Exhibit T - _____ (DWS-1T)
Docket No. UG-060256
Witness: Donald W. Schoenbeck

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. CASCADE NATURAL GAS CORPORATION, Respondent.	DOCKET NO. UG-060256

DIRECT TESTIMONY

OF

DONALD W. SCHOENBECK

ON BEHALF OF

THE NORTHWEST INDUSTRIAL GAS USERS

August 15, 2006

Q. PLEASE STATE YOUR NAME AND DESCRIBE YOUR QUALIFICATIONS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. (RCS), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I've been involved with the electric and gas utility industry for over 30 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters before numerous state commissions, public utility governing boards, governmental agencies, state and federal courts, the National Energy Board of Canada and the Federal Energy Regulatory Commission. I have appeared before the Washington Utilities and Transportation Commission (Commission) on numerous occasions. A further description of my educational background and experience is included in Exhibit No. ____ DWS-2 to this testimony.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Northwest Industrial Gas Users (NWIGU). NWIGU is a nonprofit association comprised of thirty-two end-users of natural gas with major facilities in the states of Washington, Oregon and Idaho. NWIGU members include diverse industrial interests, including food processing, pulp and paper, wood products, electric generation, aluminum, steel, chemicals, electronics and aerospace. The association provides an information service to its members and participates in various regulatory matters that affect member interests. NWIGU member companies purchase natural gas sales and transportation services from local distribution companies (LDCs), including Cascade Natural Gas Company (Cascade or Company).

Q. PLEASE STATE THE PURPOSE OF THIS TESTIMONY AND SUMMARIZE YOUR CONCLUSIONS.

A. My testimony addresses: (1) the proposed Safety and Reliability Infrastructure Adjustment Mechanism; (2) cost-of-service; and (3) rate spread and rate design specific to transportation customers.

NWIGU opposes the implementation of the Company's safety infrastructure tracker. NWIGU considers this to be single issue rate making, and the proposal is not justified.

With respect to cost-of-service, the Commission in previous orders has given specific guidance on how such studies should be performed. Cascade's cost of service study ignored important guidance from previous Commission decisions and provided no explanation for the deviation. NWIGU has prepared a cost-of-service study consistent with Commission precedent. It shows the current charges for the two transportation tariffs—Schedules 663 and 664—are in excess of the cost of serving these customers.

The Company's rate spread proposal in this proceeding is to move each major class to its cost-of-service using the results from the Company's cost study. For Schedule 663, the Company's proposal results in a class average *decrease* of 44.5% or $3.8 million. Schedule 664 customers however would receive an average *increase* of 27.6% or $1.6 million. While NWIGU believes the Commission should implement cost-based charges, NWIGU does not support the one-step movement to the Company's alleged cost based rates as proposed by the Company at this time. However, NWIGU does recommend and support a net margin decrease of $1.9 million for all transportation customers as a step toward establishing cost-based rates for all of Cascade transportation customers. This amount is close to the net decrease proposed by the Company of $2.2 million for these same customers.

The Company is also proposing a significant re-design of its transportation tariffs. This re-design includes the establishment of a contract demand charge applicable for firm transportation service elections and a reduction in the number of volumetric charges or blocks. Most importantly, however, the Company's "proposed" rate charges are really just poorly derived placeholders. The Company's intent is to conduct an "open season" during which customers would elect an amount of firm and/or interruptible service each desires. After this open season, the Company would then compute—in a yet to be explained manner—the final rate charges for transportation service.

The Company's approach to redesigning its transportation rates is unworkable. NWIGU recommends adoption of a single transportation rate for all Schedule 663 and 664 customers that does not require a re-computation of the rate charges. The rate would allow a customer to elect firm service with a contract demand charge or by paying an additional volumetric firming charge. Based upon the results of our cost study, NWIGU's recommended rate design includes a cost-based contract demand charge of $1.20 per year and four volumetric block charges. The volumetric firming charge is 1.04 cents per therm. The recommended rate results in former 663 customers receiving a decrease of about $2.1 million while former Schedule 664 customer margin revenues would increase by about $200,000.

Finally, NWIGU recommends that certain terms and conditions of the transportation tariffs should be rejected or modified. In this proceeding, the Company is proposing an in-kind payment for lost and unaccounted for gas instead of continuing the current practice of recovering this cost through margin revenues. NWIGU urges the Commission to reject this proposal. NWIGU recommends continuing the current practice of recovering this cost in the volumetric rate charges. In addition, the Company's balancing provisions for under or over nominations are based upon the lesser of 50,000 therms or 5% of the prior month's nominations or consumption. NWIGU recommends that the 50,000 therm limit resulting from the "lesser of" condition be eliminated. It is arbitrary and simply too restrictive for large customers. Moreover, the limit results in customers incurring charges from Cascade when there is no imposition of costs on Cascade by Northwest Pipeline Corporation.

SAFETY AND RELIABILITY INFRASTRUCTURE ADJUSTMENT MECHANISM

Q. PLEASE BRIEFLY DESCRIBE THE SAFETY AND RELIABILITY INFRASTRUCTURE ADJUSTMENT MECHANISM PROPOSED BY CASCADE.

A. Cascade is proposing a rate mechanism it has called a "Safety and Reliability Infrastructure Adjustment Mechanism," which is set forth as an exhibit to Mr. Stoltz's testimony and proposed as new rate schedule Rule 21. *See* Exhibit JTS-9. The mechanism would allow Cascade to increase its natural gas rates between rate cases to reflect increases in the Company's rate base associated with new investments in gas distribution infrastructure. *Id.* Cascade is proposing this tracking mechanism to surcharge all firm distribution rate schedules in order to recover increased expenses stemming from growth in rate base due to natural gas transmission and distribution plant investments made to replace aging infrastructure, relocate piping due to public works projects, or investments designed to "improve the reliability and/or capacity of distribution system during peak weather events." Exh. ___(JTS-9) (Schedule 7 of 7, p. 7 of 26).

Q. HAS CASCADE JUSTIFIED ITS PROPOSED SAFETY AND RELIABILITY INFRASTRUCTURE ADJUSTMENT MECHANISM?

A. No. The Safety and Reliability Infrastructure Adjustment Mechanism proposal should be rejected by the Commission because it is single-issue ratemaking that isolates one of many factors that impact a utility's earnings between rate cases. The proposal advanced by Cascade does not balance shareholders' and ratepayers' interests. There has been no showing by Cascade that it has been or is likely to experience earnings attrition of a magnitude that would justify allowing a rate adjustment mechanism of such broad application.

Q. ON BEHALF OF THE COMPANY, MR. CUMMINGS CLAIMS IN EXHIBIT __ (FJC-IT) THAT THE SAFETY AND RELIABILITY INFRASTRUCTURE ADJUSTMENT MECHANISM IS DESIGNED TO ADDRESS REGULATORY LAG THAT CASCADE WILL OTHERWISE EXPERIENCE BETWEEN RATE CASES AS IT INVESTS IN INFRASTRUCTURE REPLACEMENTS AND IMPROVEMENTS. WHY DO YOU DISAGREE WITH THIS PROPOSAL?

A. There are many reasons why a utility might earn less than its authorized return in years immediately following a rate case. Loads can be lower than forecasted, operating expenses can be higher, and the cost of debt can be higher than forecasted. It is equally true that numerous events can result in a utility earning more than was forecasted when rates were set in a rate case. Expenses can be below forecasts, revenues can exceed those used in establishing rates, and the cost of capital can decline. New investments in infrastructure are only one of numerous elements that impact Cascade's business that can cause its return on equity to change over time.

Q. MR. CUMMINGS STATES THAT IN THE NEXT FIVE YEARS CASCADE WILL EXPERIENCE HIGH LEVELS OF CAPITAL INVESTMENT IN NATURAL GAS INFRASTRUCTURE IMPROVEMENTS, AND THUS AN INFRASTRUCTURE RATE ADJUSTMENT MECHANISM IS WARRANTED. WHY DO YOU DISAGREE?

A. First, Cascade has not filed a general rate case in Washington in nearly 10 years. There is no evidence that Cascade has been experiencing earnings attrition such that an adjustment mechanism is warranted at this time to address so-called regulatory lag. Cascade wants the ability to adjust rates upward each year to reflect "the sum of return, property taxes, depreciation expense and revenue-related taxes" related to infrastructure investments as they would define such investments. The mechanism is overly broad and does nothing to balance Cascade's customers interests with those of the Company's shareholders.

One of the largest adjustments would stem from changes in depreciation expense, yet depreciation is purely an accounting expense. While changes in depreciation expenses can impact the Company's earnings, it is vastly different than purchased gas costs, for example, that could put a real cash strain on the Company.

Cascade also fails to note that the incremental expenses associated with infrastructure improvements can also lead to cost savings in other areas of the Company's operations. When older pipe is replaced, for example, operation and maintenance expenses should decline.

With its infrastructure adjustment proposal, Cascade is focusing on one negative change that can occur to the Company's earnings between general rate cases and proposing a surcharge mechanism to address that one element in a manner that will enhance the Company's earnings. The Company is ignoring, however, the changes between rate cases that work in Cascade's favor, such as productivity improvements, additional revenue the Company realizes by obtaining new customers, lower capital costs, and lower maintenance expense. Since Cascade has not filed for a general rate increase in Washington in approximately a decade, these are elements that the Company has experienced in the past that have enhanced the Company's earnings position.

Allowing Cascade to adjust its rates by isolating increased expense due to infrastructure improvements would be a bad regulatory policy. While Cascade is allowed to adjust rates to reflect changes in gas costs through its Purchased Gas Adjustment, single-issue ratemaking is, and must continue to be, a rare exception to the broader policy of only adjusting a utility's rates through a general rate case. The circumstances facing Cascade today do not warrant the adjustment that it seeks.

COST-OF-SERVICE

Q. IS COST-OF-SERVICE AN IMPORTANT CONSIDERATION FOR DETERMINING CLASS REVENUE RESPONSIBILITY AND RATE DESIGN?

A. Yes. Cost-of-service studies are of great importance in ratemaking proceedings to measure the relationship between the cost of serving a customer class and the revenues derived from the service rendered to the same customer class. In order to accurately assess the revenue to cost relationship for the various customer classes, a cost-of-service study should be prepared that assigns costs to the various customer classes based upon the reason that the costs were incurred. This fundamental principle is referred to as cost-causation.

Q. DO STATE COMMISSIONS TAKE COST-OF-SERVICE STUDIES INTO ACCOUNT IN SETTING RATE CHARGES?

A. Yes. State commissions commonly use the results of cost-of-service studies in establishing the rate spread and rate design in regulatory proceedings. In fact, the Idaho, Oregon and California commissions rely heavily on the cost studies for determining the class revenue requirement.

Q. HAS THE WASHINGTON COMMISSION RECOGNIZED THE IMPORTANCE OF COST-OF-SERVICE STUDIES?

A. Yes. In *Cascade vs. WUTC,* WUTC Cause No. U-86-100, Fourth Supplemental Order (1987) the Commission stated:

> The Commission has determined that cost of service analyses provide information useful to the Commission in evaluating rate spread alternatives for natural gas companies. In future natural gas rate proceedings, the Commission will consider cost of service study results as one factor when making rate spread and rate design decisions. The Commission will therefore require a cost of service study to accompany future general rate increase filings.
> Fourth Supplemental Order, p. 11.

Pursuant to this directive issued in 1987, all Washington LDCs have since filed such studies.

Q. HAS THE COMMISSION GIVEN GUIDANCE ON HOW THE COST STUDIES SHOULD BE CONDUCTED?

A. Yes. The Commission gave some guidance in Cause No. U-86-100 referenced above, but the most recent directives were specified in a *Washington Natural Gas Company vs. WUTC*, WUTC Docket No. UG-940814, Fifth Supplemental Order (1995) ("Supplemental Order"). Since its issuance in 1995, this foundational ruling has been employed as the "yardstick" for measuring cost-of-service for all Washington LDCs. The cost studies are generally referred to as a "Commission Basis" study.

Q. DID THE COMPANY COMPLY WITH THIS ORDER IN PERFORMING ITS COST STUDY?

A. No, the Company did not comply with the Commission's cost-of-service directives in several major areas. The Supplemental Order gave specific directives on the manner in which the administrative and general expense accounts were to be allocated. For many of these accounts, the allocation factor is suppose to be 50% operations and maintenance expenses (excluding gas costs) and 50% throughput. The allocation factor used in the Company's study is derived from operations and maintenance expense and depreciation expense. Similarly, the Commission directed that customer contributions be assigned to the residential class absent a special study showing the source of the contributions. In the Company's study, however, customer contributed rate base is assigned using a gross plant allocation factor across all customer classes. In allocating its costs for transmission and distribution mains and compressor stations, the Company assigned 100% of the cost of four inch or larger mains to certain large customer classes with no portion of these costs assigned to other customer classes. This is an inappropriate assignment as other customers are served by these facilities. Consistent with the Supplemental Order, the cost of these four inch or larger mains not specifically serving large customers should be allocated to all customer classes. In allocating sales expense accounts, the Company's study uses an allocation factor based upon equal parts of peak demand, throughput and customers. The Commission Basis method uses simply a customer allocation factor for these costs.

Q. HAVE YOU PREPARED A COST-OF-SERVICE STUDY USING THE COMMISSION DIRECTIVES?

A. Yes. Attached as Exhibit ____ DWS-3 to this testimony is a summary sheet from the Commission Basis study we prepared. In addition to the major differences I have already discussed, this study contains two additional allocation factor changes from the Company study. Maintenance expense of general plant was allocated on general plant and not total net plant as done in the Company study. Revenue-related taxes were allocated based upon the normalized rate schedule revenue instead of the revenue factor derived by the Company. The following table compares the revenue-to-cost ratios from the Company's study with our Commission Basis result for the major customer classes (over $1 million in margin revenue). A revenue-to-cost ratio less than 1.00 indicates a class is not contributing sufficient revenue to cover its cost of service. Conversely, a revenue-to-cost ratio in excess of 1.00 indicates a class is contributing sufficient revenue to cover all of its costs plus make a contribution toward the shortfall arising from other classes not paying their cost of service.

Revenue-to-Cost Ratio
Current Rates – Excluding Gas Costs

Customer Class	Rate Schedule	Cascade Study	Commission Basis
Residential	503	0.87	1.00
Commercial	504	0.96	0.86
Large Volume	511	1.47	1.22
Industrial Firm	505	0.92	0.78
Distribution Transportation	663	2.25	2.55
Large Vol Transportation	664	0.93	1.16
Special Contracts	901	1.51	0.75

As shown by the table, for all of the rate schedules the revenue-to-cost ratios changed significantly under the Commission Basis allocation method. For four of the rate schedules—504, 511, 505 and Special Contracts—there was a decline in the revenue-to-cost ratio. For the remaining schedules—503, 663 and 664—the revenue-to-cost ratio increased.

Q. DID YOU USE THE COMPANY'S COST-OF-SERVICE MODEL TO PRODUCE THESE RESULTS?

A. No. We developed our Commission Basis study using Microsoft's EXCEL software. However, we confirmed or "benchmarked" our model by replicating the Company's allocation methods and observing an identical result as presented by the Company.

Q. WHAT IS THE IMPORT OF THE SIGNIFICANT REVENUE-TO-COST RATIO FOR SCHEDULE 663?

A. It means that on average these customers are paying over three times their cost-of-service. Under the current rate charges for these customers, the Company receives on average 9.9 cents/therm in revenue. However, at the Company's current earned rate of return, the cost of serving these customers is less than 4 cents/therm. In fact, even if the Company was granted its full rate increase and achieved its requested rate of return, the cost of serving these customers would be only 4.8 cents/therm. Thus, under any measure, these customers are paying charges far in excess of cost.

Q. HOW DOES YOUR COMMISSION BASIS STUDY TREAT LOST AND UNACCOUNTED FOR GAS FOR THE TRANSPORTATION CLASSES?

A. The study presented in Exhibit ___ DWS-3 includes $780,888 of gas costs representing the transportation classes' allocation of the systems losses and unaccounted for contribution on a system average basis. To date these costs have been a component of the margin revenue collected from these customers. The embedded rate charge for this cost item is about 0.3 cents/therm. However, under the Company's proposal in this proceeding, the transportation customers will be responsible for supplying this fuel "in kind" instead of through the rate charges. If this treatment is adopted by the Commission, it needs to taken into account in reviewing cost of service studies, evaluating rate spread proposals in this proceeding and designing the specific transportation charges. As will be addressed later in this testimony, NWIGU opposes this tariff change.

RATE SPREAD AND RATE DESIGN

Q. HOW IS THE COMPANY PROPOSING TO COLLECT THE ADDITIONAL MARGIN REVENUE IT IS SEEKING IN THIS PROCEEDING?

A. The Company is proposing to move all classes to a cost-based rate level using the results of the cost-of-service study the Company submitted in this proceeding. The following table shows the Company proposal for the major customer classes.

Cascade Rate Spread Proposal
Major Customer Classes
($000)

Customer Class	Rate Schedule	Current Margin	Proposed Increase	Percent Increase
Residential	503	$29,933	$9,729	33%
Commercial	504	$16,418	$3,184	19%
Large Volume	511	$1,015	-$499	-49%
Industrial Firm	505	$1,408	$473	34%
Distribution Transportation	663	$8,620	-$3,839	-45%
Large Vol Transportation	664	$5,923	$1,635	28%
Special Contracts	901	$5,832	$0	0%
Total		$69,149	$10,683	15%
Transportation	663/664	$14,543	-$2,204	-15%
Transportation - Fuel In-kind	663/664	$14,543	-$1,423	-10%

The Company's rate spread proposal has rather large percentage increases or decreases for these major classes. For the transportation rate schedules, the large increase for Schedule 664 and the large decrease to Schedule 663 net to an overall decrease of $2.2 million as shown by the table. This amount does not appear to take into account the separate fuel in-kind payment that is required under the Company's proposal. Valuing this additional cost at the Company's pro forma gas price ($781,000) lowers the effective decrease to only $1.4 million for all transportation customers.

Q. DO YOU SUPPORT THE COMPANY'S RATE SPREAD PROPOSAL?

A. No. The Company's proposal is founded on a faulty cost-of-service study. In addition, this Commission has never accepted complete movement to cost-based rates in one step as is being proposed by the Company. However, review of our Commission Basis study does show that special attention to Schedule 663 customers is warranted given the very substantial above-cost rates these customers are being charged.

Q. WHAT IS YOUR RECOMMENDATION FOR ADDRESSING THE RATES CHARGED TO SCHEDULE 663 CUSTOMERS?

A. Schedule 663 customers should receive a substantial decrease in order to move these customers closer to a cost-based level. Given the large disparity we have identified—for this tariff—about $5.40 million—a decrease of at least $2.0 million is appropriate for these customers. This represents about a one-third movement toward cost of service, a recommendation consistent with prior Commission decisions or rate spread settlements.

Q. HOW DO YOU RECOMMEND THE RATE CHARGES BE DERIVED FOR THESE CUSTOMERS?

A. The Commission Basis study we prepared showed very little difference in the cost of serving Schedule 663 customers as compared to Schedule 664 customers. At the Company's requested revenue in this proceeding, the difference is only about 0.7 cents/therm. This suggests the two transportation tariffs should be combined into a single tariff applicable to all transportation customers.

Q. HAS THE COMPANY PROPOSED CHANGES TO ITS TRANSPORTATION RATE DESIGN?

A. Yes, the Company is proposing a major re-design of its transportation tariffs. In addition to the fuel in-kind proposal I have already mentioned, the Company is proposing to institute a firm contract demand charge and reduce the number of volumetric blocks for Schedules 663 and 664.

Q. DO YOU AGREE WITH THE COMPANY'S CONTRACT DEMAND CHARGE FOR FIRM SERVICE?

A. NWIGU would support the imposition of a contract demand charge or equivalent volumetric firming charge with certain conditions. First, the contract demand or firming charge should provide the transportation customer with firm service equal to the firm service provided to core customers. In other words, if the customer's gas supply arrives at the city gate, it must be delivered by Cascade to the customer's meter. Second, the customer must have the unilateral right to elect the amount of firm service desired. This includes allowing a customer to elect a combination of both firm and interruptible service. Third, the customer's election should be based upon known prices for the services. Deriving the final rate for the service only after the customer's election is inappropriate. Finally, the contract demand charge should be cost-based to reflect the difference in quality of service. Under these conditions, NWIGU would support a contract demand charge or an optional volumetric firming charge.

Q. DOES THE COMPANY PROPOSAL SATISFY ALL YOUR CRITERIA?

A. No. The Company's proposal appears to satisfy the first two criteria—namely the contract demand rate only applies to firm service elections and customers may elect a combination of firm and interruptible service. However, it does not satisfy the last two criteria with regard to known rates and an appropriate cost basis.

Q. WHY WON'T THE COMPANY'S RATES BE KNOWN WHEN CUSTOMERS MAKE THEIR SERVICE ELECTIONS?

A. As noted on page 3 of Exhibit ___ JTS-1T, the Company is proposing to finalize the demand and commodity charges only after the customers have made their service elections during an "open season." Thus, the proposed charges the Company has filed in this proceeding are simply illustrative placeholders based upon a critical assumption.

Q. WHAT WAS THE COMPANY'S CRITICAL ASSUMPTION?

A. The Company assumed that for two-thirds of each customer's maximum daily quantity ("MDQ") the customer would select firm service. For the remaining one-third of its MDQ, the customer would elect interruptible service. This is a very critical—and sensitive—assumption as shown by the following table. The table presents a range of possible margin revenue the Company could realize based upon the service elections the customers could select using the Company's contract demand assumptions.

Cascade Natural Gas
Transportation Rate Design
Company Proposal
($000)

	663	664	Total
Current Margin Revenue	$8,176	$5,783	$13,958
Proposed Margin at			
Firm Election at 67% of MDQ	$6,530	$7,390	$13,920
Firm for Full MDQ	$7,507	$9,497	$17,004
No Firm Elections – All Interruptible	$4,576	$3,177	$7,753
Range of Revenue Deviations Due to CD Elections			
Decrease from Current Margin	-$3,600	-$2,606	-$6,206
Increase from Current Margin	-$669	$3,714	$3,045
Range	$2,931	$6,320	$9,251

Under the Company's proposed charges and contract demand equal to 67% of the MDQ, the Company's margin revenue is only slightly reduced from its current level. (There appears to be an error in the Company's workpapers so that the overall targeted reduction for these two classes of $2.2 million is not achieved.) However, if all customers elect full firm service, the Company would gain over $3.0 million in margin revenue. On the other hand, if all customers choose interruptible service, the Company's margin revenue would decrease by over $6.0 million. Thus the range of possible outcomes is over $9.0 million. As shown by the above-referenced table, the specific customer elections can make quite a difference in the expected margin revenue.

Q. DO YOU EXPECT THAT THE ELECTIONS WILL RESULT IN A CONTRACT DEMAND EQUIVALENT TO 67% OF MDQ FOR FIRM SERVICE?

A. I do not know if that will be the case for 663 customers. However, I do know that value is far too great for 664 customers.

Q. WHY?

A. The Company's calculations are based upon an MDQ for Schedule 664 customers of over 2.1 million therms. (It appears that the MDQ value for one large account is mis-stated as being 20,000 therms when it is in fact 200,000 therms. The corrected total MDQ for 664 customers is almost 2.3 million therms.) Hence, 67% of this value is 1.4 million therms for a firm contract demand assumption. However, for the two largest accounts—representing over 1.1 million therms—54% of the total—the firm service election is very likely to be zero. Without these accounts, the maximum contract demand election—if all remaining accounts choose 100% firm service—would only be 1.0 million therms. Even after correcting the apparent MDQ error, 100% firm service elections for all other customers would only total 1.1 million therms. Accordingly, it is virtually impossible for this class to achieve the Company's assumption.

Q. HOW DOES INCLUDING THESE TWO LARGE ACCOUNTS AFFECT THE COMPANY'S RATE DESIGN CALCULATIONS?

A. Under the Company's proposed demand charge of $3.00 per year, the Company has assumed $2.3 million in demand revenue from these two customers. This is a substantial amount. In fact, since the Company's targeted additional revenue from this customer class is only $1.6 million, under the Company's proposed rates many customers would receive a substantial decrease.

Q. DO YOU EXPECT THESE TWO CUSTOMERS WILL ELECT THIS SUBSTANTIAL AMOUNT OF FIRM SERVICE?

A. No. I believe these two customers will not elect any firm service.

Q. IF THIS TURNED OUT TO BE THE CASE, WHAT WOULD HAPPEN UNDER THE COMPANY'S RATE DESIGN PROPOSAL?

A. Under the Company proposal the margin revenue would be achieved from increasing the proposed rates after the open season for all other customers. Assuming all this "lost" revenue was recovered from increasing the demand charge, the demand charge would have to double to over $6 per year.

Q. DO YOU SUPPORT THE COMPANY'S PROPOSED DEMAND CHARGE OF 25 CENTS PER MONTH OR $3.00 PER YEAR?

A. No. As explained in the testimony of Mr. Stoltz, the charge is derived from applying a modified fixed-variable rate design to the class specific revenue requirement. Application of this approach results in a substantial contract demand rate and therefore, a substantial difference between firm and interruptible service. Using the Company's billing determinants, for Schedule 663 the interruptible discount from firm service is 39%

while for 664 customers the discount is 67%. For all transportation customers, the discount is 54%. This difference seems too large and would undoubtedly influence some customer elections.

Q. HAVE YOU PERFORMED ANY ANALYSIS TO DETERMINE A MORE APPROPRIATE INTERRUPTIBLE DISCOUNT FOR CASCADE'S TRANSPORTATION SERVICE?

A. Yes. According to the Company's cost study, the overall peak load factor of Schedule 663 customers is 53%. In our Commission Basis cost study, the cost of serving these customers was 4.8 cents/therm assuming the Company is granted its full rate increase request. Using our EXCEL spreadsheet model, we performed a sensitivity analysis to derive the cost of serving Schedule 663 customers assuming a class load factor of 100%. This study resulted in a cost of serving these customers of only 4.0 cents/therm, about 20% below the Commission Basis cost-of-service. As this analysis indicates the average cost of the additional capacity needed to serve these customers, I recommend a 20% discount be provided to customers electing interruptible service as compared to firm service.

Q. WHAT CONTRACT DEMAND CHARGE PRODUCES A 20% DIFFERENCE BETWEEN FIRM AND INTERRUPTIBLE SERVICE?

A. This discount level can be achieved with a demand charge of $1.20 per year or 10 cents/month. This is just 40% of the rate proposed by the Company.

Q. COULD AN ALTERNATIVE VOLUMETRIC CHARGE BE USED TO COLLECT THE SAME AMOUNT OF CAPACITY COSTS?

A. Yes. The $1.20 contract demand charge can be converted to a firm volumetric charge—applicable to all volumes—of 1.04 cents/therm. NWIGU recommends that the transportation tariff allow customers to select on an annual basis either a contract demand charge or an equivalent volumetric charge for paying for the cost of firm service.

Q. HOW IS THE COMPANY PROPOSING TO MODIFY THE VOLUMETRIC CHARGES IN ITS RATE RE-DESIGN?

A. For Schedule 663, the Company is proposing to reduce the number of blocks from five down to just two blocks as shown by the following table.

Schedule 663 Comparison
(Charges Cents/therm)

Current Rate Block	Current Rate Charge	Proposed Rates Block	Proposed Rates Charge
First 10,000	13.313	First 100,000	4.300
Next 10,000	12.003	Over 100,000	4.100
Next 30,000	10.038		
Next 50,000	6.038		
Over 100,000	3.025		

For Schedule 664, the Company is proposing to reduce the number of blocks from seven down to just two blocks. The following table shows the current and proposed or "placeholder" volumetric charges for Schedule 664.

Schedule 664 Comparison
(Charges Cents/therm)

Current Rate Block	Current Rate Charge	Proposed Rates Block	Proposed Rates Charge
First 100,000	6.238	First 100,000	4.300
Next 200,000	2.797	Over 100,000	0.357
Next 200,000	1.891		
Next 100,000	1.875		
Next 300,000	1.695		
Next 400,000	1.500		
Over 1,300,000	1.350		

As illustrated by the tables referenced above, the Company has moved the two rates much closer to each other than is currently the case. Under the Company's proposal, both rates would have identical dispatching charges, contract demand charges and the same rate for the first 100,000 therms of usage per month. The only difference in charges would be the second block volumetric rate. As shown by the two tables, there is a substantial difference between the two tail blocks of over 3.7 cents/therm.

Q. IS THIS GREAT OF A DIFFERENCE IN TAIL BLOCK CHARGES JUSTIFIED?

A. No. As noted previously, the Commission Basis cost study we completed showed only a modest difference in cost between these two rate schedules. In addition, 21 of the Schedule 663 customers have test period usage in excess of 1,000,000 therms per year. The largest Schedule 663 customer had a test period throughput of almost 10,000,000 therms. There were only three Schedule 664 customers that exceeded this amount. Consequently, the very large difference in tail block charges does not appear to be appropriate.

Q. WHAT IS YOUR TRANSPORTATION RATE DESIGN RECOMMENDATION?

A. NWIGU recommends that a single tariff be designed for all Schedule 663 and 664 customers. As noted previously, the rate should contain a firm service option by a customer electing to pay *either* a contract demand charge or a volumetric firming charge. However, NWIGU recommends the rate contain more than just two volumetric blocks to mitigate rate impacts and to recognize the mix of customers served under the single tariff. The following table presents the recommended tariff charges.

NWIGU Recommended Transportation Rate

Firming Charges (Optional)	
Contract Demand or	$0.10
Volumetric - per therm	$0.0104
Dispatching Service Charge	
Customer - per month	$500.00
Volumetric - per therm	$0.0002
Volumetric Charges	
First 100,000 therms	0.06000
Next 200,000	0.03000
Next 200,000	0.01300
Over 500,000	0.00700

Q. IS AN OPEN SEASON REQUIRED UNDER YOUR RATE DESIGN?

A. No. In designing the specific charges shown in the above table, we have assumed no firm service election from the two large accounts we discussed earlier. For the remaining customers, we assumed the same 67% conversion rate as the Company had used for firm service even though the Company's charge for firm service was considerably higher. Since our cost-based contract demand charge is much less than the Company's proposal, we have eliminated much of the risk associated with the Company's design. No open season is required as the adoption of the above charges will likely result in the Company realizing the targeted revenue from these customers.

LOST AND UNACCOUNTED FOR GAS

Q. DO YOUR RECOMMENDED CHARGES INCLUDE THE COST OF LOST AND UNACCOUNTED FOR GAS?

A. Yes. The rates were designed assuming over $780,000 is collected as a cost of lost and unaccounted for gas attributable to these customers.

Q. IS THIS CONSISTENT WITH THE COMPANY'S PROPOSAL IN THIS FILING?

A. No. NWIGU opposes the Company's proposal to pay for lost and unaccounted for gas through an in-kind payment of 0.4103% of the customer's throughput. Our recommended design includes this cost in the volumetric rate charges consistent with the current method of payment.

Q. WHY DOES NWIGU OPPOSE THE IN-KIND PAYMENT APPROACH?

A. NWIGU opposes the Company's proposal for two reasons. First, and most importantly, the in-kind payment percentage is based upon a system loss and unaccounted for calculation. NWIGU believe a more detailed analysis would reveal a much lower percentage of lost and unaccounted for gas is attributable to Cascade's transportation customers than the system average. Second, the Company's proposal would require the additional in-kind payment without an offsetting reduction in the tariff charges. This is inequitable as the Company's cost of gas supply would decrease. For these reasons, NWIGU recommends continuing the current payment methodology at this time.

BALANCING CHARGES

Q. DOES NWIGU HAVE OTHER ISSUES TO ADDRESS RELATED TO CASCADE'S TRANSPORTATION TARIFF?

A. Yes. There are aspects of Cascade's Unbundled Distribution System Transportation Service Rules, Rule No. 20, that should be changed relating to transportation customers keeping their nominations and usage in balance. All shippers on the Northwest Pipeline system must keep their nominations and deliveries within a five percent monthly tolerance band or incur penalties. Cascade's Rule 20 reflects the five percent tolerance band, requiring Cascade's transportation customers to keep their nominations and deliveries largely within the same balancing tolerance bands and passing through any pipeline imposed penalties to any transportation customers in proportion to the nomination imbalance associated with each customer or group of customers. Cascade varies, however, from Northwest Pipeline's monthly tolerances in one very troublesome way.

Cascade imposes an arbitrary limit of 50,000 therms on the level of imbalance a transportation customer can incur without penalties under its Rule 20. Furthermore, Cascade fails to allow a customer that is out of balance with a reasonable time frame in which to bring nominations back in balance with deliveries at the end of a month.

Finally, Cascade calculates penalties using the "costs of any supplemental gas supply," without specifying how the supplemental supply will be priced. I recommend changes in three aspects of Rule No. 20 to make Cascade's balancing rules more reasonable, better aligned with Northwest Pipeline's rules and more in sync with the balancing rules of other Washington local distribution companies.

Q. WHY DO YOU CONSIDER THE 50,000 THERM LIMIT ON IMBALANCES INAPPROPRIATE?

A. There is no reason to arbitrarily limit an individual transporter to a 50,000 therm imbalance. Northwest Pipeline's Rule 15.3 imposes a limit, but it is the <u>greater of</u> 50,000 therms or 5 percent, not the lesser. Northwest Pipeline's Rule 15.3 states:

> Receiving Party Imbalances and Penalties. If Receiving Party's cumulative monthly Receiving Party Imbalance is more than 5,000 Dth or 5 percent, above or below total confirmed nominations for that month, whichever is greater, Transporter shall notify Receiving Party that Receiving Party Imbalances exceed allowed tolerances. Such notice shall be provided by the fifteenth day of the month following the month service is rendered. Transporter will notify Receiving Party of any Receiving Party Imbalances, and specify whether a penalty situation

> exists. Receiving Party will be given 45 non-entitlement days from the date of notification by Transporter to eliminate any Receiving Party Imbalances. If at the end of such 45 non-entitlement day period Receiving Party remains in a penalty situation, Receiving Party shall pay a penalty to Transporter equal to $10.00/Dth on the imbalance over the greater of 5,000 Dth or 5%, as described above. Receiving Party Imbalances shall be cumulative and Receiving Party must specifically adjust nominations as necessary to eliminate such imbalances

Cascade has mistakenly imposed a "lesser of" 50,000 therms, limiting the application of the 5 percent tolerance band on its shippers.

Q. DO THE OTHER LOCAL DISTRIBUTION COMPANIES IN THIS STATE HAVE THIS "LESSER OF" CONDITION IN THEIR BALANCING PROVISIONS?

A. No. None of the other LDCs—NW Natural, Puget Sound Energy or Avista Utilities have this restrictive provision. The balancing provisions of these companies essentially mirror the Northwest Pipeline requirements.

Q. WHY IS THE DIFFERENCE SO IMPORTANT TO CASCADE'S TRANSPORTATION CUSTOMERS?

A. A large volume transporter could go above a 50,000 therm imbalance in just a few days. Northwest Pipeline allows imbalances of up to 5 percent, while allowing a small volume customer to go as much as 5,000 decatherms (50,000 therms) out of balance, even if that imbalance would exceed the 5 percent limit. Cascade has turned the tolerance band on its head, limiting a shipper to 50,000 therms, even if the shipper's imbalance is within a 5 percent tolerance band. There is no reason to arbitrarily limit a customer to a 50,000 therm imbalance.

Another problem with Cascade's Rule 20 is that a party that exceeds the tolerance band for its imbalance immediately faces penalties even through the Northwest Pipeline tariff gives a transporter 45 non-entitlement days to eliminate its imbalance. Cascade's transportation customers should have the same 45 non-entitlement days to eliminate an imbalance.

Q. AREN'T YOU SEEKING TO GIVE CASCADE'S TRANSPORTERS FLEXIBILITY THAT COULD EXPOSE CASCADE TO IMBALANCE PENALTIES FROM NORTHWEST PIPELINE?

A. No. What I am proposing is to give Cascade's transporters, individually, the same flexibility that Cascade has as a shipper on Northwest Pipeline. As long as Cascade's transporters keep their nominations and deliveries within the same tolerance bands as Northwest Pipeline, then the transporters can not cause Cascade to experience an imbalance that would trigger penalties from Northwest Pipeline. By changing Cascade's rule to be "the greater of 50,000 therms or 5 percent" Cascade's rule would parallel Northwest Pipeline's tolerance band.

Q. DO YOU TAKE ISSUE WITH ANOTHER ASPECT OF CASCADE'S BALANCING RULES?

A. Yes. Cascade's penalty for being out of balance is that it charges an offending customer the "cost of any supplemental gas supply."

A customer has no way of confirming what Cascade's cost of supplemental supply is when the offending imbalance occurs without a substantial audit process. Since most spot-market gas purchases are under monthly indices, it would be reasonable to use a published monthly index price, like Inside FERC, for the month in which the imbalance occurred to derive the average cost of the gas delivered at the Canadian border and the Rockies, as they are the basins from which Cascade purchases gas on Northwest Pipeline.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

QUALIFICATIONS AND BACKGROUND OF DONALD W. SCHOENBECK

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Donald W. Schoenbeck, 900 Washington Street, Suite 1000, Vancouver, Washington 98660.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and I am a member of Regulatory & Cogeneration Services, Inc. (RCS).

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Kansas and a Master of Science Degree in Engineering Management from the University of Missouri.

From June of 1972 until June of 1980, I was employed by Union Electric Company in the Transmission and Distribution, Rates, and Corporate Planning functions. In the Transmission and Distribution function, I had various areas of responsibility, including load management, budget proposals and special studies. While in the Rates function, I worked on rate design studies, filings and exhibits for several regulatory jurisdictions. In Corporate Planning, I was responsible for the development and maintenance of computer models used to simulate the Company's financial and economic operations.

In June of 1980, I joined the national consulting firm of Drazen-Brubaker & Associates, Inc. Since that time, I have participated in the analysis of various utilities for power cost forecasts, avoided cost pricing, contract negotiations for gas and electric services, siting and licensing proceedings, and rate case purposes including revenue requirement determination, class cost-of-service and rate design.

In April 1988, I formed RCS. RCS provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers. We also assist in the negotiation of contracts for utility services for large users. In general, we are engaged in regulatory consulting, rate work, feasibility, economic and cost-of-service studies, design of rates for utility service and contract negotiations.

Q. IN WHICH JURISDICTIONS HAVE YOU TESTIFIED AS AN EXPERT WITNESS REGARDING UTILITY COST AND RATE MATTERS?

A. I have testified as an expert witness in rate proceedings before commissions in the states of Alaska, Arizona, California, Delaware, Idaho, Illinois, Montana, Nevada, North Carolina, Ohio, Oregon, Washington, Wisconsin and Wyoming. In addition, I have presented testimony before the Bonneville Power Administration, the National Energy Board of Canada, the Federal Energy Regulatory Commission, publicly-owned utility boards and in court proceedings in the states of Washington, Oregon and California.

Exhibit ____ DWS-3

Cascade Natural Gas Corporation
Per Books Cost Allocation - 12 Months Ended September 30, 2005 - Adjusted
State of Washington
Commission Basis Summary Report

Line No.	Description	Total_Company	REOS 503	DO 502	GAC 541	COGS 504	CNG 512	LV 511	INDGS 505	INTGEN 570	INSINTINS 577	NCGEN 663	NCLV 664	NCSPECC 901
	Operating Revenues													
1	Rate Sched Revenue	258,373,954	125,257,243	1,720,996	190,676	87,202,523	70,786	8,288,334	10,956,333	3,148,788	412,448	8,907,753	6,351,718	5,866,355
2	Gas Transportation Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Other Operating Revenue	889,298	508,453	6,435	507	201,655	70	11,962	21,805	1,738	269	39,272	43,253	53,880
4	Total Revenue	259,263,252	125,765,695	1,727,431	191,183	87,404,178	70,856	8,300,296	10,978,138	3,150,526	412,717	8,947,025	6,394,971	5,920,235
5														
6	Operating Expenses													
7	Total Cost of Gas	171,142,479	87,180,424	1,156,037	134,605	64,183,041	50,073	6,340,265	8,373,304	2,616,932	326,910	285,170	495,718	0
8	Manufactured Gas Production	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Distribution O&M Exp	7,682,852	3,303,418	36,685	6,185	2,110,615	520	93,611	246,509	27,384	5,862	569,644	511,368	771,050
10	Customer Accounts	4,181,215	2,253,194	24,803	4,194	1,418,526	390	56,596	168,578	29,842	5,840	186,051	15,667	17,535
11	Customer Service & Information	1,339,336	727,982	7,434	1,430	444,259	40	9,161	51,530	6,923	1,731	76,153	5,769	6,923
12	Customer Sales	441,710	241,335	2,465	474	147,277	13	3,037	17,083	2,295	574	25,246	1,913	0
13	Administration & General	16,915,982	5,634,298	66,821	10,192	3,723,184	1,475	225,292	452,868	67,645	11,287	1,478,575	2,027,512	3,216,834
14	Wage Adjustment	1,369,561	648,996	7,281	1,205	416,308	114	19,517	48,815	4,459	910	75,505	64,427	82,025
15	Depreciation & Amortization	13,659,910	6,413,149	73,769	11,744	4,179,285	1,302	226,705	489,520	22,462	4,140	648,245	749,769	839,822
16	Total Expenses Excluding Taxes	216,733,045	106,402,795	1,375,295	170,030	76,622,494	53,928	6,974,185	9,848,207	2,777,940	357,253	3,344,587	3,872,142	4,934,189
17														
18	Operating Taxes													
19	Taxes Other Than Income	23,727,650	11,313,789	151,590	17,777	7,806,969	5,741	697,654	969,941	243,037	32,328	907,932	749,808	831,084
20	State Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Fed Income Taxes	3,681,260	1,675,982	30,480	1,831	933,223	1,465	114,783	97,803	32,250	4,801	484,927	218,367	85,349
22	Total Taxes	27,408,910	12,989,772	182,069	19,608	8,740,193	7,206	812,438	1,067,744	275,286	37,129	1,392,859	968,175	916,433
23														
24	Total Operating Rev. Deductions	244,141,955	119,392,567	1,557,365	189,637	85,362,687	61,133	7,786,622	10,915,950	3,053,227	394,381	4,737,446	4,840,317	5,850,621
25														
26	Net Operating Income	15,121,297	6,373,128	170,066	1,546	2,041,491	9,723	513,674	62,187	97,299	18,336	4,209,579	1,554,654	69,614
27														
28	Rate Base	239,332,551	101,624,868	1,217,565	188,828	70,637,882	27,217	4,624,608	8,300,824	552,080	104,936	14,844,442	16,602,018	20,607,284
29														
30	Rate of Return	6.32%	6.27%	13.97%	0.82%	2.89%	35.72%	11.11%	0.75%	17.62%	17.47%	28.36%	9.36%	0.34%
31														
32	Revenue to Cost Ratio - Current Rates		1.00	1.09	0.92	0.96	1.22	1.04	0.94	1.03	1.05	2.43	1.15	0.75
33	Revenue to Cost Ratio - Excl Gas Cost -Current Rates		1.00	1.36	0.77	0.86	2.63	1.22	0.78	1.23	1.28	2.55	1.16	0.75
34	Return at 9.37% ROR	22,413,493	9,517,169	114,025	17,684	6,615,238	2,549	433,095	777,372	51,702	9,827	1,390,182	1,554,779	1,929,872
35	Revenue Deficiency at 9.37%	11,727,512	5,056,333	-90,127	25,953	7,355,625	-11,537	-129,589	1,150,180	-73,330	-13,684	-4,534,232	202	2,991,719
36	CNG Study Revenue to Cost Ratio - Excl Gas Cost		0.87	1.22	0.86	0.96	3.23	1.47	0.92	1.14	1.28	2.25	0.93	1.51
37	CNG Revenue Deficiency Calculation at 9.37%	11,727,512	10,415,379	-49,511	17,344	3,832,693	-13,345	-458,683	551,233	-21,966	-11,518	-3,530,426	2,010,306	-1,013,996
38	Difference in Revenue Deficiency	0	-5,359,046	-40,616	8,609	3,522,932	1,808	329,094	598,947	-51,365	-2,166	-1,003,806	-2,010,105	4,005,715
39	Current Revenue (Cents/therm)											9.9	4.1	
40	Cost-of-Service Full Request (Cents/therm)											4.8	4.1	