	General Service	504		0.23142	0.27357	92,551,661	$ 21,418,305	25,319,600			
6	Total					92,551,661	$ 21,418,305	25,319,600	0.306982	**3,901,295**	18.21%
7											
8	**Industrial Firm**										
9	General Service	505	First 500 therms/month	0.17851	0.21103	1,733,987	$ 309,534	365,915	0.004436	56,381	18.21%
10			Next 3,500 therms/month	0.14457	0.17090	5,632,622	$ 814,308	962,633	0.011671	148,324	18.21%
11			All over 4,000 therms/month	0.13944	0.16484	4,781,351	$ 666,712	788,152	0.009556	121,440	18.21%
12	Total					12,147,960	$ 1,790,554	2,116,699	0.025663	**326,145**	18.21%
13											
14	**Com-Ind Dual Service**										
15	Large Volume	511	First 20,000 therms/month	0.1433	0.16940	8,739,571	$ 1,252,380	1,480,499	0.017950	228,118	18.21%
16			Next 80,000 therms/month	0.10984	0.12985	4,503,350	$ 494,648	584,747	0.007090	90,099	18.21%
17			All over 100,000 therms/month	0.02709	0.03202	771,998	$ 20,913	24,723	0.000300	3,809	18.21%
18	Total					14,014,918	$ 1,767,942	2,089,968	0.025339	**322,027**	18.21%
19											
20	**Interruptible**										
21	General	570	First 30,000 therms/month	0.07895	0.09333	1,159,981	$ 91,581	108,262	0.001313	16,681	18.21%
22			All over 30,000 therms/month	0.02248	0.02657	866,599	$ 19,481	23,030	0.000279	3,548	18.21%
23	Total					2,026,580	$ 111,062	131,291	0.001592	**20,230**	18.21%
24											
25	**Total Core**					**252,308,141**	**60,880,671**	**71,969,944**	**0.872585**	**11,089,274**	**18.21%**
26											
27	**Non-Core**										
28	Distribution Trans.	663	First 100,000 therms/month	0.05331	0.06302	98,378,565	$ 5,244,561	6,199,846	0.075169	955,285	18.21%
29			Next 200,000 therms/month	0.01945	0.02299	71,561,496	$ 1,391,871	1,645,397	0.019949	253,526	18.21%
30			Next 200,000 therms/month	0.01182	0.01397	38,711,379	$ 457,568	540,914	0.006558	83,345	18.21%
31			Over 500,000 therms/month	0.00562	0.00664	319,536,160	$ 1,795,793	2,122,893	0.025739	327,100	18.21%
32	Total					528,187,600	$ 8,889,794	10,509,050	0.127415	**1,619,255**	18.21%
33											
34											
35	**Total Non-Core**					**528,187,600**	**8,889,794**	**10,509,050**	**0.127415**	**1,619,255**	**18.21%**
36											
37	**Total**					780,495,741	69,770,465	82,478,994	1.00000	12,708,529	18.21%
38										Rev. Increase	
39										Exh MCP-3	

Exhibit No. __ (IDM-5)
Docket No. UG-19____
Witness: Isaac D. Myhrum

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF ISAAC D. MYHRUM

DECOUPLING MECHANISM, AUTHORIZED REVENUE PER CUSTOMER

March 29, 2019

Cascade Natural Gas Corporation
Decoupling Mechanism, Authorized Revenue Per Customer

Table 1

A	B	C	D	E	F	G	H	I
Rate Schedules		Margin Revenue (1)		EOP Weather Normalized Or Actual Annual Therms (2)		Rate (3)		Customer Count (4)
503		$42,312,386		131,567,022		0.32160		191,816
504		$25,319,600		92,551,661		0.27357		26,579
505		$2,116,699		12,147,960		0.17424		480
511		$2,089,968		14,014,918		0.14912		86
570		$131,291		2,026,580		0.06478		8

Data Sources
(1) Margin Revenue is from Exh. IDM-2, column (R). (Margin revenue in proposed column.)
(2) Exh. IDM-2, column (K). 503, 504 EOP Weather Normalized Therms and 505, 511, & 570 EOP adjusted actuals.
(3) Rate is Column C divided by Column E
(4) End of Period annualized test year customer counts are from Myhrum Workpaper "End of Period Calculations" column "P".

Table 2
2018 Monthly EOP & Normalized/Actual Therms

A	B	C	D	E	F	G
Rate Schedules		503	504	505	511	570
January		22,583,971	15,062,224	1,617,046	2,041,837	229,390
February		17,686,847	12,545,392	1,289,997	1,411,254	221,211
March		14,398,095	9,134,851	1,430,328	1,659,310	215,253
April		9,897,677	6,882,255	1,123,179	1,396,884	213,582
May		5,928,310	3,918,036	815,133	1,066,143	177,942
June		3,780,553	3,451,958	605,511	760,762	128,467
July		2,905,524	2,866,629	535,746	659,117	103,037
August		1,428,373	1,603,252	568,324	666,023	110,230
September		4,103,551	3,921,678	651,152	627,757	93,391
October		8,795,495	6,902,607	1,042,643	1,060,123	118,645
November		17,574,430	11,278,002	993,531	976,772	197,742
December		22,484,196	14,984,777	1,475,369	1,688,938	217,688
Total		131,567,022	92,551,661	12,147,960	14,014,918	2,026,580

Data Source
(5) From Myhrum Workpaper - "End of Period Calculations"

Table 3
New Authorized Revenue Per Customer (6)

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		January	February	March	April	May	June	July	August	September	October	November	December
503		$37.86	$29.65	$24.14	$16.59	$9.94	$6.34	$4.87	$2.39	$6.88	$14.75	$29.47	$37.70
504		$155.03	$129.13	$94.02	$70.84	$40.33	$35.53	$29.51	$16.50	$40.36	$71.05	$116.08	$154.23
505		$587.00	$468.28	$519.22	$407.72	$295.90	$219.80	$194.48	$206.31	$236.37	$378.49	$360.66	$535.57
511		$3,540.56	$2,447.12	$2,877.25	$2,422.21	$1,848.70	$1,319.17	$1,142.91	$1,154.89	$1,088.53	$1,838.26	$1,693.73	$2,928.63
570		$1,857.62	$1,791.39	$1,743.13	$1,729.61	$1,440.99	$1,040.34	$834.40	$892.65	$756.29	$960.80	$1,601.33	$1,762.85

Data Source
(6) New Authorized Revenue Per Customer is (2018 Monthly EOP & Normalized/Actual Therms * Rate) divided by customer count

Exhibit No. __ (MCP-1T)
Docket No. UG-19____
Witness: Maryalice C. Peters

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-19______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF MARYALICE C. PETERS

March 29, 2019

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Maryalice C. Peters and my business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. My present position is Regulatory Analyst III for Cascade Natural Gas Corporation ("Cascade" or "Company"), a wholly-owned subsidiary of Montana Dakota Utilities Resources Group, Inc. ("MDU Resources").

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

A. I am employed by Cascade Natural Gas Corporation ("Cascade" or "Company") as Regulatory Analyst III, and have been with the Company since December 2010. In this capacity, I prepare regulatory reports and rate/tariff filings for regulatory approval, as well as provide regulatory and tariff advice and knowledge to others within the Company.

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

A. I am a 2009 graduate of Washington State University with a B.A. in Management and Operations. In 2012, I attended a seminar on basic rates put on by the American Gas Association at the University of Chicago. I have attended other pertinent conferences such as the Annual Staff Subcommittee on Accounting sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") in 2013 as well as other NARUC-sponsored events.

I have testified before the Washington Utilities & Transportation Commission ("Commission") on behalf of Cascade in Docket UG-170929 and before the Public Utility Commission of Oregon in Docket UG 347.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony will address the revenue requirements and supporting calculations.

Q. Are you sponsoring any exhibits in this proceeding?

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

Exhibit No. __ (MCP-2)	Result of Operations Summary Sheet
Exhibit No. __ (MCP-3)	Revenue Requirement Calculation
Exhibit No. __ (MCP-4)	Conversion Factor Calculation
Exhibit No. __ (MCP-5)	Summary of Proposed Adjustments to Test Year Results
Exhibit No. __ (MCP-6)	2019 Plant Additions

III. REVENUE REQUIREMENT AND RATE REQUEST PROPOSAL

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

A. After taking into account all proposed adjustments, Cascade's current rate of return ("ROR") is 6.39 percent, as shown in Exhibit No. __ (MCP-2). In contrast, the Company's authorized rate of return is 7.31 percent, having been set by the Commission in the Cascade's last general rate case, Docket UG-170929[1]. Based on the testimonies of Ms. Ann Bulkley (Return on Equity) and Ms. Tammy Nygard (Capital Structure), Cascade calculates its proposed ROR to be 7.728 percent. I calculate the incremental revenue necessary to achieve an ROR of 7.728 percent to be

[1] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Order 06 at ¶ 59 (July 20, 2018).

$12,708,529. My calculation of the incremental revenue necessary to achieve a 7.728 percent ROR is shown in Exhibit No. __ (MCP-2). The calculation of the incremental revenue is also provided in Exhibit No. __ (MCP-3). Expressed as a percentage, the Company's requested increase in base revenue is 5.56 percent.

Q. Please describe the contents of Exhibit No. __ (MCP-2).

A. The figures shown in column (1) are the actual Washington booked figures for the test year, which is the twelve months ended December 31, 2018. The Working Capital allowance on line 23 is a calculation from the Company's actual average of monthly averages balance sheet. Column (2) is the summation of all adjustments, both restating and pro forma, to achieve the pro forma result of operations. Each adjustment that is included in column (2) is identified separately in Exhibit No. __ (MCP-5), and will be described later in my testimony. Column (3) is the sum of columns (1) and (2) and represents the expected result of operations in the rate year absent any rate change. Column (4) identifies the proposed revenue increases and the net income impact of the revenue increase. The proposed revenue increase is also calculated in Exhibit No. __ (MCP-3). Column (5) is the result of operations expected during the rate year with proposed rates.

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

A. Cascade has selected the twelve months ended December 31, 2018, as the test year. This 12-month period is the most recent complete period for which Cascade has data available to perform its analysis and is most representative of the costs that will be incurred by the Company in the rate year.

Q. Please describe the contents of Exhibit No. __ (MCP-3).

A. Exhibit No. __ (MCP-3) shows the calculation of the proposed revenue increase of $12,708,529 necessary to achieve the proposed rate of return of 7.728 percent.

Q. Would you please describe Exhibit No. __ (MCP-4)?

A. Exhibit No. __ (MCP-4) shows the calculation of the conversion factor which is applied to the required net income to produce the required revenue increase. The conversion factor takes into account revenue-sensitive items that change as revenue changes, including uncollectibles, Commission fees, Washington Business and Operating ("B&O") tax, and federal income taxes. The conversion factor is calculated to be 0.75554.

Q. Please describe Exhibit No. __ (MCP-5).

A. Exhibit No. __ (MCP-5) shows each of the Company's proposed adjustments, culminating in the total column shown in column (2) in Exhibit No.___(MCP-2). The Company is proposing six restating adjustments and four pro forma adjustments.

Q. Can you please briefly provide a definition of restating and pro forma adjustments?

A. Yes. A restating adjustment is an adjustment to the actual booked operating results to a basis acceptable for ratemaking. A pro forma adjustment is a known and measurable change beyond the test year that is not offset by other factors.

Cascade's six restating adjustments are identified as R-1 through R-6 in Exhibit No. __ (MCP-5). The Company's four pro forma adjustments are also identified in Exhibit No. __ (MCP-5) and marked as P-1 through P-4.

Q. Would you describe each of the adjustments included in Exhibit No. __ (MCP-5)?

A. Yes. The first column, column (R-1), entitled "Annualize CRM Adjustment," is an adjustment to the total annualized revenues attributed to Cascade's pipeline replacement cost recovery mechanism ("CRM") and recovered from rate schedules 503, 504, 505, 511, 570 and 663, as shown in Mr. Isaac D. Myhrum's Exhibit No.__ (IDM-2). This adjustment is described by Mr. Myhrum in his Exhibit No. __ (IDM-1T). The result is an increase to net operating income of $517,053.

Q. Continue with the description of the adjustments in Exhibit No. __ (MCP-5).

A. Column (R-2), entitled "Promotional Advertising Adjustment" removes advertising costs directed at promoting the Company brand or image rather than conservation or safety, consistent with WAC 480-90-223. Cascade removed in its entirety the amounts booked to FERC accounts 913 and 930.1. The result is an increase in net income of $18,945.

Column (R-3), entitled "Restate Revenue Adjustment" is the amount required to annualize revenues at current rates. This adjustment is also described in Mr. Myhrum's Exhibit No.___(IDM-1T). The result of this adjustment is an increase in net income of $2,065,482.

Column (R-4), entitled "Restate End of Period (EOP) Adj.," is supported by Cascade witnesses Mr. Parvinen and Mr. Myhrum, who describe the proposed adjustment in Exhibit No.__ (MPP-1T) and Exhibit No.__(IDM-1T). The result of this adjustment is a decrease in net income of $664,455.

Column (R-5), entitled “Restate Wages,” describes annualized wage increases for union employees for 2019. This adjustment reduces net operating income by $66,583.

Column (R-6), entitled “Executive Incentives,” removes all incentive compensation paid to the Company’s executive group. The result is an increase in net income of $706,568.

Column (P-1), entitled “Interest Coordination Adjustment,” adjusts federal income taxes for the effect of the average debt rate used to calculate the rate of return applied to the proposed rate base shown in Exhibit No MCP-2, column (5), line 24. The result is an increase in net income of $285,943.

Column (P-2), entitled “Pro Forma Wage Adjustment,” has four components. The first component is the annualization of the 2018 increase effective April 1, 2018 for union employees. The second component layers on the 2019 actual wage increases for non-union and union employees. The third component adds in the 2020 estimated increases for the union and non-union employees. The non-union increase is estimated to be 4 percent, the same level granted in 2018. However, the actual increase will not be known until sometime in December 2019. The Company intends to update the calculation to reflect the actual non-union increase awarded at a later date. The 2019 union increase is 3 percent, the same as 2018.

The fourth component is a reflection of the 2019 and 2020 wage increase associated with employees that are allocated to Cascade rather than directly assigned. In general, all non-union employees receive the same level of increases as approved by the Board of Directors. The result is a decrease in net income of $1,265,069.

Column (P-3), entitled "Pro Forma Plant Additions," reflects the Company's budgeted capital additions expected to go into service by December 31, 2019. The proposed projects are limited to those projects that are non-revenue producing and will not be included in the Company's 2019 annual CRM filing. Exhibit No. ____ (MCP-6) identifies each project, the proposed in-service date, most current proposed budget amount, and most importantly an explanation on the investment. These are non-revenue producing upgrades that have no material offsetting factors except for one project. As the cost and timing of these projects are budgeted and estimated at this point, Cascade will update the actual costs and standing of each project as the case proceeds. The Company's intent is to add into rate base only those projects that will be used and useful by the time rates from the current proceeding go into effect.

Q. Are Cascade's pro forma capital additions consistent with the Commission's guidelines set forth in Docket No. UE-140762?

A. Yes. In Docket No. UE-140762, the Commission reaffirmed that its "long-standing practice is to consider post-test-year capital additions on a case-by-case basis following the used and useful and known and measurable standards while exercising the considerable discretion these standards allow in the context of individual cases."[2] The Commission elaborated:

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be known to have occurred during, or reasonably soon after, the historical 12 months of actual result of operations,

[2] *Wash. Utils. & Transp. Comm'n v. Pac. Power*, Docket UE-140762, *et al.*, Order 08, ¶165 (Mar. 25, 2015).

and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base.[3]

Cascade expects that its pro forma capital additions will be placed in service and used and useful during the suspension period, and anticipates that costs will become known and measurable over the course of this proceeding. Although Cascade is including estimates for the pro forma capital additions in this initial filing, Cascade intends to provide actual costs for all completed and in-service projects in its rebuttal filing. Additionally, Cascade has included supporting justification for each project included in the 2019 Pro Forma Plant Addition adjustment. The supporting documentation is included in Exhibit No. ____ (MCP-6).

Q. What is the impact of the Pro Forma Plant Adjustment?

A. The net income effect of the rate base additions, ~~for~~ depreciation expense, property taxes, and an offsetting revenue increase is a decrease of $825,347. The rate base impact is an increase of $32,408,680.

Q. Please continue with the description of the columns included in Exhibit No. ____ (MCP-5), starting with MAOP Deferral Amortization included in Column (P-4).

[3] *Id.* at ¶167 (internal citations omitted).

A. Column (P-4), entitled "MAOP Deferral Amortization," provides a ten-year amortization of the anticipated deferred balance associated with the approval in Docket No. UG-160787 of Cascade's request for deferred accounting treatment of incremental costs to implement the Maximum Allowable Operating Pressure ("MAOP") Determination and Validation Plan submitted to the Commission on April 29, 2016, under Docket No. PG-150120. In the last general rate case, Docket UG-170929, all parties agreed to let Cascade recover pre-code pipe replacement expenses from ratepayers[4] over a 10-year amortization period,[5] beginning on August 1, 2018. The deferred balance is anticipated to be $10,855,097. The net income effect is a reduction of $679,045.

Q. Please describe Exhibit No. __ (MCP-6).

A. Exhibit No. __ (MCP-6) identifies each project included in the Company's proposed pro forma adjustment for projects completed after the test year. The intent of the analysis is to comply with the Commission's previous guidance regarding the parameters for the inclusion in rate base of pro forma adjustments based on the most recent updated capital budget. The first column (A) identifies the function. The second column (B) identifies the funding project number and name. The third column (C) identifies the primary FERC account number for the project. The fourth column (D) identifies the most up to date expected cost of the project. The sixth column (F) identifies the Washington portion of the project. The seventh column (G) identifies the amount included in the current request for recovery. The eighth column (H) identifies

[4] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Partial Joint Settlement Agreement at ¶ 20 (May 17, 2018).
[5] *Id.* at 22

the footnote which provides the support for inclusion or exclusion in the current request for recovery. Finally, the last column (I) identifies the expected in-service date.

Q. Please explain where the justification or support for including each project is included in Exhibit No. ____ (MCP-6).

A. The support or identified benefit of adding each project is included on Page 3 of the exhibit.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit No. __ (MCP-2)
Results of Operations Summary Sheet
Witness: Maryalice C. Peters

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MARYALICE C. PETERS

RESULTS OF OPERATIONS SUMMARY SHEET

3/29/2019

Cascade Natural Gas
Results of Operations Summary Sheet
Twelve Months Ended December 31, 2018

		12/31/2018 Results Per Company Filing	Summary of Adjustments	Test Year Adjusted Total	Requested Revenue Increase	Adjusted Results After Proposed Revenues
	SUMMARY SHEET	(1)	(2)	(3)	(4)	(5)
	Operating Revenues					
1	Natural Gas Sales	202,965,796	4,097,028	207,062,824	12,708,529	219,771,353
2	Gas Transportation Revenue	23,006,329	0	23,006,329		23,006,329
3	Other Operating Revenues	(1,487,485)	0	(1,487,485)		(1,487,485)
4	**REVENUES**	224,484,641	4,097,028	228,581,669	12,708,529	241,290,198
	Operating Expenses					
5	Nat. Gas/Production Costs	109,783,204	0	109,783,204		109,783,204
6	Revenue Taxes	19,055,890	166,012	19,221,902	514,950	19,736,852
7	Production	241,633	7,721	249,354		249,354
8	Distribution	19,661,049	1,790,385	21,451,434		21,451,434
9	Customer Accounts	5,462,931	100,058	5,562,989	39,350	5,602,340
10	Customer Service	4,298,252	52,301	4,350,553		4,350,553
11	Sales	1,547	(1,547)	(0)		(0)
12	Administrative and General	17,010,421	(404,132)	16,606,289		16,606,289
13	Depreciation & Amortization	22,725,279	2,139,074	24,864,353		24,864,353
14	Regulatory Debits		0	0		0
15	Taxes Other Than Income	4,268,627	490,764	4,759,392		4,759,392
16	State & Federal Income Taxes	360,753	(337,100)	23,652	2,552,388	2,576,041
17	**Total Operating Expenses**	202,869,587	4,003,535	206,873,122	3,106,688	209,979,810
18	**Net Operating Revenues**	21,615,054	93,493	21,708,547	9,601,841	31,310,388
	Rate Base					
19	Total Plant in Service	780,280,561	69,733,608	850,014,169		850,014,169
20	Total Accumulated Depreciation	(379,049,328)	(2,482,660)	(381,531,988)		(381,531,988)
21	Customer Adv. For Construction	(3,984,824)	79,441	(3,905,383)		(3,905,383)
22	Deferred Accumulated Income Taxes	(75,831,769)	(574,846)	(76,406,616)		(76,406,616)
23	Working Capital Allowance	16,984,937	0	16,984,937		16,984,937
24	**TOTAL RATE BASE**	338,399,577	66,755,542	405,155,119	0	405,155,119
25	**Rate of Return**	6.39%		5.36%		7.73%

Exhibit No. __ (MCP-3)
Revenue Requirement Calculation
Witness: Maryalice C. Peters

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-170929

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MARYALICE C. PETERS

<u>REVENUE REQUIREMENT CALCULATION</u>

3/29/2019

Cascade Natural Gas
Revenue Requirement Calculation
12 Months ended December 31, 2018

1	Adjusted Rate Base	$405,155,119
2	Rate of Return	7.73%
3	Required Return (ln 1 x ln 2)	$31,310,388
4	Adjusted Net Income	$21,708,547
5	Required Net Income Increase (ln 3 - ln 4)	$9,601,841
6	Conversion Factor	0.75554
7	Revenue Increase Required (ln 5 / ln 6)	**$12,708,529**
8	Test Year Adjusted Revenue	$228,581,669
9	Overall Revenue Increase	**5.5597%**

Exhibit No. __ (MCP-4)
Conversion Factor Calculation
Witness: Maryalice C. Peters

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MARYALICE C. PETERS

<u>CONVERSION FACTOR CALCULATION</u>

3/29/2019

Cascade Natural Gas
Results of Operations Summary Sheet
Twelve Months Ended December 31, 2018
REVENUE SENSITIVE COSTS

Revenues	1.00000	
Operating Revenue Deductions		
Uncollectible Accounts	0.00310	
State B&O Tax	0.03852	
UTC Fees	0.00200	0.04362
Interest expense		
State Taxable Income	0.95638	
State Income Tax	0.00000	
Federal Taxable Income	0.95638	
Federal Income Tax @ 21%	0.20084	
Total Income Taxes	0.20084	
Total Revenue Sensitive Costs	0.24446	
RESULTS OF OPERATIONS SUMMARY SHEET		
Net-to-Gross Factor	**0.75554**	

Combo-State & Federal Income Tax	
State	0.00000
Federal	0.21000
State and Federal Effective Tax Rate	0.21

Exhibit No. __ (MCP-5)
Summary of Proposed Adjustments to Test Year Results
Witness: Maryalice C. Peters

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MARYALICE C. PETERS

SUMMARY OF PROPOSED ADJUSTMENTS TO TEST YEAR RESULTS

3/29/2019

Cascade Natural Gas
Proposed Adjustments to Test Year Results
Twelve Months Ended December 31, 2018

		Annualize CRM Adjustment R-1	Promotional Advertising Adjustment R-2	Restate Revenue Adjustment R-3	Restate End of Period (EOP) Adj. R-4	Restate Wages R-5	Executive Incentives R-6	Interest Coordination Adjustment P-1	Pro Forma Wage Adjustment P-2	Pro Forma Plant Additions P-3	MAOP Deferral Amortization P-4	**Total Adjustments**
1	**Operating Revenues**											
2	Natural Gas Sales	684,346		2,733,772	678,910							4,097,028
3	Gas Transportation Revenue									0		0
4	Other Operating Revenues											0
5	**REVENUE**	**$684,346**	**$0**	**$2,733,772**	**$678,910**	**$0**	**$0**	**$0**	**$0**	**$0**		**$4,097,028**
	Operating Expenses											
6	Nat. Gas/Production Costs											$0
7	Revenue Taxes	27,730		110,772	27,509					0		$166,012
8	Production					0			7,721			$7,721
9	Distribution					74,550			856,284		859,551	$1,790,385
10	Customer Accounts	2,118.98		$8,465	$2,102	3,650			83,722	$0		$100,058
11	Customer Service								52,301			$52,301
12	Sales		(1,547)									($1,547)
13	Administrative and General		(22,434)			92	(894,390)		512,600			($404,132)
14	Depreciation & Amortization				1,490,380					648,693		$2,139,074
15	Regulatory Debits											$0
16	Taxes Other Than Income					5,989			88,725	396,050		$490,764
17	State & Federal Income Taxes	137,445	5,036	549,052	(176,627)	(17,699)	187,822	(285,943)	(336,284)	(219,396)	(180,506)	($337,100)
18	**Total Operating Expenses**	167,293	(18,945)	668,289	1,343,365	66,583	(706,568)	(285,943)	1,265,069	825,347	679,045	$4,003,535
19	**Net Operating Revenues**	$517,053	$18,945	$2,065,482	($664,455)	($66,583)	$706,568	$285,943	($1,265,069)	($825,347)	($679,045)	$93,493
20	**Rate Base**											
21	Total Plant in Service				36,939,567					32,794,040		$69,733,608
22	Total Accumulated Depreciation				(2,158,314)					(324,347)		($2,482,660)
23	Customer Adv. For Construction				79,441							$79,441
24	Deferred Accumulated Income Taxes				(513,833)					(61,014)		($574,846)
25	Working Capital Allowance				0							$0
26	**TOTAL RATE BASE**	$0	$0	$0	$34,346,862	$0	$0	$0	$0	$32,408,680		$66,755,542
27	**Revenue Requirement Effect**	**($684,346)**	**($25,075)**	**($2,733,772)**	**$4,392,576**	**$88,126**	**($935,179)**	**($378,460)**	**$1,674,384**	**$4,407,280**	**$898,751**	**$6,704,284**

Exhibit No. __ (MCP-6)
2019 Plant Additions
Witness: Maryalice C. Peters

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MARYALICE C. PETERS

2017 PLANT ADDITIONS

3/29/2019

Cascade Natural Gas
Proposed Plant Additions
12 Months ended December 31, 2018

	(A)	(B)	(C)	(D)	(E)	(F)=(D)*(E)	(G)	(H)	(I)
Line No.	**Function**	**Funding Project - Description**	**Account No.**	**2019 Total - Figures exported from "Power Plan" the company's budget and plant accounting software**	**WA Alloc**	**WA**	**Proposed Adjustment**	**Notes**	**Estimated In-Service Date**
	Gas Intangible	FP-101480 - UG-Work Asset Management	303.00	1,268,624.99	74.85%	949,565.81			
2	Gas Intangible	FP-200064 - UG-Customer Self-Service Web/IVR	303.00	118,850.12	74.85%	88,959.31			
3	Gas Intangible	FP-200663 - UG-GIS Enhancements	303.00	124,010.28	74.85%	92,821.69			
4	Gas Intangible	FP-315865 - UG ThoughtSpot Implementation Project	303.00	101,504.52	74.85%	75,976.13			
5	Gas Intangible	FP-316447 - UG PragmaField Implementation	303.00	19,324.46	74.85%	14,464.36			
6	Gas Intangible	FP-317047 - UG Gas Scada Implement DR System	303.00	56,940.42	74.85%	42,619.90			
7	Gas Intangible	FP-317050 - UG Gas SCADA Upgrade Autosol EFM	303.00	21,160.86	74.85%	15,838.90			
8	Gas Intangible	FP-317101 - UG-JDEdwards AS400 to Oracle DB	303.00	65,552.53	74.85%	49,066.07			
9	Gas Intangible	FP-317103 - UG-PowerPlan Upgrade to 2018.X	303.00	165,560.02	74.85%	123,921.67			
10	Gas Intangible	FP-317297 - UG PragmaFIELD/Dispatcher Licences	303.00	4,517.63	74.85%	3,381.45			
11	Gas Intangible	FP-317322 Arlington Gate Upgrade; Williams Costs	303.00	965,778.40		965,778.40	965,778.40	10	6/1/2019
12		**Total Intangible Plant**		2,911,824.23		2,422,393.70	965,778.40		
13	RESULTS OF OPERATIONS SUMMARY SHEET								
14	Gas Distributior	FP-101170 - MAIN-GROWTH-OREGON	376.00	387,566.00					
15	Gas Distributior	FP-101172 - MAIN-RELO-REPL-OREGON	376.00	398,194.88					
16	Gas Distributior	FP-101176 - SERV-GROWTH-OREGON	380.00	2,844,250.00					
17	Gas Distributior	FP-101177 - SERV-RELO-REPL-OREGON	380.00	170,655.00					
18	Gas Distributior	FP-101178 - STD M&R-GROWTH-OREGON	382.00	111,676.56					
19	Gas Distributior	FP-101179 - STD M&R-RELO-REPL-OREGON	382.00	331,980.91					
20	Gas Distributior	FP-101180 - IND M&R-GROWTH-OREGON	385.00	73,402.08					
21	Gas Distributior	FP-101181 - IND M&R-REMOVE&REPLACE-OREG	385.00	122,336.92					
22	Gas Distributior	FP-101184 - GP TRAN.VEHICLE - OREGON	392.00	729,365.60					
23	Gas Distributior	FP-101186 - GP POWER EQUIP - OREGON	396.00	673,288.56					
24	Gas Distributior	PF-101187 - GP COMM EQUIP - OREGON	397.00	19,663.80					
25	Gas Distributior	FP-101190 - MAIN-GROWTH-WASHINGTON	376.00	2,907,081.16		2,907,081.16		G	
26	Gas Distributior	FP-101192 - MAIN-RELO-REPL-WASHINGTON	376.00	2,628,604.12		2,628,604.12	2,628,604.12	1	12/31/2025
27	Gas Distributior	FP-101194 - R STA-GROWTH-WASHINGTON	378.00	113,770.00		113,770.00		G	
28	Gas Distributior	FP-101196 - R STA-RELO-REPL-WASHINGTON	378.00	929,537.23		929,537.23			
29	Gas Distributior	FP-101197 - SERV-GROWTH-WASHINGTON	380.00	12,633,047.10		12,633,047.10		G	
30	Gas Distributior	FP-101198 - STD M&R-GROWTH-WASHINGTON	382.00	141,074.80		141,074.80		G	
31	Gas Distributior	FP-101199 - STD M&R-RELO-REPL-WASHINGTON	382.00	709,924.80		709,924.80		G	
32	Gas Distributior	FP-101200 - IND M&R-GROWTH-WASHINGTON	385.00	171,169.28		171,169.28		G	
33	Gas Distributior	FP-101201 - IND M&R-REMOVE&REPL-WASHING'	385.00	256,050.84		256,050.84			
34	Gas Distributior	FP-101210 - PRE-CAP MTR-GROWTH-INTERSTAT	381.00	2,947,488.36	74.49%	2,195,584.08		G	
35	Gas Distributior	FP-101259 - PRE-CAP REG-GROWTH-INTERSTAT	383.00	669,513.72	74.49%	498,720.77		G	
36	Gas Distributior	FP-101275 - SERV-RELO-REPL-WASHINGTON	380.00	341,310.00		341,310.00			
37	Gas Distributior	FP-101505 - ARLINGTON GATE UPGRADE	378.00	967,078.48		967,078.48		G	
38	Gas Distributior	FP-200686 - CRM LONGVIEW PIPE REPLACEMEN'	376.00	575,105.22		575,105.22		C	
39	Gas Distributior	FP-200687 - CRM ANACORTES PIPE REPLACEMEI	376.00	2,802,736.39		2,802,736.39		C	
40	Gas Distributior	FP-200688 - BEND PIPE REPL	376.00	2,802,736.39					
41	Gas Distributior	FP-300233 - ARLINGTON 6" HP REINFORCEMENT	376.00	833,125.93		833,125.93			
42	Gas Distributior	FP-300363 - CRM SHELTON PIPE REPLACEMENT	376.00	1,791,361.95		1,791,361.95		C	
43	Gas Distributior	FP-302369 - GB - GROUNDBED WASHINGTON	376.00	526,983.79		526,983.79			
44	Gas Distributior	FP-302370 - GB - GROUNDBED OREGON	376.00	291,706.28					
45	Gas Distributior	FP-302588 - HILDEBRAND BLVD 6" HP MAIN	376.00	29,284.38		29,284.38		G	
46	Gas Distributior	FP-302594 - CRM KELSO PIPE REPLACEMENT	376.00	2,401,110.40		2,401,110.40		C	
47	Gas Distributior	FP-302596 - WALLULA GATE STATION; GTN	378.00	4,088,411.51		4,088,411.51	4,088,411.51	2	12/31/2019
48	Gas Distributior	FP-306987 - BURLINGTON REIN. @ PETERSON RC	376.00	447,715.93		447,715.93			
49	Gas Distributior	FP-306998 - NEW SOUTH WALLA WALLA GATE	378.00	963,378.75		963,378.75		G	
50	Gas Distributior	FP-307212 - CRM KELSO GRADE ST BRIDGE REL(	376.00	394,191.90		394,191.90		C	
51	Gas Distributior	FP-307221 - 8" YAKIMA HP PIPELINE	376.00	2,436,352.30		2,436,352.30	2,436,352.30	4	12/31/2019
52	Gas Distributior	FP-308023 - ERT REPLACEMENT 2019	381.00	12,236,196.65	74.49%	9,114,742.88	9,114,742.88	5	12/31/2019
53	Gas Distributior	FP-312009 - RP;REG STA R-25 BURBANK	378.00	103,618.58		103,618.58			
54	Gas Distributior	FP-316034 - CRM; 4" HP; OTHELLO; 9,801'	376.00	2,528,268.04		2,528,268.04		C	
55	Gas Distributior	FP-316043 - MAOP; 8" HP; BELLINGHAM;1,800'	376.00	349,487.36		349,487.36			
56	Gas Distributior	FP-316045 - MAOP; 8" HP; KALAMA; 600'	376.00	404,455.13		404,455.13			
57	Gas Distributior	FP-316046 - CRM; 8" HP; YAKIMA; 3,727'	376.00	1,276,607.46		1,276,607.46		C	
58	Gas Distributior	FP-316153 - MAOP; 4,6"; BELLINGHAM; 407'	376.00	155,443.13		155,443.13			
59	Gas Distributior	FP-316158 - RP; R-TBD(R-4) MONTESANO	378.00	148,367.69		148,367.69			
60	Gas Distributior	FP-316243 - RF; 4" PE; BEND; 1,200' ARCHIE BRIG	376.00	197,024.53					
61	Gas Distributior	FP-316299 -RP; R-154 (R-26) BREMERTON	378.00	492,208.54		492,208.54			
62	Gas Distributior	FP-316401 - RP; 2,4" BRIDGE XINGS, BAKER CITY	376.00	274,270.17					
63	Gas Distributior	FP-316407 - RF; 4" PE; BEND; 1,500' NW NEWPORT	376.00	184,432.46					
64	Gas Distributior	FP-316429 - RF; 6" HP; ABER; 12,500' BASICH BLV	376.00	2,282,179.72		2,282,179.72	2,282,179.72	6	12/31/2019
65	Gas Distributior	FP-316431 - RF; 6" PE; ABER; 1,200' OAK ST	376.00	277,492.69		277,492.69		G	
66	Gas Distributior	FP-316569 - C/M RPL; 12" STL HP, LONG/KELSO PI	376.00	3,387,285.01		3,387,285.01			
67	Gas Distributior	FP-316573 - RPL; 4" HP, MADRAS PH2	376.00	2,306,938.46					
68	Gas Distributior	FP-316575 - RPL; 6" HP, BEND HP PH2	376.00	1,620,273.71					
69	Gas Distributior	FP-316579 - CRM; 2,6,8" HP; ANACORTES; PH2	376.00	1,128,679.66		1,128,679.66		C	
70	Gas Distributior	FP-316586 - RP; R-TBD ARLINGTON GATE	378.00	1,038,473.63		1,038,473.63	1,038,473.63	7	12/31/2019
71	Gas Distributior	FP-316587 - RF; R-TBD; WALLULA GATE STATIOI	378.00	963,617.88		963,617.88		G	
72	Gas Distributior	FP-316670 - RF; 12" HP; KENN; WALLULA HP LINE	376.00	7,244,612.32		7,244,612.32	7,244,612.32	8	12/31/2019
73	Gas Distributior	FP-316822 - RP; O-11(O-4) LAWR; BELLINGHAM	378.00	142,071.15		142,071.15			
74	Gas Distributior	FP-316823 - RP; O-12 (O-5) DEMI; BELLINGHAM	378.00	142,071.15		142,071.15			
75	Gas Distributior	FP-316845 - O-9 Replacement South Hermiston Gat	378.00	194,009.60					
76	Gas Distributior	FP-316865 - RP; 8" HP; CHIC; 30' V-08 & HP MAIN	376.00	187,720.50		187,720.50			
77	Gas Distributior	FP-316923 - CRM RPL 8" MARCH POINT PH 2	367.00	2,534,003.84		2,534,003.84		C	
78	Gas Distributior	FP-316939 - R-1 Burlington Outlet Piping	376.00	323,673.00		323,673.00		G	
79	Gas Distributior	FP-316940 - R-162 Burlington Replacement	378.00	179,104.89		179,104.89		G	
80	Gas Distributior	FP-316958 - FRL 400' 6" PWX MN, CRESENT HARB	376.00	138,053.53		138,053.53			
81	Gas Distributior	FP-316978 - RF; REG STA R-124, STEPTOE, KENN	378.00	164,966.50		164,966.50		G	
82	Gas Distributior	FP-317060 - FRL; 10" HP; BELL; 2000'	376.00	1,028,640.41		1,028,640.41	1,028,640.41	9	8/26/2019
83	Gas Distributior	FP-317219 - RP; 8" BRIDGE XING, WALLA WALLA	376.00	213,529.89		213,529.89			

Cascade Natural Gas
Proposed Plant Additions
12 Months ended December 31, 2018

	(A)	(B)	(C)	(D)	(E)	(F)=(D)*(E)	(G)	(H)	(I)	
Line No.	**Function**	**Funding Project - Description**	**Account No.**	**2019 Total - Figures exported from "Power Plan" the company's budget and plant accounting software**	**WA Alloc**	**WA**	**Proposed Adjustment**	**Notes**	**Estimated In-Service Date**	
84	Gas Distributior	FP-317307 - Repl MN/Bore @Purcell Blvd Bend	376.00	136,401.32						
85	Gas Distributior	FP-317332 - 1780' 4" PE & Steel MN Burbank Simp	376.00	139,882.25		139,882.25		G		
86				95,786,292.17		77,871,967.94	29,862,016.89			
87	Gas General	FP-101164 - General Purpose Communication Equip	397.00	78,151.00	74.85%	58,496.02				
88	Gas General	FP-101204 - GP TRAN. VEHICLE - WASHINGTO	392.00	1,182,172.56		1,182,172.56				
89	Gas General	FP-101206 - GP POWER EQUIP - WASHINGTON	396.00	1,727,285.36		1,727,285.36				
90	Gas General	FP-101207 - GP COMM EQUIP - WASHINGTON	397.00	19,663.80		19,663.80				
91	Gas General	FP-101213 - GP BUILDINGS - INTERSTATE	390.00	15,126.00	74.85%	11,321.81				
92	Gas General	FP-101215 - GP TRAN. VEHICLE - INTERSTAT	392.00	82,976.20	74.85%	62,107.69				
93	Gas General	FP-101216 - GP TOOLS - INTERSTATE	394.00	143,849.46	74.85%	107,671.32				
94	Gas General	FP-101237 - GP TOOLS - PENDLETON	394.00	51,529.24						
95	Gas General	FP-101255 - GP TOOLS - ONTARIO	394.00	16,336.08						
96	Gas General	FP-101261 - GP TOOLS - WENATCHEE	394.00	13,815.08		13,815.08				
97	Gas General	FP-101269 - GP OFFICE EQUIP - YAKIMA	391.00	13,109.20		13,109.20				
98	Gas General	FP-101305 - GP OFFICE EQUIP - MT. VERNON	391.00	15,126.00		15,126.00				
99	Gas General	FP-101307 - GP TOOLS - MT. VERNON	394.00	47,899.00		47,899.00				
100	Gas General	FP-101326 - GP TOOLS _ BREMERTON	394.00	98,924.04		98,924.04				
101	Gas General	FP-101344 - GP TOOLS - LONGVIEW	394.00	41,344.40		41,344.40				
102	Gas General	FP-101362 - GP TOOLS - ABERDEEN	394.00	29,243.60		29,243.60				
103	Gas General	FP-101398 - GP TOOLS - TRI - CITIES	394.00	38,319.20		38,319.20				
104	Gas General	FP-101416 - GP TOOLS - WALLAWALLA	394.00	25,714.20		25,714.20				
105	Gas General	FP-101451 - GP TOOLS - YAKIMA	394.00	26,218.42		26,218.42				
106	Gas General	FP-200661 - Data Center & Network Equipment	391.00	37,815.00	74.85%	28,304.53				
107	Gas General	FP-200662 - Personal Computers & Peripherals	391.00	113,041.64	74.85%	84,611.67				
108	Gas General	FP-306967 - DISTRICT OFFICE ACCESS CONTROL	391.00	125,738.62	74.85%	94,115.36				
109	Gas General	FP-307020 - Longview - New Operations Bldg 2018	390.00	1,966,245.17		1,966,245.17	1,966,245.17	3	3/1/2019	
110	Gas General	FP-316832 - Office Structures & Equip-GO	391.00	75,630.00	74.85%	56,609.06				
111	Gas General	FP-316853 - Verizon 3G Modem Replacement	397.00	299,529.04	74.85%	224,197.49				
112	Gas General	FP-316915 - Pur replacment display devices	391.00	49,915.80	74.85%	37,361.98				
113	Gas General	FP-317120 - Purch Training Props for Sunnyside	394.00	58,789.72	74.85%	44,004.11				
114	Gas General	FP-317191 - Security System - Yakima facility	390.00	20,168.00		20,168.00				
115	Gas General	FP-317290 - Building remodel for Bellingham Dis	390.00	201,680.00		201,680.00				
116	Gas General	FP-317291 - Roof replacement/Parking lot - Bell	390.00	65,546.00		65,546.00				
117		**Total Distribution Plant**		6,680,901.83		6,341,275.05	1,966,245.17			
118		**Total**		105,379,018.23		**86,635,636.69**	**32,794,040.46**			0

119	Notes:									
120						FERC	Budgeted 2019	Depr. Rate	Depreciation	
121	C	CRM		15,432,064.86		Acct	Investment	UG-150762	Expense	
122	G	Growth		23,378,850.81		303	965,778.40	12.81	123,716.21	
123			Total	38,810,915.67		367	0.00	1.82	0.00	
124						376	15,620,388.87	1.25	195,254.86	
125						378	5,126,885.14	1.92	98,436.19	
126						380	0.00	3.88	0.00	
127						381	9,114,742.88	2.27	206,904.66	
128						382	0.00	1.86	0.00	
129						383	0.00	2.32	0.00	
130						385	0.00	2.18	0.00	
131						390	1,966,245.17	1.24	24,381.44	
132						391	0.00	0.05	0.00	
133						392	0.00	6.15	0.00	
134						394	0.00	3.56	0.00	
135						396	0.00	5.18	0.00	
136						397	0.00	0.13	0.00	
137					Totals		32,794,040.46		648,693.37	0.019780831
138										
139							0.00			

Cascade Natural Gas
Summary of Proposed Plant Additions
12 Months ended December 31, 2018

Note:	Funding Project #	Explanation and Support
1	101192	Blanket work order. This project is routine in nature and typically have offsetting benefits. The Blanket Funding project are for forced relocates. A forced relocate is where the city or municipality requires Cascade to move facilities under the franchise agreement.
2	302596	High pressure pipeline #1 in the Kennewick District, referred to as the Attalia pipeline, is an 8-inch pipeline that was installed in 1958. The pipeline begins at the gate station north of Pasco, WA and ends at the Boise Cascade facility along Highway 12 north of the Wallula Junction, covering approximately 17 miles and serving east Pasco and Burbank. It provides service to Boise Cascade, Tyson Foods, Con Agra Foods/Lamb Weston, Oregon Potato, Western States Asphalt, and other industrial customers.
3	307020	Construct new Longview district office building.
4	307221	The natural gas system for the cities of Yakima and Union Gap have developed pressure concerns and are unable to maintain minimum delivery levels under normal operating conditions. This past winter the Yakima system had to go on bypass to help maintain operating pressures but major concerns still remain in regard to pressures and flows feeding regulators and at the end of the IP system.
5	308023	Two-year Measurement project to replace 40G outdated automatic meter reader known as encoder receiver transmitter (ERT). Replacing 40G model with modern style 100G ERT. Approximately 238,000 ERTs to be replaced throughout project timeline.
6	316429	The City of Aberdeen has large areas with low pressure issues. Aberdeen's primary high pressure feed starts at the McCleary Gate Station and extends to the west for approximately 40 miles as it feeds numerous towns before reaching the end in Aberdeen. The gas system displaces great pressure throughout this long stretch of pipe, and the high large volume customer demand in Aberdeen is adding on to the loss in pressure. To strengthen the gas system there are two reinforcement phases that need to take place. This proposal is focused on the last phase which contains a reinforcement of approximately 14,900-ft. of 6-in. high pressure steel pipe.
7	316586	Gate upgrade allows for additional capacity. The current gate is near capacity. Gate piping is unvalidated. Cascade will take over regulation, heat and install new odorizer.
8	316670	New HP line from new Wallula gate to backfeed Attalia line.
9	317060	City of Bellingham is redoing a bridge crossing and we need to relocate our 10" HP going across. Taking place in 2019 in Bellingham, WA off Ellis St. and State St. Requires a pipe installation of approx. 2100' of 10" HP.
10	317322	Cascade taking over regulation from Williams at the Arlington gate statio due to overexceeding contractial capacity. This FP will oversee from Williams side.

Exhibit No. __ (MPP-1T)
Docket No. UG-19____
Witness: Michael P. Parvinen

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-19______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF MICHAEL P. PARVINEN

March 29, 2019

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. How long have you been employed by Cascade?

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

Q. What are your educational and professional qualifications?

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

I have testified numerous times before both the WUTC and the Public Utility Commission of Oregon ("OPUC"). I have also analyzed or assisted in the analyses of numerous other utility rate filings and participated in many utility rulemaking proceedings before the WUTC. Finally, I attended the Seventh Annual Western Utility

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

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony will cover several areas. First, I will address the impact of regulatory lag on the Company and describe the Company's proposals in this case to mitigate the impact of regulatory lag. Second, I will also address the calculation of working capital that the Company has proposed for inclusion in its revenue requirement in this case. Third, I will address the conservation targets included in the settlement approved by the Commission in Docket UG-152286 and describe why the targets are no longer necessary nor appropriate.

Q. Are you sponsoring any exhibits in this proceeding?

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

Exhibit No. __ (MPP-2)

Exhibit No. __ (MPP-3)

Exhibit No. __ (MPP-4)

III. REGULATORY LAG AND COMPANY PROPOSAL

Q. Please describe what is meant by the term regulatory lag.

A. Regulatory lag refers to financial impact on the utility caused by the timing difference between when investments and costs are incurred and when they are recognized in rates. For example, if the Company replaces a distribution facility in March 2018, but does not file a rate case until March 2019, and rates from the case are not effective for another eleven months, the Company will bear the full cost of the investment for a 23-

month period. Even if the Company files annual rate cases, there can be a substantial lag between the timing of an investment and its inclusion in rates, after accounting for the use of a historical test period with limited pro forma capital additions and the suspension period. Because of these effects, regulatory lag typically erodes a utility's earning, particularly when rates are set using historical test periods.

In addition, regulatory lag can warp the price signal sent to customers because the delay in cost recovery means that customers make conservation and investment decisions based on historic and inaccurate costs and perhaps delay or suspend acquisition of more efficient equipment. This can be harmful to customers who should understand the full cost of the services provided to them.

Q. How can utilities reduce the impact of regulatory lag?

A. From a utility perspective, a company can file frequent rate cases. But, as noted above, even that approach does not fully mitigate the impact of regulatory lag. A company can also try to reduce expenses to offset the impact of regulatory lag and reduce investment on non-revenue producing investments.[1] However, cost management strategies to combat regulatory lag are largely insufficient during periods when the utility continues to make capital investments because the cost savings are overwhelmed by the unrealized returns associated with in-period capital investment. A utility can also try to reduce the costs associated with adding new customers so that the revenue generated by the new customers offset the increased costs that are not yet in rates. Unfortunately, this strategy relies on a utility's ability to find savings in the cost of line

[1] Typically, if an investment generates revenues, those revenues are also subject to regulatory lag and can offset the impact of regulatory lag on the investment.

extensions to new customers that are not passed on to customers.

Q. Has Cascade taken actions to mitigate the impact of regulatory lag?

A. Yes—although these actions have not been sufficient to address the continued regulatory lag experience. As Company witness Ms. Nicole Kivisto describes in her testimony, the Company works diligently to reduce expenses to the extent it can and has been successful in many ways. However, as Ms. Kivisto also points out, Cascade continues to make substantial investments to maintain a safe and reliable distribution to serve customers. These investments far exceed cost savings and, with delayed cost recovery because of regulatory lag, the investments make current revenues insufficient to provide an opportunity to earn an adequate return.

Cascade also modified its line extension policy in Docket UG-160967 to essentially allow a longer payback of initial investment by new customers. The line extension modification was intended to help expand natural gas into unserved and underserved areas, based on the recognition that the direct use of natural gas is a more efficient alternative to building natural-gas-fired electric generation to meet increased electric loads. As a result, adding customers creates a revenue shortfall in the early years as recovery of the investment is deferred, thereby compounding the negative impact of regulatory lag.

Q. Can the Company prudently avoid making ongoing capital investments in its distribution system, in order to reduce the impact of regulatory lag?

A. No. Cascade believes that its ongoing investments in its distribution system are required to prudently manage its system. Cascade takes its obligation to provide a safe and reliable system very seriously and that obligation requires the Company to continually monitor its seventy-year-old system and proactively replace facilities that have reached the end of their useful life and make necessary upgrades to ensure the continued provision of safe and reliable service. And the need to continually invest in these improvements inevitably results in regulatory lag.

Q. But doesn't the Company already have a Cost Recovery Mechanism for Pipeline Replacement (CRM) that allows Cascade annual recovery of certain system investments, to reduce regulatory lag?

A. Yes. The Company does have a CRM that allows for annual recovery of certain capital investments. However, the CRM is limited to investments that have been identified through the current Distribution Integrity Management Plan ("DIMP") which focusses on the highest priority system integrity projects. As evidenced by the significant pro forma capital additions included in this case, much of the Company's investment is directed to upgrading the system to ensure continued reliability and those investments are not recovered through the CRM.

Q. What is Cascade's proposal in this case to address regulatory lag?

A. Cascade requests approval to use an end-of-year or end-of-period ("EOP") calculation of all rate base items—except for working capital—depreciation expense and number of customers.

Q. Why is the Company *not* proposing to use EOP for working capital?

A. The Company is not proposing to use an EOP approach to working capital because this approach would not lead to a representative level of working capital for the expected rate year. I will provide a more detailed explanation later in my testimony.

Q. Why does the Company request using EOP balances for rate base, depreciation expense, and revenue based on the end-of-year customer count?

A We make this request to better match the rate base, depreciation expense, and revenue with the year in which new rates (rate year) will be in effect.

Q. How does the Company's proposal more closely match the rate year?

A. Using balances at the end of the test period better reflects conditions that will exist during the rate year. For example, the number of customers at the end of the test period is more likely to match the number of customers during the rate year, as compared to the number of customers at the beginning of the test period. The same is true for rate base balances—because the end of the test year is closer in time to the rate year, it better reflects the actual conditions and plant balances that will exist when rates are in effect.

If, instead of using EOP for these items the Company were to use the average of monthly averages ("AMA") calculation, then, for example, a customer added in December of the test year, the test period would include only one month's worth of revenue from that customer. Similarly, if a plant investment came into service in December, the test period rate base balance would include only one month's worth of costs for that new plant investment. But in both cases, the new customer would be served for the entire rate year and the new plant would be in-service for the entire rate year.

Q. Given that EOP rate base assumes that the investments made in the test year are in service the entire year, does the Company's proposal treat the corresponding revenues in the same fashion?

A. Yes. Because the investment is treated as if it were in service for the entire year, the Company's proposal assumes that the revenues generated by that investment were received by the Company for the entire year. In this way, the Company's proposal appropriately matches rate base and revenues.

Q. Why is the depreciation expense adjusted based on EOP plant?

A. Again, this is done in order to properly match the depreciation expense with the investment and the revenues. A potential problem with using EOP rate base is that it can distort the test period relationships when only one element is based on EOP balances. The Company's approach here reasonably addresses that concern by using EOP balances for rate base, depreciation expense and customer-count-dependent revenue.

Q. Could the same argument be made for all expenses?

A. Theoretically yes. However, Cascade has used traditional pro forma adjustments for major known and measurable changes and even though one could argue that most expenses are subject to consumer price index ("CPI") increases, Cascade is willing to accept the regulatory lag associated with these cost pressures.

Q. Has the Commission accepted the use of EOP rate base in other proceedings?

A. Yes. The Commission has recognized that using EOP rate base is one effective tool for reducing regulatory lag and has accepted EOP rate base in many recent rate cases filed by Puget Sound Energy, Avista, and PacifiCorp. In this way, the use of EOP rate base has been regularly used to help alleviate regulatory lag. In fact, in Cascade's last rate case the Commission specifically suggested using EOP rate base to mitigate regulatory lag.[2] In this way, Cascade is responding directly to the Commission's suggestion.

Q. What is the impact of the Company's EOP adjustment?

A. As can be seen in Exhibit ____(MCP-5), column R-4, entitled "Restate End of Year", the company is proposing additional revenues of $678,910. These revenues are calculated and described in the testimony of Isaac D. Myhrum Exhibit (IDM-1T). The depreciation expense adjustment is calculated by annualizing the depreciation expense applied to the end of period plant and appears in witness Maryalice Peters Exhibit ____(MCP-5), column R-4, entitled "Restate End of Year". The rate base adjustment is found in Ms. Peter's rate base work papers. The net impact of the "Restate End of Year" adjustment is a revenue requirement increase of $4,392,576.

Q. Earlier, you said that you did not propose an EOP adjustment for working capital because this approach would not lead to an amount representative of the rate year. Please explain why.

A. Working capital represents the amount of funds provided by shareholders to run the day-to-day operations of the business. The amount of working capital over the course of a year can include many increases and decreases and is typically a more volatile figure than, for example, rate base or customer count. Because working capital balances are more volatile it makes sense to use a yearly average, instead of a single point in time, which is unlikely to reflect the actual working capital balance during the rate year.

[2] *Wash. Utils. & Transp. Comm'n v. Cascade Nat. Gas Corp.*, Docket UG-170929, Order 06, ¶ 37 (July 20, 2018).

Q. Have you prepared an exhibit demonstrating the volatility associated with trying to use a point in time calculation for working capital?

A. Yes. Exhibit ____ (MPP-2) shows a summary of each month of total working capital (prior to allocation to states). The AMA calculation is shown at the top. This exhibit shows that using a single point in time is problematic and not representative of the rate year.

Q. You mentioned earlier in your testimony that the Enbridge explosion had an impact on the monthly working capital calculation. Can you explain this further?

A. Yes. Because of the Enbridge explosion, Cascade's gas costs incurred in December 2018 were approximately $25 million more than the amount included in customers' rates—meaning that the accounts payable for gas costs were $25 million higher than they otherwise would have been. Also, deferred gas costs were $25 million more than they otherwise would have been. The impact was to reduce working capital on a standalone basis by $25 million.

Q. How did Cascade pay for the increased gas costs and how would that impact the working capital calculation?

A. In January 2019, Cascade acquired $30 million of short-term debt to pay for the gas costs accrued in December 2018 and expected gas costs incurred in January. The impact of the transaction would be an increase in debt and a reduction to the gas costs accounts payable. The standalone impact would be an increase in working capital of $30 million. These two events, the $25 million in accounts payable in 2018 and the $30 million of acquired debt to cover the December gas costs, illustrate why a one-month point in time look does not present an accurate picture of working capital. To make the working capital adjustment representative of the Company's actual circumstances, the working capital calculation should consider the whole cycle of transactions during the test year. Therefore, the AMA-based result presented in my Exhibit ____ (MPP-2), portrays the most appropriate picture of Cascade's working capital.

Q. If the Commission were to require all components of rate base to match and thus require EOP working capital, would an adjustment to reflect the impact of the Enbridge explosion be appropriate?

A. Yes. As demonstrated earlier regarding the timing of the event on increased gas costs and the payment of such gas costs an adjustment would be required.

Q. Is there Commission precedent accepting an adjustment to the balance sheet for purposes of calculating working capital?

A. Yes. In Docket UG-920840, the Commission accepted a company proposal to adjust the balance sheet for a known and measurable event.

Q. Is Cascade proposing any other adjustments impacting revenue requirement to address regulatory lag?

A. Yes. Cascade is proposing a return on equity that incorporates factors such as regulatory lag. Ms. Bulkley testifies that a reasonable return on equity for Cascade is 10.30 percent and that the 10.3 percent recommendation is based on regulatory risk including regulatory lag.

Q. Has Cascade quantified the impacts of regulatory lag on the Company?

A. Yes. Cascade has attempted two separate calculations to identify the amount of regulatory lag it has experienced and will experience.

Q. Please describe the quantification of the lag that Cascade has experienced.

A. Exhibit ____ (MPP-3) provides such quantification,

Q. Can you please describe Exhibit ____ (MPP-3)?

A. This exhibit shows the results of operations since 2015 based on the Commission Basis Reports (CBRs) filed with the Commission along with the 2018 per books results included in this filing. I then compared the results to the Company's most recent authorized rate of return to determine the annual deficiency. I then calculated the average annual deficiency over the last four years to be $3,326,927.

Q. Can you now describe how Cascade will experience regulatory lag as a result of this rate case?

A. Yes. Even with the acceptance of the Company's proposed Pro Forma Plant Additions adjustment there is additional 2019 investment that will not be included in rates until some future rate case. Cascade, in Exhibit ___(MPP-4), provides a calculation of the revenue requirement on projected 2019 investments not addressed elsewhere.

Q. Can you elaborate on what you mean by investment not already addressed elsewhere?

A. Yes. I start with the capital additions forecast to be completed in 2019 and in service prior to rates going into effect. I then reduce the total investment by those projects included in Cascade's proposed pro forma capital addition adjustment sponsored by Ms. Peters. I further reduce the 2019 investment by those projects that will be included in the annual Pipeline Cost Recovery Mechanism. Finally, and in order to recognize added new customers, I further reduce the adjusted total by recognizing growth related projects as the additional revenues these projects are expected to produce will at least partially offset the return on the added investment.

Q. What is the result of this analysis?

A. The calculation shows that the revenue requirement associated with proposed 2019 investment that will not be recovered by the time rates go into effect is $1,830,212.

Q. If the Commission doesn't accept the Company's full pro forma plant adjustment is the regulatory lag further compounded?

A. Absolutely. The total 2019 investment doesn't change, so any change to the allowed recovery of projects increases the category of costs not recovered when rates go into effect.

Q. Based on the amount of regulatory lag identified in the exhibit, how much of an equity increase would be needed to provide recovery of the investment?

A. Approximately 70 basis points.

IV. REMOVAL OF CONSERVATION TARGET COMMITMENT FROM DOCKET UG-152286

Q. What is Cascade's recommendation regarding the conservation target commitment approved by the Commission in Docket UG-152286?

A. Cascade recommends that it be relieved of its commitment. The Company has worked hard to develop a comprehensive conservation program and the commitment to meeting the identified target approved years ago is no longer necessary.

Q. Please describe the Cascade conservation targets commitment that was approved as part of the settlement in Docket UG-152286.

A. In the Stipulation approved in UG-152286, Cascade agreed to take a number of actions relevant to its conservation efforts. Cascade agreed to file an annual plan, submit an annual report, hold quarterly advisory group meetings, provide advance notice of all filings to the Conservation Advisory Group (CAG), and develop a framework for analyzing Cascade's conservation program, and in addition, the Company agreed to meet 100 percent of its annual conservation target.

Q. What is the status of Cascade's commitment to all these components?

A. Cascade and the members of the CAG have worked hard to address and meet all the identified commitments. The relationship among the CAG members is solid, discussions are open and frank, information is openly shared, and plans are vetted and agreed upon. At the end of the process, the Company's conservation programs are designed with the CAG's full input and evaluation. However, despite diligent efforts, Cascade has been unable to meet 100 percent of its conservation targets.

Q. Why has the Company not been able to meet its conservation targets?

A. Cascade believes that this is true for two reasons. The first is that the conservation targets—up until very recently—have not been realistic. These targets were identified based on a study that was performed in 2014and the methods used to get to the actual target were out of date and not consistent with the CAG's preference. The second reason the Company has not been able to meet its conservation targets is that achievement of these targets is largely a function of customer decision-making that we cannot control. Therefore, regardless of how the Company may work to achieve a target, customer behavior will always have a significant impact.

Q. Has the Company recently adopted new targets?

A. Yes. Just this year, the Company hired a third-party consultant to develop a Conservation Potential Assessment to provide more realistic targets. Specifically, the assessment evaluates our service territory, current and historical conservation programs, economics, avoided costs, saturation of programs, new technologies, etc. to determine how much conservation is available in any given year. Based on this work, the Company now has updated targets for 2019.

Q. Given the updated targets, does Cascade believe that it may be appropriate to require the Company to meet them?

A. No, I do not. While the targets are more realistic, the bottom line is that a utility can do everything reasonably possible to support achievement of the targets, but the utility cannot control customer behavior, and targets may be missed nonetheless. Moreover, Cascade believes that the condition requiring Cascade to meet 100 percent of its targets has had the intended effect of focusing Cascade's efforts on working with the parties to improve its conservation programs and processes. However, that goal has been achieved, and it is no longer appropriate to maintain a requirement that Cascade meet the targets.

Q. Are any of the other LDCs in Washington required to meet their conservation targets?

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit No. __ (MPP-2)
Working Capital Summary
Witness: Michael P. Parvinen

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MICHAEL P. PARVINEN

WORKING CAPITAL SUMMARY

3/29/2019

Cascade Natural Gas
Working Capital Summary

Ln #	Month	System Working Capital
1	**AMA 2018**	**21,767,134**
2	Dec-17	29,754,660
3	Jan-18	37,086,898
4	Feb-18	42,014,126
5	Mar-18	38,203,867
6	Apr-18	31,443,194
7	May-18	19,254,046
8	Jun-18	13,774,312
9	Jul-18	8,523,309
10	Aug-18	8,884,426
11	Sep-18	16,497,287
12	Oct-18	15,433,321
13	Nov-18	14,918,850
14	Dec-18	589,276
15	Jan-19	16,500,547

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MICHAEL P. PARVINEN

COMPARISON OF ACTUAL RESULTS TO AUTHORIZED RETURN

3/29/2019

Cascade Natural Gas Corp
Comparison of Actual Results to Authorized Return

Commission Basis Report	2015	2016	2017	2018	
Rate Base	$261,601,210	$270,103,180	$283,776,156	$338,399,577	
NOI	$14,995,826	$18,458,986	$19,201,585	$21,645,054	
Actual ROR	5.73%	6.83%	6.77%	6.39%	
Authorized Return	7.31%	7.31%	7.31%	7.31%	
Conversion Factor	0.75499	0.75499	0.75499	0.75499	Four Year Average Deficiency
Revenue Requirement Deficiency	$ 5,466,592	$ 1,702,746	$ 2,043,010	$ 4,095,359	**$ 3,326,927**

Exhibit No. __ (MPP-4)
2019 Plant Additions not Included for Recovery
Witness: Michael P. Parvinen

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,
Complainant,

v.

CASCADE NATURAL GAS CORPORATION,

Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF MICHAEL P. PARVINEN

2019 PLANT ADDITIONS NOT INCLUDED FOR RECOVERY

3/29/2019

Cascade Natural Gas Corporation
UG 19_____
2019 Plant Additions not Included for Recovery in Current Filing
Twelve Months Ended December 31, 2018

Ln.	A	B	C	D	E
1	2019 Non Recovered Investment from MCP-6			$ 15,030,680.56	
2	2018 Property Tax Rate from MCP-6	1.20769%			
3	Property Tax			181,524.03	
5	Total Investment		Ln 1	15,030,680.56	
6	Depreciation Expense	0.019780831	From Exhibit No. MCP-6	297,319.35	297,319.35
7	Accumulated Depr. (Avg)		Ln 6 / 2	148,659.68	
8	Accum Tax depreciation		Ln 5 *3.75%	563,650.52	
9	Deferred Tax		(Ln 8 - Ln 6) * .21	55,929.55	
10	Accum Def Tax (Avg)		Ln 9 / 2	27,964.77	
11	FIT		Ln 6 * .21		62,437.06
12	Rate Bate			14,854,056.11	
13	Rate Base		14,854,056		
14	ROR from MCP-3		7.728%		
15	Increased NOI on Rate Base		1,147,921		
16	Increase NOI from above		234,882		
17	Net NOI Increase		1,382,804		
18	Conversion Factor from MCP-4		0.75554308		
19	Revenue Requirement to Cover Regulatory Lag		**$1,830,212**		

Exhibit No. __ (BLR-1T)
Docket No. UG-19_____
Witness: Brian L. Robertson

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-19______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF BRIAN L. ROBERTSON

March 29, 2019

TABLE OF CONTENTS

I.INTRODUCTION AND SUMMARY

Q. Please state your name and address for the record.

A. Brian L. Robertson, 8113 W Grandridge Blvd., Kennewick, WA 99336.

Q. By whom are you employed and what is your title and job duties?

A. I am employed by Cascade Natural Gas Corporation ("Cascade" or the "Company") as a Gas Supply Senior Resource Planning Analyst. My job duties include long-term forecasting, market research, upstream modeling, and other duties regarding the Integrated Resource Plan.

Q. Please describe your educational background and professional experience.

A. I am a graduate of Central Washington University with a degree in Actuarial Science. After graduating, I joined Cascade February of 2014 as a Regulatory Analyst. I joined the Gas Supply department in March of 2015 as a Resource Planning Analyst II. In July 2016, I was promoted to Senior Resource Planning Analyst.

Q. Have you previously submitted written testimony to or testified before the Washington Utilities and Transportation Commission ("Commission") or another regulatory commission?

A. Yes. I previously testified before this Commission in Cascade's most recent Washington rate cases, Dockets UG-170929 and UG-152286. I have also testified before the Public Utility Commission of Oregon in Cascade's most recent Oregon rate cases, Docket Nos. UG 347 and UG 305.

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

A. My testimony presents the results of Cascade's Weather Normalization study that I performed for this case. Based on this analysis, I show the adjustments necessary to establish the "normalized" level of therm sales that would have been made during the Test Year if Cascade had experienced "normal" weather during this period. The adjustments that I recommend here only apply to the Company's Residential and Commercial Schedules, 503 and 504.

II.WEATHER NORMALIZATION

Q. As background, please explain the recent history leading to adoption of the Weather Normalization methodology performed by Cascade for this case.

A. In Docket UG-152286, Cascade and Staff worked together to formulate the Company's Weather Normalization methodology in use today.[1] This same methodology was used to set rates in Docket UG-170929.[2] The agreed-upon methodology is a linear regression model that examines five-years of historical therm usage per customer per month for residential and commercial customers and the monthly heating degree days ("HDDs") for Cascade's four weather locations: Bellingham, Bremerton, Walla Walla, and Yakima. The model produces an intercept that indicates the "base load" therms per customer. The model also provides a best fit coefficient of use per customer for each month and weather location for both the residential and commercial customer classes. The best fit coefficient represents the heat sensitivity use per customer per HDD. The regression results can be found in exhibit BLR-2. The "normal" HDDs and actual customers from the Test Year are applied to the heat sensitive coefficient to produce normalized therms for the Test Year.

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[1] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-152286, Order 04 at ¶¶ 13 and 32 (July 7, 2016); *See also*, Exhibit No. JT_1T at 24:14-25:5.
[2] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corporation*, Docket UG-170929, Order 06 at ¶ 81 (July 20, 2018).

The weather normalization adjustment was calculated by the difference between actual recorded therms and the calculated normalized therms.

Q. Has Cascade made any changes to the agreed upon methodology for this case?

A. No, it has not. The Company's as-filed rates reflect the outcomes determined by weather normalization methodology agreed upon in the Company's 2015 rate case.

Q. Please provide the results of Cascade's weather normalization study.

A. The methodology produced the following conclusions and Test Year adjustments: residential therm usage is calculated to be 11,644,753 therms higher than actual sales; and commercial therm usage is calculated to be 6,906,939 therms higher than actual sales. These are provided in cells C18 and D18 of 'Summary – 60' tab in exhibit BLR-3.

Q. Does the Company accept these results?

A. Yes, Cascade accepts the methodology's results for this case. However, the Company believes the methodology could be improved to show results that better reflect the impact weather has on Cascade's residential and commercial customer class usage. To further refine its weather normalization outcomes, the Company is building its data base to include a broader range of results. At a point when Cascade believes its data base is sufficiently robust, it will revisit use of the current methodology and if it is believed to produce less accurate results, it will present its preferred study and results to the Commission in a future rate case.

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. __ (BLR-2)
Weather Normalization Regressions
Witness: Brian L. Robertson

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF BRIAN L. ROBERTSON

WEATHER NORMALIZATION REGRESSIONS

3/29/2019

Exhibit BLR-2 - Weather normalization methodology using linear regression model.
This database is 72 pages, please see file: NEW CNGC Exh BLR-2, 2019.xlsx

Exhibit No. __ (BLR-3)
Weather Normalization Results
Witness: Brian L. Robertson

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	

CASCADE NATURAL GAS CORPORATION

EXHIBIT OF BRIAN L. ROBERTSON

<u>WEATHER NORMALIZATION RESULTS</u>

3/29/2019

Cascade "Backcast" Methodology			
Month	R/S 503 Weather Adj Therms	R/S 504 Weather Adj Therms	Total Adj Therms
Jan-18	3,448,295	2,441,658	5,889,953
Feb-18	(284,968)	41,539	(243,428)
Mar-18	(180,944)	13,885	(167,059)
Apr-18	612,023	350,668	962,691
May-18	1,834,189	841,235	2,675,424
Jun-18	154,731	12,961	167,692
Jul-18	-	-	-
Aug-18	-	-	-
Sep-18	317,638	87,876	405,514
Oct-18	649,827	353,530	1,003,358
Nov-18	2,010,162	853,490	2,863,652
Dec-18	3,083,798	1,910,096	4,993,895
Total	11,644,753	6,906,939	18,551,692

Cascade Natural Gas Corporation
Weather Normalization Adjustment
For Twelve Months Ended 12/31/2018
State of Washington

Line No.	Description	Rate	Therms	Revenues
	Residential			
	Rate Schedule No. 503			
1	Therm Adjustment		11,644,753	
2	Revenue at Restating Rate	$ 0.79053		$ 9,205,526
	Commercial			
	Rate Schedule No. 504			
3	Therm Adjustment		6,906,939	
4	Revenue at Restating Rate	$ 0.73912		$ 5,105,057
5	**Totals**		18,551,692	$ 14,310,583
	Gas Cost			
6	Change in Gas Cost - Residential (WACOG x Adjustment)	$ 0.49569	11,644,753	$ 5,772,187
7	Change in Gas Cost - Commercial (WACOG x Adjustment)	$ 0.49304	6,906,939	$ 3,405,397
8	Totals		18,551,692	9,177,585

1/1/2018

Residential Therms/Customer/Day

Month	Bell	Brem	Walla	Yakima	Bend	Baker	Pend
1/1/2018	8487918	3651458	3676352	2877741	4732072	702826	999109
2/1/2018	8223505	3610719	3185011	2631065	4571779	630592	885746
3/1/2018	6691854	3097499	2566481	2013267	3974307	538431	735856
4/1/2018	4445853	2026229	1495111	1182967	2730347	286362	460315
5/1/2018	2057303	897001	605003	454678	1294166	107008	160569
6/1/2018	1859712	839974	534002	342372	1063401	75466	119424
7/1/2018	1489124	633334	458020	285725	827903	62734	98757
8/1/2018	722204	297376	240378	150156	400770	27332	55891
9/1/2018	1907962	834404	593346	400823	1151860	81385	152867
10/1/2018	4230317	1880573	1138875	829668	2793210	289471	375745
11/1/2018	7394444	3408478	2500587	2191762	4698328	635627	850900
12/1/2018	8283325	3929283	3998992	3188798	5495654	789584	1191316

Commercial Therms/Customer/Day

Month	Bell	Brem	Walla	Yakima	Bend	Baker	Pend
1/1/2018	3881397	2305543	2813610	3484908	2799954	650812	909922
2/1/2018	4119928	2418044	2469845	3400024	2537802	572178	762788
3/1/2018	3063781	1845077	1863152	2301042	2352209	485862	667939
4/1/2018	2260115	1367376	1314604	1539151	1493073	240929	404400
5/1/2018	1141920	691287	561026	652878	859491	117159	187425
6/1/2018	1239124	786943	675475	700387	827978	108344	208840
7/1/2018	976452	624674	576802	647674	675506	98603	194225
8/1/2018	552254	351358	318399	356937	342375	52807	106141
9/1/2018	1258299	825619	756702	930413	884506	122471	275212
10/1/2018	2102461	1418369	1207587	1723533	1549896	250997	431338
11/1/2018	3338416	2042463	2002787	2963337	2373015	485936	772129
12/1/2018	3763136	2491476	3003925	3815580	3217154	713932	1091747

Residential Customers

Month	Bell	Brem	Walla	Yakima	Bend	Baker	Pend
1/1/2018	82425	38762	39039	26784	45025	7182	11143
2/1/2018	82649	38872	39217	26799	45308	7207	11182
3/1/2018	82705	38890	39264	26746	45409	7195	11175
4/1/2018	82701	38913	39285	26615	45539	7168	11122
5/1/2018	82696	38882	39260	26461	45605	7131	11067
6/1/2018	82694	38867	39322	26357	45712	7104	11057
7/1/2018	82671	38865	39382	26262	45780	7069	11021
8/1/2018	82733	38865	39511	26173	45846	7038	11002
9/1/2018	82957	38997	39659	26256	46052	7066	11085
10/1/2018	83279	39184	40031	26667	46299	7161	11230
11/1/2018	83517	39343	40263	26933	46509	7236	11329
12/1/2018	83686	39447	40371	26994	46632	7268	11363

Commercial Customers

Month	Bell	Brem	Walla	Yakima	Bend	Baker	Pend
1/1/2018	10043	4968	5484	5753	6698	1439	1895
2/1/2018	10071	4961	5508	5763	6734	1443	1898
3/1/2018	10086	4971	5507	5751	6722	1442	1891
4/1/2018	10069	4964	5497	5729	6728	1438	1891
5/1/2018	10050	4960	5485	5704	6725	1436	1881
6/1/2018	10021	4941	5477	5680	6716	1434	1871
7/1/2018	10010	4933	5475	5671	6696	1430	1865
8/1/2018	10006	4938	5482	5656	6696	1424	1862
9/1/2018	10006	4940	5492	5655	6710	1431	1863
10/1/2018	10054	4969	5547	5707	6749	1437	1876
11/1/2018	10110	4995	5601	5766	6766	1452	1895
12/1/2018	10137	5013	5622	5799	6783	1458	1900

Weather (65 Ref Temp)

Month	Bell	Brem	Walla	Yakima	Bend	Baker	Pend
1/1/2018	694	655	731	819	879	940	779
2/1/2018	725	670	694	748	855	965	756
3/1/2018	671	601	582	635	778	789	646
4/1/2018	471	431	361	393	571	552	415
5/1/2018	218	162	54	49	213	202	85
6/1/2018	164	150	32	71	138	144	61
7/1/2018	31	30	0	7	25	16	5
8/1/2018	53	35	4	12	52	46	13
9/1/2018	192	129	69	171	267	256	129
10/1/2018	433	368	360	480	520	577	442
11/1/2018	546	539	686	823	801	877	734
12/1/2018	718	708	786	942	0	0	0

Weather (60 Ref Temp)

Month	Bell	Brem	Walla	Yakima	Bend	Baker	Pend
1/1/2018	539	500	576	664	724	785	624
2/1/2018	585	530	554	608	715	825	616
3/1/2018	516	446	427	480	623	634	491
4/1/2018	321	288	224	251	421	402	269
5/1/2018	76	51	13	11	98	82	25
6/1/2018	52	46	6	23	57	53	10
7/1/2018	1	4	0	0	8	5	0
8/1/2018	5	3	0	1	11	15	1
9/1/2018	59	31	7	69	133	132	37
10/1/2018	278	214	206	326	366	424	287
11/1/2018	396	389	536	673	651	727	584
12/1/2018	586	553	631	790	782	951	700

Monthly Normals (1981-2010)

65 Base	Yakima	Walla	Brem	Bell	Pend	Bend	Baker
1	1057	914	694	799	921	999	1240
2	809	725	599	680	742	834	995
3	676	580	589	644	617	777	849
4	477	384	488	498	432	620	646
5	261	208	374	345	246	427	435
6	98	62	247	200	83	217	225
7	19	2	165	101	7	68	67
8	28	4	153	95	8	81	80
9	160	86	196	235	112	250	290
10	496	367	395	471	407	547	637
11	830	694	578	654	710	829	958
12	1128	975	730	827	986	1068	1246

60 Base	Yakima	Walla	Brem	Bell	Pend	Bend	Baker
1	900	760	589	645	766	845	1085
2	669	585	501	539	602	694	855
3	523	426	439	488	462	622	694
4	331	243	306	348	285	471	496
5	144	101	160	197	129	288	289
6	33	15	52	75	23	112	116
7	3	1	8	16	0	20	18
8	4	1	4	14	0	22	22
9	73	30	51	104	44	141	169
10	347	230	245	319	268	394	484
11	680	546	464	504	560	679	808
12	975	823	628	679	831	913	1091

Bell		Brem		Walla		Yakima	
Variable	**Estimate**	**Variable**	**Estimate**	**Variable**	**Estimate**	**Variable**	**Estimate**
Intercept	0.596554	Intercept	0.539116	Intercept	0.451978	Intercept	0.46634
TREND	0	TREND	0	TREND		TREND	0
1	0.145919	1	0.149789	1	0.119089	1	0.124975
2	0.130381	2	0.13436	2	0.122121	2	0.12927
3	0.123301	3	0.130406	3	0.126111	3	0.121756
4	0.105985	4	0.118857	4	0.095735	4	0.099865
5	0.085486	5	0.100346	5	0.078281	5	0.080131
6	0.066433	6	0.109906	6	0	6	0
7	0	7	0	7	0	7	0
8	0	8	0	8	0	8	0
9	0.061919	9	0.104975	9	0	9	0
10	0.112824	10	0.135075	10	0.074119	10	0.052342
11	0.161704	11	0.168144	11	0.090192	11	0.094841
12	0.149097	12	0.155809	12	0.113279	12	0.115625
ar1	0	ar1	0	ar1	0	ar1	0.456004

		Days in Month
1/1/2018	1	31
2/1/2018	2	28
3/1/2018	3	31
4/1/2018	4	30
5/1/2018	5	31
6/1/2018	6	30
7/1/2018	7	31
8/1/2018	8	31
9/1/2018	9	30
10/1/2018	10	31
11/1/2018	11	30
12/1/2018	12	31
1/1/2019		

Table 1 — Normal HDDs/Day

		Bell	Brem	Walla	Yakima
1/1/2018	1	20.81	19.00	24.52	29.03
2/1/2018	2	19.25	17.89	20.89	23.89
3/1/2018	3	15.74	14.16	13.74	16.87
4/1/2018	4	11.60	10.20	8.10	11.03
5/1/2018	5	6.35	5.16	3.26	4.65
6/1/2018	6	2.50	1.73	0.50	1.10
7/1/2018	7	0.52	0.26	0.03	0.10
8/1/2018	8	0.45	0.13	0.03	0.13
9/1/2018	9	3.47	1.70	1.00	2.43
10/1/2018	10	10.29	7.90	7.42	11.19
11/1/2018	11	16.80	15.47	18.20	22.67
12/1/2018	12	21.90	20.26	26.55	31.45

Table 2 — Actual HDDs/Day

		Bell	Brem	Walla	Yakima
1/1/2018	1	17.37	16.11	18.56	21.42
2/1/2018	2	20.89	18.93	19.77	21.71
3/1/2018	3	16.65	14.37	13.76	15.48
4/1/2018	4	10.68	9.58	7.47	8.35
5/1/2018	5	2.45	1.65	0.42	0.34
6/1/2018	6	1.72	1.53	0.20	0.75
7/1/2018	7	0.03	0.13	0.00	0.00
8/1/2018	8	0.15	0.08	0.00	0.03
9/1/2018	9	1.95	1.02	0.23	2.30
10/1/2018	10	8.97	6.90	6.65	10.52
11/1/2018	11	13.20	12.97	17.87	22.42
12/1/2018	12	18.90	17.84	20.34	25.47

Table 3 — (Normal HDDs/Day - Actual HDDs/Day) * β coefficient

		Bell	Brem	Walla	Yakima
1/1/2018	1	0.501	0.432	0.709	0.951
2/1/2018	2	-0.214	-0.139	0.137	0.282
3/1/2018	3	-0.111	-0.027	-0.002	0.169
4/1/2018	4	0.097	0.073	0.061	0.268
5/1/2018	5	0.334	0.353	0.222	0.345
6/1/2018	6	0.052	0.022	0.000	0.000
7/1/2018	7	0.000	0.000	0.000	0.000
8/1/2018	8	0.000	0.000	0.000	0.000
9/1/2018	9	0.094	0.072	0.000	0.000
10/1/2018	10	0.149	0.135	0.057	0.035
11/1/2018	11	0.582	0.420	0.030	0.024
12/1/2018	12	0.448	0.377	0.703	0.692

Table 4 — Adjustment

		Bell	Brem	Walla	Yakima
1/1/2018	1	1,280,919	519,649	857,759	789,968
2/1/2018	2	(495,689)	(151,462)	150,861	211,323
3/1/2018	3	(285,533)	(32,965)	(2,476)	140,029
4/1/2018	4	241,039	85,564	71,458	213,962
5/1/2018	5	855,393	425,278	270,452	283,065
6/1/2018	6	129,101	25,630	-	-
7/1/2018	7	-	-	-	-
8/1/2018	8	-	-	-	-
9/1/2018	9	233,717	83,921	-	-
10/1/2018	10	385,231	164,076	71,209	29,312
11/1/2018	11	1,458,545	496,146	36,314	19,158
12/1/2018	12	1,163,513	460,965	880,340	578,980

Bell		Brem		Walla		Yakima	
Variable	**Estimate**	**Variable**	**Estimate**	**Variable**	**Estimate**	**Variable**	**Estimate**
Intercept	3.441301	Intercept	4.178669	Intercept	3.692782	Intercept	3.796293
TREND	0	TREND	0	TREND	0	TREND	0
1	0.521483	1	0.684733	1	0.631607	1	0.69262
2	0.46417	2	0.605212	2	0.613702	2	0.674644
3	0.383768	3	0.519383	3	0.57527	3	0.568677
4	0.290758	4	0.4183	4	0.371564	4	0.41835
5	0.220032	5	0.35792	5	0.29234	5	0.313929
6	0	6	0.437205	6	0	6	0
7	0	7	0	7	0	7	0
8	0	8	0	8	0	8	0
9	0	9	0.708506	9	0	9	0.712886
10	0.351783	10	0.605046	10	0.401488	10	0.516248
11	0.507296	11	0.673181	11	0.450992	11	0.511793
12	0.467998	12	0.651743	12	0.549386	12	0.583896
ar1	0	ar1	0	ar1	0.204534	ar1	0.34685

		Days in Month
1/1/2018	1	31
2/1/2018	2	28
3/1/2018	3	31
4/1/2018	4	30
5/1/2018	5	31
6/1/2018	6	30
7/1/2018	7	31
8/1/2018	8	31
9/1/2018	9	30
10/1/2018	10	31
11/1/2018	11	30
12/1/2018	12	31
1/1/2019		

Table 1

Normal HDDs/Day

		Bell	Brem	Walla	Yakima
1/1/2018	1	20.81	19.00	24.52	29.03
2/1/2018	2	19.25	17.89	20.89	23.89
3/1/2018	3	15.74	14.16	13.74	16.87
4/1/2018	4	11.60	10.20	8.10	11.03
5/1/2018	5	6.35	5.16	3.26	4.65
6/1/2018	6	2.50	1.73	0.50	1.10
7/1/2018	7	0.52	0.26	0.03	0.10
8/1/2018	8	0.45	0.13	0.03	0.13
9/1/2018	9	3.47	1.70	1.00	2.43
10/1/2018	10	10.29	7.90	7.42	11.19
11/1/2018	11	16.80	15.47	18.20	22.67
12/1/2018	12	21.90	20.26	26.55	31.45

Table 2

Actual HDDs/Day

		Bell	Brem	Walla	Yakima
1/1/2018	1	17.37	16.11	18.56	21.42
2/1/2018	2	20.89	18.93	19.77	21.71
3/1/2018	3	16.65	14.37	13.76	15.48
4/1/2018	4	10.68	9.58	7.47	8.35
5/1/2018	5	2.45	1.65	0.42	0.34
6/1/2018	6	1.72	1.53	0.20	0.75
7/1/2018	7	0.03	0.13	0.00	0.00
8/1/2018	8	0.15	0.08	0.00	0.03
9/1/2018	9	1.95	1.02	0.23	2.30
10/1/2018	10	8.97	6.90	6.65	10.52
11/1/2018	11	13.20	12.97	17.87	22.42
12/1/2018	12	18.90	17.84	20.34	25.47

Table 3

(Normal HDDs/Day - Actual HDDs/Day) * β coefficient

		Bell	Brem	Walla	Yakima
1/1/2018	1	1.792	1.977	3.759	5.273
2/1/2018	2	-0.763	-0.627	0.690	1.470
3/1/2018	3	-0.347	-0.109	-0.009	0.789
4/1/2018	4	0.267	0.258	0.235	1.123
5/1/2018	5	0.859	1.258	0.830	1.352
6/1/2018	6	0.000	0.087	0.000	0.000
7/1/2018	7	0.000	0.000	0.000	0.000
8/1/2018	8	0.000	0.000	0.000	0.000
9/1/2018	9	0.000	0.484	0.000	0.095
10/1/2018	10	0.465	0.605	0.311	0.350
11/1/2018	11	1.826	1.683	0.150	0.128
12/1/2018	12	1.408	1.577	3.412	3.494

Table 4

Adjustment

		Bell	Brem	Walla	Yakima
1/1/2018	1	557,767	304,457	639,059	940,375
2/1/2018	2	(215,034)	(87,071)	106,479	237,166
3/1/2018	3	(108,379)	(16,782)	(1,584)	140,630
4/1/2018	4	80,510	38,414	38,807	192,937
5/1/2018	5	267,570	193,506	141,107	239,052
6/1/2018	6	-	12,961	-	-
7/1/2018	7	-	-	-	-
8/1/2018	8	-	-	-	-
9/1/2018	9	-	71,750	-	16,125
10/1/2018	10	145,010	93,201	53,449	61,871
11/1/2018	11	553,907	252,190	25,260	22,133
12/1/2018	12	442,386	245,039	594,565	628,106