BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-111048** **Docket No. UG-111049** **(*consolidated*)**

INITIAL BRIEF OF PUGET SOUND ENERGY, INC.

MARCH 16, 2012

PUGET SOUND ENERGY, INC.

TABLE OF CONTENTS

I. INTRODUCTION 1

II. LEGAL STANDARD 3

III. REVENUE, EXPENSE AND RATE BASE RESTATING AND PRO FORMA ADJUSTMENTS 4

A. General Principles 4

1. Known and Measurable Standard For Pro Forma Adjustments 4

2. PSE's PCA Mechanism and Adjustments that Affect the Mechanism 5

B. Contested Combined Electric and Natural Gas Non-Rate Base Adjustments 7

1. Federal Income Tax (Adjustments 21.04 and 13.04); Account 236 Debit Balance 7

2. Tax Benefit of Pro Forma Interest (Adjustments 21.05 and 13.05) 7

3. Miscellaneous Operating Expenses (Adjustments 21.06 and 13.06) 7

4. Incentive Pay (Adjustments 21.10 and 13.10) 8

5. Property Taxes (Adjustments 21.11 and 13.11) 10

6. Directors and Officers Insurance (Adjustments 21.13 and 13.13) 12

7. Rate Case Expenses (Adjustments 21.15 and 13.15) 12

C. Uncontested Combined Electric and Natural Gas Non-Rate Base Adjustments 13

D. Contested Electric Non-Rate Base Adjustments 14

1. Power Costs (Adjustments 20.01 and 20.01(A)) 14

2. Lower Snake River Project (Adjustment 20.02) 26

3. LSR Prepaid Transmission Deposit (Adjustment 20.03) 27

4. Montana Electric Energy Tax (Adjustment 20.04) 27

5. Storm Damage (Adjustment 20.07) 27

6. Chelan Payments (Adjustment 20.09) 30

7. Regulatory Assets and Liabilities (Adjustment 20.10) 31

8. Production Adjustment (Adjustment 20.11) 32

9. LSR Deferral (Adjustment 20.12) 32

E. Uncontested Non-Rate Base Electric Only and Natural Gas Only Adjustments 33
F. Contested Combined Electric and Natural Gas Rate Base Adjustments 33
1. Federal Income Tax (Adjustments 21.04 and 13.04) 33
2. Working Capital (Adjustments 21.22 and 13.22) 39
G. Uncontested Rate Base Adjustments 39
H. Contested Electric Rate Base Adjustments 40
I. Summary of Revenue Requirement Determination 40
IV. CAPITAL STRUCTURE AND COST OF CAPITAL 40
A. PSE's Proposed Capital Structure That Contains 48 percent Common Equity Is Reasonable and Properly Balances Safety and Economy 40
B. PSE's Proposed Rate of Return Is Fair, Just, Reasonable and Sufficient 43
V. SETTLEMENTS 46
VI. PRUDENCE ISSUES 46
A. PSE Acted Prudently in Constructing LSR Phase 1 46
1. PSE's Decision to Construct LSR Phase 1 in Advance of RPS Target Deadlines Was Cost-Justified and Prudent 47
2. Quantitative and Qualitative Analyses Support PSE's Acquisition of the LSR Phase 1 55
3. PSE Informed and Involved its Board of Directors in the Construction of LSR Phase 1 55
4. PSE Kept Extensive Contemporaneous Records to Allow The Commission the Opportunity to Evaluate Its Actions With Respect to the Decision Process of LSR Phase 1 56
B. LSR Phase 1 Became "Used and Useful" Upon Commencement of Operations in February 2012 56
C. PSE Acted Prudently in Executing the Klamath Peakers PPA 57
VII. CSA RATES 57
A. The Undisputed Evidence Shows $18 Million in Unrecovered Costs Due to Load Reducing Effects of Conservation 59
B. The CSA Is Permissible Under the Commission's Policy Statement 60
C. The Commission Should Not Impose Upon PSE a Mechanism It Did Not Request 62
1. PSE's Objection to Bench Request 3 62

2. NWEC's Decoupling Proposal Does Not Address PSE's Needs 62
3. Staff's Proposal To Address Attrition Lacks Sufficient Detail 63
D. There Is No Evidence To Support an ROE Adjustment 63
E. Known and Measurable Is Not the Appropriate Standard 64
1. PSE Undertakes Significant EM&V of Its Conservation Savings 65
2. The CSA Rates Employ a Much More Solid Foundation For Determining Conservation Savings Than Does the Avista Limited Decoupling Mechanism approved by the Commission 66
3. The Delay in Recovering 25 Percent of the CSA Rates Provides Additional Assurances that the Conservation Savings Are Accurate...... 67
F. Other Issues Raised By Parties Do Not Preclude Approval of CSA Rates 67
VIII. ELIMINATION OF SQI 9: DISCONNECTION RATIO 68
IX. OTHER PROPOSALS AND ISSUES 69
A. Company Airplane 69
B. Low Income Funding 69
C. LSR Treasury Grant 69
X. CONCLUSION 70

PUGET SOUND ENERGY, INC.

TABLE OF AUTHORITIES

Cases

Alcoa, Inc. et al., v. Bonneville Power Administration, et al., U.S. Ct. App., 9th Cir., Docket Nos. 11-73161, et al. 21

Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) 44

Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989) 44

Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) 44

Fed. Power Comm'n v. Memphis Light, Gas & Water Div., 411 U.S. 458 (1973) 44

In re Permian Area Basin Rate Cases, 390 U.S. 747 (1968) 44

Pac. Gas and Elec. Co. v. Fed. Power Comm'n, 506 F.2d 33 (D.C. Cir. 1974) 61

People's Org. for Wash. Energy Res. v. Wash. Utils. & Transp. Comm'n, 104 Wn.2d 798 (1985) 3, 4

Puget Sound Traction Light & Power Co. v. Pub. Serv. Comm'n, 100 Wn. 329 (1918) 3

Wash. Education Ass'n v. Wash. State Public Disclosure Comm'n, 150 Wn.2d 612 (2003) 61

Statutes

RCW 19.285.040 47

RCW 80.28.010 3

RCW 80.28.020 3

RCW 80.28.260(3) 58

RCW Chapter 19.285 47

Regulations and Rules

WAC 480-07-510(3)(e)(iii) 35

WAC 480-07-920 62

Commission Decisions

In the Matter of the Joint App. of Puget Holdings LLC and Puget Sound Energy, Inc. for an Order Authorizing Proposed Transaction, Docket No. U-072375, Order 08 (Dec. 30, 2008) 38, 43

Wash. ex rel. Puget Sound Power & Light Co. v. Dep't of Pub. Works of Wash., 179 Wash. 461 (1934) 3

WUTC v. Avista Corp., Docket Nos. UE-080416, et al., Order 08 (Dec. 9, 2008) 39, 59

WUTC v. Avista Corp., Docket Nos. UE-090134, et al., Order 10 (Dec. 22, 2009) 8, 9, 12, 60

WUTC v. Avista Corp., Docket Nos. UE-991606, et al., Third Supp. Order (Sept. 29, 2000) 3, 9

WUTC v. Olympic Pipe Line Co. Docket No. TO-011472, Twentieth Supp. Order (Sept. 27, 2002) 11

WUTC v. Pacific Power & Light Co., Docket No. U-86-02, Second Supp. Order (1986) 44

WUTC v. PacifiCorp, Docket No. UE-100749, Order 06 (March 25, 2011) 9, 10

WUTC v. PacifiCorp, Docket Nos. UE-061546, et al., Order 08 (June 21, 2007) 39

WUTC v. PacifiCorp., Dockets UE-050684, et al., Order 04 (Apr. 17, 2006) 9, 38

WUTC v. Puget Sound Energy, Inc., Docket No. UE-031725, Order 12 (April 7, 2004) 46, 52

WUTC v. Puget Sound Energy, Inc., Docket Nos. UE-011570 and UG-011571, Twelfth Supp. Order, App. A (June 20, 2002) 70

WUTC v. Puget Sound Energy, Inc., Docket Nos. UE-040640, et al., Order 06 ¶ 108, (Feb. 18, 2005) ..... *passim*

WUTC v. Puget Sound Energy, Inc., Docket Nos. UE-060266, et al., Order 08 ¶¶ 16-34 (Jan. 5, 2007) 6

WUTC v. Puget Sound Energy, Inc., Docket Nos. UE-072300, et al., Order 13 ¶ 29 (Jan. 15, 2009) 5, 7

WUTC v. Puget Sound Energy, Inc., Docket Nos. UE-090704, et al., Order 11 (April 2, 2010) ..... *passim*

WUTC v. Puget Sound Energy, Inc., Docket UE-031725, Order 12 (April 7, 2004) 27

WUTC v. Puget Sound Power & Light Co., Docket No. UE-921262, et al. 1994) 46, 47

WUTC v. Puget Sound Power and Light Co., Docket Nos. UE-920433, et al., Eleventh Supp. Order (Sept. 21, 1993) 9, 44

WUTC v. U.S. West Commc'ns, Inc., Docket No. UT-950200, Fifteenth Supp. Order, (April 11, 1996) 9

WUTC v. Wash. Natural Gas Co. Docket No. UG-920840, 4th Supp. Order, (Sept. 27, 1993) 9

WUTC v. Washington Natural Gas, 23 P.U.R.4th 184 (1977) 5

Commission Policy Statements

In the Matter of the Wash. Utilis. & Transportation Comm'n Investigation into Energy Conservation Incentives, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, Docket No. U-100522 (Nov. 4, 2010) 59, 67, 69

In the Matter of the Washington Utilities and Transportation Commission Inquiry on Regulatory Treatment for Renewable Energy Resources, Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities, Docket No. UE-100849 (Jan. 3, 2011) 1

I. INTRODUCTION

1. Puget Sound Energy, Inc. ("PSE") 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 retail revenue of $124,810,136 and in natural gas revenue of $28,616,025, which includes a request that the Commission authorize a rate of return on common equity of 10.75 percent and a capital structure containing 48 percent common equity.

2. This case raises important questions about the state's energy policy and how that policy should be interpreted and implemented. For regulated utilities to be financially able to make the large capital investments necessary to satisfy state policy requirements, utilities must have some measure of certainty of timely recovery of and on the investment and an ability to earn a fair return on the business. For example, as the testimony demonstrates, PSE constructed Phase 1 of its Lower Snake River Wind Project ("LSR Phase 1") to meet the renewable energy targets in the upcoming years, as required by law. PSE timed the construction of LSR Phase 1 to take advantage of federal Treasury grants and state sales tax exemptions that saved customers tens of millions of dollars. PSE followed the guidance set forth in its Integrated Resource Plan ("IRP") and acted consistently with the Commission's Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities (the "Renewable Resource Policy Report").[1] But PSE's wind project is now being second-guessed by Public Counsel and the Industrial Customers of Northwest Utilities ("ICNU"), who ignore the long-term benefits LSR Phase 1 provides and the financial benefits PSE's customers receive because of the project timing. Instead, they argue that PSE should have maintained the status quo and waited until the last minute to acquire renewable resources. The Commission should stand firm against these specious attacks from Public Counsel and ICNU and support PSE's efforts to comply with the renewable energy targets.

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[1] *In the Matter of the Washington Utilities and Transportation Commission Inquiry on Regulatory Treatment for Renewable Energy Resources,* Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities*,* Docket No. UE-100849 (Jan. 3, 2011).

3. Additionally, state law requires the Commission to consider proposals such as the Conservation Savings Adjustment ("CSA") Rates that protect utilities from a reduction of short-term earnings that directly result from utility energy efficiency programs. The CSA Rates that PSE proposed in this case comport with the state's energy policy by helping to remove disincentives to promoting conservation. PSE has been a national leader in promoting conservation programs, but the undisputed evidence demonstrates that energy efficiency has taken a financial toll on PSE. It is not able to fully recover its fixed costs because some of these costs are recovered in volumetric rates that decline as conservation increases. The Commission cannot simply ignore the cost of pursuing all cost effective conservation; it must also carry out the Legislature's directive to consider PSE's reduction in earnings that result from this pursuit of conservation.

4. Closely related is the overall policy issue of ratemaking in Washington. PSE has filed rate case after rate case over the past decade due to the need to replace infrastructure and to add new resources. Even with numerous rate filings and other regulatory mechanisms such as accounting petitions, PSE is unable to come close to earning the rate of return authorized by the Commission. PSE has made proposals in this case, and prior cases, to address this continuous under-earning, and now other parties are beginning to recognize that the current method of ratemaking needs to be revised. In the meantime, PSE urges the Commission to act evenhandedly when considering adjustments and not adopt overly strict interpretations of rate making principles such as the "known and measurable" standard. Many of the current adjustments proposed by other parties are designed to achieve lower rates at the expense of sound ratemaking and energy policy. For example, property tax adjustments that preclude PSE from recovering in rates the property tax it will pay on plant it acquires during the test year fly in the face of long-standing ratemaking protocol endorsed by this Commission and have an undeniably harmful effect on PSE's bottom line. Also harmful to PSE's financial well-being is the proposed change to the long-standing storm damage deferral. This adjustment is designed to prevent PSE from fully recovering storm costs, despite the fact that storm recovery is an area of

utmost importance to PSE and its customers. Also problematic are adjustments that game the power cost baseline rate in the PCA, in an effort to ensure PSE absorbs even a greater share of the risk of power cost volatility. These outcome-oriented adjustments only exacerbate PSE's inability to earn a fair return on its investments. This is not merely a concern for the utility's shareholders—a financially viable utility is crucial for customers and is also needed to attract steady inflows of capital investments into the state.

II. LEGAL STANDARD

5. The ultimate legal question in a general rate case is whether the rates and charges proposed by PSE are fair, just, reasonable, and sufficient.[2] 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,[3] 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."[4]

6. 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.[5]

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

[2] RCW 80.28.020; *People's Org. for Wash. Energy Res. v. WUTC*, 104 Wn.2d 798, 808 (1985) (en banc) ("*POWER*").

[3] *POWER*, 104 Wn.2d at 808; *Puget Sound Traction Light & Power Co. v. Pub. Serv. Comm'n*, 100 Wn. 329, 334 (1918) (en banc); RCW 80.28.010(1).

[4] *WUTC v. Avista Corp.*, Docket Nos. UE-991606, *et al.*, Third Supp. Order ¶ 324 (Sept. 29, 2000).

[5] *Wash. ex rel. Puget Sound Power & Light Co. v. Dep't of Pub. Works of Wash.*, 179 Wash. 461, 466 (1934).

resulting reduction in the actual rate of return earned by them. This means 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.[6]

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

7. Only PSE's proposed relief meets these standards. No other parties' proposal will enable PSE to earn reasonable compensation on its investment and meet its service requirements.

III. REVENUE, EXPENSE AND RATE BASE RESTATING AND PRO FORMA ADJUSTMENTS

A. General Principles

1. Known and Measurable Standard For Pro Forma Adjustments

8. PSE urges the Commission to reexamine the application of the "known and measurable" standard for pro forma adjustments as discussed in more detail below and in Mr. Story's rebuttal testimony.[7] In the Final Order in PSE's 2009 general rate case the Commission applied the known and measurable standard in a manner (i) inconsistent with past Commission practice;[8] (ii) inconsistent as to different adjustments in the case;[9] and (iii) that exacerbates regulatory lag and PSE's under-earning.[10] Commission Staff and other parties have carried forward this flawed application of this rule in the current case, and PSE respectfully requests the Commission carefully examine these adjustments, giving due consideration to the historical application of the rule[11] and PSE's documented history of under earning.[12]

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[6] *POWER*, 104 Wn.2d at 811 (footnote omitted).

[7] *See* Story, Exh. No. JHS-18T 4:14-17.

[8] Story, Exh. No. JHS-18T 6:29-8:17 (contrasting Commission's use of projections for plant costs for Fredrickson in PSE's 2003 PCORC with Commission's failure to allow such projections for the Wild Horse Expansion in PSE's 2009 general rate case).

[9] *See* Story, Exh. No. JHS-18T 9:3-10:18 (discussing use of projections for Wild Horse Expansion deferral but not for Wild Horse Expansion plant additions).

[10] *See, e.g.,* Story, Exh. No. JHS-18T 10:4-15. (noting PSE was unable to recover $1.2 million of actual plant additions due to Commission's failure to include projected plant additions for Wild Horse Expansion in 2009 and contrasting this with the mere $47,419 difference between PSE's projections of plant additions and actual plant additions); *see also* Olson, Exh. No. CEO-1T 9:6-8.

[11] *See, e.g., WUTC v. Washington Natural Gas,* 23 P.U.R.4th 184, 194 (1977) (recognizing that judgments or projections made by people having special expertise has credibility and can be known and measurable, if supported by believable testimony and experience).

2. PSE's PCA Mechanism and Adjustments that Affect the Mechanism

9. The Commission should not adjust the manner in which the Power Cost Adjustment ("PCA") mechanism baseline rate is set, as parties in this case have proposed. Commission Staff and ICNU inappropriately remove significant power costs from the baseline rate and propose that these costs flow through the PCA mechanism, effectively denying PSE recovery of known and measurable rate year power costs.[13]

10. PSE's PCA mechanism was developed as a way to insulate PSE and customers from volatilities inherent in PSE's electric portfolio. To work fairly and effectively, a baseline rate must represent the most accurate depiction of costs expected to be incurred during the rate year. Indeed, this Commission has recognized that "power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred . . . ."[14]

11. The Commission has recognized in recent cases that the PCA and the process by which the power cost baseline rate is set have been working as intended.[15] The types of costs Commission Staff and ICNU propose to exclude from rates have been included in the baseline rate since the inception of the PCA in the case of the mark-to-market adjustments, and since PSE acquired wind resources in 2005, in the case of wind integration costs.[16] Commission Staff and ICNU have not—and cannot—present any cogent argument in support of imposing a downward bias on the baseline rate, and the Commission should continue to set the baseline rate as closely as possible to power costs that are reasonably expected to be actually incurred.

12. The Commission should be especially wary of these proposed "back-door" revisions to the PCA mechanism not only for the reasons noted above but also because parties have thus far failed to respond to the Commission's instruction in the last general rate case to examine

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[12] Gaines, Exh. No. DEG-1T 23:4-24:7.

[13] *See, e.g.,* Buckley, Exh. No. APB-1CT 14:19-22 and 18:16-19; Schoenbeck, Exh. No. DWS-1CT 9:16-21; Mills, Exh. No. DEM-11CT 5:2-14; *see generally,* Mills, Exh. No. DEM-11CT (discussing wind integration and mark to market/hedging costs).

[14] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-040640, *et al.*, Order 06 ¶ 108, (Feb. 18, 2005).

[15] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-072300, *et al.*, Order 13 ¶ 29 (Jan. 15, 2009).

[16] Mills, Exh. No. DEM-11CT 8:24–9-13.

> whether there are asymmetrical risks in the distribution of power costs that may affect the sharing of risks and benefits accomplished by the PCA sharing bands. It seems particularly appropriate that the Commission should hear more on this question in the future given the Company's 2007 study concerning the balance between risk and benefits associated with deviations from baseline power costs and how it should properly be considered in the design of the PCA and its sharing bands.[17]

PSE is the only party that provided substantive testimony in response to the Commission's order.[18] Parties should not be permitted to circumvent the Commission's order—and the Commission should reject their proposed modifications to the PCA baseline rate—when the parties have failed to examine the issue raised by the Commission. Moreover, the Commission should not be swayed by Commission Staff's mischaracterization of the PCA mechanism.[19] PSE does not receive a guaranteed return on $2 billion in rate base nor does PSE recover all PCA costs by updating the baseline rate as Commission Staff alleges.[20] The ten-year history of the PCA belies Commission Staff's baseless claim that the risk of power cost variation is not being shared between ratepayers and PSE.[21]

Furthermore, PSE disagrees with Commission Staff's request for a separate proceeding to review PSE's PCA mechanism and power cost only rate case ("PCORC"). PSE presented an analysis of the symmetry of the PCA sharing bands in its 2006 general rate proceeding.[22] In addition, PSE complied with the Commission's order in the past two cases and provided analyses of the symmetry of the PCA sharing bands,[23] but no party responded substantively to the 2008 study or the testimony PSE provided in this case. As for the PCORC, the Commission thoroughly evaluated the mechanism in a litigated proceeding and issued an order in 2009 approving the continuation of the PCORC with minor revisions.[24]

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[17] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 118 (April 2, 2010).
[18] Aladin, Exh. No. SA-1CT.
[19] *See* Schooley, Exh. No. TES-1T 9:8-12.
[20] Story, Exh. No. JHS-18T, 53:7-54:21.
[21] *See* Mills, Exh. No. DEM-11CT 8:24-9:13.
[22] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-060266, *et al.,* Order 08 ¶¶ 16-34 (Jan. 5, 2007).
[23] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶¶ 108, 116, 118 (April 2, 2010); *see* Aladin, Exh. No. SA-1CT.
[24] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-072300, *et al.,* Order 13 (Jan. 15, 2009).

B. Contested Combined Electric and Natural Gas Non-Rate Base Adjustments

13. Appendix A lists the contested combined electric and natural gas non-rate base adjustments and associated differences in net operating income ("NOI"), which are discussed below.

1. Federal Income Tax (Adjustments 21.04 and 13.04); Account 236 Debit Balance

14. The Commission should reject Commission Staff's proposal to reclassify all of PSE's current tax expense to deferred tax expense.[25] This reclassification is inappropriate as Mr. Marcelia explains in his testimony.[26]

2. Tax Benefit of Pro Forma Interest (Adjustments 21.05 and 13.05)

15. PSE and Commission Staff agree on the methodology used in the calculation. The only differences among the parties are the proposed rate base and the weighted cost of debt which are used in the calculation of the tax benefit of pro forma interest. This adjustment will change based on the final rate base determined in this proceeding.

3. Miscellaneous Operating Expenses (Adjustments 21.06 and 13.06)

16. In rebuttal, PSE accepted Commission Staff's adjustment decreasing the amount of wages allocated to utility operations for PSE's President and CEO, Ms. Kimberly J. Harris.[27]

17. Commission Staff's arbitrary elimination of 50 percent of Board of Directors fees and expenses ignores the significant allocation of the fees and expenses that PSE made to non-utility and the various holding companies in its original filing.[28] The Board of Directors fees and expenses are a necessary cost of doing business and are required to properly operate the utility.[29] Moreover, Commission Staff misreads the recent decision in the Avista general rate case when claiming that customers should pay for only 50 percent of Directors fees and expenses no matter the appropriateness of the expense by PSE. An underlying factor for the 50 percent sharing in

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[25] Exh. No. RCM-2 (Adjustment 21.04 page 1, column 4, lines 30 and 31); Exh. No. CTM-2 (Adjustment 13.04 page 2, column 4, lines 29 and 30).

[26] *See* Marcelia, Exh. No. MRM-14T 62:17-63:15.

[27] Stranik, Exh. No. MJS-10T 10:5-12.

[28] Stranik, Exh. No. MJS-10T 12:2-21.

[29] Stranik, Exh. No. MJS-10T 10:19-11:1.

the Avista proceeding was the nature of the expenses which were shown in the record as not providing ratepayer benefit.[30] The record in this proceeding has not shown a similar situation.[31]

4. Incentive Pay (Adjustments 21.10 and 13.10)

18. The Commission should reject Commission Staff's proposal to remove 50 percent of the cost of incentive pay. PSE's Goals and Incentive Plan ("Plan") is an important part of the total compensation program PSE uses to attract and retain qualified employees, and it should be recovered in rates like other elements of employee compensation.[32] Funding of the Plan is dependent on two performance measures: a service quality measure based on Service Quality Indices ("SQI") performance, and a financial measure based on Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA").[33] The Plan benefits customers by encouraging employees to achieve key performance objectives, including customer service, reliability, safety, and operational efficiency.[34] The Plan also benefits customers by helping to attract and retain highly qualified employees, while slowing the base wage growth that would otherwise increase.[35]

19. Commission Staff proposes to arbitrarily disallow 50 percent of the Plan's costs based on the unsupported assertion that this would be "fair."[36] The Commission has rebuffed similar claims by Commission Staff in past cases.[37] Commission Staff wrongly asserts that ratepayers "do not receive any benefit when PSE achieves the financial goals."[38] As Mr. Hunt testified, including a financial measure helps motivate employees to control costs, stay within budget, and operate efficiently, all of which benefits customers.[39] The Commission has long recognized that

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[30] *WUTC v. Avista Corp.*, Docket Nos. UE-090134, *et al.*, Order 10 ¶ 142 (Dec. 22, 2009).
[31] Stranik, Exh. No. MJS-10T 16:11-15.
[32] Hunt, Exh. No. TMH-11T 2:10–3:1; Exh. No. TMH-1T at 16:16–17:9, 18:16-19.
[33] Hunt, Exh. No. TMH-1T 19:16–20:18; Exh. No. TMH-11T 6:19–7:8.
[34] Hunt, Exh. No. TMH-1T 17:3–14, Exh. No. TMH-11T 2:16-18.
[35] Hunt, Exh. No. TMH-1T 17:3, 17:15–18:5; Exh. No. TMH-11T 2:16-20.
[36] Erdahl, Exh. No. BAE-1T 8:11.
[37] *See, e.g., WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UG-040640, *et al.*, Order 06 ¶¶ 141-44 (Feb. 18, 2005) (rejecting proposal to disallow 40% of costs tied to PSE's earnings and finding Plan complied with prior Commission directives).
[38] Erdahl, Exh. No. BAE-1T7:9-10.
[39] Hunt, Exh. No. TMH-11T 5:3-8, 6:11-16, 7:5-8, 8:18–9:13, Hunt, Exh. No. TMH-1T 20:4-18.

operational efficiency and cost control are goals that benefit customers.[40] On cross-examination, Commission Staff witness Ms. Erdahl conceded that customers benefit from an efficiently run company.[41]

20. Commission Staff's reliance on decade-old Commission orders to support its argument is unpersuasive.[42] It is surprising that Commission Staff ignores the Commission's most recent pronouncement on recovery of incentive in the recent PacifiCorp case.[43] The Commission has identified three criteria to determine whether to include incentive compensation when, as here, this compensation is part of the overall structure of employee compensation: (1) whether the plan offers benefits to ratepayers; (2) whether the total compensation is unreasonable; and (3) whether the compensation in total exceeds the market average.[44] No party has questioned the

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[40] *See, e.g., WUTC v. Wash. Natural Gas Co.* Docket No. UG-920840, 4th Supp. Order, Section III.A.7 (Sept. 27, 1993) (stating that appropriate incentive plan goals "include controlling costs"); *WUTC v. PacifiCorp.*, Dockets UE-050684, *et al.*, Order 04 ¶ 128 (Apr. 17, 2006) (recognizing circumstances in which Commission authorized recovery of payments under plans that have a dual benefit to shareholders and ratepayers).

[41] Erdahl, TR. 800:3-13 (acknowledging that customers benefit from long-term operational efficiency and would not benefit from achieving SQIs at any cost).

[42] Although Commission Staff does cite to one 2009 case, *WUTC v. Avista Corp.*, Docket Nos. UE-090134, *et al.*, Order 10 (Dec. 22, 2009), the Commission, contrary to Commission Staff's suggestion, did not set forth a new legal standard governing recovery of incentive pay. The Commission merely noted that the record was insufficiently developed and directed Avista to provide specific information in its next rate case. *See id.* at ¶¶ 128–29. Regardless, Avista's incentive program, which offered incentives to employees for achieving O&M savings, is not comparable to PSE's Goals and Incentives Plan, which is an integral part of PSE's overall compensation program and is specifically structured to provide customer benefits. The Commission disapproved of the incentive plan in the U.S. West case cited by Commission Staff because the plan was structured so that "the financial incentives were independent of the service incentives" and "if the Company exceeded the stated financial goals by only 8%, employees could 'replace' all of the bonus that they would 'lose' for failure to achieve customer service goals." *WUTC v. U.S. West Commc'ns, Inc.*, Docket No. UT-950200, Fifteenth Supp. Order, p. 48 (April 11, 1996). The older Avista case cited by Commission Staff involved the same flaw—financial goals trumping customer service goals. *See WUTC v. Avista Corp.*, Docket No. UE-991606, Third Supp. Order ¶¶ 272–73 (Sept. 29, 2000). In contrast, under PSE's Goals and Incentive Plan, the financial measure and service measure are linked and dependent on each other, and there is no payout if SQI performance falls below the minimum threshold, no matter how well the Company performs financially. While there is similarly no payout if financial performance falls below the minimum threshold, no matter how well the Company performs on SQIs, this simply reflects the fact that the two performance measures are dependent on each other, and that employees still need to focus on operational efficiency and cost control while achieving SQIs. Finally, the 1992 Puget rate case order addresses recovery of executive incentives; it is not relevant to the issues raised in this proceeding. *See WUTC v. Puget Sound Power and Light Co.*, Docket Nos. UE-920433, *et al.*, Eleventh Supp. Order, p. 61 (Sept. 21, 1993).

[43] *WUTC v. PacifiCorp*, Docket No. UE-100749, Order 06 ¶¶ 240–50 (March 25, 2011).

[44] *WUTC v. PacifiCorp*, Docket No. UE-100749, Order 06 ¶¶ 240–50 (March 25, 2011) (emphasizing that "[w]e do not wish to delve too deeply into the Company's management of its human resources and the manner in which it determines overall compensation policy" and noting, "[t]here does not appear to be disagreement that [incentive-based compensation] is a preferable means to structure employee compensation").

reasonableness of PSE's total compensation or the fact that PSE's compensation is consistent with the market average. PSE's Plan benefits customers by focusing employees on both meeting the SQIs and achieving operational efficiency. The Commission should reject Commission Staff's proposed arbitrary disallowance.

5. Property Taxes (Adjustments 21.11 and 13.11)

21. Commission Staff's property tax adjustment that excludes all property acquired during the test year violates the matching principle and should be rejected by the Commission. It cannot be disputed that PSE incurs tax liability and will pay property taxes on property owned during the test year. Despite this undisputed fact, Commission Staff proposes a property tax adjustment that uses a January 1, 2010 lien date and thus ignores for ratemaking purposes all tax on property PSE acquired after the first day of the test year. The effect of this adjustment is to exclude for ratemaking purposes 7.5 percent of PSE's property from tax liability.[45] Commission Staff provides no rational justification for excluding this significant portion of used and useful property PSE owned and operated in the test year.[46]

22. Due to the timing of the events that factor into the calculation of property tax liability, estimates of property tax liability are appropriate, and the Commission has approved the use of estimates of tax liability on test year and pro forma plant in past cases.[47] Commission Staff wrongly argues that its calculation of property taxes results in a known and measurable adjustment. Commission Staff's adjustment truly is an estimate of the tax liability owed on PSE's property—and is a poor estimate at best because it excludes a significant percentage of PSE's property.[48]

23. Additionally, Commission Staff's property tax adjustment testimony is inconsistent and

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[45] Marcelia, Exh. No. MRM-14T 68:11-12.

[46] Applegate, Exh. No. RTA-1T 14:10-14 ("Any property acquired by PSE during the test period is not subject to property tax liability until January 1 of the following year, which is outside of the test year. Accordingly, no additional revenue than what is provided in my adjustment is necessary to support the Company's property tax obligations during the test year.").

[47] *See* Exh. No. B-18 (PSE's Response to Bench Request No. 18 at 2-4.)

[48] Marcelia, Exh. No. MRM-14T 68:11-12.

contradictory. For example, Commission Staff witness Rick Applegate acknowledges that Staff's calculation fails to consider property acquired *during* the test year. He specifically states that the Commission should "allow the Company to recover the actual amount of property tax payable for property owned by PSE *at the start of* the test year."[49] Yet, later in his testimony, Mr. Applegate testifies that his proposed adjustment "matches revenue requirement with the actual cash outlays PSE must make as a result of owning and operating its property during the test year."[50] This second statement is false as evidenced by Commission Staff's earlier admission that its adjustment only includes property owned on the first day of the test year—not all property owned during the test year. Moreover, Mr. Applegate's testimony seems to argue for a cash basis for accounting of property tax, which is inconsistent with past Commission practice[51] and FERC accounting requirements. If the Commission were to use a cash basis, which it should not do, the property tax adjustment would be the cash paid during the test year—which would clearly be inappropriate as the property tax payments made in 2010 would relate only to property owned by PSE up to the lien date of January 1, 2009.[52]

24. In contrast to Commission Staff's inaccurate estimate of property taxes, PSE's property tax adjustment begins with the lien date of January 1, 2011, which captures all assets owned on the last day of the test year, December 31, 2010.[53] PSE updates its property tax calculation as the system ratio and levy rates become available, which in this case were immaterial adjustments

[49] Applegate, Exh. No. RTA-1T 12:16-20 (emphasis in original).
[50] Applegate, Exh. No. RTA-1T 14:8-10.
[51] Marcelia, Exh. No. MRM-14T 65:1-13. *See, e.g., WUTC v. Olympic Pipe Line Co.* Docket No. TO-011472, Twentieth Supp. Order ¶ 130 (Sept. 27, 2002) ("only the accrual basis clearly allows an examination of events in a given period and only the accrual basis provides the proper matching of expenses for revenues that is the foundation of ratemaking.").
[52] Marcelia, Exh. No. MRM-14T 65:14-66:14; TR. 1010:23-1011:20.
[53] Marcelia, Exh. No. MRM-1T 42:8-12; *see* Marcelia, Exh. No. MRM-12.

relative to the initial filing.[54] This is the same manner in which PSE calculates its property tax expense for accounting purposes.[55]

6. Directors and Officers Insurance (Adjustments 21.13 and 13.13)

25. PSE's adjustment for Directors and Officers ("D&O") insurance utilizes a reasoned approach to allocate insurance expense between utility and non-utility activity.[56] PSE's adjustment is consistent with PSE's past allocation of D&O insurance[57] and with the Commission's allocation methodology approved in Avista's general rate case in which the cost of the premiums was shared 90/10 between utility and non-utility.[58]

26. In contrast, Commission Staff arbitrarily carves out a quarter of D&O insurance expenses.[59] Commission Staff improperly relies on the *Avista* decision addressing Board of Directors fees and expenses—rather than D&O insurance.[60] Further, Commission Staff overlooks the fact that the vast majority of activities and D&O claims relate to utility operations.[61] The Commission should reject Staff's unreasoned adjustment, which is very similar to the adjustment rejected by the Commission in PSE's 2009 general rate case.[62]

7. Rate Case Expenses (Adjustments 21.15 and 13.15)

27. Commission Staff's proposal to abandon the existing normalization of rate case expenses should be rejected by the Commission. Commission Staff's proposal to use test year expenses

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[54] *See* Exh. No. B-17 (PSE's Response to Bench Request No. 17). As Mr. Marcelia testified: "PSE uses the best information available to determine what the property taxes will be. . . . The property tax calculation becomes more accurate over the course of the year as more factors become available. Generally Accepted Accounting Principles ("GAAP") require updates to these calculations as PSE receives better information throughout the year." Marcelia, Exh. No. MRM-1T 42:16–43:2. PSE did not update its system ratio in this case because it was "very, very close" to PSE's estimate. Marcelia, TR:1004:8-14. The levy rate will become available in late March 2012. *Id.* at 1003:18-21.

[55] Marcelia, Exh. No. MRM-1T 42:15-16.

[56] Stranik, Exh. No. MJS-1T 22:4-9. PSE allocates 9.95% of these insurance expenses to shareholders based on the time spent on non-utility activities. Additionally, PSE's calculation allocates a portion of insurance expense to subsidiaries. Stranik, Exh. No. MJS-10T 17:6-9.

[57] Stranik, Exh. No. MJS-10T 17:10-13.

[58] *WUTC v. Avista Corp.*, Docket Nos. UE-090134, *et al.*, Order 10 ¶ 137 (Dec. 22, 2009).

[59] One quarter is the result of Commission Staff disallowing 50% of the D&O insurance expenses that PSE attributed to board members, which was 50 percent of the total.

[60] *WUTC v. Avista Corp.*, Docket Nos. UE-090134, *et al.*, Order 10 ¶ 137 (Dec. 22, 2009).

[61] Stranik, Exh. No. MJS-10T 15:8-18.

[62] Stranik, Exh. No. MJS-10T 16:17-20.

discards a methodology Commission Staff endorsed only a few years ago[63]—and which has been undisputed since that time.[64] There is no sound basis for this change; it is outcome-oriented in a short-sighted manner, apparently designed to lower rates in this case while potentially exposing customers to higher rates and more volatility on an ongoing basis. Indeed, if test year rate case expenses had been used in PSE's 2009 general rate case as Commission Staff now proposes, customers would have been worse off than under the existing normalization methodology for recovering rate case expenses. [65] Moreover, given that the majority of expenses for any given rate case are not incurred during the test year for that rate case, but are incurred after the test year, in some instances a utility would recover no rate case expenses under Commission Staff's proposed methodology.[66]

28. In other circumstances in this case, Commission Staff acknowledges the importance of using normalization to smooth fluctuating costs that are not consistent from year to year.[67] Yet here, Commission Staff proposes a results-driven methodology for recovery of a fluctuating expense that is contrary to current and prior testimony from Commission Staff and is contrary to Commission precedent.

29. Moreover, Commission Staff confuses normalization of like-type costs with deferral and amortization of specific costs. By normalizing rate case costs PSE is not recovering specific costs from a given case but is building into rates a normal level of rate case expenses, which benefits customers by eliminating volatility.[68]

C. Uncontested Combined Electric and Natural Gas Non-Rate Base Adjustments

30. Appendix B lists the uncontested combined electric and natural gas non-rate base adjustments and associated differences in NOI, which the Commission should adopt. It is PSE's

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[63] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UG-040640, *et al.*, Order 06 ¶ 164-65 (Feb. 18, 2005).
[64] Stranik, Exh. No. MJS-10T 18:7-11.
[65] *See* Stranik, Exh. No. MJS-21.
[66] Stranik, Exh. No. MJS-20T 3-12.
[67] *See, e.g.,* Buckley, Exh. No. APB-1T 7:10-22 (discussing production O&M).
[68] Stranik, Exh. No. MJS-10T 21:17-19

understanding that Commission Staff has accepted PSE's rebuttal adjustments for General Revenues and Expenses (Adjustments 21.02 and 13.02), which were updated to incorporate the impacts on revenues for conditions agreed to in the settlement agreement for electric cost of service and rate design,[69] and gas cost of service and rate design, which reflects the loss of revenues resulting from a major industrial natural gas customer ceasing operations in spring 2012.[70] Further, PSE understands that Commission Staff has accepted PSE's rebuttal adjustments for Employee Insurance (Adjustments 21.21 and 13.21).

D. Contested Electric Non-Rate Base Adjustments

31. Appendix C lists the contested electric non-rate base adjustments and associated differences in NOI. Each of these contested electric adjustments is discussed below.

1. Power Costs (Adjustments 20.01 and 20.01(A)[71])

a. Uncontested Power Cost Adjustments

32. No party has disputed the following power cost adjustments, which represent changes from PSE's 2009 general rate case: (i) the use of the average of the 70-year Mid-Columbia stream flow history from 1929 through 1998 to project power costs for the rate year;[72] (ii) the use of forward gas price differentials between the Alberta Energy Company and Station 2 gas hubs to determine the projected rate year gas prices at Station 2;[73] (iii) the above-market costs of generation using distillate fuel to test PSE's combustion turbines under its Power Generation Combustion Turbine Fleet Distillate Fuel Management Program;[74] (iv) the inclusion of the net costs for 25,853 MMBtu per day of Westcoast pipeline deliverability (released from BNP Paribas) between the Station 2 and Sumas gas hubs;[75] (v) the inclusion of the costs for 28,928 MMBtu per day of gas for power pipeline capacity from Stanfield, Oregon, to Deer Island,

[69] Story, Exh. No. JHS-18T, 46:17-20.
[70] Stranik, Exh. No. MJS-10T, 7:16-20; Phelps, Exh. No. JKP-14CT 2:8-9.
[71] Not all adjustments supported by David Mills are included in Adjustment 20.01. Adjustment 20.01 (A) provides a guide for the other adjustments that contain power costs. *See* JHS-20 2.
[72] Mills, Exh. No. DEM-1CT 42:2-43:20.
[73] Mills, Exh. No. DEM-1CT 47:9-48:10.
[74] Mills, Exh. No. DEM-1CT 56:15-57:8.
[75] Riding, Exh. No. RCR-1T 8.

Jackson Prairie and Bellingham;[76] (vi) capacity releases of 50 MDth per day effective November 1, 2014 to provide firm service from Stanfield, Oregon, to the interconnect between Northwest Pipeline and FortisBC north of Bellingham, Washington;[77] and (vii) the extension of the assignment between PSE's Core Gas book and PSE's power book for Jackson Prairie storage service.[78]

33. Although the dollar amount of Jackson Prairie storage service is not contested, its treatment in the PCA mechanism remains at issue. PSE requests the Commission approve treating the Jackson Prairie storage costs as variable within the PCA mechanism. PSE's proposal to treat these storage rental costs as variable within the PCA mechanism matches the variable treatment for the storage rental revenues in PSE's purchased gas adjustment mechanism. Although Commission Staff argues these costs will not vary, they proposed a pro forma adjustment that PSE agreed to on rebuttal to recognize the fees in the rate year were lower than the test year.[79] The fact that these fees are changing demonstrates that they are properly classified as variable costs.[80] The Commission should approve these fees as variable costs in the PCA.

34. Finally, PSE understands that Commission Staff has withdrawn its adjustment to remove costs associated with the Cedar Hills gas for power contract. Commission Staff's decision to withdraw their adjustment resulted from PSE clarifying that forecast contracted revenues from the environmental attributes will be included in the renewable energy credit ("REC") tracker that was created in the Multiparty Settlement Re: Electric Rate Spread and Rate Design while the costs of the contract will be included in power costs.

b. Wind Integration Costs

35. PSE's testimony and exhibits validate PSE's wind integration costs, which should be

[76] Riding, Exh. No. RCR-1T 9.
[77] Riding, Exh. No. RCR-1T 10.
[78] Riding, Exh. No. RCR-1T 4.
[79] Riding, Exh. No. RCR-4HCT, 9:14-10:6.
[80] Riding, Exh. No. RCR-4HCT 9:18-10:6.

included in rate year power costs. Generally, wind integration costs incurred by PSE—internally and through BPA—represent the costs of having to reserve capacity to balance wind generation. In essence, generation capacity that may have been dispatched, but for the presence of wind, is withheld from the energy market. Conversely, uneconomic generation that would not have been dispatched, but for the presence of wind, may be committed into the market. Rate year power costs include PSE's internal cost of integrating its wind resources as well as the wind integration costs paid to BPA.[81]

36. Wind generation is an intermittent and non-dispatchable generation resource. There can be large differences between the wind generation forecast and actual generation. These large, short-term, unanticipated changes (up or down) in generation present some of the greatest challenges PSE operators have to effectively manage to ensure compliance with its electric system reliability standards. To ensure that PSE has sufficient ability to increase (up following) or decrease (down following) generation to balance wind, generation capacity must be held in reserve.[82]

37. The Hopkins Ridge, Klondike III, and LSR Phase 1[83] wind projects are located in the BPA Balancing Authority Area. As a result, BPA provides integration services to manage the variable output of these wind projects. Under this service, BPA delivers the hourly scheduled amount of wind generation to PSE's system by utilizing its own balancing reserves and charges PSE a Variable Energy Resource Balancing Service ("VERBS") rate and a Generation Imbalance rate. Wild Horse is located in PSE's Balancing Authority Area and, therefore, it is PSE's responsibility. PSE manages the moment-to-moment variability in Wild Horse generation as well as the deviations between actual and scheduled generation.[84]

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[81] Mills, Exh. No. DEM-1CT 21:10-17.
[82] Mills, Exh. No. DEM-1CT 21:19–22:11.
[83] LSR Phase 1 began commercial operation on February 29, 2012.
[84] Mills, Exh. No. DEM-1CT 22:20-21.

i. Day-Ahead Wind Integration Costs

38. The Commission should reject Commission Staff's and ICNU's respective recommendations to ignore all of the costs of integrating PSE's wind resources on a day-ahead basis.[85] The day-ahead wind integration costs are costs PSE incurs due to the variability and uncertainty of wind power generation. These costs represent the "opportunity" costs associated with setting up a power portfolio position on the day-ahead basis (employing a forecast of wind generation) as contrasted to the hour-ahead generation level that actually occurs.[86] Commissions in other jurisdictions have recognized that these are real costs and have allowed for recovery of these costs.[87]

39. ICNU erroneously asserts that AURORA fully accounts for day-ahead wind integration costs because AURORA calculates "the expected value of the variable costs of operating PSE's generating resources."[88] This statement is false because the calculation of wind integration costs involves a comparison of wind forecasts to actual wind generation. The PSE wind profiles in AURORA only use a set of forecast or fixed-generation profiles for each plant. These fixed profiles do not account for any day-ahead forecast error (or hour-ahead forecast error for that matter). The AURORA model dispatches PSE's combustion turbines based upon their individual operating information as compared to the market heat rates in AURORA. Therefore, the fixed hourly generation of PSE's wind resources have no impact on the AURORA modeled gas fired units' generation or costs. By having essentially zero operating costs, wind generation is more akin to a reduction in load rather than an increase in PSE's generating assets.[89]

40. Moreover, the designation of wind resources as "must run" in AURORA does not capture the day-ahead uncertainty in wind production. AURORA models wind production as fixed and firm and does not consider how changes in the wind production forecast from day-ahead to real-time affects power costs. This is precisely why these costs have been modeled separately using

[85] Buckley, Exh. No. APB-1CT 16:16-21:12; Deen, Exh. No. MCD-1CT 6:17-8:7.
[86] Mills, Exh. No. DEM-11CT 13:13-18.
[87] Mills, Exh. No. DEM-11CT 19:1-14.
[88] Deen, Exh. No. MCD-1CT 7:19-21.
[89] Mills, Exh. No. DEM-11CT 17:16–18:6.

actual historical data and included in the Not in Models costs.[90]

41. To ensure sufficient balancing capacity in real-time, PSE must transact in the day-ahead market or commit thermal units based on day-ahead market prices or heat rates. When real-time market prices clear, PSE's day-ahead operating practice results in *both* incremental costs and benefits, which combine to a net cost. The Commission should adopt PSE's proposed adjustment, which accounts for the pro forma net cost implications of day-ahead wind generation forecast uncertainty.[91]

ii. Within-Hour Wind Integration Costs

42. Commission Staff's proposed adjustment completely disregards within-hour wind integration costs for Wild Horse while allowing such costs for PSE's wind plants in BPA's balancing authority. PSE should be allowed to recover its within-hour wind integration costs for Wild Horse just as it recovers its within-hour wind integration costs paid to BPA through the VERBS rate.

43. PSE incurs within-hour wind integration costs for all of its wind resources. Within-hour wind integration costs reflect costs incurred as actual wind generation levels vary within each operating hour after delivery schedules are established and tagged. In instances where Wild Horse wind generation changes within the hour, PSE must adjust other resources to counter the wind production changes in order to maintain the system's load-resource balance. Additionally, PSE's resources must stand ready at the start of each hour to balance any fluctuations in Wild Horse wind generation, regardless of whether they occur or not.[92]

44. Commission Staff proposes that the Commission ignore PSE's within-hour wind integration costs for Wild Horse on the flawed premises that such costs lack "sufficient robustness for inclusion in rate year net power costs" and "do not rise to a sufficient level of

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[90] Mills, Exh. No. DEM-11CT 18:7-13.
[91] Mills, Exh. No. DEM-11CT 20:14–21:3.
[92] Mills, Exh. No. DEM-11CT 21:13-19.

certainty to warrant inclusion".[93] Mr. Mills' testimony disproves Commission Staff's premise.[94] Each step in the Ancillary Valuation Model used by PSE to develop the within-hour balancing reserve requirements for Wild Horse relies on known and measurable data, whether the historical within-hour wind volatility or the unique operating characteristics of each resource, and is consistent with the AURORA simulation of hydro and price conditions for the rate year.[95]

c. Gas For Power Hedges Cost Recovery Limitation

45. The Commission should reject, as it did in PSE's last general rate case,[96] proposals by ICNU and Commission Staff to impose a cap on the monthly volume of the rate year gas-for-power hedges. ICNU proposes to remove the *monthly* volume of gas hedges—priced at the *monthly* average cost for all natural gas hedges—that exceed the *monthly* gas need as calculated using the AURORA model gas fired generation. Commission Staff proposes to remove the *annual* volume of gas hedges—priced at the *annual* average cost for all natural gas hedges—that exceed the *annual* gas need calculated using the AURORA model gas fired generation. In PSE's 2009 general rate case, the Commission expressly rejected the proposals and emphasized the appropriateness of including the cost of all hedges in power cost rates. [97]

46. The mark-to-market adjustments for natural gas hedges recommended by ICNU and Commission Staff are unreasonable. They seek to limit hedges in excess of those calculated by AURORA for ratemaking purposes, even though PSE does not use the AURORA model for day-to-day active management of the power portfolio.[98] PSE uses a probabilistic modeling risk system that runs several times weekly, using updated operational and market intelligence that includes regularly updated prices of power, natural gas, and resulting market heat rates.[99]

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[93] Buckley, Exh. No. APB-1CT 20:3-7.

[94] Mills, Exh. No. DEM-11CT 24:15–25:6.

[95] Mills, Exh. No. DEM-11CT 25:7-18.

[96] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶¶ 151–55 (April 2, 2010).

[97] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶¶ 151-55 (April. 2, 2010) ("The adjustment has routinely been an element of the power cost calculation and we see no principled reason to exclude it from rates simply because of its size in this case.").

[98] *Id.* at ¶ 151 (noting the difference between the methods used to set baseline power rates and the methods used to manage day-to-day operations).

[99] Mills, Exh, No. DEM-11CT 31:3-9.

47. PSE has not modified its energy commodity hedging strategies since its last general rate case, and PSE's strategy and the resulting hedges have been explained in detail in PSE's prior nine PCA compliance filings.[100] Neither ICNU nor Commission Staff have presented convincing reasons to change the treatment of mark-to-market hedges for ratemaking purposes.

d. Gas Pipeline Escalation Costs

48. ICNU proposes to remove rate year forecast cost increases for PSE's contracted pipeline obligations with Westcoast Energy, Inc., Northwest Pipeline GP and Cascade Natural Gas.[101] Contrary to the arguments suggested by ICNU, the PSE estimates of firm transportation costs on these pipelines are not speculative and should be included in this case.[102]

e. Winter Peak Planning Costs

49. The Commission should reject ICNU's proposed methodology for determining peak resource shortfalls and its corresponding adjustment.[103] ICNU proposes to remove costs to procure on-peak physical power to meet winter months' peak loads.[104] ICNU's adjustment fails to recognize that in actual operations, PSE must be prepared for *unexpected* winter peak events, and ICNU's proposal to avoid planning for all peak hours presupposes that PSE is able to predict the actual hour in which a peak event will occur. Moreover, even if PSE had perfect foresight and knew the exact hours in which its load would exceed its available resources, there is no reliable standard hourly option product that exists in the market to meet this peak.[105]

f. FERC 557 Other Power Supply Costs

50. The numerous errors in ICNU's FERC 557 account adjustment invalidate the adjustment.[106] Most significantly, Mr. Deen failed to use the correct pro forma account

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[100] Mills, Exh, No. DEM-11CT 31:10-15.
[101] Deen, Exh. No. MCD-1CT 10:21–11:27.
[102] Riding, Exh. No. RCR-4HCT 4:10–9:12.
[103] Mills, Exh. No. DEM-11T 34:1–38:2.
[104] Schoenbeck, Exh. No. DWS-1CT 14:13–16:5.
[105] Mills, Exh. No. DEM-11T 37:11-13.
[106] *See* Story, Exh. No. JHS-18 20:6–21:23.

balance.[107] ICNU's argument to normalize trended data to remove "significant variation" and "provide a more appropriate level of expense for prospective ratemaking purposes" is simply unfounded.

51. Also unsupported by the evidence is ICNU's claim that legal fees associated with BPA litigation should be averaged over five years. The BPA annual reports and statements on which ICNU seeks to rely do not carry the day. While some parties to the BPA residential exchange litigation may have settled, the case is currently under appeal.[108] As with all legal actions, the matters eventually resolve, but other claims take their place. PSE will continue to pay legal fees on these matters, and ICNU has not provided sufficient evidence or justification to support its proposed change to a five-year average of these legal fees.

g. AURORA Model Inputs For Minimum Up Times For Gas Fired Turbines

52. The Commission should decline ICNU's proposal to modify the minimum up times input to the AURORA model for certain of PSE's combined cycle plants.[109] ICNU's proposal to adjust the AURORA model reflects only a portion of the changes to the operating characteristics of the combustion turbines. If PSE were to update the AURORA model with all of the assumption changes, rate year power costs would *increase* significantly.[110] If the Commission would like to update the operating characteristics of the combustion turbines, then PSE recommends the Commission order the AURORA model be updated to reflect all the current thermal operating assumptions.[111]

h. Extension of 23 MW Transmission Contract

53. PSE requests that the Commission reject Commission Staff's inappropriate adjustment to remove the cost of PSE's renewal for 23 MW of cross-Cascades transmission capacity from rate

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[107] *See* Story, Exh. No. JHS-18 20:6–16

[108] *Alcoa, Inc. et al., v. Bonneville Power Administration, et al.,* U.S. Ct. App., 9th Cir., Docket Nos. 11-73161. *et al.*

[109] ICNU proposes changes to Goldendale, Mint Farm and Sumas. *See* Deen, Exh. No. MCD-1CT 13:3-23.

[110] Mills, Exh. No. DEM-11CT 39:3-41:16.

[111] Mills, Exh. No. DEM-11CT 39:3–41:16.

year power costs. Commission Staff erroneously asserts that "PSE has made no explicit showing of benefits, or reduced costs, related to the acquisition of this firm transmission capacity."[112] PSE has shown that it relies on existing firm BPA transmission contracts from the Mid-Columbia hub to PSE's system to meet its capacity need by using this transmission to make short-term market purchases at Mid-Columbia to serve PSE's load. These short-term market purchases are referred to in the 2009 IRP as "Short Term Resources". The renewal of 23 MW of cross-Cascades meets PSE's near-term needs for long-term firm capacity and should be included in rate year power costs.[113]

i. Chelan PUD Contract Costs

54. ICNU erroneously argues that PSE's payment obligations for the Capital Recovery Charge ("CRC") and Debt Reduction Charge ("DRC") under the contract with Chelan PUD should be reduced to the minimum value of 25 percent and 2.5 percent, respectively.[114] ICNU provides no support for this argument. In contrast, PSE provided the Chelan PUD Board's approval of a recommendation to establish the CRC and DRC at 50 percent and 3.0 percent, respectively, effective January 1, 2012, and PSE has provided a letter from Chelan PUD that states those rates will be used through 2013.[115] Therefore, PSE's rate year power costs accurately reflect the Chelan PUD decision and PSE recommends that the Commission reject ICNU's adjustments. In addition, PSE requests the Commission reject ICNU's proposal to remove the annual rate increase for the Chelan Transmission Revenue Requirement, as it is reasonable to apply a 2.5 percent inflation factor for Chelan PUD's transmission costs.[116]

j. Colstrip 1/2 Dedication Fee Amortization (Adjustment 20.10)

55. Commission Staff's proposal to amortize the $5 million dedication fee for the coal supply contract for Colstrip Units 1 and 2 over a ten-year period, rather than the nine-year period over

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[112] Buckley, Exh. No. APB-1CT 22:7-9.
[113] Mills, Exh. No. DEM-11CT 43:3-44-20.
[114] Deen, Exh. No. MCD-1CT 9:6–10:12.
[115] Mills, Exh. No. DEM-12.
[116] Mills, Exh. No. DEM-11CT 47:3-47:20.

which the benefits will be received,[117] creates a mismatch between benefits flowing from the dedication fee and the costs. It also creates inconsistency between financial accounting and regulatory recognition. For financial and regulatory purposes, PSE recorded this as a prepayment on the balance sheet and began amortizing the dedication fee in 2011 over the period during which PSE and its customers receive the benefit: 2011 through 2019. Commission Staff's proposal, if accepted by the Commission, would require PSE to write-off one-tenth of this retention value even though customers are receiving the full benefit over the years 2011 through 2019. PSE has recorded the cost correctly for financial reporting purposes, and Commission Staff has not provided any valid reason why it should be treated differently for regulatory purposes.[118] Accordingly, the Commission should reject Commission Staff's proposal.

k. BPA Transmission Credit for Lower Snake River

56. Commission Staff has withdrawn its adjustment based on updated data provided by PSE and the fact that this is duplicative of Adjustment 20.03, which is uncontested.[119]

l. Update for Current Gas Price Forecast

57. PSE has consistently promoted the establishment of rate year gas prices based on forward prices as close as possible to the beginning of the rate year, regardless of whether gas prices were increasing or decreasing. PSE suggests that the final order in this proceeding require PSE to update rate year power costs with more recent gas prices with its compliance filing.[120]

m. Production Operations and Maintenance Costs

58. No party has disputed the rate year costs for the following production operations and maintenance ("O&M") adjustments that originated with this proceeding: (i) the maintenance service contracts for PSE's wind facilities based on rate year generation and escalated costs;[121]

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[117] Martin, Exh. No. RCM-1T 15:5–16:12.
[118] Story, Exh. No. JHS-18T 37:4–39:6.
[119] *See* Exh. No. B-22, (Joint Response to Bench Request No. 22).
[120] *See* Exh. No. B-21 (PSE's Response to Bench Request No. 21).
[121] Mills, Exh. No. DEM-1CT 60:11-61:1.

and; (ii) wind royalty payments to match the rate year wind generation forecasts.[122]

i. Colstrip O&M Costs

59. No party contested PSE's projected O&M costs for Colstrip operations. Sierra Club responded to PSE's testimony regarding Colstrip operations by requesting that the Commission "issue an order requiring PSE to conduct a thorough, forward-going cost and risk study of the Colstrip plant, compared to a full range of supply and demand side alternatives."[123] Sierra Club clearly stated that it was not recommending disallowance of any operations and maintenance costs.[124] PSE understands the importance of determining the costs and benefits of each resource alternative. Accordingly, PSE conducts such analyses every two years in its IRP process.[125] At the evidentiary hearing, Sierra Club's witness Ezra Hausman generally agreed that the IRP process resulted in the thorough analysis that Sierra Club is seeking.[126] Therefore, no further analysis of Colstrip is required from this proceeding.

60. Moreover, as recognized by Commissioner Jones at the hearing, many of the issues raised by Sierra Club in this proceeding are outside the scope of issues that can be addressed by the Commission, which is a body of economic regulators, not environmental regulators.[127]

ii. Production O&M Costs

61. PSE's treatment of production O&M expenses[128] in this proceeding is consistent with current regulatory precedent which, except as noted above, uses actual test year production O&M costs for PSE managed resources and third-party rate year budgets for shared resources[129]. These third-party budgets have been reviewed and approved by the majority of owners and the Commission has consistently approved the use of these budgets as these costs have been

[122] Mills, Exh. No. DEM-1CT 61:2-61:16.
[123] Hausman, Exh. No. EDH-1T 5:7-9.
[124] Initial Brief of Sierra Club at ¶ 8.
[125] *See* Story, Exh. No. JHS-18T, 52:15-53:4.
[126] Goltz and Hausman, TR. 489:3-491:25.
[127] Hausman, TR. 494:17-495:17.
[128] Production O&M includes expenses for core O&M, contract and non-contract major maintenance and other O&M expense. Gould, Exh. No. WRG-1T, 7:1-3.
[129] Mills, Exh. No. DEM-11CT 52:10-53:3.

included in PSE's last seven rate cases.[130] PSE's adjustment recognizes the Commission's longstanding preference for using the best and most representative historic data when making pro forma adjustments.[131]

62. PSE's operational reliance and demand on its thermal generation assets has increased in recent years due to PSE's lower hydroelectric capacity and integration of its increasing wind resources.[132] Accordingly, the Commission should approve the use of test year production O&M costs as the most accurate and relevant information for determining rate year costs.[133]

63. In PSE's last general rate case, Commission Staff proposed a five-year average of expenses which the Commission rejected stating, "O&M is an ongoing expense and there is no evidence that the more recent historic data upon which PSE would have us rely requires any normalizing adjustments."[134] The facts haven't changed - both ICNU's and Staff's averaging methodologies in this proceeding still fail to provide the best and most representative data for rate year O&M expenses. [135] The Commission should once again reject other parties' proposals to normalize historical data for the same reasons the Commission has rejected this adjustment in the past.

64. Commission Staff has withdrawn its proposed adjustment to other production O&M costs based on updated information. PSE urges the Commission to reject ICNU's proposed four-year averaging adjustment to other production O&M for the logic cited above.

n. FERC OATT Wind Integration Revenues

65. ICNU's proposed adjustment to FERC OATT Wind Integration Revenues is not known and measurable as the rates on which the adjustment is based are still in litigation at FERC and

[130] Jones, Exh. No. MLJ-1CT 11:2-5. *See also* Mills, Exh. No. DEM-11CT, 51:8-52:13.
[131] Order 11, 2009 GRC, ¶ 162.
[132] Gould, Exh. No. WRG-1T, 2:11-6:9.
[133] *See generally* Gould, Exh. No. WRG-1T; s*ee also* Story, Exh. No. JHS-18T.
[134] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 162 (April. 2, 2010).
[135] ICNU used a four-year average of all categories of production O&M expense for the years 2007-2010. Commission Staff's production O&M proposal is based on actual test year expenses for Core O&M and contract major maintenance, but Staff uses a five-year average of all historical expenses for non-contract major maintenance.

are subject to refund.[136] Accordingly, the Commission should reject ICNU's adjustment.

2. Lower Snake River Project (Adjustment 20.02)

66. PSE placed LSR Phase 1 into service on February 29, 2012, and revised its adjustment for LSR Phase 1 at the hearing to reflect this actual in-service date.[137]

67. PSE's power costs are based on forward-looking projections, and LSR Phase 1 will provide power for PSE's customers during the rate year. Under the matching principle, the adjustment for LSR Phase 1 should likewise recognize the full costs of the plant, as PSE has done, even though a very small percentage of these costs were based on projections. The Commission has recognized the appropriateness of forward looking adjustments for production assets such as LSR Phase 1.[138] Commission Staff incorrectly uses only actual costs included in construction work in progress plus the known and measurable contract costs through October 2011, though updated known and measurable costs through December 2011 were provided in PSE's Fourth Supplemental Response to Bench Request No. 1 for this adjustment. Commission Staff's adjustment not only violates the matching principle, it is inconsistent with another Commission Staff adjustment—Adjustment 20.12, the LSR deferral. For the LSR deferral, Commission Staff uses the actual and projected plant costs just as PSE did.[139] There is no principled reason for Commission Staff's use of an artificial cut-off date of October 2011 for the LSR plant adjustment, and use of the full plant costs for the LSR deferral. PSE's adjustment, which uses the total cost of the plant, provides proper matching, which was one of the goals stated by the Commission when it approved a production plant adjustment in a prior case.[140]

68. Further, Commission Staff's adjustment completely ignores the fact that PSE accrues property tax liability for LSR during the test year. In light of the use of rate year projections for

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[136] Story, Exh. No. JHS-18T 19:9-20:5.

[137] Story, TR:1025:13-1026:11. PSE provided replacement pages for Exh. Nos. JHS-19 through JHS-22 to reflect the February 29, 2012 in-service date.

[138] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 23 (April 2, 2010) ("We have found this forward looking approach more appropriate when considering both power costs and production related assets.").

[139] Story, Exh. No. JHS-26.

[140] *See WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 ¶ 68 (April 7, 2004).

power costs, it is appropriate for the Commission to consider, and where necessary rely on, projections to determine the full costs of the plant—including the property tax—that undeniably accrue, and will impact the rate year. Prior to PSE's 2009 general rate case, the Commission allowed PSE to pro form in all costs, including expected property tax for new generation plant.[141]

3. LSR Prepaid Transmission Deposit (Adjustment 20.03)

69. PSE filed an accounting petition in May 2010 in Docket No. UE-100882, requesting approval of specific regulatory treatment of a prepaid transmission deposit made to BPA related to the LSR Wind Project. Commission Staff made no recommendation on this accounting petition. PSE again asks the Commission to expressly approve its regulatory treatment of the prepaid transmission deposit made to BPA, which is set forth in detail in Exhibit No. JHS-1T,[142] effective as of the date the accounting petition was filed. No party has opposed this adjustment, and Commission Staff's adjustment is the same as PSE's adjustment.[143]

4. Montana Electric Energy Tax (Adjustment 20.04)

70. The methodology to calculate this adjustment is not in dispute.[144] PSE's adjustment reflects updates to Colstrip which increased rate year generation.[145]

5. Storm Damage (Adjustment 20.07)

71. PSE's storm damage adjustment should be accepted by the Commission. It follows the

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[141] Exh. No. B-18 (including Sumas and Goldendale in PSE's 2007 general rate case, Wild Horse and Everett Delta in PSE's 2006 general rate case; Hopkins Ridge in PSE's 2004 general rate case).

[142] Story, Exh. No. JHS-1T 22:13-23:18.

[143] Story, Exh. No. JHS-18T 25:5-14. The prepayments for which PSE seeks deferral treatment were made to BPA to fund construction of certain transmission network upgrades including the new BPA-owned Central Ferry Substation required to interconnect the Lower Snake River Wind Project. Under the terms of the Large Generator Interconnection Agreement between BPA and PSE, BPA must fully reimburse PSE the prepayment of the Network Upgrades within 20 years after the commercial operation date of the Network Upgrades. The full amount of the prepayment will be refunded with or without the build-out of the remainder of the generation project. Story, Exh. No. JHS-1T 22:13-23:18. Prior to the 20 year refund deadline, BPA will return to PSE the prepayments related to the Network Upgrades, plus interest, by providing a monthly credit to PSE's future transmission bill. This credit will be equal to the point-to-point transmission tariff expenses associated with the use of the Interconnection Facilities and Network Upgrades.

[144] Exh. No. JHS-18T (Story) at 25:18-19.

[145] Mills, Exh. No. DEM-11CT 58:14-19.

approach approved by the Commission in 1992 as revised in 2004 and used in subsequent general rate cases since that time.[146] It appropriately allows for the deferral of expenses that significantly fluctuate from year to year. PSE uses the six-year average of normal storm expenses for determining the amount of normal storm costs built into rates. For major storms that meet an industry standard outage threshold established by the IEEE, PSE defers the expenses in excess of $8 million per year.[147] Contrary to Commission Staff's testimony, the current methodology is not complex and has been working well since it was jointly endorsed by Commission Staff and PSE in the 2004 general rate case. It provides PSE an avenue to defer costs of major storms by giving notice to the Commission that an IEEE-qualifying storm has occurred, and alleviates the need for PSE to file accounting petitions to defer costs for storms during times when PSE's efforts are focused on storm repair.

72. Commission Staff's proposal to dismantle the existing recovery mechanism for storm damage expenses will benefit neither customers nor PSE and should be rejected by the Commission. In proposing a change to this methodology, Commission Staff witness Mr. Applegate completely ignores the industry standard—IEEE Standard 1366-2003[148]—that is currently used to determine the storms that are eligible for deferral. Mr. Applegate would discard this established, certain methodology for recovering storm costs, and replace it instead with uncertainty as to what storm costs, if any, may be deferred. Mr. Applegate admits that his proposed methodology increases PSE's risk,[149] and Mr. Story calculates this increased risk to be approximately $20 million of after tax volatility.[150] If PSE is required to absorb this additional risk, the Commission must consider an upward adjustment to PSE's return on equity, as

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[146] The deferral mechanism for recovery of major storm expense was approved by the Commission in Docket UE-921262. The Commission approved the current definition for major or catastrophic storms using the IEEE Standard in Docket UE-040641 based on a joint proposal of the Company and Commission Staff. Story, Exh No. JHS-18T 27:12-21; *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-040640, *et al.*, Order 06 ¶¶ 232, 233, (Feb. 18, 2005).

[147] Story, Exh No. JHS-18T 27:1-3; McLain, Exh. No. SML-7T 7:3-7.

[148] McLain, Exh. No. SML- 7T 2:7-4:13.

[149] Applegate, Exh. No. RTA-1T 11:2-7.

[150] Story, Exh. No. JHS-18T 31:2-10.

advocated by ICNU witness Mr. Gorman.[151]

73. There can be little doubt that customers place a high premium on prompt and effective storm damage repair. Nor can there be doubt that significant storms occur frequently in PSE's service territory. Yet Mr. Applegate expresses concern that the current "[d]eferred recognition of storm damage expense assures that rates will eventually recover storm damage costs."[152] The fact that PSE is currently able to recover its prudently incurred costs for storm damage is not a reasonable justification for dismantling the existing approach to storm damage recovery.

As Ms. McLain testified, the heavy rain, shallow rooted trees, and high winds of Western Washington combine to make widespread storm-related outages a serious threat, and in fact a reality, that PSE and its customers have experienced over the past several years.[153] While under the current system PSE has 30 days to give initial notification to the Commission of an IEEE-qualified storm that may meet the threshold for deferral, under Mr. Applegate's undefined proposal, it appears that PSE would need to file an accounting petition before deferral of storm damage could begin—if in fact deferral was allowed at all.[154]

74. Another serious flaw with Commission Staff's proposal is that it would disallow millions of dollars of storm damage expenses that PSE had deferred in reliance on the Commission-approved deferral mechanism—including the $14 million addressed in PSE's rebuttal testimony[155] and any storm costs that PSE has deferred since its rebuttal filing, such as costs associated with the January 2012 snow and ice storm. Commission Staff's proposal retroactively disallows these deferred, IEEE-qualifying storm damage costs, not because they were imprudent but because they do not fit his newly-created definition of deferred storm costs.

75. Moreover, Mr. Applegate paints an incomplete picture of the current storm damage cost

[151] *See* Gorman, TR: 422:12-16 (agreeing under questioning by Chairman Goltz that if risk to the utility is increased the ROE should be increased).

[152] Applegate, Exh. No. RTA-10CX.

[153] McLain, Exh. No. SML-1T 3:7-10; Exh. No. SML-7T 6:2-9.

[154] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UG-040640, *et al.*, Order No. 06 ¶ 170 (Feb. 18, 2005) (noting the "longstanding principle that the Commission absolutely requires a company that wishes to book costs to a deferral account for treatment as a regulatory asset to first apply for and obtain express authority to do so").

[155] Story, Exh. No. JHS-18T 32:6-8.

recovery mechanisms. First, he fails to recognize that *normal* storm damage expense can exceed $8 million, and that only *IEEE qualifying* storms that exceed $8 million per year are eligible for deferral. It is a common occurrence for PSE to exceed the $8 million of normalized storm expense that is built into rates.[156] In four of the past six years, PSE's normal storm expense (which include IEEE-qualifying storms below the $8 million threshold) totaled more than the $8 million of normal storm expense built into rates.[157]

76. Second, Mr. Applegate tries to portray the current system as complex by interpreting a third recovery mechanism.[158] In fact, there are two recovery mechanisms: (1) normalized storm recovery expenses; and (2) deferral of IEEE-qualifying storms that exceed $8 million per year. Under the second mechanism, the deferral period for IEEE-qualifying storms is currently four years with one exception. In one instance, due to the size of the deferral, the Commission ordered a ten-year deferral period for the 2006 Hanukkah Eve Storm.[159]

6. Chelan Payments (Adjustment 20.09)

77. The Commission should approve this adjustment for the amortization of the Chelan PUD reservation payment, supported by PSE and Commission Staff. The amortization expense for the reservation payment is calculated over the 20-year life of the contract and the amount included in this adjustment represents amortization expense for the rate year.[160]

78. Public Counsel's witness Andrea Crane posits an adjustment based on an erroneous definition of "net of tax rate of return" and then calculates an adjustment to the interest accrued on the contract initiation payment and the related impact on power cost amortization based on her incorrect definition.[161] Mr. Story's testimony demonstrates that Ms. Crane's claim of double

[156] Story, Exh. No. JHS-18T 26:22-27:1.
[157] Exh. No. JHS-20 at 8.
[158] Applegate, Exh. No. RTA-1T 7:5-13.
[159] Story, Exh. No. JHS-18T 26:10-12.
[160] Story, Exh. No. JHS-1T 33:11-13. The Commission approved the prudence of PSE's entry into the Chelan power sales agreements, the rate treatment for recovery of the capacity reservation payment, and the associated carrying costs through amortization over the 20 year life of the contracts in the final order in Docket No. UE-060266. *Id.* at 32:5-9.
[161] *See* Story, Exh. No. JHS-18T 34:1-4.

recovery is incorrect. Her adjustment has errors in its calculation and the adjustment is duplicative of the entry that is already reflected on PSE's books and is properly shown on PSE's and Commission Staff's adjustment.[162]

7. Regulatory Assets and Liabilities (Adjustment 20.10)

79. As discussed above in production O&M costs, the Commission should retain PSE's adjustment for contract major maintenance, which includes amortization and deferrals of major maintenance associated with long term service agreements and contract service agreements at their test year amounts with inclusion in the baseline rate as a variable cost. These deferrals are associated with major maintenance that is expected to occur approximately every two years and follows ASC 980 for financial reporting purposes and for recovery of these costs in rates.[163] PSE's methodology recognizes that, although the majority of the test year regulatory assets will be fully amortized by the rate year, there will be another major maintenance event that coincides with the end of their amortization period.[164] PSE believes this matches the intent of the Commission upon accepting in principle the deferral methodology in the 2009 general rate case.[165]

80. In contrast, Commission Staff's proposed adjustment improperly disregards the recurring nature of these major maintenance events associated with long term service agreements and contract service agreements. It is undisputed that the amortization periods for this type of cost deferral are determined based on the estimated time interval between like events and the fact that a subsequent event will occur that impacts the rate year.[166] Despite acknowledging this to be true, Commission Staff's adjustment does not try to achieve the stated goal that "rate year expenses and balances should be used for ratemaking purposes"[167] because Commission Staff

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[162] *See* Story, Exh. No. JHS-18T 34:5–36:15; Exh. No. JHS-28.
[163] Story, Exh. No. JHS-18T 39:8-42:8.
[164] Story, Exh. No. JHS-18T 39:12-19; Gould, Exh. No. WRG-1T 17:3-17.
[165] Story, Exh. No. JHS-18T 42:4-8; *see WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704 and UG-090705, Order 11 ¶ 163 (April 2, 2010).
[166] Exh. No. JHS-29.
[167] Martin, Exh. No. RCM-1T 19:4-5.

does not include the rate year events that will follow the expiring major maintenance amortization.[168]

81. Commission Staff also proposes that PSE should be required to file a separate accounting petition prior to deferring and amortizing major maintenance under long term service agreements and contract service agreements.[169] The Commission should reject this approach. PSE has followed GAAP in deferring and starting the amortization of these costs. As to the rate base treatment, PSE is appropriately asking for that regulatory treatment for major maintenance deferrals accounted for under GAAP in this proceeding. The Commission rules do not limit a company to request regulatory treatment for cost recovery with an accounting petition, and based on recent history, several of PSE's accounting petitions are not resolved until a general rate case filing.[170]

82. Finally, it is unclear if Commission Staff expressly opposes PSE's proposal to treat these costs as variable in the PCA Mechanism. PSE requests that the Commission expressly approves the variable PCA treatment.

8. Production Adjustment (Adjustment 20.11)

83. PSE and Commission Staff agree as to the methodology used to determine this adjustment. The difference on expense and rate base items are based on the production-related adjustments included in other adjustments. This adjustment will need to be updated based on final Commission determinations related to those adjustments.[171]

9. LSR Deferral (Adjustment 20.12)

84. Both Commission Staff and PSE agree that PSE may defer costs associated with LSR under RCW 80.80.060(6) from the in-service date through the date rates go into effect in this proceeding and that these costs should be amortized over a four-year period beginning the date

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[168] Story, Exh. No. JHS-18T 40:6-9.
[169] Martin, Exh. No. RCM-1T 19:15-20:3.
[170] For example, PSE filed an accounting petition, Docket No. UE-100882 regarding the LSR transmission payments. This accounting petition had been pending for a year when PSE filed this rate case. *See* Story, Exh. No. JHS-18T 25:4-14.
[171] Story, Exh. No. JHS-18T 43:1-6.

the rates in this case go into effect.[172] However, despite the fact that RCW 80.80.060(6) allows the deferral of taxes incurred in connection with the acquisition of a renewable resource such as LSR Phase 1, Commission Staff fails to include property taxes in the LSR deferral.[173] As previously discussed, it is undisputed that PSE will pay property tax on LSR. PSE accrues property tax liability for LSR during the test year and during the deferral period. Commission Staff's approach, which ignores all property acquired after January 1, 2010, the first day of the test year, is not reasonable and should be rejected by the Commission. Instead, the Commission should accept PSE's proposed adjustment for the LSR deferral as it follows the intent of RCW 80.80.060(6) which allows the deferral of costs—including tax—associated with this type of plant.

E. Uncontested Non-Rate Base Electric Only and Natural Gas Only Adjustments

85. Appendix D and Appendix E list the uncontested non-rate base adjustments and associated differences in NOI for electric and natural gas, respectively. The Commission should adopt each of these uncontested electric and natural gas adjustments.

F. Contested Combined Electric and Natural Gas Rate Base Adjustments

86. Appendix F lists the contested combined electric and natural gas rate base adjustments and associated differences in rate base, which are discussed below.

1. Federal Income Tax (Adjustments 21.04 and 13.04)

a. DFIT Repairs/Retirements

87. The Commission should reject the proposed adjustment by Commission Staff and Public Counsel to reflect the impact of PSE's repairs and retirements tax accounting method change in rate base. Their adjustments disregard the Commission's order in PSE's last general rate case, which instructed PSE to wait to implement the repairs methodology until the IRS has approved

[172] Story, Exh. No. JHS-18T 43:7-46:13.
[173] Story, Exh. No. JHS-18T 11:5-13:14.

the methodology following an audit:

> Having made this determination for purposes of this proceeding, we note that the Company should implement an increase to ADIT in a future case *if the IRS approves its methodology for treatment of repair costs following an audit*.[174]

The IRS audit is not yet complete; it is expected to be completed this year.[175]

88. The Commission's instruction to wait until completion of the IRS audit flowed from PSE's experience with the Simplified Service Cost Methodology ("SSCM"). Under the SSCM, PSE was able to deduct much more of its overhead costs for tax purposes relative to book purposes; the result of the SSCM was tax deductions of an equivalent amount to those PSE seeks with the repairs method change.[176] As Mr. Marcelia testified, when the IRS performed its audit, it disallowed the entire SSCM change. PSE appealed and successfully reinstated about 85 percent of the original deduction. The IRS, however, adopted new rules that required PSE to return to its prior method of calculating overheads. Over the course of six years and after significant controversy with the IRS, SSCM was gone, leaving PSE with a charge for interest expense associated with the timing of the tax payments.[177]

89. The Commission cited the lessons learned from the SSCM in the order requiring PSE to wait until the IRS audit was completed before reflecting this accounting methodology in rates:

> However, the Company is correct to point out that the lesson of the SSCM issue demonstrates the risks of recognizing IRS-allowed accounting changes before they are audited.[178]

90. The various arguments of Commission Staff and Public Counsel should not move the Commission from the reasoned decision it made in 2010. The amount of accumulated deferred income tax under the repairs methodology is not known and measurable; it will remain an

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[174] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 197 (April 2, 2010). (emphasis added).
[175] Marcelia, Exh. No. MRM-14T 52:14.
[176] Marcelia, Exh. No. MRM-14T 47:1-4.
[177] Marcelia, Exh. No MRM-14T 47:8-10.
[178] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 194 (April 2, 2010)..

uncertainty until the IRS completes its audit, which is likely to occur in 2012.[179]

91. Commission Staff incorrectly claims that the amount of the repairs and retirement method is known and measurable because PSE does not report the repairs method as an uncertain tax position under FIN 48. However, there is no relationship between FIN 48 and the "known and measurable" standard in WAC 480-07-510(3)(e)(iii). They are different and unrelated concepts.[180] The absence of a reserve under FIN 48 means that management believes that PSE's tax positions pass the recognition and measurement standards of FIN 48.[181] It does not mean that PSE's tax position is "known and measurable" for ratemaking purposes.

92. Furthermore, the fact that PSE included this methodology in its tax returns for the past three years does not make it known and measurable as Public Counsel claims. PSE included the SSCM in its tax return for several years, while waiting for a final IRS determination.[182] Moreover, given the recent safe harbor provision announced by the IRS in August 2011, which is different from PSE's position, there is a significant likelihood that the IRS may not fully accept PSE's methodology.[183] PSE is currently assessing whether to recalculate its entire repairs and retirement method for electric transmission and distribution in light of the recent IRS safe harbor provision.[184]

93. It is puzzling that, under the guise of "known and measurable," Commission Staff rejects PSE's estimate of property taxes—with its three discrete variables that are known within a 16-

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[179] Marcelia, Exh. No. MRM-14T 52:14.

[180] Marcelia, Exh. No. MRM-14T 49:11.

[181] FIN 48 requires the use of a two-step approach for recognizing and measuring tax positions taken or to be taken in a tax return. First, a tax position must have at least a more likely than not chance of being sustained based on the technical merits, if challenged by the taxing authorities and taken by management to the court of last resort. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50% likelihood of being sustained. PSE only includes tax positions in it federal income tax return which it believes to be correct. However, with respect to PSE's experience with the SSCM change, management believed that its position was correct and fought the IRS in appeals. PSE's position was partially upheld, but the IRS prevailed when they changed the rules. *See* Marcelia, MRM-14T 51:17-52:4.

[182] Marcelia, Exh. No. MRM-14T 46:18-47:12.

[183] The safe harbor, announced in August 2011, addresses only electric transmission and distribution (not generation or gas facilities, as does PSE's method). It uses smaller units of property than does PSE's methodology and it employs a number of computational differences, which will produce a different result as compared to PSE's method. Marcelia, Exh. No. MRM-14T 53:9-16; Marcelia, TR: 1016:2-1017:5.

[184] *See* Exh. No. MRM-14T 54:3-6.

month period, and two of which are already known—but embraces as known and measurable the repair and retirement method changes with its "extremely complex calculations requiring hundreds of assumptions and estimates" and which still requires an IRS audit to achieve certainty.[185]

b. Account 236 Debit Balance

94. Commission Staff makes an unnecessary adjustment to Account 236 that should not be allowed. As Mr. Marcelia explained in his testimony, the large debit balance in the account at the end of the test year resulted from a receivable from the IRS.[186] Contrary to Commission Staff's claims, it is not uncommon to have a large debit balance in Account 236. Account 236 may end up with a debit balance whenever PSE has a tax overpayment or is expecting a cash refund, whenever it is recovering a tax that was originally posted to Account 236.[187] Mr. Marcelia testified regarding the significant debit balances in Account 236 at year end over the past five years.[188] Commission Staff already acknowledged that net operating losses are an offset against deferred taxes in rate base,[189] and this is part of that tax loss calculation (the difference is that the debit in Account 236 is the part of the tax loss that is being refunded, while the net operating loss ("NOL") in Account 190 is the part of the tax loss that is carried forward).[190]

c. Net Operating Loss

95. The adjustment Public Counsel seeks is inconsistent with PSE's and Commission Staff's position regarding the net operating loss and should be rejected for the reasons set forth in Mr. Marcelia's rebuttal testimony.[191] Public Counsel's request to adjust income tax expense for the

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[185] *See* Exh. No. MRM-14T 69:5-14, 70:1-6. Further, neither the property tax nor the repair and retirement method has been reported by PSE as an uncertain tax position under FIN 48. Although Commission Staff points to this as an indication that the repairs and retirement accounting method is known and measurable, Commission Staff does not draw this same conclusion for property taxes. *Id.* at 69:15-70:6.

[186] Marcelia, Exh. No. MRM-14T 59:18-19.

[187] Marcelia, Exh. No. MRM-14T 61:19-21.

[188] Marcelia, Exh. No. MRM-14T 61:21-62:4.

[189] Marcelia, Exh. No. MRM-14T 62:8-11.

[190] Marcelia, Exh. No. MRM-14T 59:11-19.

[191] Marcelia, Exh. No. MRM-14T 57:4-58:21.

tax net operating loss fails to recognize that the adjustment it seeks has already been recorded on PSE's books.[192] Moreover, it is appropriate for the deferred taxes related to the NOL to offset PSE's deferred taxes on plant rate base because, as Commission Staff's witness testified PSE "has made a reasonable presentation that its NOLs related to PSE's claiming bonus tax depreciation in 2009 and 2010."[193] PSE followed the IRS normalization guidance in PLR 8818040; Public Counsel's reliance on PLR 9336010 is inappropriate as it is not relevant to PSE's situation.[194]

e. The Commission should reject ICNU's consolidated tax savings adjustment

96. Mr. Marcelia testified extensively regarding the many flaws in ICNU's proposed consolidated tax adjustment, including its: violation of the tax code,[195] violation of the test year concept,[196] disregard of the changed structure of parent and affiliated companies at PSE over the past ten years,[197] disregard of PSE's tax loss in 2009 and 2010,[198] and failure to reflect actual tax,[199] to name a few. Most significantly, ICNU's adjustment erodes the ring fencing provisions that shield PSE's customers from risks at the parent company.[200] ICNU's witness Ellen Blumenthal would use tax benefits created by a loss at the parent company to benefit PSE's

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[192] *See* Marcelia, Exh. No. MRM-14T 57: 7-16. For PSE to record a tax net operating loss, the FERC account 190 Net Operating Loss must be debited. The offset to the debit is a credit to FERC account 411, Income Tax Expense. A credit to tax expense *lowers* the tax expense which is reflected in cost of service. So, the adjustment Public Counsel seeks from the Commission has already been reflected by the very fact that a tax net operating loss has been recorded on PSE's books. *Id.*

[193] Smith, Exh. No. RCS-1T 25:7-9.

[194] *See* Exh. No. MRM-36CX, Att. A at 1-4.

[195] Marcelia, Exh. No. MRM-14T 32:7-33:20 ("ICNU's proposed consolidated tax savings adjustment ignores the carryback/carryforward limitations of IRC §172.").

[196] Marcelia, Exh. No. MRM-14T 36:3-37:10("ICNU's utilization of a ten-year window is inappropriate for ratemaking in Washington.").

[197] Marcelia, Exh. No. MRM-14T 34:3-35:16 ("ICNU's calculation includes the tax loss from Snoqualmie River Hydro from 2001. Snoqualmie River Hydro ceased to exist in 2001, yet its tax loss is presumed to benefit PSE's ratepayers in the 2010 test year.").

[198] Marcelia, Exh. No. MRM-14T 37:13-39:3 ("Since every member [of the Puget Holdings consolidated group] had a loss in 2010, no one had any taxable income which was capable of "shielding" the tax loss of another member.").

[199] Marcelia, Exh. No. MRM-14T 40:3-41:8 (noting the absence of tax credits and alternative minimum tax).

[200] *In the Matter of the Joint App. of Puget Holdings LLC and Puget Sound Energy, Inc. for an Order Authorizing Proposed Transaction,* Docket No. U-072375, Order 08 ¶¶ 20, 179 (Dec. 30, 2008).

customers—in effect cross-subsidizing PSE's customers using an asset (a tax loss) owned by the parent company.

97. The Commission has repeatedly rejected similar consolidated tax adjustments, double leverage arguments, and cross-subsidization methodologies. For example, in response to Commission Staff's and Public Counsel's proposed double leverage adjustment that would have the effect of imputing the tax deduction associated with interest expense from a holding company to PacifiCorp, the Commission stated:

> Nonetheless, after having insulated PacifiCorp and its customers from the risks of leveraged financing at the parent, Staff and Public Counsel seek to secure for customers the cost and tax benefits of that financing. The Company's expert witness argues this may violate the familiar principle in utility law that financial benefits should follow burden of risks. We agree. *If the risks and costs of activities at the parent-level are borne exclusively by shareholders-because customers are insulated from them by the ring fence-then it is fair and appropriate for the shareholders, and not the customers, to receive the benefits that result from those activities.*[201]

98. The Commission similarly rejected a proposal by Public Counsel and ICNU to impose a consolidated tax adjustment ("CTA") that would reduce Avista federal income tax rate from 35 percent to its "effective tax rate" of 31 percent because it undermined the ring fencing put in place to protect utility customers:

> Finally, under either circumstance, the CTA violates the principle, if not the letter, of our recent decisions establishing "ring-fences" that protect ratepayers from non-regulated activities by declining to pull benefits or burdens from activities "outside the ring-fence" into the regulated business. Not only are we provided no reason to act contrary to our recent precedent in this regard, doing so here could jeopardize the integrity of the rationale for "ring-fencing" and undermine its defensibility if it were attacked.[202]

99. Although ICNU attempts to disguise its adjustment as a "loan" or "tax shield" rather than

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[201] *WUTC v. PacifiCorp*, Docket No. UE-050684, Order 04 ¶ 285 (April 17, 2006) (emphasis added).

[202] *WUTC v. Avista Corp.,* Docket Nos. UE-080416, *et al.*, Order 08 ¶ 151 (Dec. 9, 2008); *see also WUTC v. PacifiCorp*, Docket Nos. UE-061546, *et al.*, Order 08 ¶ 151 (June 21, 2007) ("The second key problem is the care taken to separate the financial circumstances of PacifiCorp from the other affiliates, including MEHC, through 'state of the art ring fencing approved by the Commission in the acquisition proceeding. *In this context, it would be very difficult to justify joining the financial circumstances of MEHC and PacifiCorp by imputing MEHC debt costs into PacifiCorp's capital structure.*") (emphasis added).

imputation of parent company debt or the tax deduction associated with the debt, the effect is the same, and a clear violation of the Commission order cited above.[203]

100. It is illogical to require strict ring-fencing provisions on PSE and contravene those same provisions by lowering PSE's revenue requirement because a non-regulated affiliate generated a tax loss. By definition and by computational mechanics, the proposed consolidated tax savings adjustment looks beyond the utility to non-regulated operations and places an unmerited claim on the assets of non-regulated members and ignores the underlying cost.[204]

101. Especially troubling is ICNU's one-sided approach. If the Commission were to adopt ICNU's methodology, it should work both ways, which would mean PSE's customers could be liable for payment of interest for use of an affiliate's "tax shield" in the event PSE reported a tax loss and an affiliate had taxable income, as was the case in 2009.[205] In sum, the proposed consolidated tax savings adjustment would weaken the ring-fencing provisions that ensure rate payers bear only the benefits and burdens of utility operations.

2. Working Capital (Adjustments 21.22 and 13.22)

102. On rebuttal, PSE corrected ratemaking treatment for two balance sheet accounts in FERC Account 134 "Other special deposits" to conform to Commission Staff adjustments.[206] Other adjustments affecting working capital are discussed with tax adjustments.

G. Uncontested Rate Base Adjustments

103. Appendix G lists the uncontested combined electric and natural gas rate base adjustments and associated differences in rate base. Appendix I lists the uncontested electric rate base adjustments and associated differences in rate base. Appendix J lists the uncontested natural gas rate base adjustments and associated differences in rate base. The Commission should adopt each of these uncontested rate base adjustments.

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[203] Marcelia, Exh. No. MRM-14T 10:13-23.
[204] Marcelia, Exh. No. MRM-14T 22:2-5.
[205] Marcelia, Exh. No. MRM-14T 39:7-16.
[206] Stranik, Exh. No. MJS-10T 24:9-18.

H. Contested Electric Rate Base Adjustments

104. Appendix H lists the contested electric rate base adjustments and associated differences in rate base. These contested electric adjustments were discussed in section III.D above.

I. Summary of Revenue Requirement Determination

105. Appendix M summarizes the results of the electric retail revenue requirement deficiency of $124,810,136 proposed by PSE in this proceeding. Appendix L summarizes the results of the natural gas revenue requirement deficiency of $28,616,025 proposed by PSE in this proceeding.

IV. CAPITAL STRUCTURE AND COST OF CAPITAL

106. Appendix M presents PSE's proposed capital structure and cost of capital, which are discussed below. The parties do not dispute PSE's cost of short-term debt and long-term debt.[207]

A. PSE's Proposed Capital Structure That Contains 48 percent Common Equity Is Reasonable and Properly Balances Safety and Economy

107. The Commission should approve PSE's proposed capital structure that consists of 48 percent common equity[208] and reflects average capital structure ratios that will support utility operations during the rate year.[209] PSE's proposed pro forma capital structure is reasonable and strikes a fair balance between interests of safety and economy.[210]

108. Neither Commission Staff's nor ICNU's proposal meets the Commission's goal to set the equity ratio at the level that the evidence shows is most likely to prevail, on average, over the course of the rate year."[211] The inadequate equity ratio of 46 percent proposed by Commission Staff and ICNU does not withstand scrutiny because it contains substantially *less* common equity than (i) PSE's actual common equity ratio during the test year (48.5 percent);[212] (ii) the common

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[207] *See* Gaines, Exh. No. DEG-14T 4:5-10; Elgin, KLE-1T 50:7-9.
[208] *See* Gaines, Exh. No. DEG-1T, Table 1.
[209] *See* Gaines, Exh. No. DEG-1T 14:11-14.
[210] *See WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UG-040640, *et al.*, Order 06 ¶ 27 (Feb. 18, 2005) (indicating that the capital structure for ratemaking purposes must be reasonable and strike a fair balance between safety and economy).
[211] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UG-040640, *et al.*, Order 06 ¶ 40 (Feb. 18, 2005).
[212] Gaines, Exh. No. 14T 8:19-9:2.

equity ratio that PSE projects will be employed, on average, during the rate year;[213] and (iii) the average common equity ratio approved by state regulatory commissions during the test year (48.21 percent).[214] Although Commission Staff claims that the appropriate starting point for determining PSE's equity ratio is PSE's actual capital structure for 2010, Commission Staff deviates from this starting point. Instead of using the 48.5 percent equity ratio that supported PSE's utility operations on average during the test year, Commission Staff uses 46.0 percent. Mr. Elgin determines the 46 percent equity ratio by focusing on a single point in time—the end of the test year—rather than the average equity ratio supporting utility operations in the test year.[215] By so doing, he contradicts his own approach in the recent PacifiCorp general rate case, where he used an average equity ratio rather than a single point in time.[216] Mr. Elgin compounds his error—and violates basic mathematical principles—when he rounds *down* from the single-point in time equity ratio of 46.5 percent in order to reach his preferred 46.0 percent common equity.[217]

109. It is disingenuous for Commission Staff to claim now that an equity level of 48 percent contains too much equity and places excessive costs on PSE's customers[218] when customers gain a $40 million benefit from the increased equity.[219] It is also contrary to the Commission's 2009 merger order that required PSE to have an equity ratio of *not less than* 50 percent at closing.[220]

110. In Mr. Elgin's prefiled testimony[221] and cross examination[222] he erroneously claims that PSE's response to Staff Data Request No. 11[223] shows that his recommended equity ratio is

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[213] *Id.*

[214] Exh. No. DEG-13 at 3 (reflecting a period between January 1, 2008, through August 31, 2009); *see generally* Gaines, Exh. No. DEG-11HCT 3:6-7:15; Exh. No. DEG-16.

[215] Elgin, Exh. No. KLE-1T 15:20-16:2.

[216] Exh. No. DEG-14T 12:12-15.

[217] Elgin, Exh. No. KLE-1T 15:20-16:2.

[218] Exh. No. DEG-14T 12:15-16

[219] *See* Exh. No. DEG-14T 19:11; DEG-20.

[220] Exh. No. DEG-1T 7:4-6; *see also In the Matter of the Joint App. of Puget Holdings LLC and Puget Sound Energy, Inc. for an Order Authorizing Proposed Transaction,* Docket No. U-072375, Order 08, Appx., A, commitment 35 (Dec. 30, 2008).

[221] *See* Elgin, Exh. No. KLE-1T 16:12-13.

[222] Elgin, TR. 866:14-868:20.

[223] Elgin, KLE-9C CX at 103.

consistent with PSE’s financial forecast. This exhibit demonstrates that PSE’s projected regulatory equity was 48 percent in 2011 and is expected to remain at that level in 2012.[224] Mr. Elgin’s resulting confusion from trying to reconcile this exhibit stems from what he interprets to be the dollar amount of debt that PSE is proposing in its capital structure. Mr. Elgin does recognize that $3.7 billion is the amount PSE used in determining its cost of long-term debt. This amount of debt is shown on page 103 of Exhibit No. KLE-9C CX and is the sum of the lines labeled Hybrid Preferred and Long Term Debt. However, Mr. Elgin mistakenly equates this dollar amount of debt to the 48 percent long-term debt Mr. Gaines used in his proposed capital structure. As is shown on page 103, for the year 2011 book equity is $3,308 million, long term debt and hybrid preferred is $3,754 million and short term debt is $136 million for a capital structure of 46 percent book equity, 52 percent long term debt and 2 percent short term debt. Mr. Gaines proposed capital structure uses the 48 percent regulatory equity shown on page 103 and 4 percent short term debt. The remaining piece of the puzzle is long term debt which would have to be 48 percent.

Mr. Elgin’s confusion stems from his disregard of the fact that Mr. Gaines proposed capital structure is hypothetical. If Mr. Elgin had calculated the percentage capital structure shown on page 103 of Exhibit No. KLE-9C CX, he would have realized his theory that $3.7 billion is equivalent to 48 percent of the capital structure is erroneous. Mr. Gaines’ hypothetical capital structure includes 4.0 percent short-term debt when in reality PSE has had, and is expected to have, a lower amount of short-term debt going forward. Mr. Elgin also ignores that the presentation on page 103 is a point in time and not an average calculation. This point in time view fails to reflect the natural flow of short-term debt into tranches of long-term debt.[225] Had Mr. Elgin included the proposed capital structure of short term debt in his analysis and reconciliation, he would have arrived at PSE’s requested equity component. Mr. Elgin's

[224] Exh. No. KLE-9C CX at 103.
[225] *See* Exh. No. KLE-9C CX at 103.

apparent confusion over this exhibit is not a valid reason for the Commission to ignore the amount of equity invested in PSE, which is providing customers real benefits in terms of lower interest costs.[226]

Moreover, the increased dividends paid by PSE to Puget Energy since the 2009 merger is irrelevant, given the change in ownership structure since that time.[227] All parties to the merger proceeding were aware that there would be debt at Puget Energy to support PSE's capital expenditures that did not exist at PSE before the merger.[228] Therefore the Commission should compare dividends paid from PSE to Puget Energy prior to the 2009 pre-merger, with dividends paid from Puget Energy to the parent company after the 2009 merger.

111. ICNU's proposed common equity ratio of 46 percent should be rejected because it erroneously removes non-regulated subsidiary common equity from PSE's consolidated capital structure when PSE's proposal already reflects removal of such equity, and ICNU does not adjust the equity component for the effects of SFAS 133 and pension accounting.[229] Additionally, Mr. Gorman testified that he agrees with PSE's group of proxy utilities,[230] yet he ignores that the equity ratio reflected in rates for those proxy companies averages 48.21 percent.

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

112. 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.[231]

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[226] Gaines, TR. 836:7-24.

[227] *See* Exh. No. B-13 (requesting Commission Staff provide historical dividends PSE has paid to Puget Energy).

[228] *In the Matter of the Joint Application of Puget Holdings and Puget Sound Energy, Inc., for an Order Authorizing Proposed Transaction*, Docket U-072375, Order 08 ¶¶ 138, 146 (Dec. 30, 2008) (discussing benefits the $1 billion credit facility at Puget Energy that can be drawn upon solely to inject cash into PSE for capital expenditures and will add equity to PSE's balance sheet).

[229] Gaines, Exh. No. DEG-14T 5:2-12.

[230] Gorman, Exh. No. MPG-1T 15:4-5.

[231] *See, e.g., See WUTC v. Avista Corp.*, Docket No. UE-991606, Third Supp. Order ¶ 324 (Sept. 29, 2000); *WUTC v. Puget Sound Power and Light Co.*, Docket Nos. UE-920433, *et al.*, Eleventh Supp. Order, (Sept. 21, 1993); *WUTC v. Pacific Power & Light Co.*, Docket No. U-86-02, Second Supp. Order p. 26 (1986).

113. Similarly, several decisions of the U.S. Supreme Court require that this Commission's decision allow a utility the opportunity to earn a return on equity ("ROE") that is: (i) sufficient to assure confidence in PSE's financial integrity and maintain PSE's creditworthiness, (ii) sufficient to maintain a utility's ability to attract capital on reasonable terms; and (iii) commensurate with returns on investments in other firms having corresponding risks.[232]

114. PSE's proposed cost of equity of 10.75 percent is reasonable and should be approved. PSE relied on the Discounted Cash Flow ("DCF") Model to estimate the return required by investors on the common equity capital committed to PSE. An ROE of 10.75 percent is consistent with ICNU's witness, Mr. Gorman, who developed an average cost of common equity of 10.75 percent using a constant growth DCF model. This result was derived using the comparable companies selected by Dr. Olson,[233] and Dr. Olson agrees with Mr. Gorman's ROE results using the constant growth DCF model.[234]

115. Commission Staff and Dr. Olson agree that the DCF model is the appropriate methodology for setting the ROE. They both acknowledge that the Capital Asset Pricing Model ("CAPM") and the Risk Premium model are useful as checks on the DCF result. However, in determining a proposed return on equity for PSE, the Commission should not afford a CAPM analyses as much weight in these proceedings for a variety of reasons. First, CAPM analyses currently generated projected costs of equity that are not significantly above the cost of new debt capital and likely understate the cost of equity capital under unsettled capital market conditions. Second, the betas employed in the CAPM analysis are estimates based on a five-year historical periods, and the impact of the ongoing financial crisis is not yet fully captured in the estimates. Finally, spreads between costs of capital for private companies and government interest rates have diverged substantially following the Federal Reserve's expansionary policies designed to

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[232] *See 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).

[233] Gorman, Exh. No. MPG-1T 24-25; Exh. No. MPG-6.

[234] Olson, Exh. No. CEO-10T 13:18-19.

jumpstart the stalled economy.[235] Given this anomaly between actual market costs and projections based on CAPM analyses, the Commission should give much less weight, if any at all, to them.

116. Mr. Gorman stands alone in his "multiple models" approach to rate of return determination. He did not respond to Dr. Olson's testimony that the risk premium does not have the standing of DCF[236] and that CAPM does not measure risk.[237]

117. There is however, agreement among the parties regarding the constant growth DCF model. As indicated earlier, Dr. Olson and Mr. Gorman agree on the 10.75 percent result from that model. Mr. Elgin also agreed that the constant growth model is the only appropriate approach to DCF. In response to a series of questions from Commissioner Jones, Mr. Elgin makes it clear that he does not believe a multi-stage DCF is appropriate, nor does he agree with the sustainable yield approach.[238] In fact, Mr. Elgin relied on growth rates from Value Line in a constant growth context.[239] Thus it is clear that both Dr. Olson and Mr. Elgin are in agreement that the only valid DCF study done by Mr. Gorman was his constant growth model that produced an average return of 10.75 percent.

118. The parties agree to the use of analyst forecasts and a relatively short investor time horizon of three to five years.[240] Dr. Olson uses a consensus growth forecast (multiple analysts) as does Mr. Gorman.[241] Mr. Elgin, on the other hand relies on a single analyst from Value Line.[242] In that regard, Exhibit No. CEO-18 CX establishes that consensus earnings forecasts are superior to other types of growth rate estimates. Thus, Mr. Elgin's non-consensus forecast falls short in comparison to the consensus forecasts used by Dr. Olson and Mr. Gorman.

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[235] Olson, Exh. No. CEO-1T 11:13-13:4.
[236] Olson, Exh. No. CEO-1T 17:8-10.
[237] Olson, Exh. No. CEO-1T 19:5.
[238] Elgin, TR: 847:9-850:23.
[239] Elgin, Exh. No. KLE-1T 31:13-23.
[240] Elgin, TR. 849: 4-9.
[241] Gorman, Exh. No. MPG-1T 18:18–19:7.
[242] Elgin, Exh. No. KLE-1T 31:13-23.

V. SETTLEMENTS

119. PSE requests that the Commission approve the Multiparty Settlement Re: Electric Rate Spread and Rate Design; the Multiparty Settlement Re: Gas Rate Spread and Rate Design; and the Partial Settlement Re: Meter and Billing Performance Standards.

VI. PRUDENCE ISSUES

120. The evidence in this case demonstrates that PSE acted prudently in its decision to construct LSR Phase 1 and in the execution of the Klamath Peakers PPA. PSE respectfully requests a prudence determination for these resources

121. In PSE's 2003 PCORC proceeding, Docket No. UE-031725, the Commission reaffirmed the standard it applies in reviewing the prudence of power generation asset acquisitions. These standards address the questions of what a reasonable board of directors and company management would decide based on what should have been reasonably known.[243]

122. In addition to this reasonableness standard, the Commission has cited several specific factors that inform the question of whether a utility's decision to acquire a new resource was prudent. The utility must determine that the new resource is necessary.[244] Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When considering the purchase of a resource, the utility must evaluate that resource against other available resources and against the standard of what it would cost to build the resource itself.[245] The utility must keep its board of directors involved in the purchase decision process and informed about the purchase cost.[246] The utility must keep contemporaneous records that will allow the Commission to evaluate its actions with respect to the decision process.[247]

A. PSE Acted Prudently in Constructing LSR Phase 1

123. Public Counsel and ICNU are the only parties that challenge the prudence of PSE's

[243] *WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order 12 ¶ 19 (April 7, 2004).
[244] *See, e.g., WUTC v. Puget Sound Power & Light Co.*, Docket No. UE-921262, *et al.,* Nineteenth Supp. Order p. 11, (Sept. 27, 1994) (the "1994 Prudence Order").
[245] *See* 1994 Prudence Order at 11.
[246] *See* 1994 Prudence Order at 37, 46.
[247] *See* 1994 Prudence Order at 2, 37, 46.

decision to construct LSR Phase 1.[248] Public Counsel and ICNU's prudence analyses are incomplete and selectively ignore the evidence presented.

1. PSE's Decision to Construct LSR Phase 1 in Advance of RPS Target Deadlines Was Cost-Justified and Prudent

124. PSE's need for renewable energy resources is largely driven by the Energy Independence Act,[249] which established a renewable portfolio standard ("RPS") that requires electric utilities with more than 25,000 customers to use qualifying renewable energy to serve at least 15 percent of electric load by 2020, with benchmarks that take effect in 2012 and 2016 to demonstrate progress.[250] Although PSE is well-positioned to meet the near-term RPS benchmark in 2012, PSE determined that it required additional renewable resources to meet the 2016 benchmark and the 2020 mandate.[251]

125. PSE has consistently acknowledged in this proceeding that it constructed LSR Phase 1, in large part, to meet the RPS benchmark of meeting at least nine percent of electric load with renewable resources by 2016.[252] Although the in-service date for LSR Phase 1 is ahead of the 2016 benchmark, PSE's decision to construct the project in advance of this need was prudent due to the following significant costs savings realized by PSE:

(i) $321,108,000 nominal benefit to PSE customers from provisions of the American Recovery and Reinvestment Act of 2009 that allowed a taxpayer to claim a grant from the U.S. Treasury ("Section 1603 Treasury Grant") in lieu of investment tax credits or production tax credits for qualifying projects to be in commercial operation by December 31, 2012;[253]

(ii) $45,737,000 nominal benefit to PSE customers from Washington state sales tax exemptions through June 30, 2011, for systems generating power with renewable technologies;[254] and

(iii) a depressed resource development market that has created downward

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[248] *See generally*, Norwood, Exh. No. SN-1CT.
[249] RCW Chapter 19.285.
[250] RCW 19.285.040
[251] Garratt, Exh. No. RG-1HCT 18:4-6.
[252] *See, e.g.,* Garratt, Exh. RG-1HCT 18:4-6.
[253] Garratt, Exh. No. RG-1HCT 25:7-9.
[254] Garratt, Exh. No. RG-1HCT 25:9-10.

> price pressure on wind turbine generators, which generally comprise 60-75% of the total cost to build a wind project.[255]

In short, PSE's decision to construct LSR Phase 1 in advance of RPS target deadlines was cost-justified and prudent. Indeed, PSE projects that the construction of LSR Phase 1 in 2012 provides net present value benefits that are $190 million higher than the construction of a similarly sized alternative plant in 2016.[256]

126. PSE's acquisition of LSR Phase 1 in advance of PSE's RPS need satisfies the prudence criteria set forth in the Renewable Resource Policy Report, in which the Commission stated that it would consider the acquisition of renewable resources in advance of RPS target deadlines to be prudent if the early acquisition could be cost-justified:

> While the EIA does not, by itself, determine whether such an acquisition before the RPS deadline is prudent, it points to such a decision. To give the utilities sufficient incentive and flexibility to achieve the EIA's goals, we would support the acquisition of renewable resources in advance of RPS deadlines if the early acquisition can be cost-justified.[257]

127. The Renewable Resource Policy Report lists the following factors for consideration of whether an early acquisition is cost-justified:

> Among the factors to be considered are the relative cost of acquiring the resource earlier rather than later, the risk of a higher price if the resource is acquired nearer the RPS deadline, the anticipated ability of the utility to use or sell the power generated, the potential for sales of RECs until the output of the facility is needed to meet the RPS, whether there are federal or state tax benefits that are available in the near term, and the length of time between acquisition and the RPS deadline. In addition, because the productivity of renewable facilities can depend in substantial part on the location of the facility, acquiring a renewable facility earlier may secure a more productive (and therefore more cost-effective) facility.[258]

128. The Renewable Resource Policy Report further states that "[t]he utility should evaluate alternatives and conduct the necessary technical and economic analyses in the same manner it does when considering alternatives to meet RPS . . . ."[259]

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[255] Garratt, Exh. No. RG-1HCT 3:16–4:5.
[256] Seelig, Exh. No. AS-4HCT 3:12–6:2.
[257] Renewable Resource Policy Report ¶ 52.
[258] Renewable Resource Policy Report ¶ 53.
[259] Renewable Resource Policy Report ¶ 54.

129. At the time PSE filed its 2009 IRP,[260] PSE had already acquired sufficient renewable resources to meet the 3 percent of load benchmark in 2012 but needed to acquire approximately 81 average megawatts ("aMW") by 2016 and 261 aMW by 2020.[261] To meet this need, the 2009 IRP identified total renewable resource additions of 1,020 MW by 2020 (1,000 MW of additional wind resources and 20 MW of biomass resources).[262] Of this 1,020 MW total, the 2009 IRP identified 600 MW of cost effective additional wind resources by 2016 (300 MW added by 2012 and a cumulative total of 600 MW added by 2016).[263]

130. After the completion of the 2009 IRP, PSE conducted additional analyses to assess the impact of federal and state incentives available to renewable resources and changes in the market for such resources. PSE used the following three quantitative models to identify the cost-effective level of renewable resources that it could add:

i) a simple discounted cash flow analysis;

ii) a re-run of the 2009 IRP in the Portfolio Screening Model II (the "PSM II Model") used during the 2009 IRP; and

iii) a comparative analysis of renewable resources as part of its 2010 Request for Proposal (the "2010 RFP") processes using the Portfolio Screening Model III (the "PSM III Model") optimization model.[264]

131. Public Counsel and ICNU make various arguments attacking these analyses of the cost-effectiveness of constructing a renewable resource in advance of the RPS benchmarks. Each of these arguments, however, is either incorrect or immaterial to the analyses performed by PSE, and none of Public Counsel's or ICNU's arguments alter the fundamental conclusion that PSE's decision to construct LSR Phase 1 in advance of need is cost-justified.

132. First, Public Counsel and ICNU argue that an error in the 2009 Business as Usual (the "2009 BAU") market price scenario in the re-run of the 2009 IRP, which inadvertently reflects the costs of secondary market purchases under the assumptions used in the 2009 Trends market

[260] *See generally* Exh. No. RG-3.
[261] Exh. No. RG-3 at 81.
[262] Exh. No. RG-3 at 10.
[263] Exh. No. RG-3 at 10.
[264] Seelig, Exh. No. AS-1HCT 21:6-15.

price scenario, somehow "significantly distorted the results of PSE's analysis of the cost effectiveness of adding new wind before it was needed as well as its economic analysis of LSR 1 against wind energy proposals received in response to its 2010 RFP."[265] Correction of this error, however, does not change the conclusion. Indeed, the corrected BAU market price scenario demonstrated that the early construction of 600 MW of renewable energy to capture the Section 1603 Treasury Grant was the most cost-effective solution based on the need defined in the 2009 IRP. Indeed, seven of the eight build schedules presented were still more cost-effective than the No Early Wind build schedule.[266]

133. Second, Public Counsel and ICNU argue that PSE overstated its renewable energy need to meet the benchmark targets for the RPS.[267] This argument, however, ignores the fact that, at the time PSE's Board of Directors authorized the construction of LSR Phase 1, PSE had contractual commitments to sell most of the "surplus" RECs in the 2011–2015 period to counterparties in order to provide significant monetary benefits to customers. Moreover, Public Counsel's and ICNU's reliance on the banking provisions in RCW Chapter 19.285 is misplaced. The RPS banking provisions provide, at most, a hedge against wind generation uncertainty, wind curtailment policies, and load uncertainty and should not be used as a tool to defer meeting the requirements of the state mandated RPS.[268] By failing to include PSE's REC sale obligations, Public Counsel and ICNU overstate the volume of RECs eligible for banking from PSE's existing resources.[269]

134. Third, Public Counsel and ICNU erroneously argue that PSE assumed "PTCs would not be available for any new wind generation projects placed in service after 2013" and that such assumption "was one of the primary factors contributing to the estimated economic benefit of

[265] Norwood, Exh. No. SN-1HCT 33:1-3.
[266] Seelig, Exh. No. AS-4HCT 12:8–14:9.
[267] Norwood, Exh. No. SN-1CT 33:4 – 35:18.
[268] *See* Decker, Exh. MWD-1T 3:12–5:10; Nightingale, Exh. DN-2T 13:4-14.
[269] Seelig, Exh. No. AS-4HCT 14:10–16:12.

adding new wind early."[270] Public Counsel and ICNU further assert that PSE's assumption "had the effect of creating a significant capital cost advantage for early wind generation projects, such as LSR Phase 1, when compared to wind projects that were projected to enter service after 2013."[271] These arguments are misplaced. PSE assumed, for purposes of analyses, that PTCs would not be available for projects placed in service after December 31, 2012, because the legislation that provides for wind PTCs does not extend to projects placed in service after December 31, 2012.[272] Therefore, for purposes of much of its analysis, PSE assumed that PTCs would expire, as provided for in statute, unless extended through legislation. Even so, PSE did, in fact, conduct sensitivity analyses that considered the possibility that legislation would extend PTCs through 2016 and through 2020, and such analyses confirmed PSE's recommendation to construct or acquire renewable energy need in advance of the RPS target deadlines.[273]

135. Fourth, Public Counsel and ICNU expresses concern that "the forecast carbon prices used for PSE's 2009 Trends scenario were two to three times higher than any other carbon forecast [PSE] has used for resource planning analyses in recent years."[274] Again, this argument is misplaced. PSE used the referenced CO_2 price forecasts in the 2009 Trends Scenario in the re-run of the 2009 IRP analysis, and these analyses predated and were concurrent with the lower CO_2 price forecasts published by the Environmental Protection Agency. When the updated CO_2 price forecasts became available, PSE used these in its analyses of the projects proposed in response to the 2010 RFP.[275]

136. Fifth, Public Counsel and ICNU argue that PSE "improperly assumed that wind resources which retired after the 20-year planning period would not be replaced"[276] and that PSE's "end effects calculations are inherently uncertain due to the fact that they involve forecasts of market

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[270] Norwood, Exh No. SN-1CT 36:4-6.
[271] Norwood, Exh No. SN-1CT 36:8-10.
[272] *See, e.g.,* Norwood, Exh. No. SN-1CT 37:9-10 (acknowledging that "existing laws provided for wind PTCs to be effective for projects placed in service no later than December 31, 2012").
[273] Seelig, Exh. No. AS-4HCT 16:13–20:6.
[274] Norwood, Exh. No. SN-1CT 39:20-22.
[275] Seelig, Exh. No. AS-4HCT 20:7–28:22.
[276] Norwood, Exh. No. SN-1CT 41:21-22.

prices, generating unit performance and generation for a period that is 20 to 50 years into the future."[277] These arguments are contradictory. On the one hand, Public Counsel and ICNU suggest that PSE should assume an uncertain replacement cost beyond the 20-year planning horizon. On the other hand, Public Counsel and ICNU suggest that PSE ignore portfolio benefits and operating costs that arise from generation plants' operation performance in the power market. It is not clear from the arguments presented by Public Counsel and ICNU how PSE would consider the effects of costs twenty years in the future for some but not all items. Moreover, Public Counsel and ICNU do not propose an alternative end effects calculation but instead present an analysis that essentially removes the calculation of end effects.[278] The Commission has expressly stated in prior orders that utilities consider end effects in prudence analyses,[279] and the calculations presented by Public Counsel and ICNU effectively ignore such directives.

137. Sixth, Public Counsel and ICNU incorrectly allege that "PSE's economic analysis did not evaluate REC purchases as an alternative to the acquisition of new wind generation facilities as a means to supply a portion of [PSE's] RPS requirements."[280] PSE, in fact, evaluated REC purchases as an alternative to the acquisition of new wind generation facilities as a means to supply a portion of PSE's RPS requirements. In response to the 2010 RFP, PSE received two proposals containing a total of six offers for unbundled RECs, and PSE evaluated these unbundled REC proposals the same as it evaluated any other renewable energy proposal in the 2010 RFP. However, PSE did not receive a sufficient volume of proposed RECs to evaluate a REC-only purchase scenario. Therefore, any suggestion that PSE's economic analyses failed to evaluate REC purchases is false.[281]

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[277] Norwood, Exh. No. SN-1CT 42:10-12.
[278] Seelig, Ex. No. AS-4HCT 29:1–35:6.
[279] *See, e.g., WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order No. 12 ¶ 20 (April 7, 2004) ("The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects . . . at the time of a purchase decision.").
[280] Norwood, Exh. No. SN-1CT 43:4-6.
[281] Seelig, Ex. No. AS-4HCT 35:7–40:2.

138. Seventh, Public Counsel and ICNU erroneously assert that PSE's "[discounted cash flow] analysis did not evaluate any 'No Early Wind' scenario" and that such analysis only considered the difference in capital costs between alternative wind resource plans.[282] In fact, PSE conducted a discounted cash flow analysis in January 2010 that (i) evaluated a "No Early Wind" scenario and (ii) included an estimate of the market value benefit of wind energy relative to the incremental operating cost and transmission of wind projects. This analysis projected that the lowest cost wind development was about 800 MW by the end of 2012, which was similar to the results produced by earlier discounted cash flow model analyses that projected the lowest cost wind development was about 600 MW by the end of 2012 and the second lowest cost wind development was about 800 MW by the end of 2012. Thus, the arguments of Public Counsel and ICNU with respect to PSE's discounted cash flow analyses are incorrect because such arguments do not consider the discounted cash flow analyses conducted by PSE in January 2010.[283]

139. Finally, Public Counsel's cross-examination of Ms. Seelig, PSE's quantitative witness, focused extensively on PSE's PSM III optimization model and what Public Counsel characterizes are "errors" in such model because PSE discovered that such model did not always arrive at the optimal result.[284] The PSM III optimization model is a proprietary model developed by PSE in response to suggestions by Commission Staff that PSE use an optimization model to determine lowest cost portfolios.[285] In essence, the PSM III optimization model is largely the PSM I screening model that PSE has used for many years with the Front Line optimization tool added to provide the optimization functionality. The Front Line optimization tool combined different resources, adds up a portfolio cost, and determines a minimum cost portfolio that meets a variety of constraints that PSE establishes in the model. PSE establishes constraints for the

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[282] Norwood, Exh. No. SN-1CT 43:17–44:9.
[283] Seelig, Exh. No. AS-4HCT 40:4–43:15.
[284] *See, e.g.,* Seelig, TR. 239:10-254:25.
[285] Seelig, TR. 333:15–341:7.

optimization model to reflect better PSE's planning reserve margin, commercial realities about what PSE could build in any one given year, and the availability of governmental incentives.[286]

140. The complex combination of PSE's revenue requirement, the various market price scenarios considered by PSE, and the constraints placed by PSE on the PSM III optimization model did create conditions in which the PSM III optimization model selected suboptimal rather than optimal resource combinations.[287] PSE's analysts understood from the results of the PSM I screening model that several of the best-suited results were close in costs and would, from time-to-time, test the results of the PSM III optimization model by reconfiguring the model to select a resource automatically to test whether such results were in fact optimal. Such tests occasionally confirmed that the optimization model had selected the optimal portfolio and occasionally demonstrated that the optimization model had, in fact, selected a near-optimal portfolio.[288] PSE had no nefarious intent in testing whether the PSM III optimization model had selected the optimal result; indeed, Commission Staff agrees that such testing was appropriate and is an accepted methodology to determine the accuracy of the results.[289]

141. Moreover, Public Counsel's repeated reference at hearing to "errors" identified in the comments tab of the PSM III optimization model is without foundation. As discussed above, PSE modified the PSM I screening model to add an optimization logic to create the PSM III optimization model. The comments tab of the model is an unremarkable document that simply provides the history of the development and refinement of such model. The keeping of such a log is standard in the development and refinement of models, and nothing in such document can be read to suggest that the PSM III optimization model is somehow flawed.[290] Indeed, Public Counsel has failed to identify any specific flaws in the PSM III optimization model and simply provides innuendo for that which is not there.

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[286] Seelig, TR. 333:15–341:7.
[287] Seelig, TR. 336:18–341:7.
[288] Seelig, TR. 338:6–341:7.
[289] Nightingale, TR. 357:7–361:17.
[290] Seelig, TR. 248:3–260:17.

142. In sum, the overwhelming weight of quantitative evidence in this proceeding demonstrates that PSE's decision to construct or acquire renewable resources in advance of RPS target deadlines was cost-justified. Although Public Counsel and ICNU identified a few inconsequential errors in this mountain of evidence, these errors, once corrected, did not alter the end result. By constructing LSR Phase 1 in advance of the RPS target deadlines, PSE recognized significant cost savings that it likely would not have recognized if it had waited to construct or acquire renewable resources in 2016 or later. Indeed, PSE projects that the construction of LSR Phase 1 in 2012 provides net present value benefits that are $190 million higher than the construction of a similarly sized alternative plant in 2016.[291] Public Counsel and ICNU have not—and cannot—demonstrate otherwise in this proceeding.

2. Quantitative and Qualitative Analyses Support PSE's Acquisition of the LSR Phase 1

143. PSE's resource acquisition decisions in the 2010 RFP, which reflect a variety of qualitative and commercial analyses, supported PSE's conclusion that LSR Phase 1 was the renewable resource alternative that was the lowest reasonable cost.[292] No party to this proceeding suggested that PSE failed to meet its burden to evaluate LSR Phase 1 against other available resources or demonstrated that any alternative proposal was superior to LSR Phase 1.

3. PSE Informed and Involved its Board of Directors in the Construction of LSR Phase 1

144. PSE staff regularly kept PSE's Energy Management Committee, PSE's Asset Management Committee, and PSE's Board of Directors informed and involved in the consideration and construction of LSR Phase 1.[293] No party to this proceeding suggested that PSE failed to meet its burden of keeping its Board of Directors informed and involved in the consideration and construction of LSR Phase 1.

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[291] Seelig, Exh. No. AS-4HCT 3:12–6:2.

[292] *See* Garratt, Exh. No. RG-1HCT 47:5–55:14; Seelig, Exh. No. AS-1HCT 19:1-63:3; Exh. No. AS-3HC.

[293] *See* Garratt, Exh. No. RG-1HCT 55:15–59-16; Exh. No. RG-13HC; Exh. No. RG-14HC; Exh. No. RG-15HC; Exh. No. RG-16HC; and Exh. No. RG-17HC.

4. PSE Kept Extensive Contemporaneous Records to Allow The Commission the Opportunity to Evaluate Its Actions With Respect to the Decision Process of LSR Phase 1

145. PSE kept extensive contemporaneous records to allow the Commission the opportunity to evaluate its actions with respect to the decision process, and no party to this proceeding suggested that PSE failed to meet this burden.

B. LSR Phase 1 Became "Used and Useful" Upon Commencement of Operations in February 2012

146. In the Renewable Resource Policy Report the Commission provided further guidance on the used and useful standard in the context of the acquisition or construction of renewable resources to meet the RPS, but in advance of the RPS deadlines:

> We are convinced that the "used and useful" statute does not prevent acquisition of a renewable resource in advance of the RPS deadline. Indeed, in the context of conventional resources, we have allowed resources into rate base before they were needed to meet load.
>
> This conclusion is not driven entirely by the [Energy Independence Act]. However, like the determination of prudency, the enactment of the [Energy Independence Act] assists us in reaching this conclusion. Early acquisition of a renewable resource is "useful" in that it will meet the RPS at some point in the future. It also needs to be "used." Therefore, the utility must show that the resource produces benefits that offset the cost of early acquisition. This could include sale of energy generated from the plant, sale of RECs from the plant, or other value to the company attributable to the acquisition.[294]

147. Public Counsel and ICNU erroneously argue that LSR Phase 1 cannot satisfy the above-described "used and useful" status:

> The LSR 1 project is not needed to meet RPS requirements until 2018 at the earliest, and . . . is not expected to benefit customers when compared to the "No Early Wind" alternative for the next twenty years.[295]

These assertions, however, fail to consider the totality of the circumstances or the benefits that will accrue over the life of the project. As demonstrated in detail in this proceeding, PSE constructed LSR Phase 1 to satisfy the RPS requirements that commence in 2016, and PSE's analytical models demonstrate, without fail, that the construction of LSR Phase 1 will, over the

[294] Renewable Resource Policy Report ¶¶ 55-56.
[295] Norwood, Exh. No. SN-1HCT 50:9-12.

life of the project, provide superior benefits to the "just in time" approach advocated by Public Counsel and ICNU.

148. Public Counsel and ICNU take a very short-sighted view of the cost-effectiveness of LSR Phase 1 by arguing, for example, "all early wind addition scenarios were significantly more costly than the No Early Wind scenario over the next five to ten years."[296] This standard, if adopted by the Commission, would preclude utilities from undertaking virtually any long-term resource acquisitions because, generally speaking, no new resource is cost-effective when compared to the cost of market or REC purchases during the first decade of the life of the project. Additionally, power plant capital costs would be virtually impossible to economically justify over short time horizons because they take years, often decades, to earn a return on and of capital. The Commission should expressly reject the standard suggested by Public Counsel and ICNU because it fails to consider the cost-effectiveness of the plant over its life.

C. PSE Acted Prudently in Executing the Klamath Peakers PPA

149. No party challenges the prudence of PSE's execution of a four-year and two-month power purchase agreement with Iberdrola Renewables, Inc. for 100 MW of winter capacity associated with the Klamath peakers (the "Klamath Peakers PPA"). PSE respectfully requests that the Commission determine that PSE acted prudently in executing the Klamath Peakers PPA.

VII. CSA RATES

150. The Commission should approve PSE's proposed CSA Rates, which are designed to address the reduction of short-term earnings directly resulting from PSE's energy efficiency programs. PSE's testimony in this case documents its long history of pursuing gas and electric energy efficiency[297] and the resulting negative financial impact PSE has suffered because of its pursuit of conservation. No party disputed PSE's testimony and exhibits calculating that PSE

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[296] Norwood, Exh. No. SN-1HCT 20:17-18.

[297] *See generally,* Stolarski, Exh. No. RWS-1T; *see also* Cavanagh, TR: 428:14-16 (citing a collective ambition of Washington utilities to continue to lead the nation in energy efficiency); *id.* 429:6-7 (recalling Puget's aggressive energy efficiency program in 1993).

sponsored energy efficiency will reduce its ability to recover $18 million of costs in the rate year.[298] In fact, NWEC witness Ralph Cavanagh testified regarding the significant financial toll energy efficiency programs take on PSE: "[I]f PSE helped its customers save just one percent of system wide electricity use per year every year for the next five years, the company would automatically lose more than $75 million in authorized recovery of costs unrelated to electricity production."[299]

151. The Legislature requires the Commission to consider policies to protect companies from a reduction of short term earnings resulting from conservation:

> The commission shall consider and may adopt other policies to protect a company from a reduction of short-term earnings that may be a direct result of utility programs to increase the efficiency of energy use. These policies may include allowing a periodic rate adjustment for investments in end use efficiency or allowing changes in price structure designed to produce additional new revenue.[300]

Further, as the Commission has recognized, "[t]he policy of this state promotes the advancement of conservation resources and encourages the Commission to consider incentives for investment in such resources."[301]

152. Approval of PSE's CSA Rates is consistent with state policy and the statutes cited above. In the current historic rate setting process, the rates set by the Commission fail to reflect the ongoing load-reducing effects of conservation that takes place during and after the test year.[302] PSE has experienced, and continues to face, a reduction in short term earnings as a direct result of the load-reducing effect of company sponsored energy efficiency.[303] The CSA allows for

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[298] *See* De Boer, Exh. No. TAD-1T 6:10-14; Exh. No. TAD-4T 3:10-13; Exh. No. JAP-9; Exh. No. JAP-10.

[299] Cavanagh, Exh. No. RCC-1T 2:10-15; *see* Cavanagh, TR: 476:5-9; 461:2-7 (acknowledging that incentives for conservation are out of alignment and PSE's concern about the cost to shareholders of going to a higher conservation target).

[300] RCW 80.28.260(3).

[301] *See WUTC v. Avista Corp.*, Docket Nos. UE-090134, *et al.*, Order 10 ¶ 237 (Dec. 22, 2009) (citing RCW 80.28.024, which states in relevant part: "The legislature finds and declares that the potential for meeting future energy needs through conservation measures . . . may not be realized without incentives to public and private energy utilities. The legislature therefore finds and declares that actions and incentives by state government to promote conservation . . . would be of great benefit to the citizens of this state by encouraging efficient energy use.").

[302] Piliaris, Exh. No. JAP-1T 32:14-17.

[303] Gaines, Exh. No. DEG-1T 26:5-9.

periodic rate adjustments to mitigate the effect energy efficiency has on PSE's ability to recover its fixed costs.[304] In its Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, To Encourage Utilities To Meet Or Exceed Their Conservation Targets ("Policy Statement")[305], the Commission acknowledges this directive from the Legislature and cites to programs such as Avista's limited decoupling program as the Commission's attempt to comply with this directive from the Legislature.[306]

A. The Undisputed Evidence Shows $18 Million in Unrecovered Costs Due to Load Reducing Effects of Conservation

153. The evidence presented by Mr. Piliaris documents the upward trajectory of cumulative conservation savings that occur during the 38 month period between the beginning of an historic test period that is used to set rates and the end of the rate year.[307] New rates set by the Commission for the rate year will not take into consideration much of the load-reducing effects of conservation that have occurred since the start of the test year. Specifically, the rates in the rate year do not include:

- Roughly half of the conservation achieved in the test year, plus
- All of the conservation achieved between the end of the test year and the beginning of the rate year, plus
- Half of the conservation achieved in the rate year.[308]

154. PSE's CSA Rates proposal uses a bottom up approach[309] to determine the actual conservation savings that occur from the beginning of the test period to the end of the rate year. PSE then determines the amount of these savings that are not included in rates during the rate

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[304] Piliaris, Exh. No. JAP-1T 26:5-6.

[305] *In the Matter of the Wash. Utilis. & Transportation Comm'n Investigation into Energy Conservation Incentives*, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, Docket No. U-100522 (Nov. 4, 2010).

[306] Policy Statement at ¶¶ 16-17.

[307] Exh. No. JAP-8.; Piliaris, Exh. No. JAP-1T 27-29.

[308] Piliaris, Exh. No. JAP-1T 29:3-7.

[309] *See WUTC v. Avista*, Docket Nos. UE-090134, *et al.*, Order No. 10 ¶ 295 (Dec. 22, 2009) (endorsing the use of a bottom up approach to determining lost margin resulting from company-sponsored conservation by starting with evidence of programmatic conservation efforts, adding the ascertainable impacts of educational efforts, and fixing the amount for deferral and later recovery).

effective period due to regulatory lag in the ratemaking process and multiplies these savings by the portion of volumetric retail rates unrelated to power or gas supply and not otherwise recovered through fixed charges results.[310] Based on this bottom up approach, the evidence shows that company-sponsored energy efficiency results in unrecovered costs of $18 million that PSE will experience during the rate year in this case without the CSA.[311]

B. The CSA Is Permissible Under the Commission's Policy Statement

155. Despite the undisputed evidence of PSE's inability to recover its costs due to conservation, and the statutory mandate that the Commission consider policies to protect PSE from this loss of earnings, several parties urge the Commission to reject the CSA Rates, claiming that they fail to precisely conform with the Commission's guidance in its Policy Statement.[312] The Commission should not be swayed by these overly rigid approaches that fail to recognize the flexible and non-precedential nature of policy statements. These parties also fail to recognize that the Commission authorized "other" mechanisms in the context of a general rate case besides those expressly discussed in the Policy Statement.[313]

156. Washington law, Commission rules, and the Policy Statement all recognize the advisory nature of policy statements. The Policy Statement is not binding and cannot be relied upon as establishing any binding requirements;[314] it cannot be used as the basis for any Commission determination regarding the merits of a lost margin recovery mechanism. Any such reliance violates the bedrock principle of administrative law that agencies cannot rely on interpretive and policy statements as though they are enforceable rules. The Policy Statement was not adopted with the panoply of procedural safeguards that are required in a rulemaking—such as, most

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[310] Piliaris, Exh. No. JAP-1T 32:18-33:13.

[311] Piliaris, Exh. No. JAP-1T 30:12-18.

[312] *See, e.g.,* Reynolds, Exh. No. DJR-1T 18:9-19:6; Crane, Exh. No. ACC-1T 24:9-11.

[313] Policy Statement at ¶ 34 ("The guidance provided in this policy statement does not imply that the Commission would not consider other mechanisms in the context of a general rate case, including an appropriate attrition adjustment designed to protect the company from lost margin due to any reason.").

[314] *See, e.g., Wash. Education Ass'n v. Wash. State Public Disclosure Comm'n*, 150 Wn.2d 612, 619 (2003) ("advisory statements have no legal or regulatory effect").

fundamentally, the right to appeal the Commission's determinations.[315]

157. Commission Staff acknowledges that the Policy Statement is not binding and a party may propose another mechanism beyond those described in the Policy Statement and the Commission is "obligated to give that proposal its full and fair consideration."[316] Nevertheless, Commission Staff's testimony on the CSA urges the Commission to reject PSE's CSA Rates proposal because it fails to meet the requirements of the Policy Statement.[317]

158. PSE viewed the Policy Statement as precisely what it is under Washington law: advisory only, and specifically providing advice to the public on the Commission's current opinions, approaches, and likely courses of action.[318] Nonetheless, PSE presented its CSA Rates proposal in the context of issues and proposed criteria raised by the Commission in its Policy Statement including found margin,[319] low income conservation programs,[320] effect on energy efficiency,[321] application to customer classes,[322] impact on customer rates,[323] earnings test,[324] accounting for

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[315] *See, e.g., Pac. Gas and Elec. Co. v. Fed. Power Comm'n*, 506 F.2d 33, 38-39 (D.C. Cir. 1974) ("A general statement of policy, on the other hand, does not establish a 'binding norm. It is not finally determinative of the issues or rights to which it is addressed. The agency cannot apply or rely upon a general statement of policy as law because a general statement of policy only announces what the agency seeks to establish as policy. A policy statement announces the agency's tentative intentions for the future. When the agency applies the policy in a particular situation, it must be prepared to support the policy just as if the policy statement had never been issued. *An agency cannot escape its responsibility to present evidence and reasoning supporting its substantive rules by announcing binding precedent in the form of a general statement of policy*.").

[316] Commission Staff Response to PSE's objection to Bench Request No. 3, ¶ 5 ("By definition, the Decoupling Policy Statement is advisory only. It does not bind any party in any proceeding. Thus, *while parties would certainly be wise to discuss the Decoupling Policy statement when making a decoupling proposal, parties are free to propose the mechanism of their choice, and the Commission is obligated to give that proposal full and fair consideration*.").

[317] *See, e.g.,* Reynolds, Exh. No. DJR-1T 14:12-14 ("The Commission should reject the CSA because PSE's direct case *fails a threshold requirement* to evaluate the proposal pursuant to the Commission's Decoupling Policy Statement.") (emphasis added); *id.* at 14:("Should the Commission go further in its analysis, it should reject the CSA because the CSA is a form of limited decoupling applicable to electric operations, and the Decoupling Policy Statement *confines* limited decoupling to natural gas operations.") (emphasis added); *id.* at 20:13-21 (stating that the Commission "*approved* full decoupling for electric utilities" but not limited decoupling and therefore the Commission should reject the CSA as a threshold matter) (emphasis added) .

[318] *See* RCW 34.05.230(1); WAC 480-07-920.

[319] *See, e.g.,* DeBoer, Exh. No. TAD-1T 13-20.

[320] See Piliaris, Exh. No. JAP-24T 8:2-4.

[321] DeBoer, Exh. No. TAD-1T 25:7-20.

[322] DeBoer, Exh. No. TAD-1T 17:10-21:2.

[323] DeBoer, Exh. No. TAD-1T 23:17-25:20.

[324] Piliaris, Exh. No. JAP-1T 42:21-43:10.

and true up.[325]

C. The Commission Should Not Impose Upon PSE a Mechanism It Did Not Request

1. PSE's Objection to Bench Request 3

159. PSE renews its objection to Bench Request No. 3.[326] First, in the Bench Request, the Commission—the decision maker in this rate proceeding—is improperly influencing the nature and content of evidence entered into the record in this proceeding. The Bench Request improperly communicates to the parties that the Policy Statement only allows for full electric decoupling; effectively pre-judging PSE's proposal and biasing the record. Second, the Bench Request may result in the imposition of a type of regulatory mechanism for addressing fixed cost recovery that PSE did not request in this general rate case. The Bench Request suggests that, rather than investigating whether PSE's proposed CSA is fair, just or reasonable, the Commission is only interested in whether some *other* rate mechanism, which PSE has not proposed, might also be fair, just and reasonable. By directing parties to focus their attention on full decoupling as opposed to fairly evaluating PSE's proposal, the Commission is exceeding its statutory authority. Third, the Bench Request, in referencing the Commission's Policy Statement, suggests that the Commission has a policy preference for full decoupling that is inconsistent with the language of the Policy Statement. As discussed above, the Policy Statement allows for options other than full decoupling.

2. NWEC's Decoupling Proposal Does Not Address PSE's Needs

160. NWEC's decoupling proposal fails to address PSE's concern regarding the financial consequences of its energy efficiency program, particularly as it relates to recovery of its fixed costs not recovered through the PCA and PGA mechanisms.[327] Although Mr. Cavanagh recognized that PSE stands to lose tens of millions of dollars as a direct result of conservation—

[325] Piliaris, Exh. No. JAP-1T 41:13-42:10; JAP-21.
[326] *See* Puget Sound Energy, Inc.'s Objection to Bench Request No. 3 (October 10, 2011).
[327] DeBoer, TR. 525:4-17.

and, specifically, PSE's unrecovered fixed costs due to conservation[328]—he candidly admitted that NWEC's decoupling proposal does not address PSE's cost recovery concerns.

3. Staff's Proposal To Address Attrition Lacks Sufficient Detail

161. PSE appreciates Commission Staff's acknowledgement of the need to address regulatory lag and attrition in some fashion.[329] However, Staff's proposal is not sufficiently developed to implement as proposed. PSE is willing to meet with parties to work together to try to develop a reasonable proposal for an expedited rate case process or formalized attrition adjustment.[330] The Commission lacks workable, understandable standards for attrition adjustments, as the evidence in this case demonstrates.[331] While such mechanisms could address some of PSE's concerns regarding under earning, they would still leave unaddressed the lack of recovery of fixed costs resulting from conservation that occurs during the test year, rate case proceeding and rate year—even with an expedited rate proceeding.[332]

D. There Is No Evidence To Support an ROE Adjustment

162. The CSA Proposal adequately protects customers from potential over-earning by PSE by including an earnings test that limits PSE's ability to recover costs through CSA Rates if recovery of such costs would cause PSE to earn in excess of its authorized rate of return.[333] It makes no sense to lower PSE's authorized return on equity where, as here, PSE has been under-earning its ROE and the CSA Rates are designed to remove one of the mandated obstacles that limits PSE's ability to earn its authorized return.[334] Moreover, no party could provide a specific quantification of the risks that would be avoided by PSE with the implementation of the CSA

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[328] Cavanagh, TR: 450:2-11 (agreeing with PSE's concern that NWEC's decoupling proposal does not address PSE's cost recovery problem); Cavanagh, Exh. No. RCC-1T 12:10-11 (concluding that "a switch to per-customer decoupling does not appear to create any substantial advantages for shareholders compared to status quo practices.…").
[329] Elgin, Exh. No. KLE-1T 80:17-81:2.
[330] Story, Exh. No. JHS-18T 60:20-61:10.
[331] Story, Exh. No. JHS-18T 55:1-61:10.
[332] Piliaris, TR. 655:7-10.
[333] Piliaris, Exh. No. JAP-1T 3:3-6.
[334] Gaines, Exh. No. DEG-14T 24:14-15.

mechanism.[335] Mr. Gorman testified that his 20 basis point ROE reduction for the CSA is "largely a gut level reaction."[336] NWEC witness Mr. Cavanagh testified that "the majority of commissions have not made a prospective downward adjustment"[337] but instead have elected to wait and see if there is a discernable effect over time on cost of equity.[338] Mr. Cavanagh further testified that the only study of which he was aware over the past 30 years showed a slight increase in the cost of equity with decoupling.[339] Further, Ms. Reynolds conceded on cross examination, there is limited information on the effects of decoupling mechanisms on a company's ROE.[340]

E. Known and Measurable Is Not the Appropriate Standard

163. The Commission requires PSE to demonstrate its compliance with biennial conservation targets and ten-year conservation potential mandated by the Energy Independence Act, Chapter 19.285, RCW. PSE must pursue all achievable, cost-effective conservation. Commission Staff, Public Counsel and other parties to this case participate in that process, monitoring PSE's targets and reviewing PSE's conservation savings.[341] Yet, in this case, Commission Staff and Public Counsel reverse course completely and argue that PSE's conservation savings are not sufficiently rigorous or verifiable for purposes of PSE's proposed CSA Rates calculations.[342] These parties cannot have it both ways. If PSE's conservation savings are sufficiently rigorous for purposes of setting state-mandated conservation targets and determining compliance with those targets—including whether PSE should be penalized for failing to meet those targets—they are also sufficiently rigorous for determining conservation that occurs between the start of the test year and the end of the rate year. The reasonableness of PSE's use of documented

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[335] Cavanagh, TR. 436:15-19 ("[I]n the record of this proceeding, there is no actual evidence on the effect on cost of capital for any decoupled utility in the country.").
[336] Gorman, TR. 424:14-18.
[337] Cavanagh, TR. 436:4-5.
[338] Cavanagh, TR. 436:9-14.
[339] Cavanagh, TR. 475:21-476:9.
[340] Reynolds, TR. 761-762.
[341] *See generally* Exh. No. RWS-5.
[342] Reynolds, Exh. No. DJR-1T 31:8-10; Crane, Exh. No. ACC-1T, 24:4-6.

conservation savings is particularly true in light of (1) the significant evaluation, measurement and verification ("EM&V") that PSE undertakes; (2) the much laxer standards that have been used to determine load-reducing effects of conservation in Commission-authorized limited decoupling programs; and (3) the delay in recovering 25 percent of costs under the CSA Rates proposal, which allows for additional time for verification of conservation savings and adjustment as needed.

1. PSE Undertakes Significant EM&V of Its Conservation Savings

164. Mr. Stolarski described the extensive EM&V of conservation savings that PSE undertakes. PSE's spent $3.2 million evaluating its conservation programs in the 2010-2011 biennium and spent an additional $2.6 million in measurement and verification activities in 2011. PSE projects an EM&V budget of $4.7 million in the 2012-2013 biennium.[343] Mr. Stolarski provides detailed testimony and exhibits demonstrating PSE's EM&V process, including on-site verification by PSE engineers and third-party evaluators.[344] As Mr. Stolarski testified at hearing, the energy savings ascribed to conservation measures are much more than just "estimates."[345] A recent KEMA review of PSE's measurement and verification processes found that they "are either in line with or exceed similar practices among utility peers."[346]

Although Commission Staff witness Deborah Reynolds at one time seemed to propose a "statistically significant post-implementation analysis" standard,[347] on cross examination she acknowledged it would be difficult to implement statistically significant post implementation analysis for all of PSE's conservation programs,[348] and Mr. Stolarski explained in his testimony why such a standard is not feasible.[349]

[343] Stolarski, Exh. No. RWS-1T 6:4-14.
[344] Stolarski, Exh. No. RWS-1T 9-16.
[345] Stolarski, TR. 718:6-7.
[346] Stolarski, Exh. No. RWS-1T 15:19-16:1; Exh. No. RWS-5.
[347] *See* Reynolds, Exh. No. DJR-5CX.
[348] Reynolds, TR. 758:4-9.
[349] Stolarski, Exh. No. RSW-1T 19:6-20:4.

165. Curiously, Commission Staff argues that PSE's verified conservation savings are not rigorous enough for ratemaking.[350] Yet customers paid approximately $200 million in the 2010-2011 biennium for conservation programs under Schedule 120 based on PSE's conservation program and budget. PSE has filed a similar tariff budget for the 2012-2013 biennium.[351]

2. The CSA Rates Employ a Much More Solid Foundation For Determining Conservation Savings Than Does the Avista Limited Decoupling Mechanism approved by the Commission

166. While Commission Staff Witness Deborah Reynolds at times seemed to take the position that a known and measurable standard should be applied to the CSA Rates proposal,[352] such a standard has not been applied to other decoupling-like mechanisms approved by this Commission. In fact, Ms. Reynolds describes the method for calculating conservation savings in Avista's limited decoupling mechanism as "more art than science."[353] The looseness of the conservation savings in Avista's decoupling mechanism can be seen by the fact that the Commission originally set the amount in Avista's deferral attributable to conservation at 90 percent and dropped it to 45 percent less than three years later. Ms. Reynolds conceded on cross examination that neither deferral amount was based on a known and measurable standard.[354] Yet, despite the lack of a "known and measurable" basis for determining company-sponsored conservation, the Commission described Avista's limited decoupling mechanisms as "designed to protect Avista from loss of earnings that are a 'direct result' of the company's conservation programs, both programmatic and educational."[355] PSE's bottom up approach to determining company-sponsored conservation, which relies on the verified savings PSE uses for compliance with conservation targets, is sufficiently rigorous, especially when viewed in light of the standard that has been applied by the Commission to similar programs. It would be arbitrary and capricious for the Commission to apply a known and measurable standard to PSE's CSA Rates,

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[350] Reynolds, Exh. No. DJR-1T 31:8-10.
[351] Exh. No. RWS 16-CX.
[352] Reynolds, Exh. No. DJR-1T 30:2-7.
[353] Reynolds, TR. 758:22-759:5.
[354] Reynolds, TR. 760:9-11.
[355] Policy Statement at ¶ 17.

when the Commission has not applied such standard in past cases involving similar mechanisms and no such standard exists for this type of mechanism in Washington law.

3. The Delay in Recovering 25 Percent of the CSA Rates Provides Additional Assurances that the Conservation Savings Are Accurate

167. The structure of the CSA Rates—with a year delay in recovering the final 25 percent of the CSA Rates—provides additional assurance regarding the veracity of the conservation savings on which the CSA Rates are based. As Mr. DeBoer testified, "PSE is attempting to strike a balance between timely cost recovery and confidence in its reported energy efficiency savings by holding back 25 percent of the cost recovery until the underlying savings have been verified."[356] Further, PSE proposes that recovery of these costs be conditioned upon third-party verification of the savings used to derive the CSA Rate.[357] This third-party verification would be similar to the one-time third-party verification to which PSE agreed as part of the settlement of its 2010-11 biennium conservation target.[358] Further, as Mr. Stolarski testified, "PSE is willing to work with the parties to determine a level of analytical rigor that balances cost, timing, risk and technical feasibility."[359]

F. Other Issues Raised By Parties Do Not Preclude Approval of CSA Rates

168. PSE provides and has provided significant conservation programs to low-income customers as described in the testimony.[360] The Commission should reject other parties' claims to the contrary. This is not a reasonable or valid basis for denying PSE's CSA Rates proposal. Moreover, as Ms. Reynolds conceded on cross examination, there is limited information available regarding the effect of decoupling type programs on low income customers.[361]

169. The misapplied concept of "found margin" does not preclude the Commission from approving PSE's CSA Rates. PSE witnesses Mr. DeBoer and Mr. Piliaris point out the

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[356] DeBoer, Exh. No. TAD-1T 21:17-20.
[357] DeBoer, Exh. No. TAD-1T 22:3-4.
[358] Exh. No. RWS-5 at 9; Stolarski, Exh. No. RWS-1T 20:7-18.
[359] Stolarski, Exh. No. RWS-1T 23:21-24:3.
[360] DeBoer, Exh. No. TAD-1T 25:7-20; Stolarski, Exh. No. RWS-1T 25:1-27:3.
[361] Reynolds, TR. 761-62.

inconsistencies between current ratemaking methodology and the concept of "found margin" as set forth by the Commission in its Policy Statement and relied upon by parties in this case.[362] Customer and use-per-customer growth have historically helped utility revenue growth keep pace, at least in part, with cost growth. Simply put, what the Commission considers "found margin" is required for the successful application of historic test year ratemaking, particularly in an environment of increasing costs. Offsetting the effects of energy efficiency with so-called "found margin" ignores this reality, hindering the ability of a utility's revenue growth to keep pace with its growth in costs.[363] For total revenues (i.e., customers multiplied by revenue-per-customer) to "match" total expenses (i.e., customers multiplied by cost-per-customer) in the test year and rate year, any increase in expense-per-customer between these two points in time must be accompanied by a similar increase in revenue-per-customer.[364]

170. The legislative mandate that the Commission consider policies to protect a utility from a reduction in short term earnings that may be a direct result of conservation does not make an exception for "found margin." Indeed, "found margin," as defined by the Commission in its Policy Statement, is not caused by conservation and should not be considered an offset to lost margin—which is a direct result of conservation. Moreover, the Commission's stated concern with "found margin" is that a company may earn more than its authorized rate of return,[365] but PSE has put protections in place so that the CSA Rates will not cause it to over earn.

VIII. ELIMINATION OF SQI 9: DISCONNECTION RATIO

171. The Commission should approve PSE's proposal to permanently eliminate Service Quality Index 9 ("SQI 9"): Disconnection Ratio (and the associated benchmark, penalty and inclusion in the annual report card), in order to ensure fair customer treatment. Placing an

[362] Piliaris, Exh. No. JAP-24CT 17:3-18:12; DeBoer, Exh. No. TAD-4T 15:13-19:9.

[363] DeBoer, Exh. No. TAD-1T 14:2-4. *See WUTC v. PSE,* Dockets UE-090704 and UG-090705, Order 11 at ¶ 223 (April 2, 2010).("The theory, well supported by ratemaking theory and past commission practice, is that once the relationship [between revenues and expenses] is set [in the historic test year], it will continue to provide appropriate income to the company in the future. If the utility hooks up new customers, the revenues and expenses will increase in the same proportion as existed in the test year.").

[364] DeBoer, Exh. No. TAD-1T 15:3-7; DeBoer, TR. 527:9-528:1.

[365] *See* Policy Statement, ¶ 11.

arbitrary cap on the number of disconnections does not improve service quality; however, it does result in arbitrary and unequal treatment of customers in violation of Washington law.[366] Those customers who fail to pay for service at the beginning of the year will be disconnected while those customers who fail to pay later in the year, when the cap is reached, will not be disconnected. No party presented testimony against permanently discontinuing SQI 9 in this proceeding, and Commission Staff supports its permanent elimination.[367]

IX. OTHER PROPOSALS AND ISSUES

A. Company Airplane

172. PSE provided evidence in this case that the corporate aircraft is more economical than other forms of travel available, in compliance with the Commission's order.[368] No party contested this evidence.

B. Low Income Funding

173. PSE takes no position on The Energy Project's proposal to increase the low income funding level from $15,541,000 to $20,175,000.[369] However, The Energy Project has provided no support for its theory that PSE payment assistance should be comparable on a percentage of revenue basis with the other utilities in the state. Each utility service territory is unique and there is no rational basis to link the level of funding to a percentage of a utility's revenue. If the Commission determines that The Energy Project has met its burden of proof and approves this increase in ratepayer funding, the increase in ratepayer funding should take place as part of the normal ongoing annual true-up compliance filing (on August 31, 2012), as provided for in the original settlement terms for low income payment assistance.[370]

C. LSR Treasury Grant

174. Mr. Schooley requests that the Commission order PSE to defer the LSR Treasury Grant

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[366] McLain, TR. 788:9-14; Kouchi, Exh. No. RK-1T 7:17-8:2.
[367] Kouchi, Exh. No. RK-1T.
[368] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 201 (April 2, 2010).
[369] *See* De Boer, Exh. No. TAD-4T 19:14-20.
[370] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 and UG-011571, Twelfth Supp. Order, App. A (June 20, 2002).

to allow parties the opportunity to review how the Treasury Grants should be handled for ratemaking treatment.[371] Although Treasury Grants are not an issue in this proceeding PSE does not object to deferring the LSR Treasury Grant and reflecting the appropriate ratemaking treatment, with any associated impact on the Wild Horse Treasury grant, in its November 2012 Schedule 95A filing. In this short interim period, PSE would deposit the funds into an interest bearing account and defer the interest.

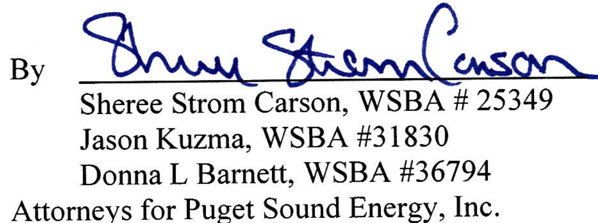
X. CONCLUSION

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

DATED this 16th day of March, 2012.

Respectfully submitted

PERKINS COIE LLP

By 

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[371] Schooley, Exh. No. TES-1T 4:15-18.

APPENDIX A

The table below presents the contested combined electric and natural gas non-rate base adjustments and associated differences in net operating income ("NOI").

Contested Combined Electric and Natural Gas Non-Rate Base Adjustments

Adjustment	NOI
Federal Income Tax (Adjustments 21.04 and 13.04)	($89,305,652)
Tax Benefit of Pro Forma Interest (Adjustments 21.05 and 13.05)	$71,116,599
Miscellaneous Operating Expenses (Adjustments 21.06 and 13.06)	($4,047,271)
Incentive Pay (Adjustments 21.10 and 13.10)	$728,840
Property Taxes (Adjustments 21.11 and 13.11)	($5,028,217)
Directors and Officers Insurance (Adjustments 21.13 and 13.13)	$56,960
Rate Case Expenses (Adjustments 21.15 and 13.15)	($98,313)

APPENDIX B

The table below presents the uncontested combined electric and natural gas non-rate base adjustments and associated differences in net operating income ("NOI").

Uncontested Combined Electric and Natural Gas Non-Rate Base Adjustments

Adjustment	NOI
Temperature Normalization (Adjustment 13.01 and 21.01)	$19,622,696
General Revenues and Expenses (Adjustments 21.02 and 13.02)	($18,265,155)
Pass-Through Revenue & Expense (Adjustment 13.03 and 21.03)	($151,721)
General Plant Depreciation (Adjustment 13.07 and 21.0 and 21.07)	$1,073,452
Injuries & Damages (Adjustment 13.08 and 21.08)	($779,928)
Bad Debt (Adjustment 13.09 and 21.09)	$3,212,612
Excise Tax & Filing Fee (Adjustment 13.12 and 21.12)	($250,235)
Interest on Customer Deposits (Adjustment 13.14 and 21.14)	($68,854)
Deferred G/L on Property Sales (Adjustment 13.16 and 21.16)	($1,120,911)
Property & Liability Insurance (Adjustment 13.17 and 21.17)	($88,725)
Pension Plan (Adjustment 13.18 and 21.18)	($1,782,772)
Wage Increase (Adjustment 13.19 and 21.19)	($2,282,253)
Investment Plan (Adjustment 13.20 and 21.20)	($124,237)
Employee Insurance (Adjustments 21.21 and 13.21)	($16,752)

APPENDIX C

The table below presents the contested electric non-rate base adjustments and associated differences in net operating income ("NOI").

Contested Electric Only Non-Rate Base Adjustments

Adjustment	NOI
Power Costs (Adjustment 20.01)	$111,802,838
Lower Snake River Project (Adjustment 20.02)	($37,445,852)
LSR Prepaid Transmission Deposit (Adjustment 20.03)	($726,665)
Montana Electric Energy Tax (Adjustment 20.04)	($103,079)
Storm Damage (Adjustment 20.07)	$1,349,514
Chelan PUD Payments (Adjustment 20.09)	($4,607,243)
Regulatory Assets and Liabilities (Adjustment 20.10)	$3,683,316
Production Adjustment (Adjustment 20.11)	$2,317,637
LSR Deferral (Adjustment 20.12)	($3,012,122)

APPENDIX D

The table below presents the uncontested electric non-rate base adjustments and associated differences in net operating income ("NOI").

Uncontested Electric Only Non-Rate Base Adjustments

Adjustment	NOI
Wild Horse Solar (Adjustment 20.05)	$179,073
ASC 815 (Adjustment 20.06)	$108,519,513
Remove Tenaska (Adjustment 20.08)	$30,284,100

APPENDIX E

The table below presents the uncontested natural gas non-rate base adjustments and associated differences in net operating income ("NOI").

Uncontested Natural Gas Only Non-Rate Base Adjustments

Adjustment	NOI
Water Heater Depreciation (Adjustment 12.01)	$4,071,209
Reclass Bare to Wrapped Steel (Adjustment 12.02)	($195,347)
Contract Charges (Adjustment 12.03)	$640,161

APPENDIX F

The table below presents the contested combined electric and natural gas rate base adjustments and associated differences in rate base.

Contested Combined Electric and Natural Gas Rate Base Adjustments

Adjustment	Rate Base
Federal Income Tax (Adjustments 21.04 and 13.04)	$0
Working Capital (Adjustments 21.22 and 13.22)	($1,891,576)

APPENDIX G

The table below presents the uncontested combined electric and natural gas rate base adjustments and associated differences in rate base.

Uncontested Combined Electric and Natural Gas Rate Base Adjustments

Adjustment	Rate Base
General Plant Depreciation (Adjustment 13.07 and 21.0 and 21.07)	($346,836)

APPENDIX H

The table below presents the contested electric rate base adjustments and associated differences in rate base.

Contested Electric Only Rate Base Adjustments

Adjustment	Rate Base
Lower Snake River Project (Adjustment 20.02)	$669,984,171
LSR Prepaid Transmission Deposit (Adjustment 20.03)	$110,846,093
Chelan PUD Payments (Adjustment 20.09)	$135,630,302
Regulatory Assets and Liabilities (Adjustment 20.10)	($19,546,418)
Production Adjustment (Adjustment 20.11)	($50,017,853)
LSR Deferral (Adjustment 20.12)	$10,444,648

APPENDIX I

The table below presents the uncontested electric rate base adjustments and associated differences in rate base.

Uncontested Electric Only Rate Base Adjustments

Adjustment	Rate Base
Wild Horse Solar (Adjustment 20.05)	($3,370,636)
Remove Tenaska (Adjustment 20.08)	($56,496,129)

APPENDIX J

The table below presents the uncontested natural gas rate base adjustments and associated differences in rate base.

Uncontested Natural Gas Only Rate Base Adjustments

Adjustment	Rate Base
Water Heater Depreciation (Adjustment 12.01)	($2,218,846)
Reclass Bare to Wrapped Steel (Adjustment 12.02)	($97,673)

APPENDIX K
Electric Revenue Requirement

	Rate Base	$4,896,732,494
×	Rate of Return	8.26%
	Operating Income Requirement	$404,470,104
−	Pro Forma Operating Income	$326,627,188
	Operating Income Deficiency	$77,842,917
÷	Conversion Factor	62.07490%
	Revenue Requirement Deficiency	$125,401,598
−	Large Firm Wholesale	$427,352
−	Sales from Resale-Firm	$164,110
	Revenue Requirement Deficiency	**$124,810,136**

APPENDIX L Gas Revenue Requirement		
	Rate Base	$1,657,792,777
×	Rate of Return	8.26%
	Operating Income Requirement	$136,933,683
−	Pro Forma Operating Income	$119,149,110
	Operating Income Deficiency	$17,784,573
÷	Conversion Factor	62.149%
=	**Revenue Requirement Deficiency**	**$28,616,025**

APPENDIX M
PSE's Proposed Capital Structure and Rate of Return

Capital Component	Capital Structure	Cost Rate	Weighted Cost
Short-Term Debt	4.0%	2.68%	0.11%
Long-Term Debt	48.0%	6.22%	2.99%
Common Equity	48.0%	10.75%	5.16%
Overall Rate of Return	**100.0%**	**N/A**	**8.26%**