EXHIBIT NO. ___(JLM-4HC)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: JOEL L. MOLANDER

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-06____** **Docket No. UG-06____**

THIRD EXHIBIT (HIGHLY CONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF JOEL L. MOLANDER ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

FEBRUARY 15, 2006

MEMORANDUM

January 10, 2006

To: PSE Board of Directors

From: Eric M. Markell

Subject: Proposed Power Sales Agreement by Public Utility District No. 1 of Chelan County to Puget Sound Energy for 25% of Chelan Power System Output, totaling approximately 487 MW Capacity and 243 MW Average Annual Energy[1]

The purpose of this Memorandum is to describe:

- A proposed transaction by which Public Utility District No. 1 of Chelan County (the "District") and PSE would enter into a 20-year Power Sales Agreement for 25% of Chelan Power System Output (and, separately, a Transmission Agreement for an adequate amount of Chelan Transmission System capability to deliver Output to PSE), commencing upon or shortly after expiration of PSE's existing long-term contracts with the District for Rocky Reach and Rock Island (expiring in 2011 and 2012, respectively).
- The key commercial terms and risk factors of the proposed transaction.
- The estimates of future costs that will determine the power price to be paid by PSE.

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[1] Chelan Power System as defined in the Agreement means, collectively, the Rocky Reach and Rock Island projects—two hydroelectric dams located on the Columbia River in central Washington with installed capacities of 1,287 MW and 660 MW, respectively. Output means an amount of Energy, Capacity, and certain rights available from the Chelan Power System.

- The need for, and benefit of, the proposed transaction.
- The expected ratemaking and accounting treatment for the proposed transaction.
- The plan to finance the prepayment amounts required for PSE to gain the rights to Output under the proposed Power Sales Agreement.
- The analysis and projected "stand-alone" financial pro forma for the combined Power Sales Agreement and Transmission Agreement.
- Management's recommendation to PSE's Board of Directors for approval to complete contract documentation and to execute the definitive agreements.

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The Need for, and Benefit of, the Proposed Transaction

PSE's 2005 Least Cost Plan ("LCP") was published in April 2005 as part of PSE's efforts to analyze and document its projected load and corresponding need for additional resources. The LCP incorporated a comprehensive assessment of available conservation resources and a fully-integrated portfolio analysis that evaluated both conservation and supply resources.

The LCP identified a need for additional electric energy resources based upon the "B2" planning standard, which was adopted by PSE's Board of Directors. The "B2" standard requires PSE to plan energy supply additions to meet its highest deficit month. PSE's increasing resource need is driven both by forecast load growth and loss of existing generating resources. Over the period from 2006 through 2013, the "B2" planning deficit rises from 208 aMW to 1,471 aMW. For planning purposes, PSE assumed that its contracts with the District would be renewed in the aggregate at half of their existing levels. The proposed transaction improves upon that assumption with respect to Chelan by 39 aMW. In addition, PSE's conservation efforts are expected to reduce the 2013 deficit by 195 aMW, resulting in a need for 1,237 aMW of additional supply resources to be acquired (via outright ownership or power purchase agreements) in order for PSE to meet its planning standard by 2013. (See **Exhibit 1**, "Resource Need, Portfolio and Market Benefits.")

Context and Background Information

Under cost-based contracts, PSE currently purchases approximately 43% (830 MW capacity) of the District's aggregate output from its Rocky Reach and Rocky Island hydroelectric projects on the Columbia River.

- Rocky Reach: 38.9% (500 MW), expiring October 31, 2011

➢ Rock Island: 50.0% (330 MW), expiring June 7, 2012[2]

In 2004, output from the two projects constituted approximately 15% of PSE's energy production. The present price for that power under the current contracts and budgets is approximately $17 / MWh, which does not reflect a full amortization of outstanding project debt over the terms of the current contracts. In addition, the present price of power is not indicative of the future price for Chelan Power System Output. This is because current costs do not reflect significant impending capital outlays related to relicensing Rocky Reach and refurbishing Rock Island, some of which will be incurred prior to the expiration of these current contracts. PSE's estimate of future power costs under the proposed Power Sales Agreement does include all estimated future capital costs.

In addition to capacity and energy, PSE receives various ancillary services under its current contracts and through implementation of the Mid-Columbia Hourly Coordination Agreement.

<u>No Right of First Refusal or First Offer</u>

PSE's existing long-term contracts with the District contain no provisions for any right of first refusal, right of first offer or extension beyond their current term.

<u>A Lengthy Dialogue</u>

Beginning in mid-2002, the District and PSE engaged in periodic conversations about a possible new contract. Extensive discussions did not commence until July 2005, when the District delivered to PSE a term sheet that outlined proposed terms and conditions for a new contract. Negotiations became continuous after that, culminating in an agreement in principle on key commercial terms in late November.

Unlike the expiring contracts, the proposed Power Sales Agreement aggregates the output from the Rocky Reach and Rock Island projects into a single system slice. The proposed

[2] To be more precise, PSE now has contract rights to 50% of Rock Island I and 55% of Rock Island II. The District will make its one remaining withdrawal from PSE's share of Rock Island II effective November 2006, which will reduce PSE's share of Rock Island II from 55% to 50%. PSE's contract right will remain at 50% of Rock Island for the rest of the contract term.

Power Sales Agreement will be effective upon or soon after the expiration of the existing contracts.[3] The total capacity made available to PSE under the new contract is approximately 487 MW, or about 8.9% of PSE's current peak power resources.

Since 2002, District representatives regularly stated that they would offer PSE at most a 20% slice of the District's combined projects—if a new contract could be reached at all. The District's July 2005 term sheet was consistent with that position. Throughout the 2005 negotiations, however, PSE representatives stressed the Company's need for power and its desire for a larger share of the output, as well as for a longer term. Ultimately PSE was successful in obtaining a larger share of system output than initially offered by the District.

Key Commercial Terms of the Proposed Transaction

PSE and the District have reached agreement on the following key terms of a new long-term Power Sales Agreement for Chelan Power System Output:

- **Term:** 20 years, expiring October 31, 2031
- **Project Share:** 25% slice of the Chelan Power System. Output, as defined, includes:
  - Capacity: approximately 487 MW
  - Energy: approximately 243 aMW
  - Specified ancillary services, including spinning and non-spinning operating reserves, load following and regulation, and pondage.[4]

[3] The current Rock Island contract expires on June 7, 2012 and the District's proposed new Power Sales Agreement takes effect on July 1, 2012 for Rock Island Output, resulting in a 23 day gap between contracts. This is a desirable outcome as it 1) cleanly separates the terms and conditions from the expiring contract from those of the new Power Sales Agreement and 2) occurs during a time of year when PSE is normally surplus or the region has excess hydropower.

[4] PSE will have access to 90% of its slice share of pondage rights under the proposed contract, in lieu of 100% under the current contracts.

- **Pricing:** The proposed transaction continues the cost-based nature of the existing contracts with the District. In addition, the District demanded and the Company agreed to an upfront capacity reservation payment of $89 million, to be paid within 30 days of receipt of all necessary approvals.

- **PSE's Estimated Long-term All-in Power Cost Including Transmission:** (See **Exhibit 5.a-c**, "Project Financial Pro Forma")

	Levelized – 2006	Levelized – 2011
Operating Cost per MWh	[redacted]	
Imputed Debt		
Total Cost per MWh		
Replacement Cost per MWh[5]		
Levelized Savings per MWh		

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- **Take or Pay:** PSE will pay 25% of Chelan Power System costs as defined and bear the risk of output, similar to the expiring contracts.

- **Delivery Commencement:**
    - November 1, 2011 for Rocky Reach Output
    - July 1, 2012 for Rock Island Output

- **Approvals:** PSE's Board of Directors

  District's Board of Commissioners

  FERC[6]

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[5] The levelized replacement cost is based on a synthetic hydro resource, calculated using an Aurora-based long-term forecast of short-term energy prices at the Mid-C Hub and procurement costs related to ancillary service, including load following and regulation, spinning and non-spinning reserves, and capacity charges.

[6] FERC approval under Section 22 of the Federal Power Act is required due to the proposed Power Sales Agreement term extending beyond the expiration of project FERC licenses.

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- **Contracts:** 1) Power Sales Agreement

  2) Transmission Agreement

- **Operational Control:** The District will retain operational control over its projects. PSE may make recommendations to the District regarding its operation and maintenance of the Chelan Power System, but the District is not obligated to implement such recommendations.

- **Capital Project Financing:** PSE's current contracts with the District require the District to fund capital projects with the proceeds of debt issued by the District.[7] PSE estimates that practice will result in an outstanding principal District debt of approximately [redacted] at 2011/2012, when the contracts expire. In the course of the 2005 negotiations, the District informed PSE that it was absolutely unwilling to repeat such a circumstance in any new contract. Accordingly, the District was unmovable in its position to have the flexibility to place future capital requirements of the two hydro projects on a "pay-as-you-go" funding basis. PSE's financial modeling of the new contracts depicts the effects of this new methodology on the cost of Output.

- **Mandatory Step-up Provision:** If another purchaser defaults under a similar contract to the proposed PSE contract, the District chooses to terminate that purchaser's contract, and the District does not need such output and cannot secure another buyer, the new contract gives the District the right to force PSE to "step-up" into its pro rata share of the defaulting purchaser's Output under the terms and conditions of PSE's contract. PSE's maximum obligation to purchase Output in these circumstances, however, is capped at 40%, including its base 25% interest.

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[7] Under the current contracts, the District must first make use of annual reserve and contingency fund payments, which total approximately $3.2 million per year for Rocky Reach and Rock Island combined, prior to issuing debt for capital projects.

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Power Sales Agreement and Projected Power Costs

Evaluation of this proposed contract requires an understanding of the types of costs that will be charged to PSE. To perform that evaluation, PSE projected and accumulated cost components and forecasts more than 25 years into the future. Broadly speaking, the costs payable under the contract consist of operation and maintenance (O&M); debt service related to unamortized debt at expiration of the current contracts; debt service and "pay-as-you-go" charges related to capital costs to be incurred during the term of the new contract; and working capital.

In the course of negotiations, the District provided access to feasibility assessments related to the present condition and future rehabilitation requirements of Rocky Reach and Rock Island. However, the District did not provide PSE with a projection of its future operating cost and capital requirements. Thus, future project costs are best estimates.

Nonetheless, PSE has substantial information that has been used to forecast future project costs based upon PSE's longstanding participation in these projects and its substantial experience as a hydro project licensee and operator. PSE's projection of future O&M costs and capital expenditures used past results, budgets, estimated facility service lives, feasibility and condition assessment reports, and information about future investment plans gathered during meetings with District personnel. Further, PSE's financial model of the District's future cash requirements took into account the "pay-as-you-go" funding approach contemplated in the new Power Sales Agreement.

Initial construction of the Rock Island and Rocky Reach projects was completed in 1931 and 1961, respectively.[8] Since inception, these projects have periodically undergone capital improvements and equipment upgrades based on economics, regulatory or environmental requirements, and prudent utility practices. Ongoing estimates of these aging projects suggest numerous equipment upgrades will be required to meet FERC

[8] Rock Island Powerhouse No. 1 was constructed in 1931 and expanded in 1953. Rock Island Powerhouse No. 2 was constructed in 1979.

relicensing and other existing and emerging environmental and regulatory requirements during the 20-year term of the proposed Power Sales Agreement.

PSE prepared the following estimate of future O&M and capital expenditure requirements: (See **Exhibit 5.a-c** "Project Financial Pro Forma.")

- **Licensing Costs [redacted] million nominal):** The Rocky Reach project license expires in 2006. The District reached a multi-party settlement agreement in December 2005, which is estimated to cost approximately [redacted] million (nominal O&M and capital costs) during the contract term.[9] Major components of the expected settlement include:

Rocky Reach FERC License (100% Cost During Contract Term)	**O&M Nominal $ Millions**	**Capital Nominal $ Millions**	**Total Nominal $ Millions**
Shoreline Erosion Management Plan	[redacted]		
Anadromous Fish Protection			
Comprehensive Fish Management Plan			
Bull Trout Management Plan			
Pacific Lamprey Monitoring and Management Plan			
Wildlife Management Plan			
Cultural Resources Management Plan			
Recreation Management Plan			
Total Cost (nominal)			

The Rock Island project license expires in 2028. PSE has used the Rocky Reach process and expected settlement agreement as a proxy for future cost requirements, which are estimated at approximately [redacted] million (nominal O&M and capital) during the contract term.

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[9] Source: Applicant prepared FERC Preliminary Draft Environmental Assessment for Rocky Reach, FERC No. 2145.

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Rock Island FERC License (100% Cost During Contract Term)	O&M Nominal $ Millions	Capital Nominal $ Millions	Total Nominal $ Millions
Relicensing Studies			
Shoreline Erosion Management Plan			
Anadromous Fish Protection			
Comprehensive Fish Management Plan			
White Sturgeon Management Plan			
Bull Trout Management Plan			
Pacific Lamprey Monitoring and Management Plan			
Wildlife Management Plan		REDACTED	
Cultural Resources Management Plan			
Recreation Management Plan			
Total Cost (nominal)			

- **Rehabilitation / Modernization Costs [redacted] million nominal):** PSE estimates future rehabilitation and modernization costs of approximately [redacted] million and [redacted] million (nominal capital costs) for Rocky Reach and Rock Island, respectively, during the contract term. PSE based its estimates on past results and budgets, estimated equipment service lives, feasibility and condition assessment reports, and information gathered during meetings with District personnel.

Rehabilitation and Modernization (100% Cost During Contract Term)	Rocky Reach Nominal $ Millions	Rock Island Nominal Cost Millions
1.0 Turbines		
2.0 Auxiliary Mechanical		
3.0 Generators		
4.0 Controls		REDACTED
5.0 Transformers		
6.0 Switchgear		
7.0 Miscellaneous		
Total Cost		

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- **Operation and Maintenance Expense [redacted] nominal):** PSE has evaluated historical O&M budgets for both Rocky Reach and Rock Island and, using a 2.0% real growth rate and a 2.5% escalation factor, estimates future O&M costs of [redacted] and [redacted] for Rocky Reach and Rock Island, respectively, during the contract term.
- **Existing (non-incremental) Debt Service Obligations [redacted] million nominal):** Existing Rocky Reach debt service obligations total [redacted] million for Rocky Reach and [redacted] million for Rock Island during the new contract term.
- **Additional and Re-shaped Costs to Future Purchasers of Chelan Power System Output**: The District is expecting to aggressively manage its current and future debt position and will be equally attentive to its working capital needs and the credit quality of purchasers. Under the terms of the proposed Power Sales Agreement, PSE will pay the additional costs and charges described below.
    - **Capacity Reservation Charge:** PSE's current contracts with the District simply expire at the end of their term. The current contracts do not provide PSE with rights of first refusal, first offer, or any extension. In any event, the new contract imposes a non-refundable capacity reservation charge of $89 million for PSE's 25% slice, payable 30 days after the last needed regulatory or board approval is obtained. The $89 million capacity reservation charge payment will not be credited against any future payment obligations under the contract and the funds may be used by the District, as determined in its sole discretion, for any lawful purpose.
    - **Working Capital Charge:** The contract requires a non-refundable payment of $2.5 million per project (stated in 2004 dollars) to be paid on the Project Availability Date to provide the projects with an adequate working capital balance.[10] The District may increase this amount during any Contract Year, on a

[10] Project Availability Date means for Rocky Reach, November 1, 2011, and for Rock Island, July 1, 2012.

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pro rata basis by Purchaser percentage, as reasonably determined by the District.

- **Coverage Fund Charge:** The contract requires a non-refundable coverage fund charge payment calculated by applying a formula to the outstanding District debt obligations each year. PSE expects this amount to total approximately $2.1 million (nominal) during the contract term.

- **Prepayment Charge:** The contract requires a prepayment amount as security against a late or missed payment under the Power Sales Agreement or Transmission Agreement. For PSE this total is $18,500,000, which will be refunded to PSE, without interest, by applying the funds to PSE's final power cost bills at the end of the contract term.

- **Debt Reduction Charge and Capital Recovery Charge:** The contract implements two funds that are designed to facilitate the "pay-as-you-go" approach the District has adopted for future capital items for the projects. In particular, the contract imposes a Debt Reduction Charge and a Capital Recovery Charge, each and both intended to permit the District to purchase, redeem or defease debt of the Chelan Power System, to fund deposits to Reserve and Contingency Funds or to fund capital improvements related to the Chelan Power System. The Debt Reduction Charge and the Capital Recovery Charge are both non-refundable, and are calculated by formulas set forth in the contract. Charges imposed as Debt Reduction Charges or Capital Recovery Charges must be spent on the projects. Together the charges are subject to an adjusted annual cap that applies to unspent funds in the accounts.[11] That cap is initially set at $25 million per year stated in 2004 dollars.

[11] PSE is not obligated to pay its percentage of the Debt Reduction Charge and Capital Recovery Charge for any contract month if the aggregate amount of unspent cash and investments on deposit in the Debt Reduction Charge Fund and the Capital Recovery Charge Fund exceeds the product of the Capital Recovery Charge Base multiplied by five (the "cap multiplier"). The cap multiplier is reduced by a factor of one for each of the last four contract years.

- **Debt Administrative Charge:** The contract requires a Debt Administrative Charge as compensation for the District's provision of credit to PSE, and is calculated through a formula set forth in the contract. PSE estimates that this payment will average approximately [redacted] million annually during the contract term. All Debt Administrative Charge payments are non-refundable.

Transmission Agreement and Projected Cost

In a contract separate from the Power Sales Agreement—a structure intended to comply with FERC requirements—the District agrees to provide transmission services adequate to deliver the Output to the PSE system or other agreed upon points of delivery. As part of that obligation, the District acknowledges and agrees to accommodate compliance with the Mid-Columbia Hourly Coordination agreement as well as other obligations such as returning Canadian Entitlement energy and/or complying with the Pacific Northwest Coordination Agreement. In general, these agreements define operating parameters across the mid-Columbia hydroelectric projects, including federal facilities, and make operation of those projects unique and interrelated. The agreements also require or presume multi-directional movement of power, depending upon real-time conditions. As such, the Transmission Agreement will be unique; however, it will also be consistent with the transmission service the District has provided to PSE for the last several decades.

The Transmission Agreement calculates PSE's transmission charges through a formula that assesses the share of the Chelan Transmission System that was needed or used by PSE for delivery of Output in each preceding year. The charges imposed are payable monthly, and are non-refundable. PSE estimates these annual charges to be approximately [redacted] million on a nominal basis.

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Summary of Transaction Benefits

- **Lowers PSE's Overall Portfolio Costs.** The costs and benefits of the proposed Power Sales Agreement to PSE's overall resource portfolio were evaluated using the Company's 20-year Portfolio Screening Model that is used to evaluate all potential resource acquisition opportunities. PSE's portfolio costs with the proposed Power Sales Agreement are over $359 million lower on a present value basis than a portfolio with an assumed mix of contracts, gas and coal generation. The above savings are for the reference price scenario. PSE also conducted the analysis for a low gas price scenario. Under low gas and power prices the benefit of the proposed Power Sales Agreement to the portfolio is approximately $300 million lower on a present value basis.

  Comparatively, the proposed Power Sales Agreement and Transmission Agreement all-in cost on a levelized basis is competitive with alternatives recently acquired by PSE or contemplated through its portfolio planning and analysis activities. In addition, Output, as defined, includes ancillary services that may not be reflected in the estimates for the alternatives provided below.

Project	Approximate Levelized Cost per MWh	Variance to Proposal with Imputed Debt
1. Proposed Transaction - Without imputed debt - With imputed debt	[redacted]	
2. Hopkins Ridge		
3. Ormat Heat Recovery Facility		
4. Surrogate Wind PPA		
5. Surrogate Gas CCCT		

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- **Secures Critical Operational Flexibility.** PSE's execution of the proposed Power Sales Agreement assures the Company's continued access to one of the region's most valuable and scarce hydroelectric resources. Moreover, historically the output from these projects has been foundational to PSE's long-term energy supply portfolio and its daily operational flexibility. Continued access to this large hydro resource is a critical step toward assuring a stable, reliable, and low cost electric supply, including ancillary services, and helps to ensure PSE's ability to meet base-load, daily and seasonal peaking requirements, integrate existing and/or incremental wind or other variable production resources into the Company's supply portfolio, and provides increased certainty related to modeling and determination of PSE's future resource needs and supply alternatives.
- **Reduces Projected Long-term Energy and Capacity Deficit.** The proposed Power Sales Agreement secures 487 MW of hydroelectric capacity and 243 aMW energy that PSE has no contractual rights to beyond expiration of the current contracts. With respect to PSE's resource planning efforts, the Proposed Power Sales Agreement secures an additional 70 MW of hydroelectric capacity and 39 aMW of energy than previously assumed.
- **Continues Important Long-term Relationship with Leading Public Utility District and Central Washington Communities.** PSE and the District have shared common interests and objectives during the term of the current contracts. The District has proved to be a reliable owner/operator of the Chelan Power System.

Key Risk Factors Related to the Proposed Transaction

PSE has evaluated risks associated with the proposed transaction—many of which are continuing from or associated with the expiring contracts. Key risk factors and mitigation include:

Risk	Mitigation
Approval Requirements ➢ District's Board Approval	PSE has no obligation to the District unless its Board approves the transaction. Early indications are that the District Board may view the transaction favorably. In addition, PSE's upfront and 20-year commitments provide immediate and long-term financial benefits and certainty to the District.
Mandatory Step-up Provision ➢ PSE may be required to step-up into pro rata share of another terminated purchaser's share of Output under the terms and conditions of PSE's contract if 1. the District chooses to terminate that purchaser's contract, and 2. the District does not need such output and cannot secure another buyer because the contract is above market.	PSE's expectation is that the price of Output would be well below market, even in circumstances where another purchaser has defaulted. In addition, PSE's total project share is capped at 40%, including any mandatory step-up amounts.
Operating and Investment Controls ➢ The contract provides PSE with no right to impose its view on operating, financing or capital decisions of the District.	The proposed Power Sales Agreement provides PSE with annual power cost audit and verification rights, and does not preclude PSE from making suggestions to the District. However, PSE will be limited to relying on persuasion in cases where PSE desires to influence specific

Risk	Mitigation
	operations. Nonetheless, because the District will use substantial portions of the Projects' output to serve its own retail customers, the District's operating goals should be aligned with those of PSE in virtually all instances.
Transmission Rights ➢ FERC review and acceptance, rejection or modification of the proposed Transmission Agreement. ➢ Uncertainty related to BPA treatment of Mid-C Transmission Hub. ➢ RTO formation in the Northwest and its treatment of the Mid-C Transmission Hub.	Numerous contracts (Mid-Columbia Hourly Coordination Agreement, Pacific Northwest Coordination Agreement, and contracts related to the Columbia River Treaty obligations) affect the amount and location of power to be delivered to or by PSE under the proposed Power Sales Agreement and otherwise, necessitating a transmission agreement with sufficient flexibility to accommodate those contract obligations. The proposed Transmission Agreement preserves that flexibility. In the event an RTO is formed, it will most likely preserve pre-existing transmission agreement rights. The proposed Transmission Agreement accommodates that sort of RTO formation. During its term, the Mid-Columbia Hourly Coordination Agreement requires the continuation of the flexibility provided by the current practices surrounding the Mid-Columbia Transmission Hub.
Disputes Resolution ➢ No arbitration rights in the event of a contract dispute.	PSE and the District agree to first negotiate in good faith to attempt to resolve any dispute arising out of or relating to the proposed Power Sales Agreement. If the Parties are unsuccessful in resolving the dispute through negotiations, either Party may proceed to litigation regarding the dispute.

Price of Chelan Power System Output	
➢ PSE's payments to the District are cost-based and will be driven largely by the size and timing of future capital expenditures and FERC license or regulatory requirements, which may be unpredictably different than PSE's planning assumptions.	The design and scale of the Chelan Power System provides significant economies of scale and an ability to absorb unanticipated costs prior to rendering such projects uneconomic relative to alternatives.
➢ The proposed Power Sales Agreement continues PSE's exposure to annual power cost changes and may increase the magnitude of such changes due to the District's future setting of the Debt Reduction and Capital Recovery Charges.	The District is required to provide PSE with one-year's advance notice of any change to the Debt Reduction Charge and Capital Recovery Charge. In addition, PSE and the District will meet, at minimum, semi-annually to discuss the District's planning activities and projections for future power costs.
➢ The price paid by PSE may be greater than alternative resource costs in the future.	Analysis indicates that future Chelan Power System costs are expected to be well below long-term market prices and the cost of thermal and other alternatives; variable fuel costs are zero; hydroelectric technology is mature.
Take or Pay Contract	
➢ PSE is obligated to take or pay for any Output, whether or not produced, during the term of the proposed Power Sales Agreement.	Useful remaining facility life is estimated to be perhaps a half century and will be prolonged once incremental investments are made; insurance programs and value of power output in the market provide a high degree of assurance that in the event of a major casualty loss (e.g., earthquake) the projects will be re-built and continue in service. Moreover, this risk is lessened due to the District's long history of operating these projects and their transmission system precisely in a way to facilitate the generation and transmission of Output that the contracts contemplate.

Planning Uncertainties	
➢ Hydro volatility—normal precipitation and temperature-driven hydro volatility have been and continue to be contemplated by PSE.	PSE operations personnel regularly monitor precipitation, snow pack and temperature conditions and integrate such knowledge into the Company's portfolio management and hedging activities.
Licensing/Regulatory Risk	
➢ Licensing procedure changes ➢ Fisheries/wildlife protection or mitigation requirements ➢ Water quality requirements	Future outcomes of FERC license processes are not knowable, but PSE and the District have extensive experience in and on-going involvement with the communities of interest they serve and with hydro regulatory officials and requirements. PSE's best estimates project that operating and capital costs associated with these FERC-licensed hydro facilities are well within the range of reasonableness; no specific provision is made in PSE's cost projections for unusual and adverse judicial activism in the area of fish protection; however, we believe sufficient contingency is provided in such projection to cover unforeseen and adverse cost developments.
Political Risk	
➢ Dam removal advocates ➢ PUD Board volatility	The District is one of the largest employers in the greater Wenatchee area. Enormous political and business opposition would arise to oppose any dam removal effort. Further, PSE is establishing a local presence and implementing a community relations program through the District and local businesses and schools.

Dam Safety	
➢ Additional, unforeseen costs as a result of FERC criteria driven by Potential Failure Mode analysis, or increase in probable maximum flood and/or maximum credible earthquake events.	PSE has conducted a high-level review of the District's dam safety program and its compliance with rules and regulations prescribed by the FERC. The District's Rocky Reach and Rock Island projects meet the dam safety requirements in effect during its most recent FERC inspections, conducted in 2002. The District's projects will be re-inspected during 2006 and 2007. Future FERC dam safety criteria are not knowable, but PSE and the District have extensive experience and on-going involvement with FERC dam safety officials and requirements. No specific provision is made in PSE's cost projections for unusual and adverse dam safety remediation; however, we believe sufficient contingency is provided in such projection to cover unforeseen and adverse cost developments. (See **Exhibit 6**, "Dam Safety Assessment.")

Ratemaking and Accounting Treatment

The proposed transaction will be accounted for pursuant to the applicable accounting rules of the FERC and WUTC.

WUTC approval of the accounting and ratemaking treatment of the proposed transaction will need to be implemented in several steps because of the $89 million upfront capacity reservation charge, expected to be paid in 2006. Such a date is more than five years before the Chelan Power System Output will be provided to PSE under the proposed Power Sales Agreement.

PSE anticipates filing an Accounting Petition with the WUTC in January 2006 that will request the WUTC's approval of: (i) deferred accounting treatment of the $89 million upfront payment, and (ii) the booking of carrying charges on that payment at PSE's approved net of tax rate of return. The Accounting Petition will further request that the WUTC consider two issues as part of PSE's 2006 general rate case ("GRC"): (i) the prudence of PSE's decision to enter into the proposed transaction, and (ii) the rate treatment for recovery of the $89 million capacity reservation charge payment and carrying charges on that payment. In particular, PSE will request in the GRC that the WUTC permit the recovery in rates during the 20-year life of the contract of the $89 million capacity reservation charge payment and carrying charges on that payment commencing as of the date Chelan Power System Output begins to be provided to PSE under the proposed Power Sales Agreement (November 1, 2011).

Thus, the 2006 GRC will not request immediate rate recovery in the revenue requirement for that case of any of the costs associated with the proposed transaction. Such recovery would be requested in future rate cases as appropriate depending on the timing of future rate cases as related to the November 1, 2011 date of commencement of deliveries. However, by requesting that the WUTC determine the prudence of the transaction in the 2006 GRC, PSE will seek to avoid a situation in which the prudence of the transaction is first addressed years after the decision has been made, in what may be a different industry context with information that is not and cannot be known to PSE at the time of its decision to enter into the proposed transaction.

The ultimate impact of the proposed transaction on rates is anticipated to be favorable. The levelized long-term all-in power cost o[redacted]/ MWh (as of 2011) is significantly lower than other power resource alternatives. (See **Exhibit 3**, "Regulatory Treatment.")

Financing Plan

The cash requirements will be included in PSE's capital budget and will be funded as a component of the Company's overall financial strategy. It is expected that the Company will fund the initial cash requirements with its existing short-term credit facilities and then refund those borrowings using the proceeds of permanent long-term financing when

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conditions for issuing such financing are favorable in the capital markets. Permanent financing may include senior secured notes, preferred stock, and common equity.

Recommendation

Based on the described benefits of the proposed transaction, management recommends that the Board of Directors approve the transaction as proposed.

List of Exhibits

1. Resource Need, Portfolio and Market Benefits
2. Rocky Reach and Rock Island Projects Description
3. Regulatory Treatment
4. Accounting Treatment
5. Project Financial Pro Forma
    a. Assumptions for Financial Pro Forma
    b. Project Stand Alone Income Statement
    c. Capital Expenditure Forecast
6. Dam Safety Assessment
7. Power Sales Agreement
8. Transmission Agreement

Board of Directors' Meeting

Public Utility District No. 1 of Chelan County
20-year Power Purchase Agreement

25% Slice of Chelan Power System

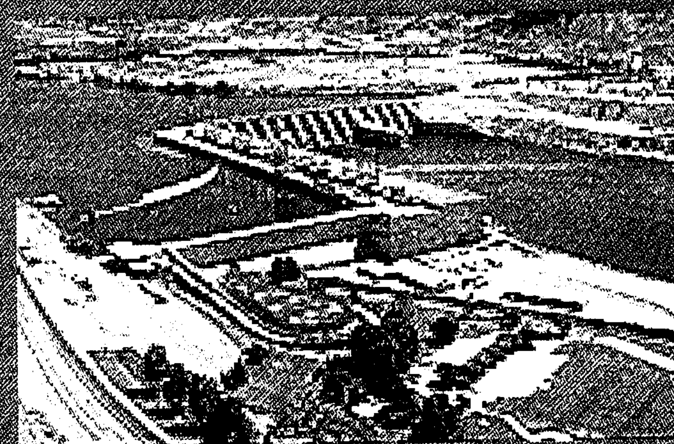
Eric M. Markell
Senior Vice-President, Energy Resources

January 10, 2006

PUGET SOUND ENERGY
pse.com

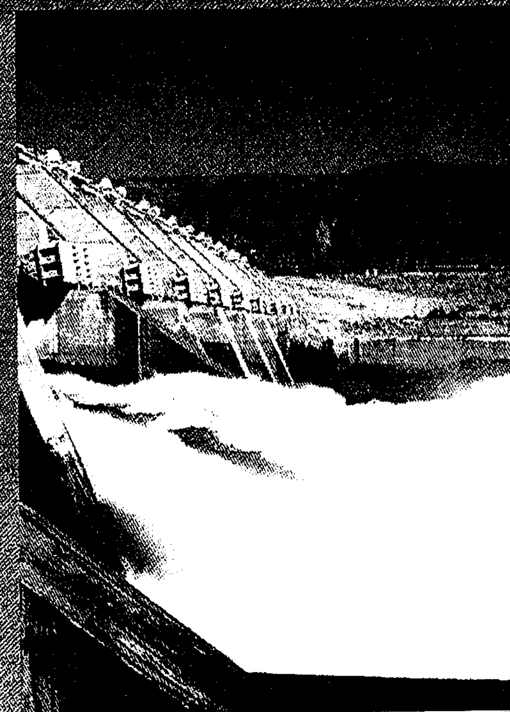
Chelan Power System

- **Owner:** Public Utility District No. 1 of Chelan County (the "District")
- **Projects:** Chelan Power System (1,947 MW, 100%)
  - Rocky Reach dam (1,287 MW, shown top)
  - Rock Island dam (660 MW, shown bottom)
- **Location:** Columbia River Chelan County, WA State
- **Transmission:** Chelan Transmission System, BPA, and PSE owned
- **Generation:** Hydroelectric



Expiring Contracts

- Rocky Reach: 38.9% (500 MW), expiring October 31, 2011
- Rock Island: 50.0% (330 MW), expiring June 7, 2012
- Aggregated portfolio contribution – 2004:
  - 830 MW capacity – 20% of PSE's peak power resources
  - 402 aMW energy – 15% of PSE's energy production
  - Current cost of approximately $17 / MWh – not indicative of future cost
- No rights of first refusal, rights of first offer, or rights to extend



Why Negotiate Now?

- PSE's desire to secure valuable resources for the foreseeable future
- PSE's expected need of nearly 1,700 aMW in 2013 if contracts are not renewed (excluding conservation initiatives) and desire to minimize uncertainty related to replacement planning and procurement
- District's desire to negotiate first with PSE and to reach agreement in principle by end of 2005
- District's desire to reduce uncertainty surrounding repayment of outstanding debt obligations past expiration of the current contracts
- District's desire to begin resolving future oversubscription of its system

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Key Commercial Terms

- Term: 20 years
- Project Share: 25% slice of Chelan Power System output:
  - Capacity: approximately 487 MW
  - Energy: approximately 243 aMW
  - Specified ancillary services
  - Certain use of the Chelan Transmission System
- Take or Pay: PSE will pay 25% of Chelan Power System costs as defined and bear the risk of output as it does presently
- Pricing: Preserves cost-based nature of expiring contracts including:
  - Operations and maintenance
  - Fixed-schedule debt service on District's outstanding debt obligations at expiration of current contracts
  - "Pay-as-you-go" capital financing charges in addition to debt service on incremental borrowings during term of proposed contract
    - Coverage fund charge
    - Working capital contributions
    - Upfront capacity reservation charge of $89 million and power cost prepayment charge of $18.5 million, paid in 2006 (anticipated) and 2011, respectively
    - Debt administration charge

Key Commercial Terms (continued)

- PSE's all-in power cost estimate:
  - Includes transmission to PSE or third-party transmission provider (BPA)
  - Operating revenues to fund
    - $89 million reservation charge
    - $18.5 million prepayment amount (refunded in 2031)
  - Conservative estimate of District's "pay-as-you-go" capital charges
- Operational and financial control retained by District
- Mandatory "step-up" provision

Proposed Transaction	Levelized	Levelized - 2011
Operating Cost per MWh	[redacted]	
Imputed Debt per MWh		
Total Cost per MWh		
Replacement Cost per MWh *(synthetic hydro resource)*		
Levelized Savings per MWh		

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Comparative Projects	Approximate Levelized Cost per MWh	Variance to Proposed Transaction
Chelan Power System Proposal	[redacted]	
Hopkins Ridge		
Ormat Heat Recovery		
Surrogate Wind PPA		
Surrogate gas CCCT		

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Due Diligence

- Transaction Financial Pro Forma – Comprehensive Forecasts of Future Costs
  - Significant construction and rehabilitation costs anticipated at Rock Island
  - FERC relicensing requirements at both Rocky Reach and Rock Island
  - Reshaping of debt service and capital financing through "pay-as-you-go" charges
- Portfolio Analyses
  - Replacement Cost Analyses
  - Portfolio Evaluation
  - Hydro Variability
- Dam Safety Assessment
- FERC Relicensing Assessment and Fisheries Management Review
- Accounting and Regulatory Treatment

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Key Risk Factors and Mitigation

- Take or Pay Contract
  - Investment and management controls
  - Hydro variability
  - Mandatory step-up
- Regulatory
  - FERC Licensing
  - Environmental
  - Dam safety

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Summary of Key Findings

- District maintains safe and reliable projects
- Both Rocky Reach and Rock Island are well positioned with respect to fisheries management and FERC licensing
- Cost-based price is expected to be well below alternative resources during the contract term
- Transaction produces over $359 million NPV portfolio benefit relative to existing portfolio and Least Cost Plan generics
- Levelized cost savings in excess of [redacted] / MWh compared to replacement alternatives
- Continues long-standing relationship with key partner in Pacific Northwest energy arena and surrounding communities
- Favorable outcome for PSE's customers and shareholders
- Preliminary indications of majority support among the District's Board of Commissioners

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Timeline / Next Steps

January 10, 2006	Management recommends the Board of Directors approve the transaction as proposed
Mid-January 2006	WUTC Accounting Petition related to Proposed Transaction
January 16, 2006	District's Board expected to announce resolution authorizing Proposed Transaction with PSE, commencing 2-week comment period
January 30, 2006	District's Board expected to approve resolution authorizing District to execute Power Sales Agreement and Transmission Agreement with PSE
February 1, 2006	GRC Filing
Q1/Q2 2006	FERC Section 22 filing and anticipated approval
Q1/Q2 2006	$89 million capacity reservation charge paid to District upon receipt of FERC Section 22 approval
2011/2012	Deliveries commence under the new contract

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Board of Directors' Meeting

Presentation Appendix

Eric M. Markell
Senior Vice-President, Energy Resources

January 10, 2006

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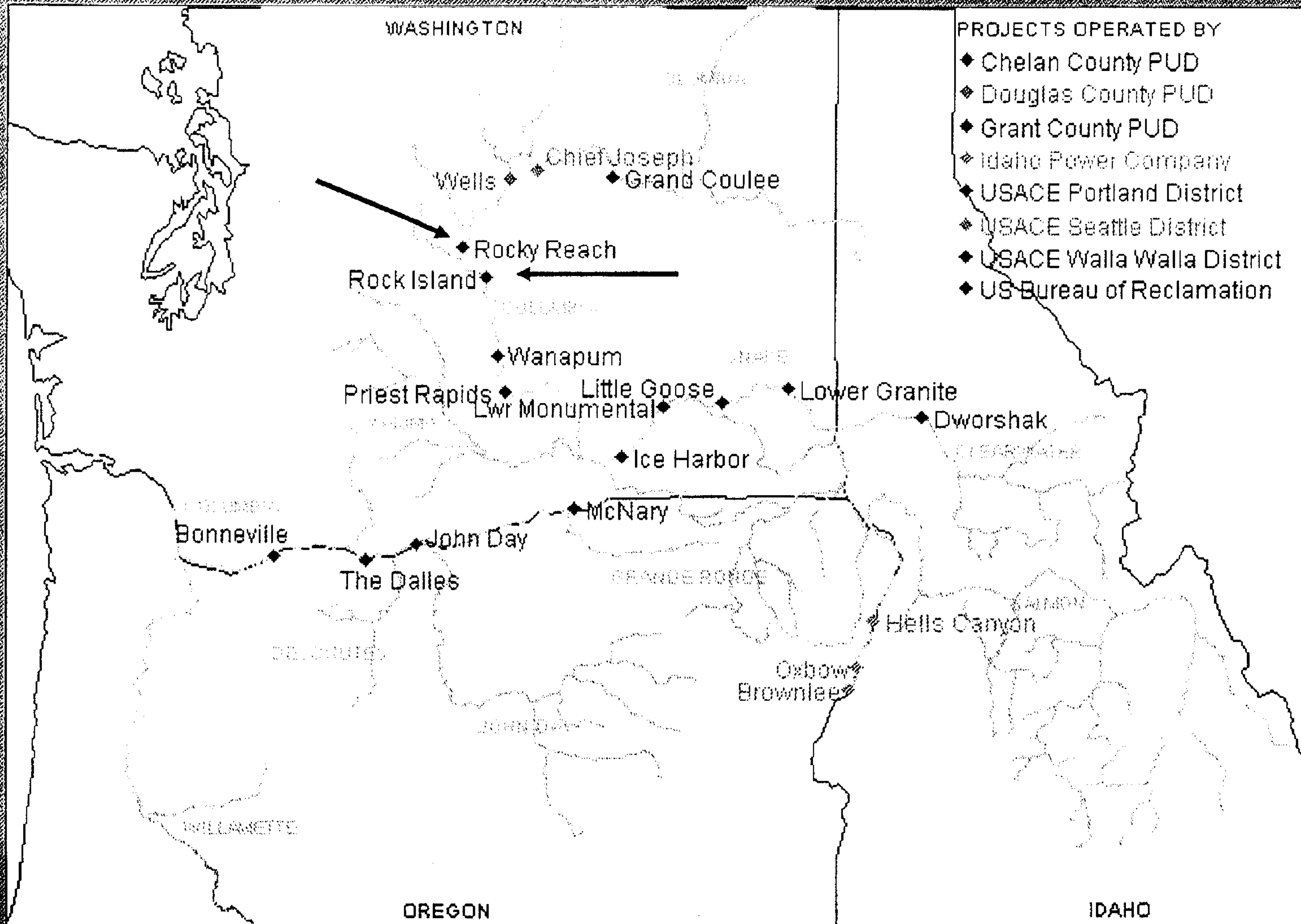
Location Map



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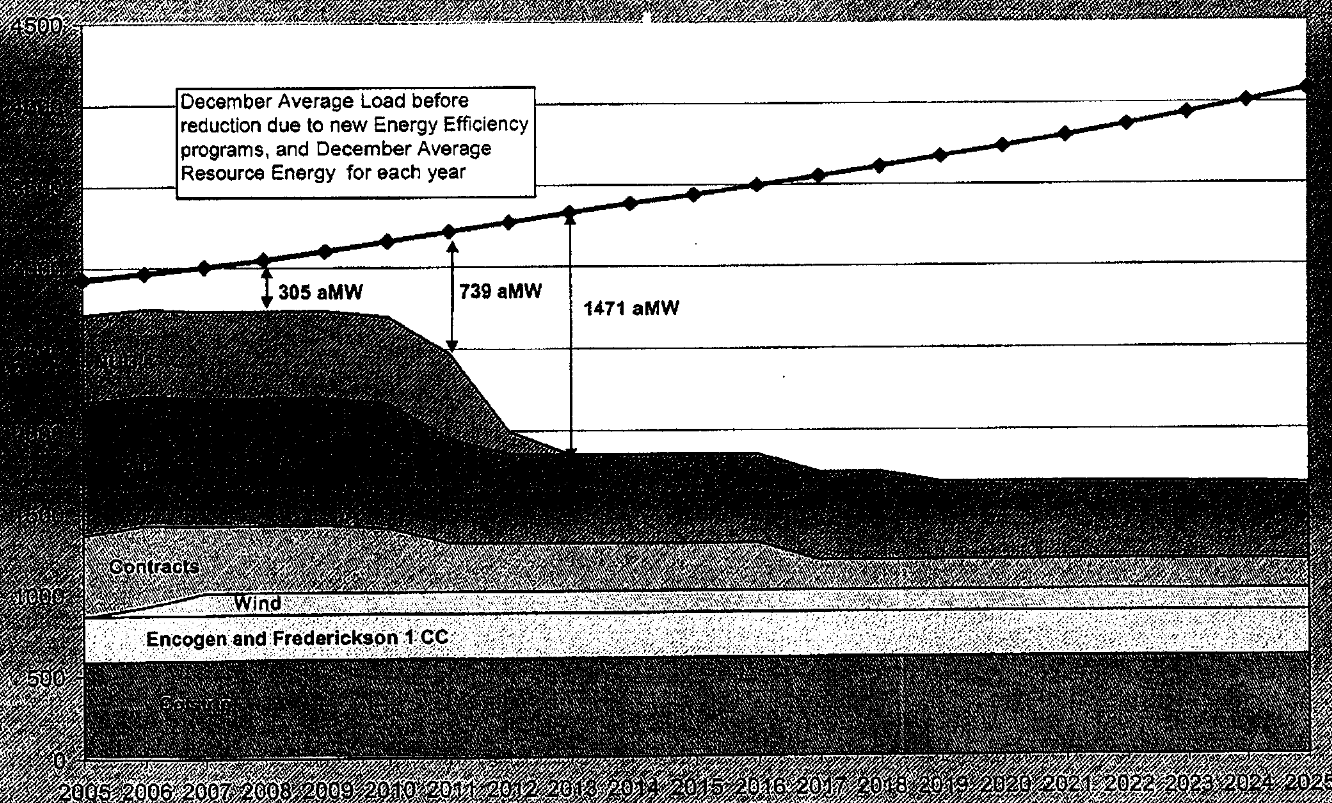
2005 Least Cost Plan
2006 – 2025 Load Resource Balance



For 2005 LCP planning purposes, PSE assumed that its contracts with the District would be renewed in the aggregate at half of their existing levels. The proposed transaction improves upon that assumption with respect to Chelen by 39 aMW in 2013.

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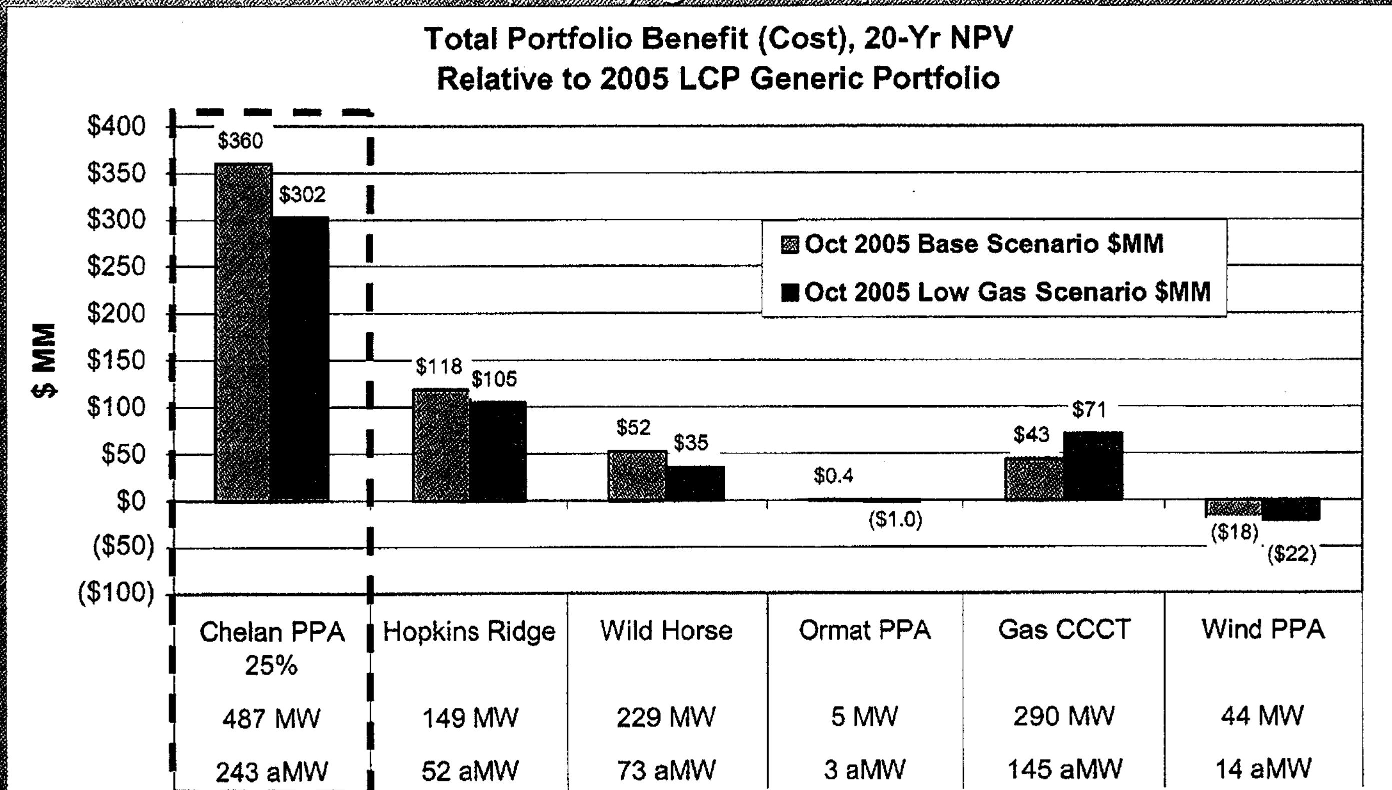
Portfolio Analysis Shows Significant Benefit from Chelan PPA

Portfolio Net Present Value (NPV) ranking as compared to 2005 Least Cost Plan (LCP) generic portfolio



Note: Generic portfolio consists of 10% renewable. Balance of need through 2015 is met with 50% gas and 50% market contract. In 2016 and beyond, balance of need is met with 50% gas and 50% coal.

Resource Cost Comparison

Resource and Technology 20-yr Levelized Energy Cost Comparison ($/MWh)

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Notes:

1. Preliminary cost data from PSE estimates. Costs have not been fully vetted.
2. Preliminary cost data from non-binding offer. Costs have not been fully vetted.

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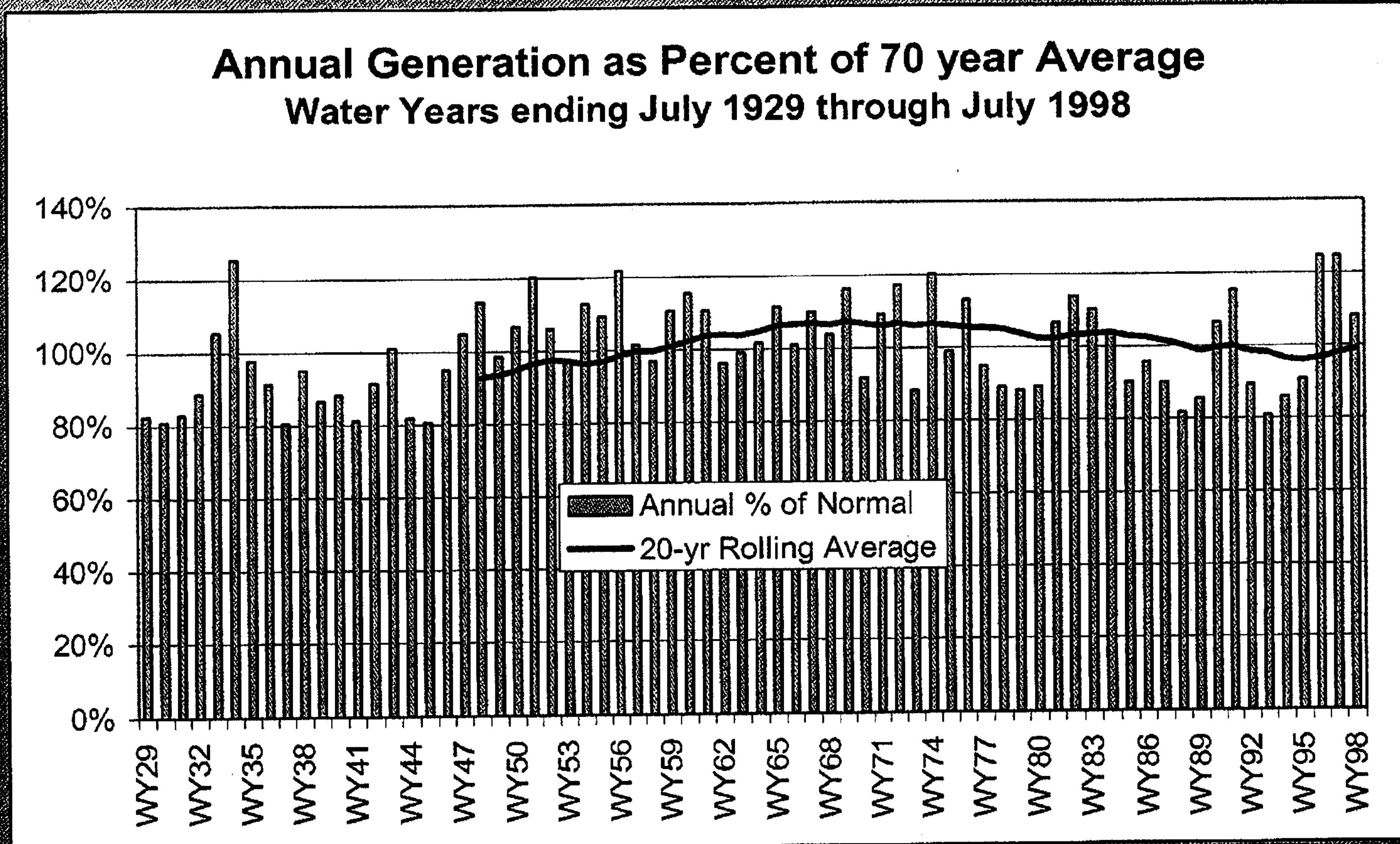
Hydro Variability – Annual



- Source: Final Regulation 2006 from NW Power Pool.
- Lowest Year = Water Year 1937 at 80%
- Lowest 20 Years = Water Years 1929 – 1948 at 93%

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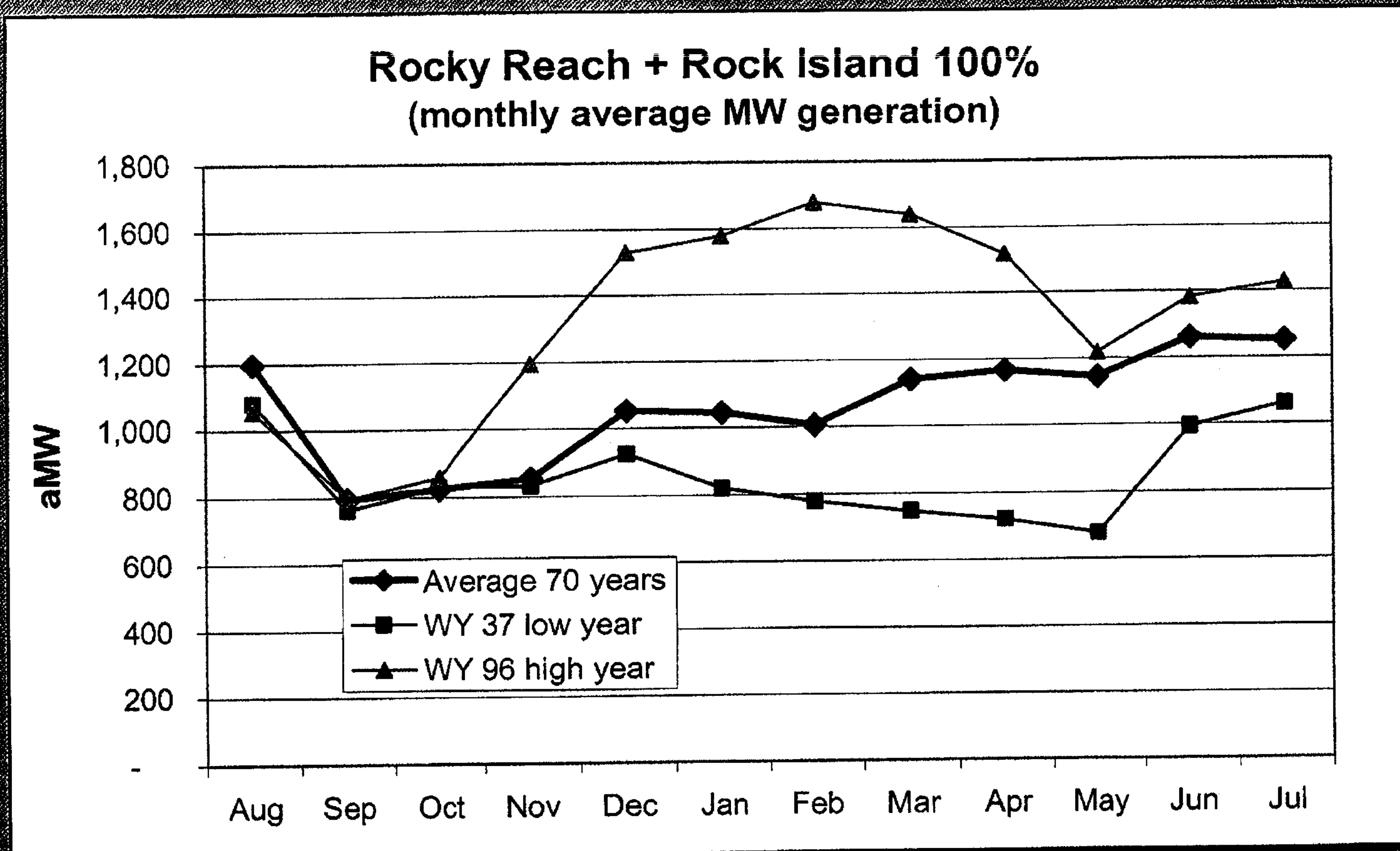
Hydro Variability – Seasonal



- Source: Final Regulation 2006 from NW Power Pool – 70 year average
- August – November is period of refill on upper Columbia River
- Highest variability in winter and spring

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Impact of Hydro Variability on Levelized Cost

Variability of 20-yr Levelized Cost $/MWh

[redacted]

Variability of year 2013 Cost in $/MWh

[redacted]

Twenty year levelized cost

- [redacted]
- Includes cost of imputed debt (S&P method) about $5.00 / MWh.
- If all 20 years are like the worst water year of 1937 (an extremely unlikely set of events), then levelized cost is [redacted]

Single year cost variability (2013)

- [redacted]
- Includes cost of imputed debt

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Comparison with Power Price Forecast

(Price includes synthetic hydro characteristics)

[redacted]

- AURORA forecast October 2005
- AURORA prices weighted by monthly hydro generation shape
- Capacity and storage value represents fact that PPA has approximately 50% capacity factor and provides flexibility for hourly load changes.
- Ancillary services represent value of reserves and load following.

[redacted]

[redacted]

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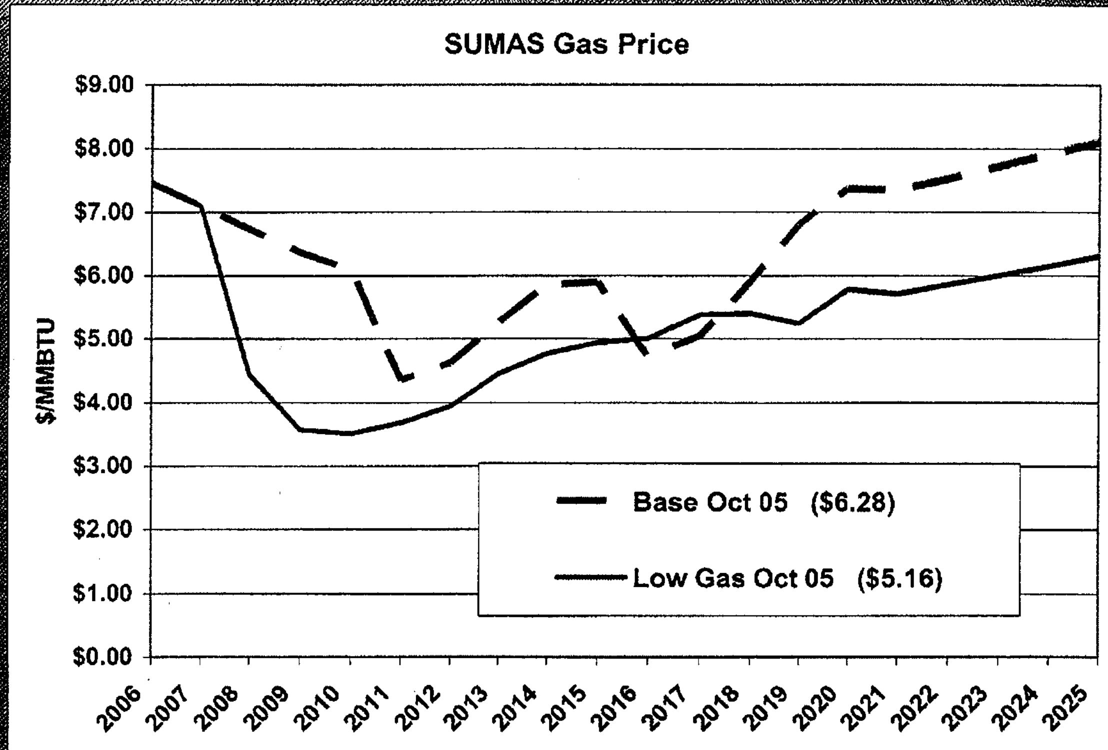
AURORA Gas Inputs October 2005

Base Gas Price Assumptions

- Levelized = $6.28 / mmbtu (2006-2025)
- 2006 – 2010 use forward prices based on average of historic forward prices 6/1/2005 through 8/15/2005. Forward prices are pre hurricanes Katrina and Rita.
- 2011-2020 CERA (Cambridge Energy Research Associates) "Rear View Mirror" forecast dated Q4 2004.



Low Gas Price Assumptions

- Levelized = $5.16 / mmbtu (2006-2025)
- 2006 – 2007 use forward prices based on average of historic forward prices 6/1/2005 through 8/15/2005. Forward prices are pre hurricanes Katrina and Rita.
- 2008-2020 CERA (Cambridge Energy Research Associates) "World in Turmoil" forecast dated Q4 2004.

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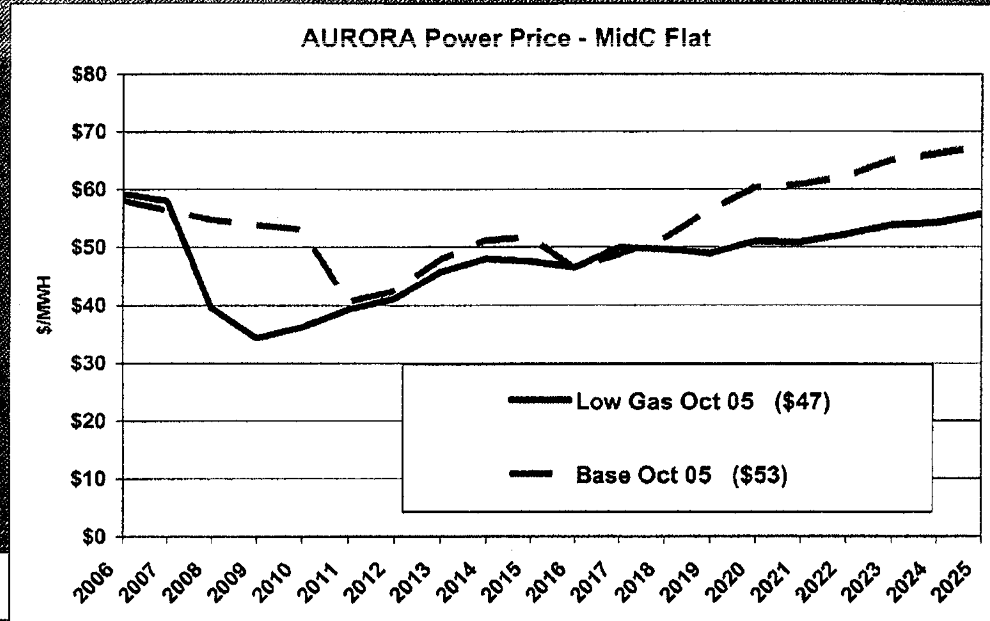
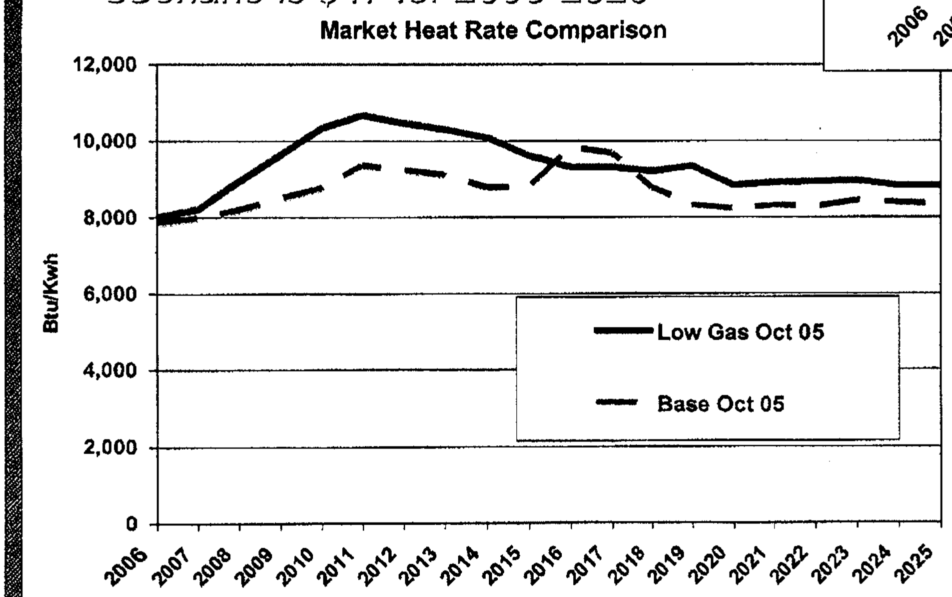
Aurora Power Prices and Heat Rate

- The AURORA model is a fundamentals-based production costing model that simulates regional wholesale power market prices using, among other factors, the supply of resources, the demand for power and constraints due to transmission.
- Levelized power price for the base scenario is $53 for 2006-2025
- Levelized power price for the low gas scenario is $47 for 2006-2025





- Power prices generally follow gas price inputs.
- Market heat rate is defined as the power price per kwh divided by gas price per mmbtu
- Heat rate is in units of mmbtu / kwh.
- The higher the heat rate the more attractive natural gas fired generation is relative to other generation sources.

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Exhibit 5a

Assumptions for Financial Pro Forma

Public Utility District No. 1 of Chelan County

Power Sales Agreement and Transmission Agreement

Table of Contents

I. Assumptions and Definitions

Contract:	Power Sales Agreement ("PSA" or the "Agreement")
Seller:	Public Utility District No. 1 of Chelan County (the "District")
Buyer:	Puget Sound Energy ("PSE")
Power Source:	Chelan Power System comprising the Rocky Reach and Rock Island projects, both hydroelectric dams located on the Columbia River in central Washington with installed capacities of 1,287 MW and 660 MW, respectively.
Output:	25% share of Chelan Power System Approximately: 243 aMW energy (60 year average) 487 MW capacity
Term:	November 1, 2011 through October 31, 2031
Project Availability Dates:	November 1, 2011 for Rocky Reach July 1, 2012 for Rock Island
Signing Date:	Projected to occur Q1 2006

Conditions precedent to effectiveness:

(1) No default shall have occurred and be continuing, as of each respective Project Availability Date, under the current contract(s) between the Parties.

(2) No Event of Default or Potential Event of Default exists under the Power Sales Agreement.

(3) The representations contained in Article IV of the PSA continue to be true.

(4) The Existing Rocky Reach Power Sales Contract shall have terminated on or prior to the Rocky Reach Project Availability Date.

(5) The Existing Rock Island Power Sales Contract shall have terminated on or prior to the Rock Island Project Availability Date.

(6) No termination described in Section 3.03 of the PSA has occurred.

II. The Projection

This document and its attachments (the "Projection") illustrate the projection of financial results to PSE from its Upfront and Prepayments, and from its ongoing purchase of energy and capacity from the District. Although the Agreement will be integrated into both PSE's power portfolio and financial books, the pro forma financial statements are presented for clarity as though the Agreement were a contract of a stand-alone subsidiary.

III. Capital and O&M Cost Assumptions

- **Rehabilitation and Modernization Capital.** PSE estimates future rehabilitation and modernization costs of [redacted] million and [redacted] million (nominal capital costs) for Rocky Reach and Rock Island, respectively, during the term of the Agreement. Such estimates were prepared by using past results and budgets, estimated equipment service lives, feasibility and condition assessment reports prepared by the District or engineering consultants to the District, and information gathered during meetings with District personnel. Annual details are contained in Exhibit 5b, pages 4 – 11, and PSE's forecast methodology is described in Exhibit 5c.

- **FERC Licensing.** Significant investment is required in support of FERC licensing and compliance. The Rocky Reach project license expires in 2006 and the District reached a multi-party settlement agreement in December 2005, which is estimated to cost approximately [redacted] million (nominal O&M and capital costs) during the term of the Agreement. Annual details are contained in Exhibit 5b, pages 4 – 11, and PSE's forecast methodology is described in Exhibit 5c.

  The Rock Island project license expires in 2028. PSE has used the Rocky Reach process and expected settlement agreement as a proxy for future cost requirements, which are estimated at [redacted] million (nominal O&M and capital) during the contract term. Additional licensing costs for both Rocky Reach and Rock Island are forecast

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in the years beyond the contract term, which ends in 2031, and are not included in the analysis. The District has agreed not to accelerate payment of costs associated with measures required or agreed upon for the relicensing of either Project in advance of the date(s) necessary to comply with existing and anticipated FERC and other regulatory requirements or settlement agreements related to relicensing.

- **Operation and Maintenance.** PSE has evaluated historical O&M budgets for both Rocky Reach and Rock Island and, using a 2.0% real growth rate and a 2.5% escalation factor, estimates future normal / recurring O&M costs of [redacted] and [redacted] for Rocky Reach and Rock Island, respectively, during the term of the Agreement. These totals include the licensing O&M discussed above. An annual forecast of O&M is shown in Exhibit 5b pages 6 and 7.

IV. Debt Service Assumptions

Per the Agreement, debt service is categorized as either Outstanding Debt Obligations or Future Debt Obligations.

- **Outstanding Debt Obligations**. Existing debt service obligations for Rocky Reach and Rock Island total [redacted] million and [redacted] million for Rocky Reach and Rock Island, respectively, during the new contract term. See Exhibit 5b page 4.

  Financing costs for Outstanding Debt Obligations, as of the signing date, are shown below (and also in the Power Sales Agreement) as Schedule A-1. Schedule A-1 is developed from a compilation of outstanding bonds for Rocky Reach (from 1968 Series through 2005 Capital Appreciation Bonds) and for Rock Island (Series 1955 through 2003 re-loans of the 1995A Series). The District used an assumption of 7.8% (interest and issuance costs) for the pricing of bonds that are periodically re-priced, such as the 1997A Series.

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POWER SALES AGREEMENT

SCHEDULE A-1
SCHEDULE OF FINANCING COSTS WITH RESPECT TO DEBT OBLIGATIONS OUTSTANDING AS OF THE SIGNING DATE

	Principal	Interest	Total Principal & Interest	Reserve & Contingency	Total Debt Service	Total Debt Obligation Outstanding
Nov-Dec 2011	2,852,437	2,379,448	5,231,886	333,333	5,565,219	233,562,832
2012	23,987,606	23,530,694	47,518,300	3,134,250	50,652,550	542,715,735
2013	31,996,487	32,095,381	64,091,868	4,268,500	68,360,368	510,563,330
2014	34,118,081	30,360,600	64,478,682	4,268,500	68,747,182	476,276,282
2015	33,502,319	28,687,729	62,190,049	3,268,500	65,458,549	440,540,853
2016	33,324,797	26,991,602	60,316,399	2,268,500	62,584,899	407,017,620
2017	33,684,144	25,173,513	58,857,657	2,268,500	61,126,157	373,118,431
2018	25,841,036	22,976,565	48,817,600	2,268,500	51,086,100	347,044,352
2019	23,874,302	21,050,139	44,924,441	2,268,500	47,192,941	322,917,501
2020	25,338,963	19,640,037	44,978,999	2,268,500	47,247,499	297,304,851
2021	26,157,575	18,122,238	44,279,814	2,268,500	46,548,314	271,001,958
2022	27,586,910	16,511,202	44,098,112	2,268,500	46,366,612	243,415,048
2023	29,200,050	14,820,353	44,020,403	2,268,500	46,288,903	214,214,998
2024	30,438,134	13,050,228	43,488,362	2,268,500	45,756,862	183,776,864
2025	29,728,862	11,183,738	40,912,600	2,268,500	43,181,100	154,048,001
2026	29,820,252	9,355,448	39,175,700	2,268,500	41,444,200	124,227,749
2027	30,162,959	7,535,267	37,698,226	2,268,500	39,966,726	94,064,790
2028	30,851,917	5,708,472	36,560,390	2,448,740	39,009,129	63,212,872
2029	17,519,006	3,175,850	20,694,856	1,073,951	21,768,807	26,873,687
2030	6,833,512	1,607,282	8,440,794	-	8,440,794	20,040,175
2031	5,083,965	1,205,474	6,289,439	-	6,289,439	14,956,210

- **Future Debt Obligations.** Debt obligations that are incurred after the Signing Date are called Future Debt Obligations. For its share of these obligations, PSE will (a) pay, commencing November 1, 2011, the monthly amortization of the Assumed Debt Service on such Debt Obligations attributable to Rocky Reach, and (b) pay, commencing July 1, 2012, the monthly amortization of the Assumed Debt Service on such Debt Obligations attributable to Rock Island. Following the issuance or incurrence of any Future Debt Obligation, the District will make available a written schedule showing the Capital Improvements expected to be financed by the District from the proceeds thereof, the estimated Average Service Life of such Capital Improvements as determined by the District and the scheduled monthly Financing Costs associated with such Debt Obligations.

PSE assumed [redacted] annual interest and a term of 25 years for Future Debt Obligations. The annual interest rate is based upon an estimate of the District's taxable borrowing cost of [redacted] multiplied by the 110% adjustment factor as defined in the Power Sales Agreement, Appendix A, page 2.

As shown in Exhibit 5b, page 4, PSE estimates the amount of incremental debt service for Future Debt Obligations to be [redacted] million for Rocky Reach and [redacted] million for Rock Island (100% of Chelan Power System) during the term of the Agreement.

The total amount of incremental debt service depends on the forecast of Future Debt Obligations, which in turn depends upon the level of "pay-as-you-go" capital payments in the form of the Debt Reduction Charge and the Capital Recovery Charge. For the Projection, PSE assumed the highest level of "pay-as-you-go" cash payments allowed by the District per the Agreement – 3% for the annual Debt Reduction Charge and 50% for the Annual Capital Recovery Charge.

The Debt Reduction Charge is computed by multiplying the Debt Reduction Charge Percentage (which ranges from 0% to 3% as determined by the District) for the

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Contract Year times PSE's 25% share of Debt Reduction Charge Obligations for such Contract Year. The Debt Reduction Charge Obligations are the aggregate principal amount of all Debt Obligations assumed to be outstanding as of the first day of each Contract Year.

The Capital Recovery Charge is computed by multiplying the Capital Recovery Charge Percentage (which ranges from 0% to 50% as determined by the District) for the Contract Year times the Capital Recovery Charge Base for such Contract Year. The Capital Recovery Charge Base is equal to $25,000,000, the District's estimate of its average annual capital requirement during the term of the Agreement, expressed in 2004 dollars and adjusted annually for inflation.

V. Other Modeling Assumptions

- **Cost of Capital.** The Projection uses PSE's allowed return as specified in the 2005 General Rate Case Order #6, DOCKET NOS. UG-040640 and UE-040641 (consolidated).

	Ratio	**Cost**	**Weighted Cost**
Long-term Debt	47.53%	6.88%	3.27%
Short-term Debt	3.11%	4.81%	0.15%
Trust Preferred	6.32%	8.60%	0.54%
Preferred Stock	0.04%	8.51%	0.0034%
Common Equity	43.00%	10.30%	4.43%
Total	**100.00%**		**8.40%**

- **Cost Escalation.** Costs were escalated using a 4.5% annual rate, assuming 2.5% inflation and 2.0% real cost escalation.

- **Capacity and Energy.** A 25% share of the Chelan Power System is expected to produce about 243 aMW or 2,125,000 MWh per year.

Capacity (MW)	**100%**	**25%**
Rocky Reach	1,287.0	321.8
Rock Island	660.0	165.0
System Total (MW)	1,947.0	486.8

Average Energy (aMW)	**100%**	**25%**
Rocky Reach	641.6	160.4
Rock Island	328.6	82.2
System Total (aMW)	970.2	242.6

- **Hydro uncertainty.** PSE evaluated the hydro variability using Final Regulation, FR06, a forecast developed by the Northwest Power Pool for 70 water years from 1929 through 1998. The variability of a single water year has a 12.7% coefficient of variation (standard deviation / mean) and the variability for a set of 20 water years has a 4.7% coefficient of variation. The results are presented in Exhibit 2, section 3.

VI. Income Statement Pro Forma

The following income statement summary depicts totals during the term of the Agreement as well as for selected years throughout the term. On a nominal basis, the total revenue requirement during the term of the Agreement is about [redacted] or approximately [redacted] on a levelized unit cost basis. A complete pro forma income statement is contained in Exhibit 5b, pages 1 and 2.

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PSE Board of Directors
January 10, 2006

Exhibit 5a, Confidential and Proprietary
PSA - Stand Alone Financial Pro Forma

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Line #	Income Statement $000	2011-2031	2012	2015	2020	2025	2030
1	Operating Revenue Requirement						
2							
19	Total Purchased Power Expense						
20							
21	Amortization of Regulatory Asset						
22							
25	Total Income Tax						
26							
27	Total Operating Expenses						
28							
29	Operating Income	REDACTED					
30							
32	AFUDC						
34							
35	Income Before Interest Charges						
36							
37	Interest Expense						
38							
40	Less: Preferred Stock Dividends				REDACTED		
41	Income for Common Stock						
42							
43	Beginning Ratebase (Regulatory Asset)						
49	ROR (Op. Inc. on Beginning Ratebase)						
50							
51	Unit Cost Calculation						
52	Operating Revenue Requirement						
53	Energy GWH						
54	PPA Cost per MWh						
55							
56	Imputed Debt (S&P 30% Risk Factor)						
57	Cost of Equity Offset						
58	Unit Cost of Equity Offset $/MWh						
59							
60	Total Cost Including Equity Offset $/MWh						

The following is a line by line description of the pro forma income statement provided in Exhibit 5b, pages 1 and 2.

Revenues

Operating Revenue Requirement, Line #1

The Projection calculates revenues required to recover PSA costs including a return on pre-payments (regulatory assets) included in the rate base, as well as fixed and variable operating expenses. The rate-recovery mechanism modeled assumes that all costs are recovered in a timely manner.

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O&M and Debt Service

Rock Island I & II O&M, Line #5 PSE has projected recent O&M budgets for Rock Island, using a 2.0% real growth rate and a 2.5% escalation factor, and estimates future normal / recurring O&M costs of [redacted] for Rock Island during the term of the Agreement. PSE's share would be 25% of this forecast amount.

Licensing studies as O&M, Line #6 The Rock Island project license expires in 2028. PSE has used the Rocky Reach process and expected settlement agreement as a proxy for future cost requirements. The Agreement provides that re-licensing costs associated with studies and the administrative process will be expensed as O&M. Such costs, anticipated in 2024 through 2029, are expected to total [redacted] in nominal dollars. PSE's share would be 25% of this forecast amount.

Credit for Prepayment Requirement, Line #7 The District shall apply any unused portion of the Prepayment amount, without interest, to the last payment(s) due from the Purchaser under this Agreement. The Projection credits the $18.5 million Prepayment against PSE's contract payments in 2031.

Rocky Reach O&M, Line #8 PSE has projected future O&M budgets for Rocky Reach using a 2.0% real growth rate and a 2.5% escalation factor, and estimates future normal / recurring O&M costs of [redacted] during the term of the Agreement. PSE's share would be 25% of this forecast amount.

Rock Island I & II and Rocky Reach Debt Service, Line #9 & #10 Debt service is categorized for either Outstanding Debt Obligations or Future Debt Obligations. Lines #9 and #10 include both existing debt service for Outstanding Debt Obligations and incremental debt service for Future Debt Obligations.

Other Contract Charges

Transmission Charge, Line #12 The District requires payment for the use of and wheeling across the Chelan Transmission System by PSE to transmit PSE's share of Output to PSE or a third party transmission provider. PSE and the District are currently finalizing a separate Transmission Agreement, under which the District has indicated it will charge PSE a FERC methodology-based tariff for PSE's use of the Chelan Transmission System. All Transmission Charge payments are non-refundable.

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Working Capital Charge, Line #13 The District requires a non-refundable payment of $2.5 million per project (stated in 2004 dollars) to be paid on the Project Availability Date to provide the projects an adequate working capital balance. This amounts to estimated initial payments of $3.4 million in November 2011 for Rocky Reach, and $3.5 million in July 2012 for Rock Island. In addition, the District may, from time to time during any Contract Year, require payment of an amount equal to the product of the Purchaser's percentage multiplied by any additional working capital necessary, as reasonably determined by the District.

Coverage Fund Charge, Line #14 The District requires a non-refundable Coverage Fund Charge payment equal to the positive difference, if any, between the product of the Purchaser's percentage multiplied by 15% multiplied by the District's outstanding debt obligations during each contract year, minus Coverage Fund Payments previously paid by the Purchaser. Payments would first be due within 30 days of each Project Availability Date. PSE expects this amount to total approximately [redacted] (nominal) during the term of the Agreement.

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Debt Administrative Charge, Line #15 The District requires a Debt Administrative Charge as remuneration for the use and value of the District's current AA debt credit rating and for the District's management of debt associated with the Chelan Power System. The Debt Administrative Charge is calculated annually as the product of 1.0% multiplied by the Purchaser's percentage multiplied by the principal balance of Chelan Power System debt obligations outstanding at the beginning of each Contract Year. All Debt Administrative Charge payments are non-refundable.

Interest (Credit) on DRC and CRC, Line #16 The District agrees to invest any unexpended amounts of the Debt Reduction Charges and the Capital Recovery Charges during any Contract Year. The interest benefit is shown as a credit to costs for ease of modeling. In reality, the interest earned would reduce additional Debt Reduction and Capital Recovery Charges.

Debt Reduction Charge (DRC), Line #17 The District intends to reshape costs associated with the Chelan Power System through a "pay-as-you-go" capital expenditure funding program. The Debt Reduction Charge is a requirement of the District and the first of two charges intended to facilitate this program. Receipts may be used to purchase, redeem or defease debt of the Chelan Power System, to fund deposits to Reserve and Contingency Funds or to fund capital improvements related to

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the Chelan Power System. The Debt Reduction Charge is calculated per contract year as the product of the Purchaser's percentage multiplied by the debt reduction charge percentage (ranging from 0% to 3% per year as determined by the District), multiplied by the principal amount of debt obligations outstanding and attributable to the Chelan Power System. All Debt Reduction Charge payments are non-refundable.

The Projection assumes a 3% rate for the duration of the Agreement, thus providing a conservative (high) cost estimate.

Capital Recovery Charge (CRC), Line #18

The Capital Recovery Charge is the second of two charges required by the District to facilitate the "pay-as-you-go" capital expenditure funding program and reshaping of Chelan Power System costs. Similar to the Debt Reduction Charge, Capital Recovery Charge receipts may be used to purchase, redeem or defease debt of the Chelan Power System, to fund deposits to Reserve and Contingency Funds or to fund capital improvements related to the Chelan Power System. The Capital Recovery Charge is calculated per contract year as the product of the Purchaser's percentage multiplied by the capital recovery charge percentage (ranging from 0% to 50% per year as determined by the District), multiplied by the District's estimated average annual capital requirements (the "Capital Recovery Charge Base," currently estimated at $25,000,000 in 2004 dollars) adjusted for inflation and as otherwise adjusted from time to time by the District. All Capital Recovery Charge payments are non-refundable.

The Projection assumes a 50% rate for the duration of the Agreement, thus providing a conservative (high) cost estimate.

Total Purchased Power Expense, Line #19

Total Purchased Power Expense is the subtotal of O&M, licensing, debt service, transmission, working capital, coverage fund, debt administration as well as the Debt Reduction and Capital Recovery Charge. Line #19 is the sum of lines #5 through #18.

<u>Other Income Statement Lines</u>

Amortization of Regulatory Asset, Line #21

The amortization of regulatory asset assumes that the WUTC allows PSE to capitalize the upfront payment of $89 million and the prepayment requirement of $18.5 million (see also line #44). The regulatory asset is amortized over the term of the contract.

For modeling simplicity, amortization is spread evenly over 20 calendar years from 2012 through 2031. Actual accounting would amortize beginning November 1, 2011 through October 31, 2031.

Current Income Tax, Line #23 — Current Income Tax is the calculation of taxable income multiplied by a 35% effective Federal Income Tax rate. Taxable income arises from the allowed return earned on the regulatory asset, otherwise this agreement is a pass-through of the costs and hydro generation benefits to PSE customers.

Deferred Tax, Line #24 — There is no deferred tax in this model since the amortization of the regulatory asset for book purposes is equal to the amortization for tax purposes.

Total Income Tax, Line #25 — Sum of current and deferred income tax.

Total Operating Expenses, Line #27 — Sum of purchased power expense (line #19), plus amortization of regulatory asset (line #21), plus total income tax (line #25).

Operating Income, Line #29 — Operating Revenue Requirement (line #1) minus Total Operating Expenses (line #27).

Other Income, Line #31 — n/a

AFUDC, Line #32 — The Projection assumes WUTC approval of an accounting order allowing PSE to capitalize as a regulatory asset the Upfront and Prepayments, and to earn PSE's allowed 8.4% return on the regulatory asset. The Projection further assumes that this return is not immediately collected in rates, but rather accumulated similar to the Allowance for Funds Used During Construction (AFUDC). While the AFUDC is a credit to income it also increases the amount in the regulatory asset account for amortization during the term of the Agreement.

Total Other Income, Line #33 — Sum of other income (line #31) and AFUDC (line #32).

Income Before Interest Charges, Line #35 — Sum of operating income (line # 29) plus total other income (line #33).

Interest Expense, Line #37 Interest cost is calculated as the weighted borrowing cost of short-term debt, long-term debt and trust preferred multiplied by the beginning of year ratebase (regulatory asset).

Net Income, Line #39 Income before interest (line #35) minus interest expense (line #37).

Less: Preferred Stock Dividends, Line #40 Preferred stock dividend is calculated as the weighted cost of preferred stock, 0.0034%, times beginning of year ratebase (regulatory asset).

Income for Common Stock, Line #41 Net income (line #29) minus preferred stock dividends (line #40).

Ratebase Calculation

Beginning Ratebase (Regulatory Asset), Line #43 Regulatory asset account equal to the ending balance from the prior year.

Upfront and Prepayment Requirement, Line #44 The District and PSE negotiated an Upfront charge of $89 million, to be paid within 30 days upon receipt of all necessary approvals by the parties.

The District requires a Prepayment sufficient to satisfy a Purchaser's payment obligations in the event a payment is not made on time as required under the proposed Power Sales Agreement or Transmission Agreement. PSE and the District have negotiated an amount equal to $18,500,000, which will be refunded to PSE, without interest, against its final power cost statement(s) at the end of the contract term.

AFUDC, Line #45 See line #32. In this line the AFUDC is added to the year balance in the regulatory asset account.

Amortization, Line #46 See line #21. Annual regulatory asset amortization expense, which is subtracted from beginning of year ratebase.

Ending Ratebase, Line #47 Ending ratebase is the sum of beginning ratebase (line #43), plus upfront payments (line #44), plus AFUDC (line #45), minus amortization expense (line #46).

ROR (Op. Inc. on Beginning Ratebase), Line #49 Rate of Return (ROR) is the calculated return of operating income (line #29) divided by beginning of period ratebase (line #43).

Unit Cost Calculation

Operating Revenue Requirement, Line #52 Same as line #1.

Energy GWH, Line #53 Twenty five percent (25%) of expected generation from Rocky Reach, starting November 1, 2011, and Rock Island, starting July 1, 2012 (estimated annual generation derived from a refill study based on FR04-05 and adjusted for encroachment and Canadian Entitlement obligations).

PPA Cost per MWh, Line #54 Unit cost is calculated by dividing operating revenue requirement (line #52) by energy in MWh (line #53 * 1000).

Imputed Debt (S&P 30% Risk Factor), Line #56 The Standard and Poor's ("S&P") rating agency considers long-term take-or-pay contracts debt-like in nature and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Hence, there is a cost associated with issuing equity to rebalance the Company's debt/equity ratio in response to imputed debt if PSE is to maintain its current credit rating. Imputed debt is calculated using a similar methodology to that applied by S&P. The Projection assumes that income statement lines #9 through #18 are payments that S&P would treat as fixed obligations. This yearly fixed obligation is then multiplied by a 30% risk factor. Imputed debt is the sum of the present value (using a 10% discount rate and a mid-year cash flow convention) of this risk-adjusted fixed obligation.

Cost of Equity Offset, Line #57 The cost of imputed debt is the equity return on the amount of equity that would be required to offset the level of imputed debt to maintain the Company's capital and interest coverage ratios.

Unit Cost of Equity Offset $/MWh, Line #58

Cost of equity offset to imputed debt (line #57) divided by energy in MWh (line #53 * 1000).

Note: The unit cost of equity offset in 2011 and 2012 is relatively high because there is a full year of imputed debt but only a partial year of energy production from the Agreement.

Total Cost Including Equity Offset $/MWh, Line #60

Sum of PSA Cost per MWh (line #54) plus Unit Cost of Equity Offset $/MWh (line #58).

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Proposed Power Sales Agreement with PUD No. 1 of Chelan County Project (Stand Alone) Pro Forma Income Statement $000's

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Line #	Income Statement $000	2011-2031	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
1	Operating Revenue Requirement														
2															
3	Operating Expenses:														
4	Purchased Power Expense														
5	Rock Island I & II O&M														
6	Licensing studies as O&M? Yes														
7	Credit for Payment Reserve														
8	Rocky Reach O&M														
9	Rock Island I & II Debt Service														
10	Rocky Reach Debt Service														
11	Other Contract Charges														
12	Transmission Charge														
13	Working Capital Charge														
14	Coverage Fund Charge														
15	Debt Administrative Charge														
16	Interest (Credit) on DRC and CRC														
17	Debt Reduction Charge (DRC)														
18	Capital Recovery Charge (CRC)														
19	Total Purchased Power Expense														
20															
21	Amortization of Regulatory Asset														
22															
23	Current Income Tax														
24	Deferred Tax														
25	Total Income Tax														
26															
27	Total Operating Expenses														
28															
29	Operating Income														
30															
31	Other Income														
32	AFUDC														
33	Total Other Income														
34															
35	Income Before Interest Charges														
36															
37	Interest Expense														
38															
39	Net Income														
40	Less: Preferred Stock Dividends														
41	Income for Common Stock														
42															
43	Beginning Ratebase (Regulatory Asset)														
44	Up Front and Prepayment Requirement														
45	AFUDC														
46	Amortization														
47	Ending Ratebase														
48															
49	ROR (Op. Inc. on Beginning Ratebase)														
50															
51	Unit Cost Calculation														
52	Operating Revenue Requirement														
53	Energy GWH														
54	PSA Cost per MWh														
55															
56	Imputed Debt (S&P 30% Risk Factor)														
57	Cost of Equity Offset														
58	Unit Cost of Equity Offset $/MWh														
59															
60	Total Cost Including Equity Offset $/MWh														

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Pro Forma Income Statement
Exhibit 5b Page 1

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Proposed Power Sales Agreement with PUD No. 1 of Chelan County Project (Stand Alone) Pro Forma Income Statement $000's

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Line #	Income Statement $000	2011-2031	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Operating Revenue Requirement														
2															
3	Operating Expenses:														
4	Purchased Power Expense														
5	Rock Island I & II O&M														
6	Licensing studies as O&M? Yes														
7	Credit for Payment Reserve														
8	Rocky Reach O&M														
9	Rock Island I & II Debt Service														
10	Rocky Reach Debt Service														
11	Other Contract Charges														
12	Transmission Charge														
13	Working Capital Charge														
14	Coverage Fund Charge														
15	Debt Administrative Charge														
16	Interest (Credit) on DRC and CRC														
17	Debt Reduction Charge (DRC)														
18	Capital Recovery Charge (CRC)														
19	Total Purchased Power Expense														
20															
21	Amortization of Regulatory Asset														
22															
23	Current Income Tax														
24	Deferred Tax														
25	Total Income Tax														
26															
27	Total Operating Expenses														
28															
29	Operating Income														
30															
31	Other Income														
32	AFUDC														
33	Total Other Income														
34															
35	Income Before Interest Charges														
36															
37	Interest Expense														
38															
39	Net Income														
40	Less: Preferred Stock Dividends														
41	Income for Common Stock														
42															
43	Beginning Ratebase (Regulatory Asset)														
44	Up Front and Prepayment Requirement														
45	AFUDC														
46	Amortization														
47	Ending Ratebase														
48															
49	ROR (Op. Inc. on Beginning Ratebase)														
50															
51	Unit Cost Calculation														
52	Operating Revenue Requirement														
53	Energy GWH														
54	PSA Cost per MWh														
55															
56	Imputed Debt (S&P 30% Risk Factor)														
57	Cost of Equity Offset														
58	Unit Cost of Equity Offset $/MWh														
59															
60	Total Cost Including Equity Offset $/MWh														

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Pro Forma Income Statement
Exhibit 5b Page 2

E5b-Financial Statements (value copy)-12282005.xls

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NPV Summary

PSE Share: Chelan Power System

Contract Costs	2006 - 2031 Nominal ($000)	2006 - 2031 NPV 2006$ ($000)	2006 - 2031 Levelized ($/MWh)	2011 - 2031 Nominal ($000)	2011 - 2031 NPV 2011$ ($000)	2011 - 2031 Levelized ($/MWh)
Operating Costs	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]	$ [redacted]	[redacted]
Equity Offset Imputed Debt	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]	[redacted]	[redacted]
TOTAL	$ [redacted]	$ [redacted]	[redacted]	$ [redacted]	$ [redacted]	[redacted]

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Market Replacement	2006 - 2031 Nominal ($000)	2006 - 2031 NPV 2006$ ($000)	2006 - 2031 Levelized ($/MWh)	2011 - 2031 Nominal ($000)	2011 - 2031 NPV 2011$ ($000)	2011 - 2031 Levelized ($/MWh)
Market + ancillary services	$ [redacted]	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Levelized Savings $/MWh $24.02 $25.80

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Chelan Power System Debt Service and Operation and Maintenance Summary $000 Nominal

All Values x 1,000

Total Cost - Chelan Power System	2011-2031	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rocky Reach												
O&M												
Existing Debt Service												
Incremental Debt Service												
Subtotal												
Rock Island I & II												
O&M												
Licensing studies as O&M? Yes												
Existing Debt Service												
Incremental Debt Service												
Subtotal												
TOTAL CHELAN POWER SYSTEM (x 1,000)												
100% Total Debt Service												
100% Estimated Principal Balance												

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Chelan Power System Debt Service and Operation and Maintenance Summary $000 Nominal

All Values x 1,000

Total Cost - Chelan Power System	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rocky Reach										
O&M										
Existing Debt Service										
Incremental Debt Service										
Subtotal										
Rock Island I & II										
O&M										
Licensing studies as O&M? Yes										
Existing Debt Service										
Incremental Debt Service										
Subtotal										
TOTAL CHELAN POWER SYSTEM (x 1,000)										
100% Total Debt Service										
100% Estimated Principal Balance										

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Chelan Power System Operation and Maintenance

100% Nominal $000's

All Values x 1,000

Operations & Maintenance	2011-2031	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rocky Reach											
Plant O&M											
Licensing O&M											
Relicensing Costs											
Shoreline Erosion Management Plan											
Water Quality											
Anadromous Fish Protection											
Comprehensive Fish Management Plan											
Bull Trout Management Plan											
Pacific Lamprey Monitoring and Management Plan											
Wildlife Habitat											
Cultural Resources Management Plan											
Recreation and Resources Management Plan											
Subtotal Licensing											
Subtotal Rocky Reach											
Rock Island											
Rock Island I O&M											
Rock Island II O&M											
Licensing O&M											
Relicensing Costs											
Shoreline Erosion Management Plan											
Water Quality											
Anadromous Fish Protection											
Comprehensive Fish Management Plan											
Bull Trout Management Plan											
Pacific Lamprey Monitoring and Management Plan											
Wildlife Habitat											
Cultural Resources Management Plan											
Recreation and Resources Management Plan											
Subtotal Licensing											
Subtotal Rock Island											

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Chelan Power System Operation and Maintenance

100% Nominal $000's

All Values x 1,000

Operations & Maintenance	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Rocky Reach											
Plant O&M											
Licensing O&M											
Relicensing Costs											
Shoreline Erosion Management Plan											
Water Quality											
Anadromous Fish Protection											
Comprehensive Fish Management Plan											
Bull Trout Management Plan											
Pacific Lamprey Monitoring and Management Plan											
Wildlife Habitat											
Cultural Resources Management Plan											
Recreation and Resources Management Plan											
Subtotal Licensing											
Subtotal Rocky Reach											
Rock Island											
Rock Island I O&M											
Rock Island II O&M											
Licensing O&M											
Relicensing Costs											
Shoreline Erosion Management Plan											
Water Quality											
Anadromous Fish Protection											
Comprehensive Fish Management Plan											
Bull Trout Management Plan											
Pacific Lamprey Monitoring and Management Plan											
Wildlife Habitat											
Cultural Resources Management Plan											
Recreation and Resources Management Plan											
Subtotal Licensing											
Subtotal Rock Island											

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Rocky Reach Capital Expenditures
100% Nominal $000's

All Values x 1,000		Start	2	3	4	5	6	7	8	9	10	11
		11/1/2011										
Contract Year	**2011-2031**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Rocky Reach Licensing												
Shoreline Erosion Management Plan												
Water Quality												
Anadromous Fish Protection												
Comprehensive Fish Management Plan												
White Sturgeon Management Plan												
Bull Trout Management Plan												
Pacific Lamprey Monitoring and Management Plan												
Wildlife Habitat												
Cultural Resources Management Plan												
Recreation and Resources Management Plan												
Subtotal												
Rocky Reach PP&E												
1.0 Turbine												
2.0 Auxiliary Mechanical												
3.0 Generators												
4.0 Controls												
5.0 Transformers												
6.0 Switchgear												
7.0 Miscellaneous												
Subtotal												
TOTAL Rocky Reach Capital												

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Rocky Reach Capital Expenditures
100% Nominal $000's

All Values x 1,000

Contract Year	12 2022	13 2023	14 2024	15 2025	16 2026	17 2027	18 2028	19 2029	20 2030	21 2031
Rocky Reach Licensing										
Shoreline Erosion Management Plan						-	-	-	-	-
Water Quality										
Anadromous Fish Protection										
Comprehensive Fish Management Plan										
White Sturgeon Management Plan										
Bull Trout Management Plan										
Pacific Lamprey Monitoring and Management Plan										
Wildlife Habitat										
Cultural Resources Management Plan										
Recreation and Resources Management Plan										
Subtotal										
Rocky Reach PP&E										
1.0 Turbine										
2.0 Auxiliary Mechanical										
3.0 Generators										
4.0 Controls										
5.0 Transformers										
6.0 Switchgear										
7.0 Miscellaneous										
Subtotal										
TOTAL Rocky Reach Capital										

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Rock Island Capital Expenditures
100% Nominal $000's

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All Values x 1,000		1	Start 7/1/2012	3	4	5	6	7	8	9	10	11
Contract Year	2011-2031	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rock Island Licensing												
Relicensing Costs - process and studies as O&M		[redacted]										
Shoreline Erosion Management Plan												
Water Quality												
Anadromous Fish Protection												
Comprehensive Fish Management Plan												
White Sturgeon Management Plan												
Bull Trout Management Plan												
Pacific Lamprey Monitoring and Management Plan												
Wildlife Habitat												
Cultural Resources Management Plan												
Recreation and Resources Management Plan												
Subtotal		-										
Rock Island PP&E												
1.0 Turbine		[redacted]										
2.0 Auxiliary Mechanical												
3.0 Generators												
4.0 Controls												
5.0 Transformers												
6.0 Switchgear												
7.0 Miscellaneous												
Subtotal PP&E		-										
Rock Island General												
15.0 Fisheries Equipment		[redacted]										
16.0 Spillway Improvements												
Subtotal Fish and Spillway Improvements												
TOTAL		-										

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Rock island Capital Expenditures
100% Nominal $000's

All Values x 1,000

Contract Year	12 2022	13 2023	14 2024	15 2025	16 2026	17 2027	18 2028	19 2029	20 2030	21 2031
Rock Island Licensing										
Relicensing Costs - process and studies as O&M										
Shoreline Erosion Management Plan										
Water Quality										
Anadromous Fish Protection										
Comprehensive Fish Management Plan										
White Sturgeon Management Plan										
Bull Trout Management Plan										
Pacific Lamprey Monitoring and Management Plan										
Wildlife Habitat										
Cultural Resources Management Plan										
Recreation and Resources Management Plan										
Subtotal										
Rock Island PP&E										
1.0 Turbine										
2.0 Auxiliary Mechanical										
3.0 Generators										
4.0 Controls										
5.0 Transformers										
6.0 Switchgear										
7.0 Miscellaneous										
Subtotal PP&E										
Rock Island General										
15.0 Fisheries Equipment										
16.0 Spillway Improvements										
Subtotal Fish and Spillway Improvements										
TOTAL										

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Exhibit 5c

Capital Expenditure Forecast

Public Utility District No. 1 of Chelan County

Power Sales Agreement

Table of Contents

I. Regulatory Context

Two of the greatest uncertainties faced by owners of hydroelectric projects are the potential cost and operating impact caused by the issuance and acceptance of a new FERC license, and the potential for new regulation—specifically, costs and operational requirements manifested through protection, mitigation and enhancement measures mandated by the FERC, NOAA Fisheries, U.S. Fish and Wildlife Services, Washington State Department of Fish and Wildlife and others. With respect to the dams on the mid-Columbia River, passage and survival rates of anadromous species has historically been the most contentious environmental issue facing dam owners/operators.

II. Habitat Conservation Plans

During the past several years, the District, working together with Public Utility District No. 1 of Douglas County ("Douglas"), successfully negotiated with state and federal fisheries agencies and tribes to develop the first Hydro Power Habitat Conservation Plans (HCPs) for anadromous salmon and steelhead. The District and Douglas developed plans for their respective projects, both committing their utilities to a 50-year program to ensure that their hydro projects have no net impact on mid-Columbia salmon and steelhead runs. Primary measures to be funded and implemented under these plans include:

- Fish bypass systems installed at the dams
- Spill at the hydro projects
- Off-site hatchery programs and ongoing evaluations
- Habitat restoration work conducted in mid-Columbia tributary streams

Both utilities collaborated with state and federal resource agencies and tribes with great success. Signatories include:

- NOAA Fisheries

- U.S. Fish and Wildlife Service
- Washington State Department of Fish and Wildlife
- The Confederated Tribes of the Colville Reservation
- The Yakama Tribe of Indians
- Both Public Utility Districts

Most significantly, NOAA Fisheries issued Section 10 permits that provide for the continued operation of Douglas' Wells hydro project, and the District's Rocky Reach and Rock Island hydro projects even though these projects may result in incidental takes of spring Chinook salmon and steelhead listed under the Endangered Species Act. In addition, both PUDs have committed to fund hatcheries through the plans and Section 10 permits. Absent the NOAA Section 10 permits, both PUDs would have faced significant uncertainty surrounding the future operation and investment requirements of their respective hydro projects and hatcheries.

The HCPs were submitted to the FERC for review in late 2003 and received approval in June 2004.

III. Chelan Power System FERC Licenses

During the past five years, the District has pursued a new license for its Rocky Reach project using the FERC's Alternative Licensing Process (ALP)—the process used by PSE during the relicensing of its Baker River project. The Rocky Reach FERC license expires in June 2006 and the District has, through licensing settlement negotiations and its Habitat Conservation Plan, significantly reduced the largest and most significant uncertainty related to continued operation and purchase of output from the Chelan Power System. PSE has actively monitored and, when appropriate, participated in and supported the District's relicensing efforts. PSE's projection of the District's future cost obligations related to relicensing and compliance relies primarily upon the District's analyses, as presented in its FERC license application and Applicant Prepared

Preliminary Draft Environmental Assessment, and as updated from time to time. It also relies on PSE's own experience and expertise in the area of FERC relicensing. Accordingly, PSE anticipates significant investment in support of the District's Rocky Reach FERC license implementation and compliance activities. The District reached a multi-party license settlement agreement in December 2005, which is estimated to cost approximately [redacted] (nominal O&M and capital costs) during the term of the new Agreement. The Capital and O&M for Rocky Reach licensing are summarized below and shown in detail in Exhibit 5-b, pages 4 – 11.

Rocky Reach FERC License (100% Cost during Term of Agreement)	**O&M Nominal $ Millions**	**Capital Nominal $ Millions**	**Total Nominal $ Millions**
Shoreline Erosion Management Plan			
Anadromous Fish Protection			
Comprehensive Fish Management Plan			
Bull Trout Management Plan			
Pacific Lamprey Monitoring and Management Plan			
Wildlife Habitat			
Cultural Resources Management Plan			
Recreation and Resources Management Plan			
Total Cost (nominal)			

In addition, the District's Rock Island project license expires in 2028 and PSE has used the Rocky Reach process requirements and expected settlement agreement as a proxy for future costs, which are estimated at [redacted] (nominal O&M and capital) during the contract term. The Capital and O&M for Rock Island licensing are summarized in the following table and shown in detail in Exhibit 1-b, pages 4 – 11.

Text in box is Confidential

REDACTED

Rock Island FERC License (100% Cost during Term of Agreement)	**O&M Nominal $ Millions**	**Capital Nominal $ Millions**	**Total Nominal $ Millions**
Relicensing Studies			
Shoreline Erosion Management Plan			
Anadromous Fish Protection			
Comprehensive Fish Management Plan			
White Sturgeon Management Plan			
Bull Trout Management Plan			
Pacific Lamprey Monitoring and Management Plan		REDACTED	
Wildlife Habitat			
Cultural Resources Management Plan			
Recreation and Resources Management Plan			
Total Cost (nominal)			

Text in box is Confidential

Additional licensing costs for both Rocky Reach and Rock Island are forecast in the years beyond the contract term, which ends in 2031, and are not included in the analysis. The District has agreed not to accelerate the payment of costs associated with measures required or agreed upon for the relicensing of either Project in advance of the date(s) necessary to comply with existing and anticipated FERC and other regulatory requirements or settlement agreements related to relicensing.

The tables provided in Exhibit 1-b, pages 4 through 11, are based upon the District's estimated FERC licensing and implementation forecast for protection, mitigation and enhancement measures as of August 2005. The District's estimate was prepared conforming to the "current-cost" economic evaluation method required by the FERC and does not represent contemporary financial or economic analysis methodology in that it excludes inflationary effects. Accordingly, PSE has converted those costs denoted as incremental by the District to nominal values for the purpose of PSE's financial modeling of the new Agreement. As a precautionary note, PSE expects that costs may change as the District finalizes its negotiations with project stakeholders or as the Rocky Reach license application is processed by the FERC.

PSE Board of Directors
January 10, 2006

Exhibit 5c, Confidential and Proprietary
Capital Expenditure Forecast

REDACTED

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PSE Board of Directors
January 10, 2006

Exhibit 5c, **Confidential and Proprietary**
Capital Expenditure Forecast

REDACTED

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PSE Board of Directors
January 10, 2006

Exhibit 5c, **Confidential and Proprietary**
Capital Expenditure Forecast

REDACTED

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PSE Board of Directors
January 10, 2006

Exhibit 5c, Confidential and Proprietary
Capital Expenditure Forecast

REDACTED

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