Exhibit No. ___(DWS-1T)
Docket No. UE-070565
Witness: Donald W. Schoenbeck

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|---|---|---|
| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION** | ) | |
| **Complainant,** | ) | **Docket No. UE-070565** |
| **v.** | ) | |
| **PUGET SOUND ENERGY, INC.** | ) | |
| **Respondent.** | ) | |

**DIRECT TESTIMONY OF DONALD W. SCHOENBECK**

**ON BEHALF OF**

**THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES**

**REDACTED VERSION**

**June 15, 2007**


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## 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 35 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 "Commission") at least 40 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 "Puget" or "PSE").

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

**A.** My testimony addresses the proposed power cost increase Puget is seeking in this docket and the manner in which any cost increase should be recovered from the various customer classes.

**Q. PLEASE BRIEFLY STATE THE ISSUES YOUR TESTIMONY WILL ADDRESS.**

**A.** The Company's supplemental filing proposes a rate increase of $77.8 million (or 4.4%) attributable to the acquisition of a 270 MW gas fired resource—the Goldendale Generating Station (Goldendale)—and cost pressures in all other power-related areas.

The power cost adjustments addressed by ICNU would lower the proposed rate increase by about $30.2 million, resulting in a rate increase of $47.6 million (or 2.7%). All of the ICNU adjustments are attributable to matters related to projecting the appropriate level of base power costs for the rate period. The specific adjustments I address and the approximate value are: 1) the availability of the Colstrip generating units ($5.4 million reduction); 2) the appropriate level of sales for resale revenue ($2.4 million reduction); 3) the gas supply for Goldendale ($16.3 million reduction); 4) the net revenue from Renewable Energy Credits ($5.6 million reduction); and 5) Account 557 litigation expense ($0.5 million reduction).

In addition to these revenue requirement adjustments, the testimony also proposes that a series of collaborative processes be conducted and completed prior to the Company's next rate application. This would allow parties the ability to discuss and hopefully resolve the ratemaking treatment or timing of certain matters in a less contentious and more open setting. In a recent order, the Commission directed PSE to analyze the possible use of forward market prices in lieu of AURORA generated prices in the ratemaking process. WUTC v. PSE, WUTC Docket Nos. UE-060266 and UE-060267, Order No. 08 at ¶ 114 (Jan. 5, 2007).

ICNU recommends similar investigations be conducted on: 1) the scope and time period allowed for analyzing PCORC filings; 2) the revenues and costs associated with short-term market sales; and 3) maximizing the benefit of the Company's gas assets for all customers.

Finally, the ICNU testimony addresses how the rate increase should be "capped" for Schedule 40 customers to ensure the charges for power supply and transmission costs are comparable to the rates paid by Schedule 49 customers.

## II. BACKGROUND AND SUMMARY OF PUGET'S REQUEST

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

**A.** The Company's application is the third "power cost only rate case" ("PCORC") PSE has filed pursuant to a multiparty settlement adopted by the Commission in docket number UE-011570 in 2002. The chief intent of a PCORC was to allow PSE to update the base power cost level to accommodate new resources in a "limited scope" proceeding. WUTC v. PSE, WUTC Docket Nos. UE-011570 and UG-011571, Twelfth Supp. Order at ¶ 25, Stipulation Exhibit A, p. 5 (June 20, 2002). However, in submitting these filings, adjustments may be proposed to all aspects of the Company's power-related costs. In the instant filing—and as was the case in the two prior PCORCs—the Company is proposing numerous changes to the various accounts while also seeking the approval of its acquisition of Goldendale.

**Q. HOW HAS PSE CALCULATED THE PROPOSED REVENUE INCREASE IT IS SEEKING IN THIS APPLICATION?**

**A.** Exhibit A to the settlement agreement in UE-011570 illustrates the method for converting the proposed power costs into a baseline rate. Using this method, the

Company's filing is seeking to increase the power cost baseline rate from \$59.583/MWh to \$63.262/MWh. Based upon test period loads, the resulting proposed increase in overall revenue requirement is \$77.8 million or 4.4%. Exh. No.___(JHS-12) at 1.

**Q. IS IT POSSIBLE TO ISOLATE THE IMPACT OF THE ACQUISITION OF GOLDENDALE ON THE OVERALL RATE REQUEST?**

**A.** Yes. Page 6 of Exhibit No.___(JHS-10) isolates the overall expense level change from the acquisition of Goldendale at \$30.0 million (see line 24). Taking into account revenue sensitive costs, the associated revenue increase is \$31.4 million. Consequently, the revenue requirement change from the acquisition of Goldendale represents only about 40% of the rate increase sought by the Company in this proceeding. The majority of the revenue increase Puget is seeking—\$46.4 million—is associated with cost pressures in all the other production-related accounts. This is consistent with all prior PCORCs. While the "main objective" was to provide a timely inclusion of the costs of new resource in rates, in actuality the vast majority of PCORC rate increases has not been attributable to new resource costs. The abbreviated time frame of PCORC proceedings does not allow for adequate time to analyze and judge the prudence of all these other power cost items. ICNU believes an open and frank discussion should take place among all parties to evaluate and assess the PCORC procedures and see if a better resolution can be achieved to accommodate the interests of all parties. ICNU recommends the Commission order such a process and require the results be presented to the Commission prior to the Company's next rate application.

## III. ICNU POWER COST RECOMMENDATIONS

**Q. WHAT SHOULD BE THE STANDARD OF REVIEW TO TEST THE REASONABLENESS OF PUGET'S PROPOSED BASE POWER COSTS?**

**A.** Since we are establishing the base power cost to be reflected in rates and used to measure deviations to actual costs in the PCA, the only acceptable standard should be a normalized cost level that incorporates real world operations into the ratemaking process.

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

**A.** In some cases, Puget has met this standard, such as the use of 50 hydro conditions to calculate expected hydro generation in lieu of selecting one particular year. In other instances, however, Puget has failed to meet this critical yardstick. These latter instances include the availability of Colstrip, the expected revenue credit from market sales or sales for resale, the likely cost of gas supply for the gas-fired units including Goldendale, the likely amount of renewable energy credit revenue to be realized during the rate years, and power supply litigation expense.

### III. A. COLSTRIP AVAILABILITY

**Q. PLEASE DESCRIBE YOUR CONCERN WITH PUGET'S PROPOSED AVAILABILITY OF THE COLSTRIP UNITS.**

**A.** PSE has an approximately 685 MW share of the capacity of the four Colstrip coal plants. The Company's determination of the availability of the Colstrip units is based upon the performance of these units over the last seven years (2000 through 2006). The following table shows the percent of time each unit was unavailable due to an outage ("equivalent forced outage rate") as reported by PSE for each of these years.

| Colstrip Equivalent Forced Outage Rate by Unit (Percent - %) | | | | |
|---|---|---|---|---|
| Year | #1 | #2 | #3 | #4 |
| 2000 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2001 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2002 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2003 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2004 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2005 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2006 | [redacted] | [redacted] | [redacted] | [redacted] |
| 7 Year Avg: | [redacted] | [redacted] | [redacted] | [redacted] |

Note for [redacted] in 2002. Similarly for Colstrip #4, the period includes a year where the outage rate was over [redacted] (2000). These two outages are far in excess of the other values achieved during this historical period and therefore have a significant effect on the resulting average outage rates. If the Colstrip #3 outage for 2002 was excluded, the average forced outage rate would decrease by [redacted] to a value of [redacted]. Similarly, the exclusion of the unit #4 outage in 2000 would lower the outage rate on this unit by [redacted] to a value of [redacted]. Importantly, however, during this same period PSE has invested a large sum of capital towards improving the performance of these resources and has also substantially increased maintenance costs on these units. The following tables shows the incremental capital expenditures invested to improve the performance of these units and the maintenance expense excluding fuel costs. PSE has included these costs in this case. Since 2000, PSE has invested [redacted] million in these units, and the operations and maintenance expense has increased by [redacted].

| PSE Colstrip Capital Cost ($ Millions) | | |
|---|---|---|
| Year | Year End Investment | Investment Increase |
| 2000 | $643.5 | |
| 2001 | $650.9 | $7.4 |
| 2002 | $659.4 | $8.5 |
| 2003 | $670.4 | $11.1 |
| 2004 | $676.0 | $5.6 |
| 2005 | $686.8 | $10.7 |
| 2006 | [redacted] | [redacted] |
| Total: | | [redacted] |

| PSE Colstrip O & M Expense ($ Millions) | | |
|---|---|---|
| Year | O & M Expense | O & M Increase |
| 2000 | $26.8 | |
| 2001 | $20.6 | -$6.2 |
| 2002 | $26.3 | $5.7 |
| 2003 | $24.8 | -$1.5 |
| 2004 | $24.6 | -$0.2 |
| 2005 | $26.0 | $1.4 |
| 2006 | [redacted] | [redacted] |
| Total: | | [redacted] |

In my view, there is a mismatch between the costs proposed to be borne for these plants by the ratepayers with the proposed performance level. PSE is proposing to use current cost levels as reflected in the proposed rate base and maintenance cost for 2006. However, for the performance or availability level, PSE's proposed period contains years where there were extraordinary outages for units 3 and 4. In fact, the Unit 3 outage in 2002 of almost [redacted] still places this unit as one of the poorest performing units in the nation in the annual NERC Generator Availability Report ("GAR").

**Q. HOW SO?**

**A.** The NERC GAR categorizes generating units by fuel type and size. The report then presents select availability statistics based upon unit performance for the past five years. The most recent GAR documents show the statistics using unit performance averages for 2001 – 2005. Within the Colstrip unit 3 and 4 peer group (coal fuel 600 – 799 MW in size), the report indicates 92 units with an average equivalent forced outage of 6.58%. Exhibit No.___(DWS-3C) contains the pertinent pages from the most recent GAR. For this time period, the Colstrip 3 average outage rate is still [redacted]

[redacted]

Focusing on the most recent years, the performance of the Colstrip units has improved dramatically. Given that ratepayers have been and are continuing to pay for these increased performance levels through higher rate base and increased O&M expense, they should also receive the full benefit of the improved performance. At a minimum, these two extraordinary outages should be excluded from deriving a normalized outage rate for these two units. For this proceeding, ICNU recommends calculating the unit availability factors and the associated heat rates based upon the most recent four-year period. The following table shows how this recommendation would translate into the necessary input values used in the AURORA model as compared to the PSE proposed values.

| Forced Outage Rate | | | |
|---|---|---|---|
| | PSE | ICNU | Difference |
| Colstrip ½ | [redacted] | [redacted] | [redacted] |
| Colstrip ¾ | [redacted] | [redacted] | [redacted] |
| | | | |
| Heat Rate - BTU/kWh | | | |
| | PSE | ICNU | Difference |
| Colstrip ½ | [redacted] | [redacted] | [redacted] |
| Colstrip ¾ | [redacted] | [redacted] | [redacted] |

By using these lower and more realistic forced outage rates, the Colstrip generation is increased by about 104,000 MWhs. This reduces the Company's power costs by about $5.3 million (estimated from comparison of AURORA results), which is a $5.4 million revenue reduction taking into account revenue sensitive costs.

**Q. WHY DOES YOUR TABLE ALSO INCLUDE RECOMMENDED HEAT RATE VALUES FOR THE COLSTRIP UNITS?**

**A.** PSE's AURORA input heat rates for Colstrip are based on a seven-year average. With the adoption of the ICNU recommendation for forced outage rates, it would be consistent to use a four-year average for determining the heat rates as well.

## III. B. SALES FOR RESALE

**Q. HOW HAS PUGET PROJECTED SURPLUS SALES OR SALES FOR RESALE?**

**A.** As it has done in recent years, Puget has relied on the AURORA model to project the expected wholesale sales and revenue in this proceeding for ratemaking purposes. In the initial filing, the model projected surplus sales of $11.3 million from 234,000 MWh of sales (27 aMW). In the supplemental filing, the model projected surplus sales of just $6.5 million from 141,000 MWhs of sales (16 aMW).

**Q. ARE THE WHOLESALE SALES PROPOSED FROM PUGET'S MODELING REASONABLE FOR SETTING BASE RATES IN THIS PROCEEDING?**

**A.** No. I have observed that the sales levels produced by the AURORA model have been declining over the last several proceedings. The sales level that PSE now includes in the supplemental filing is simply not at all credible for normalized ratemaking purposes, which should reflect real-world expectations. The following tables show the surplus sales PSE has made from two different sources for the past several years. The first table shows surplus sales reported by PSE in the annual report to FERC (Form 1). The second table shows the value reported by PSE in the annual PCA reasonableness review filings.

| FERC Form 1 | | | |
|---|---|---|---|
| Year | Surplus Sales ($ Millions) | MWh | AMW |
| 2006 | $202.0 | 4,489,127 | 512 |
| 2005 | $177.0 | 3,150,286 | 360 |
| 2004 | $115.0 | 2,714,379 | 310 |
| 2003 | $191.5 | 5,108,364 | 583 |
| 2002 | $88.3 | 3,466,571 | 396 |

| Comparison of Projected and Actual Surplus Sales by PCA Period | | | | | |
|---|---|---|---|---|---|
| PCA # | Period | Months | Projected (Millions) | Actual (Millions) | Difference (Millions) |
| 1 | July 02 to June 03 | 12 | $37.5 | $166.8 | $129.3 |
| 2 | July 03 to June 04 | 12 | $23.1 | $104.1 | $81.0 |
| 3 | July 04 to June 05 | 12 | $24.6 | $67.5 | $42.9 |
| 4 | July 05 to June 06 | 12 | $14.4 | $104.4 | $90.0 |
| Average 1 - 4 | | | $24.9 | $110.7 | $85.8 |
| 5 | July 06 to Dec 07 | 6 | $8.7 | $52.4 | $43.7 |

A cursory review of either table shows PSE's actual surplus sales are far in excess of the very modest and declining amount projected by AURORA. For the four full twelve-month PCA periods, the AURORA model predicted average sales of ***$24.9 million,*** but the Company realized sales of ***$110.7 million.*** This is a difference between projected and actual sales of ***$85.8 million per year, an enormous discrepancy***.

**Q. WHY IS THERE SUCH A PHENOMENAL DIFFERENCE BETWEEN THE PROJECTED AND ACTUAL SALES LEVELS?**

**A.** There are undoubtedly many reasons, but chief among them must be the fact that the AURORA model essentially "buys" and "sells" all power just once. That is, the model "dispatches" the generation to meet the load requirement just once as if everything was captured or transacted in a "real time" market. In actuality, utilities such as PSE are in the forward market all the time buying and selling power to serve load, reduce risk, and capture economic opportunities. The end result of this real world market activity is that a particular block of power can "trade hands" numerous times, having a "daisy chain" of owners, some of which may have bought and sold the same power more than once. The other outcome of this activity is, of course, the fact that only a very small portion of a utility's load—just a few percent—is actually served through real time transactions even though the

AURORA model assumes 100% of load is served in this manner.

**Q. IS IT APPROPRIATE TO INCLUDE THIS SALES MARKET ACTIVITY IN DETERMINING THE BASE POWER COSTS?**

A. Yes, I believe it is. As the ratepayers are paying for all the costs associated with these market transactions, some normalized net revenue value—reflective of what PSE actually does transact—should be imputed into the revenue requirement determination as a partial credit to offset a portion of PSE's power cost.

**Q. WHAT IS YOUR RECOMMENDATION FOR THIS PROCEEDING?**

A. Investigating an appropriate value for imputed market transactions would take more time than is available in this abbreviated PCORC proceeding, but I am confident the result would be an adjustment valued in the millions of dollars. In its supplemental filing, the Company identified the reduced surplus sales level as contributing $2.4 million to the additional increase requested by the Company. See Exh. No.___(JHS-9T) at 3. The ICNU recommendation is to impute a net revenue credit equal to this value to essentially get back to the original filing. In addition, ICNU recommends that the Commission order PSE to conduct an analysis as part of a collaborative process and to report on the net benefits of their wholesale sales activity prior to PSE's next general rate case. This would give all parties the opportunity to examine this very important matter and address it in the next rate case.

## III. C. GOLDENDALE GAS SUPPLY

**Q. HOW HAS PUGET DETERMINED THE GAS SUPPLY COSTS FOR GOLDENDALE FOR THE RATE YEAR?**

A. As it has done for all its other generating units, Puget has assumed that all of the gas for Goldendale is supplied from the Sumas market hub.

**Q. WHY IS THIS A CRITICAL ASSUMPTION?**

A. Years ago, Sumas gas supplies were priced lower than domestic supplies on Northwest Pipeline due to market conditions. However, for the past few years, domestic supplies have been priced lower than Canadian supplies, and the price gap has been ever widening. Today, the differential is very large and projected to be so for the next several years. The following table indicates the differential as projected by PSE's consultant for the PCORC rate period of September 2007 through August 2008, using the three-month rolling average method approved by the Commission. As is readily apparent, the domestic supplies would provide a substantial savings over Canadian supplies if a party had access or capacity on Northwest Pipeline for delivery.

| Gas Supply Forward Price Comparison - $/MMBTU | | | | |
|---|---|---|---|---|
| | 07 PCORC – 9/07 - 8/08 | | | |
| 3-mo ending: | 02/27/07 As Filed | 05/10/07 Suppl | 05/31/07 Update | 06/07/07 Current |
| Sumas | [redacted] | [redacted] | [redacted] | [redacted] |
| Rockies | [redacted] | [redacted] | [redacted] | [redacted] |
| Differential | [redacted] | [redacted] | [redacted] | [redacted] |

**Q. DOES THE GOLDENDALE GENERATING STATION HAVE THE NECESSARY ACCESS?**

A. Yes. Goldendale has access at certain times through PSE's portfolio of gas assets. The former owner of the generating station did not obtain any long-term firm transportation rights on Northwest Pipeline, relying instead on short-term market opportunities. With the acquisition of Goldendale, PSE has obtained certain additional long-term access on Northwest Pipeline but it appears that PSE focused solely on Sumas supplies, a questionable action. However, PSE can and has managed its entire gas asset portfolio such that domestic supplies have been delivered and burned at Goldendale.

**Q. HOW CAN THIS OCCUR?**

**A.** PSE has the necessary capacity to serve the peak core load of its gas customers. [redacted] As a result, PSE has the potential to use its gas customer assets to delivery domestic gas supplies to its electric generating resources, including Goldendale, in non-peak months.

**Q. HAS PSE BEEN ABLE TO SUPPLY GOLDENDALE WITH DOMESTIC SUPPLIES?**

**A.** Yes. Exhibit No.___(DWS-5C) is PSE's supplemental response to ICNU data request 1.008. It contains the detail for supplying the Company's gas-fired electrical generating units for the month of April 2007. This data response shows [redacted] PSE currently uses a single average price or cost for all generating units. For this month, the average cost of [redacted]

[redacted]

**Q. ARE THERE OTHER TRANSACTIONS SHOWN ON THIS EXHIBIT THAT COULD OFFSET THIS PURCHASE VALUE?**

**A.** Yes. [redacted] than the Sumas market price that has been assumed for ratemaking purposes in recent years as the Company has acquired new combined cycle plants.

**Q. WHAT IS THE ICNU RECOMMENDATION FOR PRICING GAS SUPPLIES TO THE COMPANY'S GENERATING STATIONS IN THIS PROCEEDING?**

**A.** ICNU has two recommendations with regard to gas matters. First, for ratemaking purposes in this proceeding, the AURORA model should use the Rockies forward price projection for Goldendale supply for the non-peak months of April through October. This ratemaking adjustment is absolutely necessary to recognize the real world procurement of gas for the Company's generating stations. A rough comparison (simply using AURORA runs) suggests this will lower the power costs by $16.0 million, equivalent to a revenue decrease of $16.3 million. Second, with the acquisition of Goldendale and Frederickson, the PSE electric portfolio now has a large need for base load gas supplies. ICNU recommends the Commission order an all-party collaborative to investigate how all of PSE's gas assets can be used to maximize the benefit for all customers. This process should occur prior to the next general rate case filing so if there is a consensus outcome it can be incorporated into the next case. On the other hand, if consensus can not be achieved, all parties will be in a much better position to address this critical issue.

## III. D. RENEWABLE ENERGY CREDIT REVENUE

**Q. PLEASE EXPLAIN WHAT A RENEWABLE ENERGY CREDIT IS.**

**A.** A renewable energy credit ("REC") is the right to claim the environmental attribute of a renewable resource. The right can be through ownership of the generator or by contractual transfer (sale of the REC). In the case of PSE, Wild Horse and Hopkins Ridge are the primary renewable resources in the Company's portfolio. For the rate year, these two resources are projected to generate almost 1.1 million MWhs so PSE has a claim or could sell 1.1 million RECs (1 REC = 1 MWh) associated with this generation.

**Q. HAS PSE INCLUDED ANY REVENUE FROM THE SALE OF RECS IN THIS PCORC APPLICATION?**

**A.** No. This past April, PSE filed an application at the Commission seeking an accounting order on the proposed treatment of the net revenues from the sale of its RECs and other emission reduction allowances (UE-070725). In that application, PSE is seeking to use the net revenue generated from the sales for investment in research and demonstration projects of other renewable technologies or used in the Company's conservation program. This application has yet to be acted on by the Commission.

**Q. DOES ICNU CONCUR WITH THIS COURSE OF ACTION?**

**A.** No. ICNU recommends the net revenue from the sale of RECs or other environmental attributes be flowed through as a credit to offset the power cost associated with these facilities. The primary purposes for which PSE wishes to use the revenue is of extremely limited value at best (see paragraph 18 of the application). In addition, the associated "pay back" would be extremely risky and possibly not ever occur or occur over a prolonged time period. On the other hand, the immediate flow through of the sales revenue to customers would provide a real, tangible benefit at a time when there has been substantial cost pressures causing rates to rise.

**Q. WHAT AMOUNT OF REVENUE IS POSSIBLE FROM THE SALE OF PSE'S RECS?**

**A.** The value is dependent upon how the REC is "packaged" and to whom it is sold. Implicit values of $8 - $9 per REC (or MWh) have been achieved when sold as part of the renewable resource. Some entities must also acquire RECs to satisfy jurisdictional portfolio standards. However, as more and more states adopt renewable portfolio standards, the value should increase. Exhibit No.___(DWS-6C) is a presentation given to PSE's Energy Management Committee dated March 15, 2007. This document suggests [redacted] Exhibit No.___(DWS-6C) at 5.

**Q. HAS PSE SOLD ANY RECS?**

**A.** [redacted]

**Q. WHAT IS THE ICNU RECOMMENDATION WITH REGARD TO REC REVENUE IN THIS PROCEEDING?**

**A.** The Commission should require the revenue gained from the sale of RECs to be used to offset power costs. For the base cost determination in this proceeding, ICNU recommends imputing a value of [redacted] associated with the sale of RECs from Wild Horse and Hopkins Ridge for the rate year. This is a reasonable value as it reflects the current market price of RECs, and I fully expect the value to increase in the near term.

## III. E. <u>POWER SUPPLY LITIGATION EXPENSE</u>

**Q. PLEASE PROVIDE A BRIEF EXPLANATION OF THE POWER SUPPLY LITIGATION EXPENSE PSE IS SEEKING IN THIS PROCEEDING ASSOCIATED WITH THE 2001 ENERGY CRISIS.**

**A.** PSE's workpapers in support of power costs included in account 557 reflect two lawsuits that have been pursued by various parties as a result of the 2000-2001 energy crisis. As one would expect, since the initiation of the many legal actions resulting from this event, numerous lawsuits have been settled, leaving just a few parties—of which PSE is one—still attempting to resolve the claims. In the instant filing, PSE has included about $550,000 associated with the California party litigation based upon the costs incurred for the twelve months ending December 2006.

**Q. WHAT IS ICNU'S VIEW AS TO THE REASONABLENESS OF INCLUDING THIS COST FOR THE RATE YEAR?**

**A.** The Commission should remove this expense from power costs for the rate period. Virtually all the other parties have already settled the claims for this period and we fully expect PSE to do so as well. An energy crisis of the magnitude experienced in 2000-2001was a "once in a lifetime" event driven in large part by circumstances that will not likely reoccur. Therefore this historical litigation cost should be excluded.

## IV. RATE SPREAD

**Q. DOES ICNU SUPPORT THE COMPANY'S PROPOSED RATE SPREAD IN THIS PROCEEDING?**

**A.** No. ICNU feels strongly that the proposed rate increase to Schedule 40 customers under PSE's proposed rate spread is inequitable.

**Q. WHY?**

**A.** Schedule 40 was developed a short time ago in recognition of the fact that certain customers could invest the necessary capital to become High Voltage customers and be served under Schedule 49. The rate was proposed to recover cost-based Schedule 49 charges for bulk power supply costs (generation and transmission) and the specific costs of the distribution system used to serve each Schedule 40 customer. Unfortunately, the Company moved away from this method in the last general rate case. The following table shows the impact this has had on Schedule 40 customers. The column labeled "Cost Based 40 Rate" shows the values that should be in place today as compared to the current values being charged, which are shown in the column labeled "Schedule 40 Rate." This table shows the demand charges are 10% too high and the energy charges are over 20% too high.

| Demand Charge Comparison | | | | | |
|---|---|---|---|---|---|
| Voltage Level | Schedule 49 Rate ($/kVa) | Cost Based 40 Rate ($/kW) | Schedule 40 Rate ($/kW) | Difference ($/kW) | Percent Deviation |
| Transmission | $3.14 | $2.95 | $3.25 | $0.30 | 10.2% |
| Primary | | $3.01 | $3.32 | $0.31 | 10.3% |
| Secondary | | $3.10 | $3.42 | $0.32 | 10.3% |
| Energy Charge Comparison | | | | | |
| Voltage Level | Schedule 49 Rate ($/kWh) | Cost Based 40 Rate ($/kWh) | Schedule 40 Rate ($/kWh) | Difference ($/kWh) | Percent Deviation |
| Transmission | $ 0.046901 | $0.042253 | $0.050991 | $0.008738 | 20.7% |
| Primary | $ 0.046901 | $0.043081 | $0.051909 | $0.008828 | 20.5% |
| Secondary | $ 0.046901 | $0.044455 | $0.053517 | $0.009062 | 20.4% |

Taken together, we believe the Schedule 40 customers are being over charged by almost 15%, or $4.1 million per year.

**Q. DO YOU HAVE A RECOMMENDATION FOR RESOLVING THIS SCHEDULE 40 DISPUTE?**

**A.** Yes. The Schedule 40 power supply charges should simply be the exact or corresponding Schedule 49 charge adjusted for the demand billing unit (kVa versus kW) and losses. This recommendation is illustrated in the following table. The column labeled "Equivalent 49 Rate" would be the bulk power supply charges for Schedule 40. As compared to the current Schedule 40 charges, the demand rates are very close—just 2 cents/kW difference. However, for the energy charges, the current charges are still too high by over 8%.

| Demand Charge Comparison | | | | | |
|---|---|---|---|---|---|
| Voltage Level | Schedule 49 Rate ($/kVa) | Equivalent 49 Rate ($/kW) | Schedule 40 Rate ($/kW) | Difference ($/kW) | Percent Deviation |
| Transmission | $3.14 | $3.27 | $3.25 | -$0.02 | -0.6% |
| Primary | | $3.34 | $3.32 | -$0.02 | -0.6% |
| Secondary | | $3.44 | $3.42 | -$0.02 | -0.6% |
| Energy Charge Comparison | | | | | |
| Voltage Level | Schedule 49 ($/kWh) | Equivalent 49 ($/kWh) | Schedule 40 ($/kWh) | Difference ($/kWh) | Percent Deviation |
| Transmission | $ 0.046901 | $0.046901 | $0.050991 | $0.004090 | 8.7% |
| Primary | $ 0.046901 | $0.047820 | $0.051909 | $0.004089 | 8.6% |
| Secondary | $ 0.046901 | $0.049345 | $0.053517 | $0.004172 | 8.5% |

I recommend that no rate increase be assigned to the Schedule 40 customers until their power supply charges equal the equivalent rates paid by Schedule 49 customers, including the Schedule 95 rate component. In the updated filing, the proposed Schedule 95 charge for Schedule 49 customers is 0.2881 cents/kWh (see Exh. No.___(DWH-7), line 15). Since Schedule 40 customers are paying over 0.40 cents/kWh above the equivalent Schedule 49 rate, no increase should be imposed on Schedule 40 customers in this proceeding. The following table and Exhibit No.___(DWS-8) show the class impacts from the adoption of the ICNU revenue requirement and rate spread recommendations as compared to the Company.

| Comparison of PSE and ICNU Proposals ($ 000) | | | | | |
|---|---|---|---|---|---|
| | PSE Proposal | | ICNU Recommendation | | Difference |
| Major Groupings | Amount | Percent | Amount | Percent | in Amount |
| Residential | $40,672 | 4.3% | $25,438 | 2.6% | ($15,234) |
| Secondary Service | $27,564 | 4.5% | $17,240 | 2.8% | ($10,325) |
| Primary Service | $5,432 | 5.1% | $3,397 | 3.1% | ($2,035) |
| Campus Schedule | $1,769 | 5.1% | $0 | 0.0% | ($1,769) |
| High Voltage Service | $1,615 | 5.3% | $1,010 | 3.3% | ($605) |
| Lights | $315 | 2.2% | $197 | 1.3% | ($118) |
| Small Firm Resale | $28 | 5.6% | $18 | 3.5% | ($11) |
| Total | $77,396 | 4.4% | $47,300 | 2.7% | ($30,096) |

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

**A.** Yes, at this time.