EXHIBIT NO. ___(JHS-1T)
DOCKET NO. ____________
2005 POWER COST ONLY RATE CASE
WITNESS: JOHN H. STORY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

PREFILED DIRECT TESTIMONY OF
JOHN H. STORY (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

JUNE 7, 2005

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is John H. Story, and I am Director of Cost and Regulation with Puget Sound Energy, Inc. ("PSE" or "the Company"). My business address is 10885 NE 4th Street, Bellevue, Washington, 98004-5591.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(JHS-2).

Q. What are your duties as Director of Cost and Regulation for PSE?

A. As Director of Cost and Regulation, I am responsible for the Revenue Requirement department at PSE.

Q. Please summarize your testimony in this proceeding.

A. My testimony describes: (1) adjustments to PSE's power supply costs that have prompted PSE to seek the proposed increased Power Cost Rate; (2) the rate impact of adding the new Hopkins Ridge wind generation facility (the "Hopkins Ridge Project") to PSE's power supply portfolio; (3) the calculation of PSE's new Power Cost Rate, which accounts for the addition of the Hopkins Ridge Project, updates expenses to account for current power costs and corrects the allocation of deferred tax expense to production related costs; and (4) the calculation of a new tracker schedule for the Production Tax Credits associated with wind projects. I also describe some problems the Company has identified related to the removal of the PCA Mechanism's $40 million cap on excess power costs during the middle of the rate year for this case.

Q. What is the total rate increase the Company is seeking in this proceeding?

A. The total proposed rate increase resulting from these adjustments is $55,571,666, an average 3.65% increase over the rates set by the Commission in March 2005 in the Company's last general rate case, Docket Nos. UG-040640 et al.

II. THE PCA MECHANISM AND ITS POWER COST RATE

Q. Please describe the PCA Mechanism.

A. In PSE's 2001 general rate case, Docket Nos.UE-011570 and UG-011571, the Commission approved the parties' Settlement Stipulation for Electric and Common Issues ("Settlement Stipulation"). *See* Docket Nos.UE-011570 et al., Twelfth Supplemental Order (dated June 20, 2002) ("Twelfth Supplemental Order"). Among other things, the Twelfth Supplemental Order authorized the use of a Power Cost Adjustment Mechanism ("PCA") as a method for better matching the amount PSE recovers in rates for power costs with PSE's actual power costs. *See Settlement Terms for the Power Cost Adjustment Mechanism, Exhibit A to the Settlement Stipulation*, which is filed with this testimony as Exhibit No. ___(JHS-3) (as corrected pursuant to the Fifteenth Supp. Order in Docket Nos.UE-011570 et al.).

As described in the Settlement Stipulation, the PCA provides for a sharing of power cost excesses or savings between PSE and its customers over four graduated levels (so-called "bands") of power cost variances, based on the difference between a projected "power cost baseline" or "power cost rate" ("Power Cost Rate") that is embedded in PSE's rates (based on projections of power costs the Company is anticipated to incur) versus the power costs that PSE actually incurs each year. The Settlement Stipulation also established an overall cap on the Company's exposure to excess power costs of $40 million over the four year period July 1, 2002 through June 30, 2006. *See* Exhibit No. ___(JHS-3) at 1. Excess or surplus power costs are accounted for through annual true ups and a deferral account and are eventually to be surcharged or refunded to PSE's customers.

PSE is also authorized under the PCA Mechanism to file petitions in between general rate cases that seek adjustment only of the power cost portion of PSE's rates.

Q. How is the Power Cost Rate determined?

A. The PCA distinguishes between power costs and all other costs included in general rates. *See* Exhibit No. ___(JHS-3) at 3. The PCA Settlement Stipulation included a table that showed the allocation of costs between costs that can be adjusted through the PCA, and non-power costs, which cannot be adjusted through the PCA. Two categories of costs comprise the Power Cost Rate: variable rate components and fixed rate components. *See* Exhibit No. ___(JHS-3) at 4.

Q. When are the accumulated PCA excess costs or savings allocations reviewed?

A. In August of each year, PSE files an annual report detailing the power costs that it actually incurred and that were included in the deferral calculation for the period ending June 30 of each year. Through this filing, the Company's actual variable power costs are trued up from the variable power costs set in rates, with the excess or shortfall flowing through to the PCA deferral account subject to the PCA's sharing bands.

Q. How is the Power Cost Rate adjusted?

A. Independent of the yearly accounting and adjustment for power cost variances, PSE may also apply to the Commission to more closely align the Power Cost Rate to reflect all power costs identified in the Power Cost Rate. This is the means through which the fixed portion of power costs can be adjusted for events such as acquisition of new generating facilities. When PSE makes such a filing, the PCA Settlement Stipulation requires, among other things, testimony and exhibits that describe:

- Adjustments to the Fixed Rate Component
- Adjustments to the Variable Rate Component
- A calculation of pro forma production cost schedules that are consistent with this docket, including power supply and other adjustments impacting then current production costs.

See Exhibit No. ___(JHS-3) at 5**.** My testimony provides this required information in support of PSE's present application to true up its Power Cost Rate.

III. ADJUSTMENTS USED TO DETERMINE PSE'S PROPOSED NEW POWER COST RATE

Q. Would you please describe the adjustments used to determine the new Power Cost Rate?

A. In order to set future rates related to power costs, whether in a general rate case or in a power cost only rate case, the Company projects the power costs it anticipates it will incur in a future "rate year" (the one year period beginning on the day the new rates are scheduled to become effective). In a general rate case, the Company then pro forms those projected power costs back to the test year so that they can be added to other test year expenses and adjusted appropriately to develop the

Company's revenue requirement for the test year. In a power cost only rate case, there are no other test year expenses to add to power costs. However, it is appropriate to pro form the rate year projected power costs back to the test year in order to generate a new Power Cost Rate that is consistent with the methodology used to develop the Company's Power Cost Rate in its most recent general rate case revenue requirement.

Using this methodology for the present case, I have summarized the power cost adjustments, plus restating adjustments, associated with production costs in Exhibit No. ___(JHS-4). The proposed rate year used for these adjustments is December 2005 through November 2006. For this proceeding, the Company used the test year ended March 2005.

In addition to the power cost adjustments mentioned above, I provide a pro forma adjustment to account for changes to PSE's ratebase and operating expenses associated with the purchase of the Hopkins Ridge Project.

Q. Please explain what Exhibit No. ___(JHS-4) represents.

A. The first column of Exhibit No. ___(JHS-4) shows the ratebase and production costs from the test year which are considered in setting the Power Cost Rate. The first column, entitled "Test Year Actual 12 Months ended March 31, 2005", sets forth the ratebase and actual production costs for the test year ended March 2005.

The columns to the right of this column show the impact of the pro forma and restating power cost adjustments PSE is proposing for the pro forma rate year. These adjustments are presented in more detail on the succeeding pages referenced in the title of a particular column and the work papers supporting these adjustments have been provided to Commission Staff and intervenors.

The total of the test year amounts plus the pro forma and restating adjustments is shown in the column titled "Adjusted 12 months ended March 31, 2005".

The final column titled "$/MWh" contains the amounts from the previous column on a per MWh basis based on the normalized test year delivered load. These final two columns represent the costs to be used in determining the Power Cost Rate used to calculate the required rate increase. These are the same amounts shown in the first two columns of Exhibit No. ___(JHS-5C).

Q. Please describe each of the adjustments presented in Exhibit No. ___(JHS-4).

A. Other than the adjustment for the new Hopkins Ridge Project, each of the power cost adjustments are done in the same manner as approved in the Company's last general rate case, Docket UE-040461. The adjustments are:

1) Power Cost – **ADJUSTMENT-1** presents the rate year pro forma power costs discussed by Ms. Ryan and presented in Exhibit No. ___(JMR-3). These costs are the rate year variable and fixed power operating and maintenance costs that are adjusted to test year levels using the relationship of normalized test year delivered

load to rate year delivered load ("production factor"). These projected costs are a proforma adjustment to the test year costs shown on the first page of Exhibit No. ___(JHS-4). The increase in cost is $11,681,061.

2) Sales for Resale – **ADJUSTMENT-2** pro forms the test year secondary sales to rate year secondary sales. The decrease in secondary sales is $53,524,902.

3) Hopkins Ridge Project – **ADJUSTMENT-3** pro forms the cost of Hopkins Ridge Project for both ratebase and operating expenses. The assumptions for the costs used in this adjustment are explained later in my testimony.

4) Transmission Income – **ADJUSTMENT-4** pro forms the forecast transmission income for the four transmission lines identified in the power cost rate to the expected rate year levels which is the methodology accepted in the Company's last general rate case. The rate year revenues reflect the average of the last three years of revenues. This adjustment decreases transmission revenue by $927,996.

5) Depreciation and amortization – **ADJUSTMENT-5** restates the depreciation expense and accumulated depreciation to an average of the monthly averages calculation. This increases this expense

by $280,579.

6) Property taxes – **ADJUSTMENT-6** restates test year property taxes for known changes in the levy rates and production plant balances for Montana, Oregon and Washington. This increases this expense by $271,974.

7) Montana Energy Tax – **ADJUSTMENT-7** pro forms the tax that is assessed on Colstrip generation. This adjustment compares the forecast generation of the Colstrip plants to the actual generation in the test period and the difference is priced at the appropriate tax rate. This adjustment decreases expense by $135,473.

8) Property insurance – **ADJUSTMENT-8** restates production property insurance to current levels, and decreases expense by $40,554.

9) Frederickson 1 – **ADJUSTMENT-9** Frederickson 1 plant costs were recorded in April 2004 and are reflected in the beginning production ratebase at the average of monthly averages for eleven months. This pro forma adjustment is necessary so that a full year of plant costs are properly recognized for this plant as allowed in Docket UE-040641 and Docket UE-031725. In addition, duct firing is in the process of being installed at this plant as discussed by Mr. Markell, Exhibit No. ___(EMM-1HCT), and the costs

associated with this additional capacity are shown on lines 9 through 11 of this adjustment. This adjustment increases ratebase by $3,366,713 and operating expense by $474,678.

10) <u>Regulatory Assets and Liabilities</u> – **ADJUSTMENT-10** pro forms the rate year ratebase and amortization for the regulatory assets associated with Tenaska, Cabot buyout, White River plant costs, White River relicensing, BEP and the CanWest regulatory liability that was approved in Docket No. UE-041846. This adjustment reduces ratebase by $45,590,943 and increases operating expense by $1,766,581.

11) <u>Production Adjustment</u> – **ADJUSTMENT-11** pro forms the production related ratebase and expenses which have not been included in the power cost adjustments. As with the Power Cost Adjustment, these costs are adjusted to test year levels using the production factor so that the test year level of costs are collected in the rate year. The production factor is defined as the reciprocal of the relationship of test year normalized delivered load to rate year normalized delivered load. This adjustment reduces expense by $415,746 and ratebase by $3,861,407.

Q. Please explain the last two pages of Exhibit No. ___(JHS-4).

A. The second to last page of the exhibit, ADJUSTMENT 12, presents the adjustment to test year load for the difference in temperature between the test year and a normal temperature, as discussed in the prefiled direct testimony of Ms. Sara Cardwell. As the test year was warmer than normal, on average, this adjustment adds 114,014 MWhs to the actual load after adjusting for system losses. This adjustment is required to determine normal delivered load in the test year which is used in the production adjustment and is used in determining the Power Cost Rate. This adjustment is also used to determine the normal billed load for the rate spread.

The last page, ADJUSTMENT 13, is the conversion factor for revenue sensitive items. This calculation uses the bad debt percentage from the 2004 general rate case and the current annual filing fee and state utility tax rates. This conversion factor is used in determining the total revenue deficiency.

Q. Are the Snoqualmie licensing costs included in the production plant costs for this filing?

A. Yes. As discussed by Mr. Markell, the costs of the Snoqualmie relicensing are $12,946,647. The majority of these costs were closed to plant in July 2004, $12,893,645.07, with some lesser amounts closed to plant in August and September, 2004, $29,510.81 and $23,491.74, respectively. These costs are included in the AMA calculation of the production plant costs for the test period based on the dates they were actually closed.

IV. ADJUSTMENTS ATTRIBUTABLE TO THE HOPKINS RIDGE ACQUISITION

Q. Please describe each of the components presented in Exhibit No. ___(JHS-4) that are attributable to PSE's acquisition of the Hopkins Ridge Project.

A. **ADJUSTMENT-3** presents the ratebase and operating expenses associated with the Hopkins Ridge Project for the rate year. The plant balance, shown on line 3 of this adjustment, is the sum of the estimated construction cost for Hopkins Ridge, $182,815,841 and capitalized AFUDC of $6,951,502. Mr. Garratt provides the detail for these costs in his testimony, Exhibit No. ___(RG-1HCT), and in his Exhibit No. ___(RG-10HC).

Q. Please explain how the ratebase addition was calculated for rate purposes.

A. The acquisition price less the accumulated depreciation and deferred taxes for the December through November 2006 time period is the amount that PSE used to calculate the return needed to cover the capital costs for the Hopkins Ridge Project. The elements of this calculation are described below.

PSE has assumed that this construction will be finalized in November 2005. Using the end of November as the capitalization month, the Company calculated the average of the monthly averages balance for the rate period.

For book depreciation purposes, the Company is proposing that the asset be depreciated over 20 years, which is a 5% depreciation rate, and is the engineering life certified by the turbine manufacturer. For the year 2005, PSE assumed one month of depreciation and added eleven months of depreciation for the year 2006. The resulting monthly accumulated depreciation was then averaged in the same manner as the acquisition cost.

Deferred taxes were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). This Section specifies how a future projection of an asset must be treated for the normalization method of accounting. The methodology as described presents a calculation that allows deferred taxes to be deducted for ratemaking purposes if calculated based on the pro rata number of days the future period plant is considered for inclusion in ratebase and is adjusted to match the average of the monthly averages used in determining the plant balance. The methodology we have used in this calculation is slightly different than what we have used in prior cases which added rate year plant costs. The different methodology is based on private letter rulings from the IRS, PLR 9202029 and PLR 9313008, which illustrate that the future prorated deferred taxes have to be averaged once the prorate is calculated.

For the Hopkins Ridge Project, the deferred tax calculation is based on five-year tax depreciation. As the Hopkins Ridge Project will be added to plant in the last quarter of 2005, the Company is required to use the mid-quarter convention in calculating the tax depreciation and the deferred tax benefit for the first year of operation instead of the half-year convention that would normally be used. The reason for this change is that with the addition of the Hopkins Ridge Project, more than 40% of the Company's capital expenditures were booked in the last quarter of the year. When this occurs the Internal Revenue Code requires the Company to calculate tax depreciation and deferred taxes for that year based on each quarter's additions rather than the mid year convention. This reduces the amount of the tax depreciation and deferred tax for the plant added in the last quarter of the year; however, this tax difference is picked up over the remaining tax life of the asset by the use of slightly higher tax depreciation rates in the following years.

These adjustments increase ratebase by $177,408,108.

Q. Please explain the other costs associated with the Hopkins Ridge Project on Exhibit No. ___(JHS-4) at 5.

A. I explained depreciation expense (shown on line 15) above. The basis for the plant property insurance and property taxes are discussed in Mr. Garratt's Exhibit No. ___(RG-12HC).

Wheeling expenses were included with the power costs presented by Ms. Ryan and are in Exhibit No. ___(JMR-10). For presentation purposes these costs have been removed from the power cost adjustment and are presented on this adjustment so that all the costs of the Hopkins Ridge Project are shown together. Wheeling costs for the rate year are shown on two lines: line 16 is the prepaid demand charge for transmission totaling $1,742,822, discussed below, and line 22 totaling $1,505,347 is the remaining costs for transmission associated with wheeling power to the Mid-C hub.

The total of all these expenses is $18,382,944 as shown on line 26 of **ADJUSTMENT-3.**

Q. Are the Hopkins Ridge Project costs subject to change?

A. As presented by Mr. Garratt's Exhibit No. ___(RG-10HC), a portion of these costs have already been paid, thus will not change. PSE is contractually obligated to pay most of the remaining costs as construction milestones are reached. A small portion of the costs represent additional costs PSE estimates it will incur for the project based on current information. PSE will provide updated information on amounts actually paid related to the Hopkins Ridge Project during the course of this proceeding, as well as any updating that is necessary regarding the estimated portion of the costs.

Q. What does the Company propose the Commission approve in this proceeding with respect to Hopkins Ridge Project costs?

A. PSE is seeking approval in this proceeding of rates set based on the total amount of costs set forth in Exhibit No. ___(JHS-4), Adjustment 3.

The Company also seeks the Commission's approval to true up the final costs associated with the Hopkins Ridge Project as part of its PCA monthly calculation and the annual PCA compliance filing in August 2006. When the actual final closing costs for the Hopkins Ridge Project are known, they would be used to calculate the ratebase for this plant on Schedule B of the PCA Mechanism. If the final closing costs are higher or lower than the costs approved for the rate year as part of this proceeding, the Company will present evidence in the compliance filing explaining the reasons for the increase or decrease and request Commission approval of the final costs.

Q. What does the adjustment for the Hopkins Ridge Project prepaid transmission expense represent?

A. The $9,138,350 increase to ratebase on Line 9 of Adjustment 3 represents the AMA balance during the rate year of the ten million dollar payment made to BPA to upgrade their transmission substation and transmission lines for interfacing with the Hopkins Ridge Project. As discussed by Mr. Garratt, Exhibit No. ___(RG-1HCT), the Company will receive a credit for the demand charge on its transmission billing for this payment.

Q. How does the Company propose to handle this payment for the PCA?

A. The Company proposes to handle this payment for the PCA as a regulatory asset that will earn the current net of tax rate of return in the same manner as other power cost related regulatory assets. The Company will clear this account based on BPA transmission billings that will show the actual transmission demand cost associated with Hopkins Ridge for a given month.

This demand charge for the transmission billing will be offset by two adjustments. The first adjustment is a credit against the transmission demand charge for a carrying cost that is based on the remaining balance of the original payment times the monthly FERC interest rate. This will be a reduction in transmission expense that is passed through to the customer. The second offset will be a reduction on the demand charge associated with the original ten million dollar payment. This reduction in cost is credited against the prepayment and as long as there is a balance associated with the prepayment this second adjustment will reduce the demand charge to zero. For ratemaking purposes, PSE will credit the regulatory asset account for this second adjustment and charge transmission expense. This charge to transmission expense will be picked up in the PCA.

For this filing, the Company has calculated the regulatory asset balance on the projected average of the monthly balances during the rate year based on the expected generation for Hopkins Ridge. PSE has also included the associated transmission costs in operating expenses. These costs are shown as variable expenses and will be trued up to actual generation and transmission expense during the PCA period.

Q. Why is the Company proposing to earn its authorized rate of return on the transmission investment rather than retaining the FERC interest rate?

A. The FERC interest rate at the date of this filing is 5.3%. By contrast, the Company's currently authorized net of tax rate of return is 7.01%. When the

Company earns a return on funds it has invested that is lower than its authorized rate of return, it drives down the rate of return that the Company is capable of actually earning. The Company's proposal to treat its transmission investment for the Hopkins Ridge Project as a regulatory asset that earns the Company's authorized rate of return will reimburse the Company for its actual cost of funds as allowed in its last general rate case.

The Company believes that this treatment is appropriate as the transmission investment was required in order to use the generation from the Hopkins Ridge Project to serve PSE's system, and as such, is part of the costs of that plant that should be treated on par with the ratebase portion of the production asset.

PSE's proposed method, described above, of passing through to customers the transmission cost credit associated with the FERC interest rate paid by BPA will prevent double collection by the Company of a return on its transmission investment.

Q. What is the total revenue requirement for the Hopkins Ridge Project?

A. The revenue requirement, before revenue sensitive items and production tax credits, is $38,335,321 for the test year. To get the actual impact the production tax credits and the associated return on the production tax credits deferred tax asset would have to be deducted from this amount. These amounts are valued at $12,548,595, for the test year as shown on Exhibit No. ___(JHS-7), line 4. The net impact is a revenue requirement of $25,786,726 for the test year, before revenue sensitive items.

Q. Does this mean that approximately 46% of the revenue deficiency is associated with the Hopkins Ridge Project?

A. No. Taking into account the power cost savings from Hopkins Ridge described in Ms. Ryan's testimony as well as removing the capital investment and other expenses for Hopkins Ridge, there would be a revenue deficiency of approximately $49 million for the test year without the Hopkins Ridge Project. Thus, the net impact of adding the Hopkins Ridge Project is an increased revenue requirement of only $5.7 million during the test year. Moreover, the important revenue requirement impact that the Hopkins Ridge Project will have on rates is the cost of this resource over its life compared to the alternatives. As Mr. Elsea explains, this is projected to be a net present value savings of approximately $30 million over twenty years.

V. THE NEW POWER COST RATE

Q. Please describe the impact of the pro forma adjustments on the Power Cost Rate.

A. Exhibit No. ___(JHS-5C) at 1 shows the impact of the above adjustments on the Power Cost Rate. This exhibit is prepared in the same manner as Exhibit A included in the PCA Settlement Stipulation. See Exhibit No. ___(JHS-3) at 15. The costs have been allocated in the same manner between fixed and variable costs and the total costs are adjusted for revenue sensitive items. Following the same methodology set forth in Exhibit A in the Settlement Stipulation, this result is then divided by the test year delivered load to calculate the new Power Cost Rate of $54.876 per MWh, shown on line 38. This is the rate that is used for determining the required revenue increase in Exhibit No. ___(JHS-6).

Q. Please explain the column labeled Adjustment to Power Cost Rate in Exhibit No. ___(JHS-5C).

A. In the 2004 general rate case, the ratebase impact of the deferred taxes associated with Cabot, White River and Tenaska regulatory assets were properly reflected in the Power Cost Rate. However, the turn around of these deferred taxes was improperly included in the power cost expenses for the Power Cost Rate. As these taxes are an offset to current taxes payable, which are not part of the Power Cost Rate, these taxes should not have been included in the expense side of this calculation. This adjustment removes the impact of these taxes from the Power Cost Rate and moves them to the non-power cost portion of general rates. With this adjustment the Power Cost Rate that would be used during the rate year is $52.503 per MWh before adjustment for revenue system items.

Q. Please explain the remaining pages included in Exhibit No. ___(JHS-5C).

A. The remaining pages of this exhibit are equivalent to the exhibits A-2 through E included in the PCA Settlement and have been updated to reflect the changes in power costs presented by the Company. In the upper left hand corner of each of these pages is the reference to the exhibit being replaced in the Power Cost Adjustment Mechanism.

Q. How will the new Power Cost Rate be implemented as the proposed rate year does not match the annual PCA accounting period of July through June?

A. Each month the Company calculates the potential over or under collection of power costs for the PCA. For the fixed cost component of the PCA, the Company assumes that these costs are collected equally over the twelve month period. Once PSE has the new rate approved, the Company will change this part of the calculation to reflect the new monthly fixed costs allowed in the PCA for the remaining months of the PCA period.

As the variable costs are adjusted to actual variable costs, PSE will treat these costs in the same manner as the current PCA calculation. The Company will then deduct for any adjustments required under the PCA mechanism, including, for example, the Schedule E Contract Adjustments. Exhibit E for the third PCA period will be divided into two rate periods: (i) a 5-month period, July 2005 through November 2005, that will use the contract rates approved in WUTC Docket No. UE-040641, and (ii) a 7-month period, December 2005 through June 2006, that will use the contract rates approved in this Docket.

The monthly total of the above adjustments will then be compared to each month's delivered kWh's times the appropriate Power Cost Rate and any variance will be the amount that will be considered in the sharing mechanism of the PCA.

The total of each month's variance for the PCA period will determine if there is any refund or collection of power costs required for the PCA period, after consideration of the various PCA bands and caps.

VI. REQUESTED RATE INCREASE

Q. Please explain how the Company calculated the rate increase required after taking into consideration the power cost pro forma and restating adjustments.

A. As the Company is only requesting that a portion of its rates be adjusted using the power cost only rate filing, the Company has calculated the required change in rates using the difference between the current and proposed Power Cost Rate. This calculation is shown in Exhibit No. ___(JHS-6). As shown on line 15 of this exhibit, the new rate is $54.876 and the current rate is $51.445 after revenue sensitive items are applied. The difference between these two rates is multiplied by the normalized delivered load for the test period. The result of this calculation is the requested change in revenue requirement of $68,711,052 after revenue sensitive items. This change in rates results in an average increase of approximately 4.52%. However, the rate increase being requested by the Company is lower than this amount due to the impact of the Production Tax Credit associated with the Hopkins Ridge Project, as described below.

Q. Would you please explain what the Production Tax Credit is?

A. The Production Tax Credit ("PTC") is a subsidy provided by the U.S. Government for generating electricity from wind. The amount of the subsidy is currently 1.9 cents per kilowatt hour for wind generation and will be adjusted over time due to inflation adjustments. As of the date of this filing, this subsidy can be claimed for the first 10 years for a new wind project put into service prior to January 1, 2006. The use of the credit is restricted in that it can only be used to offset 25% of a company's current taxes payable. However, unused credits can be carried forward for up to 20 years.

Q. How does the Company propose to pass the PTC through to the customer?

A. The PCA mechanism only includes tax accounts associated with production plant and production related regulatory assets. As mentioned above, the use of the tax credits are restricted to offsetting 25% of the Company's current taxes payable, with the possibility of being carried forward to future years' taxable income if it is not possible to utilize them in the current year. In addition, the tax credits are associated with the current years taxable income which is payable in quarterly installments during the year with any final payments being made in September of the following year. This creates a deferred tax account based on the timing difference between the generation of the tax credits associated with actual generation of electricity from the wind plant and how the tax credits would impact current taxes for taxable income. This accounting impacts Account 236, current taxes payable, and Account 190, Accumulated deferred income taxes which are not reflected in the PCA tracking.

To properly flow these tax credits through to the customer, the Company proposal is to create a PTC tracker that will pass through to the customer the actual production tax credits as they are generated and the tracker would not be subject to the sharing bands in the PCA. This pass through will be adjusted by the carrying costs for the deferred tax account for the PTCs that have been generated but have not been used for the current years tax credit. As the customer is receiving the benefit of the tax credits as they are generated and the Company does not receive a credit from the IRS until the tax credits are utilized the Company is reimbursed its carrying costs for funds through this calculation. This tracker would initially be used for the Hopkins Ridge Project, but would also be available for the PTCs that may be associated with other wind generating facilities that the Company may acquire in the future.

The initial tracker for these credits has been estimated using the projected PTCs to be generated by the Hopkins Ridge Project and the estimated balance of the deferred tax account. This calculation is shown on Exhibit No. ___(JHS-7). During the rate year, and beyond, the actual PTCs generated by PSE's wind facilities and the return on the actual deferred tax balance will be compared to the amount included on customers' bills. Any difference between the actual amounts versus what was credited to customers will be used to adjust the tracker. PSE will also adjust the tracker for any new estimates of PTCs based on a forward looking tax year. It is our expectation that this tracker will be adjusted yearly to reflect these differences or a report will be filed showing why an adjustment is not necessary. As this tracker is not tied to a PCA period or a PCORC filing, and instead is tied to the Company's tax filings, the Company proposes to file an update every October for the next tax year with the ability to file sooner to adjust a tax year if the PTC's generated versus what were estimated vary by more than 25%.

Q. What is the resulting adjustment to the revenue requirement the Company is requesting in this proceeding for the PTCs?

A. The result of this calculation is a change in revenue requirement for a credit of $13,139,386 after revenue sensitive items. This change results in an average rate decrease of approximately 0.86%.

Q. What is the total rate increase the Company is requesting in this proceeding?

A. The requested rate increase is the sum of the PCORC revenue deficiency and the Production Tax Credit revenue calculation. This is shown on Exhibit No. ___(JHS-8). The total rate increase is $55,571,666 which is a 3.65% increase over current rates.

Q. Is the Company proposing any adjustment to rates for power costs that have been previously deferred?

A. Not at this time. Power costs that have been deferred based on the PCA sharing bands do not total, and are not projected to total, $30 million dollars at this time. This amount is the trigger which would allow the Company to file for deferral recovery.

The Company is entitled to recover in rates any amounts that have been deferred in excess of the overall $40 million dollar cap when the cap is removed at the end of June, 2006, which will occur during the rate year for this PCORC. As stated in the PCA Settlement, at page 2, the Company can file for any deferred balances associated with the cap when the cap is removed on June 30, 2006. We will not know what that balance is until after that date.

VII. ISSUES RELATED TO REMOVAL OF THE $40 MILLION PCA CAP

Q. Are there any other items that need to be considered with respect to the removal of the $40 million cap at the end of June, 2006?

A. Yes. Because the Company is projected to incur excess power costs in an amount over the $40 million cap during the period that the rates set in this case will be in effect, there is a problem with how the customer deferrals are calculated under the PCA Mechanism before and after the cap is removed.

The PCA Rate during a PCA period is an average rate based on projected power costs during the rate year as a whole, and is not shaped into the months when the power costs are expected to be incurred. In addition, for actual power cost recovery, the fixed power costs are assumed to be recovered equally over a twelve month period. As load varies from month to month, the variable and fixed costs built into rates as an average rate do not match the actual variable and fixed costs that are calculated for a given month.

Q. Why is this a problem?

A. Normally this would not cause a problem as the total costs from rates and the actual costs over the PCA year would be equal (assuming the projection were accurate). However, as I mentioned earlier, the Company is expected to be over the $40 million cap on excess power costs during the first seven months these new rates are in effect. During this time period, the customer is allocated 99% of any excess power costs or of any power cost savings.

Because the variable power costs are projected to be lower during the first part of the rate year when compared to the average rate set in the PCA Rate and the fixed costs recovered in rates during the first seven-month period of the rate year will be greater than the fixed costs assumed in the actual power cost calculation, the Company will appear to have experienced "power cost savings" during this seven-month period. Under the 99% sharing band associated with the $40 million cap, it is estimated that customers will receive a credit of approximately $12.7 million against power costs for the period. However, that $12.7 million is in fact needed to cover the power costs that are projected for the last five months of the rate year.

In the last five months of the rate year for this case, the average PCA Rate compared to the Company's actual costs for power will show an under recovery of power costs. If the $40 million cap were still in place, these additional costs would be deferred for recovery from customers and would offset the costs previously credited to the customers. However, because the Company will now be at the beginning of a new PCA period and because the $40 million overall cap will have been removed, the Company will be in the first $20 million sharing band, in which the Company absorbs 100% of these additional power costs.

Q. What is the ultimate result?

A. The Company is projecting from the outset of this PCORC case that it will be forced to credit customers with phantom "power cost savings" and, in fact, to absorb significant excess power costs during the course of the rate year for this case, due entirely to a coincidence of the timing of this case, the date set in July 2001 for the removal of the $40 million PCA Mechanism cap, and the fact that power costs typically are not shaped for recovery during a rate year based on when they are projected to occur within the rate year.

Q. Do you have an exhibit that demonstrates how this occurs?

A. Yes. Exhibit No. ___(JHS-9) shows the average rate for the first seven months of the rate year, the last five months of the rate year and the twelve month rate period. It also separates the variable and fixed cost components of the Power Cost Rate. As shown on the exhibit, variable costs are over recovered ~$6.7 million, line 8 and fixed costs are over recovered ~$6 million, Line 23. Over the next five months the opposite occurs and the Company under recovers these costs.

Q. Are there any other issues related to expiration of the $40 million cap?

A. Yes. With the $40 million cap in place, the highest exposure the Company faced was $40 million during a calendar year. With the cap removed, the PCA Mechanism annual sharing bands will determine the excess power costs to which the Company is exposed.

The annual sharing bands contemplate limiting the Company's exposure to excess power costs on an annual basis. Under the sharing bands, the Company must absorb 100% of the first $20 million of excess power costs, 50% of $20-40 million, 10% of $40-120 million, and 5% after $120 million. However, because the 2001 general rate case happened to settle such that new rates went into effect on July 1, 2002, the PCA year is currently July through June. Because there are two PCA periods within the calendar year, the Company's power cost exposure during a fiscal year is different than its exposure during a calendar year.

Q. Would you please provide an example?

A. Say, for example, that the Company experiences $20 million in excess power costs in the first part of the calendar year, which is the second half of one PCA period. Rather than having some assurance that its exposure will be limited to 50% of the next $20 million in excess power costs it incurs in the second part of the calendar year, and to 10% of amounts in excess of $40 million, the Company is in fact exposed to absorbing far more excess power costs during that fiscal year because the sharing bands are reset to zero on July 1 with the start of a new PCA period.

Q. Is the Company proposing an adjustment to address these issues at this time?

A. No, the Company is not proposing a specific remedy to this problem at this time. As discussed by Ms. Harris, the Company plans to meet with Commission Staff, Public Counsel and other parties to discuss this and other issues during the course of this proceeding to attempt to develop an agreed solution, which would be filed with the Commission.

VIII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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