**BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PUGET SOUND ENERGY, INC., Respondent.	**DOCKET NO. UG-040640** **DOCKET NO. UE-040641** *(consolidated)*
In the Matter of the Petition of PUGET SOUND ENERGY, INC. For an Order Regarding the Accounting Treatment for Certain Costs of the Company's Power Cost Only Rate Filing.	**DOCKET NO. UE-031471** *(consolidated)*
In the Matter of the Petition of PUGET SOUND ENERGY, INC. For an Accounting Order Authorizing Deferral and Recovery of the Investment and Costs Related to the White River Hydroelectric Project.	**DOCKET NO. UE-032043** *(consolidated)*

**DIRECT TESTIMONY OF
DONALD W. SCHOENBECK
ON BEHALF OF
THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES**

REDACTED VERSION

September 23, 2004

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 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 ("FERC"). I have appeared before the Washington Utilities and Transportation Commission ("WUTC" or the "Commission") at least 20 times since 1982. A further description of my educational background and work experience is summarized in Exhibit No. ___ (DWS-2).

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

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Puget Sound Energy (the "Company" or "PSE").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses certain aspects of the proposed $82.3 million increase in electric rates that the Company is seeking in this Docket along with rate spread and rate design matters. With regard to revenue requirement matters, it is important to note that we have performed a detailed review of only a few select cost items. Accordingly, my testimony does not address numerous other revenue requirement matters of concern raised by the Company's filing. This silence should not be construed as acceptance by ICNU of the Company's proposals on all these other items.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. The Company's filing proposes another substantial increase in rate schedule charges on the heels of the recently completed Power Cost Only Rate Case ("PCORC") in Docket No. UE-031725. Significantly, about one-half of the proposed increase in this Docket is attributable to fuel and purchase power costs. The remaining $43 million is associated with proposed increases in all other areas, including about $15 million related to cost of capital.

The limited adjustments proposed by ICNU in this testimony reduce the Company's electric request by $34.2 million and, coincidently, the gas request by $0.4 million. Roughly $30.6 million of the ICNU adjustments are attributable to matters related to projecting the appropriate level of base power costs for the rate period (March 2005 to February 2006) given the fact that the Company has a power cost adjustment mechanism ("PCA"). My recommendations are based on using normalized results of operations to set the baseline power cost value. This is totally different from PSE's approach, which looked at the costs the Company could incur during the March 2005 through February 2006 time period. The specific adjustments I address related to base power costs include: 1) the water years for determining hydro availability ($10.4 million reduction); 2) the test period wheeling expense; 3) the gas price used by PSE's AURORA model (roughly a $13.3 million reduction); and 4) the cost for peaking capacity ($6.9 million reduction). The non-power cost adjustments I address relate to services provided by outside consultants and attorneys. On these issues, I recommend reductions of $3.6 million that are electric-related and $0.4 million related to gas activities.

Finally, the testimony addresses cost-of-service, rate spread, and industrial rate design matters. Regarding cost-of-service, ICNU recommends modifying the peak credit classification calculation performed by the Company to correct for the omission of property taxes from the cost of the peaking resource, adopting a more appropriate cost of fuel for the peaking resource, and using the entire cost of the peaking resource to reflect the value of capacity. The Company's cost-of-service testimony also addresses the use of the average of the 200 highest hours for deriving the peak demand allocation factor. This is inappropriate as it shifts cost responsibility away from the class that causes the costs to be incurred. ICNU recommends the peak demand allocation factor be derived by averaging the hourly peaks that are within 90% of the highest peak hour. For spreading any revenue increase resulting from this proceeding, ICNU supports the Company proposal of moving one-half of the way towards parity along with an appropriate ceiling limit. However, this movement should be based upon the ICNU cost study. A comparison of the rate spread proposed by the Company with ICNU's recommendation is presented in the following table.

Rate Spread Comparison - $000

	Company Proposal		ICNU Recommendation		Difference
	Amount	**Percent**	**Amount**	**Percent**	**Amount**
Residential	$56,601	7.3%	$66,142	8.6%	$9,541
Secondary:					
Schedule 24	$6,636	3.8%	$1,534	0.9%	-$5,102
Schedule 25	$5,865	2.9%	$5,865	2.9%	$0
Schedule 26	$2,464	2.0%	-$1,104	-0.9%	-$3,568
Schedule 29	$26	2.9%	$26	2.9%	$0
Secondary Total	$14,991		$6,321		-$8,670
Primary					
Schedule 31	$5,589	5.7%	$5,590	5.7%	$1
Schedule 35	$12	5.7%	$8	3.8%	-$4
Schedule 43	$1,038	8.6%	$1,038	8.6%	$0
Primary Total	$6,639		$6,636		-$3
Retail Wheeling	$183	2.9%	$183	2.9%	$0
High Voltage					
Schedule 46	$249	11.1%	$106	4.7%	-$143
Schedule 49	$1,677	8.3%	$952	4.7%	-$725
High Voltage Total	$1,926	8.6%	$1,058	4.7%	-$868
Lighting	$1,107	8.6%	$1,107	8.6%	$0
Firm Resale	$154	8.6%	$154	8.6%	$0
Total Sales	$81,601	5.7%	$81,601	5.7%	$0

The ICNU High Voltage industrial rate design recommendation is to apply the same percentage increase to Schedules 46 and 49 as shown by the above table. Similarly, the ICNU retail wheeling recommendation is to apply the same percentage increase for both primary voltage and high voltage retail wheeling customers. Finally, ICNU recommends instituting a new rate schedule for those customers with loads comprising a significant portion of a distribution feeder. Designated as Schedule 40, this cost-based tariff has been discussed and formulated during meetings between the Company and ICNU.

II. <u>BACKGROUND AND SUMMARY OF PSE'S REQUEST</u>

Q. PLEASE EXPLAIN THE BASIS FOR THE COMPANY'S APPLICATION.

A. The Company filed its application on April 5, 2004, prior to receiving an order from the Commission in the PCORC. For electric rates, the Company's original request was for $81.4 million. On June 2, 2004, the Company supplemented its filing to comply with the PCORC decision issued on May 13, 2004. The revised request seeks to increase electric rates by $82.3 million, or 5.8%. While the Company is seeking to recover alleged cost increases in many accounts, a significant portion of the rate increase is attributable to increases in production costs, including fuel and purchase power expense. To illustrate this fact, consider that the Company's original baseline power rate pursuant to Exhibit A-1 of the PCA is $43.953/MWh. The Company's filing is seeking to increase this base power rate to $48.481/MWh, generating additional revenue of about $91.6 million a year since the PCA was instituted. The recent PCORC decision increased revenue by about $44.1 million. <u>Re PSE</u>, WUTC Docket No. UE-031725, Order No. 14 at 4 (May 13, 2004). Thus, the increase in production-related costs in this proceeding is about $47.5 million, a substantial sum.

Q. WILL MOST OF THESE PRODUCTION-RELATED COSTS BE RECOVERED THROUGH THE PCA MECHANISM EVEN WITHOUT THIS RATE CASE?

A. Yes. The PCA would allow for the flow through of all production-related cost increases except the proposed increase in cost of capital. The production-related revenue associated with the proposed change in cost of capital is about $7.2 million. Hence the remaining $40 million would be eligible for recovery through the PCA.

The PCA Stipulation sets forth the manner in which annual deviations in actual power costs from a base power cost level would be shared between the Company and its customers. The PCA mechanism has four bands, or levels, for power cost deviations with a corresponding sharing percentage for annual adjustments. For the first $20 million deviation (either plus or minus), the Company absorbs 100% of the cost or benefit. The second band is for deviations of $20 to $40 million. These amounts are shared equally between the Company and its customers (50%-50%). The third band is for deviations from $40 to $120 million with the Company being responsible for 10% and customers for the remaining 90%. Finally, the fourth band is for deviations in excess of $120 million. In these cases, the Company is responsible for 5% and customers are responsible for the remaining 95%.

More critical to this proceeding, the PCA also contains a cumulative sharing mechanism for the initial period of July 1, 2002, through June 30, 2006. During this term, the customers are responsible for 99% of any deviation should the Company's share of the power costs exceed $40 million. If the Company has reached this cumulative value, 99% of the proposed increases in power costs would be recovered from the Company's ratepayers subsequent to June 30, 2006.

Q. ARE THERE OTHER MAJOR ISSUES RELATED TO THE COMPANY'S FILING?

A. Yes, there are many issues that are of concern to ICNU and, I am sure, to the other parties with regard to the Company's filing. In addition to the power costs sought by the Company, another significant issue is the cost-of-capital level. While ICNU will not address this topic, I note that the 11.75% return on common equity along with a 45% equity capitalization ratio inflates the increase sought by the Company by about $15 million over the current authorized level for these two metrics. ICNU does not have the resources to cover all issues in this docket; therefore, we will review and potentially adopt adjustments proposed by other parties.

III. ICNU POWER COST RECOMMENDATIONS

Q. HAVE YOU ANALYZED THE ADJUSTMENTS PSE IS PROPOSING TO ITS POWER COSTS?

A. Yes.

Q. WHAT SHOULD BE THE STANDARD OF REVIEW TO TEST THE REASONABLENESS OF PSE'S PROPOSED ADJUSTMENTS?

A. Since, as part of this general rate case, we are re-establishing the base power cost to be reflected in rates and used to measure deviations from actual costs in the PCA, the only acceptable standard should be a normalized cost level. This means that the cost to be utilized in determining the base level is not necessarily the expected cost for the rate period that the Company will or may incur. Instead, the costs used should be based on normalized costs.

I illustrated this critical point by the following example in the PCORC proceeding. Assume PSE has the ability to know precisely the production-related costs it will incur for the rate year (March 2005 through February 2006) in each and every account. This includes knowing that all Colstrip units will be out of service for 6 months, that the Pacific Northwest will experience its lowest historic hydro conditions, that unreasonably high gas costs will occur, and that short-term power market prices would exceed all historical highs to date. Establishing a base power cost using this precise knowledge of extraordinary conditions would be inequitable to ratepayers because it would essentially eliminate the PCA risk sharing bands in favor of the Company. In other words, with a base power cost that assumes these extreme circumstances, there would be no sharing of adverse market events between the Company and ratepayers through the PCA. Ratepayers would be responsible for 100% of the costs through the base rate charges. Moreover, should subsequent years return to normal conditions, the Company would receive an inappropriate windfall from having actual power costs below the base level used to establish rates. This example illustrates why it is paramount that the base power costs in this proceeding be determined using a "normalized" cost standard and not a "next year," or adverse, cost standard.

Q. HAS PSE EMPLOYED A NORMALIZED STANDARD IN DERIVING THE PROPOSED BASE POWER COST IN THIS PROCEEDING?

A. In some cases, PSE has utilized a normalized standard. For example, PSE has replaced the actual test period short-term purchase and sales amounts with values produced from an AURORA production simulation run. Similarly, the Company used hydro data for 60 hydro years to calculate expected hydro generation instead of selecting one particular year. While there are aspects of this analysis we do not agree with—including the use of 60 water years—it illustrates the proper procedure for determining normalized power costs for the test period. In other instances, however, PSE has failed to use normalized data. These latter instances include the selection of water years, the gas price forecast used as an input to the AURORA model run, and the call option expense and wheeling costs that PSE is proposing to recover. I propose adjustments related to these issues based, in part, on PSE's failure to harmonize the effects of these issues on power costs and the PCA.

A. SELECTION OF WATER YEARS

Q. PLEASE DESCRIBE PSE'S PROPOSAL WITH REGARD TO THE HYDRO GENERATION.

A. PSE has set many of its power costs based on calculations performed by the AURORA model that produces a portfolio cost of power from PSE's owned and contracted resources. In performing the AURORA modeling, PSE used 60 historical water years, 1929 through 1988, and averaged the results.

The use of the 60 historical water years is a change from prior practices, when PSE used the average of 40 historical water years. PSE's new methodology is untested and unproven as to whether it produces better results. What is known is that it produces higher costs of about $9.9 million ($10.4 million in revenue) than if the Company had used the latest 40 year period of available hydro inputs.

PSE's new methodology is also inconsistent with the current Commission standard. WUTC v. Avista, WUTC Docket Nos. UE-991606, UG-991607, Third Suppl. Order at 43 (Sept. 29, 2000); WUTC v. PSE, WUTC Docket Nos. UE-920433, Eleventh Suppl. Order at 41-43 (Sept. 21, 1993). As I have stated before, the effect of actual hydro conditions on PSE's costs will be taken into account in the PCA, so PSE is made whole whether or not the 60 hydro year average is used. Therefore, it is not necessarily a question of which method best describes expected hydro conditions, but which is the best policy implementation at this time to determine the level of base rates.

ICNU proposes that PSE use the latest 40 years of hydro data in the development of their base rates until the Commission determines that a different standard should be used and applied for all three investor-owned utilities in the state.

B. WHEELING EXPENSE

Q. HOW HAS PSE PROJECTED THE EXPECTED WHEELING EXPENSE?

A. It appears that PSE increased its wheeling expense based on expectations of a rate increase by the Bonneville Power Administration ("BPA") beginning October 2006. They applied a [redacted] increase to the current BPA rate. This increase is based on the expected increase that BPA has discussed.

At the time of this testimony, many of BPA's transmission customers are negotiating with BPA in an attempt to settle the transmission rate case. The customers have advocated an increase significantly less than PSE's assumed level.

Q. WHAT IS YOUR RECOMMENDATION FOR PROJECTING THE TEST PERIOD WHEELING EXPENSE?

A. The state of the potential settlement should be known when the Commission produces its final order on PSE's application. ICNU proposes that, should a settlement with BPA be reached before the Commission's final order, the amount of the settled rate increase be substituted for the assumed transmission rate increase in calculating PSE's wheeling expense.

C. GAS PRICE FORECAST AND GAS PROCUREMENT

Q. HOW HAS PSE DETERMINED THE GAS PRICE FORECAST FOR THE RATE YEAR?

A. PSE used the average NYMEX future prices published during the period of December 22, 2003, through January 8, 2004. This period contained ten days of published monthly prices for the rate year. See Exhibit No. ___ (DWS-3C) at 1. The NYMEX monthly average was $4.94/MMBTU for the rate year. PSE then adjusted these values to take into account or recognize market price differentials. To illustrate this step, for the Sumas market hub, PSE adjusted the monthly NYMEX prices downward by an average of [redacted] in recognition of the fact that gas procured at Sumas has traditionally been far below Henry Hub (the NYMEX pricing point). Thus, for Sumas, PSE's average price was [redacted] for the rate year. Id. at 2.

Q. HOW DO THE GAS PRICES PROPOSED BY PSE IN THIS PROCEEDING COMPARE WITH THE VALUES FROM PSE'S PCORC?

A. The following table compares the values from the PCORC to the proposed rate year for the Sumas market hub. On average, the Company's projection is only [redacted]

PSE Sumas Gas Price Comparison
($/MMBTU)

	[redacted]		[redacted]
Apr-04	[redacted]	Mar-05	[redacted]
May-04	[redacted]	Apr-05	[redacted]
Jun-04	[redacted]	May-05	[redacted]
Jul-04	[redacted]	Jun-05	[redacted]
Aug-04	[redacted]	Jul-05	[redacted]
Sep-04	[redacted]	Aug-05	[redacted]
Oct-04	[redacted]	Sep-05	[redacted]
Nov-04	[redacted]	Oct-05	[redacted]
Dec-04	[redacted]	Nov-05	[redacted]
Jan-05	[redacted]	Dec-05	[redacted]
Feb-05	[redacted]	Jan-06	[redacted]
Mar-05	[redacted]	Feb-06	[redacted]
Avg	[redacted]	Avg	[redacted]

Q. DO YOU HAVE ANY CONCERNS WITH THE COMPANY'S METHOD FOR PROJECTING THE GAS PRICES FOR THE RATE YEAR?

A. Yes. As I stated in the PCORC proceeding, I continue to have three significant concerns with the Company's pricing approach and gas procurement strategy: 1) the NYMEX contract volumes do not reflect a robust market for the rate period thereby making the prices highly suspect and uncertain; 2) NYMEX prices take into account near-term circumstances and therefore are not representative of a base year or normalized gas price that is needed for determining a reasonable baseline power cost value; and 3) the Company is continuing to rely upon short-term purchases of gas supply for its power portfolio.

Q. PLEASE ELABORATE ON YOUR CONCERN REGARDING THE ROBUSTNESS OF THE NYMEX PRICES.

A. The following table summarizes the daily NYMEX contracts traded for delivery in the period of February 2004 through February 2006 (the end of the rate year), during the ten days used by PSE to derive its average NYMEX price.

NYMEX Contract Volumes For
December 22, 2003 – January 8, 2004

Month	Volume	Percent
January ’04	372,269	28.1%
February	284,394	21.5%
March	149,743	11.3%
April	97,905	7.4%
May	72,338	5.5%
June	55,495	4.2%
July	48,476	3.7%
August	42,603	3.2%
September	36,912	2.8%
October	32,100	2.4%
November	25,390	1.9%
December	23,305	1.8%
January ’05	18,488	1.4%
February	12,971	1.0%
March	10,888	0.8%
April	8,900	0.7%
May	7,759	0.6%
June	6,657	0.5%
July	5,410	0.4%
August	3,658	0.3%
September	2,614	0.2%
October	2,276	0.2%
November	2,129	0.2%
December	1,811	0.1%
January ’06	1,238	0.1%
February	65	0.0%
Outside Rate Period:	1,272,389	96.0%
Rate Period:	53,405	4.0%

As is always the case, the vast majority of the reported NYMEX activity is for the next month or quarter. Indeed, for this trading period, the January 2004 volume is 28% of the total activity and the first three months encompass 61% of the reported activity. Focusing on the rate period in this proceeding (March 2005 - February 2006), the contract volumes represent only 4% of the activity, with most of this occurring during the first quarter of the rate year (March 2005 through May 2005). In other words, 96% of the trades during these days were transactions for months outside the rate period. In fact, the trading activity for each of the last 8 months of the rate period is so minimal that it rounds to a 0% value. In my opinion, this is not a meaningful or liquid market—and therefore not a meaningful price—on which to base this critical cost item.

Q. HOW DO THE RATE PERIOD VOLUMES COMPARE TO THOSE OF THE PCORC PROCEEDING?

A. The following table compares the contracts for the two forecast periods. As can be seen from the table, the volumes in this rate case are similar to those from the PCORC proceeding. In my view, this limited market simply does not give any confidence in the resulting value—a value critical to determining base power costs for calculating the revenue requirement in this proceeding.

NYMEX Contract Volumes Comparison
By Rate Period Month

Month	PCORC	GRC
First	12,300	10,888
Second	6,397	8,900
Third	3,632	7,759
Fourth	2,869	6,657
Fifth	2,921	5,410
Sixth	2,545	3,658
Seventh	2,444	2,614
Eighth	1,256	2,276
Ninth	1,709	2,129
Tenth	1,001	1,811
Eleventh	1,516	1,238
Twelfth	2,753	65
Rate Period:	41,343	53,405

Q. PLEASE EXPLAIN YOUR CONCERNS WITH NYMEX PRICES NOT REFLECTING A NORMALIZED BASE RATE PERIOD VALUE.

A. NYMEX prices will respond or move based upon current events or news far beyond the period that one might logically believe is impacted. Consequently, it is not unusual to see an upward or downward tick in prices for each of the 36 months being reported due to a near-term event. While these movements may be appropriate indicators for the general direction of gas costs, the resulting prices are not appropriate for this proceeding, in which a normalized base gas price is needed instead of a near-term or "next year" price.

Further, there appears to be a growing amount of NYMEX speculative trading as compared to NYMEX hedge trading, which may be having an impact on reported prices. By this I mean that some parties simply are entering into transactions based on their bet on the direction of a price movement instead of entering into transactions to reduce the risk or exposure one has with a particular commodity. If this is the case, this would be another reason why a NYMEX-based price series would not be appropriate for determining the base gas prices in this proceeding.

Q. DOES THE COMPANY EVALUATE ITS RISK EXPOSURE AND DEVELOP HEDGING STRATGIES USING A SINGLE NYMEX-BASED PRICE SERIES?

A. No. As I noted in the PCORC proceeding, PSE evaluates its portfolio risk using an analytical approach that is far more rigorous than simply using a series of NYMEX forward prices. Re PSE, WUTC Docket No. UE-031725, Exh. No. 231HC (Schoenbeck Response Testimony) at 15-16 (Jan. 30, 2004). This more sophisticated analysis is what I believe is needed to determine a more appropriate baseline gas price for the PCA.

Q. PLEASE EXPLAIN YOUR CONCERN WITH PSE'S PROCUREMENT OF GAS SUPPLY FOR ITS POWER PORTFOLIO.

A. At the time the Company made its filing in this case, it had yet to procure any gas supply for its gas-fired facilities other than the long-term gas supply it had procured for Encogen some time ago. Exhibit No. __ (DWS-4C) at 1-4. As discussed during the PCORC proceeding with regard to Tenaska, the Company procurement strategy has relied upon short-term (less than one year) gas transactions for its power portfolio. This is not a reasonable risk mitigation approach. Attached as Exhibit No. __ (DWS-5C) and Exhibit No. __ (DWS-6) are the Company responses to Staff data request Nos. 173 and 220. Both of these responses discuss the implementation of a strategy that acquires forward supply in a reasoned incremental manner. Attachment A to data response No. 173 depicts the substantial risk exposure from having an unhedged position. However, the primary focus of both of these documents is for less than a year. Given the significant amount of gas-fired generation the Company owns and controls, a longer-term approach is needed for managing its gas-related power portfolio.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE GAS PRICE USED TO DETERMINE THE BASE POWER COST IN THIS PROCEEDING?

A. Yes. The gas price approved by the Commission in this proceeding will likely not change until sometime after July 1, 2006. Accordingly, the value selected by the Commission in this proceeding will have little effect on the Company since the $40 million PCA shareholder cap will likely have been reached well before this date. When the cap is reached, 99% of any subsequent deviations are borne by the ratepayers. Therefore, a gas price of $3.50/MMBTU versus $5.50/MMBTU will have a relatively modest impact on the Company—less than a $2.0 million impact on shareholders prior to

July 1, 2006. However, when the cap expires on July 1, 2006, the gas price will be very significant because deviations around the base power cost will be shared more symmetrically between ratepayers and shareholders. Since the base power rate established in this proceeding is likely to be in place beyond July 1, 2006, the examination of the appropriate gas price to employ in calculating the base power cost in this proceeding should focus on the period beyond July 1, 2006.

In the PCORC proceeding, I recommended that the results of a fundamentals analysis such as the one that PSE has employed in deriving the electricity price forecast and similar to the one in PSE's Risk Management Committee ("RMC") presentations should be used. I continue to believe this type of analysis, which incorporates basic supply and demand factors while ignoring most of the short-term market fluctuations or swings, is appropriate for a baseline gas value.

Q. WHAT IS YOUR RECOMMENDATION FOR A GAS PRICE IN THIS PROCEEDING?

A. In modeling its power costs in January, the Company assumed the following gas prices at the Sumas market hub for 2005 through 2008:

PSE Aurora Gas Prices
Sumas Market Hub
($/MMBTU)

Year	Gas Price
2005	[redacted]
2006	[redacted]
2007	[redacted]
2008	[redacted]
2006 to 2008 Average	[redacted]

Further, in reporting the impact of the Commission's decision regarding the Tenaska disallowance to the Securities and Exchange Commission ("SEC") in its Form 8-k filing, dated August 5, 2004, the Company employed the following gas prices:

PSE SEC 8-K Gas Prices
Sumas Market Hub
($/MMBTU)

Year	Gas Price
2005	[redacted]
2006	
2007	
2008	
2009	
2010	
2011	
2006 to 2011 Average	

Both of these prices series—advanced by the Company—reflect years when the gas price is in the [redacted] range, which I advanced as a reasonable level in the recently completed PCORC proceeding. I continue to believe a price around this level is what is required for a balanced PCA mechanism. However, in partial recognition of the current level of gas costs, I recommend a gas price that averages [redacted] at the Sumas Market Hub be used for determining the base power cost in this proceeding. I arrived at this level from consideration of the price used by PSE in the SEC filing for 2006-2011, and by considering the average of the two price series presented above for the nearer term period of 2006-2008. This recommendation is intended, in part, to remove the controversy over using a third party provider. If PSE believes these to be the expected values, they can be used now as the baseline power cost target value. ICNU recommends this value be used in the final AURORA model run employed to determine the revenue increase as directed by the Commission. A rough calculation indicates that adoption of this gas value will reduce the gas-related expenses by about $12.7 million, translating into a revenue requirement reduction of $13.3 million.

D. PEAKING COST - CALL OPTIONS

Q. PLEASE EXPLAIN THE PEAKING COST PSE IS PROPOSING TO INCLUDE IN ITS BASE RATE DETERMINATION.

A. PSE has included $5.5 million in its filing designed to address the risk of extreme temperature variations from November 2005 to February 2006. This is shown in Exhibit No. ___ (JWR-11), which contains a listing by FERC account and resource (or contract) of the power costs that PSE is proposing to recover in the three columns under the 2004 GRC label. Towards the bottom of this exhibit, there is an account 555 row (line number 43) simply entitled "Capacity," for which PSE has included $5,512,000 in its filing. This amount is composed of two types of transactions. It reflects a cost of [redacted] associated with a series of transmission exchange agreements and [redacted] in option costs (really an upfront reservation charge) that PSE is proposing to include in its base rate determination. This option call cost figure is an excessive amount for these peaking options given both the actual risk of extreme weather events that PSE faces and the long history of PSE including a high value in a rate filing—such as is in the instant filing—and then never procuring this amount of capacity.

Q. HOW HAS PSE CALCULATED THE PRICE OF THESE PEAKING OPTIONS?

A. Exhibit No. ___ (DWS-7C) presents the assumptions and calculations employed by PSE to arrive at the proposed option cost. Line 65 indicates that PSE expects to have a remaining unfilled capacity of 1,867 MW-months based upon the following extreme temperatures: November: 19 degrees, December: 12 degrees, January: 14 degrees, and

February: 17 degrees. These temperatures are far colder than the 23 degrees expected peak hour temperature value. Lines 71 through 79 show the prices assumed by PSE for obtaining call options for the remaining unfilled extreme peak need along with the associated megawatts on lines 82 through 90. It is important to emphasize that PSE has not executed any of these options for the rate period. PSE has assumed it can obtain the megawatts each month from the designated suppliers and then fill any remaining need at the price shown on line 71. PSE valued the remaining unfilled need at an equivalent price of [redacted] higher than the assumed price of the first 100 MW.

Q. WHAT WAS THE BASIS FOR PSE'S ASSUMED PRICES FOR THE UNFILLED NEED?

A. The prices used for the unfilled extreme need were derived from an informal solicitation process summarized in PSE's response to ICNU data request No. 3.13, which is included as Exhibit No. ___ (DWS-8C).

Q. DOES PSE HAVE ADEQUATE WINTER PEAKING RESOURCES UNDER NORMAL WEATHER CONDITIONS FOR THE RATE YEAR?

A. Under normal expected peak weather conditions, taking into account all available capacity, PSE has sufficient capacity for all four winter months.

Q. HOW DID YOU MAKE YOUR DETERMINATION?

A. The following table compares the extreme and expected peak values for PSE.

PSE Peak Comparison
(MWs)

Month	Extreme Peak	Expected Peak	Difference in Need	Available Capacity
November	[redacted]	[redacted]	[redacted]	[redacted]
December	[redacted]	[redacted]	[redacted]	[redacted]
January	[redacted]	[redacted]	[redacted]	[redacted]
February	[redacted]	[redacted]	[redacted]	[redacted]

Using expected peak weather (50-50 chance of occurrence), PSE has adequate capacity in all but the month of [redacted] However, there appears to be a mismatch in the temperatures used in determining the peak load and the available resource capacity. In other words, while PSE has projected a peak demand based upon extreme weather conditions, the assumed availability of the resources does not account for such conditions. To illustrate, consider the month of January 2006. PSE's peak load is based upon the extreme temperature of 14 degrees. The following table presents the capacity rating of PSE's combustion turbines at a temperature of 15 degrees versus the values used by the Company, which appear to be based upon a temperature well above this value.

PSE CT Capacity
(MWs)

Resource	PSE Value	Capacity @ 15.5
Whitehorn 2&3	[redacted]	[redacted]
Frederickson ½	[redacted]	[redacted]
Fredonia ½	[redacted]	[redacted]
Fredonia ¾	[redacted]	[redacted]
Total	[redacted]	[redacted]

Using a consistent temperature for both the available resources and loads will increase the available capacity for meeting the peak load.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO INCLUDE [redacted] OF PEAKING OPTIONS IN THE BASE POWER RATE?

A. No. As I noted in my PCORC testimony, the effective price of the option energy is far too expensive to be cost effective. The Company's past procurement of options has not come close to the level included in the current charges. Furthermore, the Company appears to be pursuing other hedging strategies that do not require the substantial reservation charges included in the peaking options. Finally, the institution of the PCA should handle the very limited risk that the peaking options are intended to address instead of including this cost in the base power charge. Using expected peaks, which are based upon a 50-50 change of occurrence, is more consistent for determining a base power cost for PCA purposes than using extreme peaks, which have a very low probability of occurring.

Q. WHAT IS THE EFFECTIVE COST OF THE ENERGY OBTAINED UNDER THESE OPTIONS?

A. The effective cost will be dependent upon the amount of energy that actually is procured under the option agreements, which in turn is dependent upon the weather that will be experienced during the upcoming winter season. The agreements typically are structured with a reservation charge that is paid up front, which accounts for PSE's proposed [redacted] expense in this proceeding, and then a strike price when the energy actually is needed. Based upon the solicitation results, the strike price is generally around [redacted] Another significant feature is that PSE must give daily notice and take the block of power at a flat delivery rate for the entire 16-hour peak period. The amount of options that PSE currently is proposing to include in rates would allow the procurement of [redacted] of on-peak power during the four winter months. This is a substantial sum.

Q. DOES PSE HAVE A NEED FOR THIS AMOUNT OF ON-PEAK ENERGY?

A. No. To need this amount of energy, each and every day of the winter season would have to be substantially colder than normal. By way of comparison, for the cold snap that occurred from December 1, 2003, to January 21, 2004, there were only five days that equaled or exceeded 10 heating degree days ("HDD") colder than normal, as measured at Sea-Tac. For the entire period, the aggregate HDDs were actually 14 less (or warmer) than normal.

In Olympia, this extreme cold snap included two days where the lowest hourly temperature was actually below the 12 degree extreme temperature used by PSE for December. The extreme weather in Olympia from January 3, 2004, through January 6, 2004, was 57 HDD above normal. If this extreme weather had occurred throughout PSE's service territory, the Company would have needed only an additional [redacted]. This is only [redacted] of the energy amount that PSE could acquire under the options that the Company proposes to include in rates in this proceeding.

The following table depicts the effective cost of power under the proposed options at various levels of need.

Effective Cost of PSE's Option Energy

MWh Need	Reservation Charge ($/MWh)	Strike Price ($/MWh)	Effective Cost ($/MWh)
10,000	[redacted]	[redacted]	[redacted]
20,000	[redacted]	[redacted]	[redacted]
30,000	[redacted]	[redacted]	[redacted]
40,000	[redacted]	[redacted]	[redacted]
50,000	[redacted]	[redacted]	[redacted]
60,000	[redacted]	[redacted]	[redacted]
70,000	[redacted]	[redacted]	[redacted]
80,000	[redacted]	[redacted]	[redacted]
90,000	[redacted]	[redacted]	[redacted]
100,000	[redacted]	[redacted]	[redacted]

Based upon the example of [redacted] of need due to extreme weather conditions, the effective cost under the proposed option strategy would be [redacted]. During the January cold snap, the Mid-Columbia daily prices were only around $50-60/MWh. This table shows that, for the very limited, short, low temperature excursions experienced in the Pacific Northwest, having a substantial amount of daily call options is not cost effective.

Q. HAS PSE PERFORMED AN ANALYSIS ON THE COST EFFECTIVENESS OF DAILY CALL OPTIONS THAT PRODUCED SIMILAR RESULTS?

A. Yes. Exhibit No. ___ (DWS-9C) contains a presentation to the RMC on May 1, 2003, regarding the need to acquire additional options for the 2003 winter. The analysis was done using the Company's risk assessment software (KW3000) using 100 scenarios. The minutes from that meeting contain the following recommendation:

[redacted]

Exhibit No. ___ (DWS-10C) at 2.

Q. DOES IT APPEAR THAT THE COMPANY HAS FOLLOWED THROUGH WITH THIS RECOMMENDATION?

A. Yes. Since the recommendation was made to the RMC, PSE has only procured very limited daily options, and the Company has focused on exchange power arrangements to achieve winter reliability needs. As noted previously in this testimony, the Company has been very successful in obtaining peak exchanges. Conversely, the Company has continued its "track record" of acquiring only limited amounts of call options. The last general rate case stipulation adopted $11.2 million of reservation costs for option purchases in 2002. However, the Company only expended [redacted] for the winter of 2003/2004, and all of this cost was incurred prior to the RMC meeting. For the winter of 2002/2003, the Company only expended [redacted].

Q. WHAT AMOUNT OF MONEY DO YOU RECOMMEND THE COMMISSION INCLUDE FOR TEMPERATURE-RELATED HEDGING COST IN THE BASE POWER RATE?

A. No costs associated with call options should be included because they are not needed under "normal" or expected peak weather conditions.

Q. PLEASE EXPLAIN THE COST OF THE PEAK EXCHANGES PSE IS PROPOSING TO INCLUDE IN ITS COST ESTIMATE.

A. These costs are related to peak transmission exchanges. These exchanges provide important system benefits. First, the exchanges allow for the deliverability of the needed power to PSE's service territory. Second, the exchanges allow for savings in serving the load due to a reduction in the cost of system losses. This latter point is explained in a confidential document entitled "Backward Looking Assessment of winter 2003-2004" provided as part of PSE's response to ICNU data request No. 3.16. The document is attached as Exhibit No. __ (DWS-11C). As noted in this document, the net cost of the exchanges was [redacted]—the value the Company is seeking to include in its base rate determination. Exhibit No. __ (DWS-11C) at 4. However, the Company is not proposing to include the savings associated with the reduced losses that occur under these arrangements. This value is [redacted]. Id. Accordingly, the net "cost" of these arrangements is in fact a savings of [redacted]. Id. ICNU recommends these savings be taken into account in determining the base power cost in this proceeding. As compared to the PSE cost of $5.5 million, ICNU recommends a net savings of $1.1 million be used in calculating the power cost in this case. This is a cost difference of $6.6 million, which reduces the Company's revenue increase by $6.9 million.

E. OUTSIDE SERVICES EXPENSES

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF PSE'S OUTSIDE SERVICES EXPENSES.

A. PSE has included about $8.1 million in outside services in electric operations for such items as accountants, consultants, attorneys, engineers, security, software, and public relations. In reviewing PSE's historical basis for determining the amount they propose to recover in rates, two things stood out. First, PSE has included about [redacted] in consulting expenses from Navigant Consulting. In addition, PSE has included about $6.1 million for regulatory expenses related to the PCORC proceeding ($1.3 million) and this electric and gas rate case filing ($4.8 million).

Q. PLEASE DESCRIBE THE NAVIGANT CONSULTING EXPENSES AND YOUR PROPOSED TREATMENT OF THESE EXPENSES.

A. An examination of prior years showed that there were no Navigant expenses in 2001, and in 2002 the expenses were about [redacted]. Exhibit No. __ (DWS-12C) at 4, 10. The [redacted] from 2003 that PSE proposes to include in rates appears excessive when compared to the other years. See id. at 15. However, this time period was when PSE was actively developing a resource acquisition program and complementary evaluation tools that resulted in the acquisition of Frederickson.

Normally, utilities will capitalize expenses that are directly related to the acquisition of a resource together with other costs of the acquisition. This allows the costs of the acquisition to be recovered over the life of the resource. Instead, PSE proposes to recover the cost of this outside consulting for their acquisition in one year.

Recognizing that PSE has ongoing expenses related to the resource acquisition program, ICNU proposes that a portion of the Navigant Consulting expenses be allowed to cover those ongoing expenses. However, the bulk of the expenses appear to be related to a one-time event and were capitalized as part of the resource acquisition program. As a result, ICNU's proposal is to reduce the amount to $300,000 to reflect the ongoing nature of the resource acquisition program. This is a $2.6 million expense reduction or $2.7 million in revenue requirement.

Q. WHAT COST IS PSE SEEKING TO RECOVER FOR OUTSIDE SERVICES FOR REGULATORY EXPENSES IN THIS PROCEEDING?

A. In the current filings, PSE is seeking about $4.8 million in rate case-related outside services for this rate case alone. It is comprised mostly of legal expenses and expert consulting services. In addition to this amount, PSE has included $1.3 million for expenses related to the PCORC. However, since the original filing, this figure has been updated to almost $1.8 million. Exhibit No. __ (DWS-13C) at 3. Accordingly, PSE is likely to spend $6.6 million for outside services just for the past proceeding and the current docket. While PSE may have legitimate needs to procure these outside services, the amount that PSE is proposing to recover is far outstripping the ability of intervenors and ratepayer advocates to keep pace with a corresponding level of effort.

Q. WHY IS PSE'S PROPOSAL TO RECOVER OUTSIDE RATE CASE EXPENSES LIMITING THE ABILITIES OF RATEPAYERS AND THE COMMISSION?

A. With the extensive use of outside consultants and attorneys, PSE's ability to expand their rate proposals and the defense of their case has left intervenors and ratepayer advocates struggling to keep up. Rate cases are becoming more and more complex, and it is impossible for intervenors to fully examine the utility's proposals for inappropriate and expensive items. These are items that need to be tested before the Commission to determine if the utility is recovering expenses that are truly the responsibility of the ratepayer. With the limits on the abilities of intervenors to properly examine the utility's proposal, the Commission is limited in its ability to fulfill its duties to balance the interests of the utility and the ratepayer.

The use of these outside consultants and attorneys results in substantial costs that the Company is seeking to have paid solely by the ratepayers. To illustrate how the budget for outside rate case services is becoming so substantial, consider the legal expenses. PSE's own analysis of their legal budget, which was provided as Attachment F to the Company's response to ICNU data request No. 6.12, shows that they are paying an average of [redacted] per hour for outside counsel. Exhibit No. __ (DWS-14C) at 22. In comparison, they show that PSE's inside counsel averages [redacted] per hour, and that the national law firm average hourly rate is [redacted] per hour. Id.

Q. WHAT IS ICNU'S PROPOSAL FOR ADDRESSING THESE LIMITATIONS?

A. There are two approaches that could be considered. The Commission could simply limit the recovery of rate case costs. This could be set at a level such as 50%, implying that the remaining 50% be borne by the Company's shareholders. The second alternative is to have an intervenor funding mechanism in Washington. Such mechanisms are available in other states such as California, Oregon, and Idaho. In my view, it is critical to create such a mechanism to ensure an appropriate funding level to allow intervenors to spend the time required to thoroughly examine a Company filing and raise issues of concern before the Commission. Until such a system can become effective, I recommend PSE only be allowed to recover 50% of its outside legal and consulting expenses for activity deemed prudent by the Commission.

Should intervenor funding be implemented at some future time, it would still be appropriate to maintain some level of shareholder responsibility for rate case cost recovery. This sharing helps bring a cost effectiveness limitation to the utility's rate case expense.

Q. DO YOU HAVE ANY COMMENTS ABOUT PSE'S PETITION FOR DEFERRED ACCOUNTING TREATMENT OF THE LEGAL AND CONSULTING EXPENSES FROM THE PCORC?

A. Yes. PSE initially sought to recover its legal and consulting expenses from the PCORC through a deferred accounting petition in Docket No. UE-031471. The Commission consolidated PSE's petition with the Company's request for a general rate increase in this Docket, and the Company has now included the $1.3 million in PCORC expenses in the cost increase it is seeking in the general rate case. Nevertheless, PSE has not withdrawn its request for deferred accounting related to the PCORC expenses, nor has the Commission denied that request. Thus, the status of PSE's petition is unclear, but PSE has sought to recover the PCORC expenses as part of the general rate increase request in this Docket.

ICNU explained in an April 23, 2004 letter to the Commission that the PCORC legal and consulting fees were excessive and inappropriate for recovery through deferred accounting, and recommended that the Commission deny the Company's petition. Re PSE, WUTC Docket No. UE-031471, ICNU Letter to Commissioners (Apr. 23, 2004). Staff initially recommended denial of the Company's petition as well. Exhibit No. __ (DWS-15) at 1. As described above, it appears that PSE's petition in Docket No. UE-031471 is still pending before the Commission. ICNU recommends that the Commission deny the deferred accounting petition. Without an order denying PSE's petition, there is a risk that the Company may recover the PCORC expenses both retroactively through deferred accounting, as well as prospectively through any rates established in this rate case.

Q. WHAT IS YOUR RECOMMENDATION FOR THE OUTSIDE SERVICES COSTS RELATED TO THE PCORC?

A. First, I propose reducing the amount to $500,000 based on the normalization rationale presented by Commission Staff in response to PSE's petition for deferred accounting treatment of these costs. Exhibit No. __ (DWS-15) at 1. I then propose to share this remaining expense 50/50 between ratepayers and shareholders for the reasons expressed above. Therefore, the amount that would be included in rates would be $250,000.

Q. PLEASE QUANTIFY THE IMPACT OF THESE RECOMMENDATIONS.

A. Yes. The following table indicates the impact for both the electric and gas expense in this proceeding. In total, it reduces the revenue requirement by $1,204,000.

PSE Rate Case Amortization Expense
Docket Nos. UG-040640 & UE-040641
50%/50% Sharing

	Electric		**Gas**	
	Company	**ICNU 50%**	**Company**	**NWIGU 50%**
Balance at 2/28/05	$756,277	$756,277	$1,035,155	$1,035,155
New GRC	$2,394,763	$1,197,382	$2,394,763	$1,197,382
PCORC	$1,300,000	$250,000	$0	$0
Total:	$4,451,040	$2,203,659	$3,429,918	$2,232,537
Annual Amortization	$1,483,680	$734,553	$1,143,306	$744,179
Less Test Yr Amort:	$767,268	$767,268	$600,936	$600,936
Increase (Decrease)	$716,412	-$32,715	$542,370	$143,243
Increase (Decrease) FIT:	-$250,744	$11,450	-$189,830	-$50,135
Increase (Decrease) NOI:	-$465,668	$21,265	-$352,541	-$93,108
Conversion Factor:	0.6200972	0.6200972	0.6200972	0.6200972
Revenue Requirement:	$750,959	-$34,293	$568,525	$150,150
Recommended Adjustment:		-$785,252		-$418,374
Total:	-$1,203,626			

F. <u>COST-OF-SERVICE</u>

Q. PLEASE EXPLAIN THE METHODS USED BY THE COMPANY TO DETERMINE CLASS COST RESPONSIBILITY.

A. First of all, the Company has developed a new EXCEL based cost-of-service model to assign and allocate the costs of serving the various customer classes. The model allows the user to quickly perform sensitivity cases with regard to the requested rate relief. ICNU appreciates the Company's efforts in this regard.

Second, the Company has refined its allocation methods by relying more on the direct assignment of costs where possible instead of general allocation factors. This has resulted in improved cost assignments, particularly between primary voltage and secondary voltage customers. The Company also relied upon its accounting records to ascertain and perform these cost assignments. All of these procedures have resulted in a more accurate assignment of costs to the customer classes than prior studies performed by the Company. Consequently, ICNU supports much of the Company's efforts, but I do take exception to two inter-related matters of the Company's analysis.

Q. WHAT ARE THE TWO EXCEPTIONS?

A. First, I disagree with the Company's derivation of the peak credit percentages used to classify production and transmission related costs between demand and energy. Second, the peak demand allocation factor—based upon the average of the two hundred highest system peak hours—is inappropriate as it shifts costs to customers who are not responsible for the costs.

Q. HOW DID THE COMPANY PERFORM ITS PEAK CREDIT CALCULATION?

A. The Company appears to have used the same procedure as in the last proceeding. One-half the cost of a single cycle combustion turbine ("CT") was used as the value of capacity and the additional cost for a combined cycle combustion turbine ("CCCT") are considered energy-related. The Company's calculation resulted in 13% of production and transmission costs being classified as demand-related and the remaining 87% being considered energy-related.

Q. DO YOU AGREE WITH THE COMPANY'S DETERMINATION?

A. No. I disagree with four aspects of the Company's calculation. First, I believe there was an error in the calculation, because property taxes were not taken into account in determining the cost of a combustion turbine. This is a real cost and must be included in the analysis. The omission of property taxes understates the cost assigned to capacity by about 1%. Second, the Company uses the same gas price for both the CT and the CCCT. This is inappropriate because the gas cost associated with meeting winter peak-like demands would be much higher than the average annual gas price resulting from generating electricity from a CCCT evenly throughout the year. Similarly, the oil price used by the Company for when the CT is assumed to be fired by oil is less than the annual CCCT gas price for 22 of the 30 years used in the analysis. This also is inappropriate. Like the winter CT gas price, the oil price should be far above an annual gas value. Correcting the CT fuel cost to reflect a 70% premium above the CCCT fuel costs increases the cost assigned to capacity by another 2%. These first three corrections result in 16% of the production and transmission costs being capacity-related and the remaining 84% being energy-related. Finally, I continue to disagree strongly with the ruling by the Commission that only one-half of the costs of the CT should be considered capacity-related. The Commission's ruling was premised on the idea that the CT could perform other functions once it was built, including providing energy. While this may be the case, the peak credit method was advanced to split the joint costs of a plant that can provide both capacity and energy into the appropriate values. The full capacity value of the base load plant is the full capacity value of the CT and it should be used to determine the classification percentages.

Q. WHY IS USING THE 200 HIGHEST HOURS FOR THE PEAK DEMAND ALLOCATION FACTOR WRONG?

A. There is simply too great a drop off in the loads placed on the system versus the capacity needed by the Company to serve the peak loads. The difference in load level from the first to the 200th hour is about 1,126 MW. This is simply far too great a drop off in load to allocate peak demand cost. Further, most of this amount occurs in the residential and secondary voltage classes (1,108 MW). Thus, a more accurate cost causation allocation factor is needed to correctly and more accurately assign peak demand costs.

The following table shows the class average loads based upon the 200 highest hours, the 19 hours that fall within 90% of the peak value and the 6 hours that fall within 95% of the peak value. Note that the demands are 400-600 MW higher than the 200 hour value. Further, PSE's expected January peak for planning and resource purposes is 4,573 MW. Accordingly, class contributions relative to this value should be used for cost allocation as well. If not, there is a mismatch between revenue responsibility and cost responsibility because those customers who are causing the costs to be incurred will not pay their appropriate share.

Comparison of Peak Demands

	200	**90%**	**95%**
Residential	2,283	2,628	2,831
Secondary:			
Schedule 24	419	444	446
Schedule 25	487	509	493
Schedule 26	307	316	300
Secondary Total	1,213	1,269	1,239
Primary	304	322	314
Retail Wheeling	248	254	253
High Voltage	60	59	59
Lighting	7	4	3
Firm Resale	17	17	17
Total Sales	4,132	4,553	4,716
Difference		421	584

ICNU recommends the Commission allocate system demand-related costs based upon values indicated in the middle column of the above table, which represent hours that are within 90% of the peak hour.

Q. HOW ARE THE PEAK CREDIT CLASSIFICATION ISSUE AND THE PEAK DEMAND ALLOCATION FACTOR INTERRELATED?

A. The fuel cost of the peaking resource is based upon 200 hours of operation. As ICNU is recommending that only 19 hours be used in the peak demand allocation factor, it is appropriate to use only 19 hours of CT operation in deriving the peak credit classification percentages. Based upon 19 hours, 21% of the system production and transmission costs should be classified to demand and the remaining 79% to energy.

Q. HAVE YOU PREPARED A STUDY USING YOUR COST-OF-SERVICE RECOMMENDATIONS?

A. Yes. The following table presents the results of the analysis by comparing the revenue to cost ratio of the ICNU-preferred cost allocation method with the Company study as corrected for the omission of property taxes and the CT fuel expense. The revenue to cost 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. As can be seen by the following table, both studies have similar revenue to cost ratios with the largest difference being that of the High Voltage customers.

Revenue to Cost Comparison
Classification & Peak Demand Sensitivities
Company Allocation Method

Classification %:	16/84%	21/79%
Peak Demand Hours:	200	90%
Residential	95%	94%
Secondary:		
Schedule 24	103%	104%
Schedule 25	115%	118%
Schedule 26	109%	112%
Primary	100%	103%
Retail Wheeling	126%	129%
High Voltage	91%	95%
Lighting	87%	89%
Firm Resale	95%	96%
Total	100%	100%

G. RATE SPREAD

Q. WHAT IS THE COMPANY'S RATE SPREAD PROPOSAL?

A. The Company's rate spread approach is explained in the pre-filed testimony of Mr. Heidell. Exhibit No. __ (JAH-1T) at 12. The testimony notes the results of the cost studies coupled with customer impact considerations were used as a guide in determining the proposed method. The Company has proposed moving all classes halfway to parity subject to certain floor and ceiling values. The classes below parity (revenue to cost ratio of 100%) are targeted to receive an increase no greater than 150% of the average level.

Those classes significantly above parity are targeted for an increase that is about 50% of the average value.

Q. DOES ICNU SUPPORT THIS RATE SPREAD PROPOSAL?

A. Yes except for the imposition of a floor value. ICNU recommends the Commission adopt the ICNU recommended cost-of-service study for determining the rate spread in this case. All classes should be moved halfway toward parity, subject to a ceiling constraint. The ICNU recommendations produce the rate spread presented in the following table along with the Company's method.

Rate Spread Comparison - $000

	Company Proposal		ICNU Recommendation		Difference
	Amount	**Percent**	**Amount**	**Percent**	**Amount**
Residential	$56,601	7.3%	$66,142	8.6%	$9,541
Secondary:					
Schedule 24	$6,636	3.8%	$1,534	0.9%	-$5,102
Schedule 25	$5,865	2.9%	$5,865	2.9%	$0
Schedule 26	$2,464	2.0%	-$1,104	-0.9%	-$3,568
Schedule 29	$26	2.9%	$26	2.9%	$0
Secondary Total	$14,991		$6,321		-$8,670
Primary					
Schedule 31	$5,589	5.7%	$5,590	5.7%	$1
Schedule 35	$12	5.7%	$8	3.8%	-$4
Schedule 43	$1,038	8.6%	$1,038	8.6%	$0
Primary Total	$6,639		$6,636		-$3
Retail Wheeling	$183	2.9%	$183	2.9%	$0
High Voltage					
Schedule 46	$249	11.1%	$106	4.7%	-$143
Schedule 49	$1,677	8.3%	$952	4.7%	-$725
High Voltage Total	$1,926	8.6%	$1,058	4.7%	-$868
Lighting	$1,107	8.6%	$1,107	8.6%	$0
Firm Resale	$154	8.6%	$154	8.6%	$0
Total Sales	$81,601	5.7%	$81,601	5.7%	$0

As presented in the table, the ICNU recommendation increases the revenue assigned to the residential class by $9.5 million, or 1.3%, while the secondary and high voltage customers have their revenue responsibility reduced by this amount.

Q. WHY DO SCHEDULE 26 CUSTOMERS RECEIVE A DECREASE UNDER THE RATE SPREAD RECOMMENDATION?

A. The Company's rate spread EXCEL spreadsheet was used for consistency with the Company's methods. This spreadsheet incorporated logic to reflect the agreement reached by certain parties in the last general rate case to move toward a cost-based differential between large secondary voltage customers and primary voltage customers.

H. <u>INDUSTRIAL RATE DESIGN</u>

Q. WHAT INDUSTRIAL RATE DESIGN ISSUES WILL YOU ADDRESS?

A. I address the proposed rate design for the high voltage interruptible schedule (Schedule 46) and the corresponding firm schedule (Schedule 49), the proposed retail wheeling rate design (Schedule 449), and the institution of a new tariff for customers with concentrated distribution feeder loads.

Q. WHAT HAS THE COMPANY PROPOSED FOR SCHEDULES 46 AND 49?

A. The Company has proposed to incorporate the tariff specific Schedule 95 charges as part of an identical energy charge for the two tariffs. This increases the base energy charge by about 17.6%. The Company has proposed to decrease the Schedule 46 demand charge by $0.10/kVa ($1.58 to $1.48) and maintain the Schedule 49 charge at its current level of $2.79/kVA.

Q. DOES ICNU SUPPORT THE HIGH VOLTAGE RATE DESIGN PROPOSAL?

A. No. ICNU believes the Company's rate design proposal should not be adopted by the Commission. First, the uniform energy charge proposed by the Company has resulted in a greater percentage increase for the interruptible schedule. This lowers the interruptible credit paid to this class of customers. The Company has provided no evidence in this proceeding for this action. Second, based upon the ICNU cost study, the energy is already about at a cost-based level. ICNU recommends applying an equal percentage increase to all Schedule 46 and Schedule 49 tariff charges. This will maintain the same level of discount for interruptible service, which is appropriate given the Company's need for new resources. The following tables illustrate the ICNU rate design charges for these two schedules along with the Company proposal based upon the Company's claimed revenue requirement.

Schedule 46
Rate Design Comparison

Charge	Company	ICNU
Energy (Cents/kWh)	4.3810	4.0430
Demand ($/kVa)	1.48	1.653
Schedule 95 (Cents/kWh)	0.0	0.0

Schedule 49
Rate Design Comparison

Charge	Company	ICNU
Energy (Cents/kWh)	4.3810	4.1738
Demand ($/kVa)	2.79	2.922
Schedule 95 (Cents/kWh)	0.0	0.0

Q. PLEASE ADDRESS THE COMPANY'S RETAIL WHEELING RATE DESIGN PROPOSAL.

A. The Company's rate spread proposal is to give all three categories of retail wheeling customers (Schedule 449 Primary Voltage, Schedule 449 High Voltage, and Schedule 459 High Voltage) the same percentage increase. However, since the vast majority of schedule revenue is recovered through a three significant digit demand charge, this goal could not be achieved. ICNU supports the Company's equal percentage increase rate spread proposal to all three categories. ICNU recommends the Commission simply approve a demand charge based upon four significant digits. The following table illustrates this simple recommendation based upon the allocated increase to these customers.

Retail Wheeling
Demand Charge Comparison
($/kVa)

Category	Company	ICNU
449 Primary	4.04	4.12
449 High Voltage	1.58	1.575
459 High Voltage	1.58	1.575

Q. PLEASE PROVIDE A BRIEF EXPLANATION OF THE NEW TARIFF ICNU IS RECOMMENDING THE COMMISSION IMPLEMENT.

A. For the last several months, ICNU has been working with the Company to develop a new tariff for customers having a concentrated load on a distribution feeder. A distribution feeder is the name given to a circuit emanating from a Company distribution substation. Generally, for each substation transformer—the typical size of which is 25 MVA—there are five distribution feeders. Each feeder is designed to carry and serve about 5 MVA. ICNU and the Company agreed to define concentrated load as being 3 MVA (or 3,000 kVa), or 60% of the distribution feeder capacity. Just as important, the Company and ICNU agreed that the charges under the tariff would be cost-based from an analysis of the facilities serving the eligible customers.

Q. HOW MANY CUSTOMERS WOULD BE ELIGIBLE FOR THE TARIFFED RATE?

A. It is my understanding that about six customers would be eligible for the tariff although our discussions just centered on the most highly concentrated and largest customer. For this customer, numerous distribution feeders and a large number of meter points are required to serve a vast complex of buildings that are currently served under Schedules 24, 25, 26, and 31.

Q. IS IT APPROPRIATE TO OFFER THE NEW TARIFF TO THESE CUSTOMERS?

A. Yes. I believe unique customers should be afforded the opportunity to pay the costs of the facilities required to serve their load. This concept is the cornerstone of the proposed tariff under which the distribution facilities used by these customers are simply paid for by these same customers. This is equitable and fair.

Q. WHAT RATEPAYERS SHOULD BE RESPONSIBLE FOR THE REDUCTION IN REVENUE FROM THE IMPLEMENTATION OF THIS TARIFF?

A. The reduced revenue from each rate schedule should be assigned to that rate schedule. To explain by way of an example, consider the case where a customer receiving service entirely under Schedule 31 is eligible for the new tariff. The new tariff saves the customer $50,000. This amount should be assigned to the remaining Schedule 31 customers since the costs of serving these customers were being paid for by the former Schedule 31 customer.

Q. WHAT WOULD BE THE IMPACT ON THE REMAINING CUSTOMERS FROM THIS INCREMENTAL ASSIGNMENT?

A. If all eligible customers elected service under the new tariff, the remaining customers on Schedules 24, 25, 26, and 31 would experience an incremental increase of just 0.3%, a very modest amount.

Q. DO YOU HAVE A DRAFT TARIFF TO ILLUSTRATE THIS TARIFF CONCEPT?

A. Yes. Attached as Exhibit No. __ (DWS-16) is a draft tariff prepared by the Company. Designated as Schedule 40, it illustrates the prices, terms and conditions for service under this rate for one of the eligible customers. The specific charges assume the Company receives its full revenue increase request. ICNU recommends the Commission approve this rate concept and direct the Company to derive new charges for each customer based upon the final revenue requirement determination in this proceeding with an effective date identical to all other tariff changes resulting from this Docket.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.