BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-060266 Docket No. UG-060267 (*consolidated*)

INITIAL BRIEF OF PUGET SOUND ENERGY, INC.

OCTOBER 31, 2006

REDACTED
VERSION

PUGET SOUND ENERGY, INC.

TABLE OF CONTENTS

PUGET SOUND ENERGY, INC.

TABLE OF AUTHORITIES

Cases

Statutes

Other Authorities

Washington Utilities and Transportation Commission Decisions

Administrative Decisions of Other Jurisdictions - Cases

Administrative Decisions of Other Jurisdictions - Codes and Statutes

I. INTRODUCTION

1. Puget Sound Energy, Inc. ("PSE" or the "Company") respectfully requests that the Commission issue an order approving its request for general rate relief in an amount equal to an annual increase in electric revenue of $33,472,231 and in natural gas revenue of $38,903,324,[1] which includes a request that the Commission authorize a rate of return on common equity of 11.25% and a capital structure containing 45% common equity. PSE does not take lightly this request for a rate increase. PSE has been, and remains, concerned about the impact of rate increases on its customers. PSE has worked hard to identify and implement cost-saving measures wherever it can.[2]

2. PSE has been doing great things for its customers and the State of Washington. The Company is a leader in searching out and investing in cost-effective energy efficiency measures. PSE is investing in its delivery systems and in new electric resources in order to continue to provide efficient, high quality, reliable gas and electric service, now and into the future.

3. It is undisputed that the Company is facing a critical need for massive investments in new energy resources and new electric and gas system delivery infrastructure in order to serve the needs of a steadily growing customer base and to upgrade aging facilities. The Company has come to the Commission requesting financial relief that supports these efforts. Over the next two years the Company plans to spend $1.4 billion in capital investments, which is equal to approximately 33% of the Company's existing ratebase. The 11.25% return on equity ("ROE") that PSE seeks is consistent with the expectations of the market, and is needed to account for PSE's higher construction costs and higher risk of excess power costs given the recent expiration

[1] These revenue numbers are exclusive of the Depreciation Tracker or "known and measurable adjustment". See section IV *infra* for the additional revenue requirement associated with those mechanisms.
[2] *See, e.g.*, Harris, TR. 140:20 – 141:7; McLain, Exh. 241C 3:6 – 5:16; Hunt, Exh. 211 5:11 – 6:6, 10:13 – 11:2.

of the cumulative $40 million cap in the Power Cost Adjustment ("PCA") Mechanism. Even with the changes to the PCA Mechanism that PSE proposes, the Company is absorbing much more risk now than it did prior to the June 30, 2006 expiration of the $40 million cap.

4. The Company is also asking the Commission to approve the mechanisms that PSE has proposed in order to remove or reduce regulatory disincentives that exist to the important tasks PSE is undertaking and to reduce costs both for the Company and its customers. These include:

- A Depreciation Tracker that will allow the Company to recover its depreciation expense on new energy delivery plant in between rate cases and thereby facilitate the Company's ability to replace aging infrastructure to maintain a high level of system reliability for PSE's customers and the region;
- The Gas Revenue Normalization Adjustment ("GRNA"), a gas decoupling mechanism that includes a weather adjustment mechanism. The GRNA will eliminate the current disincentive for PSE to invest in gas energy efficiency measures. It will also provide bill stability to customers, help to ensure that customers do not overpay or underpay the fixed costs of providing gas service when the weather is warmer or colder than normal, and will reduce costs by providing revenue stability to PSE; and
- A revised PCA Mechanism that will better incent all parties to set an accurate Power Cost Baseline Rate, that will allow customers to immediately share in cost reductions when power costs are below the Power Cost Baseline Rate, and that will share more fairly power costs that are in excess of the Power Cost Baseline Rate, given the extent to which power costs are outside the control of the Company as well as its customers.

5. The Company carefully designed the proposals it is making in this case in order to reduce some unnecessary, artificial and harmful misalignment between the interests of the Company and its customers. In many cases, the solutions and mechanisms PSE has proposed will provide immediate benefits for customers as well as the Company. This case presents the Commission with important policy issues. Fundamentally, the question is whether the actions PSE is taking and the investments PSE is making in efficient and responsible energy production and delivery systems are in the long-term interest of, and provide significant and important benefits to, the

Company's customers. If so, the Commission should support the continuation of such efforts by approving PSE's balanced proposals and requested financial relief.

II. LEGAL STANDARDS

6. The ultimate legal question in a general rate case is whether the rates and charges proposed by the Company are fair, just, reasonable, and sufficient.[3] In making these determinations, the Commission is bound by the statutory and constitutional mandate that a regulated utility is entitled to (i) reasonable and sufficient compensation for the service it provides[4] and (ii) the opportunity to earn "a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk."[5]

7. Unless a utility is given the opportunity to earn a reasonable return on its investment and recover its costs, customers as well as investors are harmed:

> It is just as important in the eye of the law that the rates shall yield reasonable compensation as it is that they shall be just and reasonable and non-discriminatory from the standpoint of the customer, because unless every rate does yield reasonable compensation, public service companies must resort to discrimination in order to live or must eventually be forced out of business. Every statutory element must be recognized in the fixing of rates, or the result will be to defeat the legislative purpose.[6]

The Washington Supreme Court has observed that when the Commission disallows an operating expense a utility has incurred to serve its customers:

> the shareholders of the utility must absorb the disallowed expenses, with a resulting reduction in the actual rate of return earned by them. This means

[3] RCW 80.28.020; *People's Org. for Wash. Energy Res. v. WUTC*, 104 Wn.2d 798, 808 (1985) ("*POWER*").
[4] *POWER*, 104 Wn.2d at 808; *Puget Sound Traction, Light & Power Co. v. Pub. Serv. Comm'n*, 100 Wash. 329, 334 (1918); RCW 80.28.010(1).
[5] *WUTC v. Avista Corp.*, Docket Nos. UE-991606, *et al.*, Third Supp. Order at ¶324 (2000).
[6] *State ex rel. Puget Sound Power & Light Co. v. Dept. of Pub. Works*, 179 Wash 461, 466 (1934).

> that disallowance of an expense in a rate case has the very real effect, among others, of increasing the risks of investing in the utility.[7]

These concerns should apply with equal force to situations in which the traditional methods utilized by the Commission to set rates result in chronic under-recovery of the levels of revenues and rates of return on equity that the Commission has authorized.[8]

8. Only the Company's proposed relief meets these standards. No other party adequately addresses the Company's need to improve its financial integrity so that it can attract capital on reasonable terms and continue forward with its efforts on behalf of its customers and the region.

III. POWER COST ADJUSTMENT ("PCA") MECHANISM

A. PSE's Proposed Changes Are Narrowly Tailored to Address the Power Cost Volatility It Faces and to Bring Greater Symmetry to the PCA Mechanism

9. PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics.[9] PSE's power costs exceeded the amounts recovered through the Power Cost Baseline Rate during the first three PCA periods (2002-2005) under the PCA Mechanism, primarily for reasons outside PSE's control such as variations in temperature, hydro, power prices and load from the figures assumed in PCA Power Cost Baseline Rates.[10]

10. The Company's experience during the first few years under the PCA Mechanism demonstrates the difficulty of setting a Power Cost Baseline Rate so that power costs can be recovered within a reasonable margin of error. The Power Cost Baseline that is embedded in rates is based on projections of future conditions that cannot be known at the time rates are set.[11]

---

[7] *POWER*, 104 Wn.2d at 811.

[8] *See, e.g., In re Northwest Natural Gas Co.*, Oregon Pub. Util. Comm'n, at 2 (Order No. 02-634 Sept. 12, 2002) (approving decoupling mechanism to address flaws in traditional ratemaking).

[9] *See* Markell, Exh. 611C 3:16 – 8:1; *see also* Aladin, Exh. 11C 4:14 – 7:14; *see generally* Mills, Exh. 251C.

[10] *See* Aladin, Exh. 11C 8:14 – 9:12.

[11] *See* Harris, Exh. 171 20:10-18.

11. The Company proposes several changes to the current PCA Mechanism based on PSE's four years of experience operating and litigating under the mechanism and the financial circumstances the Company finds itself in now and going into the next several years.[12] First, the Company proposes that the sharing bands be revised to the following:[13]

Power Costs ($ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders's Share
$0 - $25 +/-	50%	50%
$25 - $120 +/-	90%	10%
> $120 +/-	95%	5%

These revised sharing bands will better align the interests of the Company and its customers with respect to power cost risks and the setting of the Power Cost Baseline Rate in rate cases.[14]

12. Second, the Company proposes the elimination of Exhibit E of the current PCA Mechanism. Elimination of Exhibit E will correct for the current situation under which cost increases for certain Commission-approved long-term power contracts, such as the March Point and Sumas purchased power agreements, are ignored in determining the amount by which PSE's actual annual power costs have exceeded or fallen below the Power Cost Baseline Rate.[15]

13. Third, the Company proposes the elimination of paragraph 10 of the PCA Mechanism,[16] which was meant in 2002 to ensure that the Company would file a general rate case to true up all costs if a PCORC was filed after three years from the initial implementation of the PCA Mechanism without an interim general rate case.[17] Two general rate cases and two PCORC's

[12] *See* Valdman, Exh. 457C 20:5 – 28:10; Harris, TR. 109:21 – 110:20. The other parties' comfort with the current PCA Mechanism is based on outdated information. They rely on the credit agencies' favorable reaction when the mechanism was first adopted in 2002, at a time when the expiration of the $40 million cumulative cap was several years out into the future. Joint Parties (PCA), TR. 854:1 – 855:21; *see also* Valdman, TR 253:16 – 255:3.
[13] *See* Harris, Exh. 171 21:8-10.
[14] *See id.* 21:11 – 22:13.
[15] *See* Story, Exh. 421 50:4 – 51:3.
[16] *See* Story, Exh. 428C, which sets forth the Company's proposed revisions to the PCA Mechanism.
[17] *See* Story, Exh. 426 6:¶10.

later, this provision is not necessary and would result in inefficient ratemaking. No party has expressly objected to such revision.

14. Finally, the Company proposes to include in the Power Cost Baseline Rate and the PGA mechanism the actual costs associated with a new line of credit to support the Company's wholesale power and gas market hedging transactions.[18] No party objects to this PSE proposal to add to the PCA and PGA mechanisms the costs associated with this new line of credit that are related to hedges for the respective power and gas portfolios.[19]

B. PSE's Proposed Revisions to the Current PCA Mechanism Satisfy the Principles Enunciated by the Commission in Its Recent *PacifiCorp* Decision

15. Subsequent to PSE's filing of its direct testimony, this Commission issued its final order in *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company*[20] (the "*PacifiCorp* Decision"). In the *PacifiCorp* Decision, the Commission stated that the following principles should guide the development of a properly designed power cost adjustment mechanism:

- The purpose is to recognize variability in the cost of operating *existing* power supply resources as a result of abnormal weather conditions that are out of a utility's control. Customers understand the connection between weather and rates;
- Power cost adjustment mechanisms are *short-run* accounting procedures to address *short-run* cost changes resulting from unusual weather;
- It is not appropriate to include new resources in a power cost adjustment mechanism. New resources must be considered in general rate cases or power cost only rate cases;
- Customers should receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for customers and earnings stability for stockholders, and;

[18] *See* Story, Exh. 421 51:4 – 52:6, Exh. 428C 3, 5, 6, 8:28, 15:22; Harris, Exh. 171 22:14 – 23:11; Mills, Exh. 251C 31:2 – 33:21; Karzmar, Exh. 222 32:11 – 35:6.
[19] *See* Joint Parties (PCA), TR. 845:17-24; Russell, Exh. 521 3:21 and 4:7-9.
[20] Docket No. UE-050684, Order 04 (2006). The Company filed its direct testimony in this proceeding on February 15, 2006 – more than two months before the issuance of the *PacifiCorp* Decision.

- Power cost adjustment mechanisms should not interfere with least cost planning, conservation or other regulatory goals.[21]

The *PacifiCorp* Decision states that any power cost recovery mechanisms should also apportion risk equitably between the Company and its customers.[22] The Company's proposed revisions to the current PCA Mechanism satisfy each of the principles outlined in the *PacifiCorp* Decision.

1. The Company's Proposed PCA Revisions Address Existing Power Costs That Are Out of the Company's Control

16. PSE's proposed PCA revisions address only existing resources and do not attempt to change the power cost only rate case portion of the PCA Mechanism. Further, the Company's proposed changes to the PCA Mechanism address factors that are outside of the Company's control and are primarily weather-related—specifically precipitation and temperature.

17. PSE submitted significant evidence in this proceeding demonstrating the extent to which power costs can be driven higher or lower than "normal" depending on whether streamflows are higher or lower than "normal" and whether temperatures are higher or lower than "normal" (thereby impacting PSE's load). PSE's modeling also shows that other factors over which PSE has no control, such as wholesale market natural gas prices, drive volatility in PSE's portfolio.[23]

18. The Staff, Public Counsel and ICNU, testifying jointly ("Joint Parties") and FEA overstate the Company's ability to control power costs.[24] Their unsupported assertions (which ignore the extensive analysis presented by PSE) fail to acknowledge the extent of the power cost volatility caused by changes in hydroelectric conditions and temperature. These are not risks that the Company can control. These parties also largely ignore the evidence presented by PSE

---

[21] *PacifiCorp* Decision, Docket No. UE-050684, Order 04 at ¶91 (2006) (emphases in original and footnotes omitted).

[22] *Id.* at ¶96.

[23] *See* Aladin, Exh. 11C 10:7 – 17:13.

[24] *See, e.g.*, Joint Parties (PCA), Exh. 599 23:18 – 24:22; Selecky, Exh. 491 9:1-14.

that, although it has a sophisticated risk management program and can reduce power cost exposure to some extent in the near term through certain hedging activities,[25] the Company cannot effectively hedge the hydro exposure in its portfolio.[26]

19. The Joint Parties and FEA confuse PSE's ability to *respond* to the variability in hydro conditions with PSE's ability to *manage* the variability in hydro conditions. The suggestion that PSE is in a better position than customers to manage power cost risks ignores the significant extent to which power costs are outside of the control of PSE as well as its customers.[27]

2. The Company's Proposed PCA Revisions Do Not Alter the Short-Run Nature of the Current PCA Mechanism

20. PSE's proposed revisions would not alter the short-run nature of the PCA Mechanism.

3. A Reduction From the Upper End of the Range of PSE's Proposed ROE May Be Warranted If PSE's PCA Revisions Are Adopted Along With Its Other New Mechanisms

21. Both Mr. Valdman and Dr. Morin acknowledge that the proper authorized return on equity for PSE should be balanced with the Commission's adoption of PSE's proposed regulatory mechanisms. Mr. Valdman discusses a "range of reasonableness" expected by the financial markets for PSE's return on equity. He acknowledges that the Commission may reduce the authorized return on equity from the level it would otherwise have set in this case if it adopts the Company's proposed revisions to the PCA Mechanism, the Depreciation Tracker, the GRNA and a residential gas customer charge of $17.00 per month. Conversely, if the Commission rejects any of PSE's proposed mechanisms, then the Commission should increase the authorized return on equity above the level it would otherwise have set to account for PSE's higher relative risks.[28]

[25] *See* Mills, Exh. 251C 4:1 – 24:24.
[26] *See* Aladin, Exh. 11C 17:14 – 18:9.
[27] *See generally id.* 3:3 – 19:7.
[28] *See* Valdman, TR. 292:20 – 293:14.

22. Dr. Morin concludes that PSE (with its proposed mechanisms to reduce risk) contains greater risks than that of his comparable group of utilities (with their mechanisms to reduce risk). This additional risk warrants the addition of 25 basis points to a return on equity of 11.0% (which includes 30 basis points for flotation costs) to compensate shareholders for this additional risk.[29]

23. The Joint Parties claim that PSE's proposed PCA revisions do not incorporate

> a corresponding reduction in the cost of capital or equity capitalization ratio. In fact, the Company is seeking an increased equity ratio, despite the fact that its financial risk has been reduced by the maturation of the existing PCA, and would be further reduced by the Company's proposed changes to the PCA.[30]

This ignores the fact that PSE's risk has been greatly increased by the recent expiration of the cumulative $40 million cap. The Company's current 10.3% ROE was set at a time when the cumulative cap was still firmly in place. It was also based on different evidence than is before the Commission in this case. Even with the Company's proposed PCA revisions, the PCA Mechanism will expose the Company to greater risk of extreme power costs than was present under the cap.[31] Full adoption of the Company's proposed PCA revisions will only mitigate the resulting increased exposure. At this time, the Company requires a much higher ROE than the 10.3% that was authorized under the $40 million cap. It is misleading and irresponsible for the other parties to steadfastly ignore the expiration of the cap, point back to the current 10.3% ROE, and argue that the Company's authorized ROE should be further reduced in this case.

4. The Company's Proposed PCA Revisions Do Not Interfere With Least Cost Planning, Conservation or Other Regulatory Goals

24. The Company's proposed revisions to the PCA Mechanism are modest, reasonable and would not interfere with PSE's least cost planning, conservation or other regulatory goals.

---

[29] *See* Morin, Exh. 301 58:4 – 77:17.
[30] Joint Parties (PCA), Exh. 599 8:22 – 9:4.
[31] *See* Aladin, Exh. 14 3:8 – 12:16.

5. The Company's Proposed PCA Revisions Would Apportion Risk More Equitably Between the Customers and Shareholders

a. The New Sharing Bands

25. As described above, power cost risks in PSE's portfolio are significant, some of which—particularly hydro availability—PSE is unable to control or hedge. PSE's hydro variability alone accounts for $25 million. In two years out of three (65% of the time), one would expect hydro variability to increase or decrease power costs by up to $25 million.[32] Under the current PCA Mechanism, PSE is exposed to a large portion of uncontrollable hydro risks or gains[33] that, theoretically, should be fully passed through or shared with customers because they cannot be controlled or hedged adequately regardless of how well PSE manages its electric portfolio overall.

26. Although many jurisdictions allow complete or nearly complete pass through of fuel or power costs to customers,[34] PSE is not proposing to fully pass through this $25 million in uncontrollable hydro risk to its customers. Instead, PSE proposes to share exposure within this first $25 million band equally with its customers. By sharing this first band 50/50, PSE and its customers will typically share equally in the upside of good hydro years and the downside of bad hydro years.[35]

---

[32] *See* Aladin, Exh. 11C 20:3-15.
[33] *See id.* 17:14 – 18:9.
[34] Colorado: *In re Aquila, Inc.*, 2004 Colo. PUC LEXIS 940 (2004); Florida: *In re Fuel & Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor*, 1984 Fla. PUC LEXIS 234 (1984); Georgia: Ga. Code Ann. § 46-2-26; Hawaii: Haw. Code R. § 6-60-6; Idaho: *In re Avista Corp.*, 237 P.U.R. 4th 53 (2004) (permitting recovery or refund of 90% of the amount above or below the base power supply costs); *In re Idaho Power Co.*, 2006 Ida. PUC LEXIS 86 (2006) (same); Indiana: Ind. Code § 8-1-2-42; Iowa: Iowa Admin. Code 199-20.9(476); Kansas: *In re Westar Energy, Inc.*, 246 P.U.R. 4th 108 (2005); Kentucky: 807 Ky. Admin. Regs. 5:056; Louisiana: *General Order*, 1997 La. PUC LEXIS 130 (1997); Mississippi: Miss. Code R. § 77-3-42; North Carolina: 4 N.C. Admin. Code 11.R8-55; South Carolina: S.C. Code Ann. § 58-27-865; Wyoming: 023-020-002 Wyo. Code R. § 249.
[35] *See* Aladin, Exh. 11C 21:11-18.

27. In addition, elimination of the current deadband is appropriate because setting the Power Cost Baseline Rate is an inexact endeavor that is heavily dependent on assumptions about future market prices and normalized hydro and weather conditions that will inevitably turn out to be different from future actual conditions. This Commission has recognized that it is good public policy to set the level of power costs recovered in rates as accurately as possible because it sends proper price signals to customers.[36] Under the current deadband structure, other parties benefit by setting the baseline rate too low. Setting the baseline rate at an artificially low level results in the Company being forced to absorb costs that it has prudently incurred to provide power to its customers. Having litigated the baseline rate several times since the PCA Mechanism was first established, the Company hopes that elimination of a deadband and a 50/50 sharing of the first $25 million of power costs will align all parties to set the Power Cost Baseline Rate as close as possible to the level that is actually likely to be experienced during the rate year.[37]

28. The Company's proposed second band, from $25 million to $120 million, would be shared 10% by the Company and 90% by customers. This second band is designed to capture a significant range of power cost risks reflected in PSE's electric portfolio, while preserving an upper range similar to that in the current PCA Mechanism. By retaining 10% of the upside or downside of this second band, the Company will continue to have significant incentive to manage power costs and achieve power cost savings.[38]

29. The final sharing band, for costs or savings in excess of plus or minus $120 million, with 95% customer sharing and 5% Company sharing, is meant to continue to provide protection to

---

[36] *See In the Matter of Purchased Gas Adjustment Mechanisms*, Cause No. UG-970001, Policy Statement at 2 (May 1997); *see also WUTC v. Puget Sound Energy, Inc.*, Docket No. UG-040640 et al., Order No. 06 at ¶107 (Feb. 18, 2005).

[37] *See* Harris, Exh. 171 21:4-7; Harris, TR. 109:22 – 110:20; Aladin, Exh. 11C 22:4-8.

[38] *See* Aladin, Exh. 11C 22:10-16.

the Company in the current PCA Mechanism sharing bands from extreme negative departures from the power costs that are embedded in rates, as well as to continue to provide some upside incentive in the event such significant power cost savings could be achieved.[39]

30. The Joint Parties and FEA erroneously assert that the Company's proposed revisions would result in a large shifting of risk to PSE's customers.[40] They fail to recognize that, until very recently, PSE has been protected by the cumulative $40 million cap from power costs that exceed the amount of power costs that is built into electric rates. At the same time, customers have been bearing the risk for 99% of costs that exceeded the cap. With the expiration of the cap, a huge amount of extreme power cost risk is being shifted onto PSE going forward, unless the Commission approves modification of the PCA Mechanism in this case. PSE's proposed changes to the PCA moderate this exposure, but still result in greater risk to the Company from extreme power cost events than have been experienced over the past four years with the cap.[41]

31. Although PSE's proposal will result in customers being at risk of having to pay 50% of the first $25 million of power costs in excess of those recovered in rates, this is a fair risk for customers to bear given the magnitude of power cost volatility that cannot be controlled by the Company due to hydro variability alone.[42] Moreover, this risk is counterbalanced by the opportunity customers will have to immediately share in the power cost savings that result in years with good hydro conditions, under PSE's 50/50 sharing proposal.[43]

b. Elimination of Exhibit E

---

[39] *See id.* 22:17 – 23:2.

[40] *See, e.g.*, Joint Parties (PCA), Exh. 599 19:8 – 20:2; Selecky, Exh. 491 at 4:8-15.

[41] *See* Aladin, Exh. 14 3:6 – 12:16.

[42] The customers' 50% share of $25 million—$12.5 million—comes out to only 66 cents ($0.66) per month for the average residential customer. *See* Hoff, Exh. 186 21:19-20.

[43] *See* Aladin, Exh. 14 10:1 – 12:16.

32. Exhibit E does not true-up costs symmetrically, is inequitable and should be eliminated. When the actual contract rate is *higher* than the Exhibit E contract rate, the actual contract rate is not used in the PCA true up calculation; rather the lower Exhibit E contract rate is used. When the actual contract rate is *less* than the Exhibit E contract rate, the actual rate is included in the allowed power costs, and PSE does not receive a credit to offset the higher Exhibit E rate. If Exhibit E is not eliminated, it should be modified to use the actual contract rates rather than the lower of the actual contract rate or the approved forecast rate.[44]

33. The Joint Parties assert that the elimination of Exhibit E from the PCA Mechanism "benefits the Company to the detriment of consumers." They assert that maintaining Exhibit E somehow balances the fact that the PCA Mechanism holds return on rate base associated with Company owned generation constant and assert that elimination of Exhibit E would upset this symmetry.[45] These assertions are incorrect. The lack of rate base adjustment in the PCA Mechanism for depreciating resources is counterbalanced by other benefits provided to customers under the PCA, such as foregone revenue growth on production plant and regulatory assets.[46]

C. The Joint Parties Wrongly Assert That the Current PCA Was Designed Based on the Company's "Retention"

34. The Joint Parties baldly assert, without support, that the current PCA Mechanism was designed "so that Puget is at risk for only a portion of its power supply cost variations that result from weather or power market conditions. The amount of risk was designed to be only a fraction

[44] *See id.* 24:14 – 25:3.
[45] *See* Joint Parties (PCA), Exh. 599 22:12 – 23:16.
[46] *See* Story, Exh. 439 22:15 – 23:2. Moreover, the power cost contracts listed on Exhibit E are for Qualifying Facilities under PURPA, small hydro facilities and other contracts that are not related to Company-owned resources. These contracts have been approved by the Commission for inclusion in rates, and no valid reason exists for holding their costs constant. *See id.* 24:9-13.

of the Company's 'retention' each year."[47] This premise is flatly wrong as evidenced by the prefiled testimonies and the transcript of the oral testimony and cross-examination of the panel[48] testifying in support of the current PCA Mechanism (collectively, the "PCA Settlement Joint Testimony"). There is no reference to "retention" in the PCA Mechanism, the PCA Settlement Joint Testimony, or the Commission's order approving the current PCA Mechanism.[49]

35. "Retention" is an inappropriate measure of the power cost risk PSE can absorb. Earnings that are not paid out as dividends should not be viewed as available to pay power costs that are not recovered in rates. These funds are used to help finance new capital investment, such as infrastructure replacement and other expenditures necessary to provide service to customers.[50]

36. The Commission should not place any weight on the Joint Parties' related arguments regarding PSE's power cost risks relative to those of Avista. The evidence demonstrates that PSE's proposed changes to the PCA Mechanism—not the current mechanism—would be more consistent with the revisions to the Avista mechanism that the Commission recently approved.[51]

IV. MECHANISMS TO ADDRESS HIGH CAPITAL INVESTMENT NEEDS AND REGULATORY LAG

A. Regulatory Lag Is Threatening the Company's Ability to Maintain a High Level of System Reliability

37. The Company faces extremely high levels of energy delivery systems investments over the next several years in order to maintain system safety and meet customers' increasing demands for highly reliable and efficient energy service. Investments in this critical

---

[47] *See* Joint Parties (PCA), Exh. 599 10:10-13.
[48] *See generally* Story, Exh. 444 29-168. The PCA Panel in PSE's 2001 general rate case consisted of Mr. Story and Mr. Elsea on behalf of PSE, Mr. Merton R. Lott on behalf of Staff, and Mr. Lazar on behalf of Public Counsel.
[49] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 & UG-011571, Twelfth Supp. Order at ¶¶ 22-30 (2002); *see, generally,* Story, Exh. 444. There is no mention of "retention," or any derivative thereof, in 168 pages of testimony supporting the adoption of the current PCA Mechanism. *See also* Story, Exh. 439 21:7-9.
[50] *See* Valdman, Exh. 457C 21:4-17.

infrastructure benefit customers and further the State's public policy of fostering economic development.[52] In 2006, the Company is spending approximately $444 million in energy delivery technology and facilities; in 2007 it plans to spend approximately $500 million.[53]

38. Without the Depreciation Tracker or the alternative known and measurable adjustment proposed by the Company, customers begin receiving the benefit of new plant when it is placed in service but they do not begin to pay for the investment until the plant is added to the Company's ratebase in the next general rate case after the plant has been put in service. Although the Company begins incurring depreciation expense on the new plant immediately, it does not begin to recover the total depreciation expense until the next general rate case.[54] This situation threatens the Company's ability to continue to fund and provide its delivery system investments at the pace the Company believes is most ideal for maintaining system reliability.[55]

39. PSE has proposed implementation of a Depreciation Tracker in this case that will provide the Company with more timely recovery of depreciation expense. This mechanism only addresses "recovery of" and not "recovery on" the investment. In response to the objections of other parties about establishing an ongoing tracker, PSE proposed an alternative, "known and measurable" adjustment that would add to the revenue requirement for this case the non-revenue producing and non-expense reducing transmission and distribution energy delivery system plant that was put into service after the test year ended on September 30, 2005 through June 30, 2006.

B. The Depreciation Tracker

---

[51] *See id.* 20:5 – 28:10; Gaines, Exh. 137C 37:4 – 43:6; Aladin, Exh. 14 3:6 – 14:11.
[52] *See, e.g.*, RCW 43.160.010(1).
[53] *See* Valdman, Exh. 457C 6:10-16, 7:4; *see also* Exh. 801.
[54] *See* Story, Exh. 421 59:3-9.
[55] *See* Valdman, Exh. 457C 28:19 – 29:9; McLain, Exh. 245 13:12-15.

40. The Company's proposed Depreciation Tracker would allow PSE to recover the change in depreciation expense associated with its investments in transmission and distribution infrastructure through a surcharge to existing tariff schedules. This surcharge would be based on the incremental depreciation expense of natural gas and electric transmission and distribution investment over and above the depreciation expense reflected in rates. The cost recovery takes into consideration the growth in revenues associated with increased load so that there is no "double recovery" with new natural gas and electric transmission and distribution investment.[56] The Depreciation Tracker is a relatively simple, transparent mechanism that can be estimated in advance, trued up to actual after the fact, and will go part of the way toward addressing the attrition the Company is experiencing related to its increasing infrastructure investments.[57]

41. The Depreciation Tracker provides an equitable and balanced approach for new plant put in service after the test year because it addresses only the "recovery of" PSE's investment in the new plant in service. It does not include the new plant in rate base and thus does not provide the Company "recovery on" transmission and distribution system investments made since the end of the most current test year, even though customers benefit from this plant from the time it is placed into service.[58] Recovery *on* the new plant would continue to be forgone until that new plant is added to the Company's ratebase in a subsequent rate case.[59] The Depreciation Tracker would increase the electric revenue requirement by $7,878,988 and increase the gas revenue requirement by $10,884,680, which would be collected in a new Depreciation Tracker rate.[60]

C. The Alternative "Known and Measurable" Adjustment

[56] *See* Story, Exh. 421 68:4-7, 72:13 – 75:13; 77:6-10.
[57] *See id.* 77:6-10.
[58] *See* Harris, TR. 153:22 – 154:11; McLain, TR. 219:1 – 11; Story, Exh. 439 at 26:9-18.
[59] *See* Story, Exh. 421 67:9-12.
[60] *See* Story, Exh. 421 74-75.

42. As an alternative to the Depreciation Tracker, the Company proposed an adjustment in this case for transmission and distribution energy delivery system plant that has been put in service since the close of the test year, a type of adjustment proposed by FEA witness Mr. Smith in his response testimony.[61] This adjustment would increase the electric revenue deficiency by $8.8 million and increase the gas revenue deficiency by $3.5 million.[62]

43. This alternative is also an equitable and balanced approach whereby the Company and customers share in the expense of PSE's significant capital expenditures for its transmission and delivery system. Customers will pay for energy delivery system plant additions—such as the Novelty Substation—that were added since the close of the test year and that serve current customers.[63] Only the non-revenue producing plant put into service during the nine month time frame from October 1, 2005 through June 30, 2006 is included in PSE's alternative adjustment.[64] PSE would wait for its next general rate case to recover depreciation on all other transmission and distribution plant put into service after October 1, 2005, even though it incurs depreciation expense on these investments, and even though customers benefit from these plant additions.[65]

44. Contrary to the objections of Staff, the new plant in service that PSE has included in this adjustment will not produce incremental revenues for the Company without regulatory action; nor is this plant expected to reduce expenses over historical levels.[66] Costs associated with this adjustment generally involve additions to or replacements of the backbone of the gas and electric

---

[61] *See* Smith, Exh. 492 14:7-17.
[62] *See* Story, Exh. 439 31:5-7.
[63] *See* Harris, TR. 153:22 – 154:11; McLain, Exh. 245 9:9 – 10:10.
[64] The Company's adjustment appropriately reduces the non revenue producing transmission and distribution plant additions by the depreciation and deferred taxes associated with the additions. Mr. Smith inappropriately offsets all depreciation associated with historical transmission and distribution investment against the new additions. *See* Story, Exh. 746 4:1 – 5: 2.
[65] *See* Harris, TR. 153:22 – 154:11; McLain, TR. 219:1-11.
[66] *See* McLain, Exh. 245 5:12 – 6:11.

systems that will improve the reliability and performance of the systems. PSE also took into consideration the retirement of like facilities during the time period for which it is seeking recovery of new delivery system investments.[67]

D. Approval of Either the Depreciation Tracker or Known and Measurable Adjustment Would Be Consistent With This Commission's Past Orders

45. The Commission has recognized that it is appropriate to take steps to address earnings attrition in situations, such as this, where the Company would not otherwise have a reasonable opportunity to earn its allowed rate of return:

> When the company is experiencing vastly different rates of change in revenues, expenses and ratebase, the problem of earnings attrition occurs. The Commission finds that a refusal to recognize this problem, as demonstrated by the record in this case, would amount to a refusal to allow the company a reasonable opportunity to earn its allowed rate of return.[68]

PSE is experiencing vastly different rates of change in ratebase and expenses, due to its unprecedented capital spending for energy delivery system infrastructure needed for the foreseeable future.[69] It is well within this Commission's authority and precedent to address, in the manner proposed by PSE, this mis-match so that PSE's rates are sufficient to support its delivery system investments on behalf of its customers.

46. Other state commissions and legislatures have recognized and addressed the regulatory lag associated with high levels of infrastructure investments through cost recovery mechanisms and adjustments to rate base to reflect known and measurable pro forma changes.[70] Although other parties minimize the seriousness of the regulatory lag PSE is experiencing, the problem is

---

[67] *See* McLain, TR. 189:7-20; McLain, TR. 207:2-14.

[68] *WUTC v. Wash. Water Power Co.*, Docket No. U-82-10 *et al.*, Second Supplemental Order, 1982 Wash. UTC LEXIS 3 at *53-55 (Dec. 1982)..

[69] *See* McLain, Exh. 241C 15; McLain, Exh. 245 3:6 – 5:11.

real and demonstrated by the evidence.[71] PSE should be provided a reasonable opportunity to earn its allowed rate of return through implementation of the Depreciation Tracker or the alternative known and measurable adjustment proposed for this case.

V. CAPITAL STRUCTURE AND COST OF CAPITAL

A. PSE's Proposed Capital Structure That Contains 45% Equity Is Reasonable and Properly Balances Safety and Economy

47. The Company has proposed a capital structure that consists of 45.00% equity, 48.44% long-term debt, 2.11% short-term debt, 0.70% trust preferred stock, and 3.75% preferred stock.[72] No party to this proceeding has argued that the Company's proposed *pro forma* capital structure is unreasonable or fails to strike a fair balance between interests of safety and economy.[73] Instead, Staff and ICNU assert that the Commission should reject the *pro forma* capital structure proposed by PSE because the Company's equity ratio does not yet equal the 45.0% included in PSE's proposed capital structure.[74]

48. The capital structures proposed by Staff and ICNU would result in rates of return that fail to provide recovery of the true costs of the Company's capital.[75] Staff's proposed equity ratio of

---

[70] *See generally* Amen, Exh. 34; *see, e.g., In re Northwest Natural Gas Co.*, Tariff Advice No. 04-10, (Or. PUC 2004); *In re Laclede Gas Co.*, Docket No. GO-2004-0443, Order Approving Tariffs (Mo. PSC 2004); 83 Ill. Adm. Code 656 (Qualifying Infrastructure Plan Surcharge).

[71] In addition to performing trended attrition analyses that demonstrate the real impact of regulatory lag on the Company, PSE also provided a financial model, which shows electric and gas operations for 2007 and takes into consideration the complex interactions of the different economic considerations that Staff claims must be considered. *See* Story, Exh. 439 29:4 – 30:3.

[72] *See* Gaines, Exh. 137C 6:Table 1; Gaines, Exh. 140C at 1.

[73] *See WUTC v. Puget Sound Energy, Inc.*, Order No. 06, at ¶27, Docket Nos. UG-040640, *et al.* (2005) (indicating that the capital structure for ratemaking purposes must be reasonable and strike a fair balance between safety and economy).

[74] *See, e.g.*, Hill, Exh. 531C 29:4 – 30:16; Gorman, Exh. 471C 4:10 – 6:13. Mr. Gorman erroneously refers to PSE's proposed capital structure as "hypothetical." Gorman, Exh. 471C 4:10-12. PSE's proposed capital structure is *pro forma*—not hypothetical—because PSE anticipates that its actual capital structure will have a 45.0% equity ratio, on average, during the rate year.

[75] *See* Morin, Exh. 315 85:3-15.

43%—the authorized equity ratio on which Company rates are currently set[76]—fails to include the equity invested in PSE by Puget Energy during the past year.[77] This equity infusion increased PSE's equity ratio to above 44%, an equity level that prevailed through June 30, 2006.[78]

49. ICNU proposes a capital structure with an equity ratio of 44.13%—the actual equity ratio of the Company as of December 31, 2005.[79] This proposed capital structure reflects the equity invested in PSE in 2005 but fails to reflect the reasonable levels of equity projected to be invested in the Company throughout the rate year. This is inconsistent with the approach used by the Commission in the Company's 2004 general rate case:

> Our goal in this proceeding should be to set the Company's equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year.[80]

50. The Commission should adopt PSE's proposed capital structure because such capital structure (i) is reasonable, (ii) properly balances safety and economy, and (iii) is the capital structure most likely to prevail, on average, over the course of the rate year.

B. PSE's Proposed Rate of Return Is Fair, Just, Reasonable and Sufficient

51. Rate of return is the weighted average cost of PSE's various sources of capital and is intended to compensate the Company for the amount of money it must spend to obtain the capital it uses to provide electric and natural gas services. Multiple orders of this Commission have provided the following formulation with regard to the appropriate rate of return:

> A utility is entitled to the opportunity to earn a rate of return sufficient to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk.[81]

---

[76] *See* Hill, Exh. 531C 37:14-17.
[77] *See, e.g.*, Valdman, Exh. 455 229-230.
[78] *See, e.g.*, Valdman, Exh. 466 16.
[79] *See* Gorman, Exh. 471C 4:14 – 5:3.
[80] *WUTC v. Puget Sound Energy, Inc.*, Order No. 06, at ¶40, Docket Nos. UG-040640, *et al.* (2005).

52. Similarly, several decisions of the U.S. Supreme Court require that this Commission's decision allow PSE the opportunity to earn a ROE that is: (i) sufficient to assure confidence in the Company's financial integrity and maintain the Company's creditworthiness, (ii) sufficient to maintain PSE's ability to attract capital on reasonable terms; and (iii) commensurate with returns on investments in other firms having corresponding risks.[82]

1. PSE's Embedded Costs of Debt, Trust Preferred Stock, and Preferred Stock Are All Undisputed and Reasonable

53. The following embedded costs of PSE's long-term debt, short-term debt, trust preferred stock and preferred stock are all undisputed[83] and reasonable:[84]

Type of Security	Embedded Cost
Long-Term Debt	6.64%
Short-Term Debt	6.66%
Trust Preferred Stock	8.54%
Preferred Stock	7.61%

Accordingly, PSE respectfully requests that the Commission authorize an overall rate of return that includes the cost rates indicated above.

2. PSE's Proposed Cost of Equity of 11.25% Properly Accounts for Flotation Costs and PSE's Higher Relative Construction, Power Cost, Regulatory and Financial Risks

54. Dr. Morin, the cost of equity witness for PSE, employs three market-based methodologies—the Discounted Cash Flow ("DCF") Model, the Capital Asset Pricing Model ("CAPM") and the Market Risk Premium—to estimate the return required by investors on the

[81] *See, e.g., WUTC v. Avista Corp.*, Docket Nos. UE-991606 & UG-991607, Third Supp. Order, at ¶324 (2000); *WUTC v. Puget Sound Power & Light Co.*, Docket Nos. UE-920433, *et al.*, Eleventh Supp. Order, at 25 (Sept. 21, 1993); *WUTC v. Pac. Power & Light Co.*, Docket No. U-86-02, Second Supp. Order, at 26 (1986).

[82] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *In re Permian Area Basin Rate Cases*, 390 U.S. 747 (1968); *Fed. Power Comm'n v. Memphis Light, Gas & Water Div.*, 411 U.S. 458 (1973); *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989).

[83] *See* Hill, Exh. 531C 38:5-7; Gaines, Exh. 139 1; Gorman, Exh. 471C at 7:9-12.

[84] *See* Gaines, Exh. 137C 6:Table 1 and Gaines, Exh. 140C 1 for the embedded cost of each security.

common equity capital committed to PSE. Based on his analysis of these three methodologies, Dr. Morin recommends an authorized ROE for PSE of 11.00%, adjusted upward to 11.25% to account for PSE's higher relative construction, power cost, regulatory and financial risks.[85]

55. Mr. Hill, the cost of equity witness for Staff, recommends an authorized ROE for PSE of 9.375%,[86] which is far below the approximate 10.5% ROE equity authorized by other regulatory commissions, on average, in 2005 and 2006.[87] Mr. Hill could not identify a single investor-owned regulated electric utility, natural gas utility or combination electric and natural gas utility with a market capitalization in excess of $1 billion, with an allowed rate of return on common equity that is as low as his recommended return on equity.[88] Indeed, the average authorized ROE for (i) Mr. Hill's comparable group of electric utilities is 10.80%[89] and (ii) Mr. Hill's comparable group of natural gas utilities is 10.86%.[90]

56. Mr. Gorman, the cost of equity witness for ICNU, recommends an authorized ROE for PSE of 9.9%,[91] which is also below the reasonable range of returns of equity authorized by other regulatory commissions and required by investors.[92] The average authorized ROE for Mr. Gorman's comparable group of combination utilities is 10.88%.[93]

57. In addition, as discussed above, the Company's current ROE of 10.3% was set when the PCA Mechanism protected the Company from excess power costs with a $40 million cumulative cap.[94] With the expiration of that cap, the Company faces much higher exposure to excess power

[85] *See* Morin, Exh. 301 58:4 – 77:17.
[86] *See* Hill, Exh. 531C 4:17-20.
[87] *See* Gaines, Exh. 134 3.
[88] *See* Valdman, Exh. 460 1.
[89] *See* Valdman, Exh. 457C 17:12-18; *see also* Valdman, Exh. 461 1.
[90] *See* Valdman, Exh. 457C 18:3-10; *see also* Valdman, Exh. 462 1.
[91] *See* Gorman, Exh. 471C 22:17 – 23:4.
[92] *See* Gaines, Exh. 134 3.
[93] *See* Valdman, Exh. 457C 18:13 – 19:2; *see also* Valdman, Exh. 463 1.
[94] *See* Valdman, TR. 253:2 – 255:3.

cost risk, even if the Commission accepts the Company's revisions to the PCA Mechanism,[95] and thus the Company requires a ROE that reflects the increased risk. The ROE must also include flotation costs, which neither Mr. Hill or Mr. Gorman included in their ROE calculations. And the massive capital investments anticipated over the next several years provide further justification for the Company's requested ROE of 11.25%. If the Commission approves all of the proposals offered by PSE—the Depreciation Tracker, the GRNA and the revisions to the PCA Mechanism—a ROE less than 11.25% could be appropriate. However even then, a ROE level in the high 10% range would be required to account for the risk associated with the Company's construction plans that is not addressed by the Depreciation Tracker, flotation costs and the Company's increased exposure to excess power costs with the expiration of the $40 million PCA cap.[96]

a. A Flotation Cost Allowance Is Necessary for PSE to Recover Costs Incurred in the Issuance of Equity

58. Flotation costs are the costs associated with the issuance of a security and have a direct and an indirect component. This Commission has recently suggested that adjustments for flotation costs are appropriate where the utility issued equity in the test year or plans to do so in the future.[97] Here, Puget Energy issued common stock during the test year and expects to incur flotation expenses during the rate year to finance PSE's considerable construction program.[98]

59. Empirical finance literature demonstrates that total flotation costs amount to 5% of gross proceeds—4% for the direct component and 1% for the indirect (market pressure) component.[99] This empirical evidence is consistent with the direct component flotation costs of 3.12% of gross

[95] *See* Aladin, Exh. 14 3:8 – 12:16.
[96] *See* Valdman, Exh. 457C 14:10 – 16:5; Valdman TR. 292:20 – 293:14; Morin TR. 382:12 – 383:2.
[97] *PacifiCorp* Decision at ¶122.
[98] *See* Morin, Exh. 315 71:18-21; Gaines, Exh. 136C 2:10; Gaines, Exh. 140C 2:10.
[99] *See* Morin, Exh. 301 52: 3 – 56:2; *see also* Morin, Exh. 314 1-9; Morin, Exh. 315 12:15 – 18:4 and 70:13 - 71:21.

proceeds incurred by Puget Energy, Inc. in its October 2005 equity issuance.[100] Flotation costs of 5% of gross proceeds approximate an increase to the allowed ROE of approximately 30 basis points, depending on the magnitude of the dividend yield component.[101] Therefore, each of the market-based ROE estimates presented by Dr. Morin and discussed below includes a flotation cost adjustment of 30 basis points. In contrast, Mr. Hill and Mr. Gorman fail to include any allowance whatsoever for flotation costs in their ROE recommendations. Therefore, their ROE estimates are downward-biased by approximately 30 basis points from that omission alone.

b. Proper DCF Analyses Generate Estimated ROEs Between 9.6% and 11.2%, With an Average ROE of 10.4%

60. The DCF model posits that the value to an investor of any security, under certain assumptions,[102] is the expected discounted value of the future stream of dividends or other benefits.[103] Dr. Morin applies the DCF model to three proxies for PSE: (i) PSE's parent company, Puget Energy, Inc.; (ii) a group of investment-grade combination gas and electric utilities that derive the majority of their revenues from regulated operations; and (iii) a group of actively traded dividend-paying natural gas distribution companies drawn from the Value Line Gas Distribution Group.[104] Dr. Morin's DCF analysis provides a range of ROE estimates for PSE with a low of 9.6%, an average of 10.4%, and a low of 11.2%.[105]

61. In contrast to Dr. Morin, Mr. Hill exclusively relies on the sustainable growth method to determine the growth component of DCF, despite empirical finance literature that demonstrates

[100] *See* Bench Exhibit, Exh. 9 1.
[101] *See* Morin, Exh. 301 52:3 – 56:2; *see also* Morin, Exh. 314 1-9.
[102] *See* Morin, Exh. 301 19:15 – 21:15, 42:11 – 43:2 for the assumptions underlying the DCF Model.
[103] *See id.* 41:12 – 42:10.
[104] *See id.* 47:6 – 51:11.
[105] *See id.* 301 41:9 – 51:11.

that such technique is a very poor explanatory variable of market value and is not significantly correlated to measures of value, such as stock price and price/earnings ratios.[106]

62. Mr. Hill bases his sustainable growth rate forecasts on ROE estimates generated from (i) achieved ROEs in the past five years (2002-2006) and (ii) Value Line's forecast ROE for 2007 and for the 2009-2011 period.[107] The Value Line forecasts, however, are based on end-of-period rather than average book equity, which results in DCF estimates that are understated by 10-20 basis points, depending on the magnitude of the book value growth rate forecast.[108]

63. Additionally, Mr. Hill's sustainable growth rate forecasts are inaccurate because he assumes that his sample group of utilities, on average, will actually earn a ROE that is significantly higher than their costs of equity.[109] PSE has consistently failed to realize its authorized ROE by a significant margin.[110]

c. Proper CAPM Analyses Generate Estimated ROEs Between 11.2% and 12.1%, With an Average ROE of 11.7%

64. The traditional CAPM quantifies the additional return, or risk premium, required by investors for bearing incremental risk. The CAPM formula accounts for an asset's sensitivity to market risk (in a number often referred to as beta (β)), as well as the expected return of the market and the expected return of a risk-free asset.[111] Dr. Morin provides four estimates of PSE's ROE based on the CAPM methodology—two based on the "plain vanilla" CAPM and two

---

[106] *See* Morin, Exh. 315 23:17-20.
[107] *See id.* 21:19-21.
[108] *See id.* 24:3-19.
[109] *See id.* 315 21:17 – 23:15.
[110] *See* Bench Exhibit, Exh. 5 1-7 (PSE Response); Valdman, Exh. 451 12:6 – 14:13.
[111] *See* Morin, Exh. 301 22:13 – 23:3.

based on the "empirical" CAPM. Dr. Morin's CAPM analysis provides a range of ROE estimates for PSE with a low of 11.2%, an average of 11.7%, and a high of 12.1%.[112]

i. The Proper Risk-Free Rate for the CAPM Is the Projected Yield on 30-Year Treasury Bonds (5.3%)

65. For both the plain vanilla CAPM and the empirical CAPM, Dr. Morin utilizes two different risk-free rates: (i) an historical risk-free rate of 4.70% and (ii) a projected rate year risk-free rate of 5.30%.[113] Dr. Morin's projected risk-free rate is identical (5.30%) to Mr. Gorman's risk-free rate, the only other projected risk-free rate provided in this proceeding.

66. Unlike Dr. Morin and Mr. Gorman, Mr. Hill fails to employ a projected risk-free rate. Instead, Mr. Hill employs a range of historical risk-free rates from 4.69% to 4.97%, with the low end of the range based on the yield on 90-day Treasury Bills and the high end of the range based on the yield on 20-year Treasury bonds.[114] The yield on 90-day Treasury Bills, however, is a very poor proxy for the risk-free rate in the CAPM because common stocks are very long-term instruments more akin to very long-term bonds.[115]

ii. The Proper Beta for the CAPM Is the Average Beta for Investment-Grade Combination Utilities (0.83)

67. Dr. Morin uses a beta of 0.83 for PSE, which he derives from the average beta of 0.83 for the investment-grade combination gas and electric utilities that are covered by AUS Utility Reports and Value Line and have utility revenues that constitute at least 50% of total revenues.[116]

68. Mr. Hill provides betas of 0.82 and 0.81, respectively, for his samples of electric and natural gas utilities.[117] More current issues of Value Line, however, report an average beta of

---

[112] *See id.* 22:2 – 36:9.
[113] *See id.* 26:8 – 27:7.
[114] *See* Hill, Exh. 544 1-2.
[115] *See* Morin, Exh. 315 32:15 – 33:1.
[116] *See* Morin, Exh. 301 28:1-16.

0.84 and 0.85 for Mr. Hill's sample groups. These differences in beta amount to an understatement of Mr. Hill's ROE estimates by approximately 20 basis points.[118]

69. Although the average beta of Mr. Gorman's comparable group of combination utilities is 0.90,[119] Mr. Gorman asserts, without support or explanation, that "[a] normal utility beta estimate is approximately 0.70 based on a long-term assessment of utility beta estimates."[120] Ultimately, Mr. Gorman bases his CAPM analysis on the beta estimate of a single company—Puget Energy, Inc. (0.80). Mr. Gorman's reliance on the beta for a single utility for a CAPM analysis deviates significantly from Mr. Gorman's past practice to rely on the average beta of his comparable group of utilities.[121] Use of a beta for an individual company is fraught with error because a single-company beta can contain measurement errors. Moreover, the empirical financial literature demonstrates that the standard error of beta estimation is considerably smaller for portfolios (e.g., comparable groups and/or industries) than for individual company observations.

70. If Mr. Gorman had followed his usual practice and used the group average beta of 0.90 for his comparable group, his CAPM estimates would be between 60 to 80 basis points higher than the ROE estimates based on the CAPM that are set forth in his testimony.[122]

iii. The Proper Long-Term Market Risk Premium for the CAPM Is the Average of the Arithmetic Averages of the Historical and Projected Long-Term Market Risk Premiums (7.5%)

71. Dr. Morin uses a long-term market risk premium of 7.5%, which is the average of results of studies of both historical (7.2%) and projected (7.7%) long-term market risk premiums.

[117] *See* Hill, Exh. 544 1-2.
[118] *See* Morin, Exh. 315 33:14-17.
[119] *See* Gorman, Exh. 484 1.
[120] Gorman, Exh. 471C 35:17-18.
[121] Mr. Gorman asserts that he did not use the group average beta estimated for his comparable group, in part, because "several of the companies have betas of 0.90 or higher" and several of the companies in his "comparable"

Dr. Morin's historical long-term market risk premium of 7.2% properly analyzes the historical market risk premium over the income component (rather than over the total return) of long-term Treasury bonds as reported in the Ibbotson Associates study.[123] Dr. Morin's projected long-term market risk premium results from a DCF analysis of the aggregate equity market using the December 2005 edition of the Value Line Investment Analyzer ("VLIA") software.[124]

72. Mr. Hill and Mr. Gorman use market risk premiums of 6.5%, which is the arithmetic average of the historical market risk premiums for the 1926-2005 period published by Ibbotson Associates. The market risk premium of 6.5% represents the historical long-term market risk premium over total return (*i.e.* the coupon rate + capital gain) for such period.

73. The use of the historical long-term market risk premium over the income component of long-term Treasury bonds (*i.e.* the coupon rate) is a superior estimate of expected return. The historical long-term market risk premium over the *total* return (*i.e.* the coupon rate + capital gain) is an inferior estimate of expected return because bond investors generally do not expect realized capital gains or losses. The long-term (1926-2005) market risk premium (based on income returns) is the 7.1% market risk premium used by Dr. Morin, rather than 6.5%.[125]

74. Mr. Hill also improperly uses the geometric average of the historical market risk premiums for the 1926-2005 period published by Ibbotson Associates for his CAPM analysis. Indeed, the Ibbotson Associates publication from which Mr. Hill's market risk premium estimate is derived contains a detailed and rigorous discussion of the impropriety of using geometric

---

group face significantly different risk profiles. *See id.* 34:3-16. If these utilities present risk profiles that are truly different than PSE, Mr. Gorman should not have included them within his comparable group of combination utilities.

[122] *See* Morin, Exh. 315 79:12-17.

[123] *Stocks, Bonds, Bills, and Inflation, 2004 Yearbook.*

[124] *See* Morin, Exh. 301 29:1 – 33:1.

[125] *See* Morin, Exh. 315 34:4-14, 80:2-23.

averages in estimating the cost of capital. There is no theoretical or empirical justification for the use of geometric mean rates of returns.

75. Mr. Hill's use of the geometric mean market risk premium of 4.9% rather than the arithmetic mean of 6.5% significantly understates the market risk premium, which suggests an understatement of PSE's cost of equity by approximately 130 basis points (assuming for purposes of argument Mr. Hill's beta for PSE of 0.82). Using Mr. Hill's long-term Treasury yield of 4.97%, a revised average beta of 0.84 and an arithmetic mean market risk premium of 6.5%, would increase Mr. Hill's CAPM estimate to 10.5% without flotation cost and 10.8% with flotation cost.

76. Mr. Gorman calculates a prospective risk premium of 6.3%, which combines the historical real return on stocks (9.1%) with the medium-term consumer price index forecast (2.3%) to project market returns of 11.6%.[126] Mr. Gorman's use of a medium-term inflation rate forecast, however, fails to recognize that equity has a perpetual life. More appropriate measures would have been long-term consumer price index forecasts, which are approximately 45 basis points higher than the medium-term consumer price index forecast of 2.3%. This 45 basis point differential (2.75% - 2.3%) would increase Mr. Gorman's prospective market risk premium from 6.3% to about 6.75% and Mr. Gorman's CAPM estimate by approximately 32 basis points.[127]

d. Historical Risk Premiums in the Utility Industry Suggest a ROE Between 10.6% and 11.3%, With an Average ROE of 10.95%

77. Dr. Morin bases his historical risk premium of 5.6% for the electric utility industry on an annual time series analysis from 1931 to 2001[128] applied to the electric utility industry as a

[126] *See* Gorman, Exh. 471 21:17 – 22:2.
[127] *See* Morin, Exh. 315 81:3-12.
[128] Data after calendar year 2001 were not readily available following the acquisition of Moody's by Mergent. *See* Morin, Exh. 301 37:5-6.

whole, using Moody's Electric Utility Index as an industry proxy. Similarly, Dr. Morin bases his historical risk premium of 5.7% for the natural gas utility industry on an annual time series analysis from 1955 to 2001[129] applied to the natural gas utility industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy.[130] Dr. Morin's historical risk premium analysis provides a range of ROE estimates for PSE with a low of 10.6%, an average of 10.95%, and a high of 11.3%.

78. Mr. Hill concedes that "[u]tility equity return awards in the U.S. over the past year have averaged about 10.5%."[131] His assertion that regulatory commissions have authorized returns on equity over the past year that are allegedly in excess of investor expectations out of ignorance of "new research" regarding declines in market risk premiums is not credible.[132]

79. Moreover, Mr. Hill has selectively chosen published studies that purport to show that the average historical market risk premium published by Ibbotson Associates is high. His assessment of the state of research regarding market risk premium is inaccurate and misleading. For example, Mr. Hill cites to a published work that reports average risk premiums over long-term bond returns for all countries of 5.0% but fails to mention that the same study reported a market risk premium of 7.0% for the U.S. In short, Mr. Hill fails to provide any evidence that proves that the average historical market risk premium published by Ibbotson Associates is too

[129] Again, data after calendar year 2001 were not readily available following the acquisition of Moody's by Mergent. *See id.* 37:5-6.

[130] *See id.* 36:11 – 38:15.

[131] Hill, Exh. 531C 6:11-12.

[132] *See id.* 16:18-21. Mr. Hill quotes from, or cites to, the same evidence that market risk premiums are lower than the average historical market risk premium published by Ibbotson Associates that he presented in PSE's and Pacific Power & Light Company's last general rate proceedings. Given Mr. Hill's previous testimony regarding the alleged overstatement of market risk premium before this Commission, Mr. Hill cannot assert that this Commission was "generally not aware" of the alleged overstatement of market risk premium asserted by Mr. Hill when the Commission granted PSE and Pacific Power & Light Company authorized returns on equity substantially higher than the 9.375% recommended by Mr. Hill in this proceeding.

high.[133] Nor does he explain why he uses the average historical market risk premium published by Ibbotson Associates as the market-risk premium for his CAPM analysis but then argues that such market risk premium is too low for a market risk premium analysis.[134]

e. Allowed Risk Premiums in the Utility Industry Suggest a ROE Between 10.7% and 11.0%, With an Average ROE of 10.85%

80. Dr. Morin also analyzes the risk premiums implied in ROEs allowed by regulatory commissions for electric utilities relative to the prevailing long-term Treasury bond yields over the 1996-2005 period. Dr. Morin's allowed risk premium analysis provides a range of ROE estimates for PSE with a low of 10.7%, an average of 10.85%, and a high of 11.0%.

81. Mr. Gorman suggests a risk premium of 5.0% implied by the ROEs authorized by regulatory commissions over the period 1986-2005, relative to the contemporaneous level of long-term Treasury and "A" rated utility bond yields.[135] Mr. Gorman, however, failed to account for the inverse relationship between authorized risk premiums and interest rates.[136] If Mr. Gorman were to correct such error, his allowed risk premium would increase to 5.6%, which would result in an authorized ROE for PSE of 10.9% (5.3% + 5.6%), which is 100 basis points greater than Mr. Gorman's recommended ROE of 9.9%.[137]

82. Although Mr. Hill attempts to use a Graham and Harvey survey to counter Dr. Morin's empirical evidence that market risk premiums varied inversely with interest rates,[138] that survey states that the market risk premium for *the equity market* varies directly with interest rates, not that the market risk premium for the *utility industry* directly varies with interest rates. The

[133] *See* Morin, Exh. 315 45:13 – 50:11.
[134] *See id.* 34:10-14
[135] *See* Gorman, Exh. 471C 15:20 – 16:19.
[136] *See* Morin. Exh. 315 83:9-15.
[137] *See* Morin, Exh. 315 83:3 – 84:15.
[138] *See* Hill, Exh. 531C 101:14-23.

market risk premium for the *utility industry* varies inversely to interest rates, and the Graham and Harvey survey does not suggest otherwise.[139]

f. PSE's Higher Relative Construction, Power Cost, Regulatory and Financial Risks Necessitate an Upward Risk Adjustment of Approximately 25 Basis Points

83. Dr. Morin adjusts his recommended ROE of 11.0% upward by 25 basis points to 11.25% to account for PSE's higher relative construction, power cost, regulatory and financial risks. He bases this risk increment on (i) the differences in yield between utility long-term bonds rated Baa and those rated single A and (ii) the differences between PSE's debt ratio adjusted for the presence of purchased power obligations and that of the electric utility industry.[140]

84. Dr. Morin's recommended ROE takes into account continuation of PSE's PCA Mechanism, with the changes proposed by PSE. Cost recovery mechanisms (fuel adjustment clauses, purchased water adjustment clauses, environmental riders, and purchased gas adjustment clauses) are widespread in the utility business.[141] All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy. Dr. Morin testifies that the expiration of the cumulative cap in the PCA Mechanism would likely (i) cause PSE's financial condition to deteriorate, (ii) result in a review by credit ratings agencies for possible downgrade, and (iii) subject PSE's customers to the risk of having to pay higher rates due to access to increasing capital for PSE.[142] Adoption of PSE's proposed revisions to the PCA Mechanism will mitigate the uncontrollable risks associated with such power costs.[143]

---

[139] *See* Morin, Exh. 315 63:13 – 65:9.
[140] *See* Morin, Exh. 301 58:4 – 77:17.
[141] *See id.* 301 63:4-8.
[142] *See id.* 301 62:7 – 64:12.
[143] *See id.* 61:17 – 64:12.

85. Electric utilities that hold a relatively high percentage of their resource portfolios as long-term purchased power contracts, such as PSE, have higher financial risks than utilities without such contracts, all else remaining constant. A company's obligations pursuant to long-term purchased power contracts are comparable to long-term debt and are treated as such by investors and bond rating agencies. PSE's 2005 year-end capital structure consisted of approximately 45% common equity and 55% debt, unadjusted for purchased power contracts. According to Standard and Poor's calculations, the inclusion of PSE's purchased power contracts as debt equivalent lowers PSE's common equity ratio from 45% to approximately 43%, a decrease of 2%. This decrease of 2% requires an upward adjustment of approximately 25 basis points to the initial cost of common equity estimate of 11.0% to mitigate the additional risk associated with imputed debt from long-term purchased power contracts alone.[144]

86. The Commission should approve the Company's proposed overall rate of return on rate base of 8.76%, as detailed in Appendix A to this brief. This overall rate of return is fair, just, reasonable and sufficient for PSE to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk.

VI. DECOUPLING—GAS REVENUE NORMALIZATION ADJUSTMENT ("GRNA")

87. Decoupling is a ratemaking and regulatory tool that is designed to break the link between (i) a utility's recovery of fixed cost and (ii) the energy consumption of its customers.[145] This Commission has recognized the potential benefits of decoupling to overcome disincentives

[144] *See id.* 66:1 – 73:9.
[145] *See PacifiCorp* Decision at ¶ 102.

related to the pursuit of energy efficiency and conservation programs.[146] In response to the Commission's invitation to present decoupling proposals in general rate cases,[147] PSE proposes a Gas Revenue Normalization Adjustment (GRNA) that complies with the elements the Commission has stated it expects to see in a decoupling mechanism.[148]

A. The GRNA Will Align the Interests of PSE and Its Customers by Breaking the Link Between Recovery of Fixed Cost and Customers' Gas Usage

88. When gas rates are designed to capture most of the approved revenue requirements for fixed costs through volumetric rates, a utility will over or under recover these costs, and customers will over or under pay these costs, as a result of customers consuming more or less gas than assumed in setting the volumetric rates. This can be remedied by decoupling—periodically adjusting these rates to reflect the variations in actual gas volume sales from those assumed in the rate case. PSE's proposed decoupling mechanism will result in a better alignment of the interests of the Company and its customers and promote PSE's pursuit of energy efficiency.[149]

89. The GRNA is designed to help stabilize the level of gas margin[150] revenues that are recoverable from customers on an annual basis. It will periodically adjust the Company's distribution service rates to recover the margin revenues per customer, as established in this general rate case, that fluctuate due to variances in gas volumes caused primarily by weather, energy efficiency gains and conservation efforts. The GRNA will apply to the Residential

[146] *Natural Gas Decoupling Rulemaking*, Docket UG-050369, "Summary, Analysis of Comments and Decision to Close Docket without Action," at 10 (Oct. 17, 2005) ("Commission Summary Order"); *PacifiCorp Decision* at ¶108.

[147] Commission Summary Order at 10.

[148] *See generally* Commission Summary Order; *PacifiCorp* Decision at ¶ 109. Only Public Counsel has opposed a decoupling mechanism. As discussed below, Staff favors a decoupling mechanism but argues that weather normalization should not be included in the mechanism.

[149] *See* Amen, Exh. 21 38:6-11.

[150] "Gas margin" does not mean "profit." The cost of the gas supplied to customers -- the commodity cost – is collected through the PGA. The costs other than the gas commodity costs – in other words all of the fixed costs of

General Service Schedule 23, Commercial and Industrial General Service Schedule 31, Special Commercial Heating Service Schedule 36, Special Multiple Unit Housing Service Schedule 51, and Propane Service Schedule 53. These are the customer classes that have exhibited weather sensitivity and trends in declining use per customer.[151]

B. The GRNA Embodies the Elements Set Forth by the Commission for Decoupling Proposals

90. The GRNA embodies the elements that the Commission has stated it expects to be addressed in decoupling proposals.[152] PSE has: (a) defined the scope of events to be covered by its proposed decoupling mechanism;[153] (b) assessed the appropriate customer classes to be included;[154] (c) designed the scope of the measurement and timing of the adjustments, and tested them against actual historical weather patterns, customer growth assumptions and usage projections;[155] (d) incorporated ongoing growth and/or changes to the level of customers in the mechanism's design, which will provide a greater level of confidence that the resulting margin revenue target will reflect current conditions on the Company's system;[156] and (e) addressed the potential impact on low income customers by constructing the GRNA as an adjustment to the volumetric distribution charge and reduced potential volatility by limiting adjustments to an

---

the delivery system (including but not limited to an appropriate return on shareholders' investment) – are collected through what is known as the "margin". *See* Amen, TR. 461:13-19; Amen, Exh. 21, 30:18-31:10.

[151] *See* Amen, Exh. 21 97:3-14; Amen, Exh. 24:1-3.

[152] *See generally* Commission Summary Order and *PacifiCorp* Decision at ¶109. PSE filed its general rate case, including its proposal for a decoupling mechanism, before the Commission issued the *PacifiCorp* Decision. However, the GRNA complies with the elements set forth by the Commission in its Natural Gas Decoupling Rulemaking and the *PacifiCorp* Decision.

[153] *See* Amen, Exh. 21 47:3-14.

[154] *See id.* 47:8-14.

[155] *See id.* 47-55; Amen, Exh. 30 1-2.

[156] *See* Amen, Exh. 21 47-55.

annual basis.[157] Additionally, the GRNA will be relatively easy to administer, thus keeping implementation costs at a minimum.[158]

C. The GRNA Will Allow PSE to Continue and Expand Energy Efficiency Programs Without Suffering Margin Losses Due To Resulting Reduced Customer Consumption

91. The GRNA will remove the disincentive that currently exists for PSE to invest in more gas energy efficiency measures. Public Counsel suggests that no decoupling is necessary because PSE is already committed to energy efficiency. The issue, however, is not PSE's commitment to conservation, but rather the existence of a disincentive. The Commission's Summary Order encourages decoupling that overcomes disincentives to the offering of conservation programs:

> As a matter of policy, the Commission favors utility efforts to accomplish cost-effective conservation that reduces both the utility's costs and enables consumers to manage their natural gas bills. Companies that perceive that a decoupling mechanism would overcome disincentives to their offering such conservation programs should include a decoupling mechanism in a future general rate case filing.[159]

It may be difficult for PSE to sustain its energy efficiency efforts over the long run if the lost revenues issue is not addressed.[160] In addition, decoupling removes the incentive for a company to increase sales between test years.[161]

92. In the *PacifiCorp* Decision, the Commission rejected NRDC's and PacifiCorp's decoupling proposal because it failed to provide "necessary operational details" and to identify incremental conservation measures as a counterbalance to the potential reduction in risk.[162]

---

[157] *See id.* 47-55.
[158] *See id.* 53:18-20.47:1 – 49:4.
[159] Summary Order at 10.
[160] *See* Weiss, TR. 680:13-20, 696:1-3, 12-17; Shirley, TR. 599:11-22.
[161] *See* Brosch, TR. 666:6-11.
[162] *PacifiCorp* Decision, Docket No. UE-050684, Order 04 ¶ 328 (2006) .

However, as recognized by Staff witness Ms. Steward, the question whether incremental energy efficiency measures should be demanded as a condition of approving decoupling should be approached on a utility by utility basis. No such condition should be required or used to deny PSE a decoupling mechanism.[163] It is uncontested that PSE is making great efforts at energy efficiency, both electric and gas.[164] The Conservation Resource Advisory Group ("CRAG") has supported decoupling in large part because of PSE's history of supporting and promoting gas conservation programs despite the financial disincentive to the Company.[165] PSE faces practical limits on its ability to achieve any more gas efficiency savings than the levels to which it has already committed.[166] It would be perverse and poor public policy for the Commission to deny decoupling to PSE because it is committed to energy efficiency and has already undertaken those cost effective gas efficiency measures it has been able to identify. This would essentially punish PSE for being a regional and national leader in the area. It could well chill other utilities from undertaking additional efforts unless and until they first receive regulatory relief such as that requested by PSE.

D. Weather Normalization Is a Critical Component of PSE's Decoupling Proposal

93. The weather adjustment included in PSE's proposal will help protect the Company and its customers from the unnecessary risks of over or under collection of margin due to weather variability. Decoupling that includes weather is a "win-win" solution for PSE and its customers.[167] It does not shift risk to customers.[168] It actually reduces risks to customers

[163] *See* Steward, TR. 747:6 – 748:10, 765:16-23.
[164] *See* Harris, TR. 115:13 – 116:22, 120:8 – 122:7; Amen, TR. 499:15-24, 530:11-20; Steward Exh. 561 10:10-18.
[165] *See* Steward TR. 747:6-748:13; 767:9-768:5.
[166] *See* Shirley, TR. 584:11 – 585:2, 592:22 – 595:5, 596:18 – 599:23, 620:5 – 623:3, 625:4 – 20.
[167] *See* Amen, Exh. 21 46:6-13; Amen, Exh. 31 18:1-9.
[168] *See* Amen, TR. 542:13-20.

because they only pay for Commission allowed fixed costs, receiving a refund when colder weather results in more revenues being collected than the level last approved by the Commission.[169] Further, the revenue stabilization that results is viewed positively by the financial community, could help increase PSE's credit rating, and ultimately could lower the return on equity that customers pay in their rates.[170]

94. Weather variability is a factor that is widely recognized by utility regulators in allowing gas utilities to make periodic and automatic adjustments to their rates through weather normalization adjustment ("WNA") mechanisms.[171] Moreover, although Public Counsel opposes PSE's decoupling proposal in this case, Public Counsel's expert witness conceded at hearing that weather normalization adjustment mechanisms may have merit.[172]

95. The GRNA will not cause increased bill volatility that reduces bill stability; it will result in a uniform monthly adjustment that will change only once each year.[173] Further, the adjustment amount can be decreased by implementing a more appropriate customer charge, as discussed below.

E. The GRNA Appropriately Includes an Adjustment for New Customers

96. Consistent with the Commission Summary Order discussed above, PSE's proposed GRNA includes an adjustment for new customers in the margin to be recovered: the margin, as adjusted for new customers, to be collected is compared to the actual margin recovery in determining the amount of the GRNA. It would not be appropriate to reduce the amount of

---

[169] *See id.* 541:13 – 543:6; Brosch, TR. 675:8 – 676:2.

[170] *See* Amen, TR. 548:18-25, 549:23 – 552:1; Brosch, TR. 677:1-12.

[171] A recent survey found that 21 states have approved WNA mechanisms for gas companies serving 40 different service areas. *See* Amen, Exh. 31 17:8-14; Amen, Exh. 35:1-3.

[172] *See* Brosch, TR. 672:13-25.

[173] *See* Amen, Exh. 31 17:1, 18:3-9. If the adjustment is scheduled to coincide with a Purchased Gas Adjustment ("PGA") which typically occurs once a year, it may offset a contemporaneous PGA rate change. *See id.* at 18:1-3.

margin recovery for each new customer based on the fact that new customers are using less as proposed by Staff and NWEC.[174] The fact that new customers are using less is part of the reason that the Company's margins are eroding and a decoupling mechanism is needed. Absent the Company's proposal to reflect new customers in the same fashion as it reflects existing customers, the Company would have a perverse incentive to encourage new customers to increase consumption, which would be contrary to the conservation ethic and goals of the Company.[175] Moreover, the manner in which PSE accounts for new customers in its GRNA is consistent with decoupling proposals approved by commissions in other jurisdictions.[176]

VII. ELECTRIC ENERGY EFFICIENCY INCENTIVE

A. PSE's Proposal Encourages Aggressive Cost-Effective Energy Savings

97. PSE proposed an electric energy efficiency incentive in its direct testimony. In response to concerns raised by other parties, and in a spirit of compromise, the Company modified its electric energy efficiency incentive proposal in its rebuttal filing. PSE's modified proposal adopts elements from each of the proposals set forth by the other parties[177] but is more balanced than any of those proposals.

98. The Company proposes an electrical incentive mechanism beginning in 2007 with a 16.5 aMW baseline target. A symmetrical deadband, without an incentive or penalty, would apply to conservation achievements between 95%-105% of the base target.[178] The Company proposes a $5 to $20 per MWh incentive, with the incentive payout increasing as actual energy savings

[174] *See* Amen, TR. 505:11 – 507:1.
[175] *See id.* 505:19 – 506:3.
[176] *See* Amen, Exh. 31 27:3-28:11.
[177] FEA is the only party to assert that the Commission should not adopt an electric energy incentive mechanism. FEA's argument that a utility has an obligation to provide the least cost service and, therefore, should not be provided incentives that "artificially increase the program costs," Selecky, Exh. 491 13:18-19, overlooks the fundamental requirement in PSE's proposed mechanism that all programs must be cost effective in order to be eligible for an incentive. *See* Shirley, Exh. 379 5:10-6:9.

increase above 105% of baseline target. Further, the Company proposes a shared net value incentive of 0% to 50%, depending on incentive range. The Company's proposal also includes penalty levels ranging from $75 to $115 per MWh of shortfall below 95% of base target.[179]

99. The Company's baseline target is based on collaborations with the Conservation Resources Advisory Group ("CRAG") and takes into account evaluation of specific real world factors that will affect energy savings in 2007. PSE's incentive and penalty mechanisms provide for a balanced regulatory policy that creates incentives nearly equal to disincentives. The Company must achieve meaningful savings to receive any incentive amount, and it also must realize greater than nominal deficiencies before it obtains a penalty. PSE has proposed an easily administered and intuitive mechanism that is straightforward and easily explained to customers.

B. The Alternatives Proposed by the Other Parties Are Unbalanced

100. The Commission should reject Public Counsel's proposal. The baseline target of 20 aMW is set too high—it is the stretch savings goal set forth in the PSE's 2005 Least Cost Plan and is nearly three times the annual conservation PSE achieved in 2000 or 2001.[180] As Staff testified, the Least Cost Plan is only a guide and should not be mechanically applied.[181] In recognition of the overly-aggressive target, Public Counsel sets the deadband at 80% to 90% of baseline,[182] thus providing incentive payments to the Company even if it fails to meet the target. It is better policy and more understandable to stakeholders to set a reasonably achievable target and then incent the Company to reach beyond that target.

---

178 *See* Shirley, Exh. 379 8:9-10, 9:1-3.
179 *See id.* 379 9:6-13.
180 *See* Klumpp, Exh. 510 8:14-15.
181 Steward, TR. 756:19-20.
182 *See* Klumpp, Exh. 510 9. The aggressiveness of Public Counsel's target was the primary factor in establishing its proposed deadband.

101. Public Counsel and NWEC propose unbalanced and punitive penalty mechanisms. Public Counsel proposes a penalty of $40/MWh for energy saving beginning at less than 16.0 aMW and escalating to $115 for achievements falling below 50% of 20 aMW. NWEC proposes a penalty of $1.5 million for each aMW of energy conservation less than 95% of base target (16.0 aMW). These proposals both result in penalties that are significantly in excess of incentives.

102. Both parties base their penalty figures on an amount that a third party would need to expend if it were to invest in conservation on PSE's behalf, which is a faulty premise.[183]

103. Staff's proposal sets the 2007 baseline target at 18.3 aMW, creates an asymmetrical deadband at 90% to 100%, contains multi-tiered incentive levels that will be complicated to calculate and a penalty level that begins at 16.5 aMW.[184] Staff's baseline target is nearly the same as the Company's accelerated target of 18.6 aMW set forth in the Company's 2005 Least Cost Plan. Staff departs from the baseline target that has been set in a collaborative effort by the CRAG that includes analyses of specific, current factors affecting energy efficiency.

VIII. LOW INCOME PROGRAMS

104. In the Partial Settlement Agreement Re: Electric Rate Spread, Rate Design and Low Income Energy Assistance ("Electric Rate Design Settlement"), the parties, including the Company, propose to increase the funding cap in the low income bill assistance electric program by $1,225,000—from the current $5.7 million to $6.925 million. PSE requests that the Commission approve the Electric Rate Design Settlement, including the increase to PSE's low income electric bill assistance program.

[183] *See* Glaser, Exh. 499 8:9-10, 20-22; Klumpp Exh. 510 13:9-10, 20-21; Shirley, Exh. 379 18:2-5.
[184] Steward, Exh. 561 24:4-25:2.

105. PSE objects to certain rate design issues in the Partial Settlement Agreement Re: Natural Gas Rate Spread, Rate Design and Low Income Energy ("Gas Rate Design Settlement") and is therefore not a party to the Gas Rate Design Settlement. PSE nonetheless supports the portion of the Gas Rate Design Settlement that provides for an increase of $525,000 to its low income natural gas rate assistance program (from the current $2.8 million to $3.325 million).

IX. WEATHER NORMALIZATION

106. PSE requests that the Commission approve the weather normalization methodology proposed in this case. Staff agrees that PSE's methodology should be used, but asks that the approval be limited to this case only[185] and PSE be required to conduct costly studies that are unlikely to yield any more reliable results than the methodology PSE presents in this case.[186]

107. There is no reason to qualify the Commission's acceptance of PSE's weather normalization model. The Company rigorously investigated alternative specifications that systematically addressed concerns expressed by Staff and presented the results of these investigations to Staff.[187] Moreover, PSE did not adopt a model that was the most financially favorable to it, but instead put forth a robust methodology that has been subjected to expensive and exhaustive investigation by both Staff and PSE.[188] Approval of PSE's methodology would not prevent Staff, any other party, or PSE from proposing revisions to that methodology in future cases as warranted by additional information or evidence supporting the proposed changes.

108. The Commission should reject Staff's request to order PSE to undertake a micro-level hourly study of customers. Staff has not demonstrated that this additional data is relevant or that it would produce an improvement in PSE's weather normalization, which already explains 97%

[185] Mariam, Exh. 552 6:10-12.
[186] *See* Mariam, Exh. 552 8:1 – 9:3; Dubin, Exh. 85 16:14 – 18:10.
[187] *See* Dubin, Exh. 85 3:4-5, 9:3 – 15:6; Dubin, Exh. 86 1-15.

of the variation in the data.[189] Moreover, implementing the type of study proposed by Staff will cost roughly $3,500,000.[190] If the Commission were to adopt Staff's proposal, the costs of such program should be added to the revenue requirement calculation for gas and electric service.[191]

X. REVENUE REQUIREMENT

A. Contested Adjustments—Electric[192]

1. Adjustment 20.03—Power Cost

109. Rate year power costs should be based on projections that are as close as possible to costs the Company will actually incur to provide power to its customers during the rate year.[193] PSE does not object to the timely updating of its power cost projections for the rate year with more recent data than the information that was available at the time PSE prepared its rebuttal testimony. However, it would be insufficient to update only natural gas prices, as suggested by ICNU. Other changes in the power portfolio for 2007 that are now known should also be included if power cost projections for the rate year are to be updated.[194]

110. The Commission should reject proposed adjustments to PSE's projected rate year power costs that "cherry pick" potential downward cost movements without regard to whether the Company is actually likely to obtain or generate power at such costs during the rate year or that fail to recognize offsetting upward cost movements. Because the PCA Mechanism does not provide a dollar for dollar pass through of power costs—even if PSE's proposed changes are

---

[188] *See* Dubin, Exh. 85 3:6-20.
[189] *See id.* 14-19.
[190] *See* Dubin, Exh. 85 18:12-16; Hoff, Exh. 186 21:6-11; Hoff, Exh. 190 1-3.
[191] *See* Hoff, Exh. 186 21:11-13; Hoff, Exh. 190 1-3.
[192] Appendix B lists the contested electric adjustments and associated differences in net operating income (NOI) and rate base, and also lists the electric adjustments PSE understands are uncontested.
[193] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-040640, *et al.*, Order 06 at ¶ 107 (2005), ("[w]e must strive to determine, with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that PSE will experience in the near and intermediate terms.")
[194] *See* Mills, TR. 920:11 – 923:2.

accepted—there is a temptation for other parties to advance arguments that will set the level of power costs recovered in rates too low, thus forcing the Company to absorb "excess" power costs it will incur to provide power to its customers. This violates the fundamental legal principle that a regulated utility is entitled to recover the costs it prudently incurs to serve its customers.[195]

111. Setting the level of power costs recovered in rates too low is bad public policy; it sends the wrong price signals to customers. The Commission has recognized this principle:

> PGA rates, *as price signals*, should provide *the most accurate estimate of expected gas costs and should be based on the Company's most accurate estimate of prospective gas costs*, with deferral accounting and true-up of revenues collected to actual costs.[196]

a. AURORA Model Prices

112. Power cost projections using AURORA modeling combined with "not in AURORA" costs were used in this proceeding in the same manner that has been approved by the Commission in PSE's 2001 general rate case, 2003 PCORC, 2004 general rate case, 2005 PCORC, and 2005 PCORC update.[197]

113. The Joint Parties now argue that the AURORA input data and resulting hourly prices derived from the AURORA model contain "major deficiencies."[198] They recommend replacing the AURORA modeled market prices with three-month average monthly on and off-peak forward electricity prices for the Mid-C market hub to value PSE's short term power costs. The Joint Parties' recommendation, rather than being based on asserted shortcomings of the model as a whole, appears to be motivated by an attempt to manipulate model outputs to produce lower

---

[195] *See Puget Sound Power & Light Co.*, 179 Wash. at 466.

[196] *In the Matter of Purchased Gas Adjustment Mechanisms*, Cause Nos. UG-940778 and UG-970001, Policy Statement at 2 (1997) (emphasis added); *see also WUTC v. Puget Sound Energy, Inc.*, Docket No. UG-040640 et al., Order No. 06 at ¶108 (2005).

[197] *See* Mills, Exh. 269C 11:11 - 12:11.

[198] Joint Parties (Power Cost), Exh. 588C 3:2.

power costs. The Joint Parties admit that their review of the AURORA model inputs has been piecemeal and limited.[199] They provided no analysis to support the validity of using a three-month Mid-C market price.[200] Additionally, they used inconsistent forecast periods for gas and power prices.[201] Considering that the AURORA model has been relied on, audited, and approved by the Commission in many proceedings, including those other than PSE's, a downward adjustment to PSE's power costs should be based on more than a partial or arbitrary review of AURORA inputs.[202]

b. Hydro Shaping

114. The 50-year Mid-C streamflow history from 1928 through 1977 is an AURORA model input to project power costs for the rate year, consistent with the Commission's order in 2004.[203] The Joint Parties argue that the AURORA model does not model enough hydro into high-value, on-peak hours, and they propose shaping more hydroelectric generation into these hours.[204]

115. The sole argument and evidence advanced by the Joint Parties on this point in their response testimony was that PSE's risk assessment model projects greater hydro availability during on-peak hours than AURORA.[205] PSE's rebuttal testimony explained why the risk assessment model projections cannot be substituted for AURORA, and that artificially shaping more of PSE's Mid-C hydro contracts generation into the highest value hours of the day disregards how electric systems are actually managed.[206] The actual historical on-peak shaping

---

[199] *See id.* 9:17-19.
[200] *See* Mills, Exh. 269C 29:17-20.
[201] *See id.* 33:3-13.
[202] *WUTC v. Pacific Power and Light Co.*, Docket No. UE-050684 Order 04 at 68 ¶ 188 (April 17, 2006) (The fact that the Company generally bears the burden of proof in a rate case does not relieve a party from providing full evidentiary support in the record for a proposition it advances.)
[203] *See* Mills, Exh. 251C 37:1-3.
[204] *See* Joint Parties (Power Cost), Exh. 588C 9:17-18.
[205] *See id.* 18:7-19:1.
[206] *See* Mills, Exh. 269C 23:12-17.

of the Mid-C generation that PSE has been able to achieve in the last five years is 62.1%, which is even lower than the AURORA rate year projections of 64.5%. The artificially high levels of on-peak shaping proposed by the Joint Parties should not be used for setting rates.[207]

c. Additional Plant Generation and Capacity

116. PSE reviewed and supports the Joint Parties' recommendation to add two generating plants and to update the capacity rating of certain generating facilities.[208] PSE's rebuttal rate year power costs have been reduced $3.2 million in consideration of these adjustments.[209]

d. Minimum Up and Down Times for Gas-Fired Combustion Turbines

117. The Commission should reject the Joint Parties' recommendation to selectively change the AURORA input minimum up and down times of new large combined cycle combustion turbines ("CCCT"). The Company contracts with EPIS, a third party provider, to maintain the AURORA database, which includes cycling times for CCCT facilities. PSE does, however, modify EPIS' base data set to consider, among other things, PSE's more granular knowledge of its owned and contracted resources.[210]

118. The Joint Parties propose disregarding the cycling times in the EPIS-provided data set and instead instituting minimum up and down times of [redacted] hours and [redacted] hours, respectively.[211] The Joint Parties' proposal should be rejected for several reasons. The Joint Parties' recommendation is based on a review of only three contracts totaling 1,820 megawatts,[212] whereas their requested changes would apply to a total of 37 CCCT plants amounting to over 23,000 megawatts of

---

207 *See id.* 269C 23:18-24:8.

208 *See id.* 15:15-21. This addition is consistent with the updated version of the AURORA model that was released after this case was filed. *See* Mills, Exh. 269C 15:16-18.

209 *See* Story, Exh. 439 3:20.03. Mills, Exh. 269C 37:2-38:13

210 *See* Mills, TR. 875:4-876:2; Exh. 269C 12:19 – 13:2.

211 *See* Joint Parties (Power Cost), Exh. 588C 15:20.

212 *See* Mills, Exh. 269C 17:14 – 18:2; Mills, Exh. 277 1.

CONFIDENTIAL per Protective Order in WUTC Docket Nos. UE-060266/UG-060267

generating capacity.[213] One of these three contracts (Sunrise) in fact contains an increasing fee schedule for more frequent cycling of the plant that would make cycling the plant per the Joint Parties' proposed adjustment uneconomic.[214] This is consistent with the contract for one of PSE's own CCCT generating plants, which restricts PSE from increasing the number of daily thermal cycles.[215] Such restrictions recognize that any economic benefit of increased cycling is outweighed by increased maintenance costs. Based on the Company' experience in dispatch and operation of generating plants, PSE estimates that applying the Joint Parties' proposed minimum up and down times may increase Variable Operation and Maintenance costs by $[redacted] to $[redacted] per MWh, which could nearly offset, and possibly exceed, the proposed reduction in power costs.[216]

2. Adjustment 20.12—Director and Officer Insurance

119. PSE's proposed adjustment to director and officer insurance is the same for electric and gas operations, and is discussed under gas Adjustment 12.20 below. PSE's proposed allocation results in a decrease in net operating income of $13,291 for PSE's electric operations.

B. Uncontested Adjustments With Variations Due to Differing Inputs—Electric

120. Several adjustments are not disputed, but differences in one or more of these adjustments for revenue deficiency or net operating income may exist because of differing inputs for such adjustments. For the Commission's convenience, an explanation of how these inputs impact the various uncontested adjustments is provided in Appendix B.

C. Rate Base, Deferred Taxes and Working Capital—Electric

121. PSE proposes to reflect as a ratebase reduction the average of monthly averages balance

CONFIDENTIAL per Protective Order in WUTC Docket Nos. UE-060266/UG-060267

REDACTED

[213] *See* Mills, Exh. 269C 18:6-7.
[214] *See* Mills, TR. 910:17 – 912:16.
[215] *See* Mills, Exh. 269C 20:20 – 21:1.
[216] *See id.* 19:23 – 20:9.

of accumulated deferred income taxes, rather than end of period balance, and Staff does not contest this proposal. The Company is currently seeking a ruling from the Internal Revenue Service ("IRS") on the treatment of historical deferred taxes when offset against ratebase.[217]

D. Contested Adjustments—Gas[218]

1. Adjustment 12.20—Director and Officer Insurance

122. The Company proposes to apply the traditional allocation method, which was explicitly approved by the Commission in WUTC Docket Nos. UE-920433, UE-920499, and UE-921262, to allocate director and officer insurance premiums of the Company's parent, Puget Energy, among PSE and its non-utility subsidiaries, Puget Western Inc. and Hydro Energy Development Corp. A Puget Energy subsidiary, InfrastruX, was sold on May 7, 2006, during the test year in this proceeding, and a portion of the test year insurance premiums was allocated directly to InfrastruX. Puget Energy's director and officer insurance liability did not change as a result of the sale of InfrastruX.[219] Proper allocation of director and officer insurance results in a decrease in net operating income of $8,946 for PSE's gas operations.[220]

123. Staff's proposed adjustment allocates director and officer insurance to Puget Energy's subsidiaries based on the simple average of the percentage relationship between PSE and InfrastruX of (1) their total assets, (2) their number of employees; and (3) their number of director and officers.[221] This method is flawed because there is no relationship between the number of employees and directors and officer insurance. Staff provides no support for this

[217] *See* Story, Exh. 421 4:3 – 5:19 and 16:10 – 17:7; *see generally* Story, Exh 433C.
[218] Appendix C sets forth a list of the contested gas adjustments and associated differences in NOI and rate base, and also lists the gas adjustments PSE understands are uncontested.
[219] *See* Karzmar, Exh. 232C 13:19-21.
[220] *See id.* 14:10-12.
[221] *See* Russell, Exh. 521 11:17-20.

method of allocation.[222] Further, Staff fails to allocate director and officer insurance to PSE's non-utility subsidiaries, Puget Western Inc. and Hydro Energy Development Corp. Additionally, since Puget Energy sold InfrastruX as of May 7, 2006, this subsidiary will not exist during the rate year, and adoption of Staff's proposal would result in all future director and officer insurance premiums being improperly allocated to PSE.[223]

E. Uncontested Adjustments With Variations Due to Differing Inputs—Gas

124. Several adjustments are not disputed but differences may exist because of differing inputs for such adjustments, as shown in Appendix C.

F. Rate Base, Deferred Taxes and Working Capital—Gas

125. These elements of the case are not contested. In the future, the ruling from the IRS described above with respect to the electric rate base would also apply to the gas rate base.

XI. RATE SPREAD AND RATE DESIGN

A. Electric Rate Spread and Rate Design

126. PSE is a party to the Electric Rate Design Settlement, which was filed with the Commission on June 25, 2006.[224] PSE requests that the Commission approve the Electric Rate Design Settlement and implement the principles and methods contained within such agreement.

B. Gas Rate Spread and Rate Design

1. PSE's Proposal Is the Only Gas Rate Spread in This Proceeding Based on a Principled, Rigorous and Current Cost of Service Study

127. PSE proposes a gas rate spread and rate design that appropriately requires those who take service of various kinds to pay rates that are more closely aligned with the costs of providing such service. PSE's proposal is moderate, does not rigidly force various rate classes into parity

[222] *See id.* 11:14-20.
[223] *See* Karzmar, Exh. 232C, 13:17-14:5.

and will not cause rate shock.[225] The Company's principal considerations in proposing its revenue allocation among the different customer classes were: (1) PSE's cost of service study ("COS Study") results; (2) each class's contribution to present revenue levels; (3) customer impacts; (4) providing appropriate price signals to customers; and (5) revenue stability.[226]

128. The Joint Parties offered no evidentiary basis in their prefiled testimony for the Commission to depart from PSE's proposal.[227] The Joint Parties' proposal boils down to a "black box" agreement not to litigate among themselves the gas rate spread and rate design issues, without regard to how their agreement may impact members of all customer classes.

129. Over a decade has passed since gas rate spread and rate design were last litigated to final order before the Commission in Docket Nos. UG-940034 and UG 940814.[228] It is time to update this outdated 1995 "Commission Basis" cost of service methodology and adopt a gas rate spread and design that more closely track the costs of the gas services that PSE's customers are using, as set forth in PSE's proposal.

2. PSE's COS Study Design Day Peak Demand Allocation Is More Appropriate Than a Method Based on Recent Weather Conditions

130. The primary difference between PSE's COS Study and the 1995 Commission Basis Methodology is that the COS Study uses the system design day as its peak demand allocator. Under the 1995 Commission Basis Methodology, the estimated Company peak demand is based on the five highest load days experienced during a recent three-year period. Developing peak

[224] *See* Bench Exhibit, Exh. 2.
[225] *See* Amen, Exh. 38 27:2-19; *see also* Hoff, Exh. 186 11:8-16 and fn. 11 (discussing "rate shock").
[226] *See* Amen, Exh. 38 26:14-17.
[227] The Joint Parties (Gas Cost) could not reach consensus on which model (the Commission Basis Model or the Company's updated COS Study) best reflects cost causation. Thus, the gas rate spread of the Joint Parties does not reflect any study in particular but instead reflects an agreement among the Joint Parties. *See* Amen, TR. 470:25 – 471:25 (stating that "because they could not reach consensus and because they offered no evidentiary basis upon which to suggest that the Company's Cost of Service study was inappropriate . . . there was really nothing to rebut",); *see also* Joint Parties (Gas Cost), Exh. 581 5:3-10; Joint Parties (Gas Cost), TR. 839:22 – 840:23.

demand and system load factor using limited, recent historic weather conditions is inconsistent with the cost drivers of PSE's gas delivery system.[229]

131. The Company's system design day underwent extensive review and analysis in PSE's 2005 Least Cost Plan.[230] The Company used this updated system design day peak in its COS Study.[231] The Company designs its system to meet a design day peak demand, which is based on cold weather conditions, and the Company incurs the costs associated with being able to provide natural gas service on a design day. For this and the reasons presented below, design day peak is a better indicator of cost causation than historical peak demands.

132. Design day peak also provides a more stable allocation factor than historical peak volumes provide. Historical volumes change from year to year, yet these changes are not related to the costs of the Company's system.[232] The Company's modified peak and average approach to allocation of demand costs reflects a superior balance between the way the system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions).[233]

3. PSE's Gas Customer Charge Proposals Benefit Customers and PSE

133. PSE is proposing in this proceeding to deal head on with a fundamental shortcoming in traditional gas rate design—the assignment of fixed costs for recovery in volumetric rates. The problem with traditional rate design is that it seeks to recover the majority of the utility's fixed costs volumetrically over each unit of product delivered. This practice fails to recognize the importance of reflecting in rates the nature of fixed costs incurred to provide utility delivery

---

[228] *See* Amen, Exh. 38 9:18 – 10:8.
[229] *See id.* 15:1-3.
[230] *See* Amen, Exh. 38 14:4-5; Donahue, Exh. 71 19:3-11; *see generally* Donahue, Exh. 79; Donahue, Exh. 80.
[231] *See* Amen, Exh. 38 14:4-10.
[232] *See id.* 14:18 -15:13.

service. Assigning fixed costs to volumetric rates also results in customers under or over paying these costs, depending on customer usage patterns, weather, and conservation efforts, under current rates.[234] The Company proposes to increase customer charges, which would reduce the portion of non-volumetric related, fixed costs of providing gas service ("margin") that are assigned for recovery through the volumetric delivery charges in six rate schedules.[235]

134. The Company's proposed customer charges would help alleviate the under or over payment of the fixed costs of providing gas service, thereby benefiting both the Company and its customers. Even with PSE's proposed increases in customer charges, a large portion of its non-volumetric or fixed customer-related costs will continue to be recovered through volumetric rates. The Company's proposed customer charges reflect the need to move toward cost of service fixed cost recovery, but does not attempt to move all the way to current cost of service levels.[236]

135. No party challenges the desirability of increasing the customer charge, but the Joint Parties challenge the magnitude of such increase for five of the six schedules proposed by PSE.[237] The following chart summarizes the current customer charge, PSE's proposed customer charge and the Joint Parties' proposed customer charge for each of the schedules:

---

[233] *See id.* 14:11-14.

[234] *See id.* 29:3 – 30:1.

[235] These schedules are: (i) Schedule 23 (Residential); (ii) Schedule 31 (Commercial & Industrial General Service); (iii) Schedule 36 (Commercial & Industrial Heating); (iv) Schedule 41 (Commercial & Industrial Large Volume); (v) Schedule 51 (Multiple Unit Housing Service); and (vi) Schedule 53 (Propane).

[236] *See* Amen, Exh. 38 29-30; *see also* Hoff, Exh. 186 4:16 – 6:3 (discussing how the Company's proposal (Modified SFV Rate Proposal) for a customer charge of $17 per month would recover a significantly greater portion of the Company's margin but to avoid undue bill impacts would be less than the SFV Rate Proposal for a customer charge of $29.76 per month).

[237] The Joint Parties (Gas Cost) agree with the Company that the customer charge for Schedule 36 (Commercial & Industrial Heating) should increase from $30.00 per month to $35.00 per month. *See* Joint Parties (Gas Cost), Exh. 585 2:Item 2.B.

Schedule	Current Customer Charge	PSE Proposed Customer Charge	Joint Parties Proposed Customer Charge
Schedule 23 (Residential)	$6.25	$17.00	$7.00
Schedule 31 (Commercial & Industrial General Service)	$15.00	$20.00	$17.50
Schedule 36 (Commercial & Industrial Heating)	$30.00	$35.00	$35.00
Schedule 41 (Commercial & Industrial Large Volume)	$70.00	$85.00	$80.00
Schedule 51 (Multiple Unit Housing Service)	$6.25	$8.25	$7.00
Schedule 53 (Propane)	$5.50	$8.25	$7.00

136. The most contentious of the proposed customer charge increases is the proposed increase to Schedule 23 (Residential). The Company presented evidence in this proceeding regarding four different residential customer charge levels for this class.[238] The current charge recovers only about 24% of the current residential gas margin, and the remaining 76% of the (non-volumetric) margin is assigned for payment through the (volumetric) delivery charge. Under this assignment, a customer's bill is more volatile and the customer will either overpay or underpay this 76% of the margin depending on the season and weather. In contrast, the Company's $17.00 proposed customer charge would recover about 60% of the residential gas margin in this proceeding.[239]

137. The Joint Parties propose a residential customer charge of $7.00 per month but do not agree on the methodology to be used for computing the customer charge and do not discuss the impact such a charge will have on bill volatility and the potential overpayment or underpayment of margin.[240] Instead, they present three different calculations of residential gas customer costs,

---

[238] The four charge levels are the following: (i) the current customer charge of $6.25, (ii) the Company's initial proposed customer charge (with GRNA) of $8.25 (the "Initial Proposal"), (iii) the "straight-fixed variable" rate design customer charge proposal of $29.76 (the "SFV Proposal") under which all fixed costs are recovered through a fixed charge, and (iv) a Modified SFV rate design customer charge proposal of $17.00 (also with GRNA) (the "Modified SFV Proposal"), which the Company recommends that the Commission adopt. *See* Hoff, Exh. 186 4:16 – 6:3.

[239] *See* Hoff, Exh. 186 7:3-8.

[240] *See* Joint Parties (Gas Cost), Exh. 581 9:20 – 10:2.

which include 100%, 50% and 0% of the service line costs, respectively.[241] Service line costs should be included in the customer cost in their entirety and are included under the Commission Basis Methodology and PSE's updated COS Study. The Joint Parties do not explain their exclusion of 50% or 100% of service line costs from their calculations.[242]

138. Moreover, the Joint Parties propose to assign only about 24% of the residential gas margin through the customer charge—the same portion as under existing rates. In other words, the Joint Parties are proposing essentially no increase in the percentage of fixed costs recovered through the customer charge.[243] The argument that their proposal is a more gradual "change"[244] ignores the fact that it is not a change in any meaningful sense because both the existing customer charge and the Joint Parties' proposed charge are set to recover 24% of the margin.[245]

139. Ms. Steward, witness for Staff, identifies the following rate design principles in her separate testimony, without any discussion of how the Joint Proposal achieves these principles:

> The general principles to be applied in rate determination are fairness, rate stability for the company, rate stability for customers, understandability, and sending proper price signals.[246]

As described below, the Company proposal of $17.00 satisfies each of these criteria.

140. A higher customer charge benefits customers within a class of customers by fairly assigning the fixed costs amongst the individual customers within that class. Under the Joint Parties' proposal, customers who have very little annual usage, such as owners of second homes, can pay less than 50% of their allocated customer costs, while very high use customers can pay

---

[241] *See id.* 10:3-16.
[242] *See* Hoff, Exh. 186 8:4-14.
[243] *See id.* 7:11-15.
[244] *See* Joint Parties (Gas Cost), Exh. 581 10:9-16.
[245] *See* Hoff, Exh. 186 7:1-15, 10:16 – 11:2.
[246] *See* Steward, Exh. 561 4:14-16.

over 200%.[247] This unfair rate of recovery is caused by the customer charge of $7.00 substantially undercovering the fixed cost of $29.76 for residential gas customers and putting much of the fixed cost burden on volume.[248]

141. A higher customer charge provides increased bill stability for customers and increased revenue stability for the Company because the margin included in the fixed cost rate is billed monthly instead of billed on gas usage.[249] The Joint Parties' proposal provides the least stable bills of all proposals analyzed.[250] Lower customer charges, as proposed by Joint Parties, recover substantially more of the margin in the winter and less in the summer. Stability in monthly bills can be gained with little impact to individual customers compared to the current rate design if the Company's $17.00 proposal is adopted. The bill impacts for low income customers are not dissimilar to that for all other customers.[251]

142. The Company's proposal also sends proper price signals. The proportion of non-volumetric costs recovered through volumetric rates is lower in the Company's proposal than in the Joint Parties' proposal.[252] The higher the proportion of non-volumetric costs recovered through volumetric rates, the worse the price signal becomes with respect to the true costs of using gas service. For example, customers pay more margin when their consumption is higher, as in the winter or during a cold snap, even though the Company's fixed costs are not higher in the winter or during a cold snap.

143. The Company proposal is more understandable than the Joint Parties' proposal: to the extent customers pay fixed costs through a volumetric charge, they are exposed to over or under-

---

[247] *See* Hoff, Exh. 188 2.
[248] *See* Hoff, Exh. 186 19:3 – 20:5.
[249] *See id.* 12:3 – 13:5.
[250] *See id.* 13 figure 1 and 13:1-3.
[251] *See id.* 14:3 – 17:3.

paying fixed costs—which violates this Commission's desire for customers to understand the cause behind higher or lower bills. It is intuitively obvious, and understandable, that a customer should not pay more for fixed costs when the weather is cold, and conversely should not pay less for fixed costs when the weather is warm.[253]

4. PSE's Gas Customer Charge Proposals and the GRNA Work Together to Provide Both Customer and Company Benefits

144. Increasing gas customer charges will decrease the portion of gas margin to be recovered through the volumetric delivery charge and hence reduce the magnitude of adjustments to be made under the GRNA.[254] The GRNA will adjust the remaining amount of gas margin collected through the volumetric delivery charge so that the costs included in the margin approved by the Commission are not over or under collected. Thus, the GRNA and increased customer charge work together to alleviate both customer bill instability and PSE's revenue instability created by recovery of a portion of the fixed costs through the volumetric delivery charge.[255]

5. PSE's Other Gas Rate Design Proposals Appropriately Set Charges That Better Reflect the Cost of Service

145. PSE's proposed increases to the balancing charge for Schedule 57 and procurement charge for Schedule 87 are designed to make these charges more consistent with the cost of performing these services.[256] The Company's rate design proposal for Schedule 41 is designed to encourage large, high load factor customers to take service under that schedule and to encourage smaller, low load factor customers to instead take service under Schedule 31, which better fits

---

[252] *See id.* 17:4 – 18:1.

[253] *See id.* 18:2 – 19:2.

[254] The GRNA would apply to all of the gas rate schedules for which an increase in the customer charge is proposed, except Schedule 41 (Commercial & Industrial Large Volume). *See* Amen, Exh. 21, 47:8-14.

[255] *See* Exh. 802; Amen, TR. 503:1-10.

[256] *See* Amen, Exh. 38 28:13-16; Amen, Exh. 31 31:9 – 32:8.

their load characteristics.[257] Finally, the Company's rate design proposals under Schedules 101 and 106 are designed to make the gas cost recovery rates under these schedules more consistent with the underlying commodity costs.[258]

146. The Joint Parties oppose PSE's proposed increase to the balancing charge in Schedule 57 but do not present any specific arguments against this increase.[259] Instead, the Joint Parties allege, without support, that their rate design adjustments "narrow the . . . cost of service disparity between Schedules 57 and 87 rate charges."[260] However, the Joint Parties ignore the COS Study with regard to both the balancing charge and the procurement charge. The Joint Parties propose a balancing charge that is only 4% of the cost of providing the service and a procurement charge that is 130% of the cost of providing the service.[261] Additionally, the Joint Parties propose to increase the procurement charge in Schedule 87 above the cost of service level, whereas the Company proposes to increase it to the cost of service level.[262]

147. The Joint Parties oppose the Company's proposed rate design with respect to Schedule 41 (Commercial & Industrial Large Volume) because of its impact on small customers.[263] The Joint Parties' proposal ignores the fact that Schedule 41 is an optional schedule and that small, low load factor customers can and should migrate back from the commercial and industrial large volume schedule (Schedule 41) to the more appropriate commercial and industrial general service schedule (Schedule 31). With such migration, small, low load factor customers will

[257] *See* Amen, Exh. 38 28:17-19; Amen, Exh. 31 30:7 – 31:8.
[258] *See* Amen, Exh. 38 28:20-24; Amen, Exh. 31 32:9 – 33:8; Donahue, Exh. 71 18:1 – 23:14.
[259] *See* Joint Parties (Gas Cost), Exh. 581 11:20 – 12:13; TR. 467:1 – 468:9.
[260] Joint Parties (Gas Cost), Exh. 581 11:21-22.
[261] *See* Amen, Exh. 31 31:12 – 32:8
[262] *See id.* 31:15 – 32:5.
[263] *See* Joint Parties (Gas Cost), Exh. 581 11:8-10.

avoid experiencing an adverse impact due to the proposed demand charge and customer charge adjustments under Schedule 41. Only the Company's proposal sends the proper price signals.[264]

148. For Schedules 101 and 106, the Company proposes an allocation of demand-related PGA gas costs consistent with the COS Study.[265] In its 2005 PGA filing, the Commission proposed to allocate demand-related gas costs consistent with the cost of service study that was settled in the 2004 general rate case. At that time, Staff stated that the change should be made in a general rate case.[266] In this proceeding, however, the Joint Parties are now taking the position that the change should not be made in this general rate case: "Because not all of the Joint Parties accept that methodology [the COS Study], we recommend that the Commission continue to use the current methodology."[267] The Commission should reject this reasoning and instead adopt the Company's proposals with respect to Schedules 101 and 106.

XII. PRUDENCY OF RESOURCE ACQUISITIONS

149. The Commission uses the following standard to determine prudency of resource acquisitions:

> The test this Commission applies to measure prudency is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures.[268]

150. No party has challenged the question of need or the appropriateness of the expenditures of (i) PSE's acquisition of the Wild Horse wind farm; (ii) the 20-year purchased power agreement between PSE and OrSumas, LLC; (iii) PSE's relicensing of the Baker River

---

[264] *See* Amen, Exh. 31 30:17 – 31:8.
[265] *See* Amen, Exh. 38 33:17 – 34:13
[266] *See* Amen, Exh. 31 33:2-8.
[267] Joint Parties (Gas Cost), Exh. 581 14:10-12.
[268] *WUTC v. Puget Sound Power & Light Co.*, Cause No. U-83-54, Fourth Supp. Order at pages 32 (1984).

Hydroelectric Project; (iv) the 20-year purchased power agreement and related transmission agreement between PSE and Public Utility District No. 1 of Chelan County, Washington (including recovery of interest at the net of tax rate of return); and (v) PSE's acquisition of long term gas pipeline transportation capacity formerly held by Duke Energy Trading and Marketing. The Company has described extensively the need and appropriateness of these expenditures.[269]

151. Therefore, PSE respectfully requests that the Commission formally find and conclude in the final order in this proceeding that each of the above-listed resources are prudent and their associated costs are reasonable for recovery in rates. Please see Appendix D for interest accrual details related to the Chelan contract that should be authorized in the final order.

XIII. CONCLUSION

152. For the reasons set forth above and in the evidence that is before the Commission, the Company respectfully requests that the Commission issue an order approving its requested relief.

DATED this 31st day of October, 2006.

Respectfully submitted

PERKINS COIE LLP

By ______________________
Kirstin S. Dodge, WSBA #22039
Sheree Strom Carson, WSBA # 25349
Jason Kuzma, WSBA #31830
Attorneys for Puget Sound Energy, Inc.

[269] *See, e.g.*, Garratt, Exh. 153HC 3-27; Molander, Exh. 291HC, 2-17; Olin, Exh. 351HC 6-29.