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

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August 31, 2017

Mr. Steven V. King
Executive Director and Secretary
Washington Utilities & Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

Re: UG-17______, Cascade Natural Gas General Rate Case, Advice No. 17-08-01

Dear Mr. King,

Cascade Natural Gas Corporation ("Cascade" or "Company") herewith submits the attached rate case filing wherein the Company seeks Commission authorization to increase its rates and charges for natural gas services to its customers in the state of Washington. The Company is proposing an overall increase of 2.71% in base rates or $5,884,984 for natural gas service.

As directed by the Washington Utilities and Transportation Commission ("Commission") Records Center, the Company encloses one original and 10 copies of its prepared direct testimony and exhibits, and three copies of work papers showing how test year data was adjusted. A USB containing the electronic version of this filing and all supporting documents is enclosed as well.

This submission includes the following revisions to Cascade's Tariff, WN U-3, stated to become effective with service on and after October 1, 2017:

Thirty-Sixth Revision Sheet No. 2
Third Revision Sheet No. 25
Third Revision Sheet No. 200
Second Revision Sheet No. 200-A
Fifty-Fifth Revision Sheet No. 502
Sixtieth Revision Sheet No. 503
Forty-Fourth Revision Sheet No. 504
Forty-Third Revision Sheet No. 505
Sixtieth Revision Sheet No. 511
Fifty-Fourth Sheet No. 570
Eighteenth Revision Sheet No. 663

The Company also withdraws the following sheets:

Thirty-Ninth Revision Sheet No. 512
Fiftieth Revision Sheet No. 577
Second Revision Sheet No. 577-A

Cascade provides an overview of its proposed changes to its Tariff below. A more in-depth discussion of the changes is included in the Direct Testimony of Jennifer G. Gross, Exhibit No. __ (JGG-1T).

- The basic service charges and base rates in Rate Schedules 503, 504, 505, 511 and 570, and the contract demand charge in Rate Schedule 663 are revised to collect the proposed revenue requirement, as presented in the Testimony and Exhibits of Michael Parvinen, and in the manner those costs are allocated among customer classes, as presented in the Testimony and Exhibits of Ronald J. Amen.

- The gross revenue fee in Rate Schedule 663, which collects the costs for uncollectibles, UTC fees, and State B&O taxes, is going down.

- Schedule 502, Building Construction Temporary Heating and Dry-Out Service is frozen effective October 1; 2017, and the rate components in Schedule 502 are changed to mirror Schedule 503. Future dry-out or building construction customers will be served on Schedule 503.

- The Company proposes removing Schedule 512, Compressed Natural Gas Service and Schedule 577, Limited Interruptible Service Rate. Customers served on these schedules will migrate to Schedule 504, General Commercial Service Rate and 570, Interruptible Gas Service, respectively.

- Consistent with a revised revenue requirement, Cascade proposes changes to the authorized margin revenue per customer as stated on Sheet 25 in Rule 21, Decoupling Mechanism. The revisions to Rule 21 include removing Schedules 512 and 577, and incorporating Schedule 502 with Schedule 503.

- Cascade proposes removing the New Premise Charge, and increasing the Disconnect Charge, the Returned Payment Charge, the Pilot Light Charge, and the Reconnect Charge for regular and for after business hours. These charges are found in Schedule 200, Various Miscellaneous Charges.

- Finally, the Table of Contents (Sheet No. 2) is revised to reflect the removal of Schedules 512, Compressed Natural Gas Service and Schedule 577, Limited Interruptible Service Rate.

In compliance with WAC 480-90-193(1), the Company will post the proposed changes to its tariff on its website: www.cngc.com

Cascade requests the Commission **immediately suspend the operation of the general tariff revisions** included in this filing, and promptly set the matter for hearing, including the establishment of a prehearing conference, at the earliest possible date.

Included with this cover letter are the following attachments:

- Attachment A – The proposed tariffs
- Attachment B – The legislative tariffs
- Attachment C – A summary document on the Company's proposed case as required per WAC 480-07-510.
- Attachment D – The Index of Testimony, Exhibits, and Work Papers
- Attachment E – The List of Files included in the electronic submission
- Attachment F – The Rate Case Compliance Matrix
- Attachment G – Financial Documents required per WAC 480-07-510(7)
- Attachment H – Certificate of Service
- Claim of Confidentiality
- Testimony, Exhibits, and Work Papers
- USB – Contains the electronic files

Please note that certain sections of the exhibits of Ronald J. Amen and Tammy Nygard have CONFIDENTIAL information. Additionally, as required by WAC 480-07-160, the Company is also submitting a Claim of Confidentiality regarding the submission of the unredacted versions of the above-referenced CONFIDENTIAL exhibits and work papers. These documents should be treated as CONFIDENTIAL per WAC 480-07-160.

On the same day as this filing, the Company submits "Cascade Natural Gas Corporation's Motion for a Protective Order Pursuant to WAC 480-07-420."

The Office of Public Counsel is served a hardcopy of all documents included in this filing as well as a USB containing all the electronic files that comprise this submission.

In compliance with WAC 480-90-197, the Company will provide public notice once the public hearing dates have been selected.

In response to the requirement in WAC 480-07-510(3)(i), the Company states it has no additional material affiliated transactions to report impacting the test year that otherwise were not already reported in the Company's annual 2016 Report of Affiliated Interest Transactions. The Company's 2016 annual report was filed on June 8, 2017.[1]

Service of documents pertaining to this filing should be to the following Cascade Natural Gas Corporation representatives:

[1] *See* Docket UG-170303.

Michael Parvinen
Director of Regulatory Affairs
Cascade Natural Gas Corporation
8113 West Grandridge Boulevard
Kennewick, WA 99336-7166
Telephone: (509)734-4593
Facsimile: (509)737-7166
Email: CNGCRegulatory@cngc.com

Lisa Rackner
McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
Telephone: 503-595-3925
Facsimile: 503-595-3928
Email: lisa@mcd-law.com

Additional copies of this filing, supporting testimony and exhibits are available from the Company upon request.

Questions regarding this filing should be directed to Michael Parvinen at (509) 734-4593.

Sincerely,

/s/ Michael Parvinen

Michael Parvinen
Director, Regulatory Affairs
Cascade Natural Gas Corporation
8113 W Grandridge Blvd
Kennewick, WA 99336-7166
michael.parvinen@cngc.com

Enclosures

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT A: PROPOSED TARIFFS

August 31, 2017

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Optional Unbundled Services Listed on Next Page

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 502, 503, 504, 505, 511, and 570. (C)

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, 593, 594, 595, 596, 597, and 598. The amount of Margin Revnue billed and net unbilled amuonts are reduced by the 0.00417 percent to account for uncollectibles.

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**	
502/503	$32.68	$27.48	$22.56	$14.48	$9.24	$6.24	(D)(C)
504	$117.98	$95.78	$79.46	$52.75	$36.30	$28.95	
505	$423.29	$375.82	$340.06	$268.58	$231.03	$191.51	
511	$1,906.04	$2,016.69	$1,623.09	$1,172.66	$1,047.38	$615.94	(D)
570	$2,623.39	$2,022.60	$2,332.27	$1,968.48	$1,581.35	$1,289.96	(D)(C)
Table 2	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	
502/503	$4.90	$4.80	$6.25	$13.73	$25.27	$34.14	(D)(C)
504	$24.02	$25.06	$28.59	$49.63	$84.59	$744.85	
505	$184.03	$220.00	$284.54	$313.88	$423.04	$447.72	
511	$736.98	$670.75	$810.88	$1,231.06	$1,746.33	$2,070.43	(D)
570	$1,446.99	$1,082.52	$1,071.47	$2,242.41	$2,198.15	$2,504.69	(C) (D)

(Continued)

VARIOUS MISCELLANEOUS CHARGES
RATE SCHEDULE 200

APPLICABLITY:
This schedule sets forth the provisions for various charges throughout these rules and regulations. The name and amount of the charges are listed below. The rules or rate schedules to which each charge applies are in parenthesis.

I. Reconnection Charge (Rule 5):

A reconnection charge of twenty-eight dollars ($28.00) will be required to reestablish service between the hours of 8 a.m. and 5 p.m. on weekdays, and a reconnection charge of seventy ($70.00) will be required to reestablish service after 5 p.m. on weekdays and on Saturdays, Sundays, and holidays, except in the case of medical emergency. (I) (I)(T)

II. Disconnect Visit Charge - (Rule 5):

A disconnect charge of twelve dollars ($12.00) may be charged, whenever Cascade is required to visit a customer's address for the purpose of disconnecting service and service is not disconnected. (I)

III. Late Payment Charge – (Rule 6 – Part A):

Unless otherwise specified in the customer's contract, a late payment charge at the rate of 1.0% per bill cycle will be applied to all unpaid balances in accordance with Rule 6 – Part A.

IV. Returned Check Charge - (Rule 6 - Part D):

A returned check fee of twenty-one dollars ($21.00) may apply for any check returned from the bank unpaid. (I)

V**.** Residential Excess Flow Valves – (Rule 8):

In Conjunction With The Construction Of A New Service Line: $ 38.00

Modifying an Existing Service Line:

Time of Construction Crew	up to	$220.00 per hour
Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.		
Installation of the Excess Flow Valve		$ 38.00

The customer will be responsible for any future maintenance or replacement costs that may be incurred due to the excess flow value. Such cost shall be based upon time and materials, as follows:

Time of Construction Crew	up to	$220.00 per hour
Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.		
Installation of replacement Excess Flow Valve, if necessary		$ 38.00

(Continued on next page)

VARIOUS MISCELLANEOUS CHARGES
RATE SCHEDULE 200
(Continued from previous page)

APPLICABLILITY: (continued from Previous Page)

(D)

VI. Tampered Meter Charge (Rule 5): (T)

A meter tampering charge will be billed to a customer who tampers with any part of any service line or meter or any other apparatus of Company. The charge will be the actual costs of damages, repairs or any additional or unusual costs or services directly related to the interference, plus the amount of unbilled gas determined to have been lost plus the applicable reconnect charges will be applied to the customers account.

VI. Pilot Light Service Charge: (T)

A Pilot Light Service charge of twenty-four dollars ($24.00) may be applied to the customer's current bill when the customer requests the company turn-on or turn-off a pilot light or gas insert during regular business hours. (I)

BUILDING CONSTRUCTION TEMPORARY HEATING AND DRY-OUT SERVICE
SCHEDULE NO. 502

AVAILABILITY:
Service under this Schedule shall be frozen as of October 1, 2017. Service under this schedule shall be for natural gas supplied at a permanent point of delivery for use in permanently installed gas heating equipment to be used for temporary heating and dry-out purposes during the period (maximum of six months) that building is under construction and prior to occupancy. (C)

LIMITS OF AVAILABILITY:
Upon occupation or sale, whichever is first after completion of construction or, in any event, after a maximum period not to exceed six (6) months, service under this schedule shall immediately terminate and billings thereafter shall be made under the terms and conditions of the regular applicable rate schedule.

RATE:

	Margin	WACOG	Total		
Basic Service Charge			$6.00	per month	
All gas used per month at	$0.30446	$0.49569	$0.80015	per therm	(R) (I)

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

MINIMUM CHARGE:
Minimum monthly bill $6.00

(R)

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.

(D)

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 resold to others.

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			$ 6.00	per month	(I)
All Gas Used Per Month	$0.30446	$ 0.49569	$0.80015	per therm	(I)

RATE ADJUSTMENT:

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

MINIMUM CHARGE:

Basic Service Charge: $ 6.00 per month (I)

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.

(D)

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 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			$15.00	per month	(I)
All Therms Used	$0.23313	$0.49304	$0.72617	per therm	(R)

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

MINIMUM CHARGE:
Basic Service Charge $15.00 (I)

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.

(D)

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			$75.00	per month	(I)
First 500 therms/month	$0.17779	$0.47993	$0.65772	per therm	(R)
Next 3,500 therms/month	$0.14399	$0.47993	$0.62392	per therm	(R)
All over 4,000 therms/month	$0.13888	$0.47993	$0.61881	per therm	(R)

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

MINIMUM CHARGE:
Basic Service Charge $75.00 (I)

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.

(D)

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.

LARGE VOLUME GENERAL SERVICE RATE
SCHEDULE NO. 511

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			$200.00	per month	(I)
First 20,000 therms/month	$0.14028	$0.47993	$0.62021	per therm	(R)
Next 80,000 therms/month	$0.10753	$0.47993	$0.58746	per therm	(R)
All over 100,000 therms/month	$0.02652	$0.47993	$0.50645	per therm	(R)

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

WEIGHTED AVERAGE COMMODITY GAS COST:
The per them average commodity gas cost unit rate is $0.32009 plus the commodity rate change reflected on Schedule 595.

CONTRACT:
Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve (12) consecutive months' use. The Annual Minimum Quantity is to be negotiated and included as part of the contract but shall in no case be less than 50,000 therms. Said contract shall also state the Maximum Winter Daily Requirement of natural gas that Company agrees to deliver as well as the Maximum Non-Winter Daily Requirement if the Non-Winter requirement is greater than the Winter requirement.

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

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.

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 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.

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INTERRUPTIBLE SERVICE
SCHEDULE NO. 570

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 60,000 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			$500.00	per month	(I)
First 30,000 therms/month	$0.09426	$0.46687	$0.56113	per therm	(I)
All over 30,000 therms/month	$0.02684	$0.46687	$0.49371	per therm	(I)

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

WEIGHTED AVERAGE COMMODITY GAS COST:
The per therm average commodity gas cost unit rate is $0.32009 plus the commodity rate change reflected on Schedule 595.

ANNUAL DEFICIENCY BILL:
In the event customer purchases less than the Annual Minimum Quantity as stated in the contract, customer shall be charged an Annual Deficiency Bill. Annual Deficiency Bill shall be calculated by multiplying the difference between the Annual Minimum Quantity and the therms actually taken ("Deficiency Therms") times the difference between the commodity rate in this Rate Schedule No. 570, as modified by any applicable rate adjustments and the weighted average commodity cost of gas rate as modified by any applicable modifying rate schedules or changes, as such rates are reflected in the Company's tariffs. If service is curtailed or interrupted by Company, the Annual Minimum Quantity shall be reduced by a fraction, the numerator of which is the actual number of days, or fraction thereof, service was curtailed and the denominator of which is 365.

CONTRACT:
Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve (12) consecutive months' use. The Annual Minimum Quantity is to be negotiated and included as part of the contract but in no case shall the Annual Minimum Quantity be less than 60,000 therms which shall include all firm therms, if any. Said contract shall state the maximum daily consumption of natural gas that Company agrees to deliver.

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.

UNAUTHORIZED USE OF GAS:
Gas taken by customer under this schedule by reason of its failure to comply with Company's curtailment order shall be considered as any unauthorized overrun volume. Company shall bill and customer shall pay for such unauthorized overrun at the rate of $0.25 per therm for all gas used between 103% and 105% of the customer's gas day allocation and $0.50 per therm for all gas used in excess of 105%, in addition to the regular charges incurred in the RATE section of this schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun.

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DISTRIBUTION SYSTEM TRANSPORTATION SERVICE
SCHEDULE NO. 663

AVAILABILITY:
This unbundled distribution system transportation service schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part, provided, in the sole judgment of the Company, there are adequate facilities in place at the existing distribution line or as such line may be enhanced by the Company from time to time to provide service.

RATE:
The rates set forth in sections A - D are exclusive of fuel use requirements designed to cover distribution system lost and unaccounted for gas.

A. Contract Demand Charge (Per CD Therms per month) ....$0.22 per month (I)

B. Basic Service Charge $750.00 per month (I)
All customers receiving gas supply service through this schedule will be invoiced a monthly Basic Service Charge for each single metering facility.

C. Delivery Charge For All Therms Delivered Per Month

First	100,000	$ 0.05970 Per Therm Per Month	(I)
Next	200,000	$ 0.02179 Per Therm Per Month	
Next	200,000	$ 0.01324 Per Therm Per Month	
Over	500,000	$ 0.00629 Per Therm Per Month	(I)

D. System Balancing Charge...$.0004 per therm

E. The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company. The current Gross Revenue Fee is 4.431%. (R)

F. Fuel use requirements
Customer served on 663 shall provide the company with in-kind fuel for distribution system lost and unaccounted for gas. The fuel use factor is based on the Company's 5-year average lost and unaccounted for percentage, which shall be updated annually. The current rate is 0.1615%

All other terms and conditions of services shall be pursuant to the Rules and Regulations set forth in the Company's filed tariff.

OTHER SERVICES:
Service under this schedule shall include transportation on the Company's distribution facilities only. Service under this schedule requires customer to secure both gas supply and pipeline transportation capacity services either through the Company or through third party arrangements.

RATE ADJUSTMENTS:
Rates for service under this schedule are subject to various adjustments as specified in Schedule Nos. 593, 595, 596, and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington Utilities & Transportation Commission.

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CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT B: LEGISLATIVE TARIFFS

August 31, 2017

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Optional Unbundled Services Listed on Next Page

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 502, 503, 504, 505, 511, and ~~512,~~ 570~~, and 577~~. (C)

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, 593, 594, 595, 596, 597, and 598. The amount of Margin Revnue billed and net unbilled amuonts are reduced by the 0.00417 percent to account for uncollectibles.

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	
~~502~~	~~$10.38~~	~~$8.51~~	~~$7.43~~	~~$4.82~~	~~$2.86~~	~~$1.47~~	(D)
502/503	$32.68~~$30.89~~	$27.48~~$25.31~~	$22.56~~$21.18~~	$14.48~~$13.29~~	$9.24~~$8.64~~	$6.24~~$5.80~~	(C)
504	$117.98~~$123.03~~	$95.78~~$101.99~~	$79.46~~$82.09~~	$52.75~~$52.56~~	$36.30~~$36.19~~	$28.95~~$28.49~~	
505	$423.29~~$463.97~~	$375.82~~$523.33~~	$340.06~~$416.44~~	$268.58~~$304.64~~	$231.03~~$260.88~~	$191.51~~$210.75~~	(C)
511	$1,906.04~~$2,041.51~~	$2,016.69~~$1,863.54~~	$1,623.09~~$2,265.26~~	$1,172.66~~$1,350.28~~	$1,047.38~~$1,081.41~~	$615.94~~$768.73~~	(D)
~~512~~	~~$744.68~~	~~$817.71~~	~~$890.73~~	~~$779.90~~	~~$862.38~~	~~$863.67~~	(C)
570	$2,623.39~~$2,392.65~~	$2,022.60~~$2,405.61~~	$2,332.27~~$2,046.01~~	$1,968.48~~$1,952.64~~	$1,581.35~~$1,875.99~~	$1,289.96~~$1,575.53~~	(D)
~~577~~	~~$1,171.73~~	~~$1,160.16~~	~~$920.18~~	~~$886.31~~	~~$794.84~~	~~$635.75~~	
Table 2	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	
~~502~~	~~$0.90~~	~~$0.75~~	~~$0.77~~	~~$1.34~~	~~$4.07~~	~~$9.67~~	(D)
502/503	$4.90~~$4.78~~	$4.80~~$5.37~~	$6.25~~$5.81~~	$13.73~~$12.51~~	$25.27~~$24.62~~	$34.14~~$33.37~~	(C)
504	$24.02~~$26.96~~	$25.06~~$29.73~~	$28.59~~$33.57~~	$49.63~~$57.37~~	$84.59~~$93.26~~	$744.85~~$123.58~~	
505	$184.03~~$199.50~~	$220.00~~$161.71~~	$284.54~~$219.19~~	$313.88~~$481.47~~	$423.04~~$330.25~~	$447.72~~$499.01~~	
511	$736.98~~$560.62~~	$670.75~~$584.83~~	$810.88~~$456.19~~	$1,231.06~~$697.04~~	$1,746.33~~$881.75~~	$2,070.43~~$1,998.69~~	(C)

(D)

~~512~~	~~$848.85~~	~~$829.30~~	~~$932.83~~	~~$893.31~~	~~$725.35~~	~~$810.19~~	
570	$1,446.99~~$1,412.24~~	$1,082.52~~$1,472.06~~	$1,071.47~~$1,309.92~~	$2,242.41~~$1,622.41~~	$2,198.15~~$1,729.62~~	$2,504.69~~$2,193.50~~	(C)
~~577~~	~~$686.70~~	~~$549.39~~	~~$541.41~~	~~$620.15~~	~~$750.22~~	~~$1,029.98~~	(D)

(Continued)

VARIOUS MISCELLANEOUS CHARGES
RATE SCHEDULE 200

APPLICABLITY:
This schedule sets forth the provisions for various charges throughout these rules and regulations. The name and amount of the charges are listed below. The rules or rate schedules to which each charge applies are in parenthesis.

I. Reconnection Charge (Rule 5):

A reconnection charge of ~~24~~ twenty-eight dollars ($2~~4~~8.00) will be required to reestablish service between the hours of 8 a.m. and 5 p.m. on weekdays, and a reconnection charge of seventy ($~~6~~70.00) will be required to reestablish service after 5 p.m. on weekdays and on Saturdays, Sundays, and holidays, except in the case of medical emergency. (I) (I)

II. Disconnect Visit Charge - (Rule 5):

A disconnect charge of ~~ten~~ twelve dollars ($1~~0~~2.00) may be charged, whenever Cascade is required to visit a customer's address for the purpose of disconnecting service and service is not disconnected. (I)

III. Late Payment Charge – (Rule 6 – Part A):

Unless otherwise specified in the customer's contract, a late payment charge at the rate of 1.0% per bill cycle will be applied to all unpaid balances in accordance with Rule 6 – Part A.

IV. Returned Check Charge - (Rule 6 - Part D):

A returned check ~~of fee eighteen~~fee of twenty-one dollars ($~~18~~21.00) may apply for any check returned from the bank unpaid. (I)

V. Residential Excess Flow Valves – (Rule 8):

In Conjunction With The Construction Of A New Service Line:		$ 38.00
Modifying an Existing Service Line:		
Time of Construction Crew	up to	$220.00 per hour
Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.		
Installation of the Excess Flow Valve		$ 38.00

The customer will be responsible for any future maintenance or replacement costs that may be incurred due to the excess flow value. Such cost shall be based upon time and materials, as follows:

Time of Construction Crew	up to	$220.00 per hour
Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.		
Installation of replacement Excess Flow Valve, if necessary		$ 38.00

(Continued on next page)

VARIOUS MISCELLANEOUS CHARGES
RATE SCHEDULE 200
(Continued from previous page)

APPLICABLILITY: (continued from Previous Page)

~~VI. New Premises Charge :~~ (D)

~~A New Premises Charge of forty five dollars ($45.00) where service has not been previously available will be required to establish service. In accordance with WAC 480-90-108(4)(b)(ii), when a customer seeks service at a location where facilities do not exist, the Company will provide a date by which service will be made available. If the Company becomes aware that the service date cannot be met, the Company will notify the applicant on or prior to the service date.~~ (D)

V~~I~~I. Tampered Meter Charge (Rule 5): (T)

A meter tampering charge will be billed to a customer who tampers with any part of any service line or meter or any other apparatus of Company. The charge will be the actual costs of damages, repairs or any additional or unusual costs or services directly related to the interference, plus the amount of unbilled gas determined to have been lost plus the applicable reconnect charges will be applied to the customers account.

V~~I~~II. Pilot Light Service Charge :

A Pilot Light Service charge of twenty-four dollars ($~~20~~24.00) may be applied to the customer's current bill when the customer requests the company turn-on or turn-off a pilot light or gas insert during regular business hours. (T) (I)

WN U-3

Fifty-~~Fourth~~ Fifth Rev~~.~~ision Sheet No. 502
Canceling
Fifty-Fourth~~Third~~ Rev~~.~~ision Sheet No. 502

CASCADE NATURAL GAS CORPORATION

BUILDING CONSTRUCTION TEMPORARY HEATING AND DRY-OUT SERVICE
SCHEDULE NO. 502

AVAILABILITY:
~~This schedule~~Service ~~is available~~under this Schedule shall be frozen as of ~~-~~October 1, 2017, ~~upon written application 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 supplied at a permanent point of delivery for use in permanently installed gas heating equipment to be used for temporary heating and dry-out purposes during the period (maximum of six months) that building is under construction and prior to occupancy. (C)

LIMITS OF AVAILABILITY:
Upon occupation or sale, whichever is first after completion of construction or, in any event, after a maximum period not to exceed six (6) months, service under this schedule shall immediately terminate and billings thereafter shall be made under the terms and conditions of the regular applicable rate schedule.

RATE:

	Margin	WACOG	Total		
Basic Service Charge			$~~14~~6.00	per month	(R)
All gas used per month at therm	$0.30446~~09183~~	$0.~~49304~~ 49569	$0.80015~~58487~~	per	(I)

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

MINIMUM CHARGE:
Minimum monthly bill $6.00~~14.00~~ (R)

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:~~ (D)
~~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, or for other reasons arising through the action of the customer. In the event service has been turned off for nonpayment of any bill due under this schedule, a new service under this schedule at another location shall not be established in the name of the customer until all previous bills shall be paid in full.~~

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 resold to others.

FROZEN

CNG/W17~~6~~-09~~8~~-~~02~~01

ISSUED ~~September~~ August ~~30~~31, ~~2016~~2017 EFFECTIVE ~~November~~ October 1, 201~~6~~7

ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY Michael P

Michael Parvinen

TITLE **Director**
Regulatory Affairs

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			$ ~~4~~6.00	per month	(I)
All Gas Used Per Month per therm	$0.~~29484~~30446	$ 0.49569	$0.~~79053~~80015		(I)

RATE ADJUSTMENT:

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

MINIMUM CHARGE:

Basic Service Charge: $ ~~4~~6.00 per month (I)

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:~~ (D)

~~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.

Forty-~~Third~~ Fourth Rev~~.~~ision Sheet No. 504
Canceling
WN U-3 **Forty-~~Second~~ Third Rev~~.~~ision Sheet No. 504**

CASCADE NATURAL GAS CORPORATION

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			$1~~0~~5.00 per month	(I)
All Therms Used	$0.23313~~24608~~	$0.49304	$0.72617~~73912~~ per therm	(R)

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

MINIMUM CHARGE:
Basic Service Charge $~~10~~15.00 (I)

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:~~ (D)
~~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.

CNG/W17-08-01~~6-09-02~~
ISSUED SeptemberAugust 3031, 20162017 EFFECTIVE November

ISSUED BY **CASCADE NATURAL GAS CORPORATION**

BY Michael Parvinen
Michael Parvinen

TITLE **Director**
Regulatory Affairs

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			$~~48~~75.00	per month	(I)
First 500 therms/month	$0.17779~~18843~~	$0.47993	$0.~~66836~~ 65772	per therm	(R)
Next 3,500 therms/month	$0.14399~~15175~~	$0.47993	$0.~~63168~~ 62392	per therm	(R)
All over 4,000 therms/month	$0.13888~~14620~~	$0.47993	$0.~~62613~~ 61881	per therm	(R)

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

MINIMUM CHARGE:
Basic Service Charge $~~48~~75.00 (I)

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:~~ (D)
~~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.

LARGE VOLUME GENERAL SERVICE RATE
SCHEDULE NO. 511

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			$2~~1~~00.00	per month	(I)
First 20,000 therms/month	$0.14028~~834~~	$0.47993	$0.~~62827~~ 62021	per therm	(R)
Next 80,000 therms/month per therm	$0.~~11295~~ 10753	$0.47993	$0.~~59288~~ 58746		(R)
All over 100,000 therms/month per therm	$0.~~02541~~ 02652	$0.47993	$0.~~50534~~ 50645		(R)

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

WEIGHTED AVERAGE COMMODITY GAS COST:
The per them average commodity gas cost unit rate is $0.32009 plus the commodity rate change reflected on Schedule 595.

CONTRACT:
Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve (12) consecutive months' use. The Annual Minimum Quantity is to be negotiated and included as part of the contract but shall in no case be less than 50,000 therms. Said contract shall also state the Maximum Winter Daily Requirement of natural gas that Company agrees to deliver as well as the Maximum Non-Winter Daily Requirement if the Non-Winter requirement is greater than the Winter requirement.

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

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.

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 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.

- Continued on Next Page –

INTERRUPTIBLE SERVICE
SCHEDULE NO. 570

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 60,000 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			$~~130~~500.00	per month	(I)
First 30,000 therms/month	$0.~~08233~~ 09426	$0.46687	$0.~~54920~~56113	per therm	(I)
All over 30,000 therms/month	$0.~~02251~~ 02684	$0.46687	$0.~~48938~~ 49371	per therm	(I)

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

WEIGHTED AVERAGE COMMODITY GAS COST:
The per therm average commodity gas cost unit rate is $0.32009 plus the commodity rate change reflected on Schedule 595.

ANNUAL DEFICIENCY BILL:
In the event customer purchases less than the Annual Minimum Quantity as stated in the contract, customer shall be charged an Annual Deficiency Bill. Annual Deficiency Bill shall be calculated by multiplying the difference between the Annual Minimum Quantity and the therms actually taken ("Deficiency Therms") times the difference between the commodity rate in this Rate Schedule No. 570, as modified by any applicable rate adjustments and the weighted average commodity cost of gas rate as modified by any applicable modifying rate schedules or changes, as such rates are reflected in the Company's tariffs. If service is curtailed or interrupted by Company, the Annual Minimum Quantity shall be reduced by a fraction, the numerator of which is the actual number of days, or fraction thereof, service was curtailed and the denominator of which is 365.

CONTRACT:
Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve (12) consecutive months' use. The Annual Minimum Quantity is to be negotiated and included as part of the contract but in no case shall the Annual Minimum Quantity be less than 60,000 therms which shall include all firm therms, if any. Said contract shall state the maximum daily consumption of natural gas that Company agrees to deliver.

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.

UNAUTHORIZED USE OF GAS:
Gas taken by customer under this schedule by reason of its failure to comply with Company's curtailment order shall be considered as any unauthorized overrun volume. Company shall bill and customer shall pay for such unauthorized overrun at the rate of $0.25 per therm for all gas used between 103% and 105% of the customer's gas day allocation and $0.50 per therm for all gas used in excess of 105%, in addition to the regular charges incurred in the RATE section of this schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun.

- Continued on Next Page -

DISTRIBUTION SYSTEM TRANSPORTATION SERVICE
SCHEDULE NO. 663

AVAILABILITY:
This unbundled distribution system transportation service schedule is available throughout the territory served by the Company under the tariff of which this schedule is a part, provided, in the sole judgment of the Company, there are adequate facilities in place at the existing distribution line or as such line may be enhanced by the Company from time to time to provide service.

RATE:
The rates set forth in sections A - D are exclusive of fuel use requirements designed to cover distribution system lost and unaccounted for gas.

A. Contract Demand Charge (Per CD Therms per month) .... $0.~~20~~ 22 per month (I)

B. Basic Service Charge $~~500~~750.00 per month (I)
All customers receiving gas supply service through this schedule will be invoiced a monthly Basic Service Charge for each single metering facility.

C. Delivery Charge For All Therms Delivered Per Month

First	100,000	$ 0.~~05730~~ 05970 Per Therm Per Month	
Next	200,000	$ 0.~~02023~~ 02179 Per Therm Per Month	(I)
Next	200,000	$ 0.~~01187~~ 01324 Per Therm Per Month	
Over	500,000	$ 0.~~00508~~ 00629 Per Therm Per Month	(I)

D. System Balancing Charge.......... $.0004 per therm

E. The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company. The current Gross Revenue Fee is 4.~~469~~431%. (R)

F. Fuel use requirements
Customer served on 663 shall provide the company with in-kind fuel for distribution system lost and unaccounted for gas. The fuel use factor is based on the Company's 5-year average lost and unaccounted for percentage, which shall be updated annually. The current rate is 0.1615%

All other terms and conditions of services shall be pursuant to the Rules and Regulations set forth in the Company's filed tariff.

OTHER SERVICES:
Service under this schedule shall include transportation on the Company's distribution facilities only. Service under this schedule requires customer to secure both gas supply and pipeline transportation capacity services either through the Company or through third party arrangements.

RATE ADJUSTMENTS:
Rates for service under this schedule are subject to various adjustments as specified in Schedule Nos. 593, 595, 596, and 597 (when applicable) as well as any other applicable adjustments as approved by the Washington Utilities & Transportation Commission.

(Continued on Next Page)

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT C: SUMMARY DOCUMENT

August 31, 2017

Cascade Natural Gas Corporation
Attachment C
Summary of Request Natural Gas Rate Increase
Washington Jurisdiction
Filed on August 31, 2017

1) **The date and amount of the latest prior general rate increase authorized by the Commission, and the revenue realized from that authorized increase in the test period, based on the company's test period units of revenue.**

Date:	September 1, 2016
Amount:	$4,000,000
Amount Realized in the test period:	$512,000

2) **Total revenues at present rates and at requested rates.**

Present Rates	$217,191,907
Requested Rates	$223,076,890

3) **Requested revenue change in percentage, in total, and by major customer class.**

Residential	4.41%
Commercial & Industrial	0%
Transportation and Interruptible	6.7%
Total	2.71%

4) **Requested revenue change in dollars, in total, and by major customer class.**

Residential	$4,614,984
Transportation and Interruptible	$1,270,000
Total	$5,884,984

5) **Requested rate change in dollars per month, per average residential customer.**

Monthly impact at average usage of 54 therms per month is $2.09.

6) **Most current customer count by major customer class.**

Residential	183,772
Commercial	25,601
Industrial	540
Transportation	186
Total	210,099
Twelve-months ended	December 31, 2016

7) Current authorized overall rate of return and authorized rate of return on common equity.

Overall rate of return	7.35 percent
Rate of return on common equity	N/A

8) Requested overall rate of return and requested rate of return on common equity, and the method or methods used to calculate rate of return on common equity.

Overall rate of return	7.598 Percent
Rate of return on common equity	9.90 Percent
Method(s) of Calculation:	Primarily rely on Discounted Cash Flow (DCF)

9) Requested capital structure.

Short-Term Debt	0
Long-Term Debt	50 Percent
Preferred Stock	0
Common Equity Stock	50 Percent

10) Requested total net operating income.

Net operating income	$22,859,398

11) Requested total rate base and method of calculation, or equivalent.

Rate base:	$300,860,726
Method(s) of calculation:	Average of Monthly Average (AMA)

12) Requested revenue effect of attrition allowance, if any requested.

No attrition allowance is requested.

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT D: INDEX OF TESTIMONY, EXHIBITS, AND WORKPAPERS

August 31, 2017

Cascade Natural Gas Corporation - Index of Testimony, Exhibits, and Work Papers
UG-17_____
August 31, 2017

Attachment D

1. Nicole A. Kivisto – Testimony and Exhibits

Exhibit No. ___ (NAK-1T)	Direct Testimony of Nicole A. Kivisto

2. J. Stephen Gaske – Testimony and Exhibits

Exhibit No. ___ (JSG-1T)	Direct Testimony of J. Stephen Gaske
Exhibit No.___ (JSG -2)	General Economic Statistics
Exhibit No.___ (JSG -3)	Resume of J. Stephen Gaske

3. Jennifer G. Gross – Testimony and Exhibits

Exhibit No. __ (JGG-1T)	Direct Testimony of Jennifer G. Gross
Exhibit No. __ (JGG-2)	Proposed Tariffs
Exhibit No. __ (JGG-3)	Decoupling Mechanism, Authorized Revenue Per Customer

4. Michael P. Parvinen – Testimony and Exhibits

Exhibit No. __ (MPP-1T)	Direct Testimony of Michael P. Parvinen
Exhibit No. __ (MPP-2)	Results of Operation Summary Sheet
Exhibit No. __ (MPP-3)	Revenue Requirement Calculation
Exhibit No. __ (MPP-4)	Conversion Factor Calculation
Exhibit No. __ (MPP-5)	Summary of Proposed Adjustments to Test Year Results
Exhibit No. __ (MPP-6)	2017 Plant Additions

Michael P. Parvinen – Workpapers

MPP WP-1.0	Index
MPP WP-1.1	Operating Report
MPP WP-1.2	Rate Base
MPP WP-1.3	Plant in Service & Accumulated Depreciation
MPP WP-1.4	Advance for Construction & Deferred Taxes
MPP WP-1.5	Schedule of Investor-Supplied Working Capital
MPP WP-1.6	Capital Structure Calculation
MPP WP-1.7	State Allocation Formula
MPP WP-1.8	Weather Normalization
MPP WP-1.9	Promotional Advertising Expense Adjustment
MPP WP-1.10	Restate Revenues
MPP WP-1.11	Low-Income Bill Assistance

Attachment D

MPP WP-1.12	Interest Coordination Adjustment
MPP WP-1.13	Pro Forma Wage Adjustment
MPP WP-1.14	Pro Forma Plant Additions
MPP WP-1.15	Rate Case Costs
MPP WP-1.16	Pro Forma Compliance Department
MPP WP-1.17	MAOP Deferral Amortization
MPP WP-1.18	Miscellaneous Charges
MPP WP-1.19	CRM Adjustment (a)
MPP WP-1.20	CRM Adjustment (b)
MPP WP-1.21	Revenue Adjustment
MPP WP-1.22	Working Capital Work Paper

5.. Ronald J. Amen – Testimony and Exhibits

Exhibit No. __ (RJA-1T)	Direct Testimony of Ronald J. Amen
Exhibit No. __ (RJA-2)	Summary of COSS Results
Exhibit No. ___ (RJA – 3)	Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
Exhibit No. ___ (RJA – 4)	Analysis of Revenue by Detailed Tariff Schedule
Exhibit No. ___ (RJA – 5)	Residential Impact by Month
Exhibit No. ___ (RJA – 6)	Impact of Recommended Rate Changes
Exhibit No. ___ (RJA – 7)	Determination of Gas Resource Demand Costs by Customer Class
Exhibit No. ___ (RJA – 8)	Resume of Ronald J. Amen

Ronald J. Amen – Work Papers

RJA WP-1.0	CONFIDENTIAL, Cost of Service Study
RJA WP-2.0	COSS Datasheet work paper
RJA WP-3.0	CONFIDENTIAL, Cascade WA Large Customer Plant
RJA WP-4.0	Mains work paper.xlsx
RJA WP-5.0	Services work paper.xlsx
RJA WP-6.0	CONFIDENTIAL, Industrial M_R_385 work paper.xlsx
RJA WP-7.0	Cascade WA Rate Design
RJA WP-8.0	CONFIDENTIAL, Resource Allocation

Attachment D

6. Tammy J. Nygard – Testimony and Exhibits

Exhibit No. __ (TJN-1T)	Direct Testimony of Tammy J. Nygard
Exhibit No. __ (TJN-2C)	CONFIDENTIAL, Cascade's Currently Outstanding Debt
Exhibit No. __ (TJN-3C)	CONFIDENTIAL, Long-Term Debt

7. Brian Robertson – Testimony and Exhibits

Exhibit No. __ (BR-1T)	Direct Testimony of Brian Robertson
Exhibit No. __ (BR-2)	Forecast Model
Exhibit No. __ (BR-3)	Analysis of Methodology of Calculating HDDs
Exhibit No. __ (BR-4)	Weather Normalization Adjustment
Exhibit No. __ (BR-5)	Analysis of Weather Normalization Adjustment
Exhibit No. __ (BR-6)	Results of Weather Normalization Forecast Model

Brian Robertson – Work Papers

Weather Normalized Therms, WP Supporting Exhibit No. __ (BR-6)

BR WP-1.0	Index
BR WP-1.1	Residential
BR WP-1.2	Commercial
BR WP-1.3	Industrial
BR WP-1.4	Total

Weather Normalization Regression Results, WP Supporting Exhibit No. __ (BR-4)

BR WP-2.0	Index
BR WP-2.1	Bellingham Base Data Schedule 503
BR WP-2.2	Bellingham Results Schedule 503
BR WP-2.3	Bremerton Base Data Schedule 503
BR WP-2.4	Bremerton Results Schedule 503
BR WP-2.5	Walla Walla Base Data Schedule 503
BR WP-2.6	Walla Walla Results Schedule 503
BR WP-2.7	Yakima Base Data Schedule 503
BR WP-2.8	Yakima Results Schedule 503
BR WP-2.9	Bellingham Base Data Schedule 504
BR WP-2.10	Bellingham Results Schedule 504
BR WP-2.11	Bremerton Base Data Schedule 504
BR WP-2.12	Bremerton Results Schedule 504
BR WP-2.13	Walla Walla Base Data Schedule 504
BR WP-2.14	Walla Walla Results Schedule 504
BR WP-2.15	Yakima Base Data Schedule 504
BR WP-2.16	Yakima Results Schedule 504

Brian Robertson – Work Papers (continued)

BR WP.3 through 3.149*	Actual Usage Data, Support for WP-2

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*Too voluminous to print

8. Eric Martuscelli – Testimony and Exhibits

Exhibit No. ___ (EM-1T)	Direct Testimony of Eric Martuscelli

9. Ryan Privratsky - Testimony and Exhibits

Exhibit No. ___ (RP-1T)	Direct Testimony of Ryan Privratsky
Exhibit No. ___ (RP-2)	Deferred Costs

10. Maryalice C. Rosales - Testimony and Exhibits

Exhibit No. ___ (MCR-1T)	Direct Testimony of Maryalice C. Rosales
Exhibit No. ___ (MCR-2)	Summary of Revenues by Rate Schedule
Exhibit No. ___ (MCR-3)	Revenue Adjustment
Exhibit No. ___ (MCR-4)	Restatement of Revenue

Maryalice C. Rosales -Work Papers

MCR WP-1.0	Index
MCR WP-1.1	Total Operating Revenue
MCR WP-1.2	Average Cost of Gas
MCR WP-1.3	Margins by Month
MCR WP-1.4	Miscellaneous Service Revenue
MCR WP-1.5	Therms 2016
MCR WP-1.6	September 2016 (Old Rates)
MCR WP-1.7	September 2016 (New Rates)
MCR WP-1.8	November 2016 (Old Rates)
MCR WP-1.9	November 2016 (New Rates)
MCR WP-1.10	Weather Normalization Adjustments

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT E: LIST OF FILES

August 31, 2017

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UG-17_____
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File Name	Description
NEW CNGC General Rate Case CLtr, 8.31.17.pdf	Cover Letter
NEW CNGC Attch A Proposed Tariffs, 8.31.17.pdf	Proposed Tariffs
NEW CNGC Attch B Legislative Tariffs, 8.31.17.pdf	Legislative Tariffs
NEW CNGC Attch C GRC Summary, 8.31.17.pdf	GRC Summary Document
NEW CNGC Attch D Index Testimony, 8.31.17.pdf	Index of Testimony, Exhibits and Work Papers
NEW CNGC Attch E List of Files, 8.31.17.pdf	List of Electronic Files
NEW CNGC Attch F GRC Compliance Matrix, 8.31.17.pdf	GRC Compliance Matrix
NEW CNGC Attch G Financial Doc Overview, 8.31.17.pdf	Overview of previously provided financial documents
NEW, CNGC Financial docs 2016 10-K Annual Rpt, 8.31.17.pdf	Most recent annual report to shareholders
NEW, CNGC Financial docs 2016 FERC Form No.2, 8.31.17.pdf	Most recent FERC Form 2
NEW, CNGC Financial docs 2016 Washington Supplement, 8.31.17.pdf	Most recent FERC Form 2 Supplement
NEW, CNGC Financial docs 2015 10-K Annual Rpt, 8.31.17.pdf	Form 10-Ks
NEW, CNGC Financial docs 2014 10-K Annual Rpt, 8.31.17.pdf	Form 10-Ks
NEW, CNGC Financial docs 6.30.15 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 9.30.15 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 3.31.16 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 6.30.16 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 9.30.16 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 3.31.17 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 6.30.17 MDU 10-Q, 8.31.17.pdf	Form 10-Q
NEW CNGC Attch H, Cert of Service, 8.31.17.pdf	Certificate of Service
NEW CNGC Claim of Confidentiality, 8.31.17.pdf	Claim of Confidentiality
NEW CNG Kivisto Exh NAK-1-T, 8-31-17	Direct Testimony of Nicole A. Kivisto

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NEW CNG Gaske Exh JSG-1-T, 8-31-17	Direct Testimony of J. Stephen Gaske
NEW CNG JSG-2, 8-31-17.pdf	JSG -2, General Economic Statistics
NEW CNG JSG-2, 8-31-17.xlsx	JSG -2, General Economic Statistics
NEW CNG JSG-3, 8-31-17.pdf	JSG -3 Resume of J. Stephen Gaske
NEW CNG Gross Exh JGG 1-T 8-31-17.pdf	Direct Testimony of Jennifer G. Gross
NEW CNG JGG-2, 8-31-17.pdf	JGG-2 Proposed Tariffs
NEW CNG JGG-3, 8-31-17.pdf	JGG-3, Decoupling Mechanism, Authorized Revenue Per Customer
NEW CNG Parvinen Exh MPP 1-T 8-31-17.pdf	Direct Testimony of Michael P. Parvinen
NEW CNG MPP-2 8-31-17.pdf	MPP-2, Results of Operation Summary Sheet
NEW CNG MPP-3 8-31-17.pdf	MPP-3, Revenue Requirement Calculation
NEW CNG MPP-4 8-31-17.pdf	MPP-4, Conversion Factor Calculation
NEW CNG MPP-5 8-31-17.pdf	MPP-5, Summary of Proposed Adjustments to Test Year Results
NEW CNG MPP-6 8-31-17.pdf	MPP-6, 2017 Plant Additions
NEW CNG Parvinen Exh MPP 2-6 and WP-1 8-31-17.xlsx	MPP work papers
NEW CNG Parvinen Exh MPP WP 1, 8-31-17.pdf	MPP work papers
NEW, CNG, Ron Amen Exh RJA-1T, 8.31.17.pdf	Direct Testimony of Ron Amen
NEW, CNG Exhibit No. RJA-2, 8.31.17.pdf	RJA-2, Summary of Non-Gas COSS results
NEW, CNG Exhibit No. RJA-3, 8.31.17.pdf	RJA-3, Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
NEW, CNG Exhibit No. RJA-4, 8.31.17.pdf	RJA-4, Analysis of Revenue by Detailed Tariff Schedule
NEW, CNG Exhibit No. RJA-5, 8.31.17.pdf	RJA-5, Residential Impact by Month
NEW, CNG Exhibit No. RJA-6, 8.31.17.pdf	RJA-6, Impact of Recommended Rate Changes
NEW, CNG Exhibit No. RJA-7, 8.31.17.pdf	RJA-7, Gas Resource Demand Cost Allocation

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NEW, CNG Exhibit No. RJA-8, 8.31.17.pdf	RJA-8, Resume of Ronald J. Amen
NEW, CNG RJA WP-1 CONFIDENTIAL, 8.31.17 (C).xlsx	RJA WP -1 Cost of Service Study
NEW, CNG RJA WP-1_Cost of Service Study, 8.31.17(C).pdf	RJA WP-1 Cost of Service Study
NEW CNG RJA Redacted WP-1 CONFIDENTIAL Cost of Service Study 8-31-17.pdf	RJA WP-1 Cost of Service Study
NEW CNG RJA Redacted WP-1 CONFIDENTIAL Cost of Service Study 8-31-17.xlsx	RJA WP-1 Cost of Service Study
NEW, CNG RJA WP-2_COSS Datasheet, 8.31.17.xlsx	RJA WP-2 COSS Datasheet
NEW, CNG RJA WP-2 COSS Datasheet, 8.31.17.pdf	RJA WP-2 COSS Datasheet
NEW, CNG RJA WP-3 Cascade WA Large Customer Plant, 8.31.17.xlsx	RJA WP-3 Large Customer Plant
NEW, CNG RJA WP-3 Large Customer Plant, 8.31.17.pdf	RJA WP-3 Large Customer Plant
NEW, CNG RJA WP-4_Mains, 8.31.17.pdf	RJA WP-4 Mains
NEW, CNG RJA WP-4_Mains, 8.31.17.xlsx	RJA WP-4 Mains
NEW, CNG RJA WP-5 Services, 8.31.17.xlsx	RJA WP-5 Services
NEW, CNG RJA WP-5 Services, 8.31.17.pdf	RJA WP-5 Services
NEW, CNG RJA WP-6 CONFIDENTIAL, Industrial M_R_385, 8.31.17(C).xlsx	RJA WP-6, Industrial
NEW, CNG RJA WP-6 CONFIDENTIAL, Industrial M_R_385, 8.31.17(C).pdf	RJA WP-6, Industrial
NEW CNG RJA Redacted WP-6 CONFIDENTIAL, Industrial M_R_385 8-31-17 (C).pdf	RJA WP-6, Industrial
NEW CNG RJA Redacted WP-6 CONFIDENTIAL, Industrial M_R_385 8-31-17 (C).xlsx	RJA WP-6, Industrial
NEW, CNG RJA WP-7 Cascade WA rate design, 8.31.17.xlsx	RJA-7 Rate Design
NEW, CNG RJA WP-7 Cascade WA rate design, 8.31.17.pdf	RJA-7 Rate Design
NEW, CNG RJA WP-8 CONFIDENTIAL Resource Allocation CNGC, 8.31.17 (C).pdf	RJA-8 Resource Allocation

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NEW, CNG RJA WP-8 CONFIDENTIAL Resource Allocation CNGC, 8.31.17 (C).xlsx	RJA-8 Resource Allocation
NEW, CNG RJA Redacted WP-8 CONFIDENTIAL Resource Allocation, 8-31-17 (C).xlsx	RJA-8 Resource Allocation
NEW, CNG RJA Redacted WP-8 CONFIDENTIAL Resource Allocation, 8-31-17 (C).pdf	RJA-8 Resource Allocation
NEW CNG Nygard Exh TJN-1T, 8-31-17.pdf	Direct Testimony of Tammy J. Nygard
NEW CNG Exh TJN 2C, 8-31-17(C).pdf	TJN-2, Cascade's Currently Outstanding Debt
NEW CNG Exh TJN 3C, 8-31-17(C).pdf	TJN-3, Long Term Debt
NEW CNG Redacted Exh TJN-2C, 8-31-17(C).pdf	TJN-2, Cascade's Currently Outstanding Debt
NEW CNG Redacted Exh TJN-3C, 8-31-17(C).pdf	TJN-3, Long Term Debt
NEW CNG Robertson Exh BR-1T, 8-31-17	Direct Testimony of Brian Robertson
NEW CNG Exh BR-2, 8-31-17.pdf	BR-2, Forecast Model
NEW CNG Exh BR-3, 8-31-17.pdf	BR-3, Analysis of Methodology of Calculating HDDs
NEW CNG Exh BR-3, 8-31-17.xlsx	BR-3, Analysis of Methodology of Calculating HDDs
NEW CNG Exh BR-4, 8-31-17.pdf	BR-4, Weather Normalization Adjustment
NEW CNG Exh BR-4, 8-31-17.xlsx	BR-4, Weather Normalization Adjustment
NEW CNG Exh BR-5, 8-31-17.pdf	BR-5, Analysis of Weather Normalization Adjustment
NEW CNG Exh BR-5, 8-31-17.xlsx	BR-5, Analysis of Weather Normalization Adjustment
NEW CNG Exh BR-6, 8-31-17.pdf	BR-6, Results of Weather Normalization Forecast Model
NEW CNG Exh BR-6, 8-31-17.xlsx	BR-6, Results of Weather Normalization Forecast Model
NEW CNG BR WP-1 Weather Normalize Therms 8-31-17.xlsx	BR WP-1, Work Paper Supporting Exhibit No. __ (BR-6)
NEW CNG BR WP-1 Weather Normalize Therms 8-31-17.pdf	BR WP-1, Work Paper Supporting Exhibit No. __ (BR-6)
NEW CNG BR WP-2 Weather Normalize Regression Results 8-31-17.xlsx	BR WP-2, Work Paper Supporting Exhibit No. __ (BR-4)
NEW CNG BR WP-2 Weather Normalize Regression Results 8-31-17.pdf	BR WP-2, Work Paper Supporting Exhibit No. __ (BR-4)

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NEW CNG BR WP-3, 8.31.17.xlsx	BR WP-3, Work Paper Index
NEW CNG BR WP-3.1, 8.31.17.xlsx	BR WP-3.1, Actual Usage Data
NEW CNG BR WP-3.2, 8.31.17.xlsx	BR WP-3.2, Allocated usage and customers
NEW CNG BR WP-3.3, 8.31.17.xlsx	BR WP-3.3, Usage Allocation
NEW CNG BR WP-3.4, 8.31.17.xlsx	BR WP-3.4, Normalization Aggregates
NEW CNG BR WP-3.5, 8.31.17.xlsx	BR WP-3.5, Weather Data
NEW CNG BR WP-3.6, 8.31.17.xlsx	BR WP-3.6, Citygate Weather Map
NEW CNG BR WP-3.7, 8.31.17.xlsx	BR WP-3.7, Town to Citygate Mapping
NEW CNG BR WP-3.8, 8.31.17.xlsx	BR WP-3.8, 7th Day School Commercial
NEW CNG BR WP-3.9, 8.31.17.xlsx	BR WP-3.9, 7th Day School Industrial
NEW CNG BR WP-3.10, 8.31.17.xlsx	BR WP-3.10, 7th Day School Residential
NEW CNG BR WP-3.11, 8.31.17.xlsx	BR WP-3.11, Acme Commercial
NEW CNG BR WP-3.12, 8.31.17.xlsx	BR WP-3.12, Acme Residential
NEW CNG BR WP-3.13, 8.31.17.xlsx	BR WP-3.13, AM Rendering Commercial
NEW CNG BR WP-3.14, 8.31.17.xlsx	BR WP-3.14, AM Rendering Residential
NEW CNG BR WP-3.15, 8.31.17.xlsx	BR WP-3.15, Arlington Commercial
NEW CNG BR WP-3.16, 8.31.17.xlsx	BR WP-3.16, Arlington Industrial
NEW CNG BR WP-3.17, 8.31.17.xlsx	BR WP-3.17, Arlington Residential
NEW CNG BR WP-3.18, 8.31.17.xlsx	BR WP-3.18, Athena Commercial
NEW CNG BR WP-3.19, 8.31.17.xlsx	BR WP-3.19, Athena Residential
NEW CNG BR WP-3.20, 8.31.17.xlsx	BR WP-3.20, Baker City Commercial
NEW CNG BR WP-3.21, 8.31.17.xlsx	BR WP-3.21, Baker City Industrial
NEW CNG BR WP-3.22, 8.31.17.xlsx	BR WP-3.22, Baker City Residential
NEW CNG BR WP-3.23, 8.31.17.xlsx	BR WP-3.23, Bend Loop Commercial
NEW CNG BR WP-3.24, 8.31.17.xlsx	BR WP-3.24, Bend Loop Industrial
NEW CNG BR WP-3.25, 8.31.17.xlsx	BR WP-3.25, Bend Loop Residential
NEW CNG BR WP-3.26, 8.31.17.xlsx	BR WP-3.26, Bremerton Commercial
NEW CNG BR WP-3.27, 8.31.17.xlsx	BR WP-3.27, Bremerton Industrial
NEW CNG BR WP-3.28, 8.31.17.xlsx	BR WP-3.28, Bremerton Residential

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NEW CNG BR WP-3.29, 8.31.17.xlsx	BR WP-3.29, BurbankHeights Loop Commercial
NEW CNG BR WP-3.30, 8.31.17.xlsx	BR WP-3.30, BurbankHeights Loop Industrial
NEW CNG BR WP-3.31, 8.31.17.xlsx	BR WP-3.31, BurbankHeights Loop Residential
NEW CNG BR WP-3.32, 8.31.17.xlsx	BR WP-3.32, Castle Rock Commercial
NEW CNG BR WP-3.33, 8.31.17.xlsx	BR WP-3.33, Castle Rock Residential
NEW CNG BR WP-3.34, 8.31.17.xlsx	BR WP-3.34, Chemult Commercial
NEW CNG BR WP-3.35, 8.31.17.xlsx	BR WP-3.35, Chemult Residential
NEW CNG BR WP-3.36, 8.31.17.xlsx	BR WP-3.36, Dehawn Dairy Residential
NEW CNG BR WP-3.37, 8.31.17.xlsx	BR WP-3.37, Deming Commercial
NEW CNG BR WP-3.38, 8.31.17.xlsx	BR WP-3.38, Deming Residential
NEW CNG BR WP-3.39, 8.31.17.xlsx	BR WP-3.39, East Stanwood Loop Commercial
NEW CNG BR WP-3.40, 8.31.17.xlsx	BR WP-3.40, East Stanwood Loop Industrial
NEW CNG BR WP-3.41, 8.31.17.xlsx	BR WP-3.41, East Stanwood Loop Residential
NEW CNG BR WP-3.42, 8.31.17.xlsx	BR WP-3.42, Finley Commercial
NEW CNG BR WP-3.43, 8.31.17.xlsx	BR WP-3.43, Finley Residential
NEW CNG BR WP-3.44, 8.31.17.xlsx	BR WP-3.44, Gilchrist Commercial
NEW CNG BR WP-3.45, 8.31.17.xlsx	BR WP-3.45, Gilchrist Residential
NEW CNG BR WP-3.46, 8.31.17.xlsx	BR WP-3.46, Grandview Commercial
NEW CNG BR WP-3.47, 8.31.17.xlsx	BR WP-3.47, Grandview Industrial
NEW CNG BR WP-3.48, 8.31.17.xlsx	BR WP-3.48, Grandview Residential
NEW CNG BR WP-3.49, 8.31.17.xlsx	BR WP-3.49, Hermiston Commercial
NEW CNG BR WP-3.50, 8.31.17.xlsx	BR WP-3.50, Hermiston Industrial
NEW CNG BR WP-3.51, 8.31.17.xlsx	BR WP-3.51, Hermiston Residential
NEW CNG BR WP-3.52, 8.31.17.xlsx	BR WP-3.52, Huntington Commercial
NEW CNG BR WP-3.53, 8.31.17.xlsx	BR WP-3.53, Huntington Residential
NEW CNG BR WP-3.54, 8.31.17.xlsx	BR WP-3.54, Kalama#1 Residential
NEW CNG BR WP-3.55, 8.31.17.xlsx	BR WP-3.55, Kalama#2 Commercial
NEW CNG BR WP-3.56, 8.31.17.xlsx	BR WP-3.56 Kalama#2 Industrial
NEW CNG BR WP-3.57, 8.31.17.xlsx	BR WP-3.57, Kalama#2 Residential

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NEW CNG BR WP-3.58, 8.31.17.xlsx	BR WP-3.58, Kennewick Loop Commercial
NEW CNG BR WP-3.59, 8.31.17.xlsx	BR WP-3.59, Kennewick Loop Industrial
NEW CNG BR WP-3.60, 8.31.17.xlsx	BR WP-3.60, Kennewick Loop Residential
NEW CNG BR WP-3.61, 8.31.17.xlsx	BR WP-3.61, Lapine Commercial
NEW CNG BR WP-3.62, 8.31.17.xlsx	BR WP-3.62, Lapine Residential
NEW CNG BR WP-3.63, 8.31.17.xlsx	BR WP-3.63, Lawrence Commercial
NEW CNG BR WP-3.64, 8.31.17.xlsx	BR WP-3.64, Lawrence Industrial
NEW CNG BR WP-3.65 8.31.17.xlsx	BR WP-3.65, Lawrence Residential
NEW CNG BR WP-3.66, 8.31.17.xlsx	BR WP-3.66, LDS Church Commercial
NEW CNG BR WP-3.67, 8.31.17.xlsx	BR WP-3.67, LDS Church Residential
NEW CNG BR WP-3.68, 8.31.17.xlsx	BR WP-3.68, Longview South Loop Commercial
NEW CNG BR WP-3.69, 8.31.17.xlsx	BR WP-3.69, Longview South Loop Industrial
NEW CNG BR WP-3.70, 8.31.17.xlsx	BR WP-3.70, Longview South Loop Residential
NEW CNG BR WP-3.71, 8.31.17.xlsx	BR WP-3.71, Madras Commercial
NEW CNG BR WP-3.72, 8.31.17.xlsx	BR WP-3.72, Madras Industrial
NEW CNG BR WP-3.73, 8.31.17.xlsx	BR WP-3.73, Madras Residential
NEW CNG BR WP-3.74, 8.31.17.xlsx	BR WP-3.74, McCleary Commercial
NEW CNG BR WP-3.75, 8.31.17.xlsx	BR WP-3.75, McCleary Industrial
NEW CNG BR WP-3.76, 8.31.17.xlsx	BR WP-3.76, McCleary Residential
NEW CNG BR WP-3.77, 8.31.17.xlsx	BR WP-3.77, Milton-Freewater Commercial
NEW CNG BR WP-3.78, 8.31.17.xlsx	BR WP-3.78, Milton-Freewater Industrial
NEW CNG BR WP-3.79, 8.31.17.xlsx	BR WP-3.79, Milton-Freewater Residential
NEW CNG BR WP-3.80, 8.31.17.xlsx	BR WP-3.80, Mission Tap Commercial
NEW CNG BR WP-3.81, 8.31.17.xlsx	BR WP-3.81, Mission Tap Residential
NEW CNG BR WP-3.82, 8.31.17.xlsx	BR WP-3.82, Moses Lake Commercial
NEW CNG BR WP-3.83, 8.31.17.xlsx	BR WP-3.83, Moses Lake Industrial
NEW CNG BR WP-3.84, 8.31.17.xlsx	BR WP-3.84, Moses Lake Residential
NEW CNG BR WP-3.85, 8.31.17.xlsx	BR WP-3.85, Moxee Commercial
NEW CNG BR WP-3.86, 8.31.17.xlsx	BR WP-3.86, Moxee Industrial

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NEW CNG BR WP-3.87, 8.31.17.xlsx	BR WP-3.87, Moxee Residential
NEW CNG BR WP-3.88, 8.31.17.xlsx	BR WP-3.88, North Pasco Commercial
NEW CNG BR WP-3.89, 8.31.17.xlsx	BR WP-3.89, North Pasco Industrial
NEW CNG BR WP-3.90, 8.31.17.xlsx	BR WP-3.90, North Pasco Residential
NEW CNG BR WP-3.91, 8.31.17.xlsx	BR WP-3.91, Nyssa-Ontario Commercial
NEW CNG BR WP-3.92, 8.31.17.xlsx	BR WP-3.92, Nyssa-Ontario Industrial
NEW CNG BR WP-3.93, 8.31.17.xlsx	BR WP-3.93, Nyssa-Ontario Residential
NEW CNG BR WP-3.94, 8.31.17.xlsx	BR WP-3.94, Othello Commercial
NEW CNG BR WP-3.95, 8.31.17.xlsx	BR WP-3.95, Othello Industrial
NEW CNG BR WP-3.96, 8.31.17.xlsx	BR WP-3.96, Othello Residential
NEW CNG BR WP-3.97, 8.31.17.xlsx	BR WP-3.97, Patterson Commercial
NEW CNG BR WP-3.98, 8.31.17.xlsx	BR WP-3.98, Pendleton Commercial
NEW CNG BR WP-3.99, 8.31.17.xlsx	BR WP-3.99, Pendleton Industrial
NEW CNG BR WP-3.100, 8.31.17.xlsx	BR WP-3.100, Pendleton Residential
NEW CNG BR WP-3.101, 8.31.17.xlsx	BR WP-3.101, Prineville Commercial
NEW CNG BR WP-3.102, 8.31.17.xlsx	BR WP-3.102, Prineville Industrial
NEW CNG BR WP-3.103, 8.31.17.xlsx	BR WP-3.103, Prineville Residential
NEW CNG BR WP-3.104, 8.31.17.xlsx	BR WP-3.104, Pronghorn Commercial
NEW CNG BR WP-3.105, 8.31.17.xlsx	BR WP-3.105, Pronghorn Residential
NEW CNG BR WP-3.106, 8.31.17.xlsx	BR WP-3.106, Prosser Commercial
NEW CNG BR WP-3.107, 8.31.17.xlsx	BR WP-3.107, Prosser Industrial
NEW CNG BR WP-3.108, 8.31.17.xlsx	BR WP-3.108, Prosser Residential
NEW CNG BR WP-3.109, 8.31.17.xlsx	BR WP-3.109, Quincy Commercial
NEW CNG BR WP-3.110, 8.31.17.xlsx	BR WP-3.110, Quincy Industrial
NEW CNG BR WP-3.111, 8.31.17.xlsx	BR WP-3.111, Quincy Residential
NEW CNG BR WP-3.112, 8.31.17.xlsx	BR WP-3.112, Redmond Commercial
NEW CNG BR WP-3.113, 8.31.17.xlsx	BR WP-3.113, Redmond Industrial
NEW CNG BR WP-3.114, 8.31.17.xlsx	BR WP-3.114, Redmond Residential
NEW CNG BR WP-3.115, 8.31.17.xlsx	BR WP-3.115, Sedro Woolley Loop Commercial

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NEW CNG BR WP-3.116, 8.31.17.xlsx	BR WP-3.116, Sedro Woolley Loop Industrial
NEW CNG BR WP-3.117, 8.31.17.xlsx	BR WP-3.117, Sedro Woolley Loop Residential
NEW CNG BR WP-3.118, 8.31.17.xlsx	BR WP-3.118, Stanfield Commercial
NEW CNG BR WP-3.119, 8.31.17.xlsx	BR WP-3.119, Stanfield Residential
NEW CNG BR WP-3.120, 8.31.17.xlsx	BR WP-3.120, Stearns Commercial
NEW CNG BR WP-3.121, 8.31.17.xlsx	BR WP-3.121, Stearns Industrial
NEW CNG BR WP-3.122, 8.31.17.xlsx	BR WP-3.122, Stearns Residential
NEW CNG BR WP-3.123, 8.31.17.xlsx	BR WP-3.123, Sumas SPE Loop Commercial
NEW CNG BR WP-3.124, 8.31.17.xlsx	BR WP-3.124, Sumas SPE Loop Industrial
NEW CNG BR WP-3.125, 8.31.17.xlsx	BR WP-3.125, Sumas SPE Loop Residential
NEW CNG BR WP-3.126, 8.31.17.xlsx	BR WP-3.126, Sunnyside Commercial
NEW CNG BR WP-3.127, 8.31.17.xlsx	BR WP-3.127, Sunnyside Industrial
NEW CNG BR WP-3.128, 8.31.17.xlsx	BR WP-3.128, Sunnyside Residential
NEW CNG BR WP-3.129, 8.31.17.xlsx	BR WP-3.129, Umatilla Commercial
NEW CNG BR WP-3.130, 8.31.17.xlsx	BR WP-3.130, Umatilla Industrial
NEW CNG BR WP-3.131, 8.31.17.xlsx	BR WP-3.131, Umatilla Residential
NEW CNG BR WP-3.132, 8.31.17.xlsx	BR WP-3.132, Walla Walla Commercial
NEW CNG BR WP-3.133, 8.31.17.xlsx	BR WP-3.133, Walla Walla Industrial
NEW CNG BR WP-3.134, 8.31.17.xlsx	BR WP-3.134, Walla Walla Residential
NEW CNG BR WP-3.135, 8.31.17.xlsx	BR WP-3.135, Wenatchee Commercial
NEW CNG BR WP-3.136, 8.31.17.xlsx	BR WP-3.136, Wenatchee Industrial
NEW CNG BR WP-3.137, 8.31.17.xlsx	BR WP-3.137, Wenatchee Residential
NEW CNG BR WP-3.138, 8.31.17.xlsx	BR WP-3.138, Woodland Commercial
NEW CNG BR WP-3.139, 8.31.17.xlsx	BR WP-3.139, Woodland Industrial
NEW CNG BR WP-3.140, 8.31.17.xlsx	BR WP-3.140, Woodland Residential
NEW CNG BR WP-3.141, 8.31.17.xlsx	BR WP-3.141, Yakima Chief Ranch Residential
NEW CNG BR WP-3.142, 8.31.17.xlsx	BR WP-3.142, Yakima Loop Commercial
NEW CNG BR WP-3.143, 8.31.17.xlsx	BR WP-3.143, Yakima Loop Industrial
NEW CNG BR WP-3.144, 8.31.17.xlsx	BR WP-3.144, Yakima Loop Residential

Cascade Natural Gas Corporation – List of Files
UG-17_____
August 31 2017

Attachment E

NEW CNG BR WP-3.145, 8.31.17.xlsx	BR WP-3.145, Yakima Training Center Commercial
NEW CNG BR WP-3.146, 8.31.17.xlsx	BR WP-3.146, Yakima Training Center Residential
NEW CNG BR WP-3.147, 8.31.17.xlsx	BR WP-3.147, Zillah Commercial
NEW CNG BR WP-3.148, 8.31.17.xlsx	BR WP-3.148, Zillah Industrial
NEW CNG BR WP-3.149, 8.31.17.xlsx	BR WP-3.149, Zillah Residential
NEW CNG Martuscelli Exh EM-1T, 8-31-17	Direct Testimony of Eric Martuscelli
NEW CNG Privratsky Exh RP-1T, 8-31-17	Direct Testimony of Ryan Privratsky
NEW CNG Exh RP-2, 8-31-17.pdf	RP-2, Deferred Costs
NEW CNG Exh RP-2, 8-31-17.xlsx	RP-2, Deferred Costs
NEW CNG Rosales Exh MCR-1T 8-31-17	Direct Testimony of Maryalice Rosales
NEW CNG Exh MCR-2 8-31-17.pdf	MCR-2, Summary of Revenues by Rate Schedule
NEW CNG Exh MCR-2 8-31-17.xlsx	MCR-2, Summary of Revenues by Rate Schedule
NEW CNG Exh MCR-3 8-31-17.pdf	MCR-3, Revenue Adjustment
NEW CNG Exh MCR-3 8-31-17.xlsx	MCR-3, Revenue Adjustment
NEW CNG Exh MCR-4 8-31-17.pdf	MCR-4, Restatement of Revenue
NEW CNG Exh MCR-4 8-31-17.xlsx	MCR-4, Restatement of Revenue
NEW CNG Exh MCR-2 and WP-1 8-31-17.xlsx	MCR 2 and WPs 1.0 through 1.10, back up information

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT F: RATE CASE COMPLIANCE MATRIX

August 31, 2017

Citation	Requirement	Compliance
WAC 480-07-510 - General rate proceedings		
(1) Testimony and exhibits	The company must file with the commission nineteen paper copies of all testimony and exhibits that the company intends to present as its direct case if the filing is suspended and a hearing held, unless the commission preapproves the filing of fewer copies.	Per a phone conversation between Commission Staff and the Company (Ashley Huff to Maryalice Rosales), Commission Staff preapproved the filing of one original and ten (10) copies.
	In addition, the company must provide one electronic copy of all filed material in the format identified in WAC 480-07-140(6).	On August 31, 2017, the Company submitted the electronic files for all hardcopy documents submitted as part of this general rate case filing. The files were included on a USB thumb drive which was enclosed in the mailed boxes containing the hardcopies of the filing.
	The company must serve a copy of the materials filed under this section on public counsel at the time of filing with the commission in any proceeding in which public counsel will appear.	On August 31, 2017, the Company mailed public counsel a hardcopy of the entire general rate case filing including a USB thumb drive with an electronic version of the filing.
	The utility must provide an exhibit that includes a results-of-operations statement showing test year actual results and the restating and pro forma adjustments in columnar format supporting its general rate request.	The Company's result-of-operation for the test year is presented in Exhibit No. __ (MPP-2). Column (1) of this exhibit provides the test year actuals. Column (2) is the summation of all adjustments, both restating and pro forma, to achieve the pro forma results of operation. Exhibit No. __ (MPP-2) is discussed in Michael P. Parvinen's Direct Testimony.
	The utility must also show each restating and pro forma adjustment and its effect on the results of operations.	Exhibit No. __ (MPP-5) presents four restating adjustments, identified as R-1 through R-4, and nine pro forma adjustments identified as P-1 through P-9. Exhibit No. __ (MPP-5) also shows total impact on the results of operations. Exhibit No. __ (MPP-5) is discussed in Michael P. Parvinen's Direct Testimony.
	The testimony must include a written description of each proposed restating and pro forma adjustment describing the reason, theory, and calculation of the adjustment.	A written description of each proposed restating and pro forma adjustment describing the reason, theory, and calculation of the adjustment is provided in Michael P. Parvinen's Direct Testimony filed as Exhibit No. __ (MPP-1T). See pages 4 through 10.

Citation	Requirement	Compliance
(2) Tariff sheets	The company must file with the commission and provide to public counsel a copy of the proposed new or revised tariff sheets in legislative format, with strike-through to indicate any material to be deleted or replaced and underlining to indicate any material to be inserted, in paper and electronic format, unless already provided as an exhibit under subsection (1) of this section. The company must also file with the commission copies of any tariff sheets that are referenced by new or amended tariff sheets.	The filing includes proposed revised tariffs as Attachment A to the cover letter. Legislative tariffs where the changes to the tariff sheets are in redline/strike-out text is included in the filing as Attachment B. The proposed tariffs are also discussed in Jennifer G. Gross's Direct Testimony and included as Exhibit No. __ (JGG-2). Copies were filed with the Commission and one copy was provided to Public Counsel.
(3) Work papers and accounting adjustments	(a) At the time the company makes its general rate case filing, <u>the company must provide one copy of all supporting work papers of each witness to public counsel and three copies to staff in a format as described in this subsection.</u> Staff and each other party must provide work papers to all other parties within five days after the filing of each subsequent round of testimony filed (e.g., response, rebuttal). If the testimony, exhibits, or work papers refer to a document, including, but not limited to, a report, study, analysis, survey, article or decision, that document must be included as a work paper unless it is a reported court or agency decision, in which case the reporter citation must be provided in the testimony. If a referenced document is voluminous, it need not be provided, but the company must identify clearly the materials that are omitted and their content. Omitted materials must be provided or made available if requested.	The Company's rate case submission mailed on August 31, 2017, included three copies of work papers for Staff. The Company also mailed one copy of all supporting workpapers to public counsel on August 31, 2017. Work papers BR 3 through BR 3.149 are too voluminous to print and are only provided electronically.
(b) Organization	Work papers must be plainly identified and well organized, and must include an index and tabs. All work papers must be cross referenced and include a description of the cross referencing methodology.	Work papers contain an index by witness and identifying tab names. Each page of the work papers is numbered, and has line numbering and a column identifier. Figures are cross referenced when applicable.

Citation	Requirement	Compliance
(c) Electronic documents	Parties must provide all electronic files supporting their witnesses' work papers. The electronic files must be fully functional and include all formulas and linked spreadsheet files. Electronic files that support the exhibits and work papers must be provided using logical file paths, as necessary, by witness, and using identifying file names. A party may file a document with locked, hidden or password protected cells only if necessary to protect the confidentiality of the information within the cells or proprietary information in the document. The party shall designate that portion of the document as confidential under RCW 80.04.095, WAC 480-07-160, and/or a protective order, and the party shall provide it to any person requesting the password who has signed an appropriate confidentiality agreement.	Electronic work papers are fully functional. Each witness's work paper has identifiable names, including tab names which are stated in the footer of the work paper and identified in the work paper's index.
(d) A detailed portrayal of the development	A detailed portrayal of the development of any capital structure and rate of return proposal and all supporting work papers in the format described in this subsection.	The Company's capital structure is discussed in Tammy Nygard's Direct Testimony, filed as Exhibit No. __ (TJN-1T), pages 2 through 5. The case for Cascade's proposed rate of return proposal is presented in J. Stephen Gaske's Direct Testimony, filed as Exhibit No. __ (JSG-1T), and is supported with Exhibit No. __ (JSG-2).
(e) Restating and pro forma adjustments	Parties must provide work papers that contain a detailed portrayal of restating actual and pro forma adjustments that the company uses to support its filing or that another party uses to support its litigation position, specifying all relevant assumptions, and including specific references to charts of accounts, financial reports, studies, and all similar records relied on by the company in preparing its filing, and by all parties in preparing their testimony and exhibits. All work papers must include support for, and calculations showing, the	A detailed portrayal of restating actual and pro forma adjustments is presented in Exhibit No. __ (MPP-5) and supporting work papers. The interstate and multiservice allocation factor calculations are found on Work Paper MPP WP 1.1, page 46 of 86.

Citation	Requirement	Compliance
	derivation of each input number used in the detailed portrayal and for each subsequent level of detail. The derivation of all interstate and multiservice allocation factors must be provided in the work papers.	
(i) Change in methodologies for adjustments	If a party proposes to calculate an adjustment in a manner different from the method that the commission most recently accepted or authorized for the company, it must also present a work paper demonstrating how the adjustment would be calculated under the methodology previously accepted by the commission, and a brief narrative describing the change. Commission approval of a settlement does not constitute commission acceptance of any underlying methodology unless so specified in the order approving the settlement.	The Company proposes changes to its weather normalization adjustments as presented in Brian Robertson's Direct Testimony, filed as Exhibit No. __ (BR-1T).
(ii) "Restating actual adjustments"	"Restating actual adjustments" adjust the booked operating results for any defects or infirmities in actual recorded results that can distort test period earnings. Restating actual adjustments are also used to adjust from an as-recorded basis to a basis that is acceptable for rate making. Examples of restating actual adjustments are adjustments to remove prior period amounts, to eliminate below-the-line items that were recorded as operating expenses in error, to adjust from book estimates to actual amounts, and to eliminate or to normalize extraordinary items recorded during the test period.	Restating actual adjustments are discussed in Michael Parvinen's Direct Testimony, filed as Exhibit No. __ (MPP-1T), and are presented in summary in column (2) of Exhibit No. __ (MPP-2) and are included individually in Exhibit No. __ (MPP-5).
(iii) "Pro forma adjustments"	"Pro forma adjustments" give effect for the test period to all known and measurable changes that are not offset by other factors. The work papers must identify dollar values and underlying reasons for each proposed pro forma adjustment.	Pro forma adjustments are discussed in Michael Parvinen's Direct Testimony, filed as Exhibit No. __ (MPP-1T) and are presented in summary in column (2) of Exhibit No. __ (MPP-2), and are included individually in Exhibit No. __ (MPP-5). Michael Parvinen's Direct Testimony identifies the underlying reason for the pro forma adjustments.

Citation	Requirement	Compliance
(f) A detailed portrayal of revenue sources.	A detailed portrayal of revenue sources during the test year and a parallel portrayal, by source, of changes in revenue produced by the filing, including an explanation of how the changes were derived.	Sources of revenue during the test year are discussed in Maryalice Rosales's Direct Testimony, filed as Exhibit No. __ (MCR-1T). Exhibit No. ___ (MCR-2) shows revenues by rate schedule; Exhibit No. ___ (MCR-3) shows adjustments to revenue; and Exhibit No. ___ (MCR-4) shows weather normalized, adjusted test year revenues. Work Papers identify source documents.
(g) ROR explanation	If the public service company has not achieved its authorized rate of return, an explanation of why it has not and what the company is doing to improve its earnings in addition to its request for increased rates.	Discussions on why Cascade needs a rate case and how Cascade has controlled costs to mitigate the need for a rate case are found on pages 4-5 of Nicole Kivisto's Direct testimony, included as Exhibit No. __ (NAK-1T).
(h) Representation of rate base and results of operations	A representation of the actual rate base and results of operation of the company during the test period, calculated in the manner used by the commission to calculate the company's revenue requirement in the commission's most recent order granting the company a general rate increase.	These items are discussed in Michael Parvinen's Direct Testimony, filed as Exhibit No. __ (MPP-1T) and presented in Exhibit No. __ (MPP-2). Detailed rate base calculations are included in MPP WP 1.1, 1.2, 1.3 and 1.4.
(i) Supplementation of the annual affiliate and subsidiary transaction reports	Supplementation of the annual affiliate and subsidiary transaction reports as provided in rules governing reporting requirements for each industry, as necessary, to include all transactions during the test period. The company is required to identify all transactions that materially affect the proposed rates.	Affiliate transaction detail was provided in Cascade's Annual Affiliate Interest Report filed on April 27, 2017, in Docket No. 170303.
(4) Summary document	The company must file with the commission a summary document that briefly states the following information on an annualized basis, if applicable. In presenting the following information, the company must itemize revenues from any temporary, interim, periodic, or other noncontinuing tariffs.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	The company must include in its rate change percentage and revenue change calculations any revenues from proposed general rate change tariffs that would	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.

Citation	Requirement	Compliance
	supersede revenue from noncontinuing tariffs. The summary document must also include:	
	(a) The date and amount of the latest prior general rate increase authorized by the commission, and the revenue realized from that authorized increase in the test period, based on the company's test period units of revenue.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(b) Total revenues at present rates and at requested rates.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(c) Requested revenue change in percentage, in total, and by major customer class.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(d) Requested revenue change in dollars, in total, and by major customer class.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(e) Requested rate change in dollars, per average customer, by customer class, or other representation, if necessary to depict representative effect of the request. The summary document must also state the effect of the proposed rate increase in dollars per month on typical residential customers by usage categories.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(f) Most current customer count, by major customer class.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(g) Current authorized overall rate of return and authorized rate of return on common equity.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(h) Requested overall rate of return and requested rate of return on common equity, and the method or methods used to calculate rate of return on common equity.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(i) Requested capital structure.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(j) Requested net operating income.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
	(k) Requested rate base and method of calculation, or equivalent.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.

Citation	Requirement	Compliance
	(l) Requested revenue effect of attrition allowance, if any is requested.	This information is provided in the Company's "Summary Document", included as Attachment C to the cover letter.
(5) **Required service of summary document**	The company must serve the summary document on public counsel and mail the summary document described in subsection (4) of this section to the persons designated below on the same date it files the summary document with the commission:	On August 31, 2017, the Company mailed public counsel a hardcopy of the entire general rate case filing including the Company's "Summary Document", included as Attachment C to the cover letter.
	(a) All intervenors on the commission's master service list for the company's most recent general rate proceeding;	On August 31, 2017, the Company also emailed the Company's "Summary of Request Natural Gas Rate Increase" to all persons on the Commission's master service list for the Company's most recent general rate case.
	(b) All intervenors on the master service list for any other rate proceeding involving the company during the five years prior to the filing, if the rates established or considered in that proceeding may be affected in the company's proposed general rate filing;	On August 31, 2017, the Company also emailed the Company's "Summary of Request Natural Gas Rate Increase" to all persons who intervened in UG-170855.
	(c) All persons who have informed the company in writing that they wish to be provided with the summary document required under this section. The company must enclose a cover letter stating that the pre-filed testimony and exhibits and the accompanying work papers, diskettes, and publications specified in this rule are available from the company on request or stating that they have been provided. This provision does not create a right to notice in persons named to receive the summary.	No one has yet contacted the Company asking to be provided with a summary document. If the Company does receive such a request the information along with the prescribed cover letter will be provided.
(6) **Cost studies**	The company must file with the commission any cost studies it performed or relied on to prepare its filing, identify all cost studies conducted in the last five years for any of the company's services, and describe the methodology used in such studies.	See Exhibit No. __ (RJA-1T). Also, The Company had Cost of Service Studies prepared for the general rate cases, UG-152286 in WA, UG 287, and UG 305 in OR. The Company had Administrative and General Cost Comparisons prepared for UG-152286 and UG-287.

Citation	Requirement	Compliance
(7) **Other**	The company must file with the commission its most recent annual report to shareholders, if any, and any subsequent quarterly reports to shareholders; the most recent FERC Form 1 and FERC Form 2, if applicable; and the company's Form 10K's, Form 10Q's, any prospectuses for any issuances of securities, and quarterly reports to stockholders, if any, for the most recent two years prior to the filing date.	The Company filed one original and ten copies of these financial reports with its rate case docketed as UG-170855. Per a conversation with Staff (Schooley) the only new financial report included in this filing is the most recent 10Q.

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT G: FINANCIAL DOCUMENTS

August 31, 2017

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

FINANCIAL DOCUMENTS
REQUIRED PER
WAC 480-07-510(7)

Cascade filed a general rate with the Commission on July 31, 2017, that was docketed as UG-170855. In response to a Commission Motion to reject the filing, the Company withdrew the filing in its entirety. With the understanding that the Company would be refiling a rate case by August 31, 2017, Commission Staff (Schooley) agreed to retain the financial documents submitted in UG-170855 in compliance with WAC 480-07-510(7), allowing the Company to forgo re-copying those same documents for its August 31, 2017, filing. In accordance with this understanding, the following documents are provided electronically but copies are not included with the hardcopy submission.

NEW, CNGC Financial docs 2016 10-K Annual Rpt, 8.31.17.pdf	Most recent annual report to shareholders
NEW, CNGC Financial docs 2016 FERC Form No.2, 8.31.17.pdf	Most recent FERC Form 2
NEW, CNGC Financial docs 2016 Washington Supplement, 8.31.17.pdf	Most recent FERC Form 2 Supplement
NEW, CNGC Financial docs 2015 10-K Annual Rpt, 8.31.17.pdf	Form 10-Ks
NEW, CNGC Financial docs 2014 10-K Annual Rpt, 8.31.17.pdf	Form 10-Ks
NEW, CNGC Financial docs 6.30.15 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 9.30.15 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 3.31.16 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 6.30.16 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 9.30.16 MDU 10-Q, 8.31.17.pdf	Form 10-Qs
NEW, CNGC Financial docs 3.31.17 MDU 10-Q, 8.31.17.pdf	Form 10-Qs

The following file was issued after UG-170855 was filed. Hardcopies and an electronic file are provided with this filing

NEW, CNGC Financial docs 6.30.17 MDU 10-Q, 8.31.17.pdf	Form 10-Qs

CASCADE NATURAL GAS CORPORATION GENERAL RATE CASE
Docket No. UG-17____

ATTACHMENT H: CERTIFICATE OF SERVICE

August 31, 2017

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Cascade Natural Gas Corporation's Summary Document in its Washington General Rate Case Filing upon all parties of record in this proceeding by mail to the addresses of each party or party representative as listed below.

Stokes, Chad M Attorney Cable Huston Benedick Haagensen & Lloyd, LLP 1001 SW 5th Avenue Portland, OR 97204 cstokes@cablehuston.com	Shearer, Brett Assistant Attorney General WUTC PO Box 40128 Olympia, WA 98504-0128 Bshearer@utc.wa.gov
O'Connell, Andrew Assistant Attorney General WUTC P.O. Box 40128 Olympia, WA 98504 AOConnel@utc.wa.gov	Brooks, Tommy A Attorney Cable Huston Benedick Haagensen & Lloyd, LLP 1001 SW 5th Avenue Portland, OR 97204-1136 tbrooks@cablehuston.com
ffitch, Simon Attorney at Law 321 High School Rd. NE, Suite D3, Box No. 383 Bainbridge Island, WA 98110 simon@ffitchlaw.com	Gafken, Lisa W Office of the Attorney General 800 Fifth Avenue, Suite 2000 Seattle, WA 98104-3188 Lisa.gafken@atg.wa.gov
Armikka R. Bryant Assistant Attorney General Office of the Attorney General 800 Fifth Avenue, Suite 2000 Seattle, WA 98104-3188 ArmikkaB@atg.wa,.gov	Rackner, Lisa McDowell Rackner & Gibson PC 419 SW 11th Avenue Portland, OR 97205 lisa@mcd-law.com
Shawn Collins The Energy Project 3406 Redwood Avenue Bellingham, WA 98225 shawnc@oppco.org	

I declare under penalty of perjury that the foregoing is true and correct.
Dated at Kennewick, Washington this 31th day of August 2017.

/s/ *Maryalice Rosales*
Maryalice Rosales
Regulatory Analyst II
Cascade Natural Gas Corporation

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UG-17____

MICHAEL P. PARVINEN

CASCADE NATURAL GAS CORPORATION

CLAIM OF CONFIDENTIALITY

I, Michael P. Parvinen, represent Cascade Natural Gas Corporation. I am Director for Regulatory Affairs for Cascade Natural Gas Corporation ("Cascade" or "Company") and I am appearing on its behalf in this proceeding.

I make this claim of confidentiality pursuant to WAC 480-07-160(3)(a) because Cascade, through its supporting exhibits and workpapers provided in the above captioned docket, is disclosing certain information that is CONFIDENTIAL and constitutes VALUABLE COMMERCIAL INFORMATION as defined by WAC 480-07-160(2) and protected under WAC 480-07-160 and RCW 80-04-095.

Any printed information Cascade provides will, as required under WAC 480-07-160, be marked as CONFIDENTIAL PER WAC 480-07-160, submitted on yellow or canary paper, and will be provided under separate cover. The electronic information Cascade provides will also be marked as CONFIDENTIAL PER WAC 480-07-160.

The confidential information that Cascade is disclosing can be classified as information pertaining to contract prices, terms and conditions, risk management practices, and plant operation data, and, as such, comprises valuable commercial information. Cascade also asserts that the aforementioned information is confidential in that certain contract information is prohibited, by the contract terms, from public disclosure.

I am of the opinion, therefore, that this information is "CONFIDENTIAL," as defined by WAC 480-07-160, and should be protected from public inspection, examination and copying.

RESPECTFULLY SUBMITTED this 31st day of August 2017.

/s/ Michael P. Parvinen

____

Michael P. Parvinen
Director
Regulatory Affairs
Cascade Natural Gas Corporation

Exhibit No. __ (NAK-1T)
Docket No. UG-17____
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-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF NICOLE A. KIVISTO

August 31, 2017

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Please describe your duties and responsibilities.

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-two 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 Natural Gas Co. 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 case, Docket No. UG-152286, and before the Public Utility Commission of Oregon in Cascade's most recent Oregon rate case, Docket No. UG 305.

II. SCOPE AND SUMMARY OF TESTIMONY

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

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

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

A. Yes. Increasing rate base and operating expenses require Cascade to request an increase of $5,884,984 or 2.71 percent. This increase is based on an overall rate of return of 7.60 percent with a capital structure common equity component of 50 percent and a return on equity of 9.9 percent. The Company is using a historical test year based on the twelve months ended December 31, 2016. The 2016 test year was selected as the most recent, appropriate, and supportable to represent the period in which rates will be in effect. Mr. Michael Parvinen provides further discussion of the test period in his testimony. The Company is using the results of an embedded cost of service study as a starting point in the proposed spread of the requested increase to the various rate schedules. The results of the cost of service study show that the residential customer class is highly subsidized by the other rate classes; therefore, the proposed increase is being assigned primarily to the residential class, bringing rates more in line with actual costs to provide service. Mr. Ronald Amen provides testimony supporting the cost study and rate spread issues.

Based on an average usage level of 54 therms per month, the average residential customer will see a bill increase of $2.09 per month from $47.45 to $49.54. This equates to an average increase of 4.41 percent.

Q. When was the Company's last general rate increase?

A. Cascade's last filed general rate case in Washington was in December 2015, docketed as UG-152286. Prior to 2015, Cascade had not filed a rate case since 2006 in Docket No. UG-060256. The 2015 rate case resulted in a 1.6 percent increase, or $4 million in additional revenue.

III. OVERVIEW OF CASCADE

Q. Please briefly provide an overview of the Company.

A. Cascade provides natural gas distribution service in 96 communities in Washington and Oregon. Cascade's headquarters is located in Kennewick, Washington. Cascade is wholly owned by MDU Resources, which is located in Bismarck, North Dakota. Cascade has 282,186 customers, of which 210,000 are in Washington. Although Cascade serves approximately 50 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 was originally formed in 1953 to serve smaller and predominantly rural communities in the Pacific Northwest. Cascade serves a non-contiguous service territory with 339 dedicated employees. Cascade became a subsidiary of MDU Resources in 2007.

IV. REASONS FOR RATE INCREASE REQUEST

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

A. There is not one primary factor causing the rate increase, but rather a combination of increased rate base additions and increased pressures on operating and maintenance ("O&M") expenditures. In fact, depreciation expense alone is nearly $2 million higher than the last rate case, as a result of the Company's substantial investments to assure the safety and reliability of its system. Notably, the 2017 capital budget for Washington includes over $47 million for planned investments. Of the $47 million in planned investments, $11 million will be used to replace segments of our highest risk pipeline and is included in the annual pipeline Cost Recovery Mechanism ("CRM"). The rate base included in this filing includes only $18 million of the remaining $36 million of investment. Mr. Parvinen provides support for the inclusion of this investment in his direct testimony. Revenue producing investment is anticipated to be $15 million. Of the Company's planned investments, approximately $3 million will not be used and useful in time to allow for recovery in this case or have other offsetting factors, and accordingly those planned investments are not included in this request for recovery.

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

A. Cascade has a history of mitigating increased cost pressures in order to avoid filing rate cases. Since the acquisition by MDU Resources, Cascade has found synergy savings in the form of joint senior management, a unified customer service center, a joint billing facility and process, and uniform accounting and customer information system software. The utility group continues to look for ways to acquire such synergies including a new Gas Management System ("GMS") and centralization of other functions. In fact, Administrative and General ("A&G") costs in the current test year are less than one percent higher than the previous rate case test year a year and a half later.

V. CUSTOMER SUPPORT PROGRAMS

Q. Does Cascade offer its customers any bill assistance programs to help mitigate the effect of necessary rate increases?

A. Cascade provides a number of programs to assist customers in meeting their energy bill obligations. Cascade has its Washington Energy Assistance Fund ("WEAF") and its Winter Help program to provide bill assistance to low-income customers. Cascade also offers a program called the Budget Payment Plan to customers, which serves to reduce bill volatility associated with seasonal fluctuations in usage.

Cascade also provides conservation programs for all customers, as well as conservation programs through community action agencies specifically designed for low-income customers.

Both the WEAF and conservation programs were updated in the last rate case to better serve low-income customers. The WEAF program has been so successful that the Company has recently filed a petition seeking to lift the funding cap placed on the program which was approved by order on June 28, 2017.

The Commission approved significant modifications to the low-income conservation program in December 2016, which were designed to remove barriers to success and serve more customers. It is too early to evaluate the success of these modifications, however, similar changes in Oregon allowed participation levels to increase to previous American Recovery and Reinvestment Act-funded levels.

Q. Please briefly describe the Budget Payment Plan.

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

Q. How many of Cascade's customers take advantage of the Company's Budget Payment Plan?

A. As of December 31, 2016, there are 19,180 Washington customers participating in the Budget Payment Plan, or 9.1 percent of Cascade's Washington customers.

VI. GENERAL COMMENTS

Q. Do you have any general comments in regards to Cascade's recent interactions with the Commission?

A. Yes. Cascade's 2014 Integrated Resource Plan ("IRP") was not well received by the Commission. The Company seriously and carefully considered the feedback provided by the Commission and has made a concerted effort to not only provide adequate staffing resources to develop the 2016 plan, including two new full-time personnel and the addition of services from an outside consultant, but also to incorporate IRP planning considerations into the day to day operations of the Company. Cascade filed its 2016 IRP on December 14, 2016, in Docket No. UG-160453, and Cascade believes the 2016 IRP was a significant improvement over the 2014 IRP as noted in the Commission's acknowledgement letter dated July 14, 2017.

Q. Do you have another example?

A. Yes. I want to ensure that the Commission understands that the company has also taken the Maximum Allowable Operating Pressure ("MAOP") complaint case in Docket No. PG-150120 very seriously. As a result of the complaint, the resulting settlement, and the commitments from management and the board of directors, Cascade will have a verifiably safe system and industry leading asset management processes to assure continuation of adequate and appropriate documentation. Mr. Eric Martuscelli and Mr. Ryan Privratsky provide further details on this process. Mr. Parvinen describes the accounting and rate recovery sought in this proceeding regarding MAOP deferred costs.

The Company has made substantial efforts and commitments to perform to the standards expected from the Commission.

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.

Dr. Stephen Gaske, Senior Vice President – Concentric Energy Advisors, will discuss the requested overall return on equity for Cascade.

Mr. Michael Parvinen, Director – Regulatory Affairs, will discuss the overall revenue requirement, including the proposed adjustments, and will also address the status of commitments from the settlement in the last general rate case, Docket No. UG-152286.

Ms. Jennifer Gross, Regulatory Analyst, will discuss the proposed tariff changes.

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

Ms. Maryalice Rosales, Regulatory Analyst, discusses the test year revenue proof and proposed revenue adjustments.

Mr. Brian Robertson, Senior Resource Planning Analyst, will discuss the weather normalization adjustment and method behind the calculation as well as a status update on Cascade's commitment to initiate a load study arising from the settlement in Docket No. UG-152286.

Mr. Eric Martuscelli, Vice President Operations, will provide an overview of the MAOP settlement from Docket No. PG-150120 as well as provide a discussion of the benefits and justification for recovery of deferred costs associated with MAOP validation.

Mr. Ryan Privratsky, Director of System Integrity, provides a description of work being performed to provide MAOP validation, timelines, and identification of third party costs.

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

A. Yes.

Exhibit No. __ (TJN-1T)
Docket No. UG-17____
Witness: Tammy J. Nygard

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF TAMMY J. NYGARD

August 31, 2017

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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. and Great Plains Natural Gas Co., Divisions of MDU Resources, as well as Controller for Intermountain Gas Company, a subsidiary 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 15 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 Utilities Co., Director of Accounting and Finance for Cascade, and my current position, Controller.

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

A. I explain and support the cost of debt, capital structure and rate of return requested in this proceeding.

In brief, I provide information that shows:

- Cascade's proposed rate of return ("ROR") of 7.598 percent provides a reasonable return for Cascade's investors at a fair cost to Cascade's customers. The ROR is based on a 50.0 percent common equity ratio with a Return on Equity of 9.9 percent and a debt cost of 5.295 percent.

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

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, 2016, was valued at $214,471,000 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 5.295 percent is calculated based on the weighted average outstanding debt at December 31, 2016, 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. Since 2006, the Company has been able to reduce its average annualized cost of debt from approximately 7.598 percent to 5.295 percent.

Q. What has the Company done in recent years to reduce the cost of long-term debt?

A. The Company has taken advantage of the current market's low interest rates by securing new long-term debt corresponding with the anticipated life of the new plant currently being constructed throughout Cascade's service territory. The interest rate spreads between the recently retired debt and newly acquired debt has allowed Cascade to lower average interest rate costs by over 200 basis points.

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 rate of return and capital structure that Cascade is requesting in this case?

A. The Company is requesting a rate of return of 7.598 percent with 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%	9.90%	4.950%
Total Debt	50%	5.295%	2.648%
	100%		7.598%

Q. The Company is proposing a capital structure of 50 percent equity and 50 percent debt. Why does the Company feel this is the appropriate capital structure?

A. The requested capital structure is based upon Cascade's actual average capital structure for the last five years. 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						
	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	Average
Total Debt	46%	52%	49%	53%	52%	50%
Common Equity	54%	48%	51%	47%	48%	50%

Q. Why is the Company proposing a 9.90 percent return on equity?

Dr. J. Stephen Gaske calculated a range for the cost of common equity capital for Cascade's Washington natural gas distribution operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Cascade's Washington gas distribution operations. Dr. Gaske then placed the Company within the range of reasonableness established by the DCF analysis by comparing the risks of Cascade's Washington natural gas distribution operations to those of the proxy gas distribution companies and by considering several alternative benchmark analyses. The basis for the requested 9.90 percent return on equity contained within the overall requested rate of return is explained in further detail in the testimony of Dr. J. Stephen Gaske. The Company agrees with the information presented and conclusion reached by Dr. Gaske that a 9.90 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.

Exhibit No. __ (JSG-1T)
Docket No. UG-17____
Witness: J. Stephen Gaske

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF J. STEPHEN GASKE

August 31, 2017

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

A. My name is J. Stephen Gaske and I am a Senior Vice President of Concentric Energy Advisors, Inc., 1300 19th Street NW, Suite 620, Washington, DC 20036.

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

A. I hold a B.A. degree from the University of Virginia and an M.B.A. degree with a major in finance and investments from George Washington University. I also earned a Ph.D. degree from Indiana University where my major field of study was public utilities and my supporting fields were finance and economics. A copy of my résumé is included as Exhibit No. __ (JSG-3) to this testimony.

Q. Have you presented expert testimony in other proceedings?

A. Yes. I have filed testimony or testified in more than 100 regulatory proceedings in North America. These submissions have included testimony on the cost of capital and capital structure issues for electric and natural gas distribution and oil and natural gas pipeline operations before more than a dozen federal, state, and provincial regulatory bodies in the U.S., Canada, and Mexico, including the Washington Utilities and Transportation Commission ("Commission"). In addition, I have testified or submitted testimony on issues such as cost allocation, rate design, pricing, regulatory principles, market power and generating plant economics before more than a dozen federal, state, and provincial regulatory bodies in the U.S. and Canada. During the course of my consulting career, I have conducted many studies on issues related to regulated industries and have served as an advisor to numerous clients on economic, competitive, and financial matters. I also have spoken and lectured before many professional groups including the American Gas Association and the Edison Electric Institute Rate Fundamentals courses.

I. INTRODUCTION

A. Scope and Overview

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

A. I have been asked by Cascade Natural Gas Corporation ("Cascade" or the "Company") to estimate the cost of common equity capital for the Company's natural gas distribution operations in the state of Washington. In this testimony, I calculate a range for the cost of common equity capital for Cascade's Washington natural gas distribution operations based on a Discounted Cash Flow ("DCF") analysis of a group of proxy companies that have risks similar to those of Cascade's Washington gas distribution operations. I then place the Company within the range of reasonableness established by the DCF analyses by comparing the risks of Cascade's Washington natural gas distribution operations to those of the proxy gas distribution companies and by considering several alternative benchmark analyses.

Q. What rate of return is Cascade requesting in this proceeding?

A. Based on its requested capital structure of 50 percent long-term debt and 50 percent common equity, Cascade is requesting the following rate of return:

Table 1: Requested Rate of Return – Washington Gas Distribution Operations

Source	Percent	Cost	Overall Rate of Return
Long-Term Debt	50.000%	5.295%	2.648%
Common Equity	50.000%	9.900%	4.950%
TOTAL	100.000%		7.598%

As my testimony discusses, an overall allowed rate of return of 7.598 percent, with a 9.9 percent return on common equity, represents the cost of capital for Cascade at this time.

Q. Please explain why your recommended return on common equity of 9.9 percent is reasonable in light of the settlement agreement in the 2015 rate case.

A. The settlement agreement that was approved by the Commission in July 2016 included an authorized return on common equity for Cascade's Washington natural gas distribution operations of 9.40 percent. The settlement agreement was a package deal that resulted from negotiations between Cascade and the various parties. The 9.40 percent authorized return on common equity did not represent an agreement by Cascade that its proposed return on equity was incorrect or unreasonable; rather, it was part of the overall resolution of the contested issues in the 2015 rate case.

B. <u>Company Background</u>

Q. Please describe Cascade's operations and those of its parent company, MDU Resources Group, Inc.

A. Cascade is a wholly-owned division of MDU Resources Group, Inc. ("MDU Resources") that is engaged in natural gas distribution in the states of Washington and Oregon. Within Washington, Cascade provides services to 210,000 residential, commercial and industrial customers in several non-contiguous service territories in western and central Washington. Cascade does not serve any large cities. Instead it serves approximately 50 communities in Washington, the largest of which are Bellingham, Mt. Vernon, Bremerton, Tri-Cities, and Yakima.

Through its division, Montana-Dakota Utilities Co. ("Montana-Dakota"), MDU Resources is engaged in the generation, transmission, and distribution of electricity, and the distribution of natural gas in the states of Montana, North Dakota, South Dakota, and Wyoming. MDU Resources also owns Great Plains Natural Gas Company, which distributes natural gas in the states of Minnesota and North Dakota, and Intermountain Gas Company, which distributes natural gas in the state of Idaho. MDU Resources also is engaged in utility infrastructure construction services, natural gas gathering and transmission, and construction services and contracting.

Natural gas distribution assets comprised 33.4 percent[1] of MDU Resources' total assets in 2016, and natural gas distribution revenues comprised 18.6 percent[2] of total operating revenues. Washington accounted for 26.0 percent of the natural gas distribution operating sales revenues, while Idaho (34.0 percent), North Dakota 13.0 percent), Montana (8.0 percent), Oregon (8.0 percent), South Dakota (6.0 percent), Minnesota (3.0 percent) and Wyoming (2.0 percent) accounted for the other 74.0 percent of retail gas distribution operating sales revenues.[3]

Q. Would you please describe Cascade's Washington natural gas distribution service territory?

A. Cascade provides natural gas distribution service in Washington. The customer base in Washington is 87 percent residential customers and 13 percent commercial and industrial customers. Cascade's service territory consists of towns and small cities dotted throughout relatively sparsely populated areas. As such, the economy is heavily dependent on providing retail and other services for surrounding agricultural areas, and several cities are heavily dependent on military bases or government facilities.

Q. What is your understanding of the factors that are driving this rate case filing by Cascade?

A. Company witness Nicole A. Kivisto explains that the primary reasons for the filing are increased investment to replace aging infrastructure in order to enhance reliability and meet new federal safety standards, recovery of the amount in a deferral account for pipeline improvements to maintain Cascade's maximum allowable operating pressures ("MAOP"), and higher depreciation expense associated with the increased rate base additions. Ms.

[1] MDU Resources Group, 2016 SEC Form 10-K, at 81.
[2] *Ibid.*, at 80.
[3] *Ibid.*, at 12.

Kivisto testifies that Cascade's 2017 capital budget for Washington includes just over $47 million for planned investments. Of the $47 million in planned investments, $11 million will be used to replace segments of Cascade's highest risk pipeline and is included in the annual pipeline Cost Recovery Mechanism ("CRM"). The rate base included in this filing includes only $18 million of the remaining $36 million of investment.

II. FINANCIAL MARKET STUDIES

A. Criteria for a Fair Rate of Return

Q. Please describe the criteria which should be applied in determining a fair rate of return for a regulated company.

A. The United States Supreme Court has provided general guidance regarding the level of allowed rate of return that will meet constitutional requirements. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)), the Court indicated that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

The Court has further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)). There the Court described the relevant criteria as follows:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Thus, the standards established by the Court in *Hope* and *Bluefield* consist of three requirements. These are that the allowed rate of return should be:

1. commensurate with returns on enterprises with corresponding risks;
2. sufficient to maintain the financial integrity of the regulated company; and
3. adequate to allow the company to attract capital on reasonable terms.

These legal criteria will be satisfied best by employing the economic concept of the "cost of capital" or "opportunity cost" in establishing the allowed rate of return on common equity. For every investment alternative, investors consider the risks attached to the investment and attempt to evaluate whether the return they expect to earn is adequate compensation for the risks undertaken. Investors also consider whether there might be other investment opportunities that would provide a better return relative to the risk involved. This weighing of alternatives and the highly competitive nature of capital markets causes the prices of stocks and bonds to adjust in such a way that investors can expect to earn a return that is just adequate for the risks involved. Thus, for any given level of risk, there is a return that investors expect in order to induce them to voluntarily undertake that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

Q. How should a fair rate of return be evaluated from the standpoint of consumers and the public?

A. The same standards should apply. When an unregulated entity faces competition, the pressure of that competition and consumer choices will combine to determine the fair rate of return. However, when regulation is appropriate, consumers and the public have a long-term interest in seeing that the regulated company has an opportunity to earn returns that are not so high as to be excessive, but that also are sufficient to encourage continued replacement and maintenance, as well as needed expansions, extensions, and new services. Thus, both the consumer and the public interest depend on establishing a return that will readily attract capital without being excessive.

Q. How are the costs of preferred stock and long-term debt determined?

A. For purposes of setting regulated rates, the current embedded costs of preferred stock and long-term debt are used in order to ensure that the company receives a return that is sufficient to pay the fixed dividend and interest obligations that are attached to these sources of capital.

Q. How is the cost of common equity determined?

A. The practice in setting a fair rate of return on common equity is to use the current market cost of common equity in order to ensure that the return is adequate to attract capital and is commensurate with returns available on other investments with similar levels of risk. However, determining the market cost of common equity is a relatively complicated task that requires analysis of many factors and some degree of judgment by an analyst. The current market cost of capital for securities that pay a fixed level of interest or dividends is relatively easy to determine. For example, the current market cost of debt for publicly-traded bonds can be calculated as the yield-to-maturity, adjusted for flotation costs, based on the current market price at which the bonds are selling. In contrast, because common stockholders receive only the residual earnings of the company, there are no fixed contractual payments which can be observed. This uncertainty associated with the dividends that eventually will be paid greatly complicates the task of estimating the cost of common equity capital. For purposes of this testimony, I have relied on several analytical approaches for estimating the cost of common equity. My primary approach relies on two DCF analyses. In addition, I have conducted two types of risk premium analyses, a market DCF analysis of the S&P 500, and a Capital Asset Pricing Model ("CAPM") analysis as benchmarks to assess the reasonableness of the DCF results. Each of these approaches is described later in this testimony.

B. Interest Rates and the Economy

Q. What are the general economic factors that affect the cost of capital?

A. Companies attempting to attract common equity must compete with a variety of alternative investments. Prevailing interest rates and other measures of economic trends influence investors' perceptions of the economic outlook and its implications on both short- and long-term capital markets. Page 1 of Schedule 1 of Exhibit No.___(JSG-2) shows various general economic statistics. Real growth in Gross Domestic Product ("GDP") has averaged 2.6 percent annually during the past 30 years, 2.3 percent for the past 20 years, and 1.3 percent for the past 10 years. After increasing at an annual rate of 2.1 percent in the fourth quarter of 2016, the Bureau of Economic Analysis reported that the "second" estimate for the first quarter of 2017 was a real annual economic growth rate of 1.2 percent.[4] According to Blue Chip Economic Indicators, the consensus forecast for expected growth in real GDP is 2.2 percent in 2017[5] and 2.4 percent in 2018.[6] Likewise, the U.S. unemployment rate has improved in recent months to 4.3 percent for May 2017,[7] but the labor force participation rate for civilians 16 years and over was at 62.7 percent for May 2017, remaining near the lowest rate since the late 1970s.[8] Improvements in the U.S. unemployment rate contributed to the Federal Reserve's decision in June 2017 to raise its target range for the federal funds rate to a range between 1.00 – 1.25 percent for overnight loans to banks.[9]

In October 2014, the Federal Open Market Committee ("FOMC") ended its Quantitative Easing program, which provided extraordinary monetary stimulus for the U.S. economy for several years through asset purchases of mortgage-backed securities and Treasury bonds. However, the Federal Reserve's accommodative policy continues today. Specifically, in May the FOMC recently noted, "[the FOMC's] policy, by keeping the Committee's holdings of longer-term securities at sizable levels, should help maintain accommodative financial conditions."[10] But, in June, the FOMC announced a

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4 U.S. Department of Commerce, Bureau of Economic Analysis, News Release, May 27, 2017.
5 Blue Chip Economic Indicators, Vol. 42, No. 6, June 10, 2017, at 2.
6 *Ibid.*, at 3.
7 U.S. Department of Labor, Bureau of Labor Statistics, News Release, June 2, 2017, at 1.
8 Ibid, at 2.
9 Statement of the Federal Open Market Committee, June 14, 2017.
10 Statement of the Federal Open Market Committee, May 3, 2017.

contemplated end to accommodative monetary policies later this year by gradually reducing the Federal Reserve's securities holdings by decreasing reinvestment of principal payments from those securities.[11] This new policy will begin to put upward pressure on interest rates by reducing the funds available in the market. According to the July 2017 issue of Blue Chip Financial Forecasts, approximately 81 percent of economists surveyed expect the Federal Reserve will begin to shrink the size of its balance sheet in the second half of 2017.[12]

In addition to the stated expectations of the FOMC, leading economists and market analysts are expecting additional increases in interest rates in the short and medium term. The July 2017 issue of Blue Chip Financial Forecasts surveyed market participants concerning their views regarding the magnitude and timing of future increases in short-term rates by the Federal Reserve. In response to the question regarding how much more the Federal Reserve will raise interest rates in 2017, 85 percent of those surveyed by Blue Chip expect an additional increase of 25 basis points and 9 percent expect an additional increase of 50 basis points.[13] In response to the same question for 2018, 22 percent of those surveyed expect a total increase of 50 basis points in 2018, 44 expect a total increase of 75 basis points, and 30 percent expect a total increase of 100 basis points.[14] The average yield on the 30-year U.S. Treasury bond in June 2017 was 2.80 percent. By contrast, the Blue-Chip consensus estimate projects that the average yield on the 30-year U.S. Treasury bond will increase to 4.30 percent for the period from 2019 through 2023.[15] Thus, the consensus estimate from leading economists is for an increase of 150 basis points in U.S. Treasury bond yields over the next several years.

As pages 2 and 3 of Schedule 1 of Exhibit No.___(JSG-2) show, interest rates on longer-term U.S. Treasury bonds and A-rated and Baa-rated public utility bonds have

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11 Statement of the Federal Open Market Committee, June 14, 2017.
12 Blue Chip Financial Forecasts, Vol. 36, No. 7, July 1, 2017, at 14.
13 Ibid.
14 Ibid.
15 Blue Chip Financial Forecasts, Vol. 36, No. 6, June 1, 2017, at 14.

increased substantially since July 2016. For example, between July 2016 and May 2017, the average yield on 30-year US Treasury bonds increased from 2.22 percent to 2.96 percent, the average yield on A-rated public utility bonds increased from 3.57 percent to 4.12 percent, and the average yield on Baa-rated public utility bonds increased from 4.16 percent to 4.50 percent.

Investors also are influenced by both the historical and projected level of inflation. As also shown on Page 1 of Schedule 1 of Exhibit No.___(JSG-2), during the past decade, the Consumer Price Index has increased at an average annual rate of 1.8 percent and the GDP Implicit Price Deflator, a measure of price changes for all goods produced in the United States, has increased at an average rate of 1.6 percent. According to Blue Chip Economic Indicators, the Consumer Price Index is forecasted to increase by 2.3 percent[16] and 2.2 percent[17] for 2017 and 2018, respectively.

Q. How are current economic conditions reflected in the equity markets?

A. The equity markets have recovered from the large stock market decline in 2008 and 2009, but the Federal Reserve's massive purchases of federal debt and mortgage-backed securities have created artificially low interest rates on government bonds and a potential stock market valuation bubble that increases the risks in the equity market.

C. Discounted Cash Flow ("DCF") Method

Q. Please describe the DCF method of estimating the cost of common equity capital.

A. The DCF method reflects the assumption that the market price of a share of common stock represents the discounted present value of the stream of all future dividends that investors expect the firm to pay. The DCF method suggests that investors in common stocks expect to realize returns from two sources: a current dividend yield plus expected growth in the value of their shares as a result of future dividend increases. Estimating the cost of capital with the DCF method, therefore, is a matter of calculating the current dividend yield and

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16 Blue Chip Economic Indicators, Vol. 42, No. 6, June 10, 2017, at 2.

17 *Ibid.*, at 3.

estimating the long-term future growth rate in dividends that investors reasonably expect from a company.

The dividend yield portion of the DCF method utilizes readily-available information regarding stock prices and dividends. The market price of a firm's stock reflects investors' assessments of risks and potential earnings as well as their assessments of alternative opportunities in the competitive financial markets. By using the market price to calculate the dividend yield, the DCF method implicitly recognizes investors' market assessments and alternatives. However, the other component of the DCF formula, investors' expectations regarding the future long-run growth rate of dividends, is not readily apparent from stock market data and must be estimated using informed judgment.

Q. What is the appropriate DCF formula to use in this proceeding?

A. There can be many different versions of the basic DCF formula, depending on the assumptions that are most reasonable regarding the timing of future dividend payments. In my opinion, it is most appropriate to use a model that is based on the assumptions that dividends are paid quarterly and that the next annual dividend increase is a half year away. One version of this quarterly model assumes that the next dividend payment will be received in three months, or one quarter. This model multiplies the dividend yield by (1 + 0.75g). Another version assumes that the next dividend payment will be received today. This model multiplies the dividend yield by (1 + 0.5g). Since, on average, the next dividend payment is a half quarter away, the average of the results of these two models is a reasonable approximation of the average timing of dividends and dividend increases that investors can expect from companies that pay dividends quarterly. The average of these two quarterly dividend models is:

$$K = \frac{D_0(1 + 0.625g)}{P} + g$$

Where: K = the cost of capital, or total return that investors expect to receive;

P = the current market price of the stock;

D_0 = the current annual dividend rate; and

g = the future annual growth rate that investors expect.

In my opinion, this is the DCF model that is most appropriate for estimating the cost of common equity capital for companies that pay dividends quarterly, such as those used in my analysis.

D. Flotation Cost Adjustment

Q. Does the investor return requirement that is estimated by a DCF analysis need to be adjusted for flotation costs in order to estimate the cost of capital?

A. Yes. There are significant costs associated with issuing new common equity capital, and these costs must be considered in determining the cost of capital. Schedule 2 of Exhibit No.___(JSG-2) shows a representative sample of flotation costs incurred with 34 new common stock issues by natural gas distribution companies since January 2004. Flotation costs associated with these new issues averaged 4.09 percent.

This indicates that in order to be able to issue new common stock on reasonable terms, without diluting the value of the existing stockholders' investment, Cascade must have an expected return that places a value on its equity that is approximately 4.0 percent above book value. The cost of common equity capital is therefore the investor return requirement multiplied by 1.04.

One purpose of a flotation cost adjustment is to compensate common equity investors for past flotation costs by recognizing that their real investment in the company exceeds the equity portion of the rate base by the amount of past flotation costs. For example, the proxy companies generally have incurred flotation costs in the past and, thus, the cost of capital invested in these companies is the investor return requirement plus an adjustment for flotation costs. A more important purpose of a flotation cost adjustment is to establish a return that is sufficient to enable a company to attract capital on reasonable terms. This fundamental requirement of a fair rate of return is analogous to the well-understood basic principle that a firm, or an individual, should maintain a good credit rating even when they do not expect to be borrowing money in the near future. Regardless of whether a company can confidently predict its need to issue new common stock several years in advance, it should be in a position to do so on reasonable terms at all times without dilution of the value of the existing investors' common equity. This requires that the flotation cost adjustment be applied to the entire common equity investment and not just a portion of it.

E. <u>DCF Study of Natural Gas Distribution Companies</u>

Q. Would you please describe the overall approach used in your DCF analysis of Cascade's cost of common equity for its Washington natural gas distribution operations?

A. Because Cascade's Washington natural gas distribution operations must compete for capital with many other potential projects and investments, it is essential that the Company have an allowed return that matches returns potentially available from other similarly risky investments. The DCF method provides a good measure of the returns required by investors in the financial markets. However, the DCF method requires a market price of common stock to compute the dividend yield component. Since Cascade is a subsidiary of MDU Resources and does not have publicly-traded common stock, a direct, market-based DCF analysis of Cascade's Washington natural gas distribution operations as a stand-alone company is not possible. As an alternative, I have used a group of natural gas distribution companies that have publicly-traded common stock as a proxy group for purposes of estimating the cost of common equity for Cascade's Washington natural gas distribution operations.

Q. How did you select a group of natural gas distribution proxy companies?

A. I started with the eleven companies that The Value Line Investment Survey ("Value Line") classifies as Natural Gas Utilities to ensure that the company is considered to be primarily engaged in the natural gas distribution business and that retention growth rate projections are available. From that group, I eliminated any companies that did not have investment-grade credit ratings from either Standard & Poor's ("S&P") or Moody's Investors Service ("Moody's") because such companies are not sufficiently comparable in terms of business and financial risk to Cascade. In addition, I excluded any companies that did not pay dividends, or that did not have future growth rate estimates provided by either Zacks or Thomson First Call, or that were currently engaged in significant mergers or acquisitions. In order to ensure that the companies are primarily engaged in the natural gas distribution business, I eliminated any companies that did not derive at least 65 percent of their operating income from regulated natural gas distribution operations in 2016, or that did not have at least 65 percent of their total assets devoted to the provision of natural gas distribution service in 2016. As shown on page 1 of Schedule 3 of Exhibit No.___(JSG-2), seven companies met these criteria for inclusion in the proxy group.

Q. How did you calculate the dividend yields for the companies in your proxy group?

A. These calculations are shown on page 1 of Schedule 4 of Exhibit No.___(JSG-2). For the price component of the calculation, I used the average of the high and low stock prices for each month during the six-month period from November 2016 through April 2017. The average monthly dividend yields were calculated for each proxy group company by dividing the prevailing annualized dividend for the period by the average of the stock prices for each month. These dividend yields were then multiplied by the quarterly DCF model factor ($1 + 0.625g$) to arrive at the projected dividend yield component of the DCF model.

Q. Please describe the method you used to estimate the future growth rate that investors expect from this group of companies.

A. There are many methods that reasonably can be employed in formulating a growth rate estimate, but an analyst must attempt to ensure that the end result is an estimate that fairly reflects the forward-looking growth rate that investors expect. I developed two different DCF analyses of the proxy companies. In the first approach, I conducted a Basic DCF analysis that relied on analysts' earnings forecasts for the growth rate component of the model. My second approach used a combination of the analysts' earnings growth projections and "sustainable growth" rate forecasts calculated from Value Line data (based on growth from earnings retention and stock issuances) to produce a Blended Growth Rate Analysis.

F. Basic DCF Analysis

Q. How did you estimate the expected future growth rate in your Basic DCF analysis?

A. In my Basic DCF analysis, I have estimated expected future growth based on long-term earnings per share growth rate forecasts of investment analysts, which are an important source of information regarding investors' growth rate expectations. This Basic DCF analysis assumes that the analysts' earnings growth forecasts incorporate all information required to estimate a long-term expected growth rate for a company. I have used the consensus estimates of earnings growth forecasts published by Zacks Investment Research and Thomson First Call (as reported on Yahoo! Finance) as the primary sources for analysts' forecasts in my calculations. As shown on page 2 of Schedule 4 of Exhibit No.___(JSG-2), the average of the analysts' long-term earnings growth rate estimates for the natural gas distribution proxy companies is 5.86 percent, and the median is 6.00 percent.

Q. How did you calculate the cost of capital using the Basic DCF analysis?

A. These calculations are shown on page 5 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield is multiplied by the quarterly dividend adjustment factor ($1 + 0.625g$), and this product is added to the growth rate estimate to arrive at the investor-required return. Then, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the Basic DCF estimate of the cost of common equity capital for the proxy companies. The Basic DCF analysis indicates a cost of common equity for the proxy companies in a range from 7.11 percent to 11.84 percent. In this analysis, the median for the group is 9.22 percent and the third quartile is 10.22 percent.

G. Blended Growth Rate Analysis

Q. How did you use your Blended Growth Rate Analysis to estimate investors' long-term growth rate expectations for the proxy companies?

A. The Blended Growth Rate approach combines: (i) Sustainable growth rates based on Value Line retention growth rate forecasts (B*R), plus earnings accretion from new shares (S*V); and (ii) consensus estimates of long-term earnings growth for each company from various investment analysts, as published by Zacks and Thomson First Call

Q. What approach did you use in calculating the expected long-term retention growth rate?

A. The long-term retention growth rate component is based on the calculation of retention growth rates using Value Line forecasts for each company.

Q. Please describe the retention growth rate component of your analysis.

A. I have relied upon Value Line projections of the retention growth rates that the proxy companies are expected to begin maintaining three to five years in the future. Although companies may experience extended periods of growth for other reasons, in the long-run, growth in earnings and dividends per share depends in part on the amount of earnings that is being retained and reinvested in a company. Thus, the primary determinants of growth for the proxy companies will be (i) their ability to find and develop profitable opportunities; (ii) their ability to generate profits that can be reinvested in order to sustain growth; and, (iii) their willingness and inclination to reinvest available profits. Expected future retention rates provide a general measure of these determinants of expected growth, particularly items (ii) and (iii).

Q. How can a company's earnings retention rate affect its future growth?

A. Retention of earnings causes an increase in the book value per share and, other factors being equal, increases the amount of income that is generated per share of common stock. The retention growth rate can be estimated by multiplying the expected retention rate (B) by the rate of return on common equity (R) that a company is expected to earn in the future.

For example, a company that is expected to earn a return of 12 percent and retain 75 percent of its earnings might be expected to have a growth rate of 9 percent, computed as follows:

$$0.75 \times 12\% = 9\%$$

On the other hand, another company that is also expected to earn 12 percent but only retains 25 percent of its earnings might be expected to have a growth rate of 3 percent, computed as follows:

$$0.25 \times 12\% = 3\%$$

Thus, the rate of growth in a firm's book value per share is primarily determined by the level of earnings and the proportion of earnings retained in the company.

Q. How can a company increase its earnings per share and future dividends by issuing new common stock?

A. Firms can grow through external financing by issuing new shares to investors and investing the proceeds to earn a return. If the new equity funds are invested to earn the same rate of return as the existing equity, this source of financing can increase earnings per share if the market price per share (M) is greater than the book value per share (B) so that the earnings of existing shareholders is increased. The amount of growth from external share issuances is represented as:

Growth from new issuances = S*V

Where:

S = the annual percentage increase in common equity from stock issuances;

V = the portion of the stock issuance that increases the book value of existing shareholders;

= 1 – (B/M).

Q. How did you calculate the expected future sustainable growth rates of the proxy companies?

A. For most companies, Value Line publishes forecasts of data that can be used to estimate the retention rates that its analysts expect individual companies to have three to five years in the future. Since these retention rates are projected to occur several years in the future, they should be indicative of a normal expectation for a primary underlying determinant of growth that would be sustainable indefinitely beyond the period covered by analysts' forecasts. While companies may have either accelerating or decelerating growth rates for extended periods of time, the retention growth rates expected to be in effect three to five years in the future generally represent a minimum "cruising speed" that companies can be expected to maintain indefinitely. The derivation of Value Line's retention growth rate forecasts for each of the proxy companies is shown on page 3 of Schedule 4 of Exhibit No.___(JSG-2). The projected earnings per share and projected dividends per share can be used to calculate the percentage of earnings per share that is being retained and reinvested in the company. This earnings retention rate is multiplied by the projected return on common equity to arrive at the B*R portion of the projected sustainable growth rate. It is also necessary to account for projected earnings growth derived from issuing new shares by the proxy group companies. This is calculated by multiplying growth in equity from issuing new shares (S) times the portion of new equity that accrues to existing shareholders (V). The S*V portion of the projected sustainable growth rates for each of the proxy companies are also shown on page 3 of Schedule 4 of Exhibit No.___(JSG-2). The average sustainable growth rate, (B*R) + (S*V), for the proxy companies is 5.38 percent, and the median is 5.08 percent.

Q. How did you utilize the analysts' projected earnings growth rates and the projected sustainable earnings growth rates in estimating expected growth for the proxy companies in the Blended Growth Rate Analysis?

A. As shown on page 4 of Schedule 4 of Exhibit No.___(JSG-2), I calculated a weighted average of the analysts' projected earnings growth rates and the sustainable growth rates to derive long-term growth rate estimates for each of the proxy companies. In these calculations, I gave two-thirds weighting to the analysts' earnings growth rate projections and one-third weighting to the projected sustainable growth rates. The average of the blended growth rates for the proxy companies is 5.70 percent, and the median is 5.92 percent.

Q. How did you utilize these Blended Growth Rate estimates in estimating the return on common equity capital that investors require from the proxy companies?

A. These calculations are shown on page 6 of Schedule 4 of Exhibit No.___(JSG-2). Again, the annual dividend yield for each company is multiplied by the quarterly dividend adjustment factor (*1 + 0.625g*), and this product is added to the growth rate estimate to arrive at the investor-required return. Finally, the investor return requirement is multiplied by the flotation cost adjustment factor, 1.04, to arrive at the cost of common equity capital for the proxy companies. This Blended Growth Rate Analysis indicates that the cost of common equity capital for the natural gas distribution proxy companies is in a range between 7.85 percent and 10.75 percent. In this analysis, the median for the group is 9.13 percent and the third quartile is 9.64 percent.

Q. Earlier you discussed the fact that the Federal Reserve Board has been setting interest rates and monetary policy in a way that artificially depresses yields on U.S. Treasury debt. What does this mean for the cost of common equity for gas distribution companies using the DCF model?

A. The DCF cost of equity results for regulated gas distribution companies are being affected by artificial factors in the current and projected capital markets, including the following two key factors: (1) the Federal Reserve's continuing accommodative monetary policy; (2) and the market's expectation for substantially higher interest rates.

Rising interest rates historically have had a negative effect on stock prices, especially for dividend paying stocks such as utilities. As interest rates increase, the return on gas utility equities may be less attractive to investors as compared with other investments of comparable risk. The market's expectation for rising interest rates suggests that the calculated cost of equity for the proxy companies using current market data is likely to be an artificially depressed estimate of investors' required return at this time. For example, in two recent decisions, the FERC expressed concern that Federal Reserve actions may have artificially reduced current dividend yields for utilities and the results of the DCF model may not be representative of the true cost of capital at this time.[18]

H. Risk Premium Analysis

Q. Have you conducted additional analysis in determining the cost of equity capital for Cascade?

A. Yes. The risk premium approach provides a general guideline for determining the level of returns that investors expect from an investment in common stocks. Investments in the common stocks of companies carry considerably greater risk than investments in bonds of those companies since common stockholders receive only the residual income that is left after the bondholders have been paid. In addition, in the event of bankruptcy or liquidation of the company, the stockholders' claims on the assets of a company are subordinate to the claims of bondholders. This priority standing provides bondholders with greater assurances that they will receive the return on investment that they expect and that they will receive a return of their investment when the bonds mature. Accompanying the greater risk associated with common stocks is a requirement by investors that they can expect to earn, on average, a return that is greater than the return they could earn by investing in less risky bonds. Thus, the risk premium approach estimates the return investors require from common stocks by utilizing current market data that is readily available in bond yields and adding to those yields a premium for the added risk of investing in common stocks.

Investors' expectations for the future are influenced to a large extent by their knowledge of past results. Duff & Phelps annually publishes extensive data regarding the returns that have been earned on stocks, bonds and U.S. Treasury bills since 1926. Historically, the annual return on large company common stocks has exceeded the return

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18 Opinion No. 531, 147 FERC ¶ 61,234 (2014); aff'd in Opinion No. 531-B, 150 FERC ¶ 61,165 (March 3, 2015); and Opinion No. 551, 156 FERC, ¶ 61,234 (Sept. 28, 2016), para. 120-122.

on long-term corporate bonds by a premium of 570 basis points (5.7 percent) per year from 1926-2016.[19] When this premium is added to the average yield on Moody's corporate bonds in recent months of approximately 4.2 percent[20], the result is an investor return requirement for large company stocks of approximately 9.9 percent. However, investors in smaller companies expect higher returns over the long term, due to the additional business and financial risks that smaller companies face. According to Duff & Phelps, companies in the same size range as Cascade's Washington natural gas distribution operations have had a premium of 1,400 basis points (14.0 percent) over the average return on long-term corporate bonds.[21] When added to the recent average corporate bond yield, this size-related premium suggests an expected return of 18.2 percent. This analysis indicates that the rate of return that I am proposing in this proceeding would be low relative to the historic risk premiums earned by similarly-sized unregulated companies.

Q. Did you also perform a risk premium analysis that is specific to the natural gas distribution industry?

A. Yes, I did. Research studies provide empirical support for the proposition that equity risk premia generally increase as interest rates decrease, and vice versa. In fact, the data provided in Schedule 5, Exhibit No.___(JSG-2) produce statistical results that are consistent with existing research in this area. Using this data, I performed a linear regression to estimate the relationship between 30-year U.S. Treasury bonds and the risk premium required for regulated gas distribution companies. The resulting equation is presented in Schedule 5, Exhibit No.__(JSG-2) and re-created below:

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[19] Duff & Phelps Valuation Handbook, 2017 U.S. Guide to Cost of Capital, Exhibit 2.3. Calculation: (12.0 percent – 6.3 percent = 5.7 percent)

[20] Exhibit No.___(JSG-2), Schedule 1, at 3. The average yield on Moody's corporate bonds from November 2016 through April 2017 has been 4.24 percent.

[21] Duff & Phelps Valuation handbook, 2017 U.S. Guide to Cost of Capital, Exhibit 4.1. Duff & Phelps defines size ranges based on market capitalization. I calculated the implied market capitalization for Cascade's Washington natural gas distribution operations based on the Company's pro forma rate base (approximately $290 million) and the test year equity ratio (50.00 percent), which is based on the average equity ratio for Cascade for the last five years. This places Cascade's Washington natural gas distribution operations in Duff & Phelps' tenth decile. Calculation: 20.3 percent – 6.3 percent = 14.0 percent.

Intercept + Coefficient x Bond Yield = Risk Premium

0.08410 + (- 0.5560 x Bond Yield) = Risk Premium

The regression statistics indicate that this equation is statistically significant and the R-square reveals that approximately 80 percent of the variation in the risk premium is explained by the bond yield. The negative coefficient in the above equation demonstrates the inverse relationship between bond yields and the risk premium. For every change of 100 basis points in the bond yield, the risk premium changes by approximately 55 basis points in the opposite direction.

This Risk Premium analysis was conducted using three different risk-free rates: (1) the current average yield on 30-year Treasury bonds; (2) the near-term projected yields on 30-year Treasury bonds in 2017 and 2018; and (3) the longer-term projected yields on 30-year Treasury bonds from 2019-2023. Based on these three interest rates, the regression equation produces an average ROE estimate of 9.96 percent.

I. Market DCF Analysis

Q. What other analysis did you conduct in determining the cost of equity capital for Cascade?

A. For an additional benchmark of the reasonableness of my DCF results, I calculated the current required return for the companies contained in the S&P 500 Index. Using data provided by the Bloomberg Professional service, I performed a market capitalization-weighted DCF calculation on the S&P 500 companies based on the current dividend yields and long-term growth rate estimates as of April 28, 2017. These calculations are shown in Schedule 6 of Exhibit No.___(JSG-2). The current secondary market required ROE for the S&P 500 is 12.54 percent. This analysis demonstrates that the rate of return that I am proposing in this proceeding is low relative to the return required by investors who invest in the S&P 500.

J. Forward-Looking CAPM

Q. Many analysts would argue that gas distribution companies are less risky than the S&P 500 companies. Does this make the S&P 500 a poor benchmark for evaluating the DCF results?

A. No. The DCF required return for the S&P 500 is significantly greater than the return required for the natural gas distribution company proxy group, and the large magnitude of this difference is an indicator that the proxy company DCF results may be on the low side. Some analysts use the CAPM to adjust for differences in risk between the market average and a particular group of proxy companies. While I do not consider the CAPM to be a reliable measure of the cost of capital, one could use it to adjust the S&P 500 results to achieve a risk-adjusted benchmark for the natural gas distribution company proxy group. For example, Beta is frequently used as the measure of relative risk in the CAPM. As shown on Schedule 7 of Exhibit No.___(JSG-2), the average beta reported by Value Line for the proxy companies is 0.73.

Duff & Phelps recommends making a size adjustment to the CAPM results to reflect the differential in investors' return requirements for smaller and larger companies, as measured by market capitalization. On Schedule 8, page 2 of 2, of Exhibit No.___(JSG-2), I calculated the CAPM size premium for the proxy companies using the Duff & Phelps size premium data. The average size adjustment for my proxy group companies is 128 basis points. As shown on Schedule 8, page 1 of 2, of Exhibit No.___(JSG-2), using the Value Line beta estimates and the Duff & Phelps adjustments for CAPM size bias for my proxy companies, the median unbiased CAPM result for my proxy companies is 11.26 percent.

Thus, if one were to use the CAPM as a benchmark of a reasonable return, this benchmark suggests that my recommended ROE of 9.9 percent in this proceeding is a reasonable estimate of the cost of equity for Cascade at this time.[22]

K. Relative Risk Analysis

Q. Have you compared the risks faced by Cascade's Washington natural gas distribution operations with the risks faced by the proxy group of companies?

A. Yes. There are four broad categories of risk that concern investors. These include:

1. Business Risk;
2. Regulatory Risk;
3. Financial Risk; and,
4. Market Risk.

Q. Please describe the business risks inherent in the natural gas distribution industry.

A. Business risk refers to the ability of the firm to generate revenues that exceed its cost of operations. Business risk exists because forecasts of both demand and costs are inherently uncertain. Markets change and the level of demand for the firm's output may be sufficient to cover its costs at one time and later become insufficient. Sunk investments in long-lived natural gas distribution assets, for which cost recovery occurs over a period of thirty years or more, are subject to enormous uncertainties and risks that demand, costs, supply, and competition may change in ways that adversely affect the value of the investment.

Q. What are some of the business risks faced by Cascade's Washington natural gas distribution operations?

A. The Company's natural gas distribution operations in Washington face many of the same

22 This CAPM calculation is identical to the one adopted by the U.S. Federal Energy Regulatory Commission. *Martha Coakley, et al. v. Bangor Hydro-Electric Company, et al.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014); aff'd in Opinion No. 531-B, 150 FERC ¶ 61,165 (March 3, 2015); and *ABATE, et al. v. MISO, et al.*, Opinion No. 551, 156 FERC, ¶ 61,234 (Sept. 28, 2016), para. 120-122. Note that FERC used the CAPM only as a benchmark, but set the allowed rate of return above the median indicated by a DCF analysis of proxy companies because of the current abnormal financial market conditions. While Opinion No. 531 was recently remanded to the FERC by the D.C. Circuit Court, the Court's decision did not question the finding by the FERC that capital market conditions were anomalous.

business risks that are associated with other natural gas distribution companies. However, Cascade's Washington natural gas distribution operations face some particular risks that distinguish the Company from the proxy group of distribution companies, including its smaller size, generally lower incomes in the cities and towns that it serves, and the undiversified nature of the local economies in the Company's service territory.

As shown on page 1 of Schedule 3 of Exhibit No.___(JSG-2), Cascade's Washington natural gas distribution operations are significantly smaller than the operations of any of the proxy companies and a fraction of the size of the typical proxy company. For example, the 2017 test year adjusted rate base of Cascade's Washington natural gas distribution operations is equal to only 5.2 percent of the fiscal year-end 2016 total assets of the median proxy company. Similarly, Cascade's Washington natural gas distribution 2017 test year requested operating revenues and operating income are only 11.8 percent and 7.9 percent of the year-end 2016 level for the median proxy company, respectively. Thus, depending upon the measure of size, the typical proxy company is somewhere between 8 and 19 times the size of Cascade's Washington natural gas distribution operations. The Company's smaller size has significant implications for business risks. Duff & Phelps has documented the significantly higher returns that generally have been associated with small companies.

With its relatively small revenue base, Cascade's Washington natural gas distribution operations are subject to greater risk that a major employer or industry, such as a government facility or refinery, might downsize or close. Events such as these could significantly affect overall employment and income in the towns served. Factors that negatively influence the local economy can reduce demand for Cascade's Washington natural gas distribution service and adversely impact investments in facilities used to provide those services.

Q. In July 2016, Cascade was allowed to implement a full revenue-per-customer decoupling mechanism. Does this decoupling mechanism reduce the Company's risk profile relative to the proxy group?

A. No. Because the ROE recommendation is established for a company based on its risk profile relative to the proxy group, it is necessary to consider whether the companies in the proxy group also have revenue decoupling mechanisms or another comparable form of volumetric risk protection. Schedule 9 of Exhibit No.___(JSG-2) shows that 66.7 percent of the operating utilities held by the proxy companies have some form of volumetric protection (e.g., revenue decoupling mechanisms, straight fixed-variable rate design, formula rate plans). On that basis, Cascade has similar volumetric risk as the proxy group companies, and no adjustment to the authorized return on equity capital is necessary.

Considering only its smaller size, Cascade's Washington natural gas distribution operations might require a return that is approximately 100 basis points higher than the return required for the typical proxy company. In addition, the Company's operations are concentrated in smaller towns and cities with local economies that are generally less diversified than those of the proxy companies. In summary, Cascade's Washington natural gas distribution operations are riskier than the operations of the proxy companies.

Q. What are the regulatory risks faced by Cascade's Washington natural gas utility operations?

A. Regulatory risk is closely related to business risk and might be considered just another aspect of business risk. To the extent that the market demand for a natural gas distribution company's services is sufficiently strong that the company could conceivably recover all of its costs, regulators may nevertheless set the rates at a level that will not allow for full cost recovery. In effect, the binding constraint on natural gas distribution companies is often posed by regulation rather than by the working of market forces. One purpose of regulation is to provide a substitute for competition where markets are not workably competitive. As such, regulation often attempts to replicate the type of cost discipline and risks that might typically be found in highly competitive industries.

Moreover, there is the perceived risk that regulators may set allowed returns so low as to effectively undermine investor confidence and jeopardize the ability of natural gas distribution companies to finance their operations. Thus, in some instances, regulation may substitute for competition and in other instances it may limit the potential returns available to successful competitors. In either case, regulatory risk is an important consideration for investors and has a significant effect on the cost of capital for all firms in the natural gas distribution industry.

The regulatory environment can significantly affect both the access to, and cost of capital in several ways. As noted by Moody's, "[f]or rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[23] Moody's further noted that:

> Utility rates are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.[24]

Regulatory Research Associates ("RRA") recently lowered its rating for the WUTC to Average / 3, which is one notch below average on the nine-point scale.[25] RRA notes that the "regulatory environment in Washington is, on balance, somewhat more restrictive

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[23] Moody's Investors Service, *Regulated Electric and Gas Utilities*, December 23, 2013, at 9.
[24] *Ibid.*
[25] Regulatory Research Associates, Washington Commission Profile, accessed May 31, 2017.

than average from an investor viewpoint."[26] In particular, RRA notes that "authorized equity returns, some of which were approved following settlements, have been below prevailing industry averages when established."[27] This RRA rating suggests that Cascade's Washington natural gas distribution operations should be considered to have slightly above average regulatory risk.

Q. Would you please describe Cascade's relative financial risks?

A. Financial risk exists to the extent that a company incurs fixed obligations in financing its operations. These fixed obligations increase the level of income which must be generated before common stockholders receive any return and serve to magnify the effects of business and regulatory risks. Fixed financial obligations also increase the probability of bankruptcy by reducing the company's financial flexibility and ability to respond to adverse circumstances. One possible indicator of investors' perceptions of relative financial risk in this case might be obtained from credit ratings.

Page 2 of Schedule 3 of Exhibit No.___(JSG-2) shows the credit ratings assigned by S&P and Moody's to each of the companies in the comparison group and Cascade. The median S&P credit rating for companies in the proxy group is A-. By comparison, Cascade's long-term rating from S&P is BBB+. This suggests that the perceived business and financial risk of Cascade's bonds is slightly higher than that of the typical company in the comparison group.

The capital structure data on Schedule 10 of Exhibit No.___(JSG-2) show that Cascade's filed common equity ratio of 50.00 percent is very close to the 49.84 percent median for the proxy companies as of March 31, 2017, suggesting average financial risk. However, the Company's below-average credit rating suggests that a higher common equity ratio would be required to offset Cascade's above-average business risks.

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26 *Ibid.*
27 *Ibid.*

Q. Would you please describe Cascade's market risks?

A. Market risk is associated with the changing value of all investments because of business cycles, inflation, and fluctuations in the general cost of capital throughout the economy. Different companies are subject to different degrees of market risk largely as a result of differences in their business and financial risks. Overall, the market risk of Cascade's Washington natural gas distribution business is comparable to that of the companies in the natural gas distribution comparison group.

Q. How do the overall risks of the proxy companies compare with the risks faced by Cascade's Washington natural gas distribution operations?

A. Cascade's Washington natural gas distribution operations face overall risks that are above the median relative to those of the proxy companies. Cascade has above-average business risks due primarily to its small size relative to the proxy companies and its exposure to a relatively undiversified local economy and slightly above-average regulatory risks. Standard & Poor's comments: "Somewhat offsetting [the strong business risk profile for regulated U.S. utilities] are the company's small customer base in its lightly populated two-state service territory and per capita income in its service territories that is slightly weaker than the national average."[28]

The greater business and regulatory risk lead me to conclude that investors appraise the overall risks of Cascade's Washington natural gas distribution operations to be above average relative to the risks of the proxy companies. Consequently, Cascade's Washington natural gas distribution business requires an allowed rate of return that is significantly above the median of the range for the companies in the proxy group indicated by my DCF analyses.

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[28] Standard and Poor's Global Ratings, *Cascade Natural Gas Corp*., Research Update, December 18, 2014, at 4.

III. SUMMARY AND CONCLUSIONS

Q. Please summarize the results of your cost of capital study.

A. I conducted two DCF analyses on a group of natural gas distribution companies that have a range of risks that is roughly comparable to those of Cascade's Washington natural gas distribution operations. These results are summarized as follows:

Table 2: Summary of DCF Results

	Basic DCF Analysis	Blended Growth Rate DCF Analysis
High	11.84%	10.75%
3rd Quartile	10.22%	9.64%
Median	9.22%	9.13%
1st Quartile	7.82%	8.01%
Low	7.11%	7.85%

In addition, I conducted two risk premium analyses, a market DCF analysis of the S&P 500, and a size-adjusted CAPM analysis to test the reasonableness of my DCF analyses. Those results are summarized as follows:

Table 3: Benchmark Risk Premium and Market DCF Analyses

	Return
Risk Premium (Long-Term Corporate Bonds)	
vs. Large Company Stocks	9.9%
vs. Small Company Stocks	18.2%
Gas Utility Risk Premium (Regression of Authorized ROEs against 30-yr Treasury yields)	10.0%
Market DCF (S&P att0)	12.5%
Forward-Looking CAPM	11.3%

My risk premium, market DCF and CAPM analyses suggest that the median DCF results generally are low relative to current market benchmarks. In particular, the median

DCF return estimates are below the 10.0 percent risk premium return, but the top of those DCF ranges are considerably above 10.0 percent. Similarly, the median DCF estimates for the natural gas distribution proxy companies are well below the 12.5 percent market DCF estimate for the S&P 500 companies and the 11.3 percent size-adjusted CAPM estimate for the natural gas distribution proxy companies.

Q. What rate of return on common equity do you recommend for Cascade's Washington natural gas distribution operations in this proceeding?

A. My analyses indicate that an appropriate rate of return on common equity for Cascade's Washington natural gas distribution operations at this time is 9.9 percent, which is between the median and third quartile of the range for my Basic DCF analysis and consistent with the Risk Premium analyses. This recommended return reflects my assessment that the overall risks of Cascade's Washington natural gas distribution operations are above average relative to those of the proxy companies, and the fact that the DCF results appear to be low relative to the other benchmarks at this time. Although the Company has average financial risk relative to the proxy companies, it has above average business risks and slightly above average regulatory risk. In addition to its small size relative to the proxy companies, Cascade's Washington natural gas distribution operations are exposed to risks associated with relatively undiversified local economies. Thus, an allowed rate of return approximately equal to the average utility risk premium (10.0 percent) in my study is appropriately positioned to reflect the risks faced by Cascade's Washington natural gas distribution operations relative to the risks faced by the proxy companies, and also to reflect current conditions in the financial market.

Q. Does this conclude your Prepared Direct Testimony?

A. Yes.

Exhibit No. __ (MPP-1T)
Docket No. UG-17____
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-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF MICHAEL P. PARVINEN

August 31, 2017

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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 two primary areas. First, I will address the revenue requirements and supporting calculations. Secondly, I will discuss the steps Cascade has taken or is taking to fulfill its commitments under the settlement agreement filed by the parties to Docket No. UG-152286 ("Settlement Agreement").

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. __ (MPP-2)	Results of Operation Summary Sheet
Exhibit No. __ (MPP-3)	Revenue Requirement Calculation
Exhibit No. __ (MPP-4)	Conversion Factor Calculation
Exhibit No. __ (MPP-5)	Summary of Proposed Adjustments to Test Year Results
Exhibit No. __ (MPP-6)	2017 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 6.38 percent, as shown in Exhibit No. __ (MPP-2). The incremental revenue necessary to achieve the recommended ROR of 7.60 percent is $5,884,984 also shown in Exhibit No. __ (MPP-2). The calculation of the incremental revenue is also provided in Exhibit No. __ (MPP-3). The overall base revenue increase requested is 2.71 percent.

Q. Please describe the contents of Exhibit No. __ (MPP-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, 2016. The Working Capital figure on line 23 is a calculation from the Company's actual average of monthly average balance sheet. Column (2) is the summation of all adjustments, both restating and pro forma, to achieve the pro forma results of operation. Each adjustment that is included in column (2) is identified separately in Exhibit No. __ (MPP-5), and will be described later in my testimony. Column (3) is the sum of columns (1) and (2) and represents the expected results of operations in the rate year absent any rate change. Column (4) identifies the proposed revenue change and the net income impact of the revenue increase. The proposed revenue increase is also calculated in Exhibit No. __ (MPP-3). Column (5) is the results of operation 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, 2016, as the test period. 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. __ (MPP-3).

A. Exhibit No. __ (MPP-3) shows the calculation of the proposed revenue increase of $5,884,984 necessary to achieve the proposed rate of return of 7.60 percent.

Q. Would you please describe Exhibit No. __ (MPP-4)?

A. Exhibit No. __ (MPP-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 0.62120.

Q. Please describe Exhibit No. __ (MPP-5).

A. Exhibit No. __ (MPP-5) shows each of the Company's proposed adjustments, culminating in the total column shown in column (2). The Company is proposing four restating adjustments and nine 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 is proposing four restating adjustments, identified as R-1 through R-4 in Exhibit No. __ (MPP-5), and nine pro forma adjustments identified as P-1 through P-9, also identified in Exhibit No. __ (MPP-5).

Q. Would you describe each of the adjustments included in Exhibit No. __ (MPP-5)?

A. Yes. The first column, column (R-1), entitled "Weather Normalization Adjustment" is an adjustment to the test period results to reflect customer usage given normal weather. This adjustment is described by Cascade witness Mr. Brian Robertson in Exhibit No. __ (BR-1T). The result is an increase to net operating income of $3,077,609.

Q. Continue with the description of the adjustments in Exhibit No. __ (MPP-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 $35,566.

Column (R-3), entitled “Restate Revenue Adjustment” is described by Cascade witness Ms. Maryalice C. Rosales. The result of this adjustment is a decrease in net income of $1,501,021.

Column (R-4), entitled “Low-Income Bill Assistance” removes from the test period the booked expense prior to the implementation of the tracker tariff rate on September 1, 2016, as established in the last general rate case, Docket No. UG-152286. The result of this adjustment is an increase in net income of $346,667.

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 MPP-1, column (3), line 27. The result is a decrease in net income of $274,827.

Column (P-2), entitled “Pro Forma Wage Adjustment” has four components. The first component is the annualization of the 2016 increase effective April 1, 2016 for union employees. The second component layers on the 2017 actual wage increases for non-union and union employees. The third component adds in the 2018 estimated increases for the union and non-union employees. The non-union increase is estimated to be 4 percent, the same level granted in 2017. However, the increase won’t be known until sometime in December, 2017. The Company will update the calculation to reflect the actual non-union increase awarded at a later date. The 2018 union increase is estimated to be 3.1 percent, the same as 2017. However, the contract is currently under negotiations and is anticipated to be in place prior to the completion of this docket.

The forth component is a reflection of the 2017 and 2018 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 $934,593.

Column (P-3), entitled “Pro Forma Plant Additions” reflects the Company’s budgeted level of capital additions expected to go into service by December 31, 2017, well before the anticipated effective date of the current filing, June 1, 2018. The proposed projects are limited to only those projects that are non-revenue producing and will not be included in the 2017 annual Cost Recovery Mechanism (CRM). Exhibit No. ____ (MPP-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 and have no material offsetting factors except for one project. As the cost and timing of these projects is budgeted and estimated at this point, Cascade will update the actual costs and standing of each project as the case proceeds. The intent is adding into rate base only those projects that will be used and useful by the time rates from the current proceeding go into effect.

Q. Please describe the one revenue-producing project and the Company’s approach to making a pro forma adjustment for this project.

A. One project going into service was developed to provide reliability for all existing customer’s peak needs and also to meet a specific customer’s expanding load. In order to properly pro form the plant addition, Cascade is including the anticipated annual increase in revenue from the added customer load.

Q. Are Cascade’s pro forma capital additions consistent 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."[1]

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 results of operations, 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.[2]

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 expects to be able to provide actual costs for all projects in its rebuttal filing. Additionally, Cascade has included supporting justification for each project included in the 2017 Pro Forma Plant Addition adjustment. The supporting documentation is included in Exhibit No. ____ (MPP-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 $280,075. The rate base impact is an increase of $17,820,193.

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[1] *Wash. Utils. & Transp. Comm'n v. Pac. Power*, Docket UE-140762, *et al.*, Order 08, ¶165 (Mar. 25, 2015).
[2] *Id.* at ¶167 (internal citations omitted).

Q. Please continue with the description of the columns included in Exhibit No. ____ (MPP-5), starting with Rate Case Costs included in Column (P-4).

A. Column (P-4), entitled "Rate Case Costs" reflects the impacts of incremental costs associated with filing this general rate case over what was booked in 2016 for the last general rate case, Docket No. UG-152286. These costs will be updated later in the case as they become known and better estimated. The net income impact is a decrease in net income of $194,033.

Column (P-5) entitled "Pro Forma Compliance Department" reflects the addition of a new department at the Company that will be tasked with ensuring that Cascade is in full compliance with all state and federal pipeline safety regulations and other relevant requirements. The department—which is named System Integrity/System Management—has the responsibility of assuring the Cascade is in compliance with all state and federal pipeline safety matters. The new department consists of a director and two engineers. The Company expects that the addition of this department will help avoid future instances such as those that resulted the complaint filed in Docket No. PG-150120. The net income impact of this adjustment is a decrease of $181,736.

Column (P-6) entitled "MAOP Deferral Amortization" provides for 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. Amortization would begin as of the effective date of this general rate increase. The deferred balance is anticipated to be $9,590,868. The net income effect is a reduction of $623,406.

Q. How does Cascade propose to treat costs associated with the implementation of the settlement in Docket No. PG-150120 ("MAOP Settlement") going forward?

A. Cascade proposes to continue to use a deferral account to not only track additional expenditures associated with the implementation of the MAOP Settlement, but also to track recovered costs. Cascade will update the amortization amount in future rate cases as additional costs are incurred and revenues recovered.

Q. Why is Cascade proposing a ten year amortization period?

A. A period of ten years was selected to reduce the impact to customers and to amortize over an approximation of the remaining life of the pipeline segments at issue in the complaint. Virtually all of the 116 segments in question were installed prior to 1970 ("Pre Code") and many prior to Cascade's acquisition of the distribution system in 1954 ("Pre CNGC"). Anything installed Pre Code is at least forty-seven years old and anything Pre CNGC is at least sixty-one years old. Mains have roughly a sixty year life. While this was not an exact calculation, it presents a rough approximation of the remaining useful life of the pipe segments at issue and supports the use of a ten year amortization.

Cascade witness Mr. Eric Martuscelli will describe the reasons why recovery of these costs is appropriate. Cascade witness Mr. Ryan Privratsky will describe the types and level of costs being incurred to implement the MAOP Settlement.

Q. Please continue with the description of adjustments included in Exhibit No. __ (MPP-5).

A. Column (P-7), entitled "Miscellaneous Charge Changes" accounts for proposed changes to certain miscellaneous fees in Schedule 200. Cascade witness Ms. Jennifer G. Gross describes the proposed changes in greater detail in Exhibit No. __ (JGG-1T). This adjustment reduces net income by $63,142.

Column (P-8), entitled "CRM adjustment" adjusts from the average of monthly average test year investment for approved Cost Recovery Mechanism ("CRM") investments to the same level included in the most recent annual CRM filing (Docket No. UG-160788). The adjustment recognizes a full year impact of the investment as included in Docket No. UG-160788. The pro forma adjustment in column P-9 recognizes a full year of the revenue from the same CRM filing. This adjustment, along with the revenue adjustment in column P-9, fully matches the revenue with the investment. This adjustment decreases net income by $50,707 and increases rate base by $2,978,481.

Column (P-9), entitled "Pro Forma Revenue" adjusts weather normalized volumes to the most current rates. Included in this adjustment is the annualization effect of the most current CRM rates, the most current special contract rates, and the most recent general rate case. This adjustment is further described in the testimony of Ms. Rosales. This adjustment increases net income by $3,242,702.

Q. Please describe Exhibit No. __ (MPP-6).

A. Exhibit No. __ (MPP-6) identifies each project included in the Company's request. 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 identifies the funding project number. The second column identifies the funding project name. The third column identifies the expected in-service date. The fourth column identifies the primary FERC account number for the project. The fifth column identifies the most up to date expected cost of the project. The sixth column identifies the Washington portion of the project. The seventh column identifies the amount included in the current request for recovery. Finally, the eighth column identifies the footnote which provides the support for inclusion or exclusion in the current request for recovery.

Q. Please explain where the justification or support for including each project is included in Exhibit No. ____ (MPP-6).

A. The support or identified benefit of adding each project is included on Pages 4 – 7 of the exhibit.

IV. LOW-INCOME BILL ASSISTANCE PROGRAM

Q. Is the Company proposing a change to its Low-Income Bill Assistance program?

A. No.

Q. Please explain.

A. In the Company's last general rate case, Docket No. UG-152286, many changes were made to the program and funding levels. The effects of those changes have not even been in place for a full year yet as of the filing of this case.

Q. Even though the changes have not been in place for long, does Cascade have any initial conclusions regarding the modifications to the low-income program?

A. So far, it appears that the program changes were very positive. In fact, the changes have resulted in the Company seeking a request to allow for funding beyond the program cap approved in the Settlement Agreement.

V. COMPLIANCE WITH THE SETTLEMENT AGREEMENT IN CASCADE'S LAST GENERAL RATE CASE, DOCKET NO. UG-152286

Q. Did Cascade commit to fulfill certain obligations as a result of the Settlement Agreement filed in its last general rate case, Docket No. UG-152286?

A. Yes. Cascade agreed to the following items:

- Early implementation of the 2016 Purchase Gas Adjustment ("PGA") filing to offset the impact of the general rate case.
- Third party audit of the decoupling program.
- Initiate a load study prior to next rate case.
- Implementation of changes to Cascade's conservation program, including filing an annual plan, annual report, holding quarterly meetings, providing

advanced notice of filings to Conservation Advisory Group ("CAG"), developing a framework for analysis of Cascade's conservation program, and investigating and developing a proposal to remove barriers to low-income weatherization.

- Implementation of modifications to Cascade's Low-Income Energy Assistance program, including adoption of goals, establishing an advisory group, updating Cascade's tariff, rolling the existing balance over as the new beginning balance for Washington Energy Assistance Fund ("WEAF") program, performing a needs assessment, implementing design eligibility and funding procedures, evaluating the program, performing customer outreach, consideration of alternative designs, and annual reporting.
- Improvements to the annual Commission Basis Report; including the investor supplied working capital ("ISWC") calculation and weather normalization calculation.
- Separate conservation revenues and WEAF revenues from the Weighted Average Cost of Gas ("WACOG").
- Employ an industry accepted practice for determining unbilled revenues.
- Bifurcate booked revenue, margin revenue, and all other revenue sources.

Q. Can you provide a status update on each of these items, starting with the early implementation of the PGA?

A. Certainly. On August 1, 2016, Cascade filed its annual PGA and deferral amortization filing under Docket No. UG-160972. The result was a nearly $18 million reduction in revenue effective September 1, 2016, compared to the general rate increase of $4 million effective on the same date.

The Company agreed to a third-party audit of the decoupling mechanism. The audit is not scheduled to take place until after the third full year of the decoupling mechanism. The third full year will be complete at the end of 2019, accordingly, no action on the audit has occurred to date.

The Company agreed to initiate a load study before filing its next general rate case. The Company has taken the first steps in the load study by initiating what is internally referred to as a "citygate study." The data collected from the citygate study will serve as the foundation for the load study. Mr. Robertson provides additional information regarding the status of the load study.

The Company agreed to a number of commitments regarding modifications to its conservation program. Some of the commitments formalized processes already being performed, while others were new. The processes already being performed are not discussed in detail; I will instead focus on changes Cascade has made to fulfill the commitments from the Settlement Agreement. Cascade filed its annual plan by December 1, 2016, and filed its annual report by June 1, 2017, which is consistent with the filing schedule for other energy companies. Since the effective date of the Company's last rate case on September 1, 2016, Cascade has held three quarterly CAG meetings with others already scheduled for the remainder of 2017. Additionally, Cascade has scheduled quarterly CAG meetings for the full calendar year in advance of the start of the year to ensure maximum likelihood of stakeholder availability and participation. Thus far, stakeholder availability and participation in the quarterly CAG meetings has been good. Cascade has supplied all reports and filings to the CAG at least thirty days prior to filing the reports and filings with the Commission. While providing advance copies has been difficult on Cascade's staff due to the substantial decrease in the time between the data becoming available and the time by which Cascade must prepare and finalize the reports and filings, Cascade acknowledges the benefit of providing advance copies, which has been more open and productive dialogue regarding Cascade's conservation program.

Q. The last item listed under conservation is low-income weatherization; can you describe the outcome of this item?

A. Yes. The Company worked with the CAG as well as our low-income community action agencies to develop a low-income weatherization program intended to result in weatherizing more homes. Cascade formalized its low-income weatherization proposal in a tariff filing made on December 29, 2016, which essentially allows for full payment of measures included in the Washington State Department of Commerce's Weatherization Priority List. The tariff became effective on February 1, 2017. As was experienced when Cascade implemented a similar tariff in Oregon, it seems to take the community action agencies time to adapt to the new program.

Q. Can you provide an update on the low-income bill assistance obligations identified above?

A. Yes. First, the Company filed a tariff with the agreed modifications to the WEAF program arising out of the settlement. The modified program was designed to meet the program goals also identified in the settlement. An advisory group consisting of the rate case parties and each of the community action agencies was developed and has been meeting quarterly, usually by conference call. Additionally, many email exchanges have taken place to either provide information or to achieve consensus when needed, such as for modification to the needs assessment study.

The needs assessment study was contracted for and initially completed in May 2017. In consultation with the advisory group, additional work is being performed to analyze need for the program. So far, the total cost of the needs assessment is still below the level of funds set aside for the assessment in the Settlement Agreement.

Cascade has been providing not only annual reporting but monthly reporting to keep the agencies apprised of successes of the program and the status updates regarding the current funding balance.

The topic of alternative design or approaches has not yet been directly addressed. While there have been some initial conversations regarding observations about program design or suggestions for modification, so far no particular design alternative recommendation has been brought to the advisory group for full consideration. Cascade recommends allowing the program to reach its potential before assessing modifications to the program.

Q. Please describe the commitments made regarding the presentation of the annual Commission Basis Report ("CBR").

A. Cascade agreed to file the CBR using the ISWC calculation methodology approved in the rate case from 2006. Cascade also agreed to calculate weather normalization in a very specific manner. Cascade complied with these commitments in the CBR filing submitted to the Commission on April 27, 2017.

Q. Is Cascade using the same methodology for the ISWC and weather normalization in this rate case?

A. No. For ISWC the presentation is slightly different. The Commission has accepted net pension costs as a working capital item in other rate cases since 2006 so Cascade has updated its methodology to be consistent with the more current approved calculations.

The weather normalization calculation proposed by the Company is consistent with the methodology used in the Company's IRP and financial planning. The proposed methodology and support for modification is described by Mr. Brian Robertson.

Q. How has the Company addressed separating out the conservation and WEAF collections from revenues and gas costs?

A. In our last general rate case there was confusion created by the way Cascade records its deferral amortization revenues and it appeared there was a mismatch between revenues and expenses. Cascade, in this case, has eliminated the issue by pricing all weather normalized therms at the current WACOG on both the revenue and gas cost side of the books. The result is an apples-to-apples comparison where all deferrals, conservation cost recovery, WEAF recovery, and unbilled revenue have been eliminated. In other words, the revenues match the gas cost expense and are priced at the most current revenue and gas cost rates. Ms. Rosales provides testimony describing this adjustment in Exhibit No. __ (MCR-1T).

Q. How has the Company implemented an industry accepted approach to unbilled revenue determinations?

A. 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.

Because the Company is calculating its weather normalization adjustment using pipeline data or more real-time usage, unbilled revenue is inherently already included in the weather normalization calculation, therefore any net unbilled revenue booked in the test period should be removed. Cascade has done this in the revenue adjustment identified in the previous question.

Q. And finally, regarding the last commitment, describe how the Company bifurcates the booked revenue?

A. The Company has internal reports that bifurcate booked revenues, but the books are not necessarily fully bifurcated. Again, the Company has resolved the issue with the revenue adjustment proposed by Ms. Rosales.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit No. __ (JGG-1T)
Docket No. UG-17____
Witness: Jennifer G. Gross

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-17_____

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF JENNIFER G. GROSS

August 31, 2017

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address

A. My name is Jennifer G. Gross. My business address is 8113 W. Grandridge Boulevard, Kennewick, Washington 99336-7166. My email address is jennifer.gross@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 a Regulatory Analyst IV.

Q. How long have you been employed by Cascade?

A. I have been with the Company since May 4, 2015.

Q. What are your educational and professional qualifications?

A. I graduated from Oregon State University in June 1993 with a Bachelor of Arts in English and from Portland State University in December 1995 with a Master of Arts in English.

I worked for Portland General Electric for twelve years in various capacities including seven years as a Regulatory Analyst in Rates and Regulatory Affairs. Following my time at Portland General Electric, I worked for seven years as a Tariff and Compliance Consultant in the Rates and Regulatory Department at Northwest Natural Gas Corporation. In 2015, I began working for Cascade as a Regulatory Analyst.

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

A. Yes. I testified before the Commission in the Company's last general rate case in Washington, docketed as UG-152286. I have also testified before the Public Utility Commission of Oregon in Cascade's most recent Oregon general rate case, Docket No. UG 305, and I have prepared materials and assisted in other utility proceedings including advice filings, rulemakings, various Commission investigations, and rate cases.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. My testimony discusses the proposed revisions to the Company's WN U-3 Tariff.

Q. Are you sponsoring any exhibits in this proceeding?

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

- Exhibit No. __ (JGG-2), Proposed Tariffs
- Exhibit No. __ (JGG-3), Decoupling Mechanism, Authorized Revenue Per Customer

III. TARIFF REVISIONS

Q. Please provide an overview of the Company's proposed tariff changes.

A. The Company's proposed tariff changes include:

- Revisions to basic service charges and base rates in core customer rate schedules, as well as revisions to the contract demand charge and gross revenue fee in Schedule 663, Distribution System Transportation Service;
- The removal of two rate schedules: Rate Schedule 512, Compressed Natural Gas Service and Rate Schedule 577, Limited Interruptible Service Rate;
- The discontinuation of the availability of Rate Schedule 502, Building Construction Temporary Heating and Dry-Out Service;
- Revisions to certain fees in Schedule 200, Various Miscellaneous Charges: the New Premise Charge is removed, and the Reconnect Charge (business hours), Reconnect Charge (after hours), Disconnect Charge, Returned Check Charge, and Pilot Light Service Charge are increased; and
- The establishment of a new baseline of authorized margin revenue per customer for Rule 21, Decoupling Mechanism.

The proposed tariff, which includes all proposed changes to WN U-3, as well as legislative tariffs containing the changes in red-lined, strike-out text are 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.___ (JGG-2).

Q. Please explain the revisions you are proposing to rates.

A. The basic service charges and base rates in Rate Schedules 503, 504, 505, 511 and 570, and the contract demand charge in Rate Schedule 663 are revised in accordance with the presentation provided in the Direct Testimony of Ronald J. Amen, included as Exhibit No. __ (RJA-1T).

The Gross Revenue Fee in Rate Schedule 663 is revised from 4.469 percent down to 4.431 percent, consistent with the changes to the percentage applied to bills to cover the costs for uncollectibles, State B&O Tax and Commission fees, as shown in Michael Parvinen's Exhibit No. __ MPP-4.

Q. Why is Cascade removing Rate Schedule 512, Compressed Natural Gas Service and Rate Schedule 577, Limited Interruptible Service Rate?

A. Schedule 512, Compressed Natural Gas Service, promotes the use of compressed natural gas for fueling vehicles by discounting the cost of natural gas for customers who own compression facilities for vehicular fueling. To date, only one customer has signed up for Schedule 512. Due to the low level of participation in this service offering, Cascade has decided to discontinue Schedule 512, and the one customer currently served on Schedule 512 will be migrated to Schedule 504, General Commercial Service. The Company will send the customer a letter alerting the customer of the migration to Schedule 504.

Schedule 577, Limited Interruptible Service Rate, is an interruptible rate for institutions. To promote the equitable treatment of all customers within the same customer class that choose the same service option, Cascade plans to migrate Schedule 577 customers to Schedule 570, Interruptible Service. The two customers served on Schedule 577 will be notified by letter of the migration to Schedule 570.

Q. Did Cascade consider the impact these changes would have on test year revenues?

A. Yes. Exhibit No. __ (MCR-2), which is explained in the Direct Testimony of Maryalice Rosales as the presentation of test year revenue by rate schedule, shows Schedule 512 revenues and migrates them to Schedule 504; and, likewise, it shows Schedule 577 revenues and migrates them to Schedule 570.

Q. Please explain the Company's proposal for Rate Schedule 502, Building Construction Temporary Heating and Dry-Out Service.

A. Rate Schedule 502 offers service for a term of six months to homebuilders using natural gas to heat and dry-out a home as it is being constructed. The Company is proposing to discontinue offering new service on Rate Schedule 502 as of the effective date of this general rate case filing because the heating of unfinished homes tends to be an inefficient use of natural gas, and Cascade does not want to promote an inefficient use as a unique service option.

Customers served on Rate Schedule 502 prior to the schedule being "frozen" will continue to receive service on the schedule for the remainder of their six-month term, but the Company is proposing to revise Schedule 502 rates (the basic service charge, the margin rate and WACOG) such that the charges mirror those in Rate Schedule 503, Residential Rate Service. Future dry-out or building construction customers will be served on Schedule 503.

Q. Did the Company consider the impact this change will have on test year revenues?

A. Yes. Schedule 502 revenues are added to Schedule 503 revenues in Exhibit No. __ (MCR-2).

Q. What revisions is Cascade proposing to make to Schedule 200, Various Miscellaneous Charges?

A. Below is a summary of the changes proposed to Schedule 200, Various Miscellaneous Charges:

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Charge	Current Charge	Proposed Charge	% Change
Reconnect Charge (business hrs)	$24.00	$28.00	17%
Reconnect Charge (after hrs)	$60.00	$70.00	17%
Disconnect Charge	$10.00	$12.00	20%
Returned Check Charge	$18.00	$21.00	17%
New Premise Charge	$45.00	$ 0.00	-100%
Pilot Light Service Charge	$20.00	$24.00	20%

This information is also provided in Michael Parvinen's work paper for miscellaneous charges, MPP WP 1.17.

Q. Why is Cascade proposing to remove the New Premise Charge?

A. The New Premise Charge is a fee that is charged to a new customer when the customer converts to natural gas service. Cascade proposes to remove the New Premise Charge for consistency with the Company's new line extension policy filed and approved in Docket No. UG-160967, which seeks to reduce the upfront costs customers must pay to convert to natural gas service.

Q. Why is the Company proposing to increase the other five miscellaneous charges identified above?

A. Schedule 200, Miscellaneous Charges was last updated in 2007.[1] Schedule 200 charges are not fully cost-based charges because as full cost recovery for the services provided under Schedule 200 would likely prove cost-prohibitive for many of Cascade's customers. As a result, because the Schedule 200 charges are not fully cost-based, a portion of the costs are ultimately borne to some extent by all customers. For that reason, the charges must be set at a level high enough to discourage the behavior giving rise to the charges, thus limiting the impact on other customers. The Company has reviewed the charges and concluded that that the five charges identified above—Reconnect Charge

[1] Schedule 200, Various Miscellaneous Charges was last approved in UG-060256.

(business hours), Reconnect Charge (after hours), Disconnect Charge, Returned Check Charge, and Pilot Light Service Charge—are currently set at rates which no longer accomplish Cascade's objective of influencing customer behavior.

Q. Since the Schedule 200 charges are not cost-based, on what basis does the Company propose the increases?

A. In order to re-set the charges at a level where they are more likely to influence behavior, the Company identified which charges appeared to be no longer effective in influencing customer behavior, and applied to those charges the consumer price index ("CPI") inflation calculator posted on the website for the Bureau of Labor Statistics.[2] On this website, Cascade entered the current fee amount for certain Schedule 200 charges as established in 2007. The calculator was used to determine how much in real terms the fee has increased from 2007 to 2017. For instance, a $10 fee set in 2007 should be re-set to being a $12 fee in 2017 if the true cost to the customer is going to be the same. This approach results in modest adjustments, but this small incremental step up is important in keeping these charges at a level that sends the appropriate signal to customers without being overly burdensome.

Q. Will the Company notify customers about the changes to the Miscellaneous Charges?

A. Yes. Consistent with the requirement in WAC 480-90-195, the Company will notify all affected customers when the changes are effective.

Q. What changes are proposed for Rule 21, Decoupling Mechanism?

A. The authorized margin revenue per customer per month in Rule 21, Decoupling Mechanism is revised to reflect the proposed changes in revenue requirement. The derivation of the new monthly authorized margin revenue per customer is presented in

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[2] United States Department of Labor, Bureau of Labor Statistics website for CPI Inflation Calculator: https://www.bls.gov/data/inflation_calculator.htm (last visited on [January 2017]).

Exhibit No. __ (JGG-3) which divides the annual revenue per customer class as shown in Exhibit No. __ (MCR-2) by the weather normalized, test year therms per customer class as found in Mr. Brian Robertson's Work Paper BR 1.4. This amount is then multiplied by the monthly, weather normalized, test year therms per customer class, then divided by the average annual customer count in the test year to determine the authorized annual revenue per customer per month. This is consistent with the methodology approved in Order No. 04 in UG-152286.

Q. Is the Company proposing any other changes to its tariff?

A. Yes.

Q. Please describe those changes.

A. Cascade proposes to delete language from Schedules 502, 503, 504, and 505 regarding the Reconnection Charge because it does not provide a complete description of the Reconnection Charge and unnecessarily repeats information provided in Schedule 200. The Company provides a complete description of the Reconnection Charge in Schedule 200.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. __ (RJA-1T)
Docket No. UG-17___
Witness: Ronald J. Amen

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION Respondent.	DOCKET UG-17____

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF RONALD J. AMEN

August 31, 2017

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

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

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

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

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

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

Q. Please describe the firm of Black & Veatch.

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

Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

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

A. I have over 39 years of experience in the utility industry, the last 20 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included as Exhibit No. __ (RJA-8) to my testimony.

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

A. Yes. I have testified in Docket Nos. UG-931405 (General Rate Case of Washington Natural Gas Company ("WNG")), UG-940814/UG-940034 (Cost of Service and Rate Design Proceeding of WNG), UG-941246/UG-950264 (WNG Line Extension Policy), UG-950278 (General Rate Case of WNG), UE-960195 (Merger of Washington Energy

Company and Puget Sound Power and Light Company), UG-960520 (WNG Propane Service), UG-011571 (General Rate Case of Puget Sound Energy), UG-060267 (General Rate Case of Puget Sound Energy), UG-080546 (General Rate Case of NW Natural), and UG-152286 (General Rate Case of Cascade Natural Gas). I have also previously appeared before the Commission on numerous occasions regarding various regulatory, customer contract and tariff matters.

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

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and numerous state and provincial regulatory commissions.

Q. Please summarize your testimony.

A. In my testimony I present Cascade's Cost of Service Study ("COSS") and discuss its results, and I present the various rate design proposals filed by Cascade in this proceeding.

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

- Theoretical Principles of Cost Allocation
- Cascade's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Cascade's Rate Design Proposals
- Residential & Non-Residential Class Bill Impacts
- Determination of Gas Resource Demand Costs by Customer Class for Use in Cascade's PGA Filings

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

A. The following exhibits accompany my testimony.

- Exhibit No. __ (RJA-2) Summary of COSS results
- Exhibit No. __ (RJA-3) Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Exhibit No. __ (RJA-4) Analysis of Revenue by Detailed Tariff Schedule
- Exhibit No. __ (RJA-5) Residential Impact by Month
- Exhibit No. __ (RJA-6) Impact of Recommended Rate Changes
- Exhibit No. __ (RJA-7) Determination of Gas Resource Demand Costs by Customer Class
- Exhibit No. __ (RJA-8) Resume of Ronald J. Amen

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

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

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

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

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

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

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

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

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

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

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

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

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

SAC is an important concept for Cascade because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

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

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a Local Distribution Company's ("LDC's") customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer’s load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Were direct assignments of plant made in the Cascade COSS?

A. Yes. A special study was performed to determine the specific transmission and distribution mains, as well as the customer service lines, that were constructed to serve Cascade’s Special Contract customers. The plant costs related to these facilities were directly assigned to the Special Contract class in the COSS. The Company's Geographic Information System ("GIS") was queried to research the various pipeline pathways from system regulator stations to the customers' service addresses along with the related pipeline sizes, material types, and pressure classification. Historical plant records such as work orders, distribution line reports, facilities installation diagrams, statistical data sheets, and gas service record cards were reviewed to obtain the necessary facilities data and construction cost information to complete the direct assignment of the mains and services plant costs to the Special Contracts class.

III. CASCADE'S COSS

A. Process Steps and Structure of the Cost of Service Study

Q. Please describe the process of performing Cascade's COSS analysis.

A. Three broad steps were followed to perform the Company's COSS: (1) functionalization, (2) classification, and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include: production (i.e., gas supply), transmission, distribution and general. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

Q. **Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?**

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q **Why are these considerations relevant to conducting Cascade's COSS?**

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of Washington as it pertains to cost of service studies and gas ratemaking issues.

Q. **Please explain why the physical configuration of the system is an important consideration.**

A. The particulars of the physical configuration of the transmission and distribution system are important. The specific characteristics of the system configuration, such as, whether the distribution system is a centralized or a dispersed one, should be identified. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single-pressure based operation.

Q. **What are the specific physical characteristics of the Cascade's system?**

A. The physical configuration of the Cascade' system is a dispersed / multiple city-gate, integrated transmission / distribution and multi pressure-based system.

Q. What was the source of the cost data analyzed in the Company's COSS?

A. All cost of service data have been extracted from the Company's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing.

Q. How does the availability of data influence a COSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available. Cascade maintains detailed plant accounting records for many of its distribution-related facilities.

Q. How are the Cascade customer classes structured for purposes of the COSS?

A. The COSS evaluated seven customer classes: Residential Service (Tariff Schedules 502 and 503); General Commercial Service (Tariff Schedule 504) including Compressed Natural Gas (CNG) Service (Tariff Schedule 512) ; General Industrial Service (Tariff Schedule 505); Large Volume General Service (Tariff Schedule 511); Interruptible Service (Tariff Schedules 570 and 577); Distribution System Transportation Service (Tariff Schedule 663); and Special Contracts.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach historically used to establish utility rates in the state. Specifically, state regulations set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the particular cost allocation method utilized by the utility. For example, in a Washington Natural Gas (now Puget Sound

Energy) case, Docket No. UG-940814, the WUTC expressed a preference for the gas utility to utilize a costing methodology, Peak & Average, which allocates some fixed costs on the basis of annual use (or throughput) in order to reflect the proposition that a range of factors influence how gas transmission and distribution system costs are incurred and its significance in the cost study process. In its December 2016 Order in Docket Nos. UE-160228 and UG-160229 (*consolidated*), the WUTC instructed its staff to initiate a collaborative effort with the investor-owned Washington utilities and interested stakeholders to more clearly define the scope and expected outcomes for generic cost of service proceedings in an effort to establish greater clarity and uniformity in future cost of service studies.[1]

Q. Is the overall cost allocation approach utilized in Cascade's COSS consistent with that utilized in the prior rate case that you cited?

A. Yes. The overall allocation approach is similar to that adopted by the WUTC in Docket No. UG-940814.

Q. Please describe the Peak & Average methodology in greater detail as it has been applied in the Cascade COSS.

A. The Peak & Average ("P&A") methodology is a simplified version of the Average and Excess ("A&E") demand allocation methodology, also referred to as the "used and unused capacity" method. The A&E method allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the

[1] *Wash. Utils. & Transp. Comm'n v. Avista Corp., dba Avista Utils.*, Docket Nos. UE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).

average load is allocated on the basis of each class' average demand and is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand. The P&A methodology adopted in the referenced WUTC docket similarly weights the allocation of the utility's transmission and distribution system costs by the system load factor. The peak related portion of the P&A method is premised on the notion that investment in capacity is determined by the peak load(s) of the utility and therefore are allocated to each customer class in proportion to the demand coincident with the system peak of that customer class. The peak demand allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of several cold days, either consecutive or occurring over a period of several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day." The peak demands utilized in the Cascade COSS are the respective design day demands for Cascade's firm sales classes, as developed in the Company's most recent Integrated Resource Plan ("IRP"). While the IRP does not reflect peak demands for the Interruptible Service, Distribution System Transportation Service and Special Contracts classes, the average of the measured daily demands during the system three-day peak in the test year for these classes were used to provide a peak related contribution for these non-core customer classes.

Q. Why did you choose to utilize Cascade's design day demand for the firm service classes rather than an actual peak day demand in the application of the P&A allocation method?

A. Use of a utility's design day demand is superior to using its actual peak day demand or a historical average of multiple peak day demands over time for purposes of deriving demand allocation factors for a number of reasons. These reasons include:

(1) A utility's gas system is designed, and consequently costs are incurred, to meet design day demand. In contrast, costs are not incurred on the basis of an average of peak demands.

(2) Design day demand is more consistent with the level of change in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time.

(3) Design day demand provides more stable cost allocation results over time.

Q. Please explain why Cascade's design day demand best reflects the factors that actually cause costs to be incurred.

A. Cascade must consistently rely upon design day demand in the design of its own transmission and distribution facilities required to serve its firm service customers. More importantly, design day demand directly measures the gas demand requirements of the utility's firm service customers which create the need for Cascade to acquire resources, build facilities and incur millions of dollars in fixed costs on an ongoing basis. In my opinion, there is no better way to capture the true cost causative factors of Cascade's operations than to utilize its design peak day requirements within its cost of service studies.

Q. Please explain why use of design day demand provides more stable cost allocation results over time.

A. By definition, a utility's design day peak is as stable a determinant of planned capacity utilization as you can derive. If it were not a stable demand determinant, the design of a utility's gas system and supply portfolio would tend to vary and make the installation of facilities and acquisition of supply resources and capacity a much more difficult task. Therefore, use of design day demands provides a more stable basis than any of the other demand allocation factors available based on either actual peak day demand or the averaging of multiple peak days.

B. Transmission and Distribution Plant

Q. How were Transmission Mains allocated in the COSS?

A. Transmission mains were allocated to the firm and interruptible sales and transportation classes under the Peak & Average method described above, after deducting the transmission mains investment that was directly assigned to the Special Contracts class.

Q. How were Distribution Mains allocated in the COSS?

A. Distribution mains were allocated to the firm and interruptible sales and transportation classes under the Peak & Average method, after deducting the specific distribution mains investment that was directly assigned to the Special Contracts class. A special study was performed to determine the specific pipe size and type of intermediate pressure distribution main to which each of the special contract customers in the Interruptible Service class and the customers in the Distribution System Transportation Service class were attached. The respective customers' peak and average load characteristics were included in the allocation of that portion of the distribution mains investment for the tranches of mains of equal or greater pipe size than the main to which they were attached. The remaining firm sales service classes received a full allocation of all intermediate pressure mains regardless of pipe size or type. High pressure distribution mains were allocated to all classes, with the exception of the Special Contracts class, which received a direct assignment of these mains, as described earlier.

Q. Please describe the special studies conducted for purposes of allocating other distribution plant investment.

A. Regarding Cascade's major plant accounts, current cost factors were developed to allocate the following FERC plant accounts: Services – Account No. 380, Meters – Account 381, and House Regulators – Account No. 383. These cost factors reflect differences in the current unit equipment and installation costs that particular customer groups cause the Company to incur. For example, the cost of a 3/4-inch plastic service line that could serve a residential customer costs less, on a per unit basis, than the cost of a 4-inch steel service line to serve a larger industrial customer.

Q. What other noteworthy plant allocations have been made?

A. Miscellaneous Intangible Plant – Account 303, was segregated into customers, plant and throughput related categories and allocated accordingly based on a review of the investment elements in the account. For Industrial Measuring & Regulating ("M&R") Station Equipment – Account No. 385, an allocation of this plant to the various customer classes was facilitated by research of property records conducted by Cascade's Washington District Office personnel to identify specific equipment with individual customers. The remaining M&R equipment in Account No. 385 that could not be identified with individual customers were allocated to the classes based on the assignment of the identifiable M&R equipment costs.

Q. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A. These items were allocated by function in proportion to their associated plant accounts.

C. Transmission and Distribution Operation and Maintenance Expenses

Q. How did the COSS allocate transmission and distribution related operation and maintenance ("O&M") expenses?

A: In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, *i.e.*, expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Meters and House Regulator Expenses, is allocated on the same basis as its corresponding plant accounts, Meters – Account 381 and House Regulators – Account 383. With the detailed analyses supporting the assignment or allocation of major plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

D. Customer Service and Administrative & General Expenses

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

A. The category of customer related O&M expenses includes the following FERC accounts: Meter Reading – Account 902; Customer Records and Collections, including monthly billing postage and printing – Account 903; and Uncollectible Accounts – Account 904, involving the following Cascade Responsibility Centers: Customer Services (RC 4767100, RC 4767200); Credit and Collections (RC 4767000); Revenue Accounting (RC 4760700); Information Systems (RC 4767800); and the nine Washington Districts.

Meter Reading expenses were assigned to core or non-core customer groups based on an analysis of labor costs of field personnel involved in meter reading activities related to the respective customer groups and then allocated on a customer basis. Customer Records and Collections expenses were allocated to all classes using a composite allocation factor based on functions performed by the responsibility centers such as billing, revenue accounting, collection activity, and. Uncollectible Accounts expenses were assigned to the classes on the basis of uncollectible account write-offs.

Q How did the COSS allocate Administrative and General expenses?

A. Administrative and General ("A&G") expenses were allocated in relation to plant, O&M or labor expenses. Specifically, A&G expense Property Insurance – Account 924 was allocated on the basis of transmission and distribution plant, as were Rents – Account 931 and Maintenance of General Plant – Account 932. The following accounts were allocated on the basis of Cascade's labor expenses: A&G Salaries – Account 920, Office

Supplies and Expenses – Account 921, Outside Services – Account 923, Injuries and Damages – Account 925, and Pensions and Benefits – Account 926. Miscellaneous General Expense – Account 930 was allocated on the basis of transmission and distribution O&M. This is a reasonable approach to allocating A&G expenses.

Q. How did the COSS allocate taxes other than income taxes?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category, *i.e.*, payroll, property, or function. Typically, taxes of a utility other than income taxes can be grouped into the following categories: (1) labor; (2) plant; and (3) function, *e.g.*, Transmission, Distribution, Storage, etc. In the Cascade COSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated to each customer class?

A. Deferred income taxes and investment tax credits were allocated on a transmission and distribution plant basis. Current income taxes were allocated based on each individual class' revenue requirement.

E. Gas Supply O&M Expenses

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

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

The Gas Planning function includes monthly/seasonal/annual gas resource planning; supply resource modeling and optimization; market intelligence gathering and analysis; IRP development; and Canadian / U.S. pipeline and storage operational, tolls / tariffs, and shipper related activities. The expenses in Other Gas Supply Expenses – Account 813 charged to this function were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using a peak & average allocator.

The Gas Supply function includes gas supply procurement for core customers; balancing of core system supplies, including day-to-day storage activities; gas supply reporting, including commodity and closing price reporting; processing supplier invoices; updating and maintaining North American Energy Standards Board (“NAESB”) contracts; and tracking import authorizations and North American Free Trade (“NAFTA”) certificates. Types of activities relating to non-core customers include resolution of imbalances and communicating with non-core customers relating to imbalance “packing” or “drafting” that affects the overall system balance position. The expenses charged to this function in Account 813 were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the Cascade pipeline system in Washington. This is accomplished by gas control personnel through electronic monitoring of various points on the system via SCADA and Metretek measurement equipment. The SCADA sites are located at town border stations throughout the Cascade system and at some Special Contract customer locations. Metretek monitoring equipment is located at non-core customer locations for classes 570/577, 663 and 900. The expenses charged to this function in Distribution Load Dispatching – Account 871 were first segregated between core and non-core classes according to a recent twelve-month study of recorded actionable items triggered by information provided by the SCADA and Metretek sites and the related labor hours, and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

F. Cascade's Cost of Service Study Results

Q. Have you prepared a summary of Cascade's COSS results?

A. Yes. Exhibit No. __ (RJA-2) summarized the results of Cascade's COSS. In particular, the exhibit presents the resulting allocation by customer class of Cascade's proposed revenue requirement based strictly on the results of the computations included in the COSS.

Q. Please compare the resulting COSS results to the current rates and associated non-gas revenues for each of Cascade's customer classes**.**

A. Exhibit No. __ (RJA-2), page 2, line 27 presents the total COSS-based rate schedule revenue requirement for each of Cascade's customer classes at the proposed system rate of return. Line 7, page 1, of this Exhibit presents Test Year margin revenues by customer class under Cascade's current rates, net of gas costs, other operating revenues, miscellaneous charges, and revenue taxes. By comparing these two sets of revenues, one can see the extent to which Cascade's current rates and non-gas revenues are reflective of COSS. The revenue-to-cost ratios on line 45, page 2, of this exhibit portray the relative difference between these two revenue amounts for each class. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular customer class are below its indicated COSS (*i.e.*, Customer Class 502/503 and 663), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the customer class are above its indicated COSS (*e.g.*, Special Contract Class 900). These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign Cascade's proposed revenue increase to its customer classes.

Q. Please describe the information presented in Exhibit No. __ (RJA-3).

A. The COSS summarized the costs allocated to the customer classes on a functionalized (*i.e.* by production (gas supply related), transmission, and distribution), and classified (*i.e.* by demand, customer and commodity) basis. Of particular interest are the customer related costs. Exhibit No. __ (RJA-3) provides a summary of the functionalized and classified costs, and shows these on a unit cost basis. These results were used as a guide in developing the proposed monthly Basic Service Charge levels by tariff schedule, as discussed later in my testimony.

IV. PRINCIPLES OF SOUND RATE DESIGN

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

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

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

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

Q. Please discuss the principle of efficiency.

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

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

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

Q. Please discuss the principle of stability.

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

Q. Please discuss the concept of non-discrimination.

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

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

Q. Please discuss the principle of administrative simplicity.

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

Q. Please discuss the principle of the balanced budget.

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

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

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

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

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

In the case of a local distribution company ("LDC") such as Cascade, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

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

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

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

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

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

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

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

1. System cost characteristics such as established in the COSS required by the WUTC, or embedded customer, demand, and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and

4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

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

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

V. <u>DETERMINATION OF PROPOSED CLASS REVENUES</u>

Q. Please describe the approach generally followed to allocate Cascade's proposed revenue increase of $5.9 million to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Cascade's customer classes

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

A. Yes. Using Cascade's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Cascade personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first and benchmark option that I evaluated under Cascade's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

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

Q. What was the result of this process?

A. After further discussions with Cascade, I concluded that the appropriate interclass revenue proposal would consist of an adjustment to the present revenue level in Cascade's Residential Service class (Tariff Schedules 502 and 503), the Interruptible Service class (Tariff Schedules 570 and 577) and the Distribution System Transportation Service (Tariff Schedule 663). In the case of the Residential Service class, the revenue adjustment insures their proposed rates will move class revenues closer to the COSS for the class. Not only was the Residential Service class below unity (< 1.00 revenue-to-cost ratio) in the COSS results, it produced a minimal class rate of return ("ROR") at 0.07 . While the Interruptible Service class' revenue-to-cost ratio was slightly above unity at current rates (1.01), and the Distribution System Transportation Service revenue-to-cost ratio slightly less than unity (0.98), the proposed revenue adjustments bring these two classes closer in alignment with their remaining commercial /industrial class counterparts.

The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), the resulting customer impact implications for the Residential Service class has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00. That result, a revenue-to-cost ratio of 0.93, is reflected in Exhibit No. __ (RJA-2), page 2, on Line 47. From a class cost of service standpoint, this type of class movement, and reduction in the existing class rate subsidies, is desirable.

VI. CASCADE'S RATE DESIGN PROPOSALS

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

A. I will present the specific rate design changes and supporting rationale for Cascade's proposals. Cascade has proposed the following rate design changes to its current tariff schedules:

- For customers served under Residential Service class (Tariff Schedule 503), General Commercial Service class (Tariff Schedule 504); General Industrial Service (Tariff Schedule 505); Large Volume General Service (Tariff Schedule 511); Interruptible Service (Tariff Schedules 570 and 577); and Distribution System Transportation Service (Tariff Schedule 663), Cascade proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service.
- Cascade is proposing to eliminate the Tariff Schedule 502, Building Construction Temporary Heating and Dry-Out Service, and merge those customers into the Residential Service class (Tariff Schedule 502).

- Increasing the Demand Rate in the Distribution System Transportation Service (Tariff Schedule 663) to better reflect the underlying unit demand costs associated with this customer class.

Q. Please describe the changes to the monthly Customer Charge levels for Tariff Schedule 505, Schedule 511, Schedule 570, and Schedule 577 .

A. The proposed monthly Basic Service Charge for Schedule 505 is $75.00, an increase of $27.00, which raises the charge to approximately 59 percent of the upper range of the unit customer-related costs for the class, as indicated in the Unit Cost Report, Exhibit No. __ (RJA-3). The proposed monthly Basic Service Charge for Schedule 511 is $200.00, which raises the charge to within approximately 50 percent of the upper range of the indicated unit customer-related cost for the class. The proposed monthly Basic Service Charges for Schedules 570 and 577 are $500.00, which raises these charges to within 45 percent of the upper range of the indicated unit customer-related cost for the class. These increases to the Basic Service Charges will provide significant improvement in the recovery of the fixed customer-related costs via fixed charges. With the exception of Schedules 570 / 577, to offset the foregoing increases to the Basic Service Charges, all blocks of the volumetric rates in the respective tariff schedules were reduced ratably based on the margin revenue in each block.

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

A. Yes. Cascade proposes to increase the Basic Service Charges for the Residential Service Schedule 503 to $6.00 from its current $4.00 level, and the General Commercial Service Schedule 504 to $15.00 from its current $10.00 monthly charge level. At this level, the

Basic Service Charge for these two classes of service will recover more of the monthly customer-related O&M (meter reading, billing and uncollectibles), and return of and on the meter and service line plant, as indicated by the COSS Study.

Q. Please describe the proposed changes to the Distribution System Transportation Service (Tariff Schedule 663).

A. The Customer Service Charge in Tariff Schedule 663 will be increased under Cascade's proposal to $750.00 from the current level of $500.00, which is approximately 53 percent of the level of customer-related cost for this customer class as shown in the Unit Cost Report, Exhibit No. __ (RJA-3). The current System Balancing Charge of $0.0004 per therm of gas transported will remain unchanged. The revenue from the System Balancing Charge will be credited to the PGA, thus reimbursing sales customers for the use of a portion of the Jackson Prairie storage resource for balancing the net differences between the transportation customers' daily transportation deliveries and daily gas usage. The System Balancing charge was derived from a study of Cascade's net daily system imbalance activity over the past three years. The System Balancing Charge will also apply to the transported volumes for the Special Contract customers.

Finally, the current Contract Demand ("CD") Charge in Schedule 663 of $0.20 per CD therms per month will be raised to $0.22, which will recover approximately 86 percent of the unit demand-related costs for this customer class. All blocks of the volumetric Delivery Charge in Schedule 663 will be ratably increased to collect the remainder of the proposed revenue increase to this Tariff Schedule.

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

A. Yes. Exhibit No. __ (RJA-4) shows the derivation of each rate component for each of Cascade's tariff schedules.

Q. What is the impact of the foregoing proposed increases to fixed charges on the recovery of Cascade's fixed delivery service costs?

A. The proposed increases to the various Customer Service Charges and the proposed $.02 increase to the CD Charge in Schedule 663 will result in an overall increase of $7.2 million of fixed cost recovery in fixed charges or 28 percent of Cascade's total rate schedule generated non-gas revenue requirement, leaving $71.4 million of fixed transmission and distribution costs to be recovered via the volumetric Delivery Charges.

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

A. Yes. Cascade witness Maryalice Rosales presents Cascade's revenue proof for the Test Year.

VII. CUSTOMER BILL IMPACTS

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

A. The monthly and annual bill impacts for a typical residential customer using 653 therms per year is shown on Exhibit No. __ (RJA-5) The average monthly increase for this residential customer under the Company's proposed rate design is $2.09 or 4.41 percent. Monthly residential bill impacts over a range of usage are depicted on page 1 of Exhibit No. __ (RJA-6).

Q. Have you prepared bill comparisons for Cascade's other non-residential tariff schedules?

A. Yes. Exhibit __ (RJA-6) also presents bill comparisons for Cascade's non-residential service tariff schedules at varying monthly levels of gas usage, with the exception of Schedule 663. The average cost per therm of gas transported for these customers will uniquely vary based on the relationship of their level of monthly transportation volumes to their individual contract demands; in other words, the higher the load factor experienced by the individual Schedule 663 customers – the lower will be their average cost per therm. Average monthly bill increases for Schedule 663 customers under Cascade's proposed changes to the rate components of the Tariff Schedule range from a low of 3.0 percent for the largest customers to 30 percent or more for a few customers with low load factors and 30,000 therms or less of annual consumption.

VIII. DETERMINATION OF ALLOCATED GAS RESOURCE DEMAND COSTS

Q. What is the purpose of this section of your testimony?

A. This section of my testimony describes the manner in which the Company plans for and utilizes the gas transportation and storage capacity that is needed to serve its natural gas customers. I will provide a recommendation as to the allocation of pipeline capacity and storage costs for use in Cascade's PGA filings.

Q. Please describe what drives Cascade's decisions regarding the use of pipeline capacity.

A. Most of Cascade's natural gas sales customers are firm customers as opposed to interruptible customers. Firm customers expect to receive gas at all times, particularly during extremely cold weather. Demand for natural gas from Cascade's firm customers is at its highest during cold weather. However, the cold weather increases the demand of other interstate pipeline customers, thus reducing the availability of contracted but unused pipeline capacity.

Given Cascade's obligation to serve its firm customers, it is the expected customer demand, and in particular the shape of that demand, that drives Cascade to plan for and use pipeline capacity. As more fully described in the Company's 2016 IRP, Cascade seeks the least cost mix of available resources that can meet its design-day peak standard. Often, due to lack of additional storage or other peaking resources, the only available incremental resource to ensure Cascade's ability to meet its design day standard is year-round pipeline capacity.

Q. How does Cascade determine its use of pipeline capacity?

A. The process for determining the need for pipeline capacity can be summarized in the six-step process described below. The six steps reflect a logical progression in identifying why and when capacity is needed, and thus give guidance as to how to allocate the related costs.

Q. Please identify the steps and how they can guide pipeline capacity resource cost allocation.

A. **<u>Step 1:</u>** One must consider the average summer demand or sales volume level. This must be served by flowing gas supply using year-round pipeline capacity because, other than for load balancing, storage and peaking resources are not available in the summer.

Cascade's normalized average daily sales volume in the summer months during the 12 months ended December 2016 was approximately 29,975 Dth/day. Thus, average summer sales volumes require pipeline capacity of 29,975 Dth/day. Since this capacity is only available on a year-round basis and will be used to serve winter sales volumes as well (Step 2), it is reasonable to allocate the cost of this capacity to Annual Sales Volumes.

Step 2: In order to have sufficient volumes in storage to serve the winter sales volumes, storage injections must be made using flowing gas and year-round pipeline capacity. Average summer injection requirements for Jackson Prairie and Plymouth LNG are 8,259 Dth/day. Cascade could schedule its injection requirements around its customer requirements and operate all summer long with 8,259 Dth/day of pipeline capacity. Because this capacity is needed specifically to fill storage, which is in turn used to serve winter sales volumes, it is reasonable to allocate the costs of this capacity to Winter Sales Volumes. This capacity is also available to flow additional gas to serve winter sales volumes after the summer injection period (Step 3).

Step 3: Before determining the need for additional pipeline capacity to serve winter demand, Cascade considers the average availability of storage withdrawals from Jackson Prairie that use Northwest Pipeline TF-2 capacity and thus do not require the use of year-round pipeline capacity. Average Daily winter withdrawals from Jackson Prairie storage average approximately 1,371 Dth/day. The TF-2 capacity utilized by Jackson Prairie withdrawals would reasonably be allocated partially to Winter Sales Volumes, Design Peak Volumes and of course, system load balancing.

Step 4: Winter average daily sales volumes are 98,491 Dth/day. These requirements are met with the capacity acquired in Steps 1, 2 and 3, thus leaving an average winter sales demand of 58,886 Dth/day (98,491 minus 1,371 minus 8,259 minus 29,975) to be fulfilled with additional year-round pipeline capacity. It is reasonable to allocate the costs of this capacity to Winter Sales Volumes.

Step 5: Cascade considers its Design Peak Sales Requirement and the deliverability of all of its storage and peaking resources that have not already been considered in use on the average winter day. Cascade's estimated design peak requirement for the 12 months ended December 2016 was approximately 262,836 Dth/day. Cascade's peaking and storage resources provide, at maximum deliverability, a total of 78,299 Dth/day (9,577 from Jackson Prairie and 68,722 from Plymouth LNG). However, Cascade has already relied on 1,371 Dth/day from Jackson Prairie on an average winter day in Step 3, thus incremental storage and peaking provide a resource of 76,928 Dth/day (78,299 minus 1,371). It is reasonable that the costs of the various resources that provide this incremental deliverability should be allocated based on their use to serve the design peak requirements of the system.

Step 6: The design peak demand is not yet met, and no additional gas storage or peaking resources are available in a cost effective manner. Cascade thus must use additional year-round pipeline capacity of 180,827 Dth/day (262,836 minus 29,975 minus 8,259 minus 58,886 minus 78,299 plus an approximate reserve of 93,410) to make up the shortfall. Because this last increment of pipeline capacity is required only to serve the design peak day requirements of the customer demand, it is reasonable to allocate the cost of this capacity based on the contribution of various customer classes to design peak day demand. Exhibit No. __ (RJA-7), pages 2 and 3, illustrates the six steps described above in both tabular and graphical format, respectively.

Q. What is your overall recommendation as to the allocation of year-round pipeline capacity, storage, peaking and redelivery capacity (TF-2) costs?

A. As summarized in the table on page 2 of Exhibit No. __ (RJA-7), showing the six step process, I recommend that year-round pipeline capacity costs should be allocated within the PGA as 9.9 percent to Annual Sales Volumes, 19.4 percent to Winter Sales Volumes and 70.7 percent to Design Peak Volumes. I recommend that the 80 percent of Jackson Prairie and its related TF-2 capacity that is not allocated to system balancing be allocated in the PGA as follows: 11.3 percent to Winter Sales and 68.7 percent to Design Peak Day.

Q. What are the resulting unit demand cost rates for the various sales service classes in the PGA?

A. The result of the computations to determine the class-by-class unit demand cost rates that result from the foregoing allocation of pipeline, storage and peaking capacity are shown on page 1 of Exhibit No. __ (RJA-7).

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit No. __ (MCR-1T)
Docket No. UG-17_____
Witness: Maryalice C. Rosales

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF MARYALICE C. ROSALES

August 31, 2017

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I. INTRODUCTION

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

A. My name is Maryalice C. Rosales 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. Would you briefly describe your duties?

A. Yes. 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 ("AGA") at the University of Chicago. I have received additional training at 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.

Q. Have you previously written or presented testimony before this or any other commission?

A. No.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the summary of revenues by rate schedule shown in Exhibit No. __ (MCR-2). Exhibit No. ___ (MCR-3) and Exhibit No. __ (MCR-4) will describe the Company's natural gas revenue adjustments. Cascade's revised tariff sheets reflecting Cascade's proposed revenue requirement are provided as Exhibit No. __ (JGG-2), and are supported by the testimony of Company witness Ms. Jennifer G. Gross.

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

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

Exhibit No. __ (MCR-2)	Summary of Revenues by Rate Schedule
Exhibit No. __ (MCR-3)	Revenue Adjustment
Exhibit No. __ (MCR-4)	Restatement of Revenue

III. SUMMARY OF REVENUES BY RATE SCHEDULE

Q. Would you please describe the summary of revenues by rate schedule shown in Exhibit No. __ (MCR-2)?

A. Yes. Columns (B) and (C) of the summary of revenues by rate schedule show billing determinants, volumes, and rates respectively, for the test year, January 1, 2016, through December 31, 2016. The "Test Year Revenue" column (D) show total revenue for each rate schedule, including all rate components and all billing adjustments.

Q. What do the columns (E-G) labeled "Deleting schedules to combine with other" signify?

A. This section accounts for the proposed removal of three rate schedules: 502 (Building Construction Temporary Heating and Dry-Out Service Rate), 512 (Compressed Natural Gas Service), and 577 (Limited Interruptible Service Rate). This section takes the revenue from the basic service charges and the margin from these three schedules and adds it into the designated rate schedules to which all affected customers will migrate. A summary of the migration plan is as follows:

- Schedule 502, Building Construction Temporary Heating and DryOut Service Rate is being frozen. Future residential construction dry-out customers will be served on Schedule 503, Residential Service Rate;

- Schedule 512, Compressed Natural Gas Service is being removed. Customers on this rate schedule will migrate to Schedule 504, General Commercial Service Rate; and
- Schedule 577, Limited Interruptible Service Rate will be cancelled and customers will migrate to Schedule 570, Limited Interruptible Service Rate.

Additional details on these changes are provided in the testimony of Ms. Gross, Exhibit No. __ (JGG-1T).

Q. What does the "Current Rates" section in columns (H-J) of the summary of revenues by rate schedule show?

A. The current rates section presents the current rates, effective as of November 1, 2016, applied to the weather-normalized test year volumes and the test year billing determinants. Column (J) titled, "Margin" presents the total margin amount associated with each rate schedule including all rate components and all billing adjustments.

Q. What does column (K) titled "2017 Revenue Adjustment" show?

A. Column (K), "2017 Revenue Adjustment," shows the difference between the weather-normalized test year volumes and test year billing determinants for each rate class at current rates, and the test year volumes and billings at test year rates. The difference between these two sections demonstrates how much revenue can be attributed to changes in weather normalization, rate changes during the test year, and changes in special contract rates due to the annual Consumer Price Index ("CPI") update.

Q. What is shown in columns (L-N) regarding the Cost Recovery Mechanism ("CRM")?

A. This section annualizes CRM rates that were approved effective November 1, 2016. This amount is also shown in the "Revenue Adjustment," Exhibit No. __ (MCR-3).

Q. What is the CRM referred to in the previous question and why does it change on an annual basis?

A. 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, 2017 in Docket No. UG-170674, and the current rates were approved, effective November 1, 2016.

Q. What is shown in the "Proposed Rates" section of the summary of revenues by rate schedule?

A. Columns (O), (P) and (Q) show proposed rates multiplied by weather-normalized volumes and the test year billing determinants for each rate schedule. For more detailed information regarding Cascade's proposed rates, please see the Direct Testimony of Mr. Ronald J. Amen, Exhibit No. __ (RJA-1T).

Q. What does the "Proposed Margin" column (R) show?

A. Column (R) shows the difference between the proposed rates and current rates. In summary, it shows the revenue increase or decrease the Company is requesting for each rate schedule in this case.

IV. REVENUE ADJUSTMENT

Q. Please describe the revenue adjustment shown in Exhibit No. ___ (MCR-3).

A. The revenue adjustment shown in Exhibit No. __ (MCR-3) is a pro forma revenue adjustment. The adjustment starts with the January 2016 through December 2016 weather normalized test year volumes and billing determinants and adjusts for known and measureable (pro forma) changes. The result is an increase in revenue of $8,908,260. This figure is shown at the bottom of Exhibit No. ____ (MCR-2).

Q. Are there other components included in the revenue adjustment?

A. Yes. As shown in Exhibit No. ___ (MCR-3), the revenue adjustment also takes into account the annualization of the CRM rate that became effective on November 1, 2016.

Q. Please continue describing the other adjustments that need to be made to the $8,908,260 to reflect the pro forma level of margin revenue?

A. We must also perform the following adjustments:

- Subtract the weather normalized volumes multiplied by current rates because these amounts are already accounted for in the weather normalization adjustment.
- Adjusts margins for the CRM revenues already included in booked amounts.

The resulting revenue adjustment of $5,220,091 is shown in Mr. Parvinen's Exhibit No. __ (MPP-5), "Pro Forma Revenue, P-9."

V. RESTATEMENT OF REVENUE

Q. **Please describe the restatement of revenue in Exhibit No.__ (MCR-4).**

A. The restatement of revenue calculates the revenues and natural gas costs associated with weather normalized volumes at the most current gas cost revenue and expense rates thus eliminating the impact of the net unbilled amounts and all deferral amortizations including conservation expense recoveries. This calculation then identifies and adjusts to the revenue amounts that will be realized in the rate year absent new rates.

The revenue adjustment amount reflecting a decrease of $8,729,177 shown, is the net total of $110,133,417 from Exhibit MCR-2 gas cost revenue actually booked, the weather normalization adjustment of $10,051,636 from Exhibit MCR-2, net unbilled and deferrals in the amount of $834,040 from Exhibit MCR-2 minus the $112,289,916 in gas costs with the revenue sensitive factor built in.

The gas cost expense adjustment reflects a decrease of $6,033,098 which is calculated by taking the total booked gas costs of $113,645,501 minus actual gas costs (without the addition of revenue sensitive costs) of $107,612,403.

Both decreases described above, $8,729,177 and $6,033,098 are listed in Mr. Parvinen's Exhibit No. __ (MPP-5) under "Restate Revenue Adjustment, R-3."

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. __ (BR-1T)
Docket No. UG-17____
Witness: Brian Robertson

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF BRIAN ROBERTSON

August 31, 2017

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and address for the record.

A. Brian Robertson, 8113 W Grandridge Blvd., Kennewick, WA 99336.

Q. By whom are you employed and what is your title?

A. I am employed by Cascade Natural Gas Corporation ("Cascade" or the "Company") as a Gas Supply Senior Resource Planning Analyst.

Q. Please describe your education background and previous background.

A. I am a graduate of Central Washington University with a B.S. degree in Actuarial Science. After graduating, I joined Cascade in February of 2014 as a Regulatory Analyst. I joined the Gas Supply Department in March of 2015 as a Resource Planning Analyst II and was promoted to a Gas Supply Senior Resource Planning Analyst in July of 2016.

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain Cascade's weather normalization adjustment used in this case and applied to the 2016 test year. I also demonstrate how Cascade modified its weather normalization adjustment to reflect Cascade's commitments from the settlement agreement in Cascade's most recent rate case, docketed as UG-152286. I will also provide an update regarding the progress Cascade has made to date regarding the load study that Cascade initiated as part of the settlement agreement in Docket No. UG-152286.

II. WEATHER NORMALIZATION

Q. Have there been adjustments to the weather normalization since the last rate case?

A. Yes.

Q. Please describe the weather normalization methodology developed in the last rate case.

A. In Docket No. UG-152286, Cascade and Commission Staff ("Staff") worked together to develop a weather normalization methodology. The methodology is a linear regression model that analyzes five years of historical therm per customer per month usage for residential and commercial customers to monthly heating degree days ("HDDs") for Cascade's four weather locations: Bellingham, Bremerton, Walla Walla, and Yakima. The model produces an intercept which 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 class. The best-fit coefficient represents the heat sensitivity use per customer per HDD. 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. The weather normalization adjustment was calculated as the difference between actual recorded therms and the calculated normalized therms.

Q. Did Staff make any recommendations to the weather normalization adjustment in the Company's last rate case?

A. Yes. In the last rate case, Staff recommended the Company implement the following changes to its weather normalization:

a. Use 10 years of usage and weather data;

b. Use National Oceanic and Atmospheric Administration ("NOAA") weather data for both actual temperature and "normal" temperature benchmark;

c. Refine regression models to exclude insignificant monthly heating degree day variables;

d. Include a trend variable in the regression models when appropriate, and correct common statistical problems such as serial correlations. Staff may provide technical assistance;

e. Identify 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 an alternative way of reporting monthly usage if unbilled therms are not trued up monthly: align heating degree days with billing cycles on a monthly basis, rather than using monthly usage data that includes gross estimates of unbilled therms.

As part of the settlement agreement, Cascade committed to implementing these recommendations in the preparation of its Commission Basis Report ("CBR").

Q. Did Cascade implement these changes in its 2017 CBR filing?

A. Yes. Cascade fully complied with these commitments in the preparation of its CBR filing, which was submitted to the Commission on April 27, 2017.

Q. Did Cascade implement these changes to the weather normalization adjustment in this rate case?

A. Yes and no. Cascade implemented these changes as a starting point for preparing its weather normalization adjustment in this rate case, however, as discussed further below, Cascade further refined the weather normalization adjustment in this rate case.

Q. Please describe how Cascade implemented Staff's recommended changes to the weather normalization adjustment in this rate case.

A. Cascade now uses 10 years of actual usage and weather data. Both actual and normal weather data is from NOAA. In this particular instance, normal weather is referring to the average daily temperature based on the most recent 30 years of weather history in each weather location which results in the average annual temperatures as well. The weather normalization adjustment used by Cascade occurs for both Residential and Commercial Schedules 503 and 504. Cascade has excluded insignificant monthly HDD variables. The Company implemented trend variables when significant and tested for serial correlation with Durbin-Watson. When serial correlation was found, Cascade used an autoregressive model. Cascade also removed any outliers when necessary. The Company believes it has resolved issue “f”, unbilled therms, with Exhibit No. __ (BR-2), the demand forecast model.

Q. Did Cascade implement any other changes?

A. Yes. Cascade implemented a change to the methodology of calculating HDDs. Previously, Cascade calculated HDDs using a 65 °F reference temperature. For example, a 50 °F day would produce 15 HDDs (65-50). Now, the Company has implemented a 60 °F reference temperature when calculating HDDs. Cascade found that a 60 °F reference temperature has produced results that are statistically better than using a 65 °F reference temperature. Cascade has provided the results of this analysis in Exhibit No. __ (BR-3).

Q. Please explain the analysis Cascade performed to compare the use of a 60 °F reference temperature with a 65 °F reference temperature for the rest of the citygates.

A. Cascade performed the same 60 °F HDD reference analysis on the four largest citygates, one for each of the four weather locations in Washington for both the residential and commercial classes. Cascade used an autoregressive model analysis using use per customer ("upc") as the dependent variable and HDD as an explanatory variable. The analysis was performed using daily actual therm usage from July 2010 through November of 2016. The Company utilized the statistics Mean Absolute Percentage Error ("MAPE"), Mean Squared Error ("MSE"), Mean Absolute Error ("MAE"), and Akaike Information Criterion ("AIC") to determine which model was statistically better. In each case, the 60 °F reference temperature outperformed the 65 °F reference temperature.

Q. Please explain the source of the daily data performed in the analysis comparing a 60 °F reference temperature with a 65 °F reference temperature.

A. Cascade gathered daily usage data from the pipelines' electronic bulletin board ("EBB") for each of the Company's citygates. The EBB provides daily usage data at the citygate level but not at the customer class level. Utilizing Cascade's Fidelity National Information Services ("Aligne") system, the Company was able to remove the daily non-core usage data from the pipeline daily usage data, leaving the core daily usage data at the citygate level. To get the usage data to a customer class level, Cascade aligned the customer care and billing ("CC&B") data from its billing system to calendar dates as best as possible. Comparing pipeline usage data to CC&B data without shifting any data there was a 24.52 percent MAPE. Cascade found that shifting usage data to the previous month for billing cycles one through thirteen improved the MAPE to 5.29 percent. Using the newly defined CC&B data, the Company was able to create allocation percentages for each customer class by month by city. The cities were allocated to the correct citygate, based on which citygate fed natural gas to that city.

Q. Please provide the initial results of Cascade's weather normalization adjustment.

A. Cascade has prepared its weather normalization adjustment consistent with Cascade's and Staff's recommended changes. As a result, the Company has calculated that residential therms would be 15,052,093 higher than the actual sales and commercial would be 8,330,039 higher than actual sales. These initial results are provided in the summary 60 sheet in Exhibit No. __ (BR-4).

Q. Is the Company satisfied with these initial results?

A. No. In theory, applying these adjustments to the actual usage will give therm sales Cascade would have sold with normal weather. Applying an adjustment of 15,052,093 to the 110,096,508 of actual therms results in an adjusted amount of 125,148,601 therms for the residential class. For the commercial class, applying an adjustment of 8,330,039 therms to 77,935,442 of actual therms results in an adjusted amount of 86,265,481 therms. These results appear to be abnormally high, and the Company does not expect a normal weather year to be this high in usage. In the past seven years of data, the year 2012 most closely replicated the normal weather year. In 2012, Cascade had a shifted billed usage of 113,664,863 therms. Given the 1.22 percent, 1.23 percent, 1.39 percent, and 1.47 percent growth in Rate Schedule 503 (Residential) in 2013, 2014, 2015, and 2016, respectively, Cascade would expect the normal weather year to be approximately 120,000,000 therms for the Test Year 2016. This analysis is shown in Exhibit No. __ (BR-5).

Q. What does the Company propose using for the weather normalization?

A. The Company proposes using Cascade's forecast model, with actual test year customers and normal year weather to calculate the normalized therms for the test year. Cascade's forecast model forecasts at the daily citygate level which allows for more granularity.

Q. Does the Company have a document that describes Cascade's forecast model in detail?

A. Yes. The forecast model design document is provided in Exhibit No. __ (BR-2).

Q. Did the company weather normalize rate schedules other than 503 (Residential) and 504 (Commercial)?

A. Yes. The company has weather normalized rate schedules 505 (Industrial) and 511 (Large Volume) as well.

Q. What are the results of the weather normalization using the forecast model?

A. The Company has calculated that rate schedule 503 would be 119,808,249 resulting in an adjustment of 9,711,741 therms higher than the actual sales and rate schedule 504 would be 81,292,836 resulting in an adjustment of 3,357,394 therms higher than actual sales. For rate schedule 505, the normalized therms would be 11,417,671 for an adjustment of 593,880 and rate schedule 511 normalized therms is 11,107,096 for a total adjustment of 791,498. These results are shown in Exhibit No. __ (BR-6).

III. LOAD STUDY

Q. Did Cascade agree to initiate a load study prior to filing this case?

A. Yes, as part of the settlement agreement in Docket No. UG-152286, Cascade agreed to "initiate a load study" for the purpose of determining "class core responsibilities of daily therms at the city gates."[1]

Q. Has Cascade had any meetings with Staff regarding the load study?

A. Yes. Cascade had a meeting with Christopher Hancock of Staff to discuss Cascade's plans for the load study on March 9th, 2017.

Q. Did Mr. Hancock explain Staff's expectations for the load study?

A. Mr. Hancock explained that the initial concept for the load study was to sample customers in each region using meters/loggers that provide daily measurements.

Q. Does Cascade currently have the equipment in place to use meter/loggers to provide daily measurements?

A. No. Due to Cascade's geographically dispersed and noncontiguous distribution service area, implementing meter/loggers would prove to be expensive and difficult to do.

Q. Did Cascade propose an alternative approach?

A. Yes. Cascade explained the methodology of its new forecast model and discussed its potential application for the new load study. The new forecast model will forecast at the daily citygate level by each customer class. This new methodology will allow Cascade to determine the class core responsibilities of daily therms at the citygates. The forecast model design document is provided in Exhibit No. __ (BR-2).

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[1] *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-152286, Joint Settlement Agreement ¶46 (May 13, 2016).

Q. Will Cascade's alternative approach provide data adequate to analyze class core responsibilities at the citygate level?

A. The Company is optimistic that Cascade's approach will provide data adequate to analyze class core responsibilities of daily therms at the citygate level.

Q. Has the Company initiated this study?

A. Cascade has initiated the load study with the demand forecast model. The preliminary findings from the load study are not currently being used in this rate case because the customer forecast portion still needs to be tested and verified before the results can be finalized.

Q. When does Cascade expect the load study to be completed?

A. The Company has an expected completion date of August 31, 2017 for the load study, but it may be completed sooner or later depending on whether Cascade determines the need for any methodology changes to the model after testing and verifying the model results.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. ___(RP-1T)
Docket No. UG-17____
Witness: Ryan Privratsky

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET UG-17______

CASCADE NATURAL GAS CORPORATION

DIRECT TESTIMONY OF RYAN PRIVRATSKY

August 31, 2017

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I. INTRODUCTION

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

A. My name is Ryan Privratsky and my business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. I am the Director of System Integrity for Cascade, a wholly-owned subsidiary of Montana Dakota Utilities Resources Group, Inc. ("MDU Resources").

Q. Would you briefly describe your duties?

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

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

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

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

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the work Cascade is undertaking to document the basis of the maximum allowable operating pressure ("MAOP") for all high pressure and transmission pipeline segments, as set forth in the Settlement Agreement between Cascade and the Commission's Pipeline Safety Staff in Docket No. PG-150120 ("MAOP Settlement Agreement").[1] I will discuss the timelines for the work and the progress Cascade has made toward compliance with the MAOP Settlement Agreement. Also, I will provide a detailed summary of the third-party costs incurred to date, which Cascade is deferring pursuant to the Accounting Petition in Docket No. UG-160787. The prefiled direct testimony of Mr. Eric Martuscelli describes in more detail the events leading up to execution of the MAOP Settlement Agreement and the benefits that result from the work performed pursuant to the MAOP Settlement Agreement. The prefiled direct testimony of Mr. Michael P. Parvinen addresses recovery of these costs.

II. STATUS OF WORK UNDER THE MAOP SETTLEMENT AGREEMENT

Q. Would you please describe the work that is currently underway as part of the MAOP Settlement Agreement?

A. Yes. Work has been ongoing for approximately one year to document the basis for MAOP validation for high-pressure and transmission pipeline segments operating above 60 psig, consistent with the MAOP Settlement Agreement, and to put in place risk reduction measures while the MAOP validation takes place. The work can be grouped into the following categories:

(1) Performing work to document the basis for validation of MAOP on the 116 segments Cascade identified as missing some critical information necessary to document MAOP;

(2) Conducting records review of all remaining pipelines operating above 60 psig to determine if critical information is missing to validate MAOP on those high pressure segments;

(3) Developing a plan to address validation of additional segments identified in the records review;

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

(4) Leak surveying unvalidated pipeline segments with specified minimum yield strength ("SMYS") of 20 percent or greater four times annually;

(5) Maintaining pressure reduction of 20 percent for all pipeline segments with low frequency seam welds or unknown seam types with preliminary SMYS calculations of over 30 percent; and

(6) Incorporating line segments calculated at greater than 20 percent SMYS into Cascade's TIMP.

Additionally, Cascade has agreed to certain commitments related to the American Petroleum Institute Recommended Practice 1173, Pipeline Safety Management Systems. That work is addressed in the prefiled direct testimony of Eric Martuscelli.

Q. Please describe the work that is taking place to validate the MAOP for the 116 identified segments lacking some critical information.

A. Cascade has identified 116 pipeline segments missing some critical information necessary for documenting the basis for validation of MAOP, and Cascade is working diligently to validate the MAOP of these pipelines. Cascade is currently using a variety of methods to validate the MAOP. The methods include non-destructive testing, pressure testing, and pipe replacement.

The first method, conducting non-destructive or in-situ testing, is a method where a pipe segment is excavated, pipeline coating is removed, and an in-situ test is performed to measure material properties of a pipe segment in place, without having to remove the pipe from service to perform destructive testing. Some key mechanical properties obtained from in-situ testing include yield strength, uniform ductility, ultimate strength, and fracture toughness. In-situ testing allows Cascade to obtain critical pipe information for MAOP without having to make assumptions to calculate the pipe design pressure. Testing also provides additional material properties for a pipe segment which are useful in determining fracture mechanics of the pipe. In some cases, in-situ testing is required to obtain pipe material information to determine if a pipeline segment can be pressure tested safely. Cascade is utilizing ABI Services to perform the material testing, Das-Co to perform the excavations, and Parametrix to perform overall project management and data analysis. Cascade has been able to accelerate its MAOP validation work for the 116 pipeline segments from ten years to seven years due, in large part, to the use of in-situ testing.

The second method used to validate MAOP is pressure testing. Pressure testing is required to determine if the strength of the materials making up a pipe segment are strong enough to be able to operate at a given MAOP and to discover any hazardous leaks that may exist. Pressure testing is required to validate MAOP if a pipe segment is missing a documented pressure test and the MAOP cannot be established through any other methods. Pressure testing requires Cascade to remove the pipe segment from service and conduct a pressure test, per the requirements outlined in 49 CFR Part 192.503 – 192.513. If a pipe segment fails the strength test, the reason for the failed test is pinpointed and remediated and the pressure test is performed again until a successful test is completed. Pressure testing an existing pipe segment presents many different challenges, one of the major challenges being able to maintain service to customers during the test. To maintain service to customers, Cascade uses liquefied natural gas or compressed natural gas, and in some cases service needs to be interrupted to be able to perform the test. Cascade uses qualified pipeline contractors to perform pressure testing.

The third method used to validate MAOP is to replace the pipe segment. This method is needed in some circumstances if a pipe segment cannot be taken out of service for an extended period to perform a pressure test to validate MAOP and MAOP cannot be established through any other means. Replacement may also be necessary to address integrity concerns that may exist with a pipe segment. Cascade uses qualified pipeline contractors to perform pipeline replacement work. In addition to methods previously described, in some circumstances Cascade can excavate specific areas and expose a pipe fitting or component to verify it has the proper pressure rating to operate at the MAOP of the pipeline segment. Cascade has agreed to complete 50 percent of the validation by December 31, 2018, and all validation of these 116 pipeline segments by December 31, 2023.

Q. Can you quantify the progress made in documenting the MAOP validation for the 116 segments?

A. Yes. Cascade has completed replacement of more than 0.90 miles of high pressure and transmission line in 2015 and is on target to complete a total of 2.5 replacement miles by the end of 2017. Cascade has completed approximately 300 in situ tests in 2016, which validated approximately 24.43 miles of transmission and high pressure lines. Cascade is on target to complete 455 in situ tests in 2017, which will validate a total of 3.96 miles. The results that have been obtained from the in-situ testing has allowed Cascade to continue to move forward with our plans to pressure test multiple pipeline segments. Cascade also has been able to validate a total of 15.69 miles by performing excavations and validating pressure ratings of pipe fittings and components. In addition to the replacement, in-situ testing, and excavation work that has been completed, Cascade is in the planning stages to pressure test 3.74 miles in 2017. Based on Cascade's progress to date, Cascade is on schedule to complete 50 percent of the validation work by the end of 2018.

Q. What is the status of the records review?

A. Cascade hired a consultant, TRC Pipeline Services LLC ("TRC"), to review records for all remaining high pressure pipelines. TRC completed its review of the records in the first quarter of 2017. Cascade is in the process of reviewing TRC's findings. As provided in the MAOP Settlement Agreement, Cascade will submit to Pipeline Safety

Staff an updated time line that includes the additional segments identified by TRC that require additional documentation to validate the MAOP. Cascade will submit its proposed timeline for validation of the additional segments by December 31, 2017, and by March 31, 2018, Pipeline Safety Staff and Cascade will file an Amended Settlement Agreement with the Commission that reflects a completion date by which Cascade will document the basis for validation of all high pressure segments, including both the original 116 segments and those additional segments identified by TRC.

Q. Please explain the leak survey work.

A. Cascade is conducting leak surveys a minimum of four times annually on all pipeline segments that lack documentation to validate MAOP, and that have a preliminary SMYS calculation of 20 percent or greater. Once information is available to substantiate SMYS below 20 percent or to validate the MAOP of a pipeline segment, that pipeline segment will return to leak survey intervals prescribed by code. Cascade will notify Pipeline Safety Staff when a pipeline segment returns to code-based survey intervals.

Q. What is the status of the pressure reduction work?

A. For pipeline segments that lack documentation to validate MAOP, that have low frequency seam welds or unknown seam types, and with preliminary SMYS calculations over 30 percent, Cascade is maintaining these segments at a 20 percent pressure reduction. Once Cascade determine that a segment is not low frequency ERW or the SMYS is substantiated as below 30 percent, the pipeline segment will return to the previous operating pressure, and Cascade will notify Pipeline Safety Staff. To date, one such pipeline segment has returned to the previous operating pressure and Cascade has notified Pipeline Safety Staff of the increase in pressure.

Q. What progress has Cascade made with respect to the commitment to incorporate pipeline segments preliminarily calculated at greater than 20 percent SMYS into Cascade's TIMP?

A. Pipeline segments preliminarily calculated at greater than 20 percent SMYS have been incorporated into Cascade's TIMP. As provided in the MAOP Settlement Agreement, baseline assessments for pipeline segments will be completed by December 31, 2020. Upon completion of the MAOP validation, Cascade's TIMP and DIMP will be re-evaluated and updated as required.

Q. Have you quantified the costs that has been deferred pursuant to the Accounting Order in Docket No. UG-160787?

A. Yes. Attached as Exhibit No. __ (RP-2) is a detailed summary of costs for work performed by outside vendors, contractors, and consultants through May 31, 2017, to carry out the terms of the MAOP Settlement Agreement. Cascade will update the deferred costs in its rebuttal testimony.

III. MITIGATION OF RISK AND WORK PRIORITIZATION

Q. Is Cascade taking steps to mitigate risk during the multi-year process required to validate MAOP on its high pressure lines?

A. Yes. Cascade is taking steps to reduce risk during the multi-year process in which Cascade is documenting the basis for the MAOP of its high pressure and transmission lines. While Cascade believes its system is safe, and there have been no adverse incidents related to the missing documentation, Cascade has agreed to take steps to mitigate risk during this process. Several of the work categories I previously described will mitigate risk while the MAOP validation process is underway. For example, increased leak surveys and pressure reductions are two examples of risk mitigation that Cascade is currently performing. Also, Cascade has incorporated all pipeline segments assumed to be operating above 20 percent SMYS into its TIMP, and Cascade is applying the most stringent criteria in its assumptions, when carrying out the MAOP validation.

Q. What does it mean that Cascade is applying the most stringent criteria in is assumptions?

A. For purposes of compliance with the MAOP Settlement Agreement and 49 CFR Part 192.619, Cascade is calculating the percent SMYS and design pressure of a pipeline using the most stringent design criteria, if there are unknowns. Cascade uses the most conservative values for pipe grade and seam factor as allowed by 49 CFR Part 192.107 and 192.111 to calculate the design pressure when values are unknown. And Cascade also uses the most conservative values in calculating the percent SMYS on branch segments. Cascade has been able to validate 8.67 miles of pipeline by using the most stringent design criteria to calculate MAOP.

Q. What factors does Cascade use to prioritize the work?

A. Cascade utilizes a risk matrix that assigns risk based on a weighting of several different factors. Work is prioritized based on the following weighted factors:

- segment class location;
- location of high consequence areas;
- segment SMYS percentage, based on the most stringent criteria for missing pipe characteristics;
- pipe vintage, with special consideration for pre-code pipe with unknown characteristics;
- pipe material, installation characteristics, operating history or maintenance records that indicate increased risk; and
- low frequency electric resistance welded (“ERW”) and unknown seam types when SMYS is greater than 25 percent.

Q. Can you elaborate on how Cascade is prioritizing the work?

A. Yes. Cascade's work is focused on the pipelines with the highest risk potential. With respect to the 116 identified pipeline segments requiring documentation to validate MAOP, for transmission lines with SMYS of 20 percent or greater, Cascade's goal is to complete validation of MAOP by 2021. For pipelines with a preliminary SMYS of 30 percent or greater, Cascade completed work on four of these in 2016 and anticipates completing validation of three more in 2017, two more in 2018 and the remaining pipeline segment in 2019. Through the in-situ testing that has been performed on the pipeline segments that were preliminarily calculated to be operating at 30 percent SMYS or greater, by assuming stringent design criteria, Cascade has been able to be reclassify the pipeline segments to a SMYS of less than 30 percent. In-situ testing will be completed on all pipeline segments operating at 30 percent or greater by the end of 2017.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.