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May 30, 2008

VIA FEDERAL EXPRESS
AND ELECTRONIC FILING

Carol Washburn
Executive Secretary
Washington Utilities & Transportation Commission
1300 S. Evergreen Park Drive, S.W.
P.O. Box 47250
Olympia, WA 98504-7250

Re: Washington Utilities & Transportation Commission vs. Puget Sound Energy, Inc.
Docket No. UG-072301

Dear Ms. Washburn:

Enclosed please find an original and nineteen copies of the **Prefiled Direct Testimony of Donald W. Schoenbeck on behalf of the Northwest Industrial Gas Users** in the above-referenced docket. Also, enclosed are two CD's containing the Workpapers of Donald W. Schoenbeck. One CD contains the public version of the Workpapers and the other contains the Confidential version of the Workpapers.

An electronic submission of the testimony (without the Workpapers) will be sent to the Records Center on May 30, 2008, as well as to all parties listed on the current service list.

Very truly yours,

Chad M. Stokes

CMS:tr
Enclosure(s)
cc: Official Service List

EXHIBIT NO. ___(DWS-1T)
DOCKET NOS. UG-072301
2007 PSE GENERAL RATE CASE
WITNESS: Donald W. Schoenbeck

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UG-072301

PREFILED DIRECT TESTIMONY OF

DONALD W. SCHOENBECK

ON BEHALF OF

NORTHWEST INDUSTRIAL GAS USERS

May 30, 2008

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF
DONALD W. SCHOENBECK

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY OF DONALD W. SCHOENBECK

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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 in the electric and gas utility industries for over 35 years. For the majority of this time, I have provided consulting services for large industrial customers addressing regulatory and contractual matters. I have appeared before the Washington Utilities and Transportation Commission ("Commission") on many occasions, including several proceedings regarding the establishment of charges for customers of Puget Sound Energy ("Company"). A further description of my educational background and work experience can be found in the testimony I am filing today on behalf of Industrial Customers of Northwest Utilities in this proceeding. *See* ICNU Prefiled Direct Testimony of Don W. Schoenbeck, Exhibit No. ____ (DWS-2).

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 trade association whose members are large industrial customers served by gas utilities throughout the Pacific Northwest, including Puget Sound Energy.

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. I will discuss PSE's allocation of distribution mains, rate spread and industrial rate design matters. My testimony will not address revenue requirement issues at this time. This silence should not be construed as acceptance by NWIGU of the Company's proposed increase amount. NWIGU reserves the right to address revenue requirement matters at the hearing and in its briefs.

Q. PLEASE BRIEFLY SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.

A. In determining the cost of serving each customer class of a gas distribution company, one of the most critical factors is the classification and allocation of distribution main investment. The Company's allocation method in this case does not segment mains by size or rely solely on a direct assignment of mains to large users as it has done in past proceedings. As a result, the Company's cost study assigns far too much main investment to Schedule 85, 87, 57 and contract customers ("Large Users"). NWIGU recommends that main investment be allocated to large users in the same manner as the Company did in the 2004 general rate case. In that proceeding, PSE directly assigned distribution main investment to Large Users using a flow analysis and an average February temperature. The following table compares the resulting revenue to cost ratio ("parity ratio") for select customer classes from the 2004 direct assignment method for assigning main investment to Large Users with the Company's flawed approach in this proceeding. Both studies reflect the Company's customer migration proposal from phasing out Schedule 57.

Parity Ratio Comparison

Class	PSE Study	NWIGU Study
Residential	1.01	1.01
C&I (31,61)	0.89	0.88
Schedule 41	1.56	1.50
Schedule 85	1.72	1.54
Schedule 86	1.87	1.78
Schedule 87	0.92	1.25
Sch 57 & Contracts	1.22	1.34
Rentals	0.69	0.69
Total:	1.00	1.00

The Company's rate spread attempts to move certain customer classes closer to a cost-based rate level. While NWIGU appreciates the Company's acknowledgement of the current rate disparities, the Company's proposal misses its mark particularly with regard to the rental class. The NWIGU cost study should be used to determine rate spread in this proceeding. The parity ratios from the NWIGU study indicate the small commercial and industrial sales rate schedules 31 and 61, and the rental schedules, should receive an above average margin increase. The residential class should receive an average increase and the remaining schedules should be assigned a below average increase, or a decrease.

The following table summarizes and compares the NWIGU rate spread recommendation with the Company's proposal.

Rate Spread Comparison

	PSE Proposal		NWIGU Recommendation		
Class	Change in Margin	Margin Increase	Change in Margin	Margin Increase	Margin Difference
Residential	$39,565	17.5%	$38,914	17.2%	-$651
C&I (31,61)	$16,547	25.3%	$16,762	25.6%	$215
Schedule 41	$0	0.0%	$0	0.0%	$0
CNG (50)	$5	17.9%	$7	25.6%	$2
Schedule 85	($0)	0.0%	$0	0.0%	$0
Schedule 86	($309)	-8.7%	-$309	-8.7%	$0
Schedule 87	$1,272	21.9%	$496	8.5%	-$776
Schedule 57	$571	24.6%	$198	8.5%	-$372
Rentals	$414	5.3%	$1,997	25.6%	$1,583
Total:	$58,065	17.1%	$58,065	17.1%	$0

The Company's large customer rate design proposals in this case include phasing out the single transportation tariff (Schedule 57) by the end of 2012. The Company's proposal is to offer transportation service under its various and otherwise applicable sale tariffs. Under the proposal, most of the existing transportation customers would migrate to either Schedule 85 or 87. NWIGU would support the complete elimination of Schedule 57 ***if and only if*** the terms and conditions of service under Schedule 57 are fully incorporated into Schedules 85 and 87. That is, the alternate fuel requirement, minimum monthly volumetric requirement and fuel exclusivity provisions must be deleted from the sales tariffs. If these restrictions are not eliminated, NWIGU recommends retaining Schedule 57; it should not be phased out. In addition, the Company is proposing to increase the revenue it recovers from fixed tariff charges. NWIGU oppose any increase in the fixed prices of the Company's Large User tariffs. The existing charges provide a substantial amount of fixed revenue. The margin increase assigned to Schedules 85, 87 and 57 (if 57 is to be continued) should be recovered by increasing the volumetric charges.

II. ALLOCATION OF DISTRIBUTION MAIN COSTS

Q. HAS THE COMPANY PREPARED A COST-OF-SERVICE STUDY FOR THIS PROCEEDING?

A. Yes. As it has done in the last several proceedings, the Company has submitted two cost studies in its prefiled exhibits. One study includes gas costs (see JKP-6) while the second study excludes gas costs (see JKP-5). Both these studies have most of the existing Schedule 57 customers migrated to the otherwise applicable sales tariff. The Company has combined the few remaining Schedule 57 customers with the contract class in these studies. Also, in response to requests from many parties, the Company prepared additional cost studies. Attached as Exhibit No. ___ (DWS-3) are the summaries from two of these studies, both of which exclude gas costs. As this case is addressing margin or non-gas costs, all cost-of-service results presented in the remainder of my testimony will refer to cost studies that have gas costs excluded.

Exhibit No. ___ (DWS-3), page 1, shows the cost of service results under the Company's allocation methods where the existing customer classifications are retained. Exhibit No. ___ (DWS-3), page 2, shows the cost-of-service results where the Company segregated sales and transportation service under its migration proposal for Schedule 85 and 87. These models were most helpful to

NWIGU in evaluating the Company's proposal to phase out Schedule 57 as it allowed for a "before" and "after" comparison by sub-class.

Q. IN PERFORMING THESE COST STUDIES, DID PSE ALLOCATE COSTS IN THE SAME MANNER AS THE LAST PROCEEDING?

A. No. The Company used many of the same approaches for classifying and allocating its costs. However, there was a critical departure from past practice with regard to the allocation of distribution mains to large users. For many years, this Commission has recognized the need to segregate main investment by size in recognition of the fact that many large users simply can not be served through mains smaller than 4 inches in diameter. PSE has followed this method in the cost of service studies it has presented to the Commission in the last several proceedings. However, in this instant docket, the Company has not segregated mains by size. This uncalled for departure from past practice is very disappointing as the classification and allocation of distribution main costs is one of the most critical aspects of any gas cost-of-service study.

Q. HOW DID PSE CLASSIFY AND ALLOCATE DISTRIBUTION MAIN INVESTMENT IN THIS PROCEEDING?

A. The Company started by classifying—or dividing-- the total distribution main investment into demand-related and commodity-related portions based upon a system load factor of 33%. As the Company has over $1.0 billion of distribution main investment, $692.7 million was classified as being demand related and the remaining $340.5 million was considered commodity-related. Next the Company identified the distribution mains used to serve the Large Users using a gas flow model and assuming design day weather conditions. The design day weather specification was most critical as it meant all interruptible customers were in fact interrupted leaving the flow analysis to identify just $11.1 million of main investment to serve the customers on these schedules. This was the only portion of the demand-related main investment assigned to these customers. The remaining demand-related investment of $681.6 million was allocated using a design day peak factor of all other classes. The commodity related investment was allocated based upon either annual throughput or the minimum monthly volume (times 12) for the Large Users. The use of the "annual" minimum volume for the Large Users was in recognition of the lower quality of service these customers receive. The commodity-related main investment assigned to these customers was $58.9 million. In toto, the Company's approach results in the Large Users being assigned almost $70 million of main investment. A summary of the Company's main allocation method is attached as Exhibit No. ___ (DWS-4), page 1.

Q. IS THIS AN APPROPRIATE METHOD OF ASSIGNING MAIN INVESTMENT TO LARGE USERS?

A. No. It can be easily shown that the amount of main investment assigned to large users under this approach is too high. As I noted earlier, the Large Users are primarily served through mains that are at least 4 inches in diameter. The following table shows that only about 6% of the total annual throughput delivered to Schedule 85, 87 and 57 customers goes through mains that are less than 4 inches in diameter.

Delivery Comparison

< 4 Inch Volume	Annual Therms
Schedule 85	8,208,825
Schedule 87	0
Schedule 57	5,419,988
Total:	13,628,813
Total Volume:	227,018,740
<4 Inch Percentage:	6.0%

However, a substantial portion of PSE's main investment--$470 million or 44.4%--is for mains with a diameter less than 4 inches as shown by the following table.

PSE Main Investment by Size
($Millions)

Main Diameter	Investment	Percent	Accumlated Percent
<2	$231.2	21.9%	21.9%
2	$235.0	22.2%	44.1%
3	$3.4	0.3%	44.4%
4-5	$145.6	13.8%	58.1%
6	$154.8	14.6%	72.8%
8-10	$89.7	8.5%	81.3%
12	$92.3	8.7%	90.0%
14+	$105.9	10.0%	100.0%
Total:	$1,058.0	100.0%	

PSE's allocation approach has implicitly allocated a substantial portion of these smaller main costs to the Large Users. This can be illustrated by first segregating PSE's mains into those that are less than 4 inches in diameter and those that are greater than 4 inches in diameter. For the test period, the normalized volumes or throughput for the Large Users is 262 million therms. However, only about 13.6 million therms are delivered through mains less than 4 inches in diameter. Applying PSE's main classification and allocation method to the two groupings of main investment assigns just $45.5 million to the Large Users as summarized in the following table and Exhibit No. ___ (DWS-4), page 2. This is $24.4 million less than the amount assigned under the Company's "single size" main allocation.

Main Investment Allocation Comparison
PSE Method - $ Millions

Class	PSE Allocation	Segmented Allocation	Delta
Residential	$668.1	$684.0	$15.8
C&I (31,36,51,61)	$243.9	$250.0	$6.1
Schedule 41	$44.5	$46.5	$2.0
Schedule 85	$16.7	$11.5	-$5.2
Schedule 86	$6.8	$7.3	$0.5
Schedule 87	$36.8	$21.7	-$15.2
57 & Special Contracts	$16.4	$12.3	-$4.1
Subtotal Large Users:	$69.9	$45.5	-$24.4
CNG (50)	$0.1	$0.1	$0.0
Total:	$1,033.3	$1,033.3	$0.0

Q. ARE YOU RECOMMENDING THAT THIS METHOD BE USED FOR ASSIGNING MAIN INVESTMENT TO LARGE USERS?

A. No. While the above result corrects for the over allocation of smaller sized mains to large customers, it does not recognize the fact that Large Users should be assigned an above average allocation of the larger more costly mains. The following tables illustrates how the installed cost of distribution mains substantially increases with the diameter (and material—PE: plastic; ST: steel) of the pipe.

2007 Per Unit Cost

Size/Type	$/Ft
1.25 PE	$19.82
2 PE	$18.49
.75-2.5ST	$23.89
3 PE	$42.07
4 PE	$32.21
6 PE	$66.11
8 PE	$96.83
2 ST	$26.90
4 ST	$85.81
6 ST	$71.46
8 ST	$147.94
12 ST	$202.13
14-16ST	$151.82
20ST	$272.51

A uniform allocation of larger mains based simply on demand or volumes would not take into account the non-uniform cost of larger mains.

Q. CAN THIS COST CAUSATION FACTOR BE TAKEN INTO ACCOUNT?

A. Yes. The direct assignment method used in the Company's 2004 general rate case recognized and accounted for this important factor. As in the current case, a gas flow model was used to identify the mains used to deliver the gas supply to the Large Users from the city gate to the customer's service. However, the gas flow was based on an average February winter day temperature of 41 degrees. Being much warmer than a design day peak temperature, there was full service to all interruptible customers under these conditions. Thus at this temperature, every main serving the Large Users---by size and type---is identified. The following table presents a summary of the equivalent feet identified under the Company's peak design day temperature in this proceeding with the mains identified under the 2004 average winter day method for the Large Users for the test year. As is readily apparent from the table, the 2004 method identifies an additional 993,000 feet of main to deliver the average winter's day demand for all the Large Users.

Comparison of Equivalent Feet of Main for Large Users

Diameter	Total System	Design Day	Avg Winer Day	AWD as % of System
<2	34,161,463	569	4,948	0.0%
2	17,902,792	26,641	210,096	1.2%
3	108,071	710	1,683	1.6%
4-5	8,753,942	80,925	319,909	3.7%
6	4,259,830	50,856	261,066	6.1%
8-10	1,351,305	40,551	159,592	11.8%
12	830,829	22,784	137,808	16.6%
14+	715,973	15,401	136,068	19.0%
Total:	68,084,205	238,438	1,231,172	1.8%

Having identified the size and type of main, the Company's 2004 direct assignment approach then applied the current per unit installation cost in order to arrive at a main investment allocation that directly accounts for the mix of mains used to serve these Large Users and the associated cost.

Q. SHOULD THE 2004 METHOD BE USED TO DIRECTLY ASSIGN MAIN INVESTMENT TO THE LARGE USERS IN THIS PROCEEDING?

A. Yes. The 2004 method is the most equitable method as it allows for a precise identification of the mains used to deliver gas to these customers. It is superior to the Company's approach as it corrects for the over allocation of investment associated with smaller mains and the under allocation of larger mains. Application of this approach for the Large Users in this proceeding is summarized in the following table and Exhibit No. ___ (DWS-4), page 3.

Direct Assignment to Large Users
Avg Winter Day

Diameter	Main Cost ($)	Percent of Total
<2	$52,081	0.1%
2	$2,320,231	3.9%
3	$35,375	0.1%
4-5	$10,764,075	18.2%
6	$9,109,737	15.4%
8-10	$11,500,489	19.4%
12	$13,913,802	23.5%
14+	$11,449,741	19.4%
Total:	$59,145,531	100.0%

For the remaining customer classes, the Company's classification and allocation approach to distribution mains can still be done as indicated in Exhibit No. ___ (DWS-4), page 3.

Q. HAVE YOU INCORPORATED THIS ALLOCATION METHOD INTO THE COMPANY'S COST OF SERVICE MODEL?

A. Yes. Exhibit No. ___ (DWS-5) contains the summary from two cost of service studies where main investment was directly assigned to Large Users. Exhibit No. ___ (DWS-5), page 1, is comparable to Exhibit No. ___ (DWS-3), page 1 in that PSE's customers are on their existing rate schedule. Similarly, Exhibit No. ___ (DWS-5), page 2, is comparable to Exhibit No. ___ (DWS-3) page 2 with most Schedule 57 customers migrated to the otherwise applicable sales tariff. The following table compares the revenue to cost ratio or parity ratio for select customer classes based upon the cost studies I performed. The parity ratio is the most appropriate yardstick for determining whether the rate schedule charges are equitable to each customer class. A ratio less than 1.0 or 100% indicates a class is not paying its fair share of costs. Conversely, a ratio greater than 100% indicates the class is paying charges in excess of its cost responsibility.

Cost of Service Results
Comparison of Select Customer Parity Ratios

	PSE's Main Allocation		NWIGU Main Allocation	
	Migrated Customers	Existing Customers	Migrated Customers	Existing Customers
Residential	1.01	1.01	1.01	1.00
C&I (31, 61)	0.89	0.89	0.88	0.88
85 Sales	1.72	1.72	1.34	1.34
87 Sales	1.25	1.25	1.26	1.26
57/SC				
Possible 85	1.72	1.97	1.63	1.87
Possible 87	0.81	0.80	1.24	1.24
Remaining 57/SC	1.22	1.22	1.34	1.33
57/SC	1.17	1.23	1.40	1.48
Rentals	0.69	0.69	0.69	0.69

A review of the above table shows the change in main allocation methods has virtually no impact on the parity ratios of the Residential, small commercial and industrial and rental classes. It is only the Large User schedules that are affected as the parity ratio of Schedule 85 customers is lower, while for Schedules 87, 57, and for customers taking service under special contracts, the ratio is higher than under the Company's studies. However, all the Large User parity ratios are substantially greater than 1.0, indicating that customers taking service under Schedules 85, 87, 57 and special contracts are paying too much for delivery service.

III. RATE SPREAD

Q. HAS THE COMPANY ADDRESSED RATE INEQUITIES IN ITS RATE SPREAD PROPOSAL?

A. For the most part, the Company has proposed class specific increases based upon its cost of service results. The Company states its intent to assign "a relatively large portion of the revenue increase to those classes with current parity ratios below 100%" (see JKP-1T, page 44, lines 1-3). However, this does not appear to be the case with regard to the rental class. This class has a parity ratio of just 69% under the Company's cost study which is the lowest of any major class. For this class, the Company has proposed an increase of just 5.3% while the average margin increase is over 17%. In other words, the PSE increase is less than one-third of the average percentage increase. This very modest increase for the rental class can not be justified given the cost study result.

Q. HOW SHOULD THE COMMISSION ASSIGN ANY REVNEUE INCREASE AMONG THE CUSTOMER CLASSES IN THIS PROCEEDING?

A. The Company's stated intent of moving toward a cost-based level should be the guiding goal line. However, it should apply to all classes and be based upon the cost study results as shown by Exhibit No. ___ (DWS-5). The results of the Company cost study and the NWIGU cost study are very similar for many of the major classes. Consequently, the NWIGU rate spread recommendation essentially adopts the PSE proposal for the residential, small commercial and industrial, Schedule 41, Schedule 50, Schedule 85 and Schedule 86 customer groups.

However, the NWIGU cost study shows a below average increase is warranted for Schedules 87 and 57 and as previously noted, the rental class should be assigned an above average margin increase. For the rental class, NWIGU recommends an increase that is 150% of the average margin increase as PSE proposed for the small commercial and industrial customers. For Schedule 87 and 57, NWIGU recommend these classes receive one-half the average margin increase. The following table illustrates and compares the PSE and NWIGU rate spread proposals for PSE's claimed margin increase.

Rate Spread Comparison

	PSE Proposal		NWIGU Recommendation		
Class	Change in Margin	Margin Increase	Change in Margin	Margin Increase	Margin Difference
Residential	$39,565	17.5%	$38,914	17.2%	-$651
C&I (31,61)	$16,547	25.3%	$16,762	25.6%	$215
Schedule 41	$0	0.0%	$0	0.0%	$0
CNG (50)	$5	17.9%	$7	25.6%	$2
Schedule 85	($0)	0.0%	$0	0.0%	$0
Schedule 86	($309)	-8.7%	-$309	-8.7%	$0
Schedule 87	$1,272	21.9%	$496	8.5%	-$776
Schedule 57	$571	24.6%	$198	8.5%	-$372
Rentals	$414	5.3%	$1,997	25.6%	$1,583
Total:	$58,065	17.1%	$58,065	17.1%	$0

In the likely event that PSE is granted less than the amount of margin revenue being sought, the rate spread should be based on the above NWIGU recommendation. The residential class should be assigned the average margin increase percentage. The small commercial and industrial, CNG and rental classes should be assigned 150% of the overall margin increase. Schedule 86 customers should receive a decrease determined as one-half of the margin increase. The Schedule 85 revenue level should not be changed and Schedules 87 and 57 (if Schedule 57 is to be retained) should be assigned one-half the overall margin increase.

IV. INDUSTRIAL RATE DESIGN

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSED INDUSTRIAL RATE DESIGN?

A. Yes, I have reviewed the Company's rate design proposals for Schedule 85, 87 and 57. Of most importance, the Company is seeking Commission authority to close Schedule 57 to new customers at the end of this proceeding and end the rate to all existing customers in 2012. PSE is proposing that transportation service be offered to all customers under the otherwise applicable sale schedule such as 85 and 87. With regard to specific pricing elements, the Company is proposing substantial increases to the fixed customer and demand charges of these schedules. Any remaining margin increase or decrease is assigned to and recovered from the volumetric charges.

Q. DOES NWIGU SUPPORT THE FREEZING AND PHASING OUT OF SCHEDULE 57?

A. NWIGU would support the complete elimination of Schedule 57 at the conclusion of this proceeding only under certain very specific conditions. Otherwise, NWIGU recommends retaining the current tariff as the single rate schedule for transporting customer-owned gas supplies.

Q. WHAT CONDITIONS ARE NEEDED TO GAIN NWIGU'S SUPPORT FOR THE ELIMINATION OF SCHEDULE 57?

A. The PSE otherwise applicable sale schedules under which the former Schedule 57 customers would be receiving service have different terms and conditions than Schedule 57. In particular, there are fuel exclusivity clauses, alternate fuel capability requirements and monthly minimum volumetric obligations. None of these requirements are included as a condition of service under Schedule 57. NWIGU would support the elimination of Schedule 57 if these restrictions were eliminated from Schedules 85 and 87.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY A FUEL EXCLUSIVITY CLAUSE.

A. Certainly. Schedule 85, Section 5, paragraph 1 requires customer's to use gas as the exclusive or only fuel if it is available. In other words, only during periods of curtailment by PSE may the customer use an alternate fuel such as oil. By contrast, Schedule 87 Section 5, paragraph 5 states: "The customer may, at its option, utilize substitute fuels during periods of non-curtailment." The current interruptible sales tariffs of Avista, Cascade Natural Gas and NW Natural do not have a fuel exclusivity provision. Customers should be allowed to elect to use the most economical fuel in their operations. Schedule 85 should contain the optional fuel language of Schedule 87. The existing restrictive fuel exclusivity language of Schedule 85 should be deleted.

Q. IS AN ALTERNATE FUEL CAPABILITY REQUIREMENT NECESSARY?

A. No. Alternate fuel requirements have been dropped from the terms and conditions of service under the Commission regulated transportation tariffs for some time in recognition of the fact that they are unnecessary. In so doing, the Commission has allowed the customer to elect the economic choice of having and maintaining the capability to use an alternate fuel if gas service is interrupted, or accepting the service interruption by curtailing operations. In the most recent complete re-design of sales and transportation tariffs approved by this Commission, NW Natural no longer requires alternate fuel capability as a condition of interruptible sales (or transportation) service. In this instant restructuring of PSE's tariff, it is an appropriate time to delete this requirement from the terms and conditions of Schedule 85 ands 87. The tariff should simply state:

> If the Customer does not have or maintain standby facilities, and curtails or suspends operations because of a partial or total curtailment of interruptible gas supply, Customer agrees and acknowledges that such curtailment of operations results solely from its election not to install and maintain standby facilities and fuel and does not in any way constitute a breach of contract on the part of the Company.

Q. PLEASE EXPLAIN THE MINIMUM MONTHLY VOLUMETRIC PROVISIONS OF SCHEDULE 85 AND 87.

A. Schedule 85 imposes an additional charge if a minimum monthly volumetric quantity is not achieved. The minimum quantity is defined as the greater of 50% of the highest monthly quantity in the last twelve months or 15,000 therms. For Schedule 87, the minimum obligation is couched in terms of a monthly deficiency volume defined as the monthly contract volume minus the interruptible gas that was delivered. The monthly contract volume is defined as one-twelfth the annual contract volume (absent any exceptions) with the annual volume defined as 75% of the deliveries from the prior year but not less than 750,000 therms.

Q. DO ANY OF THE OTHER WASHINGTON GAS DISTRIBUTION COMPANIES (LDCs) IMPOSE MONTHLY VOLUMETRIC MINIMUMS?

A. No. None of the other LDCs have a minimum monthly volumetric tariff provision that is an eligibility requirement to qualify for interruptible service. However, two of the Washington LDCs do have annual minimum volumetric obligations. Annual volumetric obligations are not unusual as such requirements are a simple but direct way to segment customers on different tariffs. Once similar customers are grouped on the most appropriate tariff, however, monthly volumetric minimums are not needed.

Q. SHOULD PSE'S MONTHLY VOLUMETRIC MINIMUMS BE ELIMINATED?

A. Yes. The monthly volumetric minimums should be replaced with annual volumetric minimums to appropriately classify interruptible customers by size. For Schedule 85, the annual minimum volume should be 180,000 therms (the current monthly minimum of 15,000 x 12 = 180,000). For Schedule 87, the annual minimum should be the current minimum value of 750,000 therms. For each rate schedule, the pricing of the deficiency volumes can be retained. The calculation will just be made once a year as opposed to the current monthly calculation.

Q. WHAT IS THE NWIGU POSITION IF THESE THREE RECOMMENDATIONS ARE NOT ADOPTED BY THE COMMISSION?

A. In that event, NWIGU strongly urges the Commission to retain Schedule 57 for both existing transportation customers and new transportation customers. It should not be phased out or terminated. The tariff provisions of Schedule 57 have been in place for some time. They are well understood and in line with progressive rate designs. PSE's outdated sales conditions should not be imposed on current or future transportation customers.

Q. WON'T PSE'S PROPOSAL TO "GRANDFATHER" THE SCHEDULE 57 TERMS AND CONDITIONS FOR THE MIGRATED CUSTOMERS ADDRESS YOUR CONCERNS?

A. No. Over the years, customers have had and should continue to have the option to move between sales and transportation service. Having different terms and conditions depending upon the service election really makes no sense. Further, it would appear if an existing transportation customer were to elect sales service, it would lose the grandfathered rights. For both these reasons, I would urge the Commission to approve the NWIGU recommendations with regard to updating PSE's sale schedule provisions to match other LDCs in this state. If not, as a second best alternative, NWIGU recommend retaining Schedule 57.

Q. HOW IS PSE PROPOSING TO RECOVER THE MARGIN REVENUE FROM SCHEDULES 85, 87 AND 57?

A. The Company's testimony addresses the matter of proposing increases to the customer charges of these rate schedules. The Company's testimony is silent with regard to the proposed increase to the demand charge, the decrease in the

Schedule 85 procurement charge, the elimination of the transportation balancing service charge, the substantial decrease to the volumetric charges of Schedule 85 and the uniform percentage increase to the volumetric charges of Schedules 87 and 57. Exhibit No. ___ (DWS-6) presents the current and PSE proposed charges for each of these three rate schedules.

Q. WHAT HAVE YOU CONCLUDED FROM YOUR REVIEW OF PSE'S PROPOSED RATE CHARGES FOR THESE SHCEDULES?

A. PSE is proposing a substantial increase in the fixed charges for these customers and modest increases or decreases to the volumetric charges. The best illustration of this rate design emphasis is Schedule 85. PSE has proposed that no margin increase be assigned to this class. Yet, as shown by Exhibit No. ___ (DWS-6), the fixed margin revenue increases by $550,000 or 40% while the volumetric margin revenue decreases by a similar amount with an overall 12% decrease. A comparison of the PSE proposed fixed price increases with their proposed overall margin increase for all three schedules is presented in the following table.

Percent Increases

Schedule	Overall Increase	Fixed Prices
85	0.0%	40.0%
87	21.8%	45.6%
57	23.9%	41.5%

Q. IS THIS RATE DESIGN EMPHASIS JUSTIFIED?

A. I don't believe so. It must be acknowledged that the vast majority of the Company's costs are fixed in the short term. This does not necessarily mean--as the Company is arguing-- that greater fixed cost recovery is required. This

Commission long ago soundly rejected the fixed-variable costing method. Yet it appears the Company is seeking this approach for revenue recovery:

> For example, in the residential class prior to any rate changes, 71 percent of margin revenue is derived from volumetric, or per therm, charges. In contrast, less than one percent of the Company's distribution cost is related to the volume of gas the Company sells or transports. Yet most revenue is derived from volumetric rates. Because of this, the Company's revenue stream is vulnerable to changes in customer usage patterns, weather, and conservation efforts. A major concern of the Company is this continuing practice of recovering fixed costs through volumetric rates – not only customer costs but demand costs as well.
>
> Increasing the basic charge starts to address the need to recover fixed costs through fixed charges. Even with the proposed increases in customer charges, a large portion of fixed costs will continue to be recovered through volumetric rates. The proposed basic charges reflect the need to make the Company's rate structure more consistent with its cost structure. (Exhibit ___ (JKP-1T, pp 46-47)

Q. DO SCHEDULES 85 AND 87 HAVE A SIMILAR LEVEL OF FIXED COST RECOVERY AS THE RESIDENTIAL CLASS?

A. Yes. To make the analysis "an apples-to-apples" comparison, Schedule 85 and 87 customers were selected based upon firmness of service and load factor to be comparable to the firm service provided residential customers. As shown by the following table, the Company's fixed cost recovery percentage from large firm users is greater than the residential class.

Fixed Cost Recovery

	Sch 85	Sch 87	Residential
Customer	10.4%	2.2%	29.4%
Demand	25.9%	35.2%	0.0%
Subtotal:	36.2%	37.4%	29.4%
Volumetric	63.8%	62.6%	70.6%
Total:	100.0%	100.0%	100.0%

The NWIGU believe Schedules 85 and 87 customers should not be required to contribute a disproportionate share of revenue through fixed charges. As shown by the above table, PSE's rate design proposal would result in just such a disproportionate imposition of fixed charges on Schedule 85 and 87 customers.

Q. HOW DO YOU RECOMMEND ANY INCREASE IN MARGIN REVENUE BE RECOVERED FROM SCHEDULE 85, 87 AND 57 (IF IT IS TO BE CONTINUED)?

A. The NWIGU recommendation is presented in Exhibit No. ___ (DWS-6) next to the PSE proposal. NWIGU recommend the existing fixed charge prices—the customer charge and the demand charge--be maintained at the current level. For Schedule 85, the revenue lost from the elimination of the monthly minimum should be recovered by increasing the volumetric charges. For Schedules 87 and 57, the entire increase assigned to these customers should be recovered by applying an equal percentage increase to each volumetric charge.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Puget Sound Energy - 2007 Gas Cost of Service Study
Proposed Test Year Without Gas
PSE Study - Existing Customer Classification

Line No	Description	Total Company	Residential (16,23,53)	Comm & Indus. (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
	(a)	(b)	(c)	(d)	(e)	(g)	(f)	(i)	(j)	(k)	(l)
	Rate Base										
1	Plant in Service	$ 2,282,742,658	$ 1,518,339,465	$ 548,551,334	$ 63,678,717	$ 6,572,200	$ 13,254,425	$ 11,036,068	$ 75,768,858	$ 528,670	$ 44,694,890
2	Accumulated Reserve	(773,227,522)	(509,160,789)	(191,107,495)	(19,597,379)	(2,473,120)	(4,283,080)	(3,483,568)	(23,129,086)	(67,534)	(19,895,595)
3	Other Rate Base Items	(160,120,115)	(99,881,019)	(45,622,593)	(4,457,605)	(333,421)	(781,609)	(603,829)	(5,433,199)	7,919	(2,814,758)
4	TOTAL RATE BASE	$ 1,349,395,041	$ 909,296,687	$ 311,821,251	$ 39,623,732	$ 4,265,660	$ 8,189,755	$ 6,947,670	$ 47,228,553	$ 459,255	$ 21,984,537
	Revenue at Current Rates										
5	Gas Revenues	-	-	-	-	-	-	-	-	-	-
6	Base Rate Revenues	334,162,847	226,714,023	65,386,783	13,626,378	1,791,780	3,542,875	2,024,148	13,259,139	28,932	7,768,789
7	Other Revenues	6,291,644	4,614,507	1,446,076	42,152	6,081	32,661	2,271	147,177	719	-
8	TOTAL REVENUE	$ 340,454,491	$ 231,328,530	$ 66,832,859	$ 13,668,530	$ 1,797,861	$ 3,575,536	$ 2,026,419	$ 13,406,316	$ 29,651	$ 7,768,789
	Expenses at Current Rates										
9	Operation and Maintenance	108,935,613	79,799,591	21,446,709	2,202,031	404,104	561,749	518,493	3,002,711	53,476	933,750
10	Depreciation Expense	99,429,849	61,763,191	22,204,946	2,562,044	251,946	521,709	418,293	3,113,674	50,820	9,043,226
11	Taxes Other Than Income	28,160,851	18,471,725	6,919,059	814,691	85,464	169,612	139,342	975,625	5,272	600,020
12	Income Taxes	22,732,712	15,739,064	3,557,773	1,769,854	231,105	503,079	207,901	1,381,425	(17,484)	(609,995)
13	TOTAL EXPENSES - Current	$ 259,279,024	$ 175,233,571	$ 54,128,528	$ 7,348,620	$ 972,618	$ 1,779,140	$ 1,284,031	$ 8,473,434	$ 92,084	$ 9,967,001
14	Operating Income - Current	$ 81,175,467	$ 56,094,960	$ 12,704,332	$ 6,319,910	$ 825,243	$ 1,796,396	$ 742,388	$ 4,932,882	$ (62,433)	$ (2,178,212)
15	Current Rate of Return	6.0157%	6.1690%	4.0769%	15.9488%	20.2979%	21.9347%	10.6856%	10.4451%	-14.2139%	-9.9079%
	Calculation of Rate Schedule Revenue Requirement at Equal Rates of Return										
16	Required Return	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%
17	Required Operating Income	$ 116,047,973	$ 78,199,515	$ 26,799,428	$ 3,407,641	$ 349,847	$ 704,519	$ 597,491	$ 4,061,487	$ 37,776	$ 1,890,670
18	Operating Income (Deficiency)/Surplus	(34,872,507)	(22,104,556)	(14,095,096)	2,912,269	475,597	1,092,077	144,897	871,395	(100,209)	(4,068,882)
19	Revenue Conversion Factor	0.6220									
20	Revenue (Deficiency) / Surplus	$ (56,068,727)	$ (35,980,592)	$ (20,710,896)	$ 3,307,227	$ 575,159	$ 1,329,603	$ 128,264	$ 723,922	$ (131,278)	$ (5,400,110)
21	Revenue Requirement	$ 396,523,218	$ 267,309,122	$ 87,543,756	$ 10,271,303	$ 1,222,728	$ 2,245,932	$ 1,898,155	$ 12,682,394	$ 160,929	$ 13,168,899
22	Revenues Other Than Rate Sch Rev	6,291,644	4,614,507	1,446,078	42,152	6,081	32,661	2,271	147,177	719	-
23	Rate Schedule Revenue Requirement	390,231,574	262,694,615	86,097,679	10,229,151	1,216,647	2,213,272	1,895,884	12,535,217	160,210	13,168,899
24	Deficiency / (Surplus) as % of Sales & Trans Rev	16.78%	15.87%	31.67%	-24.93%	-32.10%	-37.53%	-6.34%	-5.46%	453.75%	69.33%
	Expenses at Required Return										
25	Operation and Maintenance	$ 109,200,257	$ 79,980,489	$ 21,506,679	$ 2,208,712	$ 404,719	$ 565,067	$ 519,189	$ 5,007,266	$ 53,496	$ 933,750
26	Depreciation Expense	99,429,849	61,763,191	22,234,945	2,562,044	251,948	521,709	418,293	5,113,674	50,820	9,043,226
27	Taxes Other Than Income	30,335,011	19,894,116	7,444,601	875,999	91,343	182,005	149,461	1,047,181	5,326	644,964
28	Income Taxes	41,510,128	27,971,910	9,586,102	1,216,908	125,069	251,933	213,721	1,452,786	13,512	676,289
29	TOTAL EXPENSES - Required	$ 280,475,244	$ 189,109,607	$ 60,744,326	$ 6,863,662	$ 873,081	$ 1,541,613	$ 1,300,664	$ 8,620,907	$ 123,154	$ 11,298,229
30	Current Revenue to Cost Ratio	0.86	0.86	0.76	1.33	1.47	1.80	1.07	1.06	0.18	0.59
31	Parity Ratio	1.00	1.01	0.89	1.56	1.72	1.87	1.25	1.24	0.21	0.69

Puget Sound Energy - 2007 Gas Cost of Service Study
Proposed Test Year Without Gas
PSE Study - Proposed Customer Migration

Line No.	Description	Total Company	Residential (16,23,53)	Comm. & Indus. (31,36,51,61)	Large Volume (41)	Interruptible Sales (85)	Limited Interruptible (86)	Non-Exclusive Interruptible Sales (87)	Transport & Contracts	CNG Service (50)	Rentals	Interruptible Transport (85)	Non-Exclusive Inter Transport (87)
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(n)	(o)
	Rate Base												
	Plant in Service	$ 2,282,742,658	$ 1,619,313,421	$ 546,540,162	$ 64,469,869	$ 6,571,131	$ 13,250,808	$ 11,032,103	$ 21,784,177	$ 628,854	$ 44,684,893	$ 18,698,453	$ 34,858,985
	Accumulated Reserve	(773,227,502)	(609,153,767)	(191,104,267)	(20,043,789)	(2,172,675)	(4,201,832)	(3,482,848)	(6,745,437)	(97,329)	(19,866,595)	(5,848,657)	(10,400,811)
	Other Rate Base Items	(160,120,115)	(99,879,751)	(45,821,663)	(4,484,567)	(333,632)	(781,340)	(603,581)	(1,704,367)	7,820	(2,814,758)	(1,249,517)	(2,646,060)
	TOTAL RATE BASE	$ 1,349,395,041	$ 909,280,503	$ 311,614,232	$ 39,932,017	$ 4,064,923	$ 8,197,837	$ 6,945,674	$ 13,534,368	$ 439,245	$ 21,904,637	$ 11,599,279	$ 21,812,225
	Revenue at Current Rates												
	Gas Revenues	-	-	-	-	-	-	-	-	-	-	-	-
	Base Rate Revenues	333,460,849	226,714,023	65,386,780	13,728,465	1,791,780	3,542,875	2,024,146	3,908,922	28,932	7,789,789	4,765,304	3,779,828
	Other Revenues	6,291,644	4,614,507	1,446,076	44,583	6,081	32,601	2,271	22,222	719	-	109,154	13,370
	TOTAL REVENUE	$ 339,762,293	$ 231,328,530	$ 66,832,859	$ 13,774,046	$ 1,797,861	$ 3,575,536	$ 2,026,419	$ 3,931,144	$ 29,651	$ 7,788,789	$ 4,874,458	$ 3,792,898
	Expenses at Current Rates												
	Operation and Maintenance	108,532,297	79,769,073	21,446,308	2,220,113	403,890	564,588	518,444	994,517	63,475	833,750	960,744	1,037,487
	Depreciation Expense	99,429,549	61,261,748	22,704,342	2,682,244	251,868	521,549	418,000	852,874	50,819	9,043,276	764,726	1,438,365
	Taxes Other Than Income	28,153,673	18,453,576	6,512,373	623,375	85,388	169,410	139,178	282,269	5,271	593,457	246,601	438,973
	Income Taxes	22,497,545	15,652,122	3,545,668	1,775,358	230,324	501,199	207,181	366,047	(17,415)	(607,491)	652,497	191,156
	TOTAL EXPENSES - Current	$ 259,013,563	$ 176,166,617	$ 54,108,593	$ 7,399,090	$ 971,278	$ 1,776,643	$ 1,282,893	$ 2,545,709	$ 92,161	$ 9,960,942	$ 2,601,568	$ 3,106,881
	Operating Income - Current	$ 80,738,730	$ 56,172,013	$ 12,724,266	$ 6,374,957	$ 826,583	$ 1,798,892	$ 743,526	$ 1,365,437	$ (62,600)	$ (2,180,153)	$ 2,260,800	$ 686,016
	Current Rate of Return	5.9833%	6.1776%	4.0833%	15.9645%	20.3345%	21.9664%	10.7049%	10.2382%	-14.2268%	-9.9168%	19.9602%	3.1461%
	Calculation of Rate Schedule Revenue Requirement at Equal Rates of Return												
	Required Return	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%
	Required Operating Income	$ 116,047,973	$ 78,198,156	$ 26,799,824	$ 3,434,153	$ 349,583	$ 704,137	$ 597,328	$ 1,163,956	$ 37,775	$ 1,883,870	$ 997,538	$ 1,875,851
	Operating Income (Deficiency)/Surplus	(35,309,241)	(22,026,144)	(14,074,556)	2,940,804	476,999	1,094,555	146,198	221,481	(100,275)	(4,070,823)	1,272,352	(1,189,835)
	Revenue Conversion Factor	0.6220											
	Revenue (Deficiency) / Surplus	$ (56,770,924)	$ (36,978,988)	$ (20,708,741)	$ 3,421,430	$ 570,690	$ 1,330,107	$ 128,768	$ 160,221	$ (131,276)	$ (6,403,110)	$ 1,528,829	$ (1,704,861)
	Revenue Requirement	$ 396,523,217	$ 267,307,518	$ 67,542,601	$ 10,352,617	$ 1,222,186	$ 2,245,426	$ 1,897,651	$ 3,761,924	$ 160,927	$ 13,188,899	$ 3,345,630	$ 5,497,858
	Revenues Other Than Rate Sch Rev	6,291,644	4,614,507	1,446,076	44,583	6,001	32,681	2,271	22,222	718	-	109,154	13,370
	Rate Schedule Revenue Requirement	390,231,573	262,693,009	86,096,524	10,309,035	1,216,085	2,212,765	1,895,380	3,739,701	160,208	13,188,890	3,236,475	5,484,409
	Deficiency / (Surplus) as % of Sales & Trans Rev	17.02%	15.87%	31.67%	-24.82%	-32.13%	-37.54%	-6.36%	-4.33%	453.74%	69.33%	-32.00%	45.11%
	Expenses at Required Return												
	Operation and Maintenance	$ 108,202,256	$ 79,092,632	$ 21,608,104	$ 2,224,900	$ 404,323	$ 685,921	$ 519,150	$ 985,880	$ 53,486	$ 933,760	$ 962,406	$ 1,038,865
	Depreciation Expense	98,425,649	61,261,746	22,204,392	2,582,244	251,868	621,649	418,000	882,874	50,419	9,043,228	764,726	1,438,365
	Taxes Other Than Income	30,335,012	19,893,756	7,444,445	852,930	91,346	181,955	149,419	302,869	5,335	844,864	284,143	473,840
	Income Taxes	41,510,127	27,971,324	9,585,866	1,228,300	125,046	251,868	213,663	416,346	13,612	678,289	356,817	670,988
	TOTAL EXPENSES - Required	$ 280,475,243	$ 189,109,358	$ 60,743,777	$ 6,918,464	$ 872,582	$ 1,541,292	$ 1,300,323	$ 2,597,966	$ 123,152	$ 11,296,229	$ 2,348,092	$ 3,622,007
	Rate Schedule Revenue as Proposed	$ 390,230,970	$ 265,396,615	$ 81,565,111	$ 15,729,592	$ 1,761,814	$ 3,240,609	$ 2,423,842	$ 4,467,760	$ 34,006	$ 8,193,691	$ 4,795,125	$ 4,822,911
	Other Revenue	6,291,644	4,614,507	1,446,076	44,583	6,081	32,661	2,271	22,222	719	-	109,154	13,370
	Revenue as Proposed	$ 396,522,620	$ 270,011,122	$ 83,011,187	$ 15,774,175	$ 1,767,895	$ 3,273,269	$ 2,426,113	$ 4,489,983	$ 34,725	$ 8,193,691	$ 4,904,279	$ 4,836,181
	Proposed Revenue Increase	$ 58,770,327	$ 38,682,592	$ 16,178,328	$ 127	$ (29,966)	$ (302,266)	$ 399,694	$ 558,838	$ 5,074	$ 404,902	$ 29,821	$ 843,163
	Proposed Revenue - Revenue Requirement	$ 396,522,620	$ 270,011,122	$ 83,011,187	$ 15,774,175	$ 1,767,895	$ 3,273,269	$ 2,426,113	$ 4,486,983	$ 34,725	$ 8,193,691	$ 4,904,279	$ 4,836,181
	Current Revenue to Cost Ratio	0.85	0.85	0.76	1.33	1.47	1.60	1.07	1.05	0.18	0.59	1.47	0.69
	Parity Ratio	1.00	1.01	0.89	1.56	1.72	1.87	1.26	1.22	0.21	0.69	1.72	0.81

Puget Sound Energy
2007 General Rate Case
PSE Derivation of Peak-Average Allocation Factor for Mains

Line No	Item	Amount	Percent	Allocator	Residential (16,23,53)	Comm & Indus (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transportation (57)	Special Contracts	CNG Service (50)
	Peak		67.042%										
1	Allocated Mains Costs	692,739,082											
2	Direct Assignment	11,107,538		Direct	-	-	-	2,837,535	-	2,706,464	-	5,563,540	-
3	Net Allocated Costs	681,631,544		Design Peak	485,593,738	174,028,004	21,042,167	-	954,164	-	-	-	13,471
4	Total Peak Costs	692,739,082			485,593,738	174,028,004	21,042,167	2,837,535	954,164	2,706,464	-	5,563,540	13,471
	Average		32.958%										
5	Allocated Mains Costs	340,545,871											
6	Direct Assignment	-			0	0	0	0	0	0	0	0	0
7	Net Allocated Costs	340,545,871		Volume	182,542,614	69,880,312	23,436,600	13,865,801	5,811,623	34,136,325	-	10,831,184	41,412
8	Total Average Costs	340,545,871			182,542,614	69,880,312	23,436,600	13,865,801	5,811,623	34,136,325	-	10,831,184	41,412
9	Total (PA_MAINS)	$ 1,033,284,953		Large Users 69,940,848	668,136,352	243,908,316	44,478,767	16,703,336	6,765,786	36,842,788	-	16,394,724	54,883
10	Percent	100.00%			64.66%	23.61%	4.30%	1.62%	0.65%	3.57%	0.00%	1.59%	0.01%
	Allocators												
11	Design Peak	8,828,973			6,289,753	2,254,133	272,553	-	12,359	-	-	-	174
12	Percent	100.00%			71.24%	25.53%	3.09%	0.00%	0.14%	0.00%	0.00%	0.00%	0.00%
13	Total Annual Volume	822,201,562			532,765,816	203,951,509	68,401,668	-	16,961,705	-	-		120,864
14	Minimum Annual Volume	171,709,912			-	-	-	40,468,496	-	99,629,705	-	31,611,711	-
15	Volume	993,911,474			532,765,816	203,951,509	68,401,668	40,468,496	16,961,705	99,629,705	-	31,611,711	120,864
16	Percent	100.00%			53.60%	20.52%	6.88%	4.07%	1.71%	10.02%	0.00%	3.18%	0.01%

Puget Sound Energy
2007 General Rate Case
Segregated Peak-Average Allocation Factor for Mains

Line No.	Item	Amount	Percent	Allocator	Residential (16,23,53)	Comm. & Indus. (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transportation (57)	Special Contracts	CNG Service (50)
1	Total Mains	$1,033,284,953											
2	< 4 Inches in Diameter	$458,604,938											
3	> 4 Inches in Diameter	$574,680,015											
4	> 4 Inches Peak:	$385,279,303											
5	> 4 Inches Average:	$189,400,712											
	Peak > 4 Inch		67.042%										
6	Allocated Mains Costs	385,279,303											
7	Direct Assignment	11,107,538		Direct	-	-	-	2,837,535	-	2,706,464	-	5,563,540	-
8	Net Allocated Costs	374,171,765		Design Peak	266,559,850	95,530,153	11,550,793	-	523,774	-	-	-	7,395
9	>4 Inch Peak Costs	385,279,303			266,559,650	95,530,153	11,550,793	2,837,535	523,774	2,706,464	-	5,563,540	7,395
	Average > 4 Inch		32.958%										
10	Allocated Mains Costs	189,400,712											
11	Direct Assignment	-			0	0	0	0	0	0	0	0	0
12	Net Allocated Costs	189,400,712		Volume	101,524,359	38,865,193	13,034,687	7,711,715	3,232,239	18,985,531	-	6,023,958	23,032
13	>4 Inch Average Costs	189,400,712			101,524,359	38,865,193	13,034,687	7,711,715	3,232,239	18,985,531	-	6,023,958	23,032
14	> 4 Inches (PA_MAINS)	$ 574,680,015			368,084,009	134,395,345	24,585,480	10,549,250	3,756,013	21,691,995	-	11,587,498	30,427
15	Percent	100.00%			64.05%	23.39%	4.28%	1.84%	0.65%	3.77%	0.00%	2.02%	0.01%
	Peak <4 Inch		67.042%										
16	Allocated Mains Costs	$307,459,779											
17	Direct Assignment	Included in >4											
18	Net Allocated Costs	307,459,779			219,034,088	78,497,852	9,491,374	0	430,389	0	0	0	6,076
19	<4 Inch Peak Costs	307,459,779			219,034,088	78,497,852	9,491,374	0	430,389	0	0	0	6,076
	Average <4 Inch		32.958%										
20	Allocated Mains Costs	$151,145,158											
21	Direct Assignment	-											
22	Net Allocated Costs	151,145,158			96,849,310	37,075,507	12,434,458	959,241	3,083,399	0	0	721,272	21,971
23	<4 Inch Average Costs												
24	<4 Inches (PA_MAINS)				315,883,398	115,573,359	21,925,833	959,241	3,513,788	0	0	721,272	28,048
25	Percent												
26	**Total Mains:**	$1,033,284,953		Large Users $45,509,255	$683,967,407	$249,968,704	$46,511,312	$11,508,491	$7,269,801	$21,691,995	$0	$12,308,769	$58,474
					66.19%	24.19%	4.50%	1.11%	0.70%	2.10%	0.00%	1.19%	0.01%
	Allocators												
27	Design Peak	8,828,973			6,289,753	2,254,133	272,553	-	12,359	-	-	-	174
28	Percent	100.00%			71.24%	25.53%	3.09%	0.00%	0.14%	0.00%	0.00%	0.00%	0.00%
29	Total Annual Volume	822,201,562			532,765,816	203,951,509	68,401,668	-	16,961,705	-	-		120,864
30	Minimum Annual Volume	171,709,912			-	-	-	40,468,496	-	99,629,705	-	31,611,711	-
31	Volume	993,911,474			532,765,816	203,951,509	68,401,668	40,468,496	16,961,705	99,629,705	-	31,611,711	120,864
32	Percent	100.00%			53.60%	20.52%	6.88%	4.07%	1.71%	10.02%	0.00%	3.18%	0.01%
33	Full Volumes							62,955,045		136,098,989		62,954,572	
34	Volumes through <4 inch							8,208,825				5,418,988	
35	Approx Min Vol < 4 Inch	831,446,023			532,765,816	203,951,509	68,401,668	5,276,762	16,961,705		-	3,967,698	120,864
36	Percent				64.08%	24.53%	8.23%	0.63%	2.04%	0.00%	0.00%	0.48%	0.01%

Puget Sound Energy
2007 General Rate Case
Derivation of Allocation Factor for Mains
Existing Customer Classes - DA on Average Winter Day

Line No.	Item	Amount	Percent	Allocator	Residential (16,23,53)	Comm. & Indus (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transportation (57)	Special Contracts	CNG Service (50)
1	**Total Main Investment:**	$ 1 033,284,953											
2	**Direct Assignment:**	59,145,531						5,284,576		7,640,994		46,219,962	
3	**General Allocation:**	974,139,422											
	Peak		67 042%										
4	Allocated Mains Costs	653,086,496											
5	Allocated Peak Costs	653,086,496		Design Peak	465,258,270	166,740,141	20,160,973	-	914,206	-	-	-	12,907
	Average		32.958%										
6	Allocated Mains Costs	321,052,926											
7	Allocated Average Costs	321,052,926		Volume	208,034,176	79,638,901	26,709,455	-	6,623,200	-	-	-	47,195
				Large Users 59,145,531									
8	**Total (PA_MAINS)**	$ 1,033,284,953			673,292,445	246,379,041	46,870,428	5,284,576	7,537,405	7 640,994	-	46,219,962	60,102
9	Percent	100.00%			65 16%	23.84%	4.54%	0.51%	0.73%	0 74%	0.00%	4.47%	0.01%
10	check:	0.00											
	Allocators												
11	Design Peak	8,828,973			6,289,753	2,254,133	272,553	-	12,359	-	-	-	174
12	Percent	100.00%			71 24%	25.53%	3.09%	0.00%	0.14%	0.00%	0.00%	0.00%	0.00%
13	Total Annual Volume	822,201,562			532,765,816	203,951,509	68,401,668	-	16,961,705	-	-		120,864
14	Minimum Annual Volume	-			-	-	-		-		-		-
15	Volume	822,201,562			532,765,816	203,951,509	68,401,668	-	16,961,705	-	-	-	120,864
16	Percent	100.00%			64.80%	24.81%	8.32%	0.00%	2.06%	0.00%	0.00%	0.00%	0 01%

Exhibit No. ____ (DWS-5)
Page 1 of 2

Puget Sound Energy - 2007 Gas Cost of Service Study
Proposed Test Year Without Gas
Existing Customer Classification - Mains on AWD

Line No.	Description	Total Company	Residential (16,23,53)	Comm & Indus (31,36,51,61)	Large Volume (41)	Interruptible (85)	Limited Interruptible (86)	Non-Exclusive Interruptible (87)	Transport & Contracts	CNG Service (50)	Rentals
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)
	Rate Base										
1	Plant in Service	$ 2,282,742,868	$ 1,523,820,207	$ 551,178,295	$ 68,986,523	$ 8,917,897	$ 14,076,245	$ 10,825,127	$ 61,626,745	$ 534,228	$ 44,694,890
2	Accumulated Reserve	(773,227,502)	(510,752,595)	(181,870,810)	(20,784,993)	(2,854,274)	(4,521,705)	(3,451,743)	(19,017,039)	(98,948)	(19,895,595)
3	Other Rate Base Items	(160,120,115)	(100,328,940)	(46,037,529)	(4,701,745)	(525,092)	(848,762)	(504,048)	(4,275,108)	7,465	(2,814,758)
4	TOTAL RATE BASE	$ 1,349,395,041	$ 912,738,672	$ 313,271,356	$ 41,499,785	$ 5,538,530	$ 8,705,779	$ 6,878,538	$ 38,336,098	$ 442,745	$ 21,984,537
	Revenue at Current Rates										
5	Gas Revenues	-	-	-	-	-	-	-	-	-	-
6	Base Rate Revenues	334,162,847	226,714,023	65,386,783	13,626,378	1,791,780	3,542,675	2,024,149	13,259,139	28,932	7,786,789
7	Other Revenues	6,291,644	4,614,507	1,446,076	42,152	6,081	32,861	2,271	147,177	719	-
8	TOTAL REVENUE	$ 340,454,491	$ 231,328,530	$ 66,832,859	$ 13,668,530	$ 1,797,861	$ 3,575,536	$ 2,026,415	$ 13,406,316	$ 29,651	$ 7,786,789
	Expenses at Current Rates										
9	Operation and Maintenance	108,535,613	79,899,111	21,499,213	2,251,724	460,969	601,169	516,297	2,719,794	53,587	933,750
10	Depreciation Expense	99,429,849	51,492,100	22,314,686	2,868,811	349,899	556,027	413,702	2,522,346	51,052	9,043,220
11	Taxes Other Than Income	28,180,851	18,542,417	5,952,990	853,222	115,714	180,210	137,825	793,009	5,344	500,020
12	Income Taxes	22,732,712	15,619,558	3,514,864	1,721,069	192,804	489,651	209,697	1,612,641	(17,575)	(809,985)
13	TOTAL EXPENSES - Current	$ 259,279,024	$ 175,553,185	$ 54,281,753	$ 7,522,826	$ 1,109,385	$ 1,827,057	$ 1,277,620	$ 7,647,790	$ 92,409	$ 9,967,001
14	Operating Income - Current	$ 81,175,467	$ 55,775,345	$ 12,551,107	$ 6,145,704	$ 688,476	$ 1,748,479	$ 748,799	$ 5,758,526	$ (62,757)	$ (2,178,212)
15	Current Rate of Return	6.0157%	6.1108%	4.0065%	14.8030%	12.4307%	20.0841%	10.8860%	15.0215%	-14.1745%	-9.9079%
	Calculation of Rate Schedule Revenue Requirement at Equal Rates of Return										
16	Required Return	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%
17	Required Operating Income	$ 116,047,973	$ 78,495,528	$ 26,941,337	$ 3,568,962	$ 476,314	$ 748,697	$ 591,554	$ 3,296,918	$ 38,076	$ 1,890,670
18	Operating Income (Deficiency)/Surplus	(34,872,507)	(22,720,181)	(14,390,230)	2,576,723	212,162	999,782	157,244	2,461,707	(100,833)	(4,068,882)
19	Revenue Conversion Factor	0.6220									
20	Revenue (Deficiency) / Surplus	$ (56,068,727)	$ (36,797,062)	$ (21,102,317)	$ 2,952,210	$ 225,754	$ 1,207,188	$ 144,639	$ 2,833,067	$ (132,108)	$ (5,400,110)
21	Revenue Requirement	$ 396,523,218	$ 268,125,593	$ 87,935,176	$ 10,716,320	$ 1,572,107	$ 2,368,338	$ 1,881,760	$ 10,573,249	$ 161,757	$ 13,186,899
22	Revenues Other Than Rate Sch. Rev	6,291,644	4,614,507	1,446,076	42,152	6,081	32,661	2,271	147,177	719	-
23	Rate Schedule Revenue Requirement	390,231,574	263,511,085	86,489,100	10,674,168	1,566,026	2,335,677	1,879,509	10,426,072	161,038	13,186,899
24	Deficiency / (Surplus) as % of Sales & Trans Rev	16.78%	16.23%	32.27%	-21.67%	-12.60%	-34.07%	-7.15%	-21.37%	456.61%	69.35%
	Expenses at Required Return										
25	Operation and Maintenance	$ 109,200,257	$ 80,090,009	$ 21,581,183	$ 2,266,406	$ 461,584	$ 602,386	$ 516,992	$ 2,724,550	$ 53,597	$ 933,750
26	Depreciation Expense	99,429,849	51,492,100	22,314,686	2,868,811	349,899	556,027	413,702	2,522,346	51,052	9,043,220
27	Taxes Other Than Income	30,335,011	19,970,288	7,481,107	917,504	123,924	193,421	147,833	850,469	5,413	644,564
28	Income Taxes	41,510,128	28,077,693	9,656,862	1,276,618	170,378	267,807	211,598	1,179,265	13,620	676,289
29	TOTAL EXPENSES - Required	$ 280,475,244	$ 169,630,067	$ 60,953,859	$ 7,147,338	$ 1,095,753	$ 1,619,641	$ 1,290,228	$ 7,276,430	$ 123,681	$ 11,298,229
30	Current Revenue to Cost Ratio	0.86	0.88	0.76	1.28	1.14	1.52	1.08	1.27	0.18	0.59
31	Parity Ratio	1.00	1.00	0.88	1.49	1.34	1.77	1.26	1.48	0.21	0.69

Exhibit No ____ (JWS-4)
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Puget Sound Energy - 2007 Gas Cost of Service Study
Proposed Test Year Without Gas
Proposed Customer Migration - Mains on AWD

Line No.	Description	Total Company	Residential (16,23,53)	Comm. & Indus. (31,36,51,61)	Large Volume (41)	Interruptible Sales (85)	Limited Interruptible (86)	Non-Exclusive Interruptible Sales (87)	Transport & Contracts	CNG Service (50)	Rentals	Interruptible Transport (85)	Non-Exclusive Inter Transport (87)
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(n)	(o)
	Rate Base												
1	Plant in Service	$ 2,282,742,659	$ 1,523,821,019	$ 551,179,322	$ 67,024,578	$ 8,917,609	$ 14,075,030	$ 10,925,407	$ 19,680,096	$ 534,229	$ 44,694,890	$ 19,918,474	$ 21,971,802
2	Accumulated Reserve	(773,227,602)	(510,753,090)	(191,870,639)	(20,785,133)	(2,854,115)	(4,521,174)	(3,451,884)	(6,134,445)	(98,948)	(19,865,595)	(6,203,937)	(6,658,508)
3	Other Rate Base Items	(160,120,115)	(100,328,787)	(46,037,314)	(4,703,316)	(525,284)	(848,688)	(594,863)	(1,332,439)	7,465	(2,914,758)	(1,349,207)	(1,592,923)
4	TOTAL RATE BASE	$ 1,349,395,041	$ 912,739,142	$ 313,271,369	$ 41,536,128	$ 5,538,410	$ 8,705,168	$ 6,878,879	$ 12,213,212	$ 442,745	$ 21,964,537	$ 12,365,334	$ 13,720,318
	Revenue at Current Rates												
5	Gas Revenues	-	-	-	-	-	-	-	-	-	-	-	-
6	Base Rate Revenues	333,460,649	226,714,023	65,388,783	13,729,465	1,791,780	3,542,875	2,024,148	3,909,922	28,932	7,788,789	4,765,304	3,779,628
7	Other Revenues	6,291,644	4,614,507	1,446,076	44,583	6,081	32,661	2,271	22,222	719	-	109,154	13,370
8	TOTAL REVENUE	$ 339,752,293	$ 231,328,530	$ 66,832,059	$ 13,774,048	$ 1,797,861	$ 3,575,536	$ 2,026,419	$ 3,931,144	$ 29,651	$ 7,788,789	$ 4,874,460	$ 3,792,998
	Expenses at Current Rates												
9	Operation and Maintenance	108,932,297	79,809,110	21,499,036	2,271,154	450,563	601,163	516,313	942,480	63,697	933,750	985,119	780,012
10	Depreciation Expense	89,429,849	61,491,736	22,314,550	2,688,925	349,802	555,967	413,634	805,011	51,052	9,043,226	815,672	900,214
11	Taxes Other Than Income	28,153,873	18,524,534	6,946,375	853,280	115,622	180,028	137,803	255,181	5,313	580,457	262,518	273,940
12	Income Taxes	22,497,545	15,562,659	3,502,852	1,734,814	192,163	487,796	208,916	420,263	(17,506)	(607,491)	612,657	400,723
13	TOTAL EXPENSES - Current	$ 259,013,563	$ 175,477,936	$ 54,262,613	$ 7,548,182	$ 1,108,230	$ 1,824,944	$ 1,276,666	$ 2,422,915	$ 92,476	$ 9,960,842	$ 2,675,766	$ 2,354,889
14	Operating Income - Current	$ 90,738,730	$ 55,850,592	$ 12,570,246	$ 6,226,866	$ 689,632	$ 1,750,591	$ 749,753	$ 1,508,230	$ (62,826)	$ (2,100,153)	$ 2,198,690	$ 1,438,109
15	Current Rate of Return	6.9833%	6.1190%	4.0120%	14.9680%	12.4518%	20.1090%	10.8997%	12.3492%	-14.1899%	-9.8166%	17.7811%	10.4818%
	Calculation of Rate Schedule Revenue Requirement at Equal Rates of Return												
16	Required Return	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%	8.6000%
17	Required Operating Income	$ 118,017,973	$ 78,495,508	$ 26,841,338	$ 3,572,107	$ 476,303	$ 748,644	$ 591,566	$ 1,050,336	$ 38,076	$ 1,890,670	$ 1,063,419	$ 1,179,947
18	Operating Income (Deficiency)/Surplus	(35,339,244)	(22,644,974)	(14,371,092)	2,653,759	213,328	1,001,947	158,186	457,894	(100,901)	(4,070,823)	1,135,272	258,161
19	Revenue Conversion Factor	0.6220											
20	Revenue (Deficiency) / Surplus	$ (56,770,924)	$ (36,798,312)	$ (21,102,530)	$ 3,040,621	$ 226,171	$ 1,207,343	$ 144,660	$ 462,511	$ (132,106)	$ (5,460,110)	$ 1,347,113	$ 214,615
21	Revenue Requirement	$ 396,523,217	$ 268,127,842	$ 87,935,690	$ 10,733,127	$ 1,571,690	$ 2,368,162	$ 1,881,759	$ 3,448,533	$ 161,758	$ 13,168,898	$ 3,527,345	$ 3,578,383
22	Revenues Other Than Rate Sch. Rev.	6,291,644	4,614,507	1,446,076	44,583	6,081	32,661	2,271	22,222	719	-	109,154	13,370
23	Rate Schedule Revenue Requirement	390,231,573	263,513,335	86,489,613	10,688,544	1,565,609	2,335,532	1,879,488	3,426,311	161,038	13,168,898	3,418,191	3,565,013
24	Deficiency / (Surplus) as % of Sales & Trans Rev	17.02%	16.23%	32.27%	-22.15%	-12.62%	-34.08%	-7.15%	-12.35%	456.81%	60.33%	-28.27%	-5.68%
	Expenses at Required Return												
25	Operation and Maintenance	$ 109,230,256	$ 80,092,569	$ 21,581,632	$ 2,275,940	$ 451,207	$ 602,388	$ 517,018	$ 843,843	$ 53,597	$ 933,750	$ 986,781	$ 781,330
26	Depreciation Expense	99,429,840	61,491,738	22,314,550	2,658,925	349,882	555,967	413,634	805,011	51,052	9,043,226	815,672	900,214
27	Taxes Other Than Income	30,335,012	18,970,265	7,461,107	918,419	123,945	193,404	147,937	273,641	5,413	644,984	281,091	294,827
28	Income Taxes	41,510,127	28,077,707	9,636,862	1,277,736	176,373	267,769	211,602	375,703	13,620	676,208	380,383	422,065
29	TOTAL EXPENSES - Required	$ 280,475,243	$ 188,632,276	$ 60,994,351	$ 7,161,020	$ 1,095,397	$ 1,619,548	$ 1,290,192	$ 2,298,197	$ 123,682	$ 11,298,228	$ 2,463,926	$ 2,398,436
30	Rate Schedule Revenue as Proposed	$ 390,201,165	$ 265,396,615	$ 81,565,111	$ 13,729,592	$ 1,761,814	$ 3,240,609	$ 2,423,842	$ 4,467,760	$ 34,006	$ 8,193,691	$ 4,765,304	$ 4,622,811
31	Other Revenue	6,291,844	4,614,507	1,446,076	44,583	6,081	32,661	2,271	22,222	719	-	109,154	13,370
32	Revenue as Proposed	$ 396,492,799	$ 270,011,122	$ 83,011,187	$ 13,774,175	$ 1,767,895	$ 3,273,269	$ 2,426,113	$ 4,489,983	$ 34,725	$ 8,193,691	$ 4,874,458	$ 4,636,181
33	Proposed Revenue Increase	$ 56,740,506	$ 38,682,592	$ 16,176,326	$ 127	$ (29,966)	$ (302,266)	$ 399,694	$ 558,838	$ 5,074	$ 404,902	$ -	$ 843,183
34	Proposed Revenue - Revenue Requirement	$ 396,492,799	$ 270,011,122	$ 83,011,187	$ 13,774,175	$ 1,767,895	$ 3,273,269	$ 2,426,113	$ 4,489,983	$ 34,725	$ 8,193,691	$ 4,874,458	$ 4,636,181
35	Current Revenue to Cost Ratio	0.85	0.86	0.76	1.28	1.14	1.52	1.08	1.14	0.18	0.59	1.39	1.06
36	Parity Ratio	1.00	1.01	0.88	1.50	1.34	1.78	1.26	1.34	0.21	0.69	1.63	1.24

Exhibit ___ (DWS-6)

Puget Sound Energy
2007 Gas General Rate Case
Test Year Ended September 2007
Comparison of PSE and NWIGU Rates for 85, 87 & 57

Description	Units	PSE Present Rates	PSE Proposed Rates	NWIGU Proposed Rates	NWIGU Difference	PSE Difference	Design Difference
Schedule 85/85T							
Basic Charge - Sales	Bills	$500.00	$750.00	$500.00	$0	$95,750	($95,750)
Basic Charge - Transportation	Bills	$800.00	$1,050.00	$800.00	$0	$222,000	($222,000)
Demand Charge	Demand	$1.02	$1.50	$1.02	$0	$292,836	($292,836)
Sales Procurement Charge	Therms	$0.00650	$0.00500	$0.00650	($0)	($23,266)	$23,266
Trans Balancing Service Charge		$0.00070	$0.00000	0.00000	($33,211)	($33,211)	$0
Minimum Bills		$320,874	$320,874	$0	($320,874)	$0	($320,874)
Delivery Charge:							
First 25,000 Therms	Therms	$0.10000	$0.08111	$0.10449	$127,736	($537,400)	$665,135
Next 25,000 Therms	Therms	$0.05127	$0.05751	$0.06230	$187,766	$106,225	$81,541
All over 50,000 Therms	Therms	$0.04921	$0.04217	$0.05142	$38,637	($123,080)	$161,717
Calculated Total					$354,139	($554,255)	$908,394
Trans Gas Balancing Service Charge	Therms	$0.00070	$0.00070	$0.00070	$0	$0	$0
Total Revenues					$54	($146)	$200
Schedule 87/87T							
Basic Charge - Sales	Bills	$500.00	$750.00	$500.00	$0	$47,250	($47,250)
Basic Charge - Transportation	Bills	$800.00	$1,050.00	$800.00	$0	$33,000	($33,000)
Demand Charge	Demand	$1.02	$1.50	$1.02	$0	$343,438	($343,438)
Procurement Charge		$0.00500	$0.00500	$0.00500	$0	$0	$0
Trans Balancing Service Charge		$0.00070	$0.00000	$0.00	($70,285)	($70,285)	$0
Minimum Bills		????	????	$0.00	????	$0	????
Delivery Charge:							
First 25,000 Therms	Therms	$0.12483	$0.14883	$0.14033	$120,691	$186,877	($66,186)
Next 25,000 Therms	Therms	$0.07621	$0.09087	$0.08567	$71,550	$110,880	($39,330)
Next 50,000 Therms	Therms	$0.04921	$0.05867	$0.05532	$79,376	$122,897	($43,521)
Next 100,000 therms	Therms	$0.03226	$0.03846	$0.03627	$75,711	$117,059	($41,348)
Next 300,000 therms	Therms	$0.02376	$0.02833	$0.02671	$95,017	$147,197	($52,179)
All over 500,000 therms	Therms	$0.01876	$0.02237	$0.02109	$132,032	$204,564	($72,532)
Total Volume	Therms				$574,378	$889,474	($315,096)
Trans Gas Balancing Service Charge	Therms	$0.00070	$0.00070	$0.00070	$0	$0	$0
Total Revenues					$504,093	$1,242,877	($738,784)
Schedule 57							
Basic Charge	Bills	$800.00	$1,050.00	$800.00	$0	$66,500	($66,500)
Demand Charge	Demand	$1.02000	$1.50	$1.02	$0	$187,006	($187,006)
Delivery Charge:							
First 25,000 Therms	Therms	$0.12483	$0.14883	$0.14033	$93,381	$144,590	($51,209)
Next 25,000 Therms	Therms	$0.07621	$0.09087	$0.08567	$41,678	$64,587	($22,910)
Next 50,000 Therms	Therms	$0.04921	$0.05867	$0.05532	$35,672	$55,230	($19,558)
Next 100,000 Therms	Therms	$0.03226	$0.03846	$0.03627	$22,588	$34,924	($12,336)
Next 300,000 Therms	Therms	$0.02376	$0.02833	$0.02671	$11,317	$17,532	($6,215)
All over 500,000 Therms	Therms	$0.01876	$0.02237	$0.02109	$5,193	$8,046	($2,853)
Total Volume	Therms				$209,829	$324,910	($115,081)
Balancing Service Charge	Therms	$0.00070	$0.00000	0.00000	($19,577)	($19,577)	$0
Calculated Total					$190,253	$305,333	($115,081)
Gas Balancing Service Charge	Therms	$0.00070	$0.00070	$0.00070	$0	$0	$0
Total Revenues					$190,253	$558,839	($368,586)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing document upon all parties of record (listed below) in these proceeding by mailing a copy via electronic mail and/or properly addressed with first class postage prepaid.

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Dated in Portland, Oregon this 30th day of May, 2008.

Edward A Finklea

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