[Service Date May 7, 2012]

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKETS UE-111048 and UG-111049 (*consolidated)*
Complainant,	)	ORDER 08
v.	)	
PUGET SOUND ENERGY, INC.,	)	REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING
Respondent.	)	
. . . .	)	

Synopsis: *The Commission rejects previously suspended tariff sheets Puget Sound Energy, Inc. (PSE or the Company) filed on June 13, 2011, by which the Company proposed to increase electric rates by 8.1 percent and natural gas rates by 3.0 percent. In lieu of the Company's proposed increases in rates, the Commission authorizes and requires PSE to file tariff sheets that will result in fair, just, reasonable and sufficient rates that will increase electric rates by approximately 3.2 percent and natural gas rates by approximately1.3 percent.*

The Commission reduces PSE's overall rate of return but increases the percent of equity in the Company's capital structure. This gives ratepayers the benefit of lower debt costs that reflect the Company's financial strength while providing support to PSE's ability to earn its authorized return during a period of heightened capital investment.

The Commission recognizes PSE's current need to replace aging transmission and distribution infrastructure and to add cost-effective renewable resources to its portfolio of power production assets to meet Renewable Portfolio Standards mandated by the Energy Independence Act. This is exemplified in this case by the approval of PSE's acquisition and construction of the first phase of the Lower Snake River wind power project as a prudent investment.

This Order requires PSE to update its power costs to a point contemporaneous in time with its effectiveness. This gives the Company's customers the full benefit of declining natural gas prices that are a key driver of these costs. At the same time, *this protects the Company by authorizing for recovery in rates a level of power costs that best reflect what its power cost model forecasts for the rate year. The Commission also authorizes and requires PSE to update and use its most recent actual property tax liability when calculating rates that comply with the requirements of this Order.*

The Commission considered generally in this case the possibility of full decoupling for PSE and specifically considered such a proposal presented by the Northwest Energy Coalition. Full decoupling would separate PSE's recovery of its fixed costs from the level of its energy sales, thus insulating the Company from the effects of load reductions due to conservation and other factors. PSE, however, made clear its opposition to full decoupling as discussed in the Commission's 2010 Interpretive and Policy Statement. The Commission agrees with PSE in this Order that it should not impose on the Company a decoupling mechanism that it not only did not request, but affirmatively opposed.

The Commission rejects PSE's proposed new Conservation Savings Adjustment tariff (CSA) that the Company proposed as a means to insulate itself from revenue losses it attributes to electric load lost due to its conservation efforts. The record establishes that the CSA is foundationally flawed because it depends on fixed costs that are not reliably measured and engineering estimates of conservation savings that are ill-suited to development of a revenue requirement, as PSE proposes. In addition, the Commission finds the CSA, as proposed, produces unacceptable results, including significant potential for recovery of revenue not actually lost due to the Company's conservation efforts.

Finally, the Commission recognizes throughout this Order, and specifically in connection with suggestions that the challenges evident in this period when PSE faces the need for unusually high levels of capital investment can be met by established ratemaking mechanisms such as the use of "end of period" rate base, the inclusion of CWIP (construction work in progress)in rate base, the allowance of new generation plant in rate base even when the new facilities are placed in service after the test period, fully supported attrition adjustments, or by the establishment of new regulatory processes.

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SUMMARY

1 **PROCEEDINGS:** On June 13, 2011, Puget Sound Energy, Inc. (PSE), filed with the Washington Utilities and Transportation Commission (Commission) tariff revisions designed to increase rates for electrical and natural gas services provided to customers in Washington. The tariff revisions, if allowed to become effective, would have increased rates to recover additional revenues of approximately 8.1 percent for electrical services and 3.0 percent for natural gas services. The Commission suspended operation of the as-filed tariffs by Order 01 entered in these dockets following its June 30, 2011, open meeting.[1] The Commission convened a prehearing conference in this proceeding at Olympia, Washington on July 20, 2011.

2 At various times established in its procedural schedule, and by several orders, the Commission accepted prefiled testimony and exhibits from the Company, the Commission's regulatory staff (Commission Staff or Staff),[2] and other parties. The Commission conducted evidentiary hearings on February 14 - 17, 2012. In addition, the Commission conducted public comment hearings in PSE's service territory on February 1, 2012, and on February 15, 2012, during which it received into the record oral comments and exhibits from interested members of the public.[3] The parties filed briefs on March 16, 2012, and reply briefs on March 26, 2012.

3 **PARTY REPRESENTATIVES:** Sheree Strom Carson and Jason Kuzma, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitch, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Robert D. Cedarbaum,

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[1] The Commission's Complaint and Order Suspending Tariff Revisions and Consolidation should have been identified as Order 02. Order 01 in this proceeding is the Protective Order entered on June 17, 2011.

[2] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[3] The Commission also received written comments from members of the public through the close of the record on February 24, 2012. These comments are identified in the formal record as Exhibit B-6.

Senior Assistant Attorney General, Olympia, Washington, represents the Commission Staff.

4 S. Bradley Van Cleve and Irion Sanger, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Chad M. Stokes and Tommy A. Brooks, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represents Northwest Industrial Gas Users (NWIGU). Jody M. Kyler, Michael L. Kurtz and Kurt J. Boehm, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent the Kroger Co., on behalf of its Fred Meyer Stores and Quality Food Centers divisions (Kroger). Norman Furuta, Associate Counsel, Department of the Navy, San Francisco, California, represents the Federal Executive Agencies (FEA). Ronald L. Roseman, Attorney, Seattle, Washington, represents the Energy Project. John A. Cameron, Davis Wright Tremaine LLP, represents Cost Management Services, Inc. (CMS). Damon E. Xenopoulos, Brickfield, Burchette, Ritts & Stone, PC, Washington, D.C., represents Nucor Steel Seattle, Inc. (Nucor). Kristen L. Boyles, Todd D. True and Amanda W. Goodin, Earthjustice, Seattle, Washington, represent the Northwest Energy Coalition (NWEC). Gloria Smith and Travis Ritchie, in-house counsel, San Francisco, California, represent the Sierra Club.

5 **COMMISSION DETERMINATIONS**: The Commission suspended and set for hearing the rates PSE originally proposed in its filing on June 13, 2011. Based on the record of this proceeding we find that neither the Company's as-filed rates, nor the revised rate requests PSE made at the conclusion of the advocacy phase, are fair, just and reasonable. On the other hand, we also find that PSE's current rates are insufficient. It therefore falls to us to determine fair, just, reasonable and sufficient rates based on the record.[4]

6 We find revenue deficiencies of $63,319,369 for electric service and $13,389,128 for natural gas service. We authorize PSE to file rates to recover additional revenue in these amounts, in accordance with our decisions approving rate spread and rate design settlements filed by all parties taking an interest in these issues. When thus implemented in compliance with the terms and requirements of this Order, PSE's resulting rates will be fair, just, reasonable and sufficient, and neither unduly

[4] RCW 80.28.020.

discriminatory nor preferential. The Company's new rates will be effective no earlier than May 13, 2012.

7 Among other significant findings and conclusions, we determine that PSE's capital structure should be revised to include a 48 percent equity ratio, balanced with a 48 percent long-term debt ratio and 4 percent short-term debt. This reflects most closely what we anticipate to be the Company's anticipated actual capital structure during the upcoming rate year. In terms of capital costs, we reduce PSE's authorized rate of return on equity from 10.1 percent to 9.80 percent. These determinations, coupled with PSE's lower debt costs that are uncontested, provide lower rates to customers than might otherwise be the case while, at the same time, providing support to PSE by allowing the opportunity for PSE to earn an equity return on its full equity investment.

8 We determine that PSE's acquisition and development of phase 1 of the Lower Snake River wind farm project was prudent and allow for this significant addition to the Company's production rate base. We find this early addition to PSE's power production portfolio vis-à-vis Renewable Portfolio Standards that are mandated by the Energy Independence Act is cost effective over its expected life and provides immediate benefits to customers by providing both energy and capacity without adding to carbon dioxide and other emissions that harm the environment.

9 We required PSE to update its power costs following the filing of Initial and Reply Briefs, using an approach to which all parties who testified concerning these costs agree. The result is to approximate as closely as may be done the actual power costs the Company will incur during the rate year. Setting PSE's power costs taking into account the reductions in natural gas costs that occurred during the pendency of this proceeding decreases significantly the amount of revenue PSE requires in this case relative to what it may have required at inception.

10 We approve settlements of issues concerning rate spread and rate design both for electric operations and natural gas operations. The electric operations settlement also changes the way Renewable Energy Credit (REC) revenues are returned to customers. The settlement provides a bill credit instead of an offset to rate base. A shorter amortization period will return the REC revenue to customers more quickly by shortening the amortization period for the account balances.

11 We also approve a settlement that promises to improve PSE's performance insofar as meter and billing performance standards are concerned. We eliminate one service quality index standard, SQI-9 Disconnection Ratio, because it is shown to have unintended consequences and it does not serve the public interest as intended. We find other rules provide adequate protection to customers who face disconnection for nonpayment of bills.

12 We find reasonable the Energy Project's proposal to increase the funding for PSE's low-income bill assistance program. We direct the Company to file for the increase as part of its ongoing annual true-up compliance filing on August 31, 2012.

13 We reject PSE's proposal for a new tariff that would implement its proposal for a so-called Conservation Savings Adjustment rate. We find that the Company's proposed methods for measuring load loss due to conservation and the level of cost under recovery related to this load are not adequately supported by the evidence. Moreover, we find that the operation of the CSA mechanism, as proposed, would produce unacceptable effects.

14 In the face of opposition from PSE, we reject NWEC's proposal that we order full decoupling. We also discuss certain policy options that could address some of the problems of attrition that PSE describes, including possible under recovery of costs due to implementation of conservation programs.

MEMORANDUM

I. Background and Procedural History

15 Tables 1 and 2 show the electric and natural gas revenue requirement requests and recommendations supported by the Company and parties at various stages of this proceeding.

TABLE 1
Proposed Total Adjustments to Annual Revenue Requirement (Electric)

	As-Filed	Supplemental	Response	Rebuttal/Cross	Per Briefs
PSE	160,681,142[5]	152,337,039[6]		125,401,321[7]	125,401,596
Staff			38,919,000[8]		39,143,649
Public Counsel			89,615,425[9]		
ICNU			39,990,771[10]		
Kroger[11]					

[5] Story, Exh. No. JHS-1T at 2:5-9; Exh. No. JHS-7 at 1. The full revenue deficiency identified in Exh. No. JHS-7 at 1 is $161,275,557 with $429,485 allocated for recovery from "large firm wholesale" customers and $164,930 to be recovered in the form of "sales from resales-firm."

[6] Story, Exh. No. JHS-15 at 1. The full revenue deficiency identified in Exh. No. JHS-1at 5:1 is $152,928,501 with $427,352 allocated for recovery from "large firm wholesale" customers and $164,110 to be recovered in the form of "sales from resales-firm."

[7] Story, Exh. No. JHS-18T at 2:6-10.

[8] Schooley, Exh. No. TES-1T at 3:21-22.

[9] This is an approximate figure because Public Counsel does not present its proposed adjustments in a consistent fashion.

[10] This is an approximate figure because ICNU's evidence is internally inconsistent and difficult to parse. *Compare* Schoenbeck, Exh. Nos. DWS-1CT at 4:22-5:2; DWS-7 at 1; Deen, Exh. No. MCD-1CT at 2:6-8. ICNU joins Public Counsel in proposing to reduce the Lower Snake River revenue requirement by $55 million. Norwood, Exh. No. SN-1 CT at 51:1-2.

TABLE 2
Proposed Total Adjustments to Annual Revenue Requirement (Natural Gas)

	As-Filed	Supplemental	Response	Rebuttal/Cross	Per Briefs
PSE	31,864,884[12]	N/A		28,616,025[13]	28,616,025
Staff			1,526,333 [14]		2,211,414
Public Counsel			27,529,183[15]		

16 The Commission held public comment hearings in Bellevue on February 1, 2012, and in Olympia on February 15, 2012. Twenty-five individuals, all customers of PSE, gave testimony concerning their individual perspectives on the Company's requests for increased rates and related matters (*e.g.*, service quality). In addition, the Commission received into the record written comments from numerous members of the public, principally customers.[16]

17 On February 14 - 17, 2012, the Commission held hearings in Olympia to receive evidence from the parties and to allow them an opportunity to conduct cross-examination of witnesses who prefiled testimony. These hearings also gave the Commission an opportunity to conduct inquiry from the bench. The final transcript consists of more than 1,100 pages and reflects the admission of prefiled testimony and exhibits sponsored by 42 witnesses. The documentary record includes approximately 682 exhibits. The fully developed record, including public comment and detailed

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[11] Kroger made two recommendations concerning the treatment of REC revenue. Higgins, Exh. Nos. KCH-3T at 3:7-18; KCH-4, line 10. Issues concerning REC revenues, however, are resolved by the Commission's approval of an uncontested settlement.

[12] Stranik, Exh. No. MJS-1T at 2:6-8; Exh. No. MJS-7, line 15.

[13] Stranik, Exh. No. MJS-14 at 1, line 12. PSE, however, removes $147,865 from this number as "other operating revenues," bringing the total to $28,468,160. Stranik, Exh. No. MJS-14 at 1, line 15.

[14] Mickelson, Exh. No. CTM-1T at 3:8-9.

[15] Public Counsel recommends two adjustments to Federal Income Tax that would reduce the gas revenue requirement by $1,191,989 (Crane, Exh. No. ACC-4 at 2, line 9) and $3,143,712 (Crane, Exh. No. ACC-4 at 3, line 9).

[16] Exh. No. B-6 (Public Comments).

evidence concerning PSE's revenue requirements and other issues, was closed on February 17, 2012, subject to submission of several responses to Commission bench requests made during and after the hearing.

18 Much of the public comment focused on the difficult economic times that are an important part of the context in which we consider PSE's request for increased rates. Ms. Lisa Clark, Director of the Opportunity Council testified, for example:

> As I walked out the door this morning to come here, I checked with my receptionist. I have five hundred and forty-nine people on a waiting list to have [LIHEAP funding] energy assistance. So the impact at the federal level of cuts is impacting many of our clients, many of the people in my community, many of my neighbors, our friends… It is -- things haven't changed, and the need that I've seen in the last year -- and I've been doing this 15 years -- is unprecedented…We didn't have a waiting list two years ago, because of federal dollars that came through.[17]

Ms. Jan Welker, former social service employee of Providence St. Peter's Hospital, testified: "I heard patients there saying how comfortable they were in the hospital, because they -- it's the first time they could be warm and have enough to eat, both. And this was a number of years ago, and it's gotten worse and worse and worse."[18]

19 We keep such testimony in mind as we make decisions implementing our responsibility to set rates that stimulate efforts on the Company's part to reduce operating costs and increase efficiencies. In the current economic climate, customers must make difficult decisions concerning their spending. So, too, must PSE's management make the right decisions to aggressively control the Company's earnings expectations and expenses, limit discretionary spending, and ensure that its capital investments are prudent.

20 On March 16, 2012, the parties filed simultaneous Initial Briefs. The parties filed simultaneous Reply Briefs on March 26, 2012. We have considered their arguments

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[17] Clark, TR 74:4-9, 12-14; TR 75:12-13.

[18] Welker, TR 575:13-18.

and reviewed the full record in this proceeding. Our discussion and determination of the issues follows below.

II. Discussion and Decisions

A. Introduction

21 The Commission's responsibility in general rate case proceedings is to determine an appropriate balance between the needs of the public to have safe and reliable electric and natural gas services at reasonable rates, and the financial ability of the utility to provide such services on an ongoing basis. In the words of our governing statutes, we are required to determine results that establish "fair, just, reasonable and sufficient" rates for prospective application.[19] This means rates that are fair to customers and to the Company's owners; just in the sense of being based solely on the record developed in this proceeding; reasonable in light of the range of possible outcomes supported by the evidence; and sufficient to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms.[20]

22 As shown above in Tables 1 and 2, the parties advocate results that differ significantly in terms of PSE's revenue requirements. Following long-established principles of utility ratemaking and Commission practices, we must determine on the basis of the evidence presented what levels of prudently incurred expenses the Company will experience, and allow for recovery of those expenses in rates. In addition, we must determine the Company's "rate base" and allow for an appropriate rate of return on that rate base.[21] This is necessary to allow the Company to recover the costs of its investments in infrastructure, repay its lenders, and provide an opportunity for the Company to earn a reasonable return, or profit, some of which may be distributed to its equity investors in the form of dividends. The sum of the two figures – expenses

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[19] RCW 80.28.010(1) and 80.28.020.

[20] *See Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944); *See also Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

[21] Reduced to a simple definition, rate base is the Commission-approved level of PSE's investment in facilities plus the cash, or "working capital" supplied by investors that is used to fund the Company's day-to-day operations. The Commission follows the original cost less depreciation method when determining the value of a utility's property that is used and useful in providing service to customers. *People's Organization for Washington Energy Resources v. Washington Utilities & Transportation Comm'n*, 104 Wn.2d 798, 828, 711 P.2d 319 (1985).

and return on rate base – constitutes the company's revenue requirement that we approve for recovery in rates.[22]

23 In this case, there are a number of contested issues concerning operating expenses, rate base and rate of return. We discuss and resolve each of these issues below, arriving ultimately at revenue requirements to be recovered prospectively by PSE in its electric and natural gas rates.

24 We begin our discussion of the contested issues with the topics of capital structure and costs of capital. We resolve disputes over the appropriate levels of debt and equity to include in the Company's capital structure for purpose of setting rates and disputes concerning rates of return for equity. The key outcome is an overall rate of return that, when applied to our determinations elsewhere of disputed rate base, is a principal driving factor in determining PSE's revenue requirements for electric and natural gas service. This, in turn, affects the level of rates customers will pay.

25 Following our determination of PSE's allowed return, we discuss and resolve the parties' disputes over what adjustments should be authorized for various operating expenses and rate base items, and how certain of these should be accounted for in rate setting.

26 Taking the last step in determining the rates various types of customers will pay, we address rate spread and rate design, which the parties propose to establish on the basis of negotiated settlement agreements that are unopposed. In doing so, we establish how PSE's costs will be allocated to different classes of customers, such as residential, commercial and industrial, and the means by which those costs will be recovered from each customer class in fixed rates and rates tied to levels of use. We also consider the parties' proposed settlement agreement concerning the treatment of revenues the Company receives for the sale of Renewable Energy Credits (RECs) that is allowed under the state Energy Independence Act (EIA).[23]

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[22] *See Id.* at 807-09 (describing ratemaking principles and process).

[23] Codified at RCW 19.285. The EIA resulted from the passage by voters in November 2006 of Initiative Measure No. 937.

27 In connection with the core exercise described above, the Commission is called upon in this proceeding to resolve other disputed issues that follow, in part, from voter initiatives and legislation aimed at environmental protection. In simplest terms, these issues result from the tension between two laudable but conflicting goals: the availability of electric power at reasonable costs and the need to protect the environment from carbon emissions released by fossil fuel generators. In terms of rate impacts, the most significant such issue in this case concerns the prudence of PSE's decision to acquire the Lower Snake River wind generation project. PSE's purchase and development of Phase 1 of this project substantially increases its rate base, and is a key driver of the Company's request for increased revenue.

28 Two parties, ICNU and Public Counsel, argue PSE's acquisition and development of the Lower Snake River wind generation project was imprudent and that the facility is not "used and useful." They argue PSE acquired it too early relative to the dates it is needed to meet mandatory Renewable Portfolio Standards benchmarks and that it is not cost effective. ICNU and Public Counsel recommend that we disallow recovery of a portion of the Company's costs.

29 The Sierra Club, on the other hand, supports PSE's decision to acquire and develop the Lower Snake River wind project, but in this connection argues the Commission should consider whether the Company's ongoing investments in the operation of the Colstrip generation facility, a coal-fired power plant in Montana, should at some point be deemed imprudent. This presumably would encourage, if not compel, PSE to relinquish its substantial interest in this relatively low-cost but high carbon dioxide emitting source of electricity.

30 Another issue we consider is PSE's recommendation that the Commission approve what it calls a Conservation Savings Adjustment (CSA) Rate. This proposal is for a separate tariff under which PSE would recover from its customers fixed costs that are not recovered in general rates when it experiences reductions in load between rate cases directly related to its customers' investment in conservation programs. Whether any such mechanism should be approved for PSE requires the Commission to consider significant policy issues as well as the more pragmatic questions concerning how such a mechanism might be structured to produce results that balance the interests of the Company and its ratepayers.

31 Other policy issues that do not have rate adjustment implications in this proceeding involve the subjects of decoupling PSE's fixed cost recovery from sales volumes, [24] earnings attrition and regulatory lag. We consider and express our preliminary views about certain ratemaking principles and process proposals that may be implemented in one form or another to address these issues in the future.

B. Capital Structure and Cost of Capital

32 Large combined electric and gas utilities typically finance their operations using a combination of equity, long-term and short-term debt. These three sources of capital each have carrying costs. Equity investment typically is the highest cost source of capital because it is unsecured by assets of the utility, and has historically required a premium related to its relative risk. In contrast to equity return, long-term debt receives a return that is secured in contract by the company's assets. Thus, long-term debt entails less risk for investors and is the second highest cost of capital, expressed as an interest rate demanded by lending institutions and bond holders. Short-term debt typically is the lowest cost form of capital and the smallest component of the capital structure since utility assets are long-lived and require long-term financing. The capital structure is a measure of the relative amounts and costs of each type of capital used by the utility to finance its operations. It is both an important component of rate-setting and a focus of the assessments of the financial integrity of the utility that are made by investors and credit rating agencies.

33 A company's weighted cost of capital, or overall rate of return (ROR), is determined by taking the sum of the products of each component cost (*i.e.*, equity, long-term debt and short-term debt) and the relative amount of each component in the capital structure.[25]

34 Capital markets are not static, but constantly changing. This requires a company to use good judgment in determining the mix of capital elements to employ in its capital

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[24] Decoupling has been promoted by Companies and the environmental community as necessary to remove a Company's disincentive to aggressively pursue conservation resources.

[25] The overall rate of return (ROR) should not be confused with the return on equity (ROE). As discussed, equity is only one element in the capital structure, which also includes debt.

structure, and when and how to access the capital markets for each. In competitive industries, management and the Board of Directors regularly assess both access to and the cost of capital markets to determine the most appropriate capital structure at a given point in time. The goal is to determine an optimal mix of equity and debt to balance capital costs with financial risk. The more debt in the capital structure, the lower the cost, but the higher the financial risk, because more revenue must be dedicated to servicing the debt. Increasing the proportion of equity in the capital structure reduces financial risk, but is more expensive.

35 For regulated utilities, including privately held utility companies such as PSE, the same analysis for an appropriate capital structure applies. Ratepayer interests, however, are an additional factor when considering what capital structure should be authorized by the regulator when setting rates.[26] Capital structure, and particularly the equity ratio and cost, materially impacts the price customers pay for service. Due to the relative difference between the cost of equity and the cost of debt, a capital structure with relatively more debt and less equity may result in a lower overall cost of capital.[27] This results in lower rates for customers. This is commonly referred to as "economy." On the other hand, a capital structure with relatively more equity and less debt may result in a higher overall cost of capital and higher rates for customers but enhanced financial integrity. This is commonly referred to as "safety."[28]

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[26] The Company's officers and directors, of course, are cognizant that their business is one "clothed with a public interest" because it is devoted to uses in which the public has an interest (*i.e.*, the delivery of commodities considered essential to modern life) and, hence, is subject to public control, the face of which is the Commission, as empowered by the legislature. Indeed, Mr. Gaines acknowledges these principles in proposing a capital structure with slightly less equity than what the Company maintained during the test period. Gaines, Exh. No. DEG-1T at 10:12-11:17. Mr. Gaines's testimony, as well as Dr. Olson's, also acknowledges generally that there is a range of reasonable outcomes on the question of capital structure, particularly in terms of the equity ratio and its cost.

[27] The use of equity versus debt capital is also significant because of the impact of Federal income taxes in the determination of a utility's revenue requirement. The additional revenue necessary to pay a higher return on equity must be supported by additional revenue from customers to pay Federal income taxes. On the other hand, when financing with debt the utility can deduct its interest expense resulting in a reduction in the utility's costs and revenue requirement, benefiting both customers and the utility.

[28] This simplified relationship assumes that the cost of equity does not vary with the equity ratio. In fact, the cost of equity may decline as the equity ratio increases because financial risk declines. *See.* 1 Leonard Saul Goodman, *The Process of Ratemaking at* 642-43 (1998).

36 Thus, the Commission must address this basic tension between economy and safety in determining the capital structure to use for setting a utility's rates. This tension manifests in the context of a contested case such as this one in the form of testimony from expert witnesses who recommend a range of results[29] The Commission carefully reviews the testimony presented by these cost of capital witnesses and seeks the appropriate balance as it sets rates.

37 The parties also typically disagree regarding the appropriate costs of equity and may disagree concerning debt costs. Based on the parties' evidence, the Commission establishes a reasonable range for allowed equity return vis-à-vis what would be expected for businesses of comparable risk. Once a reasonable range is determined, the Commission considers additional factors affecting the balance between maintenance of the Company's financial integrity and strength, and cost to ratepayers. Debt costs are usually readily observable based on the known costs of the Company's long-term and short-term debt instruments. If these costs are disputed, the Commission again determines on the basis of the evidence presented the level of costs it will authorize.

38 In this case, PSE included testimony on the subject of cost of capital from two witnesses, Mr. Donald E. Gaines, its Vice President for Finance, and Dr. Charles E. Olson, recommending Commission adoption of the Company's preferred capital structure and costs of capital. Mr. Gaines, among other things, offers testimony recommending an increase in PSE's currently authorized equity level in the Company's capital structure from 46.00 percent to 48.00 percent.[30] Dr. Olson

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[29] The Company witnesses typically offer testimony that defines the high end of the range in terms of equity ratio and return on equity while Commission Staff, Public Counsel or intervenor witnesses typically present testimony that recommends less equity in the capital structure and a lower return on equity.

[30]PSE proposed in its 2009 general rate case an equity ratio of 48 percent and return on equity of 10.8 percent. The Commission's Final Order established PSE's authorized ROR at 8.1 percent with a return on equity (ROE) of 10.1 percent and an equity ratio of 46 percent. *WUTC v. Puget Sound Energy*, Final Order Approving and Adopting Settlement Stipulations: Authorizing and Requiring Compliance Filing, Order 11, Dockets UE-090704 and UG-090705(consolidated) (April 2, 2010) at 92 (Table 9). In this docket, filed just seven months after the conclusion of the prior case, the Company again proposed initially an overall ROR of 8.50 percent based on a 10.8 percent ROE and an equity ratio of 48 percent.

recommends an increase in PSE's authorized return on equity from the current level of 10.10 percent to somewhere in the range of 11.0 -13.0 percent. PSE, considering both current stresses in the economy and testimony by ICNU's witness, Mr. Gorman, ultimately advocates a 10.75 percent return on equity. Dr. Olson, as noted, also supports this level of equity return in his rebuttal testimony.[31]

39 The effect of the Company's proposals for its equity ratio and return, coupled with debt structure and costs, is an overall increase to its authorized rate of return from 8.10 percent to 8.26 percent. This, along with significant additions to rate base proposed for approval in this case such as Lower Snake River Phase 1, means that a significant part of the Company's proposed rate increase in this proceeding results from its proposed capital structure and return on equity.

40 Two other parties, Commission Staff and ICNU, offer testimony and exhibits on the subject of cost of capital. Mr. Kenneth L. Elgin testifies for Staff, proposing no change in PSE's currently authorized equity share of 46.00 percent and a return on equity of 9.50 percent. Mr. Elgin, considering also the Company's debt costs, recommends an overall rate of return of 7.59 percent. Mr. Michael P. Gorman testifies for ICNU. He disputes Mr. Gaines's calculation of equity ratio and, like Mr. Elgin, recommends that it should remain at 46 percent. His primary proposal for equity return is 9.70 percent,[32] producing a 7.83 percent overall rate of return.

41 Table 3 summarizes the capital structure and cost rates from PSE's last general rate case and the recommendations of the Company, Staff and ICNU at the close of the record in this case.[33]

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[31] Gaines, Exh. No. DEG-1T at 22:13-14. Mr. Gorman's DCF analyses, discussed in more detail below, include a 10.75 percent return on equity that establishes the high end of his range of results. Dr. Olson, despite his own, higher results says this is "clearly reasonable." CEO-10T at 13:17-19.

[32] Mr. Gorman recommends 9.50 percent return on equity, if PSE's proposed Conservation Savings Adjustment Rate is approved.

[33] PSE and Staff initially differed on the cost of debt shown in Table 3, but by the time of PSE's rebuttal filing, these two parties agreed to the costs of debt in Staff's response case. Gaines, Exh. No. DEG-14T at 2, Table 1; Exh. No. DEG-15. According to Mr. Gaines's rebuttal, while Mr. Gorman initially uses the short-term debt and long-term debt from PSE's pre-filed direct testimony reflected here, Mr. Gorman later agreed with the revised lower short-term and long-

TABLE 3
Capital Structure and Cost of Capital Proposals

	Commission Approved		Company Proposal		Staff Proposal		ICNU Proposal[34]	
	Share/Cost		Share/Cost		Share/Cost		Share/Cost	
Equity	46.00	10.10	48.0	10.75	46.0	9.50	46.0	9.70
Long-Term Debt	50.05	6.70	48.0	6.22	50.0	6.22	50.0	6.37
Short-Term Debt	3.95	2.47	4.0	2.68	4.0	2.68	4.0	4.62
OVERALL ROR	**8.10**		**8.26**		**7.59**		**7.83**	

1. Capital Structure

42 Mr. Gaines testifies that the capital structure PSE requests in this proceeding is appropriate and reasonable for six reasons:[35]

- It is consistent with the Company's targeted capital structure that will likely support utility operations during the rate year.[36]
- It is similar to, albeit containing slightly less equity than, the actual 48.5 percent equity in place during the test year based on the average of monthly averages for that period.[37]

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term debt cost rates supported by Staff and PSE. *See* Gaines, Exh. Nos. DEG-14T 4:5-10; DEG-18. Based on this, ICNU's recommended overall rate of return is 7.68 percent.

[34] ICNU continues to advocate in its Initial Brief Mr. Gorman's recommendation for a 7.83 percent overall rate of return, based in part on PSE's as-filed debt costs. ICNU Initial Brief ¶9. This is perhaps an oversight given the evidence noted above that Mr. Gorman accepts the debt costs to which PSE and Staff agree. This would make Mr. Gorman's overall rate of return recommendation 7.68 percent.

[35] *See* Gaines, Exh. No. DEG-1T at 14:11-15:9. PSE's proposal in this case is consistent with its proposal in Dockets UE-090704 and UG-090705. *WUTC v. Puget Sound Energy*, Final Order Approving and Adopting Settlement Stipulations: Authorizing and Requiring Compliance Filing, Order 11, Dockets UE-090704 and UG-090705(consolidated) ¶ 270 (April 2, 2010).

[36] Gaines, Exh. No. DEG-1T at 11:12-17.

- The amount of short-term debt (the lowest cost capital component) in the capital structure, 4.0 percent, is higher than was actually in place during the test year, but is consistent with a reasonable level that can be expected during the rate year.[38]
- 48.0 percent equity in the capital structure is less than the average equity ratio recently approved for other regulated utilities nationally,[39]in the latest rate cases for PacifiCorp at this Commission, as well as less than the proxy group used by Dr. Olson.[40]
- The equity infusion by PSE's new owners following their acquisition of the Company in 2009, which raised the equity share in PSE's capital structure, contributed to credit ratings upgrades that have reduced PSE's new debt costs, thereby providing benefits to consumers.[41]
- It appropriately balances the risks and costs of funding PSE's utility operations.[42]

Mr. Gaines further argues that PSE's owners have received debt-like returns on a portion of the required $805 million equity infusion made at the close of the sale to the Investors' Consortium in 2009, due to the actual equity ratio being higher than the authorized level of 46 percent. An increase to 48 percent equity in the capital structure will ameliorate the "unrealistic" condition of expecting PSE's ownership consortium to incur debt rather than equity level returns.[43]

43 Mr. Elgin does not contest directly Mr. Gaines's results that are based on the average of monthly averages approach. Instead, he suggests that alternative measures of PSE's equity ratio may be more appropriately used. He testifies that:

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[37] Mr. Gaines testifies that PSE's actual test year capital structure includes an equity ratio of 48.5 percent, a long-term debt ratio of 49.5 percent and a short-term debt ratio of 2 percent. Gaines, Exh. No. DEG-1T at 11, Table 2.

[38] PSE proposes to reflect less long-term debt (*i.e.*, 48 percent) while doubling the amount of lower cost short-term debt to 4 percent in the capital structure.

[39] Gaines, Exh. No. DEG-6 ("Source of data: RRA/SNL").

[40] Gaines, Exh. No. DEG-14T at 2:15-3:8.

[41] *Id.* at 17:3-7.

[42] We note again that there is in every case a range of reasonable capital structures and costs that accomplish an appropriate balance. Even were the Commission convinced that what PSE proposes is within that range, the Commission could determine that a different hypothetical capital structure and different capital costs are more appropriate.

[43] Gaines, Exh. No. DEG-1T at 13:4-9.

- PSE's actual equity ratio as of December 31, 2010, the end of the test year, was 46.5 percent, with approximately 49.6 percent long-term debt and 3.9 percent short-term debt.[44]

- Considering PSE's September 30, 2011, balance sheet and its additional debt issuance in November 2011, the Company's actual equity ratio is 44.5 percent.[45]

- A 46 percent equity ratio is consistent with PSE's financial forecasts.[46]

- Summary information from AUS Utility Reports shows common equity ratios for 2010 of 46.4 percent for electric companies and 46.0 percent for combination companies. SNL reports the equity ratio of 45 utility parent companies with significant utility operations during 2010 at 44.5 percent with a median for the group of 43.6 percent.[47]

44 On rebuttal, Mr. Gaines criticizes Mr. Elgin's approach as being contrary to the "established practice of calculating the capital structure that was in place 'on average' during the test year."[48] Moreover, he says, it is contrary to Mr. Elgin's own use of an average equity ratio during the test year in a recent PacifiCorp proceeding, and Mr. Parcell's use of such an approach as Staff's cost of capital witness in PSE's most recent prior case.[49] Finally, on this point, Mr. Gaines testifies that Mr. Elgin offers no explanation of "why a point in time capital structure is better public policy than the capital structure that supported utility operations, on average, during the test year."[50]

45 Mr. Gaines testifies that the debt issuance in November 2011 to which Mr. Elgin refers involved the retirement of short-term debt with an equivalent amount of long-term debt, which was available at a favorable rate, thus having no impact on the

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[44] Elgin, Exh. No. KLE-1T at 15:20-16:1.

[45] *Id.* at 16:7-11.

[46] *Id.* at 16:12-16; Elgin, TR. 866:14-868:20.

[47] *Id.* at 16:20-17:8.

[48] Gaines, Exh. No. DEG-14T at 12:4-6.

[49] *Id.* at 13:7-11 (with reference to Dockets UE-090704 and UG-090705).

[50] *Id.* at 12:17-13:1.

relative amount of debt and equity in the Company's capital structure.[51] Moreover, Mr. Elgin ignores that PSE had net income during this period that added to the Company's equity ratio though retained earnings.[52]

46 According to PSE, Mr. Elgin's comparison of debt levels in the Company's financial forecast to equity capitalization is misplaced because it disregards that the Company's proposed hypothetical capital structure contains more short-term debt than does the forecast.[53]

47 Turning to Mr. Elgin's reference to utility industry average equity capitalization, Mr. Gaines testifies that when these figures are adjusted to remove the non-utility operations of holding companies the average allowed equity ratios of utility subsidiaries is 48.05 percent.[54]

48 Mr. Gorman, for ICNU, disputes directly Mr. Gaines's assertion that the Company's actual test year regulatory capital structure is approximately 48.5 percent.[55] Mr. Gorman testifies PSE's actual 13-month capital structure for the test year included 46.7 percent equity, 51.1 percent long-term debt, and 2.2 percent short-term debt.[56] He asserts that Mr. Gaines made two errors in calculating PSE's actual test period equity.

49 According to Mr. Gorman, Mr. Gaines failed to remove from regulated common equity all of the common equity supporting non-regulated subsidiaries. Mr. Gaines disputes this, providing considerable detail concerning the accounting that underlies the FERC Form 1 that he testifies Mr. Gorman apparently misreads.[57] According to Mr. Gaines, all non-regulated subsidiary common equity is already removed from the Company's consolidated capital structure on FERC Form 1. Thus, the effect of Mr.

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[51] *Id.* at 13:16-14:12.

[52] *Id.* at 14:7-8.

[53] PSE Initial Brief ¶110; *see* TR. 870:3-875:19; *see also* PSE Cross Examination Exhibit, Elgin, Exh. No. KLE-9CX at 39, 103.

[54] Gaines, Exh. No. DEG-14T at 15:14:19.

[55] Gorman, Exh. No. MPG-1T at 10:5-10.

[56] *Id.* at 11:20-23.

[57] Gaines, Exh. No. DEG-14T at 6:1-7:9.

Gorman's adjustment is to reduce PSE's common equity twice for non-regulated common equity.[58] There is no evidence in the record refuting Mr. Gaines's analysis of this issue.

50 Mr. Gorman also contends that Mr. Gaines's adjustment to regulated common equity for Other Comprehensive Income (OCI) adjustments related to pension income and expense, and derivative accounting, are improper.[59] Mr. Gaines, however, testifies that the Commission does not look at the accounting for pension income or expense, but only at cash pension contributions, averaged over a four-year period, which are reflected in rates. As he states on rebuttal: "Since neither pension income nor expense is reflected in rates, it is appropriate to remove the balance sheet impact of pension accounting from PSE's common equity for rate making purposes."[60]

51 The impact of non-cash unrealized mark-to-market accounting gains or losses on PSE's capitalization, generally reflected in OCI, must also be removed for rate making purposes, according to Mr. Gaines, or the balance sheet impact of these items will be inconsistent with the Company's cost recovery of these items. PSE recovers its commodity costs through the PGA and PCA mechanisms, with general rates set to reflect the expected level of electric energy costs in a base rate.[61] Mr. Gaines points out that applying Mr. Gorman's methodology could result in falsely over-inflated equity in the capital structure in years where the non-cash and unrealized marks of derivatives result in unrealized gains rather than losses. It follows, Mr. Gaines testifies, that it is appropriate to remove both the unrealized gains and losses from derivative accounting.[62]

52 *Commission Determination:* We find the evidence establishes that PSE's actual average capital structure during the test year was as portrayed by the Company through Mr. Gaines's testimony: 48.5 percent equity, 49.5 percent long-term debt and

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[58] *Id.* at 6:19-21.

[59] Gorman, Exh. No. MPG-1T at 10:12-11:8.

[60] Gaines, Exh. No. DEG-14T at 7:13-18.

[61] *Id.* at 7:19-8:1.

[62] *Id.* at 8:1-12.

2.0 percent short-term debt.[63] Thus, the capital structure PSE proposes in this case contains slightly less equity than was in place during the test period. PSE's proposed capital structure also contains more short-term debt than was actually in place, on average, during the test period. The parties do not dispute that 4.0 percent is the appropriate level for short-term debt, the least expensive form of capital available to the Company.

53 PSE's proposed capital structure is technically hypothetical.[64] However, Mr. Gaines testifies PSE expects to finance its utility operations with a slightly lower equity ratio going forward – a 48 percent equity ratio – and with the higher short-term debt ratio it proposes.[65] The Company sets forth a reasonable case in which its actual capital structure during the rate year will include on average the 48 percent equity and the 4 percent short term, and consequently 48 percent for long-term debt.

54 Given the Company's presentation, we see no reason based on this record to accept Staff's and ICNU's proposals for a capital structure with less equity. Staff and ICNU's basic argument is that there is no demonstrated need to change PSE's existing capital structure that was approved in two previous cases, first by settlement and second in a contested case. They argue the current structure appropriately balances safety and economy and that their proposals would support the financial metrics and ratings of the ratings agencies, during difficult economic times for PSE's consumers.

55 We dispense with this second line of argument by observing that there is a range of reasonable outcomes within which PSE's current, hypothetical capital structure may fall, as Staff and ICNU contend. PSE's proposed hypothetical capital structure in this case also falls within what we determine to be a reasonable range. Moreover, we have no reason to doubt at this juncture Mr. Gaines's testimony that what the Company proposes here is the most likely actual capital structure during the rate year.

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[63] We are persuaded by Mr. Gaines's testimony responding to Mr. Gorman's concerns about removal of common equity supporting non-regulated subsidiaries and the adjustment to regulated common equity for OCI.

[64] In fact, each capital witness in this case offers a hypothetical capital structure for the rate year. The Commission has approved hypothetical capital structures when circumstances merit such an approach.

[65] Gaines, Exh. No. DEG-1T at 11:12-14.

Should this turn out not to be true, a contrary result may be taken into account when the Commission evaluates evidence presented in PSE's next general rate case.

56 Turning to the question whether there is some need to allow increased equity in the Company's capital structure, there is at least some evidence that PSE may require additional regulatory support to earn its authorized return on equity. Setting the Company's equity ratio at the level it expects during the rate year is one way to provide such support.[66] Indeed, according to Mr. Elgin's testimony, PSE identified this during discovery as one of three remedies it requests in this proceeding relative to under-earnings or, as Staff describes it "attrition."[67] Retaining PSE's current equity ratio of 46 percent while the Company is actually capitalized at 48 percent and may be experiencing attrition could be viewed unfavorably by the financial markets and ratings agencies. By raising the equity ratio from its current authorized level to the level it expects during the rate year, we improve PSE's opportunity to earn its full authorized return during a period of high capital expenditures.

57 We find reasonable a capital structure for PSE that includes 48.0 percent equity, 48.0 percent long-term debt and 4.0 percent short-term debt.

2. Cost of Equity

58 While the cost of debt capital is typically observable based on bond coupon rates and short-term interest rates, the cost of equity cannot be ascertained by reviewing rates established by arms-length bargaining and straightforward contract terms. As a result, equity's cost is not readily observably and is consequently more difficult to determine. It must be estimated from investor expectations and other market factors. There are a variety of methods by which analysts make these estimates. The most commonly used is the discounted cash flow (DCF) method. Its theory is that the market value of stock is the present value of the future benefits, both dividends and growth, of holding the stock. The stream of future benefits is discounted back to

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[66] *Id.* at 13:4-9; 27:18-28:12.

[67] Elgin, Exh. No. KLE-1T at 63:4-20: "In response to Staff Data Request No. 83 PSE identifies its remedies as: an increase in its ROE from 10.1 percent to 10.8 percent ROE; an increase in its equity ratio from 46 percent to 48 percent; and the proposed Conservation Savings Adjustment mechanism." *Id.* at 63:16-20.

present value. While the formal application of this method is complex, a simplified formula can be used under certain assumptions.[68]

59 Other methods are available to indirectly estimate the cost of equity based on what investors may require to compensate for investment risk. These methods include a risk premium (RP) method and its variant, the capital asset pricing model (CAPM). Analysts using these methods essentially determine a "risk free rate" and then determine the "premium" that investors would need to receive to purchase the stock.[69]

60 RP analysis estimates the expected rate of return of investing in a stock as the long-term historic mean of a realized risk premium above an historic yield of low-risk bonds plus the current yield of the relevant bond applicable to a specific utility or peer group of utilities. The CAPM model derives the return investors in a utility's stock will expect as equal to the return for a risk-free security plus a risk premium. CAPM reflects an assessment of both systematic market risk and specific risk associated with the company in question.

61 Table 4 presents the range in analytic results calculated by the cost of capital experts, and each party's final return on equity recommendation.

TABLE 4
ROE Analytical Estimates

	Olson	Elgin	Gorman
DCF	11.00%-13.00%	9.00%-9.50%	9.19%-10.75%
Risk Premium	10.45%-12.35%		9.50%
CAPM	10.63%-10.82%	8.30%-9.80%	9.00%
Party Recommendation	**10.75%**	**9.5%**	**9.7%**

62 As an initial matter, we note that both Mr. Gorman and Mr. Elgin assert that the credit ratings outlook for combined electric and gas utilities like PSE industry are strong and

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[68] *See* James C. Bonbright, *et al.*, *Principles of Public Utility Rates* 317-322 (1988).

[69] *Id.* at 322-28.

that electric utilities' stocks have enjoyed relatively healthy return performance over the past few years.[70] Both witnesses point to specific analysts' reports that express favorable views on PSE's financial condition and the regulatory climate in Washington. They both contend that utility stocks can generally be characterized as a safe investment, with an attractive stock price and relatively high dividend yield. Mr. Gorman testifies that the utility industry currently enjoys a climate of increasing credit quality and attractive stock price performance.[71] He contends that the financial market views PSE as a reasonably stable investment with stable credit standings.[72]

63 Mr. Elgin testifies that he expects long-term interest rates to remain low for an extended period in response to federal monetary policy. He points to market evidence of sustained low interest rates and declining coupon rates for utility bonds.[73] He concludes that overall economic and financial conditions have caused investors to lower their expectations regarding returns and that this will continue to keep capital costs low.[74]

64 Dr. Olson paints a different picture, suggesting that investors are wary of financial markets due to uncertainty with the Federal budget, the foreign trade deficit, monetary policy, potential inflation, banking uncertainty and a slow recovery from recession.[75] He argues the Commission should authorize return and capital structure levels that would allow PSE to strengthen its current bond and corporate credit ratings.[76]

65 With this background in mind, we turn to the analytic estimates and opinions of the three experts whose analyses provide a foundation on which we can construct a reasonable range for ROE. We start with the witnesses' various DCF analyses. Dr.

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[70] *See, e.g.,* Elgin, Exh. No. KLE-1T, at 9:5-10.

[71] *Id.*at 5:6-7:17. Mr. Gorman cites four sources in support of his contention regarding the generally healthy credit ratings of electric utilities relative to other segments of the stock market: Standard & Poor's, Fitch, Value Line, and EEI.

[72] *Id.* at 8:4-9:8.

[73] Elgin, Exh. No. KLE-1T, at 49:3-10.

[74] *Id.* at 10:3-15.

[75] Olson, Exh. No. CEO-1T at 12:18-20.

[76] *Id.* at 13:2-4.

Olson, Mr. Gorman and Mr. Elgin agree that this approach produces the most useful results.[77]

66 PSE is a privately held corporation, and consequently has no publicly traded stock for purposes of valuation by financial markets. All three witnesses accordingly begin their analyses by identifying a group of proxy companies. Dr. Olson examined financial information from a group of 50 energy utilities.[78] Each of these companies has shares that trade on public stock markets and is followed by *Value Line*.[79] Dr. Olson eliminated entities that he believes are not comparable to PSE such as those that only distribute electricity or are not combination companies. He also eliminated any company that reduced its dividend during the past two years.[80] He further narrowed his selection to companies that had an S&P bond rating of BB to BBB+ or better and excluded companies with significant merchant generation assets.[81] Finally, Dr. Olson eliminated companies that are significantly larger or smaller in terms of total revenues as compared to PSE's 2009 revenue level of approximately $3.3 billion.[82] The end result of Dr. Olson's culling process is a group of nine utilities

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[77] The Commission has stated in past orders, and we reiterate here, that we do not limit our consideration of cost-of-equity to evidence produced by discounted-cash flow analysis. Specifically, we have considered the analyses developed by the risk premium and CAPM methodologies, as well as by several variants of DCF. We seek such a broad range of analysis because conditions in financial markets and monetary policy change and can affect the relative reliability of each analytic method. While we agree with the three capital witnesses in this case that the DCF methodologies provide the most relevant and reliable analyses in present circumstances, we still consider the evidence developed by risk premium and CAPM, giving it appropriate weight, as we develop our final decision on equity returns.

[78] Olson, Exh. No. CEO-1T at 13:17-19. Dr. Olson's testimony sets forth the simplified DCF formula using "k" as the cost of capital (*i.e.*, return on equity) which is equal to the ratio of D/MP (dividend divided by market price), plus "g" which is the expected growth in dividends, stated as: k = D/MP + g.

[79] *Id.* at 21:7-9.

[80] *Id.*at 21:10-15.

[81] *Id.*at 21:15-18.

[82] *Id.*at 21:18-21.

which he contends is a relevant proxy group sufficient to determine a reasonable DCF result and approximation of the cost of equity for PSE.[83]

67 Mr. Gorman relies on the proxy group of companies Dr. Olson identifies. Mr. Elgin eliminates from Dr. Olson's group three companies he believes are not comparable to PSE, for one reason or another. [84] He adds Avista and PGE to his group.[85]

68 The DCF model requires a current stock price, expected dividend yield, and expected growth rate. There is little difference in the analyses among Dr. Olson, Mr. Gorman and Mr. Elgin concerning the first component of the DCF equation, the current and expected dividend yield. The material difference in their analyses concerns the final element of the DCF model, the projected dividend growth rate, or the "g" factor.[86]

69 Dr. Olson uses a constant growth DCF model, which assumes a growth rate that will continue into the indefinite future. Using information gleaned from a single source, *Yahoo Finance*, Dr. Olson examined analyst growth estimates as of April 4, 2011. He determined that the individual consensus earnings growth rates for the nine utility companies in his proxy group range from 5.88 to 11.75, with an average growth rate for the entire group of 7.81 percent. By adding the individual consensus growth rates to the individual dividend yields for each company in his proxy group, Dr. Olson establishes a range of DCF-based ROEs of 10.30 to 15.26 percent. He asserts that a reasonable ROE for PSE, based on the results derived for the nine members of the

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[83] *Id.* at 22:10-11. The nine utilities in Dr. Olson's DCF analysis are Alliant Energy, CMS Energy, Great Plains Energy, NV Energy, OGE Energy, Pinnacle West Capital, TECO Energy, Western Energy, and Wisconsin Energy.

[84] Elgin, Exh. No. KLE-1T at 24:20-25:8.

[85] Mr. Elgin explains that Avista satisfies Dr. Olson's criteria and, moreover, has Washington as its primary jurisdiction thus providing "direct evidence of how investors view a combination company with a major portion of its electric and natural gas utility business under the Commission's jurisdiction." *Id.* at 25:12-14. Mr. Elgin considers PGE comparable because, being located in the Pacific Northwest, it faces "similar regional issues with respect to infrastructure, resource acquisition, and competition for its electric business." *Id.* at 25:16-17.

[86] The simplified form of the DCF formula contains only two elements: current dividend yield and expected growth in the dividend. The growth component can contribute half or more of the DCF-estimated cost of capital. Experts disagree regarding the most appropriate method for estimating the growth rate component of the DCF formula. *See* James C. Bonbright, *et al.*, *Principles of Public Utility Rates* 319-321 (1988).

proxy group, is in the range of 11 to 13 percent.[87] He says that seven of the nine companies have a DCF cost of capital of 10.84 percent or higher and the average is 12.10 percent. He points out that when his two highest and two lowest results are deleted, the modified mean is 11.80 percent.[88]

70 Mr. Elgin also uses a constant growth DCF model, but uses growth in book value and retained earnings as reference points. Taking published information from *Value Line,* Mr. Elgin forecasts that the average growth rate in book value between 2011 and 2016 for his proxy group is approximately 3.70 percent.[89] The average growth rate of the proxy group is approximately 4.45 percent for expected internal growth from retained earnings.[90] The average growth rate for dividends from 2011 to 2016 is 5.20 percent, but Mr. Elgin contends this rate is not sustainable because it doesn't account for changes or potential changes in a company's dividend policy. Finally, Mr. Elgin states that *Value Line* shows that the average rate of growth in earnings for the proxy group is 5.40 percent but, as with dividend growth estimates, he does not believe this level is sustainable over a long time period.[91]

71 Recognizing that the simple average of the observed results of the four metrics he uses produces a figure of 4.7 percent dividend growth rate, and giving more weight to the metrics showing growth in retained earnings of 4.4 percent and book value growth in the range of 4.0 to 4.5 percent, Mr. Elgin concludes that a range of 4.5 to 5.0 percent is a rate of growth investors could reasonably expect to achieve. Adding these amounts to his dividend yield analysis, Mr. Elgin concludes that a reasonable

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[87] It is noteworthy that Dr. Olson's DCF analysis produces a high end return on equity that is higher even than what he states such analysis produces for a company "down the road" from PSE, Microsoft. Olson, Exh. No. CEO-10T at 2:12-18. Microsoft is one of only four non-financial firms in the world Standard& Poor's gives an AAA credit rating. Stock analysts also routinely rate Microsoft at or near the top of the scale. It is striking both that Dr. Olson would draw a comparison between two such fundamentally incomparable companies and that he thinks investors should expect from PSE returns comparable to what they expect from Microsoft. As ICNU argues: "PSE's ROE should reflect that utilities are conservative investments that have lower returns than successful software companies." ICNU Initial Brief ¶13.

[88] Olson, Exh. No. CEO-1Tat 24:21-22.

[89] Elgin, Exh. No. KLE-1T, at 34:6-7.

[90] *Id.*at 34:15-16.

[91] *Id.*at 36:6-10.

range for the cost of equity for the proxy group is within the range of 9.00 to 9.50 percent. He recommends the Commission authorize a return no more than the higher level in this range.[92]

72 Mr. Gorman uses three variations of the DCF approach with results as set forth in Table 5 below:

TABLE 5
Summary of Mr. Gorman's DCF Results

	Constant Growth Rate DCF	Sustainable Growth Rate DCF	Multi-Stage Growth Rate DCF[93]	Average DCF Result
Proxy Group Average Dividend Yield	4.31%	4.26%		
Proxy Group Average Growth Rates	6.43%	4.93%		
Proxy Group Median Growth Rates	5.49%	4.87%		
Proxy Group Average Indicated Return on Equity	10.75%	9.19%	9.54%	9.83%

In all three analyses, Mr. Gorman estimated the dividend yield component of the DCF formula using a 13-week average stock price (ending November 18, 2011) and the most recently reported quarterly dividend, annualized and adjusted for one year's growth.[94] As shown on Table 6, the average dividend yield for Mr. Gorman's proxy group is 4.31 and 4.26 percent for the Constant Growth Rate DCF and Sustainable Growth Rate DCF, respectively.[95]

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[92] *Id.*at 38:1-2.

[93] *See* Gorman, Exh. No. MPG-12.

[94] Gorman, Exh. No. MPG-1T at 17:13-18:5.

[95] Gorman, Exh Nos. MPG-7 and MPG-11. Mr. Gorman's Multi-Stage Growth Rate DCF does not indicate an average dividend yield.

73 Mr. Gorman relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations for his constant growth DCF analysis. Instead of the single source of Yahoo Finance used by Dr. Olson, he used a broader range of analysts' growth rate estimates, the average from three sources: *Zacks*, *SNL Financial* and *Reuters*. The average dividend growth rate of his proxy group is 6.43 percent which, when added to his estimated dividend yield, produces an average constant growth DCF return for the proxy group of 10.75 percent.

74 Although Mr. Gorman estimates a constant growth DCF result of 10.75 percent, he does not believe it should be relied upon as a stand-alone result because the analysts' three to five year growth rate projections exceed the long-term sustainable growth rate required by the DCF model. He contends that these short-term rates exceed the growth rate of the overall U.S. economy and points to a consensus view of published economists, summarized in the Blue Chip Economic Indicators, that projects that the U.S. Gross Domestic Product ("GDP") will grow at a nominal rate of no more than 5.0 percent and 4.7 percent over the next 5 and 10 years, respectively. Mr. Gorman says an individual utility simply cannot grow indefinitely at a faster rate than the overall economy in which it sells its products. In his view, this means that projections for growth rates for the U.S. economy represent a ceiling on the earnings growth rate that can be sustained over long period of time.

75 Because of such observed failings of the constant growth rate DCF model, Mr. Gorman turns to a different approach, known as the sustainable growth rate model. This approach adjusts the growth rate for each of member of the proxy group based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. Mr. Gorman says that since retained and reinvested earnings increase a utility's rate base when they are used for new utility investment, the utility is allowed to earn its authorized return on such incremental rate base investment. In essence, Mr. Gorman's approach reduces the projected growth rate for utilities to the percentage of earnings retained in the company and not paid out as dividends. As the dividend payout ratio declines, the earnings retention ratio increases which fuels stronger growth because the utility funds more investments with retained earnings.

76 Using *Value Line* information, Mr. Gorman shows that his proxy group will have a declining dividend payout ratio over the next three to five years which he then factors into his sustainable growth DCF result. He estimates sustainable dividend growth rates for the proxy group to average 4.93 percent with a median of 4.87 percent. Using these growth rates, Mr. Gorman derives returns on equity averaging 9.19 percent with a median of 9.51 percent.[96]

77 Mr. Gorman's third DCF analysis uses three stages of growth, the first five years represented by the three to five year earnings estimates used in the constant growth model, the second five years represented by an interim growth rate, and the remaining period to perpetuity by the projected nominal GDP growth rate. He estimates the interim growth rate for each company by increasing or decreasing the short-term growth rate by the difference between this rate and the GDP growth rate. Mr. Gorman uses estimated GDP growth rates from *Blue Chip Indicators*, the US Energy Information Administration, and the Congressional Budget Office to estimate his interim and long-term growth rates. These rates averaged 4.9 percent. Mr. Gorman's three-stage DCF analysis produces required returns on equity that average 9.54 percent and have a median of 9.62 percent.[97] Based on the results of the his three DCF studies, Mr. Gorman testifies that a reasonable DCF return estimate for PSE is 9.83%, as shown above in Table 6.[98]

78 Mr. Gorman contends that Dr. Olson's DCF estimates are inflated because they rely on dividend growth estimates that are not sustainable in the long-term. According to Mr. Gorman, Dr. Olson's dividend growth estimates of 7.28 to 7.81 percent far exceed the growth rate of the economy and cannot be expected to be sustained beyond the short-term. He argues that even if these growth rates were included in the short-term component of his multi-stage DCF model, the resulting average of proxy group returns on equity would be 10.1 percent.[99] Mr. Elgin agrees that Dr. Olson's DCF estimates are inflated because they rely on dividend growth rates that are not reliable indicators of long-term sustainable growth. He says that the dividend growth rates

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[96] Gorman, Exh. No.MPG-1T, at 21:9-22:11.

[97] *Id.*at 23:2-25:8.

[98] *Id.*at 26:3.

[99] *Id.* at 42:3-43:14.

used by Dr. Olson focus on the short-term and are not reasonable estimates of long-term dividend growth.[100]

79 Responding to Mr. Elgin's and Mr. Gorman's emphasis on long-term sustainable dividend growth rates, Dr. Olson contends that studies have shown security analysts' projections of dividend growth rates to be superior to methods using book value and internal growth.[101] He says that the DCF is more concept than mathematics and that estimates of dividend growth need not be sustainable over the long-term for the concept to be a valid reflection of investor expectations.[102] He also contends that companies such as Microsoft can grow their earnings at rates in excess of the rate of growth of the economy.[103]

80 Taking into account all of his analytic results, Mr. Gorman recommends a return on equity of 9.70 percent, near the mid-point of his range of 9.5 to 9.85 percent.[104] He calculates the impact of his recommendation on the Company's financial credit metrics as published by S&P as a check to see if his recommended return will support the Company's investment grade bond rating.[105] Evaluating the three primary financial benchmarks used by S&P he concludes that, with an equity return of 9.70 percent and an equity ratio of 46 percent, the Company's financial results will fall well within the ranges for investment grade bond ratings.[106] Mr. Gaines responds that Mr. Gorman's recommended equity ratio of 46 percent is not consistent with S&P's expectation that PSE would have an equity ratio of 48 percent, but he does not otherwise take issue with Mr. Gorman's calculation of key credit metrics.[107]

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[100] Elgin, Exh. No. KLE-1T, at 56:15-57:21.

[101] Olson, Exh. No. CEO-10T, at 8:4-9, 15:4-20.

[102] Olson, TR. at 807:20-808:20.

[103] Olson, Exh. No. CEO-10T, at 15:18-20. ICNU responds to this point, contending that it is not appropriate to compare growth rates of software companies with those of the electric industry. ICNU Initial Brief ¶17.

[104] Gorman, Exh. No. MPG-1T, at 36:6-7.

[105] Gorman, Exh. No. MPG-20.

[106] *Id.* at 36:16-39:13.

[107] Gaines, Exh. No. DEG-14T, at 10:2-17.

81 In addition to their DCF model results, all three cost of capital witnesses present estimates based on the RP and the CAPM. While they recommend the results of these methods be given little weight in current economic circumstances, they characterize them as useful comparisons or checks against their DCF model results.[108]

82 Dr. Olson presents results using the RP method that range from 10.45 percent to 12.35 percent. His results using the CAPM method cover a range from 10.63 to 10.82 percent.[109]

83 Mr. Gorman also presents estimates of investor-required equity returns based on the RP and the CAPM methods. Using the RP method, he derives an estimate of 9.50 percent.[110] Using the CAPM method, he derives an estimate of 9.00 percent.[111]

84 Mr. Elgin produces an average result of 9.05 percent using the CAPM method, but he advises that the Commission give little weight to this model's results.[112] He undertakes an RP-type analysis that compares his recommended ROE to the Company's cost of long-term debt. He concludes that his recommendation affords a return of 375 to 450 basis points above the cost of long-term debt and that this is adequate compensation for the Company's equity owners in current capital markets.[113]

85 *Commission Determination:* We are not persuaded by Dr. Olson and Mr. Gaines that PSE's authorized ROE should be set at a level above 10.1 percent, the level set in PSE's 2010 general rate case. We find two reasons. First, the Company has not provided persuasive evidence that market conditions and investor confidence have changed sufficiently, or in a manner, that requires any increase, much less the ROE it seeks. Rather, Treasury and utility bond yields have decreased, and interest rates are

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[108] Gorman, Exh. No. MPG-1T, at 36:6-12; Olson Exh. No. CEO-1T, at 25:19-26:3, 29:9-12; Elgin, Exh. No. KLE-1T, at 24:4-7, 40:15-41:4; Olson Exh. No. CEO-10T, at 17:19-18:8.

[109] Olson, Exh. No. CEO -1T at 26:7-29:6.

[110] Gorman, Exh. No. MPG-1T, at 30:22-23.

[111] *Id.* at 35:20-22.

[112] Elgin, Exh. No. KLE-1T, at 45:7-16.

[113] *Id.* at 48:7-12.

expected to remain low for some time. Utility stocks enjoy favorable market sentiment in such an environment. There is no apparent need to increase ROE in these circumstances.

86 Second, Dr. Olson's conceptual analysis and his agreement with Mr. Gorman's 10.75 percent constant growth DCF both rest on dividend growth rates that focus on the near-term. We are persuaded by Mr. Elgin and Mr. Gorman that these growth rates are unsustainably high and do not reflect what investors could reasonably expect over the long-term.[114] The approaches used by Mr. Elgin and Mr. Gorman that consider more carefully and systematically the sustainability of growth rates are more rigorous and reliable. Considering these two reasons, the real question facing us is to what extent we should reduce the currently authorized ROE based on the testimonies of Mr. Gorman and Mr. Elgin.

87 As in previous proceedings, we look to specific methods for determining an appropriate ROE for PSE based on various analytical tools used by the three cost of capital witnesses. Our decision is framed by a number of data points that range from 10.75 percent on the high end, representing the low end of what Dr. Olson would accept, to 9.5 percent on the low end, representing the high end of what Mr. Elgin advocates. More precisely, our conclusions above narrow this range to be 9.5 to 10.1 percent. Mr. Gorman's particularly detailed examination frames the middle of this range, or zone of reasonableness.

88 Mr. Gorman provides a thorough and broad examination of equity return using three approaches to DCF analysis that produce a range of 9.19 percent to 10.75 percent. These analyses produce an average of 9.83 percent – an average that includes his 10.75 percent high-end estimate. He checks these results for reasonableness using RP and CAPM analyses. His presentation is buttressed by more than 20 detailed exhibits including relevant financial information. His analytical approach is thoughtful and well-reasoned. In our view, Mr. Gorman offers the most comprehensive analysis among the three witnesses in support of his overall recommendation of a 9.7 percent ROE. This level falls within the zone of reasonableness and his evaluation of

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[114] Mr. Gorman cautions against using his 10.75 percent, high-end result as a stand-alone estimate. Instead, he averages it with the results of his other two DCF analyses. Gorman, Exh. No. MPG-1T, at 25:11-15; ICNU Initial Brief ¶18.

financial ratios gives us confidence that an ROE near the mid-point of this range would support PSE's investment grade bond rating.

89 While we find the results of RP and CAPM analyses helpful, we are mindful of the cautions recommended by the three cost of capital witnesses regarding their reliability, particularly in these economic circumstances. Accordingly, we afford RP and CAPM results little weight and give primary weight in this case to the results of DCF analysis. In this regard, we find Mr. Gorman's DCF analyses, which average 9.83 percent, to be the most comprehensive. This average falls very near the mid-point of the reasonable range. Therefore, after careful deliberation and weighing all results, we determine that the mid-point of this range is reasonable for PSE's return on equity. PSE's authorized return on equity should be 9.80 percent.

3. Costs of Debt

90 *Commission Determination:* PSE's costs of debt are not in dispute. We find reasonable a 6.22 percent cost of long-term debt and a 2.68 percent cost of short term debt.

4. Capital Structure and Cost of Capital Summary

91 We summarize in Table 6 our determinations of the capital structure and costs for PSE that we find best supported by the evidence.[115] These determinations meet both the Company's needs and the ratepayers' needs. On the one hand, we provide regulatory support to PSE by setting the equity ratio share and return on equity at levels that produce a higher weighted cost of equity capital than what is currently embedded in rates.[116]

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[115] A decrease in the authorized ROE (from 10.1 to 9.8 percent) together with a 2 percent increase to the equity ratio and corresponding reduction in the long-term debt ratio produces a new authorized overall rate of return (ROR) of 7.80 percent; a result that is 30 basis points below PSE's current authorized ROR of 8.1 percent. This lower overall cost of debt and equity capital benefits customers in rates. PSE also benefits because its weighted cost of equity actually increases from 4.65 to 4.70 percent, and equity return increases from 57 percent to 60 percent of the company's total return.

[116] We note that this is not a "guaranteed return" on equity, the realization of which depends on a number of other factors and management decisions. Instead, this represents the "opportunity to earn" a 9.80 percent return on all capital investments supported by equity contributed by the owners. Elsewhere in this Order we have taken actions that should improve the ability of the Company to realize this opportunity by approving, among other things, forward-looking power costs, current property tax, and major plant additions occurring after the close of the test-year.

92 On the other hand, we do not set these factors so high as to deprive ratepayers of the benefits they should have as a result of PSE's improved credit ratings and lower debt costs. We endeavor to establish an appropriate balance between economy and safety in determining the cost of capital, and believe that we have struck an appropriate balance in this case. Thus, the overall rate of return of 7.80 percent that ratepayers will bear to cover PSE's combined equity and debt costs is lower than what is currently authorized in rates, an appropriate result considering the general state of the economy.

TABLE 6
Commission Determination of Capital Structure and Cost of Capital

	Share percent	**Cost percent**	**Weighted Cost percent**
Equity	48.00	9.80	4.70
Long-Term Debt	48.00	6.22	2.99
Short-Term Debt	4.00	2.68	0.11
OVERALL ROR			**7.80**

C. Revenue, Expense and Rate Base Restating and Pro Forma Adjustments

1. General Principles

93 In its final orders in two recent general rate cases, the Commission discusses in detail certain well-established general principles of utility ratemaking as applied to Washington jurisdictional utilities, stating in part: [117]

> The Commission's long-established and well-understood ratemaking practice requires companies filing for revised rates to start with an historical test year. There is a fundamental reason for this starting point: costs, revenues, loads, and all other pertinent factors are known and can be measured with a high degree of certainty because they have, in fact, occurred. The practical value of the historical test year is that the cost, revenue and plant data are available for audit, and the test year

[117] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 ¶¶ 22-33 (April 2, 2010) (PSE 2010 GRC Order); *WUTC v. Avista*, Dockets UE-090134 and UG-090135, Order 10 ¶¶ 40-50 (December 22, 2009) (Avista 2009 GRC Order).

captures the complex relationships among the various aspects of utility costs, revenue, load, and other factors over a uniform period of time.

The Commission recognizes that the test year is a snapshot in time. The typical test year is the twelve month period preceding the rate filing, ended as of the most recent auditable results of operations.[118] A utility, however, continues to operate, incur costs (including capital additions), achieve savings, and receive revenues during the pendency of its rate review subsequent to the test year that would carry over into the year in which the rates would be effective (known as the "rate year") and beyond. The theory, well supported by ratemaking theory and past commission practice,[119] is that once the relationship is set, 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. If new facilities are put into service to serve those customers, then the resulting revenues would not only cover the company's added expenses, but also effectively provide a return on that new investment.

However, our past decisions, and our rules, recognize that there are some expenses or investments that do not take place in the test year that, nevertheless, should be included in the rate-making formula. Thus, subject to important conditions, a company's rate filing may include restating and pro forma adjustments.[120] These are allowed to revise or update expenses, revenues, and rate base so long as there is a

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[118] The test year is a period of company operations for which the Commission conducts a careful audit and review prior to authorizing any change in rates. *See* 1 Leonard Saul Goodman, *The Process of Ratemaking* (Public Utility Reports, Inc. 1998) at 141 (1998).

[119] *See* Charles F. Phillips, Jr., *The Regulation of Public Utilities* 196 (1993).

[120] WAC 480-07-510 (3)(e)(ii) and (iii) provide as follows:

> (ii) "Restating actual adjustments" adjust the booked operating results for any defects or infirmities in actual recorded results that can distort test period earnings. Restating actual adjustments are also used to adjust from an as-recorded basis to a basis that is acceptable for rate making. Examples of restating actual adjustments are adjustments to remove prior period amounts, to eliminate below-the-line items that were recorded as operating expenses in error, to adjust from book estimates to actual amounts, and to eliminate or to normalize extraordinary items recorded during the test period.
>
> (iii) "Pro forma adjustments" give effect for the test period to all known and measurable changes that are not offset by other factors. The work papers must identify dollar values and underlying reasons for each proposed pro forma adjustment.

> mechanism ensuring, and evidence establishing, that these adjustments do not disturb test year relationships.[121]

94 The quoted language describes the long-standing practice in Washington that relies on a so-called modified historic test year approach. Beginning with audited results from a recent 12 month period, we make changes to the Company's revenue requirements based on substantial evidence, timely presented, that shows increases and decreases in expenses that will occur during the pendency of the rate case, or are expected with a reasonable degree of certainty to occur in the rate year that begins at the conclusion of the proceeding. This approach reduces regulatory lag[122] without burdening ratepayers with unnecessary costs determined on the basis of the more speculative future test year approach to ratemaking that is used in some jurisdictions and urged upon us, at least in principle, by PSE witnesses in this proceeding.[123]

95 Dr. Olson confirmed at hearing that his concept of a future rate year methodology is one that sets rates without specific reference to cost data from any period of actual experience. Rather, he proposes that rates should be set on the basis of the Company's own budget estimates for future periods, ideally in his view reflecting the Company's expectations about the level of its future costs over a two-year minimum period beginning at the conclusion of the ratemaking process.[124] These "expectations" would include, among other things, full recovery of the revenue the Company forecasts it will require to pay all of its budgeted operating costs, whether

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[121] Avista GRC Order at ¶¶ 41-43 (internal footnotes in original).

[122] National Regulatory Research Institute (NRRI) defines regulatory lag as: "the time interval between the occurrence of a cost or revenue and the recognition of the same cost or revenue in rates. It can work in both directions." *Utility Ratemaking: The Fundamentals and the Frontier*, NRRI, at 2-3 (April 2011). Edison Electric Institute's (EEI) definition is: "the time between a rate case filing and decision – a rough proxy for the time between when a utility needs funds and when it can recover those funds in rates." EEI, *Rate Case Summary*, Q1 2011 financial update, at 2 (undated).

[123] *See, e.g.,* Olson, Exh. No. CEO-1T at 7:11 – 10:10; Story, Exh. No. JHS-18T at 4:18 – 10:15; Marcelia, Exh. No. MRM-1T at 44:13 – 47:17. PSE does not present a forward-test-year case in this proceeding but presents the matter more as a suggested policy the Commission might adopt for future general rate case filings, either for PSE in this proceeding or, presumably, for all regulated electric and natural gas companies in a more generic proceeding. TR. 812:19 – 813:1 (colloquy between Chairman Goltz and Dr. Olson).

[124] TR. 809:4 – 812:18 (colloquy between Chairman Goltz and Dr. Olson).

or not actually incurred, and earn its authorized returns on debt and equity, presumably including return of, and return on, anticipated debt issuances and capital investments that might or might not occur.

96 Our approach, unlike Dr. Olson's forward-test year approach, strikes a balance that motivates PSE and the other utilities subject to our jurisdiction to carefully manage their costs and revenues going forward, and take full advantage of their opportunities to recover all fixed and variable costs including a reasonable return on prudent capital investments that are used and useful in providing service to customers in Washington.

97 While we have traditionally described our ratemaking practice as being based on the historic test year, a key operative part of this description is "based on." In point of fact, our practice is quite forward looking and more a process sometimes referred to as a "hybrid test year."[125] The Commission, for example:

- Approves pro-forma adjustments to test-year costs when the adjustments are adequately supported.

- Allows calculation of base power costs based on costs projected for the rate year based on data contemporaneous with the end of a general rate case (*i.e.*, at the beginning of the rate year).

- Accepts filings for updates to power costs "between rate cases." For PSE, it allows for expedited power-cost-only rate cases (PCORCs) that adjust rates to reflect addition of new power resources, or fuels costs, without requiring a comprehensive rate proceeding .

- Allows new generation plant in rate base even when the new facilities are placed in service subsequent to the end of the test period.

- Has approved end-of-period rate base when this is shown to be appropriate.

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[125] *See* Lowry, Mark Newton; Hovde, David;Getachew,Lullit;Makos, Matt, Edison Electric Institute, *Forward Test Years for U.S. Electric Utilities*, August 2010**.**

- Has allowed CWIP (Construction Work in Progress) in rate base.

- Has approved hypothetical capital structures to improve a utility's weakened financial condition.

98 In prior orders, the Commission has made clear that while its ratemaking practice starts with known data that are "historic" by definition, these data are adjusted using various approaches to set rates based on expected costs the utility will experience during the rate year following the effective date of the new rates.[126] The current case is no exception. Significantly more than half of PSE's cost of service is determined on a forward-looking basis in this proceeding, including:

- Power costs that alone represent more than half of PSE's overall cost of service. We determine these costs in rates based on a projection for the rate-year using gas price *forecasts* nearly contemporaneous with the date of this Order, not costs incurred during the test-year.

- A nearly $780 million increase to rate base for plant investment in LSR-1 and associated transmission that did not become operational until 14 months after the close of the test-year and near the end of this proceeding.[127]

- Pro-forma adjustments that reflect known and measurable increases to test year costs for such expenses as wages, pension contributions and property tax.

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[126] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶¶ 22-33 (April 2, 2010) (PSE 2010 GRC Order); *WUTC v. Avista*, Dockets UE-090134 and UG-090135, Order 10 at ¶¶ 40-50 (December 22, 2009) (Avista 2009 GRC Order). In these cases, the Commission describes its modified historic test year approach to ratemaking without relabeling its practice as being one recognized by some as a "hybrid" method. The hybrid method we use draws on historic data, but modifies this data with projections, forecasts and estimates. In other words, it is a hybrid of historic test year and forward test year ratemaking.

[127] At hearing, PSE indicated that Lower Snake River was expected to go into commercial operation on February 29, 2012. Story, TR 1030:6.

99 In addition, we adopt for purposes of this case a methodology for determining property tax expense to closely match what PSE is authorized to recover in rates with what it will actually pay during the rate year. This reflects the Commission's continuing commitment to flexibility in applying forward looking approaches on a proper showing. This is reflected, too, in our resolution of certain issues concerning federal income tax in a way that reflects closely the results of the Company's actual experience during current periods.

100 Commission practice during recent years also has allowed adjustments to rate base to bring power production facilities into rates, even though the acquisition occurred after the test period. The Commission adopted in PSE's case the PCORC mechanism, and has allowed in general rate cases pro forma adjustments for major plant additions in order to match the in-service date with the start of the recovery of those investments.[128] Lower Snake River Phase 1, which went into service on February 29, 2012, is an example in this case. The main reasons for allowing such adjustments are the materiality of the resource acquisitions and the fact that offsetting factors can be captured through the power supply and production factor adjustments.

101 With these principles in mind, we turn now to consideration of the uncontested adjustments and a number of contested issues, starting with proposed pro forma adjustments.

2. Uncontested Adjustments

102 Appendix A shows the uncontested electric adjustments in this case, as of the parties' rebuttal testimony and Initial Briefs.[129]

103 Appendix B shows the uncontested natural gas adjustments in this case, as of the parties' rebuttal testimony and Initial Briefs.[130]

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[128] In PSE's case, these include Fredrickson 1 (Docket UE-031725); Hopkins Ridge (Docket UE-050870); Wild Horse (Docket UE-060266); Goldendale (Docket UE-070565); and Whitehorn and Sumas (Docket UE-072300).

[129] Story, Exh. No. JHS-18T at 16.

[130] Stranik, Exh. No. MJS-10T at 5.

104 In addition, there is agreement on the methodology used to calculate several adjustments. These include:

- Adjustment 20.04 Montana Electric Energy Tax.
- Adjustment 20.11 Production Adjustment.
- Adjustment 21.05 Tax Benefit of Pro Forma Interest.

3. Contested Adjustments - Electric and Natural Gas - Non-Rate Base

105 This category of adjustments includes expenses that PSE incurs in connection with both electric and natural gas service. These expenses are unrelated to rate base and, hence, are unaffected by the parties' respective positions on rate of return. There are five contested adjustments in this category.

a. Miscellaneous Operating Expense

106 This adjustment is the net result of a number of unrelated, underlying adjustments ranging from a small adjustment to remove non-business or non-utility related business expenses, to significantly larger adjustments for the Wild Horse Expansion and Mint Farm Cost Deferrals, and a FERC Land Use Fee Accrual. These proposals, and most of the other handful of underlying adjustments, are uncontested. Another underlying adjustment in this expense category, an uncontested cost reclassification of certain legal expenses from FERC Account 557 to Administrative & General Expense, is contested as to amount by ICNU. We discuss this separately below in connection with power costs, of which Account 557 expenses are a part.[131]

107 Staff contests two components of PSE's miscellaneous operating expense adjustment. Staff argues that we should disallow 50 percent of the Board of Directors fees and expenses that PSE includes in its proposed rates.[132] The rationale for Staff's approach

[131] FERC Account 557 includes expenses related to net power costs. We reject ICNU's proposed normalization of this expense in favor of PSE's use of test period amounts. *See infra* Section II.C.5.a.ii.g.ii.

[132] Staff Initial Brief ¶152; Erdahl, Exh. No. BAE-1T at 5:2-6.

is that the Board provides services that equally benefit shareholders and ratepayers. Staff states that its adjustment is consistent with the Commission's decision in a recent Avista general rate case.[133] PSE disputes this, arguing that the determinative factor in the *Avista* case was the extravagant nature of the expenses, which were determined on the record to provide no benefit to ratepayers.[134]

108 Staff also recommends use of the same percentage allocation of wages to O&M Expenses for PSE's new CEO, Ms. Kimberly Harris, as the 90.2 percent recognized in the test year for Mr. Stephen Reynolds, who retired in March 2011. PSE removed former CEO Reynolds's salary but allocated 93.09 percent of Ms. Harris's salary to utility operations expense. Staff states that PSE provided no data showing changes to the duties of the CEO that would support a higher allocation factor. Ms. Erdahl testifies that "it is reasonable [to believe] that the new CEO will spend similar time on similar duties to that of the retired CEO."[135]

109 Mr. Stranik testifies on rebuttal that the Company continues to contest Staff's proposed disallowance of 50 percent of the Board of Directors meeting expenses, but agrees to accept Staff's proposed adjustment with respect to the allocation of Ms. Harris's salary. PSE confirms this agreement by the Company in its Initial Brief.[136]

110 *Commission Determination:* Staff's position on Board of Directors meeting expense is consistent in principle with its position, and the Commission's determination, in a recent Avista proceeding. In that decision, however, the Commission relied on testimony elicited from an Avista witness under cross-examination by Public Counsel showing a number of extravagances associated with Board of Director meetings, including "expensive hotels, meals, cruises, museum visits, Directors' gifts, first class air fare, and entertainment."[137] Based on this record, the Commission determined that

[133] Erdahl, Exh. No. BAE-1T at 5:5-6 *(*citing *WUTC v. Avista Corporation*, Dockets UE-090134, UG-090135 and UG-060518, Order 10, ¶141-142 (December 22, 2009)).

[134] PSE Initial Brief ¶17.

[135] Erdahl, Exh. No. BAE-1T at 5:12-13.

[136] PSE Initial Brief ¶16.

[137] *WUTC v. Avista Corporation*, Dockets UE-090134, UG-090135 and UG-060518, Order 10, ¶142, note 171 (December 22, 2009).

many expenses incurred for Avista's Board activities did not provide ratepayer benefit. The Commission noted that:

> These sorts of expenses, particularly in an era of belt tightening and cutbacks, do not cast the Company in the best light, particularly when seeking ratepayer dollars for such expenses. In any future rate proceedings, we expect that the Company will sort out those expenses related to Board of Directors' meetings that do not have any benefit to ratepayers and make the appropriate restating adjustment at the outset. The Company should not expect Public Counsel or Commission Staff to perform that review function.[138]

111 There is no evidence in this proceeding, however, that PSE included any expenses for Board of Directors meetings or fees that were other than ordinary. While it is clear as a general proposition that Board of Directors fees and expenses benefit both ratepayers and shareholders, there is no evidentiary basis upon which to disallow a portion of these costs here.

112 PSE now agrees to Staff's recommendation to use the same allocation factor for Ms. Harris's salary as was used previously for Mr. Reynolds. It follows that the Miscellaneous Operating Expense adjustment should reflect Staff's recommended allocation of CEO salary.

113 Taking both our determinations and the uncontested components into account, the adjustment for Miscellaneous Operating Expense will be based on a decrease in net operating income (NOI) of $4,308,881 for electric and an increase in NOI of $261,609 for natural gas.[139] The corresponding adjustments to revenue requirements are an increase of $6,941,422 for electric and a decrease of $420,938 for natural gas.

b. Incentive Pay

114 PSE's adjustments use a four year average of incentive compensation paid to employees and exclude officer incentive pay. PSE regards its incentive pay program

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[138] *Id.*

[139] Stranik, Exh. MJS-10T at 10:10-12. PSE Initial Brief, Appendix A shows the combined adjustment for Miscellaneous Operating Expense as $4,047,271, which is consistent with these amounts.

as a key part of its overall compensation policy, which has two parts: competitive pay in the utility workforce and pay-for-performance.[140]

115 Staff accepts the continued use of a four year average to normalize this expense, an approach the Commission has previously approved. Staff also supports PSE's exclusion of officer incentive pay from this adjustment. Ms. Erdahl testifies, however, that incentive pay should be allowed in rates only to the extent it is tied to service quality, because this is what benefits the ratepayers, in Staff's view.[141] Ms. Erdahl proposes to remove 50 percent of incentive pay from the test year as a proxy for the amount Staff contends is related to PSE's financial performance.[142]

116 PSE's Goals and Incentive Plan establishes two measures upon which incentive payments depend. First, PSE must achieve its target performance on at least six of the ten measures included in its Service Quality Index (SQI) for *any* funding to be provided for incentive pay.[143] If more than six SQI measures are met, PSE provides additional funding for the incentive pool.

117 The second measure of success is financial. Even if PSE achieves its targets on six or more SQI performance measures, the Company must also generate an adjusted EBITDA (earnings before interest, taxes, depreciation and amortization) equal to or higher than 90 percent of budget for *any* funding of the incentive pool to occur.[144]

118 Mr. Hunt testifies that the two performance measures work together for plan funding, with the focus kept on SQI performance.[145] The interplay of the service quality and financial metrics is further emphasized to employees by establishing a target of

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[140] Hunt, Exh. No. TMH-1T at 16:16-18.

[141] Erdahl, Exh. No. BAE-1T at 6:8-13.

[142] Staff Initial Brief ¶155; Erdahl, Exh. No. BAE-1T at 6:5-13. Although Ms. Erdahl refers to removal of "test year" expense, what Staff actually reduces by 50 percent is PSE's restated 4 year average expense. *Compare* Martin, Exh. No. RCM-2 at 26 ("restated" column) to Story, Exh. No. JHS-14 at 10 ("restated" column).

[143] Hunt, Exh. No. TMH-10 at 3. We note that one of the issues addressed later in this Order is the proposed elimination of one of these performance measures, SQI-9: Disconnection Ratio.

[144] *Id.* at 4.

[145] Hunt, Exh. No. TMH-11T at 7:12-21.

meeting all 10 SQI measures and 100 percent of adjusted EBITDA and by establishing funding caps relative to the target that are tied to combinations of service quality and financial performance. If, for example, the Company achieves only six SQI goals, the Goals and Incentive Plan is funded at only 60 percent of the target level even if adjusted EBITDA exceeds 100 percent of budget. At the other end of the spectrum, if the Company meets all 10 SQI goals, every 5 percent improvement in EBITDA over the 100 percent of budget target results in increased funding of the plan, up to a maximum of 200 percent of the target level.

119 Ms. Erdahl testifies that "[t]he Company met all nine of the SQIs for the test year; however, it did not meet 100 percent of the financial metrics."[146] Considering this in light of Mr. Hunt's exhibit showing the relationship between SQI achievement and financial results in determining incentive pool funding levels, Mr. Hunt testifies it is clear that no part of the incentive compensation paid during the test year relates solely to financial performance.[147] As Mr. Hunt's exhibit shows, funding of the incentive pool that arguably results principally or exclusively as a result of financial performance when PSE meets all SQI goals occurs only when the Company achieves at least 105 percent of its EBITDA goal. In that event, there is a 22.5 percent increase in funding that does not depend on any further improvement in SQI performance.

120 *Commission Determination:* The Commission has accepted the 4-year average normalizing methodology for this adjustment in prior cases for PSE and there is no reason to question it here. Thus, our starting point is that PSE's restated results for incentive pay, as portrayed in Mr. Story's exhibits, are uncontested.[148]

121 While we recognize that there may be some merit to the idea of making a further adjustment to remove from the 4-year average all or part of any incentive payments that relate principally to financial results, there is no actual evidence that PSE made any such payments during the test year. The record establishes, instead, that incentive payments made during the test year were based on a calculation involving both

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[146] *Id.* at 6:19-20. SQI-9, Disconnection Ratio, was suspended during the test year.

[147] Hunt, Exh. No. TMH-10 at 4.

[148] Story, Exh. No. JHS-14 at 10.

metrics with neither measure being particularly more or less important in determining the level of funding for the incentive plan.[149]

122 In addition, there is no evidence contesting the reasonableness of PSE's total compensation or the fact that PSE's compensation is consistent with the market average. Nor is it disputed that PSE's incentive plan benefits customers by focusing employees on both meeting the SQIs and achieving operational efficiency.[150] Thus, the criteria by which the Commission most recently evaluated incentive compensation in a contested case are met here.[151]

123 We determine that PSE's adjustments for incentive pay should be accepted. This means an increase in net operating income of $482,220 for electric and $246,621 for natural gas with corresponding adjustments to revenue requirements of ($776,836) and ($396,822).

c. Property Taxes

124 Mr. Marcelia testifies that "PSE used the same methodology that it has used over the last 30 years or so to calculate the property tax expense associated with the assets owned in the test period."[152] He acknowledges that the Commission rejected this methodology in its last prior general rate case in favor of an alternative approach advocated by Staff.[153] Staff follows here the approach it took in the prior case.[154]

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[149] Even were there evidence of payments based more on financial results than on service quality results during the test year, it is not clear whether it would be appropriate to make an adjustment by applying a percentage disallowance factor to results derived by use of a four year average instead of test year results. Nor is it clear whether any disallowance should be based on all incentive payments or just the additional funding provided when nine or more SQI's are met and financial performance exceeds 100 percent of EBIDTA.

[150] PSE Initial Brief ¶20. We note in this connection that to the extent financial results can be tied to the achievement of operating efficiency this, too, benefits ratepayers by keeping costs down.

[151] *WUTC v. PacifiCorp*, Docket No. UE-100749, Order 06 ¶¶ 240–50 (March 25, 2011) ("We do not wish to delve too deeply in to the Company's management of its human resources and the manner in which it determines overall compensation policy. Thus, we inquire only whether that compensation exceeds the market average, is unreasonable, and offers benefits to ratepayers.

[152] Marcelia, Exh. No. MRM-1T at 35:7-9.

[153] *Id.* at 44:11-12. *See also, WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11, ¶¶ 55-59 (April 2, 2010) (2009 GRC).

[154] *See generally* Applegate, Exh. No. RTA-1T.

125 The essence of the dispute is that PSE seeks to recover property tax expenses by estimating the amount it expects to pay in 2012 for property owned *at the end of the test year,* the value of which is assessed as of January 1, 2011[155] while Staff argues the Company should recover the actual amount of property tax paid during 2011 for property PSE owned a*t the start of the test year* (*i.e.,* as of January 1, 2010). The importance of this from the Company's perspective is heightened by the fact that it made significant property additions in the post-January 1, 2010, period.

126 The dispute, in this sense, focuses on the "lien date."[156] This is the date on which the taxing authorities attach a tax lien on all of PSE's taxable property each year. That is, PSE accrues a property tax liability based on the value of what it owns as of the lien date. In the tax jurisdictions in which PSE operates, the lien date is January 1 of the assessment year. The Company estimates the amount of its property tax liability on the lien date, though the exact amount of the actual tax liability is determined the following year, as described below. The company records it as required under the rules governing accrual basis accounting.

127 Property tax expense is the product of three components: (i) the assessed value, (ii) the system ratio, and (iii) the levy rates. The result is the property tax liability for the property that was owned at January 1 of the assessment year. Complicating matters for ratemaking, each component becomes known at a different time. From start to finish, the process runs from January 1 of the assessment year (Year 1) through April of the following year (Year 2) – a total of 16 months.[157] Throughout the Year 1 and Year 2 property tax cycles, the main components and their approximate timing are as follows:

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[155] Applegate, Exh. No. RTA-1T at 12:16-20; Marcelia, Exh. No. 14T at 65:20-66:9.

[156] Marcelia, Exh. No. MRM-1T at 35:11-36:11.

[157] Mr. Marcelia testifies (Exh. No. MRM-1T at 36:18-37:7) that the process is even longer if the tax payments are factored in, as the tax payments occur on April 30 and October 31 of Year 2. His Exh. No. MRM-9 illustrates the property tax timeline and shows when each component of the property tax calculation becomes available. This exhibit highlights how the property tax cycle from one year spills over into the property tax cycle of the next year, and, at certain times of the year, the two cycles run concurrently.

EVENT	DATE	
Lien date	Year 1	January 1
Unit value	Year 1	July
System ratio	Year 1	December
Levy rate	Year 2	April
Payment 1 due	Year 2	April 30
Payment 2 due	Year 2	October 31

On January 1 of Year 2, the same cycle begins for Year 2 and runs through Year 3.

128 The property tax cycle begins for PSE on January 1 of the assessment year (Year 1) because PSE must determine its best estimate of property tax expense for financial accounting purposes. The initial estimate relies heavily on data and estimates from the prior year. PSE revises the calculation as better information becomes available throughout the remainder of the cycle.[158]

129 For any given cycle, one of the first events is that the levy rates for the prior cycle will become available, generally in March or April. The prior year levy rates represent new information that must be factored into the calculation of levy rates for the current year, even though the new data for the levy rates relates to the prior year property tax. PSE typically uses a multiyear average to estimate the expected levy rate.[159]

130 Around the end of July, the Washington State Department of Revenue completes its evaluation of the value of property that PSE owned on January 1st of Year 1. Once the value has been set, PSE updates its tax calculation to reflect the new values.[160] In December, the Department of Revenue provides PSE with the unit value allocated to each county, along with the system ratios for each county. Based on this new information, PSE again updates it property tax estimate.[161]

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[158] Marcelia, Exh. No. MRM-1T at 38:6-10.

[159] *Id.* at 38:11-15.

[160] *Id.* at 38:17-20.

[161] *Id.* at 39:2-4.

131 The system ratio is the percentage that is applied to PSE's taxable value to reduce PSE's taxable value down to the level of taxation at which all the other members of the particular county are assessed. Because PSE is appraised every year and other taxpayers in the county are not appraised every year, PSE is treated differently than other taxpayers. Each county applies a different system ratio (sometimes referred to as an equalization ratio) to PSE's property to equalize PSE's values with the values of other taxpayers in that county.[162]

132 At the end of Year 1, PSE records an updated estimate of the property tax expense that it anticipates to pay for the assets it owned on January 1st of Year 1. The levy rate, however, is not provided until March or April of the following year when the actual tax bills arrive. As a result, the annual property tax expense recorded at year end remains an estimate of the final amount.[163] In the 2009 GRC Final Order the Commission rejected PSE's approach to this adjustment because the Company's use of estimated levy rates appeared to result in unreliable estimates of PSE's tax liability.[164]

133 This is significant for ratemaking because the test year is a twelve-month historic period. In this proceeding, the test year is concurrent with calendar year 2010 (*i.e.,* January 1, 2010, through December 31, 2010). In the context of a property tax calculation, using a twelve-month period is problematic because a complete property tax calculation takes about sixteen months. The issue this raises is that the property tax expense associated with Year 1 (*i.e.,* the test year) is not finalized until 3 or 4 months into the property tax cycle for Year 2. Year 2 is entirely estimated based on the available information from Year 1, which is itself an estimate.[165]

134 PSE's position is that the matching principle requires this expense to capture the property tax associated with all property that the Company owned during the test

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[162] *Id.* at 39:6-12.

[163] *Id.* at 39:15-20.

[164] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11, ¶¶ 55-59 (April 2, 2010). The Commission stated its concern that the amounts of property tax liability PSE reported as it updated its estimates during the relevant tax cycle varied widely, changing by as much as 187 percent from one estimate to another.

[165] Marcelia, Exh. No. MRM-1T at 40:10-18.

year, even if it was acquired after the lien date of January 1, 2010.[166] PSE recorded net additions through December 31, 2010 (*i.e.*, the end of the test year) of $495.9 million of new plant, which is not reflected in the property tax associated with the January 1, 2010 lien date upon which Staff would have us rely.[167]

135 The additional plant added during the 2010 test year will have an impact on PSE's property tax liability for the following year. Not reflecting this impact will disturb test year relationships because the property tax recorded in the test year is based on property from 2009, not 2010.[168] Thus, PSE's calculation in this case looks to the lien date of January 1, 2011, which captures all assets owned on the last day of the test year, December 31, 2010.[169]

136 In the 2009 GRC Final Order the Commission rejected PSE's approach to this adjustment, but this was based on the Company's use of estimated levy rates, not PSE's practice of using updated assessed values.[170] The significant variation of PSE's tax estimates from the as-filed case to the estimates presented later in the case was a key factor in the Commission's determination.[171]

137 In this case, Staff's focus shifts from the levy rates to the lien date. Staff recommends that the Commission reject PSE's use of property values at the end of the test year and instead use the property tax values that are finally assessed and become due and payable in April and October of 2011 for property owned by PSE on January 1, 2010, the beginning of the test year.[172] Mr. Applegate testifies that Staff's proposed adjustment matches revenue requirement with the actual cash outlays PSE must make

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[166] *Id.* at 41:6-14.

[167] *Id.* at 42:1-5. The breakdown of net plant additions between electric and natural gas operations is as follows: $448.6 million for electric and $47.3 million for gas. *Id.*

[168] *Id.* at 43:1-4.

[169] *Id.* at 43:11-12.

[170] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11, ¶ 60 (April 2, 2010).

[171] *Id.* ¶ 57.

[172] Applegate, Exh. No. RTA-1T at 13:15-21.

in 2011 to satisfy its 2010 tax liability.[173] Staff states this is consistent with the treatment of property tax described by the Commission's Order 11 in Docket UE-090704.

138 *Commission Determination:* We are setting rates that will become effective in 2012, at approximately the time PSE will makes its first property tax payment to the taxing authorities for property the Company owned on January 1, 2011 (*i.e.*, one day after the end of the test year). This fact militates strongly in favor of establishing January 1, 2011, as the lien date for purposes of this adjustment. PSE's response to Bench Request 17 includes known property values and system ratios for the 2011 tax year. The response is based on an estimated levy rate, but the actual rate will become known in April, before the suspension date in this proceeding.

139 Considering that property tax is an expense outside PSE's control insofar as the levy rate is concerned, we elect to make an exception to the Commission's usual practice of accepting only changed values for expenses that are known and measurable within a short period after the end of the test year. Given the timing of this case relative to the tax cycle discussed above, we choose to take a more forward looking approach and require PSE to use its actual 2011 property tax, payable in 2012, when making its compliance filing. Based on PSE's response to Bench Request 25, the adjustment for electric operations is a decrease in NOI of $3, 036,123, with a corresponding revenue requirement increase of $4,891,078. The adjustment for natural gas operations is a decrease in NOI of $1,480,271, with an increase in revenue requirement of $2,381,810.

140 We emphasize this is an exceptional approach considering the specific circumstances related to the timing of the property tax cycle relative to the timing of this case. It should not be viewed as establishing a principle for future application outside such a context or application to other adjustments.

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[173] *Id.* at 14:8-14. We note that based on Mr. Marcelia's testimony, any property acquired by PSE during the test period is not subject to property tax liability until January 1, 2011, and the amount of taxes due will not be known until 2012, when PSE is billed by the taxing authorities. Thus, the amounts will not actually be known and measurable until April 2012, at the earliest. This is long after the test period that ended on December 31, 2010.

141 Measuring property tax for recovery in rates is a particularly intractable problem because of the significant lag that is inherent to the process of its determination. This inherent lag of 16 or more months, in the context of a rate case that may itself require 10 months to complete, makes it very difficult to include an accurate, up-to-date property tax amount for recovery in rates during the future rate year. Depending on the timing of a rate case filing relative to the dates on which valuations are made, system ratios are set and levy rates are determined, property taxes included at the commencement of a general rate case may be based on estimates of one variable, on two variables, or even on all three. To one degree or another, the approach PSE has typically taken will always involve estimates and the relative accuracy of these estimates may vary significantly from one case to another.

142 Mr. Marcelia testifies that "PSE's goal in calculating property tax expense in this filing is to recover the actual tax—no more and no less."[174] He observes correctly that the amount of property tax is ultimately outside of PSE's control because it is set by state and local taxing authorities.[175] Mr. Marcelia suggests that the Commission's concerns about using estimates for this expense could be met by treating property taxes like municipal taxes, allowing them to be passed through on a rider.

143 We find merit in Mr. Marcelia's proposal. We accordingly require that PSE bring forward a proposal in its next general rate case filing that will, if approved, allow for actual property taxes—no more and no less—to be recovered in rates by means of a rider. We encourage PSE to work with Commission Staff and others who may take an interest in this matter to bring forth an agreed mechanism. If this process is not undertaken, or fails to succeed, PSE may elect to offer its own proposal as an alternative to inclusion of an estimated property tax for the rate year.

d. Directors & Officers Insurance

144 The Company's adjustment annualizes the directors' premiums based on changes during the test year and restates the portion of the Directors and Officers (D&O) Insurance that should be allocated to Company subsidiaries using a new methodology.

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[174] Marcelia, Exh. No. MRM-1T at 48:14-19.

[175] PSE does, of course, have the opportunity to challenge property tax assessments, at least as to valuations and perhaps by other means.

Mr. Stranik testifies that the allocation historically has been based on the ratio of utility to non-utility assets but says this method has become more difficult with the use of "combination accounting (Accounting Standards Codification 805)" as a result of the Company's acquisition by Macquarie, *et al.* in 2009.[176] PSE's proposed new allocation methodology gives equal weight to the "allocation of directors' fees and . . . direct labor charges for employees covered by D&O insurance between utility and nonutility operations."[177] PSE allocates 9.95 percent of these insurance expenses to shareholders based on the time spent on nonutility activities. Additionally, PSE's calculation allocates a portion of insurance expense to subsidiaries.[178] The allocation between electric and gas is based on the relative number of customers.

145 Staff does not question PSE's annualizing of recent premiums or the Company's restating adjustment. Staff, however, proposes an additional adjustment to remove 25 percent of D&O Insurance premiums, which represents half of the expense that is related to Directors.[179] Ms. Erdahl testifies for Staff that the Board of Directors provides services that equally benefit shareholders. Therefore, in Staff's view, it is fair that shareholders equally share this cost with PSE's customers.

146 Staff states that its adjustments are also consistent with what it proposes for Directors' Fees and Expenses, which we reject above because there is no evidence in the record supporting it. Staff also argues its proposed adjustment here is consistent with the Commission's decision regarding Directors' Fees and Meeting costs in a recent Avista general rate case.[180] While the Commission accepted the proposed 50/50 sharing of Directors' Fees and Meeting costs in *Avista* based on evidence unique to the record of that case,[181] it rejected Staff's proposal for the allocation of D&O

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[176] Stranik, Exh. No. MJS-1T at 21:17-22:3.

[177] *Id.* at 22:4-7.

[178] Stranik, Exh. No. MJS-10T 17:6-9.

[179] Erdahl, Exh. No. BAE-1T at 9:1-6. Staff's approach is different from the approach it advocated in PSE's 2009 general rate case, to disallow 50 percent of all D&O Insurance, which the Commission rejected. *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11, ¶ 60 (April 2, 2010). It appears to us that Staff's proposal is different only in the recommended level for this adjustment. There is no difference in the stated rationale.

[180] *WUTC v. Avista Corporation*, Dockets UE-090134, UG-090135 and UG-060518, Order 10, ¶ 141-142 (December 22, 2009).

[181] *See supra* ¶¶75, 78 (section 2.C.3.b. Miscellaneous Operating Expense).

insurance. The Commission treated D&O insurance as part of the compensation package for officers and directors and applied a 90/10 split shown by the evidence to be appropriate generally for the allocation of officers' compensation.[182]

147 *Commission Determination:* The Commission rejected Staff's proposal to disallow a portion of PSE's D&O insurance costs in the last prior PSE general rate case in significant part because Staff failed to present evidence supporting a particular allocation of these costs to shareholders.[183] That is the situation again in this case.

148 There is no dispute in the record concerning the level of this expense as proposed by PSE in its restating adjustment. There is no specific evidence that supports a disallowance of any portion of the expense by allocation to shareholders or otherwise. We have only Staff's assertion that it would be "fair" to disallow 25 percent of D&O Insurance premium costs. It would not, however, be "just" to do so absent a supportive record. We determine that PSE's adjustments for D&O Insurance should be accepted.

e. Rate Case Expense

149 PSE restates test year rate case expenses to normalized levels using the same approach it has consistently taken since it was first proposed by Staff in PSE's 2004 general rate case. This method has been accepted by the Commission since that time.[184] The Company uses the history of expense levels for power cost only rate cases and general rate cases to determine a normalized level of expenditures by averaging the costs associated with the last two general rate cases as one calculation and the last two power cost only rate cases as another calculation. The average general rate case expense is allocated 50 percent to electric and 50 percent to natural gas. The average PCORC expense is allocated only to electric operations.

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[182] *Id.* ¶ 137.

[183] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11, ¶¶ 64-65. (April 2, 2010).

[184] Stranik, Exh. No. 10T at 18:4-8. According to Mr. Stranik, the normalization approach originally proposed by Commission Staff in 2004 was unopposed in the 2006, 2007 and 2009 general rate cases (*i.e.*, Docket Nos. UE-060277/UG-060267, UE-072300/ UG-072301 and UE-090704/UG-090705, respectively).

150 Each average cost is then normalized for recovery over a time period based on the frequency of filings experienced in the recent past. The average costs for a general rate case are normalized for recovery over two years and the average costs of a power cost only rate case are normalized over four years.

151 Staff recommends that the Commission reject PSE's proposed rate case expense adjustments in their entirety and allow the Company to recover its 2010 test year rate case expenses.[185] PSE did not file a combined gas and electric GRC in 2010. Mr. Applegate testifies that the Company nevertheless incurred GRC costs during 2010 that are reflected in test year values.[186]

152 Staff argues that PSE's approach suffers from several deficiencies.[187] It violates the matching principle because general rate cases contain costs from multiple years.[188] It results in an unfair cross subsidy from gas ratepayers to electric ratepayers because electric costs are a disproportionately larger share of PSE's overall costs.[189] Finally, it includes PCORC costs that have already been recovered in base rates even though no PCORCs have been filed since 2007.[190]

153 Mr. Applegate's testimony is that these costs were included in the Company's 2007 GRC filing, normalized on a two year filing frequency. Rates for that GRC became effective on November 1, 2008. The Company's 2009 GRC also included these costs, normalized again on a two year filing frequency. Rates for that GRC went into effect on April 8, 2010. In both cases, he says, rate case costs will be recovered fully before new rates from this case go into effect.[191]

154 PSE argues that Staff confuses normalization of like-type costs with deferral and amortization of specific costs. By normalizing rate case costs PSE is not recovering

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[185] Staff Initial Brief ¶173.

[186] Applegate, Exh. No. RTA-1T at 16:11-21.

[187] Staff Initial Brief ¶172.

[188] *Id.* (citing Applegate, Exh. No. RTA-1T at 17:3-9).

[189] *Id.* (citing Applegate, Exh. No. RTA-1T at 17:10-14).

[190] *Id.* (citing Applegate, Exh. No. RTA-1T at 17:15-22).

[191] Applegate, Exh. No. RTA-1T at 17:15-22.

specific costs from a given case but is building into rates a normal level of rate case expenses, which benefits customers by eliminating volatility.[192] This means PSE's approach is not double-recovering prior expenses and the matching principle is not implicated.[193]

155 Mr. Stranik testifies concerning the high degree of variability in rate case expenses from period to period and says most such costs are incurred in periods between rate cases. These facts, he contends, demonstrate that the normalized methodology the Commission has used for the past several years is superior to the test year approach that Commission Staff proposes in this case. "The normalized methodology reduces volatility, accommodates for differing rate case schedules and filing frequencies, and provides a more levelized, representative expense."[194]

156 *Commission Determination:* Rate case expense was last a fully contested issue in PSE's 2004 rate case.[195] PSE argued then that it should be allowed to defer and recover through amortization over three years its full rate case expense, as it had done in previous cases over the prior 20 years. Ultimately, the Commission approved in that case an amount agreed between PSE and Staff using a normalized expense methodology similar to what PSE uses in this case and identical to the method it adopted in its 2007/2008 general rate case in Dockets UE-072300 and UG-07230.

157 Testimony from both the Company and Staff shows that rate case expenses vary significantly from one year to the next. It is generally appropriate to normalize such expenses. This tends to come closer to satisfying the matching principle, or at least the principles underlying it, than simply using the costs from a single year, which may be quite high or low relative to the normalized amount.[196] Using average annual costs over several years is one means to normalize such expenses, but it is not the only valid approach. We see no reason, given the present record, to change the

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[192] Stranik, Exh. No. MJS-10T 21:17-19.

[193] *Id.* at 18:16-19:1; 21:13-22:6.

[194] *Id.* at 20:15-19.

[195] *WUTC v. Puget Sound Energy, Inc.*, Dockets UG-040640, UE-040641, UE-031471, and UE-032043 (consolidated), Order 06, ¶¶ 163-176 (February 18, 2005).

[196] Stranik, Exh. No. MJS -21.

normalization method to which Staff and PSE previously agreed, and the Commission approved, for determining rate case expenses.

158 While it is true that PSE's electric costs represent a larger share of the Company's overall costs relative to natural gas operations, it is unclear from Staff's testimony how this fact relates to the costs of regulation. Many, even most, of the issues litigated in a general rate case proceeding, for example, are common to electric and natural gas operations. PSE separately calculates average expenses of PCORC proceedings and allocates those costs to electric. Moreover, the record includes no evidence that shows us what alternative allocation might be appropriate. Thus, we accept PSE's equal allocation of these costs between electric and natural gas operations.

4. Contested Adjustments - Electric and Natural Gas - Rate Base

159 This category of adjustments again includes expenses that PSE incurs in connection with both electric and natural gas service. These adjustments, however, also involve changes to rate base. PSE earns a *return on* its rate base (*i.e.*, its overall rate of return, 7.80 percent, as authorized in this Order), and a *return of* its rate base, via depreciation. Hence, PSE's revenue requirements are affected by our determinations concerning PSE's rate of return, depreciation expense[197] and operating expenses, as reflected throughout this Order. There are two contested adjustments in this category, federal income tax and working capital. We also address in this section of our Order the respective natural gas and electric adjustments for the Tax Benefit of Pro Forma Interest, which is uncontested as to method. It is a straightforward calculation, as discussed below.

a. Federal Income Tax

160 This adjustment changes PSE's federal income tax expense to regulatory levels based on the pro forma results of operations. There are a number of separate, underlying

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[197] Adjustments 14.07 and 6.07, General Plant Depreciation, are uncontested.

adjustments, most of which are not contested.[198] Staff, Public Counsel[199] and ICNU, however, raise several points that require discussion and our decisions.

i. Accounting Treatment for Repairs and Retirements

161 The key Federal Income Tax adjustment issue in this proceeding, in terms of rate base and revenue requirement, concerns PSE's current accounting treatment for repairs and retirements expense. PSE changed its accounting method for repairs in its 2008 tax return, which the Company filed in September 2009.[200] PSE adopted the same method for retirements in March 2010, and used it in PSE's 2010 federal income tax return. This tax method change allows PSE to use different units of property (UOP) for tax purposes than the UOPs used for book purposes. In general, the UOPs for tax purposes are larger than those for book purposes. By using larger UOPs for tax, more of PSE's expenditures qualify for an immediate tax deduction.[201]

162 The effect of PSE changing its tax accounting method for repairs has resulted in a significant increase in the Company's ADIT (accumulated deferred income taxes) while the corresponding change for retirements resulted in a small offset against the increased ADIT for repairs. The net impacts, according to Staff witness Ralph C. Smith, are increases to ADIT of $41,414,322 for PSE's electric utility operations and $24,564,298 for PSE's gas utility operations.[202]

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[198] Staff agrees with PSE's treatment of bonus tax depreciation impacts on accumulated deferred income taxes. Staff Initial Brief ¶ 136 (citing Smith, Exh. No. RCS-1T at 31:8-19). Staff also agrees with PSE's proposed changes to the federal income tax treatment from flow-through to normalization for capitalized property taxes, injuries and damages, and bad debts. *Id.* (citing Smith, Exh. No. RCS-1T at 33-40).

[199] Although the Energy Project co-sponsors with Public Counsel Ms. Crane's full testimony, including her recommendations concerning consolidated tax treatment, discussed below, the Energy Project does not address this issue on brief.

[200] *See* Staff Initial Brief ¶138 for a fuller discussion of the history of this change that PSE adopted before the test year, used during the test year, and uses currently.

[201] Marcelia, Exh. No. MRM-1T at 18:18-19:2.

[202] According to Mr. Smith, the impacts on ADIT from the change in tax accounting for only the repairs deductions, derived from PSE's filing, are $41,842,225 for electric utility operations and $24,996,849 for gas utility operations. Smith, Exh. No. RCS-1CT at 5:1-11. The tax accounting

163 Considering both repairs and retirements, Staff argues that PSE's 2010 rate base should be decreased by these net amounts. Mr. Smith testifies that:

> By normalizing the tax savings, similar to what has traditionally been done for book-tax timing differences related to accelerated tax depreciation, ratepayers can benefit from the source of funds provided by such tax savings. The normalization treatment helps assure that all tax savings realized by the method change will benefit ratepayers by reducing rate base. However, there is no benefit in the current PSE general rate case under the Company's proposed treatment, which is to totally exclude all impacts from the repairs deduction on ADIT.[203]

164 PSE removed the tax impact of the new method from this filing based on its interpretation of a single sentence in the Commission's Final Order in Dockets UE-090704 and UG-090705:[204]

> 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 [Internal Revenue Service] approves its methodology for treatment of repair costs following an audit.[205]

Mr. Marcelia describes this sentence as being "the Commission's instructions on the ratemaking treatment for this accounting method" and says they "are clear and unambiguous."[206] He interprets this as the Commission imposing an audit requirement as a prerequisite to recognition of the increased ADIT in rates. At the time PSE filed this case, the IRS has not yet audited the new method. For this reason, "PSE has not implemented an increase to ADIT."[207]

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method change for retirements reduces PSE's ADIT by approximately $428,000 for electric utility operations and by $433,000 for gas utility operations. *Id.* at 22:7-9.

[203] *Id.* at 7:13-19.

[204] *WUTC v. Puget Sound Energy*, Dockets UE-090704 and UG-090705(consolidated) Order 11 (April 2, 2010).

[205] Marcelia, Exh. No. MRM-1T at 19:10-13 (citing *WUTC v. Puget Sound Energy*, Final Order Approving and Adopting Settlement Stipulations: Authorizing and Requiring Compliance Filing, Order 11, Dockets UE-090704 and UG-090705(consolidated) (April 2, 2010) ¶ 197).

[206] *Id.* at 19:8-9.

[207] *Id.* at 19:15-17.

165 Mr. Smith quotes the Commission's entire discussion of this subject in its Final Order in Dockets UE-090704 and UG-090705.[208] In the "Commission Determination" section of the discussion the Commission acknowledged the" risks of recognizing IRS-allowed accounting changes before they are audited." The Commission decision however, turned on a different point, discussed as follows:

> There is the Company's argument that the permissive tax treatment was not granted until long after the end of the test period. While the Company has definitely sought to include some adjustments in its favor that reflect events as long as 12 months after the close of the test-year, the Commission's principles governing pro forma adjustments, and its decisions in this case, are fashioned to allow such adjustments only in limited circumstances.
>
> We accordingly reject FEA's adjustment in this case as an inappropriate pro forma adjustment. The final disposition with the IRS is not known and the tax impact is in any event subsequent to the test-year. 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.[209]

166 Mr. Smith points out that the Commission later considered this same issue in the context of a PacifiCorp general rates case. In that case, despite the absence of an IRS audit, the Commission required PacifiCorp to reflect the full amount of increased ADIT for the test year.[210] The Commission emphasized in its PacifiCorp order that the known and measurable quality of the proposed pro forma adjustment is determinative and explained that this is consistent with its determination in the prior PSE case: "In the PSE case, we rejected the argument that *no* adjustment could be made to rate base until after an IRS audit because the amount was not known and measurable."[211] Observing in PacifiCorp's case that the ADIT adjustment amount "is

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[208] Smith, Exh. No. RCS-1CT at 10:1-11:12.

[209] *Id.*

[210] *Id.* at 15:18-17-25.

[211] *Id.* at 16:36-37 (quoting *WUTC v. PacifiCorp*, Docket UE-100749 Order 6, ¶¶259-260 (March 25, 2011)).

both known and measurable," the Commission said further that: "The IRS allowed the tax treatment in the PSE case long after the end of the test year. Here, in sharp contrast, the IRS allowed the tax treatment *during* the test year."[212]

167 Considering both the language in the prior PSE general rate case order and the context provided by the Commission's discussion and analysis in the PacifiCorp case, "the ADIT impact from the new tax accounting method for repairs is both known and measurable in the test year."[213] Indeed, "PSE had to specifically *remove* those amounts in its filing in its attempt to *not* reflect the related ADIT balances."[214] Thus, Mr. Smith concludes, "there is no valid reason remaining to *not* reflect the known and measurable impact of the repairs deductions taken by PSE as a reduction to rate base in the current PSE rate case and the 2010 test year being used to determine PSE's revenue requirement."[215]

168 Mr. Marcelia's rebuttal testimony elaborates on the Company's argument that it is following what it interprets to be the explicit directive of a prior Commission order. He focuses on the idea that because an IRS audit may result in changes to the tax impacts of the accounting changes PSE made, the costs are not known and measurable even though PSE has been following this method in filing its federal taxes for three years. PSE adheres to this position in its Initial Brief.[216]

169 *Commission Determination:* Mr. Marcelia's testimony and PSE's argument on this issue depend on a strained interpretation of a single sentence in the Commission's prior order. Both completely ignore the context surrounding the one sentence and the determinative facts on which the issue turned. The sentence upon which PSE relies for its removal of the net ADIT for repairs and retirements describes a sufficient, but not a necessary, reason to require PSE to recognize this change for ratemaking purposes. PSE ignores that the critical factor in the Commission's earlier decision was that the tax impact of the new tax accounting method for repairs deductions

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212 *Id.* at 17:9-11.

213 *Id.* at 17:26-28.

214 *Id.* at 17:28-29.

215 *Id.* at 17:30-33.

216 PSE Initial Brief ¶¶87-92.

occurred "long after" the test year. No such circumstance is presented in the current case where the tax impact of PSE's repairs and retirements deductions occurred before and during the test year.

170 If there existed any room for serious doubt, the Commission's subsequent discussion of this very issue in the PacifiCorp general rate case, quoted above, makes the matter crystal clear. The Commission expressly rejected the argument that a completed IRS audit is required before rate base can be reduced to reflect the impact on ADIT of the change in tax accounting for repairs deductions.

> *PacifiCorp argues that the Commission denied an adjustment in the 2009 Puget Sound Energy (PSE) rate case that is identical to the adjustment Staff proposed here. The Company's reliance on that case is misplaced. In the PSE case, we rejected the argument that no adjustment could be made to rate base until after an IRS audit because the amount was not known and measurable.* Here, according to the Company, the accumulated deferred income tax liability balance as of December 31, 2009, is $28,927,370. *Thus, the amount is both known and measurable. In addition, the IRS allowed the tax treatment in the PSE case long after the end of the test year. Here, in sharp contrast, the IRS allowed the tax treatment during the test year.*
>
> We conclude that Staff is correct and we should accept its adjustment to reduce rate base by $28,927,370, which reflects the impact of the full year of the change. *The repairs deduction is an ongoing difference in accounting that will be in effect for the same period as the rates set in this proceeding. The change is known and measurable.* Accordingly, it is reasonable to normalize and reflect the impact as if it were in effect for the entire period. The impact of this adjustment reduces the revenue requirement by $1,822,309 in addition to the $1.7 million the Company has already recognized.[217]

171 We find that the impact of PSE's repairs deductions on ADIT through the 2010 test year is known and measurable and, therefore, must be reflected as a rate base deduction net of the related tax accounting change for retirements. It would be improper and unfair to ratepayers to ignore this $65,978,620 reduction to rate base

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[217] Staff Initial Brief ¶142 (citing *WUTC v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Docket UE-100749, Order 06, ¶¶259-260 (March 25, 2011) (emphasis added; footnotes omitted)).

(*i.e.*, \$(41,414,322) for electric and \$(24,564,298) for natural gas)[218] and the corresponding reduction to PSE's revenue requirement of \$8,063,733 (*i.e.*, \$(5,203,902) for electric and \$(3,082,938) for natural gas).

ii. Treasury Grant

172 The availability of grant money from the U.S. Treasury in lieu of production tax credits for wind facilities is one of the factors PSE cites in support of its arguments that the Company's acquisition of the Lower Snake River wind facility is prudent. While prudence is a separate discussion below, the treatment of these Treasury Grants allowed by the IRS warrants brief mention here.

173 A recent amendment to the American Recovery and Reinvestment Act of 2009 (ARRA) eliminated the requirement to normalize Section 1603 Treasury grants.[219] The amendment is not relevant directly to LSR because it occurred after the decision to build. However, it now allows ratepayers to benefit not only from the amortization of the grant as a credit to operating expense, but also from the return on the unamortized balance of the grant regulatory liability.

174 Staff recommends that the Commission consider alternatives to the current Schedule 95A credit for returning the benefits of the LSR Treasury grant to ratepayers, and asks the Commission to order PSE to defer the grant, when received, with interest as a regulatory liability.[220] Staff argues that this will allow parties to propose alternative treatments when PSE files to update the Schedule 95A credit for the Treasury grants.[221] Schedule 95A requires that filing within 60 days after PSE receives the grant.

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[218] R. Smith, Exh. No. RCS-3.

[219] The amendment occurred through Section 1096 of the National Defense Authorization Act for Fiscal Year 2012, H.R. 1540, 112th Cong., 1st Sess.

[220] Schooley, Exh. No.TES-3T at 4:13-18.

[221] The elimination of normalization requires revisiting the Treasury grant for the Wild Horse Expansion that was received by PSE during the test year on February 23, 2010 and amortized in rates starting January 1, 2011. *In the Matter of Puget Sound Energy, Inc. for an Accounting Order Regarding the Treatment of U.S. Treasury Grant*, Docket UE-091570, Order 01 (December 10, 2009). PSE states that eliminating normalization for the grant changes the allocation of \$375,811 total investor supplied working capital between electric, gas and non-operating, but that the change occurred too late to reflect in this docket. The rate of return on the

175 PSE states that although Treasury Grants are not an issue in this proceeding the Company 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.[222] PSE says that "in this short interim period, PSE would deposit the funds into an interest bearing account and defer the interest."[223]

176 *Commission Determination:* We agree with the parties that elimination of the requirement to normalize Section 1603 Treasury grants, which allows ratepayers to benefit not only from the amortization of the grants as a credit to operating expense, but also from the return on the unamortized balance of the grant liability, is reason enough to revisit the treatment of these federal benefits in rates. PSE's anticipated Schedule 95A filing in November 2012, or a separate filing required by Schedule 95A, will provide a forum in which this question can be addressed.

iii. ***Net Operating Loss***

177 Since the beginning of the current recession Congress has tried different approaches to revitalize the economy. One approach has been the use of "bonus depreciation" to allow rapid recovery of investment that it is assumed will be reinvested. Bonus depreciation allows companies, including PSE, to deduct from taxable income 50 percent to 100 percent of the cost of a new asset in the year the asset is acquired. The bonus depreciation greatly reduces the taxable income of the company and the amount of income taxes the Company must actually pay. For regulatory purposes the rapid recovery creates: (1) a Net Operating Loss (NOL) resulting in zero income taxes payable and (2) large deferred taxes caused by the bonus depreciation maximizing

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grant liability is included in a separate Schedule 95A filing submitted on February 29, 2012 in Docket UE-120277. Story, Exh. No. B-23, B. The amendment to ARRA states that the elimination of normalization is effective "as if included in section 1603 of the [ARRA] of 2009". Thus, an issue in Docket UE-120277 is whether PSE should compute the rate of return benefit during the period February 23, 2010 (the date the grant was received) through December 31, 2011 (the date the amendment to ARRA was enacted). Staff reserves the right to address this issue in Docket UE-120277.

[222] PSE Initial Brief ¶174.

[223] *Id.*

cash flow.[224] Cash flow is maximized because the related deferred income tax expense created by the timing differences is still recovered in rates.

178 In the Company's case, the tax basis NOL created by bonus depreciation must be carried forward to future years. NOLs act as additional tax deduction on future tax returns, reducing future taxes payable to zero until the carryforward no longer is large enough to reduce operating income to zero.[225]

179 The Company observes that as a practical matter, any tax benefits associated with the NOL will be delayed until a future tax year. According to the Company, PSE has claimed bonus depreciation on its taxes but has not received a cash benefit. The cash benefit is the amount of income taxes the Company would have paid had it not been for the accelerated recovery reflected in the bonus depreciation. The Company observes that "[a] NOL carryforward is similar to a tax receivable from the IRS except that it can only be used on future tax returns…."[226]

180 Since the NOL carryforward cannot be used by the Company to reduce a current liability, the Company argues that the deferred taxes associated with the assets that created the NOL should also be offset by a NOL carryforward deferred tax asset.[227] The reduction in the net deferred tax amount increases rate base by the amount of the tax-affected NOL.

181 While Staff agrees with the Company and recommends that rate base be increased by the NOL reflecting the impact of the deferred tax asset, Staff also recommends that the current income tax expense be reduced to zero and that all income tax expense be recognized as deferred.[228] Total proposed income tax expense remains the same but the terms of presentation are altered under Staff's response.[229] The Company responds that the tax impact of its adjustments to taxable income is appropriately

[224] Marcelia, Exh. No. MRM-1T at 25:7-19.

[225] Marcelia, Exh. No. MRM-1T at 26:2-11.

[226] Marcelia, Exh. No. MRM-1T at 26:15-27:3.

[227] *Id.* at 27:16-28:4.

[228] Smith, Exh. No. RCS-1CT, at 3:1-7.

[229] *Id.*; *See also Id.* at 32:1-5.

recorded as current, since PSE's future tax position in the rate year is unknown. More to the point, Mr. Marcelia testifies, the Company is required to follow the FERC Uniform System of Accounts.[230]

182 Ms. Crane testifying on behalf of Public Counsel and The Energy Project argues that the Company's rate base should not be increased by offsetting accumulated deferred tax by its NOL. She maintains that the Company should make an offsetting adjustment to income tax expense in order to include the impact of the NOL in regulated rates.[231] In addition she proposes that if the Commission accepts the Company's adjustment then the Commission should review other tax issues including whether the Company is subject to a consolidated income tax adjustment.[232]

183 The Company, responding to Ms. Crane, says she fails to understand how tax expense is actually recorded and because of this her testimony is contrary to PSE's and Commission Staff's testimony on the net operating loss regulatory treatment. Mr. Marcelia testifies that the adjustment Public Counsel seeks has already been reflected on the Company's books.[233] If PSE were to account for the NOL in a different manner than proposed, it would "run afoul" of normalization requirements in IRC §1.167(l)-1(h). The Company says that Ms. Crane's adjustment is "…illogical and contrary to the normalization provisions of the IRC [Internal Revenue Code]".[234]

184 *Commission Determination*: We agree with the treatment of PSE's current NOL proposed by PSE and agreed to by Staff. By using the NOL carryforward of $41.7 to reduce ADIT, the effect is to increase electric rate base by $23.2 million and natural gas rate base by $18.5 million.[235]

185 We have no reason to question Mr. Marcelia's representation that what Ms. Crane proposes has been reflected already on the Company's books following standard

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[230] Marcelia, Exhibit No. MRM-14T at 62:12-63:15.

[231] Crane, Exh. No. ACC-1T at 27:7-17.

[232] *Id.* at 27:7-28:5.

[233] Marcelia, Exh. No. MRM-14T at 57:5-16.

[234] *Id.* at 58:7-21.

[235] *See* Marcelia, Exh. Nos. MRM-7; MRM-8.

accounting practices. Moreover, it appears that it would, in all likelihood, be a violation of normalization requirements if deferred taxes were not reduced by the tax effect of the NOL.

186 With respect to Staff's proposal that we reclassify all of PSE's current tax expense to deferred tax expense, Staff has not demonstrated that the Commission should involve itself in the detail of specifying how tax-related journal entries should be recorded on the Company's books.[236] PSE, in this regard, is required to follow the FERC Uniform System of Accounts. Therefore the Commission will not order the Company to reclassify current taxes to deferred taxes.

iv. Consolidated Tax Savings

187 The Internal Revenue Service permits an affiliated group of companies (*e.g.,* Puget Holdings, Puget Energy, Inc., PSE, and various other subsidiaries and affiliates) to file a consolidated federal income tax return. A key benefit of filing such a return is that losses associated with any affiliate can be used to offset taxable income of the other affiliates in the group. ICNU argues PSE's revenue requirement should be reduced by $8.8 million on the electric side and $3 million on the natural gas side to account for ratepayers' fair share of the value of PSE's taxable income that is used to lower PSE's parent company's (*i.e.,* Puget Holdings) overall federal income taxes.[237]

188 ICNU proposes a novel approach, imputing hypothetical loans from group members with income, including PSE, to those with continuing tax losses.[238] ICNU starts with the actual taxable incomes and losses reported by each member of the consolidated group using "the sum of each company's reported taxable income and/or loss for the most recent ten years."[239] The continuing taxable incomes and continuing tax losses

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

[237] ICNU Initial Brief ¶73 (citing Blumenthal, Exh. No. EB-1CT at 2:1-5). ICNU states that its proposed adjustment is based on PSE's original filing and will change if the Commission adopts a different rate of return.

[238] Blumenthal, Exh. No. EB-1CT at 6:20-7:1.

[239] ICNU Initial Brief ¶75 (citing Blumenthal, Exh. No. EB-1CT at 8:1-2).

are segregated so that each company has the opportunity to offset its own losses before it is deemed to require a loan from its affiliates.[240]

189 ICNU says that its consolidated tax adjustment recognizes that the companies with continuing taxable incomes have made loans to those companies with tax losses and the result is a lower consolidated tax liability.[241] The total tax savings realized by the parent company equal the total losses multiplied by the federal income tax rate.[242] According to ICNU: "PSE's fair share of these savings is its proportional share of the taxable income that has been loaned to the companies with tax losses."[243] ICNU does not use the total amount that PSE ratepayers pay in taxable income for the consolidated tax adjustment, but only that portion of PSE's taxable income that it deems to have been loaned to the "loss" affiliates. The value of the adjustment is based on the time value of the money that is used to lower the consolidated group's tax liability. The time value is computed using PSE's weighted average cost of capital.[244]

190 Mr. Marcelia testifies extensively in opposition to ICNU's proposed consolidated tax adjustment,[245] arguing among other things that it: violates the tax code,[246] violates the test year concept,[247] disregards the changed structure of parent and affiliated companies at PSE over the past ten years,[248] disregards PSE's tax loss in 2009 and

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[240] *Id.*

[241] ICNU Initial Brief ¶76.

[242] *Id.*

[243] *Id.* (citing Blumenthal, Exh. No. EB-1CT at 3:15—4:2; Exh. No. EB-3).

[244] ICNU Initial Brief ¶78.

[245] Mr. Marcelia presents 43 pages of rebuttal testimony on this point, raising 21 separate objections to ICNU's proposal.

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

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

[248] 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.").

2010,[249] and fails to reflect actual tax.[250] Most significantly, PSE argues, ICNU's adjustment erodes the ring-fencing provisions that shield PSE's customers from risks at the parent company level.[251]

191 PSE argues it is illogical to impose strict ring-fencing provisions on PSE and contravene those same provisions by lowering PSE's revenue requirement because a non-regulated affiliate generates a tax loss.[252] "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."[253]

192 PSE finds it especially troubling that ICNU's proposal looks at only one side of the matter. PSE points out that if the Commission were to adopt ICNU's methodology, it could work both ways, meaning that 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.[254] In sum, PSE says, 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

193 *Commission Determination*: The Commission has repeatedly rejected proposed 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

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[249] 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.").

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

[251] PSE Initial Brief ¶96 (citing *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.

[252] PSE Initial Brief ¶100.

[253] *Id.* (citing Marcelia, Exh. No. MRM-14T 22:2-5).

[254] PSE Initial Brief ¶101 (citing Marcelia, Exh. No. MRM-14T 39:7-16).

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.[255]

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

> Finally, under either circumstance, the CTA [consolidated tax adjustment] 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.[256]

195 Accordingly, we reject ICNU's proposal in this case. Although ICNU characterizes its adjustment as a "loan" or "tax shield" rather than an imputation to PSE of parent company debt or the tax deduction associated with the debt, the effect is the same. We find ICNU's consolidated tax proposal unacceptable for the same reasons we have rejected other, similar proposals in prior cases.

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[255] *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 ¶ 285 (April 17, 2006).

[256] *WUTC v. Avista Corp.*, Docket Nos. UE-080416, *et al.*, Order 08 ¶ 151 (Dec. 9, 2008).

b. Working Capital

196 PSE's witness Mr. John H. Story accurately describes the investor-supplied working capital component of rate base as:

> Investor funding of daily operating expenditures and other non-plant investments that are necessary to sustain ongoing operations in order to bridge the gap between the time expenditures for services are required to be provided and the time cost recovery occurs.[257]

197 Working capital is included in rate base because it is generally accepted that shareholders should earn a return on the funds they invest in the Company for utility purposes that have not been accounted for elsewhere or that are not otherwise already earning a rate of return. The calculation for working capital is based on the average of the monthly averages of the asset and liability accounts.[258]

198 Staff accepts the Company's proposed working capital adjustment with two exceptions. Mr. Roland C. Martin testifies that PSE misclassified two special deposit accounts as disclosed by a Company response to one of Staff's data requests. [259] The Company agreed to correct the ratemaking treatment for these two balance sheet accounts decreasing rate base by $1,433,432 for electric operations and $551,453for natural gas operations.[260]

199 Mr. Martin's second adjustment implements a recommendation by Mr. Smith to reject PSE's inclusion in working capital of a debit balance related to federal income taxes (*i.e.,* Account 236- accrued taxes payable). According to Mr. Smith, approximately $47.3 million ($34,987,818 electric and $13,011,001 natural gas) should be removed

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[257] Story, Revised Exh. No. JHS-1T at 8:5-8.

[258] *Id.* at 8:8-13.

[259] Martin, Exh. No. RCM-1T at 25:18-21.

[260] We derive these numbers taking into account our rejection of Mr. Smith's proposal to remove from PSE's working capital a debit balance related to federal income taxes payable. Mr. Martin's computation of working capital includes the impact of debit balance. *See* Martin, Exh. No. RCM-6. Mr. Stranik's computation also does not produce the correct amount because he uses a working capital ratio based on Mr. Martin's exhibit that includes the Staff proposed adjustment that we reject. *See* Stranik, Exh. No. MJS-10T at 24:17-18.

from working capital rate base because it is abnormal for Account 236 to have a large debit balance, and the $47.3 million debit balance that PSE had in that account during the 2010 test year was largely reversed in January and February of 2011. It simply will not exist on a going forward basis.[261]

200 Mr. Marcelia's testimony shows, among other things, that it is not unusual for Account 236 to include debit balances of the amount in question, and even considerably more.[262] The ending balances in Account 236 from 2006 – 2010 shows the following year-end balances: $20.1 million debit, $37.9 million debit, $15.7 million debit, $98.1 million debit, and $60.7 million debit, respectively.[263]

201 Mr. Marcelia explains that the large debit balance in Account 236 at the end of the test year resulted because PSE was expecting a large cash refund from the IRS as a result of the tax losses PSE sustained in its 2009 tax return.[264] Part of that loss was carried back two years for a refund. The remainder was carried forward and resulted in the tax net operating loss carry-forward. The portion of the 2009 tax loss that was refunded was recorded to Account 236 as a debit balance, essentially reversing the prior accumulation of taxes payable which were originally recorded to Account 236. The debit in Account 236 is essentially a receivable from the IRS which is removed once the cash has been received.[265] In January 2011, PSE received a cash refund.[266] According to Mr. Marcelia, both Account 236 balances and cash are included in working capital. It follows, he says, that whether the refund is included in Account 236 or in some other balance sheet account, it should be included in working capital.[267]

202 According to Mr. Marcelia, it appears from the Company's interaction with Staff on this issue that Commission Staff apparently believes that the credit would be posted to

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[261] Smith, Exh. No. RCS-1CT at 41:19-42:6.

[262] Marcelia, Exh. No. MRM-14T at 63:19-64:5.

[263] *Id.* at 64:1-5.

[264] *Id.* at 61:11-13.

[265] *Id.* at 61:13-19.

[266] *Id.* at 62:3.

[267] *Id.* at 62:5-7.

Temporary Cash Investments (Account 136). Mr. Marcelia testifies that Temporary Cash Investments are considered non-operating investment.[268] However, he says, that is not where the offset to Account 236 would have been posted. According to Mr. Marcelia, it would have been posted to cash (FERC Account 131). From there, it was reinvested back into the utility, as happens with any cash received. This cash would have been spent on the ongoing financial needs of the business. No matter what the use, Mr. Marcelia testifies, one would expect it to have a similar impact on working capital relative to the impact of the debit balance in Account 236.[269]

203 Ms. Crane's broader discussion and proposals concerning PSE's net operating loss (NOL) during the test period, include her recommendation that the Commission not allow working capital associated with the NOL in rate base.[270] Her proposed working capital reductions are a small part of her full NOL proposal to reduce the Company's rate base by approximately $23 million (*i.e.,* $12,759,093 for electric and $10,161,998 for natural gas). The working capital rate base components are $609,890 for electric and $485,748 for natural gas. Her full proposal is discussed separately above in section II.C.3.a.

204 *Commission Determination:* With respect to Staff's first proposed adjustment to working capital, the Company agrees to correct the ratemaking treatment included in its direct supplemental filing for these two balance sheet accounts. We accept these adjustments, which decrease rate base by $1,378,828 for electric operations and $512,748 for natural gas operations.

205 Staff's rationale for its proposed adjustment to working capital related to Account 236, however, simply does not hold up under scrutiny. A demonstrably aberrational amount in such an account might be a sufficient reason to investigate and determine whether there are reasons to disallow all or a portion of the balance, but it is not a reason in itself to ignore the balance during the ratemaking process. In any event, Mr. Marcelia's testimony establishes that it is not even unusual for Account 236 to have a large debit balance. In addition, as Mr. Marcelia testifies, both Account 236 balances

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[268] *Id.* at 60:19-20.

[269] *Id.* at 62:14-63:8.

[270] Crane, Exh. No. ACC-1T at 27:7-17.

for tax receivables and cash, once the receivable is paid in the form of a tax refund as occurred in this instance in January 2011, are included in working capital. Staff's recommendation to remove $47.3 million from working capital is unsupported and we reject it.

c. Tax Benefit of Pro Forma Interest

206 This pro forma adjustment assures that customers receive the tax benefit associated with the interest on debt used to support rate base. This is determined by first multiplying the restated pro forma rate base times the weighted cost of debt and then multiplying the result by 0.35, based on the maximum allowed 35 percent federal income tax deduction. There is no controversy about the method by which this adjustment is calculated. It is what is sometimes referred to a "fall-out" adjustment: the application of a formula using values that result from the Commission's determination concerning PSE's rate base and, in this case, the Company's undisputed weighted cost of debt.

207 *Commission Determination:* Taking account of our approval of the weighted cost of debt the parties agree should be reflected in PSE's capital structure, and our determinations concerning various rate base adjustments, it follows that the tax benefit of pro forma interest adjustments should be as indicated in the "Commission" column of the table above.

5. Contested Adjustments - Electric Only - Non-Rate Base

a. Power Costs[271]

208 Power costs are a very significant component in the Company's overall cost of service at over one billion dollars in PSE's current rates and, albeit lower, still forecast by the Company to approach that level during the May 2012-April 2013 rate year. Staff and ICNU initially proposed adjustments that, if accepted, would reduce

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[271] Power costs and O&M related to the Lower Snake River wind power project are discussed separately below in section II.C.5.a. *See* Applegate, Exh. No. RTA-3 for a comparison.

PSE's rate year power costs allowed in rates by approximately $24 million and $53 million, respectively.[272] These adjustments fall into two major categories:

- Thermal generation production plant operation and maintenance (production O&M) expense.[273]

- Net power costs.

Staff and ICNU each challenge certain production O&M costs, contending these should be normalized (*i.e.,* averaged over a period of years) rather than being based on test period costs, which are higher in this case. Staff and ICNU, in addition, individually challenge several costs that are factored in to the final determination of net power costs.

i. ***Production Plant Operation and Maintenance (O&M)***

209 PSE identifies, and we recognize for purposes of this Order, four types of thermal generation production plant O&M expense:

- Core O&M.

- Non-Contract Major Maintenance.

- Contract Major Maintenance.

- Other Production O&M.

Contract Major Maintenance expense is the subject of a separate section of this Order.[274] Here, we are concerned with ICNU's and Staff's respective challenges to

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[272] These amounts are relative to PSE's updated power costs presented in supplemental testimony, which, at $983 million, were lower by approximately $10 million compared to the Company's initial filing.

[273] Production O&M expenses are the costs of operating thermal generation facilities, exclusive of fuel, that range from daily chemicals for the boiler water of steam plant to major maintenance overhauls that occur several times a decade. Production O&M also includes "other" production O&M expenses that represent general overhead costs related to one or more plant's O&M.

PSE's use of test year amounts for Non-Contract Major Production Maintenance expense, and ICNU's parallel challenge to all other categories of production O&M expense.[275]

210 PSE uses test year expenses for Non-Contract Major Maintenance expense attributable to its gas-fired turbines, resulting in a rate year expense level in its direct case of $8.2 million.[276] PSE states that these major maintenance costs incurred in the test year represent known and measurable costs that represent a normal level of O&M expense.[277]

211 Staff objects to the Company's use of test-year expenses and proposes instead that these expenses be normalized over five-years, 2006-2010.[278] Using the average expense over that period, Staff's proposed adjustment includes $4.7 million for the rate year, a $3.5 million reduction from the Company's proposed level.[279]

212 ICNU proposes normalizing these expenses over 4 years, resulting in a $5.1 million reduction from the level proposed by PSE.[280] ICNU's proposal encompasses all plant production O&M, including the Other Production O&M expense. Thus, while our discussion below focuses on Non-Contract Major Maintenance, it applies equally to the Other Production category.

213 The stated basis for Staff's and ICNU's recommendations is that the actual Non-Contract Major Maintenance expenses vary significantly over time and do not have a

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[274] *See infra* Section C.6.b. Regulatory Assets and Liabilities.

[275] Staff initially challenged Other Production O&M expense but withdrew its opposition in its Initial Brief on the basis of updated data regarding the budget amounts upon which Staff's proposed adjustment was based, additional explanation by PSE concerning costs identified as "discretionary benefits," and because PSE reduced rate year power costs by $303,825 consistent with Staff's adjustment to update rate year rental fees for the Jackson Prairie Storage Capacity Agreement. Staff Initial Brief ¶¶103-04.

[276] Mills, Exh. No. DEM-1CT at 64:6-12.

[277] *Id.* at 62:11-14.

[278] Buckley, Exh. No. APB-1CT at 6:22-23.

[279] *Id.* at 8:8-10.

[280] ICNU Initial Brief ¶41. Mr. Gould, testifying for PSE, identifies the amount as $5.2 million. Gould, Exh. No. WRG-1T at 7:8 (Table 1).

discernible trend.[281] Staff provides a table of the historic Non-Contract Major Maintenance expenses for nine PSE gas fired plants.[282] By way of example, Staff states that while actual annual major maintenance expense at Fredonia Units 1-4's ranged from zero to $1.8 million during the last six years, the Company proposes to use $1.8 million (the 2010 test year expense) as the normal level of O&M expense to include in rates for the Fredonia plant. [283] Staff concludes that there is normal variability in these expenses, and it is therefore appropriate to base the rate year expense on a 5-year average of actual historical expenses for the period 2006-2010.[284]

214 Mr. Schoenbeck also refers to historic data from PSE and testifies that major maintenance overhaul schedules cause the Non-Contract Major Maintenance expense at PSE's various gas-fired generation to vary significantly year-to-year.[285] This, he says, means test year expenses do not accurately reflect what can be expected in the rate year.[286]

215 Mr. Gould testifies for PSE that Staff's and ICNU's use of historic data is not representative because the Company's pattern of using its thermal plants has changed during recent periods.[287] 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.[288]

216 During 2009-2011 there were approximately 350 plant starts among PSE's fleet of single cycle combustion turbine (SCCT) compared to approximately 150 starts during the years 2005-2008.[289] The runtime-per-start ratio for these two time periods fell

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[281] Buckley, Exh. No. APB-1CT at 7:17-18; Schoenbeck, Exh. No. DWS-1CT 11:5-17.

[282] Buckley, Exh. No. APB-3 at 2.

[283] Buckley, Exh. No. APB-1CT at 7:12-16.

[284] *Id.* at 7:20-22.

[285] Schoenbeck, Exh. No. DWS-1CT at 11:8-17.

[286] *Id.*

[287] Gould, Exh. No. WRG-1T at 5:3-9.

[288] PSE Initial Brief ¶62 (citing Gould, Exh. No. WRG-1T, 2:11-6:9).

[289] Gould, Exh. No. WRG-1T at 5:3-15.

from approximately 7 hours per start down to 5 hours per start.[290] Finally, the total run time increased from approximately 1000 average hours per year during the 2005-2008 to nearly 2500 average hours per year during the more recent period.[291] These changes in operations cause increased Non-Contract Major Maintenance expense at these facilities. Given this trend of increasing use, PSE argues that the most recent expense level incurred in the test year is more representative of expected rate year expense than an historic average.[292]

217 *Commission Determination:* In PSE's most recently completed general rate case, the Commission rejected the proposed use of a five-year average for this category of expenses 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."[293] We find on the basis of the record here that the same is true today. Considering PSE's changing use of its fleet of thermal production facilities, as described by Mr. Gould, we are not surprised that maintenance costs are trending upward. As PSE's use of intermittent renewable resources such as wind farms continues to increase in response to state-mandated RPS, the pattern of more frequent start-ups, shorter run times, and total run times at thermal facilities that facilitate wind integration may lead to a continuing trend of increasing O&M costs. Absent evidence of a change in this regard, it is reasonable to continue our reliance on the more recent test year data rather than averages of historic data.

218 Inasmuch as ICNU does not distinguish between Non-Contract Major Maintenance and Other Production O&M expenses in its testimony or brief, our determination here applies to both.

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[290] *Id.* at 4:7-11.

[291] *Id.* at 6:3-9.

[292] *Id.* at 5:3-9.

[293] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-090704, *et al.*, Order 11 ¶ 162 (April. 2, 2010.

ii. ***Net Power Costs***

219 The net power cost adjustment we authorize reflects PSE's rerun of its AURORA power cost model using updated natural gas prices in response to Bench Request 24 and our resolution of contested issues that fall into five general categories:

- Transmission revenues, expenses, and credits.
- Mark-to-Market (MTM) adjustments for gas and power hedges.
- Wind integration costs and revenues.
- Addition of transmission capacity.
- Miscellaneous adjustments.

a) Power Cost Update

220 The Commission generally allows power costs to be updated during general rate cases to reflect new forecasted gas and electric market prices, new firm contracts, or budget updates from third party owners of resources such as Mid-C projects.[294] The parties support this practice and, as discussed below, we required a further update of power costs in Bench Request 24, anticipating the Company's compliance filing.

221 PSE originally projected $992 million in power costs for the rate year May 1, 2012, through April 30, 2013. This would have reduced power costs by $88.2 million relative to power costs included in current rates.[295] A substantial portion of this decrease resulted from lower prices for natural gas, a key variable in PSE's AURORA power cost model.[296]

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[294] Staff Initial Brief ¶105 (citing Buckley, Exh. No. APB-1CT at 29:9-17).

[295] Mills, Exh. No. DEM-1CT at 2:9-12, 34:7-8 and 34:15-16. Power costs, in this testimony, include production O&M expenses.

[296] Mills, Exh. No. DEM-1CT at 2:12-15.

222 In its supplemental filing on September 1, 2011, PSE projected $983 million in power costs, a decrease of approximately $10 million compared to its direct case. The supplemental filing included a decrease in power costs due to changes in the calculation of Mark-to-Market (MTM) hedge costs of $8 million.[297] Slightly higher natural gas costs at the time of the supplemental filing offset this in part, adding $1.6 million in expense to power costs.[298]

223 By the time Staff and other parties filed their response cases in December 2011, natural gas prices had fallen sharply. Staff and ICNU proposed significant reductions to PSE's supplemental power costs, driven largely, albeit not exclusively, by these lower natural gas prices. ICNU proposed to reduce power costs by approximately $26.7 million based on lower gas prices, net the effect of increases in the mark-to-mark gas hedge adjustment.[299] Commission Staff proposed to reduce power costs by approximately $10.0 million to account for reduced gas prices.[300]

224 ICNU and Staff both recommended that PSE be required to continue updating projected power costs through, and beyond, the rebuttal stage of this proceeding. Staff expressly recommended that the Commission order a further update as part of the Company's compliance filing after entry of the Final Order in these dockets.[301]

225 PSE, through Mr. Mills's rebuttal testimony, and in its Initial Brief, states that the Company:

> 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

[297] Mills, Exh. No. DEM-8C at 3:1-2.

[298]Mills, Exh. No. DEM-8C at 3:1-2 and 5:2-16.

[299] Schoenbeck, Exh. No. DWS-1T at 5:18-7:20.

[300] Buckley, Exh. No. APB-1CT at 29:5- 31:13. Mr. Buckley calculated an estimated effect of approximately a $9.96 million decrease in projected rate year power costs resulting from an average rate year gas price decrease of $0.41/MMBTU relative to the price reflected in PSE's supplemental filing.

[301] *Id.* at 31:9-12.

> update rate year power costs with more recent gas prices with its compliance filing.[302]

226 *Commission Determination:* We continue in this case our consistent, forward looking approach to the determination of power costs.[303] The Commission issued Bench Request 24 on April 30, 2012, requiring PSE to rerun its AURORA power cost model and make other adjustments to power costs based on a set of assumptions that mirror our determinations of the contested issues affecting these costs. We required PSE to use the most recent available forward gas prices, consistent with the methodology PSE has used since 2005.[304] PSE reran its AURORA power cost model using a natural gas price determined at April 25, 2012, on the basis of a three-month average of daily forward market gas prices at the Sumas trading hub for each trading day in the three-month period, a date close in time to the entry of our Final Order.

227 PSE responded to Bench Request 24 on May 1, 2012, and provided the updated power costs.[305] PSE's update resulted in pro forma power costs of $930,167,643.[306]

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[302] PSE Initial Brief ¶57 (citing Exh. No. B-21 (PSE's Response to Bench Request No. 21); *see also* Mills, Exh. No. DEM-11CT at 51:5-7.

[303] *See WUTC v. PSE*, Dockets UG-040640, UE-040641, UE-031471, and UE-032043, Order 06, ¶108 (February 18, 2005):

> We resolve the philosophical question raised by ICNU in favor of the practical conclusion 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 during short and intermediate periods following the conclusion of such proceedings.

[304] In Order 06, cited in the preceding footnote, the Commission observed:

> Determination of an appropriate "average price" or "benchmark price" that PSE will pay for fuel gas during the rate year is an exercise in its infancy. It is no older than the PCA mechanism itself, which was approved less than three years ago.

Absent a rigorous analysis showing an effect from market inefficiency undercutting use of the most recent data available (*i.e.*, the three-month forward price at the Sumas market hub as of a certain date), the Commission relied on the parties agreement "that more recent data predicts the near and perhaps even intermediate term better than older data."

Id. ¶116.

[305] We include PSE's response to Bench Request 24 as Exh. No. B-24.

This is the amount we approve for recovery in rates. In terms of the power cost adjustment, this results in an increase to NOI of $123,082,268, which reduces the Company's revenue requirement by $198,280,252.

b) Transmission Related Revenues

228 Transmission related revenues include:

- Revenue PSE receives for transmission service provided to a third party wind generator connected to PSE's transmission system.
- Accounting treatment for credits returned to PSE for interest on a deposit PSE provided BPA in order to receive new transmission service for PSE's Lower Snake River wind farm.

(i) Wind Integration OATT Revenues

229 ICNU proposes an adjustment to account for revenues the Company will receive based on its provision of transmission services under its Open Access Transmission Tariff (OATT) for third party variable generation exported out of the Company's balancing authority. Mr. Michael C. Deen testifies that while there is currently one third-party wind generation facility in PSE's balancing authority, the 96 MW Vantage wind project, PSE does not include any assumed revenues for wind integration services from this project.[307]

230 Mr. Deen states that on October 20, 2011, FERC released a decision in its Docket ER11-3735, accepting for filing PSE's proposed rate schedules seeking cost recovery for this facility. FERC suspended these tariffs for five-months with an effective date of January 5, 2012. Thus, he argues, the suspension period ends well before the May 14, 2012, rate effective date in this proceeding. ICNU recommends that the resulting

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[306] Story, Exh. No. JHS-20 at 1, line 21. We note that this is a reduction of approximately $62 million relative to PSE's as-filed case and the amount is approximately $150 million less in power costs than the amount currently embedded in rates.

[307] Deen, Exh. No. MCD-1CT at 8:12-16.

OATT revenues be included in this proceeding. This adjustment would increase revenue and reduce power costs by approximately $2.4 million.[308]

231 Mr. Story testifies that the rates Mr. Deen used to make his proposed OATT adjustment are not known and measurable, because they are still in litigation and are subject to refund.[309] Mr. Story quotes the salient language from FERC's order, as follows:

> The Commission orders:
>
> Puget's proposed Schedules 3 and 13 are hereby accepted for filing and suspended for a five-month period, to become effective January 5, 2012, *subject to refund*, as discussed in the body of this order.[310]

Given this, PSE contends the Commission should reject Mr. Deen's proposed adjustment.

232 *Commission Determination:* It is routine FERC practice to accept rates following a brief suspension period after which they are effective, subject to refund. The FERC may not make a final determination respecting the rates for months or even years. Despite the uncertainty this creates in terms of whether PSE will ultimately be allowed to retain all the revenue it recovers via its OATT tariff Schedules 3 and 13, it nevertheless is the case that PSE will recover the amount of revenue authorized by the rates that will be effective during the rate year. Thus, the OATT revenues pertinent to this proceeding are known and measurable. These revenues provide a current benefit to PSE and current customers should enjoy the benefit. If it turns out in some future period that PSE must refund all, or part, of this revenue, that too will be a known and measurable cost to the Company that should be borne by customers at the time the cost is incurred. Since, this result best satisfies the matching principle, we accept the ICNU adjustment.

(ii) BPA Transmission Service Credit

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[308] *Id.* at 8:17-9:2.

[309] Story, Exh. No. JHS-18T at 19:19-20:2.

[310] FERC Docket No. ER11-3735-000 at 24 (October 20, 2011) (emphasis added).

233 PSE filed an accounting petition in May 2010 in Docket UE-100882, requesting approval of specific regulatory treatment of a prepaid transmission deposit made to Bonneville Power Administration (BPA) related to the Lower Snake River Wind Project. Commission Staff made no recommendation on this accounting petition. PSE asks in its Initial Brief that the Commission expressly approve its proposed regulatory treatment of the prepaid transmission deposit made to BPA,[311] which is set forth in detail in Mr. Story's direct testimony,[312] effective as of the date the accounting petition was filed.[313]

234 *Commission Determination:* The accounting petition in Docket UE-100882 to which PSE refers was filed two years ago. Yet, it has not been brought forward for action in the context of an open meeting, or otherwise. Mr. Story requested our approval of this treatment in both his prefiled direct and rebuttal testimonies, but no Staff witness has responded at any stage of this proceeding.

235 This places us in a somewhat untenable position. On the one hand, given that no one contests the accounting treatment PSE proposes in this proceeding, which is identical to, albeit independent of, what it asks in its petition, we could approve it. On the other hand, we are troubled that we are asked to approve accounting treatment of a significant prepayment by PSE to BPA when our expert accounting staff has not shared with us its view on the matter.

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[311] PSE Initial Brief ¶69.

[312] Story, Exh. No. JHS-1T 21:8-25:2.

[313] 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.

236 We therefore direct Staff to bring this matter to us in an open meeting with its recommendation in Docket UE-100882 within 30 days of this Order.

c) <u>Power Hedging Costs</u>

(i) Gas at Sumas Trading Hub

237 The Commission has approved a gas mark-to-market adjustment in several PSE general rate cases, including its most recent prior case and, by PSE's account, in nine power cost only rate proceedings.[314] This post-AURORA adjustment reflects the cost difference between PSE's actual short-term forward gas purchases, which are financial as well as physical, and the current forward gas price for the rate period used in the AURORA model.

238 ICNU proposes to remove from PSE's baseline power costs the costs of monthly natural gas hedges—priced at the monthly average cost for all natural gas hedges—that exceed the volumes needed monthly for gas fired generation calculated using the AURORA model.[315] ICNU says it does not oppose PSE recovering any prudently incurred actual gas hedging costs in excess of what AURORA forecasts through PSE's power cost adjustment mechanism (PCA).[316]

239 PSE argues that ICNU's adjustment ICNU is unreasonable because it would 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 its power portfolio.[317] "PSE uses a probabilistic modeling risk system that runs

[314] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 ¶¶ 151–55 (April 2, 2010; Mills, Exh. No. DEM-11CT 32:15-17.

[315] Staff initially proposed a similar adjustment but withdrew it in its Initial Brief. Staff Initial Brief ¶90 ("Staff's adjustment has vanished as gas prices have fallen. Therefore, Staff's adjustment is no longer necessary and is withdrawn. Staff reserves the right to assert the adjustment in future cases, as may be warranted by the circumstances.").

[316] ICNU Initial Brief ¶¶61-62.

[317] PSE Initial Brief ¶46 (citing *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 ¶¶ 151 (April 2, 2010) (noting the difference between the methods used to set baseline power rates and the methods used to manage day-to-day operations)). ICNU acknowledges this point in connection with its arguments contesting PSE's wind integration costs. ICNU Initial Brief ¶55.

several times weekly, using updated operational and market intelligence that includes regularly updated prices of power, natural gas, and resulting market heat rates."[318] Although ICNU's argument at least inferentially depends on the premise that PSE's gas hedges exceed the Company's gas for power needs, there is no evidence to this effect in the record.

240 *Commission Determination:* In PSE's 2009 general rate case, the Commission expressly rejected proposals to remove the cost of all hedges in power cost rates.[319] The arguments presented by ICNU and Staff in the 2009 proceeding are theoretically similar to the arguments in this case. As here, ICNU argued that PSE had procured more gas for its power supply requirements than the AURORA model indicated would be required. ICNU proposed in the prior case to cap the volume of PSE's forward gas purchases for each month at 80 percent of the AURORA-projected baseload need for each month of the forecast rate-year period.

241 In the 2009 decision, the Commission stated that this complex issue:

> highlights the difference between the methods used to set the Company's baseline power rate and the methods the Company uses to manage its day-to-day operations. PSE uses the AURORA model only to set the baseline power rate and project normalized power costs. Fundamentally, AURORA results represent a static projection of power system operation in the rate year that cannot serve as a rigid management plan for actual operations. Accordingly, while AURORA is the benchmark used to set normalized power rates, it has been accepted practice to adjust its results to reflect actual costs that are difficult or impossible to include in the model.[320]

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[318] *Id.* ¶46 (citing Mills, Exh, No. DEM-11CT 31:3-9).

[319] *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.").

[320] *Id.* ¶151.

As in the previous case we have not been presented with any convincing reason to change the way mark-to-market gas hedges are treated in determining power costs. We therefore reject ICNU's proposed adjustment.[321]

(ii) Cedar Hills Gas

242 Staff, as noted above, withdrew its proposed adjustment to hedging costs at Sumas.[322] Staff also conditionally withdrew its proposed mark-to-market adjustment with respect to gas produced by the Cedar Hills Regional landfill.[323] Staff describes the issue as initially being:

> whether Cedar Hills' gas was acquired to meet generation needs or solely to monetize the renewable attributes of the gas and then ask ratepayers both to bear the speculative risk of purchasing and selling the gas commodity and to pay in base rates the MTM costs of the transaction. PSE claims the transaction is to meet generation needs, but that it is more advantageous at this time to sell the RECs associated with the gas. PSE also agrees to defer revenues associated with the sale of the renewable attributes for future customer credit.[324]

243 Staff argues the Commission should order PSE to file a petition for an accounting order to ensure that the revenues from the sale of these RECs are deferred and, presumably, treated in the same fashion as other REC revenues.[325] Staff states that if the Commission includes such a condition in its Final Order, its adjustment to remove

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[321] We note ICNU's statement that it does not object to actual gas hedging costs in excess of what AURORA forecasts being "recovered" through PSE's PCA mechanism. The PCA mechanism is not a cost recovery mechanism. It was developed as a way to insulate PSE and customers from volatilities inherent in PSE's electric portfolio and to balance the risks of such volatilities. PSE's mark-to-market costs have been included in the baseline rate since the inception of the PCA. The Commission has observed previously 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 . . . ." *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-040640 and UG-040641, Order 06 ¶108, (Feb. 18, 2005). Accepting ICNU's proposal in this case to remove a portion of PSE's mark-to-market costs from base rates would undercut the realization of this goal.

[322] Staff Initial Brief ¶90.

[323] *Id.* ¶102.

[324] *Id.* ¶101 (internal citation to Mills, Exh. No. DEM-11CT at 32:11-17 removed).

[325] *Id.* ¶102.

the mark-to-market costs of this transaction should be treated as having been withdrawn. Absent such a filing, however, Staff urges us to accept its mark-to-market adjustment, as originally proposed, reducing rate year power costs by $1.6 million.[326]

244 PSE states in its Initial Brief its belief that Staff was withdrawing its Cedar Hills gas mark-to-market adjustment because the Company clarified that forecasted contract revenues from the environmental attributes (*i.e.*, RECs) will be included in the renewable energy credit tracker proposed in the Multiparty Settlement Re: Electric Rate Spread and Rate Design that is before us in this case. PSE states it also clarified that the costs of the contract will be included in power costs. PSE does not address in its briefs the conditional nature of Staff's withdrawal of its adjustment to remove the costs of the contract from power costs.

245 *Commission Determination:* We see no need to order PSE to file a separate accounting petition that would do no more than confirm that the Company will treat the revenues from any sale of RECs associated with Cedar Hills in the same manner it treats all other REC revenues. Since such treatment appears to be the goal Staff proposes to ensure via its proposed condition for withdrawal of its adjustment, we deem the adjustment to be withdrawn.

d) <u>Wind Integration Cost Treatment</u>

246 Wind generation is an intermittent and non-dispatchable generation resource. There can be large differences, up or down, between the wind generation forecast and actual generation. PSE must hold in reserve sufficient capacity to increase or decrease generation to balance wind generation capacity.[327] This imposes what have come to be known as "wind integration costs."[328] PSE's rate year power costs include both the

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[326] *Id*. (citing Buckley, Exh. No. APB-1CT at 24:1-13 and Buckley, Exh. No. APB-2, line 6). Staff states that its adjustment, as initially proposed, removed the mark-to-market costs assigned to Cedar Hills in order to exclude the cost of hedging associated gas not acquired for resale.

[327] PSE Initial Brief ¶36 (citing Mills, Exh. No. DEM-1CT 21:19–22:11).

[328] PSE describes these opportunity costs in its Initial Brief ¶35, as follows:

> 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,

Company's internal cost of integrating its wind resources and the wind integration costs it pays to BPA.[329]

247 Staff removes from PSE's base rates costs associated with day-ahead wind integration for all PSE-owned wind projects and within-hour wind integration for Wild Horse and the Wild Horse Expansion.[330] ICNU also proposes to remove PSE's outside AURORA adjustment for day-ahead wind integration cost. The basis for these proposals is captured essentially by Staff's argument that PSE cannot determine these costs with sufficient "robustness" and certainty.[331] Staff and ICNU argue that PSE can recover actual power supply costs or benefits necessary to balance wind and load via the PCA. That is, they would treat wind integration costs or benefits in the same manner as actual variations in fuel costs, market prices, and load.

248 As to day ahead costs, PSE relies on historical data and models these costs separately outside the AURORA model, which does not capture them.[332] PSE says its Ancillary Valuation Model, which is used to develop 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.[333]

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uneconomic generation that would not have been dispatched, but for the presence of wind, may be committed into the market.

[329] The Hopkins Ridge, Klondike III, and LSR-1 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. PSE Initial Brief ¶37 (citing Mills, Exh. No. DEM-1CT 22:20-21); *see also Id.* at 23:1-24:13.

[330] Staff Initial Brief ¶96 (citing Buckley, Exh. No. APB-1CT at 18:12-19:2).

[331] Staff Initial Brief ¶96; Buckley, Exh. No. APB-1CT at 20:3-7; *See also* ICNU Initial Brief ¶54.

[332] PSE Initial Brief ¶40 (citing Mills, Exh. No. DEM-11CT 18:7-13).

[333] *Id.* ¶44 (citing Mills, Exh. No. DEM-11CT 25:7-18).

249 *Commission Determination:* Statutes that require utilities to meet certain Renewable Portfolio Standards in the relatively near term have hastened the development and use of wind power in Washington, as elsewhere. The highly variable nature of the resource and the industry's lack of experience in integrating such a resource pose physical and financial challenges for the industry and for regulatory authorities, including in this region the Bonneville Power Association and the state regulatory Commissions.

250 It does not appear that the parties dispute whether PSE incurs wind integration costs. Their dispute focuses on the calculation of these costs and whether they should be included in baseline rates.

251 We note above in our discussion of hedging costs that the PCA mechanism is not a cost recovery mechanism. We strive to determine net power costs for the rate year as close as can be reasonably forecast to what will be the Company's actual cost during that period. Excluding costs we know PSE will incur, such as wind integration cost would frustrate that goal. The PCA depends on our establishing accurate baseline power costs that include all reasonably anticipated, prudently incurred costs. The purpose of the PCA is to capture significant (*i.e.*, greater than net $20 million plus or minus during any given PCA period) unanticipated deviations from that baseline. Its purpose manifestly is not to capture known costs intentionally left out of the baseline power cost determination.

252 The emerging ability to forecast wind integration costs has not yet reached a level that is fully satisfactory. Nevertheless, PSE has relied on available historical data and modeling to forecast day-ahead and within-hour wind integration costs.[334] For purposes of this case we determine this to be a satisfactory basis upon which to include wind integration costs at the level PSE proposes in this case.

253 We emphasize, however, that in future cases the Commission expects PSE to present more detail concerning the historical data and modeling upon which the Company forecast of wind integration costs depend. The Commission also expects PSE to stay abreast of, and apply where cost-effective, more rigorous means to determine these costs as they develop in the industry.

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[334] Mills, Exh. No. DEM-11CT at 14:7-17:2; 25:14-26:19.

e) Transmission Capacity

254 PSE elected to renew a 23MW firm capacity contract with BPA that was previously related to the transmission of power from a City of Spokane Municipal Steam Waste project. The contract with Spokane expired on December 31, 2011. Mr. Mills testifies that by renewing this transmission contract at a rate year cost of $414,000, PSE increased its ability to purchase short-term resources at the Mid-C trading hub and reduced its transmission capacity need by 23 MW starting in 2012.[335]

255 Staff would have us disallow the $414,000 rate year costs of this transmission because, in Staff's view, PSE neither showed sufficient margins from sales or reduced costs related to the acquisition, nor provides a meaningful cost/benefit analysis justifying inclusion of the renewed contract.[336] Mr. Buckley testifies that the cost of this contract should be removed because there is no need for the Company to move power from the City of Spokane project, and no explicit showing of benefits, or reduced costs, related to the acquisition of this firm transmission capacity.[337]

256 Mr. Mills testifies that the extension of this transmission contract is a cost effective way to meet PSE's near-term capacity need on a portfolio benefit ratio basis as well as on a total portfolio cost basis as compared to the other resource alternatives in the 2010 Request for Proposal (RFP).[338] In addition, regional transmission constraints limit long-term firm transmission availability from resources east of the Cascades to load west of the Cascades. PSE's transmission system has no additional long-term firm transmission capacity across the Cascades and BPA's transmission evaluation process is on hold. The renewal of 23 MW of cross-Cascades transmission thus meets PSE's near-term needs for long-term firm capacity across the Cascades to the Mid-C market.[339]

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[335] Mills, Exh. No. DEM-1CT at 15:4-13.

[336] Staff Initial Brief ¶¶91, 93.

[337] Buckley, Exh. No. APB-1CT at 22:6-9.

[338] Mills, Exh. No. DEM-11CT at 45:15-46:2.

[339] *Id.*

257 *Commission Determination:* Any acquisition of firm transmission capacity by PSE, even a small one, should be supported by a showing of definite benefits that justify the annual cost of the expense. Other than in a most general sense, the Company failed in this instance to make such a showing. In addition, the Company provides only a cursory statement concerning its consideration of this contract vis-à-vis other options considered during the 2010 RFP process.

258 Considering, however, current constraints on the availability of long-term firm transmission across the Cascades, we are disinclined to exclude these costs, which might encourage PSE to relinquish these rights. We accordingly will not disallow the $414,000 in costs for the rate year. However, we expect PSE to provide in its next general rate case a full and detailed justification showing the prudence of this expense if the Company expects to continue to recover it in rates.

f) <u>Power cost model and related adjustments</u>

(i) Thermal Plant Operations

259 ICNU argues that we should require PSE to update AURORA by decreasing the "minimum up time" operating assumptions for the Company's thermal generation resources. PSE does not dispute that the Company's actual hourly operating data for its gas generation resources at its Goldendale, Mint Farm and Sumas facilities are significantly overstated.[340] Mr. Deen proposes to reduce the minimum up times for these facilities to 10 hours, which is closer to the amount that these facilities are expected to be operated at during the rate effective period.[341] This would lower PSE's net power costs by about $0.4 million, because it reflects that the generation facilities will cycle more economically.[342]

260 PSE argues we should reject ICNU's proposal to alter the AURORA model assumptions concerning minimum run times because it reflects only a portion of the

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[340] Deen, Exh. No. MCD-1CT at 13:3-23; Exh. No. MCD-4 at 2 (PSE response to ICNU DR 2.57).

[341] Deen, Exh. No. MCD-1CT at 13:11-20; Mills, Exh. No. DEM-11CT at 40:1-6. We note that this is a conservative adjustment relative to the actual run times shown in Exh. No. MCD-4 and the assumed times included in AURORA.

[342] ICNU Initial Brief ¶70 (citing Deen, Exh. No. MCD-1CT at 13:18-21).

changes to the operating characteristics of the Company's combustion turbines.[343] PSE argues that if it updated the AURORA model with all of the changes, rate year power costs would *increase* significantly.[344]

261 Making across the board changes to the AURORA assumptions about the operating characteristics of PSE's thermal resources might increase power costs. ICNU argues, however, that it is inappropriate for PSE to make such a suggestion at the rebuttal stage: "These types of updates should have been provided with PSE's direct testimony, or at least its supplemental filing, to allow parties adequate time to review and respond."[345] Absent this, it is appropriate to make the "limited and conservative adjustment" Mr. Deen proposes and reject "PSE's attempt to significantly broaden the scope" of the updated operating assumptions.[346]

262 *Commission Determination:* The Commission consistently strives to reflect the most recent operating and market conditions when setting power costs. In tandem with that aim, is the Company's responsibility to provide an informed record in a timely manner. In this instance, it has not met that responsibility. Mr. Deen discovered a significant deviation in minimum run times at three of PSE's thermal facilities and brought that to our attention with a proposal that we order PSE to include a more realistic and up-to-date assumption if we require it to rerun AURORA in connection with our final determination of power costs in this case.

263 The Company's testimony on rebuttal concerning a broader set of changed operating conditions is too little, too late. If relevant to the determination of PSE's power costs, the information should have been brought to our attention in the Company's direct case. If not relevant, we would expect to see that argument in response to ICNU's proposal, but we do not. PSE's late and thinly supported presentation of updates to other generation characteristics is not convincing and does not provide adequate time for review.

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[343] PSE Initial Brief ¶52.

[344] *Id.* (citing Mills, Exh. No. DEM-11CT 39:3-41:16).

[345] ICNU Initial Brief ¶71.

[346] *Id.*

264 We accept the evidence showing that PSE's assumption concerning run times at Goldendale, Mint Farm and Sumas are significantly overstated and require that the AURORA model be rerun with the shorter run times assumed.[347]

(ii) Peaking Resource Costs

265 PSE obtains peaking resources to meet winter peak hour loads and to maintain all reliability criteria, such as operating reserves.[348] Peaking resources include generating resources, purchased peak energy contracts to ensure the availability of physical power, and transmission to ensure delivery of such power to PSE's system during peak hours. With the Mid-C hub as the primary source of regional power supply, PSE must consider its available transmission capacity from the Mid-C hub to PSE's system against the forecast power needs.[349]

266 ICNU proposes to remove costs PSE includes for procuring on-peak physical power to meet winter months' peak loads:

> While acknowledging that there can be constraints to the availability of Mid-C transmission capacity or due to insufficient resources to meet the peak load, *the crux of the issue is really the number of hours this is likely to occur*. PSE has assumed resource shortages will occur in each and every on-peak hour of the four-month period based on the assumed monthly peak times a planning reserve margin of 15.7%. . . This is simply not realistic.[350]

ICNU provides its own peak load forecast based on actual hourly loads for 2007-2010 to determine which four winter months of the four years will be used to apply a "normalization factor" to every hour. ICNU's analysis determines that PSE should plan to meet peak customer demand by purchasing physical power for only specific

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[347] We required PSE to make this assumption when rerunning the AURORA model in response to Bench Request 24 and rely on the outcome of that rerun in determining PSE's net power costs to be included in rates.

[348] Mills, Exh. DEM-11CT at 35:6-10.

[349] *Id.*

[350] Schoenbeck, Exh. No. DWS-1CT at 14:3-9. (emphasis added).

hours during each month: 18 hours in January, 19 hours in February, 25 hours in November and 39 hours in December, for a total of 22,432 MWhs.[351]

267 Mr. Mills testifies that ICNU's methodology is not appropriate for three reasons:

- ICNU's methodology bases peaking costs on "expected hours where loads actually exceed PSE's resource capacity," ignoring that PSE must be prepared for unexpected winter peak events or run the risk that it would be unable to purchase power in the market and have no choice but to shed load.

- ICNU's proposal to avoid planning for all peak hours presupposes the Company can predict the actual hour in which a peak event will occur. Since this is impossible, PSE assumes resource shortages will occur in each and every peak hour of the four winter months to avoid the risk of unexpected events and ensure system generation reliability.

- Even if PSE could predict the exact hours in which its load would exceed its available resources, no reliable standard hourly option product exists in the market. If PSE were to procure such a product in advance, the premium would undoubtedly be very high.[352]

268 Mr. Mills testifies that PSE's use of a 15.7 percent planning margin is consistent with the regional standard formally adopted by the Northwest Power and Conservation Council (NPCC) to assess the adequacy and reliability of resources within the next five years to meet different uncertainties in loads, hydro, forced outage rates and wind.[353]

269 *Commission Determination:* We find ICNU's proposed adjustment to peaking costs inadequately supported and reject it. ICNU's proposed adjustment, for example, only utilizes four years of weather data instead of the typical seventy year data set. ICNU's calculation also ignores the Company's obligation to provide for the peak needs in any hour that it may occur.

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[351] *Id.* at 14:13-16:5.

[352] Mills, Exh. DEM-11CT at 36:21-37:14.

[353] The NPCC adopted a five percent LOLP standard as a reliability metric. This translates to a planning standard of 15.7 percent, as described in PSE's 2009 IRP.

270 ICNU's criticisms of PSE's method, however, impress upon us that a closer examination of this issue might provide a more accurate representation of the costs of the Company's peak load obligation than is currently available. For example, while PSE must provide for peak needs at any time the need occurs, it does not follow that the power for full peak load plus the planning margin reserve will be delivered across the Cascades in every hour. In addition, PSE fails to explain the relationship of this adjustment to the Company's hedging contracts that are purchased in part to mitigate the very exposure described as the basis of this adjustment. We expect PSE, for these reasons among others, to provide in its next rate case a more thoroughgoing body of evidence concerning the Company's method. We would hope to see a more refined approach than is evident on the record in this case.

g) <u>Miscellaneous adjustments</u>

(i) Interstate Pipeline Costs

271 PSE proposes to include in its power cost adjustment increased costs for the Company's contracted pipeline obligations with Cascade Natural Gas (Cascade), Westcoast Energy Inc. (WEI) and Northwest Pipeline (NWP).[354] These increases all were based initially on PSE's expectation that these three companies would file for rate increases with their respective regulatory authorities during the rate year.[355] ICNU recommends we disallow these increases because they are "speculative and unsubstantiated."[356]

272 Mr. Riding testifies that the Company revised downward its costs for Cascade transportation service for the Whitehorn, Fredonia and Mint Farm plants, to reflect current tariff or contract specific rates, because no rate change is expected during the rate year considering that Cascade has not yet applied for a rate change as of the date of the testimony.[357] PSE's contract with Cascade includes an escalation provision

[354] PSE Initial Brief ¶48.

[355] Cascade and NWP are subject to FERC jurisdiction insofar as their pipeline transportation rates are concerned. WEI is subject to the jurisdiction of the National Energy Board of Canada.

[356] ICNU Initial Brief ¶48.

[357] Riding, Exh. No. RCR-4HCT at 6:6-16.

with respect to both the demand and commodity charges, effective in July of each year. Mr. Riding proposes that PSE's estimated cost increase for Cascade be reduced to reflect the Company's forecast of the impact of the contract escalation only, resulting in a $75,977 reduction to power costs rather than the $91,785 reduction he says is proposed by Mr. Deen for ICNU.[358]

273 PSE's estimated cost increases for WEI are based on interim rates that are formulaic, that continued to change during the pendency of this docket, and that it appears may change again by an uncertain amount early in the rate year.[359]

274 PSE's estimated cost increases for NWP anticipate that the company will file a FERC rate case on July 1, 2012, with rates possibly effective January 1, 2013, subject to refund pending further review, if FERC accepts them following its usual 30 day review and suspension. [360]

275 *Commission Determination:* While the increased costs PSE expects for gas transportation on Cascade remains an estimate, it is not as speculative as when initially sought, in part, based on an anticipated rate increase filing that Mr. Riding testifies on rebuttal is not going to occur. We might allow PSE's estimated $61,050 cost increase to net power costs for this contract if supported by some evidence showing how it was calculated. PSE's Initial Brief, however, does not refer us to any such evidence and Mr. Riding's rebuttal testimony cited in the brief does not mention any exhibit we might look to for this detail. We accordingly fail to find sufficient support to approve either the initial increase PSE proposed, or the revised amount, as known and measureable.

276 We find even less support for the increased costs PSE proposes with respect to its contracts with NWP and Westcoast. These increases depend in part on regulatory filings that have not even been made or that remain in process with no prospect of finality until sometime during 2013, well into the rate year. It seems incongruous that PSE would suggest we allow these estimated costs in rates, while at the same time

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[358] Riding, TR. 927:4.

[359] Riding, Exh. No. RCR-4HCT at 7:1-20.

[360] *Id.* at 8:1-14.

argue with respect to revenues the Company will receive for wind integration transmission it provides to others that we cannot rely on FERC approved rates because they remain subject to refund.[361] We accept ICNU's recommendation and require PSE to remove these proposed costs from net power costs.

(ii) FERC 557 Costs

277 The Company's proposed net power costs include actual test year expenses from FERC Account 557 and its subaccounts. FERC Account 557 is for any production expenses that are not specifically required to be in any of the other production expense accounts.

278 Mr. Deen, for ICNU, recommends normalizing these expenses for ratemaking because, in his view, they show significant variation during the past five years.[362] He proposes two normalization adjustments. The first involves averaging PSE's FERC Account 557 expenses over the five year period, which results in Mr. Deen's recommended $0.9 million reduction in these power cost expenses relative to the Company's supplemental filing.[363]

279 In addition, based on PSE's uncontested decision to reclassify BPA rate case expenses from power costs to administrative and general expenses, Mr. Deen recommends basing the BPA rate case expense on a 5-year average, rather than the actual 2010 expense of about $1.5 million. Mr. Deen testifies that the past several years have seen an extraordinarily high level of ratemaking and legal activity by BPA related to implementing its new Regional Dialogue contracts with customers, developing new wind integration and thermal balancing rates, and finalizing the new long-term Residential Exchange Program Settlement Agreements. Considering this, Mr. Deen believes a five-year average will provide a more appropriate level of legal expense for prospective ratemaking purposes. The effect of the adjustment would be to reduce PSE's administrative and general expenses in this case by approximately $0.9 million, relative to the Company's supplemental filing.[364]

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[361] *See supra* Section II.C.5.a.ii.b)(i) Wind Integration OATT Revenues.

[362] Deen, Exh. No. MCD-1CT at 12:5-7.

[363] *Id.* at 12:10-12.

[364] *Id.* at 12:13-13:2.

280 Mr. Story testifies that Mr. Deen's analysis is incorrect because he only reviewed selective work orders that were charged to Account 557.[365] PSE also claims ICNUs calculation of its 5-year average was flawed because it used the $6.3 million of booked costs, not the $6.8 million of the 2006 test year amounts allowed in rates as a result of restated and pro forma adjustments.[366] ICNU used $9.4 million for 2010 in its average instead of the 2010 test year amount of $6.6 million.[367] PSE states that the total account balance for Account 557 is actually trending up, growing each year for the last five years from $6.3 million in 2006 to $9.4 in 2010.[368] ICNU acknowledges in its Initial Brief that FERC account 557 costs have trended upwards.[369]

281 PSE argues that ICNU fails to justify normalizing the Company's reclassified legal expenses incurred in connection with its involvement in regional issues affecting the Company's business, and ratepayers, particularly activities related to, and before, BPA. PSE states that its 2010 test year legal expenses are the lowest legal expense in the three years ending 2010.[370] PSE also argues that while legal expenses have different causes from year to year it is reasonable to believe new causes will cause the Company to incur new legal expenses, presumably at similar levels.[371]

282 *Commission Determination:* The evidence shows that PSE's FERC Account 557 expenses are trending upward, not varying up and down from year to year. It is better to use test period amounts in such circumstances because multi-year averages tend to understate costs that are reasonably expected to be at, or higher than, the most recent 12-month period measured. We accordingly reject ICNU's proposal to normalize these expenses.

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[365] Story, Exh. No. JHS-18-T at 20:7-12.

[366] *Id.* at 20:16-8.

[367] *Id.*

[368] *Id.* at 20:7-12.

[369] ICNU Initial Brief ¶68.

[370] Story, Exh. No. JHS-18-T at 21:9-23.

[371] *Id.*

283 ICNU fails to demonstrate that PSE's test year legal expenses incurred in protecting the Company and its customers in regional activities were extraordinary. While some parties to the BPA residential exchange litigation have settled, the case remains under appeal.[372] Wind integration and thermal balancing issues will continue to require PSE's attention as BPA and other regional entities work on solutions to emerging problems associated with these issues. BPA will continue to have rate cases on both the power and transmission sides of its business. In short, Mr. Story is correct that while the exact action that causes legal expense in one year will not be repeated in the future, new legal expense requirements will take its place. We reject ICNU's proposed normalization of PSE's reclassified legal expenses for these reasons.

h) Treatment of Jackson Prairie Storage Rent

284 PSE has contracts reserving excess storage of natural gas at Jackson Prairie for power generation. This issue is not disputed as to amount. PSE agrees to Staff's proposed adjustment to the current annual rent expense, reducing it by $826,800.[373]

285 These rental costs were recorded in FERC Account 505 for power production O&M expense, which is a fixed cost in the PCA. PSE proposes to reclassify the expense to fuel for power, which is a variable cost in the PCA.[374] PSE's rationale for this reclassification is to align its electric operations with treatment of the rental revenue on in natural gas rates, which is as a variable cost in the Purchased Gas Adjustment mechanism (PGA).[375] PSE argues, too, that this is properly classified as a variable cost because they may change from year to year.[376]

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

[373] *See* Martin, Exh. No. RCM-1T at 12:6-13:5; Mills, Exh. No. DEM-11CT at 53:3-15.

[374] This is significant because, under the PCA, the fixed power expense included in base rates does not vary until it is reset in the next general rate case. In contrast, variable expenses are used at their actual levels in determining amounts subject to the sharing bands of the PCA. Thus, reclassifying the rental expense from fixed to variable enables PSE to true-up to actual the estimated amount in the power cost rate. Martin, Exh. No. RCM-1T at 11:7-14.

[375] Story, Exh. No. JHS-1T at 15:7-8.

[376] PSE Initial Brief ¶33.

286 Staff argues that aligning the electric and gas treatments of the storage rental transaction does not justify the change because the PCA and PGA are dissimilar mechanisms.[377] The PGA involves a straight pass through of gas costs, while the PCA includes capital costs, dead bands and sharing bands.[378] Staff also argues that the rental expense to reserve Jackson Prairie storage for power generation has all the hallmarks of a fixed cost. The amount of PSE's rent is constant without regard to whether a gas-fired electric generation facility is operating or how the storage is being used, until revised by the rental agreement.[379]

287 *Commission Determination:* We find Staff's arguments persuasive. The PCA and PGA are fundamentally different mechanisms, so there is no need to align them in terms of the treatment of Jackson Prairie rental expense. PSE' suggestion that these costs are variable because the contract rate may change from time to time represents a strained use of the distinction between fixed and variable costs. Fixed costs are those that do not vary with load or throughput. Variable costs do change depending on load or throughput. Jackson Prairie Storage rental costs on the electric side of PSE's operations definitely are fixed costs given these accepted definitions of the term.

i) <u>Montana Electric Energy Tax</u>

288 The methodology to calculate the adjustment is not in dispute. The Company and Commission differ slightly on this adjustment only because, at the time PSE filed its rebuttal testimony, the parties different assumptions regarding the amount of energy being generated at Colstrip in their respective power cost adjustments result in different tax amounts. The level of this adjustment included in PSE's rerun of its power cost model, as directed by the Commission, is a $91,580 reduction to NOI, resulting in an increase in the Company's revenue deficiency of $147,531.

b. Storm Damage

289 This adjustment provides for recovery of expenses caused by storms. PSE experiences storm events throughout the year which result in maintenance or repair to

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[377] Staff Initial Brief ¶109 (citing Martin, Exh. No. RCM-1T at 11:19-21).

[378] Story, TR. 1035:20-1036:10.

[379] Martin, Exh. No. RCM-1T at 11:16-12:4 and Riding, TR. 930:22-931:1.

the electric system due to high winds and other extreme weather. The manner of storm damage recovery depends in part on the severity of the storm event and related damage; it operates in a manner the Commission approved in the Company's 2004 general rate case, as modified by a settlement the Commission approved in PSE's 2007/2008 general rate case, Docket UE-072300.[380]

290 PSE's current rates provide for recovery of up to $8 million in annual storm damage expense associated with "ordinary" storm events.[381] This normalized amount is based on an average of six years for storm damage that is charged to PSE's income statement.[382] PSE is allowed to defer catastrophic storm damage that both exceeds the annual $8 million threshold and meets a modified version of the Institute of Electrical and Electronic Engineers (IEEE) standard for catastrophic events.[383] This deferred catastrophic storm damage is amortized over four years, except in extraordinary cases—such as the Hanukkah Eve storm in 2006—in which the Commission allowed for a longer amortization period of 10 years.

291 In Staff's view, it is time to transition away from the four year amortization of deferred catastrophic storm damage expenses over $8 million. Staff has come to regard these as normal operating expenses.[384] They should not be deferred, Mr. Applegate testifies, because this forces future rate payers to pay the day-to-day costs

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[380] *See WUTC v. Puget Sound Energy, Inc.*, Dockets UE-072300 and UG-072301, Order 12, ¶ 58 (October 8, 2008). (The parties also agree with FEA's recommendation to amortize the December 13, 2006 "Hanukkah Eve" wind storm over 10 years to lessen the impact of these extraordinary costs on ratepayers. The parties further propose, in this connection, to continue the Catastrophic Storm Loss Deferral Mechanism, as set forth in Mr. Story's testimony. A new $8 million threshold level is proposed via the settlement stipulation for Institute of Electrical and Electronics Engineers related storm deferrals beginning with calendar year 2009.)

[381] Story, Exh. No. JHS-18T at 26:12-15.

[382] *Id.* at 26:20-21.

[383] The Company uses IEEE Standard 1366-2003, with a slightly modified definition of an outage to establish a trigger for determining when catastrophic storm damage has occurred on the Company's electric system. The outage definition modification includes sustained interruptions that are one minute or longer, rather than the IEEE definition which includes sustained interruptions that are five or more minutes in length. McClain, Exh. No. SML-7T at 2:7-13.

[384] *See generally* Applegate, Exh. No. RTA-1T at 9:4-10:5.

of serving present rate payers and to compensate the Company by paying a return on the deferral balances while the Company waits to recover these expenses.[385]

292 Staff does not object to the continued use of deferrals that recover storm-related damages over seven or more years when warranted by the occurrence of truly catastrophic events, such as occurred in 2006. Deferral of such extraordinary costs over a longer period may be a necessary tool in such circumstances to maintain storm damage expenses in rates at a reasonable level.[386]

293 Mr. Applegate testifies that Staff's proposed adjustment would allow PSE to amortize all storm related expenses approved for recovery in Docket UE-090704.[387] The 2008 and 2010 storm damage amounts of $86,185 and $13,909,769, respectively, which are the subject of Staff' proposed adjustment in this case, were not included in the Company's filing in that docket. Accordingly, these damage amounts were not considered by the final rate order of that GRC.[388] Staff recommends, however, that the Commission require the Company to recover these amounts "through the same six year average mechanism that applies when average annual storm costs are less than $8 million rather than through the four-year deferral."[389] Mr. Applegate says that Staff's adjustment also allows PSE to collect all storm-related costs reported by the Company in filing this rate case.

294 Mr. Story testifies for the Company that while Mr. Applegate is correct that the $8 million annual expense associated with storm damage is based on an average of six years for storm damage that is charged to the income statement, he is incorrect that any storm damage in excess of $8 million is deferred. Mr. Story states that it is a common occurrence for storm damage expense to exceed $8 million in a given year, but the Company defers only the catastrophic storm damage costs that meet the IEEE standard and that exceed the $8 million threshold. According to Mr. Story, there is a

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[385] *Id.* at 9:4-7.

[386] *Id.* at 10:18-23.

[387] *Id.* at 11:11-12.

[388] *Id.* at 11:12-15.

[389] *Id.* at 7:15-23.

significant amount of storm damage that does not meet the IEEE standard for catastrophic storms and these costs are charged directly to expense.[390]

295 Mr. Story testifies further that adoption of Staff's proposal to allow for recovery of costs through a deferral for "limited catastrophic circumstances" would seriously affect the results of using the six-year average methodology, to which Staff apparently has no objection.[391] Mr. Story relates that Staff's definition of a "limited catastrophic circumstance," provided via discovery, is:

> If a year's combined storm damage expense exceeds 233 percent (or 2 times 7 years divided by 6 years) the 6-year storm damage average, Mr. Applegate would recommend deferred recovery of the portion that exceeds the 6-year average. In Mr. Applegate's view, this treatment would mitigate rate impacts without distorting the 6-year average.

Mr. Story testifies that the Company recalculated Storm Damage expense using the last six years as the data source to see the impact of this definition. Under Mr. Applegate's proposal, the amount of normal storm damage expense that would be built into rates in this proceeding would be approximately $17 million. According to Mr. Story, Staff's threshold for deferral would be in excess of $39 million (2.33 ***x*** $17 million), rather than the $8 million deferral currently approved by the Commission.[392] It follows, he testifies, that Staff's proposal would add a risk of $20 million dollars of after-tax volatility (($39m-$8m) ***x*** .65) to the Company's earnings.[393]

296 Finally, Mr. Story objects that Staff's proposed change in the handling of these costs would require the Company to write-off the previously deferred balances of approximately $14 million.[394] Yet, these costs are not challenged as being imprudent. Mr. Story states that while Mr. Applegate testifies that this is not a disallowance it is, contrary to his testimony, exactly that.[395]

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[390] Story, Exh. No. JHS-18T at 26:13-27:4.

[391] *Id.* at 29:12-30:21.

[392] *Id.*

[393] *Id.* at 30:22-26.

[394] *Id.* at 31:6-20.

[395] *Id.* Staff concedes this point in its Initial Brief and offers a "partial compromise." Staff Initial Brief ¶¶120-21.

297 *Commission Determination:* PSE's current methodologies of accounting for storm damage costs and including them for recovery in rates have been in place for many years. The basic mechanism was most recently addressed in the Company's 2004 general rate case where the then-current definition of a catastrophic storm was replaced by IEEE standard 1366-2003, modified to shorten the duration of a sustained interruption from 5 minutes to 1 minute.[396] PSE was authorized to defer without filing a separate accounting petition the costs of catastrophic storms, thus defined, if their costs exceeded a certain threshold. This modification was jointly endorsed by Commission Staff and PSE, and approved by the Commission's Final Order.[397]

298 One of the key differences between the mechanism's current deferral methodology for catastrophic storms, and Staff's proposed elimination of it, is a question of process and timing. 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. Unless the storm is found not to qualify, PSE may defer the costs and recover them over the four year amortization period without the need for further action by the Commission. Under Staff's proposal, PSE would need to file an accounting petition before deferral of catastrophic storm damage could begin but it is not precluded from doing so.[398] In this sense, Staff's proposal simply introduces uncertainty into a process that has worked well for many years.

299 Moreover, if we adopt Staff's approach, it would eliminate PSE's opportunity to defer catastrophic storm costs that exceed both the $8 million threshold and meet the modified IEEE standard, and including those costs in the storm damage normalization equation. We note the Company's calculation that this would result in more than doubling the current six year average costs that are the basis for determining the Company's normalized storm-damage expense from $8 million to $17 million. In addition, Staff acknowledges in its Initial Brief PSE's contention that it would have to

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[396] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-040640, UG-040641, *et al.*, Order 06 ¶¶ 232-33 (Feb. 18, 2005).

[397] *Id.*

[398] *See 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").

write off approximately $14 million in deferred costs that it currently is authorized to recover.[399] Accordingly these facts inform our decision to reject Staff's proposed changes and retain the current Commission-approved mechanisms for storm damage cost recovery.

6. Contested Adjustments - Electric Only - Rate Base

a. Lower Snake River[400]

300 PSE proposes to reflect in rate base and operating expenses the first phase of its development of the Lower Snake River wind power project (LSR-1), which became operational during the pendency of this proceeding. PSE includes the expected output from this new generation plant in its AURORA power cost model run for the rate year. Thus, the Company's pro forma operating cost assumptions are included in its power cost adjustment.

301 When PSE made its initial filing in this case, it expected LSR-1 to be completed in April 2012. PSE, in its rebuttal filing, agreed with Staff that the in-service date should be moved up to mid-February 2012.[401] The facility actually went into operation on February 29, 2012, which all parties now agree should be considered its "in-service" date. This is a significant date, among other reasons, because, Construction Work in Progress (CWIP) ceases to accrue and depreciation commences when plant enters commercial operation.

302 Staff, based on the latest actual figures available at the time it filed its response testimony, proposes to limit capital additions to rate base for LSR-1 based on actual charges to CWIP as of October 31, 2011, and remaining contractual obligations.[402] This contrasts to, and is less than, PSE's addition of the amounts budgeted for

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[399] Staff Initial Brief ¶120.

[400] Public Counsel and ICNU jointly propose a $55 million reduction to revenue requirement based on their challenge to the prudence of PSE's acquisition of the Lower Snake River wind power project. We discuss their prudence challenge and proposed adjustment separately below in Section II.I.

[401] Garratt, Exh. No. RG-28CT at 21:17-18.

[402] Applegate, Exhibit No. RTA-1T at 5:4-13.

completion, as updated in its rebuttal case with more recent actual costs. Staff's position is that PSE's LSR-1 adjustment to rate base relies on forecasted costs that are not known and measurable.[403] When Staff filed its response case, its proposed rate base, at $644,066,095, was $43,644,670 less than the $687,710,765 PSE included in its supplemental filing.[404] This remains Staff's proposal as of the filing of the parties' Initial Briefs.

303 The Company continued to update the information on LSR-1 as the case progressed. PSE's rate base for LSR-1, revised in its rebuttal case, is $664,324,546.[405] PSE's final proposed amount is $669,984,171.[406]

304 Staff also recommends that the Commission reject PSE's pro forma property tax expense for LSR. Staff applies its reasoning from its general Property Taxes Adjustments, discussed above in Section II.C.3.c., and removes the Company's pro forma property taxes of $2,967,101 for LSR-1.[407] Staff states that PSE's calculation of pro forma property taxes for LSR-1 represents the product of multiple estimated values, including an adjusted total project cost, personal property tax electric discount rate, system ratio, and levy rate.[408] Staff considers these not known and measurable and removes PSE's adjustment.[409]

305 Staff's proposals concerning LSR-1 essentially track those it made in Docket UE-090704 with respect to the Wild Horse Expansion project, which the Commission accepted.[410] Mr. Story emphasizes that in both cases Staff's treatment of the Plant Adjustment is inconsistent with its treatment of the Deferral Adjustment. Staff, in both proceedings includes the Company's estimates of completion costs and property

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[403] *Id.* at 5:17-23.

[404] Applegate, Exhibit No. RTA-1T at 6:20; Exh. No. RTA-3.

[405] Story, Exh. No. JHS-18T at 24:21-22; Exh. No. JHS-20, line 7.

[406] PSE Initial Brief, Appendix H.

[407] Applegate, Exh. No. RTA-1T at 5:4-13.

[408] *Id.* at 5:7-13.

[409] *Id.* at 5:11-13.

[410] *Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc.*, Order 11 ¶¶229-232, Dockets UE-090704 and UG-090705 (April 2, 2010).

taxes in the Deferral Adjustment, but excludes them from the Plant Adjustment. Mr. Story testifies that:

> The Commission may have overlooked the inconsistent logic in these two adjustments [in the prior case] as it was not discussed in testimony, which is why I am highlighting this issue in my testimony in this case. I believe it is important that the Commission not perpetuate this treatment of pro forma adjustments relating to production plant and should take another look at these adjustments in tandem, because the same issue arises in the current case in regard to the LSR adjustments.[411]

Mr. Story testifies that Staff has not explained in its testimony why it is appropriate to use CWIP costs through a date prior to the in-service date for a new resource and the estimated cost of completion for the same project in another adjustment.[412]

306 *Commission Determination:* Although Staff's position is a principled one, based on the Commission's general reliance more on actual data than on forecasts when applying the known and measurable standard, the Commission has recognized previously the appropriateness of forward looking adjustments for production assets such as LSR-1.[413] Just as we allow updates for power costs during the pendency of a proceeding, even at the compliance stage, we also find it appropriate to allow PSE to

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[411] Story, Exh. No. JHS-18T at 9:17-10:3. Mr. Story discusses the impact of this treatment in the case of Wild Horse, as follows:

> The Company's forecasted plant balance was $98,431,202 through December 2009 and the Commission accepted Commission Staff's proposal to use $90,388,143 that was closed to plant through August 2009. The actual amount closed to in-service in December 2009 was $98,060,980. The impact on revenue deficiency for the difference between Commission Staff's estimate and the actual in-service amount was $1,216,448. The impact on revenue deficiency for the difference between Company's estimate and the actual in-service amount was $47,419. In effect the Company was penalized $1.2 million so that customers would not be "overbilled" $47 thousand.

Id. at 10:7-15.

[412] *Id.* at 12:14-20.

[413] *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.").

update the capital costs of its investment in LSR-1 with more recent available data, considering the plant's February 29, 2012, in-service date, prior to the close of the record.

307 It is important during this period of intensive capital investment by PSE to reflect the best available data in the Commission's rate base determinations. We caution that in the case of plant additions the best available data includes actual data available at or very close to the plant's in-service date, with sufficient detail for Staff and interested parties to review the need and prudence of such an investment during the pendency of the proceeding. We might, in a future case, find Staff's approach to be the better one if the expected in-service date of a proposed plant is not during the pendency of the case in which its addition to rate base is considered or, at least, before the effective date of rates that will recover the investment's costs, including return.

308 In this case, we have the benefit of an in-service date for LSR-1 (*i.e.*, February 29, 2012) that is sufficiently in advance of our determination of the issues that PSE's actual costs are known and demonstrated in this record. This is the amount of investment that should be reflected in rate base.

309 Similarly, as we discussed previously in our determination of the property tax adjustment, we have the benefit of knowing the actual property taxes for LSR-1 that PSE will pay during 2012 for the 2011 tax year. As in the case of property taxes generally, this is the amount that should be allowed for recovery in rates.

b. Regulatory Assets and Liabilities

310 Two production-related regulatory assets and liabilities adjustments are uncontested and are treated separately by all parties: Lower Snake River Transmission Deposits (*i.e.*, Adjustment 20.03) and Chelan PUD Payments (*i.e.*, Adjustment 20.09). PSE treats Lower Snake River deferred costs separately, as Adjustment 20.12. Staff includes these costs in this Adjustment 20.10 and contest the amount of the adjustment representing property tax. We discuss and determine the issue in this section of our Order. There are two other contested issues concerning PSE's regulatory assets and liabilities:

- The amortization period that should apply to PSE's contract prepayment to Western Energy Company in connection with coal that will fuel Colstrip Units 1 and 2, in which PSE has an interest.

- Contract major maintenance costs for natural gas turbines at PSE's Sumas, Fredrickson, Goldendale and Mint Farm facilities.

i. __Colstrip Units 1 and 2 Prepayment__

311 On March 21, 2007, PSE made a non-refundable reservation dedication payment of $5 million to Western Energy Company (WECo) that assured coal sales by WECo were limited to an existing contract that expired on December 31, 2010. This reservation dedication payment was booked to FERC Account 165, Prepayments. PSE includes this item in production rate base. PSE's proposed adjustment reflects amortization of this reservation payment over nine years beginning January 2011 through the end of the contract term on December 31, 2019.

312 Staff proposes to change the amortization period to 10 years, to match the terms of PSE's new contract, which runs from January 1, 2010. Staff states this is consistent with the amortization treatment of other regulatory assets previously approved by the Commission, such as the Westcoast Pipeline Capacity regulatory deferrals in Dockets UE-082013 and UE-100503. In addition, Staff's proposal is consistent with PSE's use of the 20 year contract life to amortize the Chelan PUD capacity reservation in Adjustment 13.09, which Staff does not contest. Staff argues there is no reason that supports different treatment of the WECo contract.

313 PSE argues use of the full contract term is inappropriate in the case of the WECo contract because PSE's exclusive rights under this contract to the uncommitted coal in Areas A, B and D of WECo's Rosebud mine did not mature until December 31, 2010. The Company's overlapping interests in this coal with "a third party" means that PSE's customers did not benefit from the lower costs of this coal until January 1, 2011.[414] PSE argues the amortization period should match the benefit period.[415]

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[414] Jones, Exh. No. MLJ-1CT at 11:19-12:9.

[415] *Id.*

314 *Commission Determination:* It is generally appropriate to match the amortization period to the contract term and we find insufficient justification to depart from this general practice here. It apparently was necessary for PSE to enter the WECo contract effective January 1, 2010, to gain exclusive rights to the Rosebud mine coal beginning in 2011. Acquisition of these rights provides an immediate value to PSE and its customers at the inception of the contract term. We accept Staff's recommendation to have the amortization period for this regulatory asset match the contract life of ten years.

ii. Contract Major Maintenance

315 This component of Adjustment 20.10 accounts for the rate base and amortization expenses associated with the costs of major maintenance of natural gas turbines at four facilities under a long term service agreements (LTSA) or a contract service agreement (CSA), as follows:

- Sumas November 2008 Combustion Inspection.
- Sumas November 2010 Hot Gas Path Inspection.
- Freddy 1 July 2009 Hot Gas Path Inspection.
- Goldendale May 2009 Combustion Inspection.
- Mint Farm June 2010 Combustion Inspection.[416]

316 PSE includes the test year amortization and deferrals associated with contract major maintenance in power costs as part of its production O&M expense.[417] The Company proposes to include the amortization amounts in the power cost baseline rate on the production regulatory asset amortization line, which is a variable cost line on Schedule A-1 in the PCA Mechanism.[418]

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[416] Martin, Exh. Nos. RCM-1T at 14: 16-20; RCM-2 at 15, lines 17-21, 35-42.

[417] PSE Initial Brief ¶61, footnote 128.

[418] Story, Exh. No. JHS-1T at 15:18-16:4.

317 Staff argues that PSE's proposal is at odds with the agreed treatment in the PCA, under which the amortization expenses and balances of regulatory assets and liabilities are adjusted to rate year amounts consistent with other power cost expenses and rate base.[419] Staff recommends that the costs of major maintenance under an LTSA or CSA should be treated similarly: rate year expenses and balances should be used for ratemaking purposes. Modifying the PCA, as the Company proposes, will introduce uncertain costs and create inconsistency with the existing regulatory assets and liabilities.[420]

318 PSE agrees that the majority of the test year amounts will be fully amortized by the rate year, but argues there will be other maintenance events with costs that mirror test year costs.[421] PSE, however, presents no evidence showing either that test year costs will replicate the costs of subsequent maintenance or that intervals between maintenance are certain.

319 Staff also objects to PSE's proposal that the Company be authorized to add new major maintenance as a regulatory asset once completed.[422] Staff argues that deferred costs of major maintenance should first receive Commission approval for designation as a regulatory asset in a general rate case or similar proceeding, like any other regulatory asset and liability. PSE does not offer any substantive response, arguing only that "Commission rules do not limit a company to request regulatory treatment for cost recovery with an accounting petition."[423]

320 *Commission Determination:* PSE provides no substantive reason to treat the costs of major maintenance under an LTSA or CSA in a different fashion than the amortization expenses and balances of other regulatory assets and liabilities, which

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[419] Staff Initial Brief ¶127 (citing *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 and UG-011571, 12th Suppl. Order, Appendix Exhibit A to Settlement Stipulation at 4 (Settlement Terms For PCA) (June 20, 2002)).

[420] *Id.* ¶128.

[421] PSE Initial Brief ¶79; Story, Exh. No. JHS-18T at 39:11-19.

[422] Staff Initial Brief ¶130.

[423] PSE Initial Brief ¶81.

are included in Adjustment 20.10 and adjusted to rate year amounts.[424] We therefore reject PSE's proposal to use test year amortization and deferrals.

321 PSE also fails to establish any reason to allow automatic deferral of new major maintenance expense that it incurs between rate cases.[425] The Company can protect itself from any arguable inability to recover such costs by filing an appropriate accounting petition that, if approved, will relate back to the date of filing in terms of costs allowed for recovery on a prospective basis. New major maintenance costs that occur in the rate year should not be treated as a variable line item expense in the actual costs of a PCA period. The PCA is not a mechanism for adding regulatory assets to rate base between rate cases or outside of power cost only rate cases.

iii. ***Lower Snake River Deferred Costs***

322 The purpose of this adjustment is to include the estimated rate year amortization expense and net rate base amount for deferred costs associated with Phase 1 of PSE's Lower Snake River wind electric generation project. The costs of the project from the in-service date of February 29, 2012, to the date rates will become effective for this proceeding, May 14, 2012, will be deferred under RCW 80.80.060(6), which allows cost deferral for renewable resources like LSR-1. PSE and Staff agree that a reasonable amortization period is four years from the date rates in this docket become effective.

323 The difference between the rate base included by Staff and PSE in making this adjustment is the property tax that Staff removes from the deferral amounts. In its proposal to remove the Company's pro forma property taxes for LSR-1, Staff applies the same reasoning as in its other property tax adjustments.[426] Staff asserts that PSE's calculation of pro forma property taxes for LSR-1 represents the product of multiple

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[424] Martin, Exh. No. RCM-2 at 15, lines16-21, 37-42.

[425] The Commission discussed its concerns about automatic deferral mechanisms to account for major maintenance expenses incurred between rate cases in approving only provisionally such a method for Avista as part of an overall settlement of its recent general rate case. The Commission stated, among other things, that it may revisit this issue on an industry-wide basis WUTC v. Avista Corporation, Dockets UE-110876 and UG-110877, Order 06 ¶¶ 35-37 (December 16, 2011).

[426] Applegate, Exh. No. RTA-1T at 5:4-13.

estimated values, including an adjusted total project cost, the personal property tax electric discount rate, system ratio, and levy rate.[427] Staff considers these values not to be known and measurable and removes PSE's adjustment.[428]

324 *Commission Determination:* We reject Staff's property tax adjustment for LSR-1. This is consistent with our determination of the general property tax issue above, in Section II.C.3.c. Our reasons for the determination here mirror those previously discussed.

325 Moreover, PSE is entitled as a matter of law to defer LSR-1 costs under RCW 80.80. PSE initially proposed to let this deferral accumulate until the Company's next rate case, by which time significant return would accumulate. While it is true that the property taxes would be known and measurable under Staff's method by the time the request to include the deferral amounts in rates was made, this would be more expensive for ratepayers because of the additional costs of return on the deferred amounts. In any event, the matter is resolved in the same manner as in the case of property taxes generally. PSE will reflect the known amount in the Regulatory Assets and Liabilities Adjustment at the time of its compliance filing.

c. Production Adjustment

326 This adjustment reflects the application of a production factor to complete the pro forming of production costs from the forward looking "rate year" level (May 2012 to April 2013) back to the 2010 calendar year historic "test year" amount. The adjustment is a necessary component when pro forma major production plant additions from outside the test year are included in rate base and the results of operations. The production property adjustment allows the matching of the relationship between future sales (measured by increased system load) to the production rate base.

327 PSE and Staff do not differ on the production factor itself. They agree it is 2.099 percent based on the ratio of test period loads to pro forma rate year loads.[429]

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[427] *Id.* at 5:7-13.

[428] *Id.* at 5:11-13.

328 *Commission Determination:* Production costs that are subject to the production factor are dependent on other power-related ratemaking adjustments. This adjustment is a fallout adjustment that is dependent on rate year power costs and related expenses and production rate base levels. In response to Bench Request 24 PSE updated power costs and recalculated the production adjustment. The amount reported in response to the bench request is the amount that PSE should use in making its compliance filing.

7. Summary of Electric Revenue Requirement Determination

329 Table 7 summarizes the Commission's determinations with respect to the contested electric adjustments and the uncontested adjustments, which we accept without the necessity for detailed discussion. Table 8 shows the Electric Revenue Requirement that we approve for recovery in rates.

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[429] The production factor is derived by taking future loads over test year normalized loads. The resulting production factor is then applied to the rate year production costs bringing the pro formed rate year costs, on a unit basis, back to the historic test year for proper matching and comparability of all costs used in the revenue requirement determination.

TABLE 7
Commission Determinations of Restating and Pro Forma Adjustments
Electric

Adjustment	Adj. #	NOI	Rate Base	Revenue Requirement
Power Costs	20.01	123,082,268		(198,280,252)
Lower Snake River	20.02	(36,681,492)	669,984,171	143,278,938
LSR Prepaid Transmission Deposit	20.03	(726,665)	110,846,093	15,098,953
Montana Electric Tax	20.04	(91,580)		147,531
Wild Horse Solar	20.05	179,073	(3,370,636)	(712,015)
ASC 815	20.06	108,519,513		(174,820,278)
Storm Damage	20.07	1,349,514		(2,174,009)
Remove Tenaska	20.08	30,284,100	(56,496,129)	(55,885,387)
Chelan Payments	20.09	(4,607,243)	135,630,302	24,464,649
Regulatory Assets & Liabilities	20.10	4,410,066	(21,539,982)	(9,811,026)
Production Adjustment	20.11	2,269,627	(49,973,478)	(9,935,672)
LSR Deferral	20.12	(2,977,384)	10,324,092	6,093,708
Temperature Normalization	21.01	12,971,429		(20,896,415)
Revenues & Expenses	21.02	1,352,073		(2,178,132)
Pass-Through Revenues & Expenses	21.03	(306,445)		493,670
Federal Income Taxes	21.04	(60,471,551)	(41,414,322)	92,213,171
Tax Benefit of Pro Forma Interest	21.05	52,657,745		(84,829,368)
Miscellaneous Operating Expense	21.06	(4,308,881)		6,941,422
General Plant Depreciation	21.07	688,453	(233,769)	(1,138,442)
Normalized Injuries & Damages	21.08	(725,618)		1,168,939
Bad Debts	21.09	1,638,181		(2,639,039)
Incentive Pay	21.10	482,220		(776,836)
Property Taxes	21.11	(3,036,132)		4,891,078
Excise Tax & Filing Fee	21.12	(200,979)		323,769
D & O Insurance	21.13	33,584		(54,102)
Interest on Customer Deposits	21.14	(47,149)		75,955
Rate Case Expense	21.15	44,411		(71,544)
Deferred Gains/Losses on Property Sales	21.16	(1,028,316)		1,656,573
Property & Liability Insurance	21.17	(124,477)		200,527
Pension Plan	21.18	(1,199,984)		1,933,123
Wage Increase	21.19	(1,512,830)		2,437,104
Investment Plan	21.20	(83,624)		134,715
Employee Insurance	21.21	(11,276)		18,165
Working Capital	21.22		(1,378,828)	(173,256)

TABLE 8
Electric Revenue Requirement

Rate Base	4,853,248,427
Rate of Return	7.80
NOI Requirement	378,553,377
Pro Forma NOI	339,247,942
Operating Income Deficiency	39,305,435
Conversion Factor	.620749
Gross Revenue Requirement Increase	63,319,369

8. Summary of Natural Gas Revenue Requirement Determination

330 Table 9 summarizes the Commission's determinations with respect to the contested natural gas adjustments and the uncontested adjustments, which we accept without the necessity for detailed discussion. Table 10 shows the Natural Gas Revenue Requirement that we approve for recovery in rates.

TABLE 9
Commission Determinations -Restating and Pro Forma Adjustments
Natural Gas

Adjustment	Adj. #	NOI	Rate Base	Revenue Requirement
Water Heater Depreciation	12.01	4,071,209	(2,218,846)	(6,829,199)
Reclassification Bare to Wrapped Steel	12.02	(195,347)	(97,673)	302,062
Contract Changes	12.03	640,161		(1,030,042)
Temperature Normalization	13.01	6,651,267		(10,702,130)
Revenues & Expenses	13.02	16,913,083		(27,213,765)
Pass-Through Rev. & Expense	13.03	154,724		(248,957)
Federal Income Taxes	13.04	(28,834,101)	(24,564,298)	43,312,178
Tax Benefit of Pro Forma Interest	13.05	17,720,529		(28,512,975)
Misc. Operating Expense	13.06	261,609		(420,938)
General Plant Depreciation	13.07	384,999	(113,067)	(633,668)
Norm. Inj. & Damages	13.08	(54,310)		87,387
Bad Debts	13.09	1,574,431		(2,533,317)
Incentive Pay	13.10	246,621		(396,822)
Property Taxes	13.11	(1,408,271)		2,381,810
Excise Tax	13.12	(49,258)		79,255
D & O Insurance	13.13	23,376		(37,613)
Interest on Customer Deposits	13.14	(21,705)		34,924
Rate Case Expense	13.15	(142,724)		229,648
Deferred Gains/Losses on Property Sales	13.16	(92,595)		148,989
Property & Liability Ins	13.17	35,752		(57,526)
Pension Plan	13.18	(582,788)		937,727
Wage Increase	13.19	(769,423)		1,238,030
Investment Plan	13.20	(40,613)		65,348
Employee Ins	13.21	(5,476)		8,811
Working Capital	13.22		(512,748)	(64,352)

TABLE 10
Natural Gas Revenue Requirement

Rate Base	1,633,228,479
Rate of Return	7.80
NOI Requirement	127,391,821
Pro Forma NOI	119,070,612
Operating Income Deficiency	8,321,209
Conversion Factor	.621490
Gross Revenue Requirement Increase	13,389,128

D. Electric Rate Spread and Rate Design; Renewable Energy Credits

331 Rate spread allocates the revenue requirement to each of PSE's customer classes. Parity is a key consideration in rate spread. That is, one of the principal roles of rate spread determinations is to ensure that customers that cause PSE to incur particular costs pay those costs in rates. Rate design determines the fixed and volumetric rates that each individual customer actually pays so that the Company can recover the costs it incurs in serving them.

332 On January 17, 2012, PSE, Staff, Public Counsel, ICNU, and Kroger (Settling Parties-Electric), filed their Multiparty Settlement Re: Electric Rate Spread, Electric Rate Design and Renewable Energy Credit Tracker. The remaining parties either take no interest in these issues or, if interested, neither affirmatively support nor oppose the Commission's approval and adoption of the proposed settlement of the previously contested issues of electric rate spread and rate design, and the treatment of revenues from the sale of Renewable Energy Credits (RECs).

1. Electric Rate Spread

333 The Settling Parties-Electric propose that Schedule 40 rates will be determined in accordance with a calculated rate methodology, in which Schedule 40 rates for power supply (generation and transmission) are set equal to Schedule 49 charges (adjusted for power factor and losses). Delivery-related charges will be derived based on customer specific costs of PSE distribution facilities used to provide delivery services directly to each Schedule 40 customer.

334 Kroger, through Mr. Higgins's testimony, proposed that Schedule 40's eligibility provisions be changed so a customer could remain on Schedule 40 if the customer experiences a decline in usage below the rate schedule's minimum threshold of 2 aMW, provided the customer can demonstrate that the decline in usage below the threshold is directly attributable to investments in energy efficiency at the customer's Schedule 40 facilities.[430] The Settling Parties-Electric agree that the following language should be added to the end of Section 1.b. of Schedule 40:

> However, a Customer whose Schedule 40 usage falls below 2 aMW shall remain on Schedule 40 if the Customer has a designated energy manager and can document to the Company that the reduction in its energy usage below 2 aMW is directly attributable to energy efficiency investments undertaken by the Customer during the time the Customer has been served on Schedule 40.[431]

335 In deriving a Proposed Revenue Increase Percent for all other electric rate schedules, the Settling Parties-Electric agree to the following rate spread metrics:

- Schedules 7, 24, 26, 31, 35, 43, 46, 49, 50-59, 448, and 449 shall each receive a rate increase equal to 100 percent of the uniform percentage increase; Schedules 25 and 29 shall each receive a percentage increase equal to 75 percent of the uniform percentage increase assigned to the other rates schedules above.

- Firm Resale and Special Contract Classes shall receive an increase equal to the class revenue deficiency as determined in PSE's cost of service model provided with the final compliance filing in this proceeding.

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[430] Higgins, Exh. No. KCH-3T at 4:1-6.

[431] Electric Settlement, Exh. No. SPE-2 ¶14.

336 The cost-of-service evidence indicates that the parity ratio of rate schedules 25 and 29 is significantly above one and, as a result, these rate schedules are providing higher rates-of-return at current rates than the system average rate of return. It is for this reason the Settling Parties-Electric agreed to 75 percent of the uniform rate increase for these rate schedules. They testify jointly that this represents a reasonable balancing of cost-of-service considerations with other ratemaking principles, such as making gradual moves toward parity when it is found that significantly more or less than the actual cost of providing service to a customer class is being paid by those customers in rates.[432] The Settling Parties-Electric testify that the rate spread set forth in the Multiparty Settlement represents a reasonable balancing of the factors used by the Commission to set rates, including cost-of-service, fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[433]

337 *Commission Determination:* Rate spread should recognize that rates must be just and reasonable and not cause undue discrimination. To this end, revenue responsibility for any class should be informed by the cost to serve the class. The joint testimony illustrates that the Settling Parties-Electric gave appropriate attention to the issue of parity and other issues pertinent to the determination of an appropriate allocation of costs to the Company's various rate schedules for the different customer classes. We accordingly determine that the Commission should approve and adopt the proposed Multiparty Settlement, which is unopposed, in full resolution of the issues related to electric rate spread.

2. Electric Rate Design

338 The Settling Parties-Electric' rate design follows the methods proposed by PSE.[434] Mr. Piliaris testifies in this connection that:

> The Company is not proposing any changes in this case to the design of existing rates. With only minor exceptions, all rates in a customer class will be increased by the class average percentage increase. The

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[432] Joint Testimony, Exh. No. SPE-1T at 6:5-10.

[433] *Id.* at 6:17-7:1.

[434] *See generally*, Piliaris, Exh. No. JAP-1T at 20-25 and supporting exhibits.

> exceptions are Schedule 26, where the demand and energy rates are tied to Schedule 31; Schedule 40, where customer specific distribution rates are charged and the loss-adjusted energy and demand charges are set equal Schedule 49; and Schedules 448/449, where, according to agreement, the methodology proposed in PSE's 2007 GRC for these customers was used and the rate increase was applied on an equal dollar per kVA basis rather than equal percentage.[435]

339 The parties recognize in their Joint Testimony that there are a variety of interests that need to be addressed in the design of rates, and there are tradeoffs among these interests. The parties testify collectively that the settlement represents their different perspectives on these various interests and strikes an appropriate balance among them, as does the Company's current rate design.[436]

340 *Commission Determination:* Rates should be designed so that they are adequate to recover the revenue requirement, reasonably stable, reflect the costs of providing service, are fair, send proper price signals, and are relatively simple. Considering that the proposed rate structure will be almost identical to the currently approved structure, and there is no evidence suggesting a need for changes, it follows that the proposed rate design reflects an appropriate balancing of these factors. It is apparent, too, that the Settling Parties-Electric, who represent the range of customer classes, have carefully considered the matter and agree that the proposed settlement terms adequately address their diverse interests. We accordingly determine that the Commission should approve and adopt the unopposed Multiparty Settlement in full resolution of the issues related to electric rate design.

3. REC Revenue Tracker

341 The Settling Parties-Electric propose a new rate tracker to flow the benefits of REC revenue collected by the Company to customers. This would replace prospectively what is currently required pursuant to the Commission's orders in Docket UE-070725.

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[435] Piliaris, Exh. No. JAP-1T at 20:12-20.

[436] Joint Testimony, Exh. No. SPE-1T at 7:8-11.

342 The REC revenue included in this new rate tracker would be credited to customers over a three-year amortization period,[437] with deferred balances accruing interest at PSE's authorized net of tax rate of return. REC revenue will be provided to customers by means of bill credits rather than being offset against rate base as provided under the existing mechanism. The deferred balance of RECs will include the deferred taxes associated with the timing difference between when REC income is received and when the REC credit provides the benefit to customers. Amounts included in the tracker will consist of three components: (1) continuation of the amortization of the REC regulatory liability balance, net of associated deferred taxes, existing at the start of the Tracker period; (2) addition of one-third of the amount of REC proceeds projected to occur in the Tracker period based on contracts in effect at the time of filing; and (3) a true-up.

343 The initial tracker rates will be set in May 2012, coincident with the effective date of rates in this proceeding. The tracker will then be reset annually and would become effective each January 1st. The first of these annual filings will be for new rates effective January 1, 2013. At the time of the annual filing, the tracker rates will be trued up for the actual deferred REC proceeds received to date, net of deferred taxes, within the then-current rate period and the interest thereon versus the amounts assumed when setting the rates. The rates will also be trued up for any variances between the amounts set in rates and the amount actually passed back to customers over that period due to variances in load.[438]

344 *Commission Determination:* PSE says the proposed change in its treatment of REC revenues is satisfactory because it balances customers' interest in timely, but stable, rate relief with the Company's interest in more predictable cost recovery.[439] Staff

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[437] The tracker ultimately authorized in Docket UE-070725 established a five-year amortization period during which REC proceeds in excess of those used to offset Production Tax Credits already credited to PSE's customers but which the Company had not recovered via tax savings would be offset against rate base. *In the Matter of the Amended Petition of Puget Sound Energy, Inc., For an Order Authorizing the Use of the Proceeds from the Sale of Renewable Energy Credits and Carbon Financial Instruments*, Docket Nos. UE-070725 and UE-101581, Order 06 (October 26, 2010).

[438] The Settling Parties reserve the right to revisit issues regarding implementation details of the REC tracker, such as more frequent than annual reporting and showing the revenue pass-through as a separately identified bill credit, in PSE's next general rate case.

[439] Joint Testimony, Exh. No. SPE-1T at 13:6-8.

testifies the proposed mechanism is neutral vis-à-vis the existing mechanism in terms of total benefits to customers, but the three-year amortization period brings the benefits to ratepayers sooner than the five-year period provided in Docket UE-070725.[440] Kroger states its belief that the provision to recognize REC revenues as a bill credit to customers through the proposed tracker mechanism is a reasonable means to reflect the benefits of REC revenues in customer rates. Kroger testifies that the proposed mechanism strikes an appropriate balance between the benefits of speedy recognition of the REC proceeds in customer rates with the desirability of rate stability.[441]

345 The proposed mechanism appears to have advantages relative to the existing mechanism, which reduces rate base with booked REC proceeds. In addition, by having the REC revenue returned to ratepayers as a bill credit, it will be more apparent to customers that they derive direct benefits from PSE's acquisition of renewable generation resources in advance of the time they are needed to satisfy the Company's obligations to meet the state's RPS. Considering its relative advantages over the existing mechanism for treatment of REC revenues, we determine that it is in the public interest to approve the proposed new rate tracker by which the benefits of REC revenue collected by the Company will be returned to customers.

E. Natural Gas Rate Spread and Rate Design

346 As in the case of the corresponding electric settlement, PSE, Staff, Public Counsel, ICNU, and Nucor (Settling Parties-Gas) filed their Multiparty Settlement Re: Natural Gas Rate Spread and Natural Gas Rate Design on January 17, 2012. The other parties again either take no interest in these issues or, if interested, neither affirmatively support nor oppose the Commission's approval and adoption of the proposed settlement in full resolution of the previously contested issues of natural gas rate spread and rate design.

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[440] *Id.* at 14:7-11.

[441] *Id.* at 16:5-9.

1. Natural Gas Rate Spread

347 The Multiparty Settlement assigns a uniform percentage rate increase equal to the overall percentage increase to margin revenues to Schedules 16, 23, 53, 31, 31T, 61, 87 and 87T. For Schedules 41 and 41T, the Multiparty Settlement assigns a percentage increase equal to 50 percent of the uniform percentage increase assigned to Schedules 16, 23, 53, 31, 31T, 61, 87 and 87T. For Schedules 85, 85T, 86, 86T, 71, 72 and 74, the Multiparty Settlement assigns a percentage increase equal to 25 percent of the uniform percentage increase assigned to Schedules 16, 23, 53, 31, 31T, 61, 87 and 87T.

348 The cost-of-service evidence indicates that the parity ratios of Schedules 41 and 41T are above one and, as a result, these rate schedules are providing higher rates-of-return at current rates than the system average rate of return. Therefore, assigning 50 percent of the uniform rate increase to these rate schedules represents a reasonable balancing of cost-of-service considerations with other ratemaking principles, such as making gradual moves toward parity when it is found that significantly more or less than the actual cost of providing service to a customer class is being paid by those customers in rates.

349 For Schedules 85, 85T, 86, 86T, 71, 72 and 74 the combined cost-of-service evidence[442] indicates that the parity ratios of these rate schedules are even more significantly above one than in the case of Schedules 41 and 41T. As a result, these rate schedules are providing substantially higher rates-of-return at current rates than the system average rate of return. Therefore, assigning 25 percent of the uniform rate increase to these rate schedules represents a reasonable balancing of cost-of-service considerations with other ratemaking principles, such as gradualism.

350 The Settling Parties-Gas testify that the rate spread set forth in the Multiparty Settlement represents a reasonable balancing of the factors used by the Commission

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[442] Three parties—PSE, NWIGU and Nucor—filed testimony concerning natural gas rate spread and rate design. See generally, Phelps, Exh. No. JKP-1T; Schoenbeck, Exh. No. DWS-8T; and Higgins, Exh. No. KCH-1T

to set rates, including cost-of-service, fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[443]

351 *Commission Determination:* Rate spread should recognize that rates must be just and reasonable and not cause undue discrimination. To this end, revenue responsibility for any class should be informed by the cost to serve the class. The joint testimony illustrates that the Settling Parties-Gas gave appropriate attention to the issue of parity and other issues pertinent to the determination of an appropriate allocation of costs to the Company's various rate schedules for the different customer classes. We accordingly determine that the Commission should approve and adopt the proposed Multiparty Settlement, which is unopposed, in full resolution of the issues related to natural gas rate spread.

2. Natural Gas Rate Design

352 The Settling Parties-Gas' rate design follows the methods proposed by PSE in its direct testimony,[444] with two exceptions. The first exception requires that the basic charge for residential service under Schedules 23 and 53 will be limited to $10.50 per month even if applying the uniform percentage increase to Schedule 23 results in a monthly basic charge greater than $10.50. The volumetric delivery charge will be adjusted upward, if necessary, to collect the remainder of the assigned revenue for the residential class in total. If application of the uniform percentage increase to Schedule 23 results in a monthly basic charge that is less than $10.50, the monthly basic charge will be the amount calculated.

353 The second deviation is that the demand charge for Schedules 41, 41T, 85, 85T, 86, 86T, 87 and 87T will be calculated based on the percentage increase to Schedules 85 and 85T, instead of based on the percentage increase to Schedules 87 and 87T, as originally proposed by PSE. The demand charge will be the same for all of these schedules. For each of these schedules, the percentage increase to the basic charge and volumetric rates will be adjusted proportionally to ensure the assigned revenue is recovered for the schedule in total.

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[443] Joint Testimony-Natural Gas, Exh. No. SPG-1T at 6:9-13.

[444] *See generally,* Phelps, Exh. No. JKP-1T at 27-37 and supporting exhibits.

354 The rate design agreement includes minimum volume requirements for Schedules 41, 41T, 85 and 85T consistent with those proposed by PSE in its prefiled direct testimony, which no party opposed.

355 The Settling Parties-Gas' joint testimony makes clear that the settlement proposal reflects their different perspectives, which are representative of the range of PSE's customer classes. It shows, too, that they agree that their proposal results in a reasonable apportionment of revenue responsibility among customer classes, given the range of results produced by the cost-of-service studies that were presented in this case.

356 *Commission Determination:* The Commission recognizes that insofar as rate design is concerned there are a variety of interests that need to be addressed, and there are tradeoffs among these interests. Rates should be adequate to recover the Company's revenue requirement, be reasonably stable, reflect the costs of providing service, be fair, send proper price signals, and be relatively simple. The Multiparty Settlement proposes some changes to the current structure but, in general, the rate structure will be similar to the current structure. The changes proposed produce rates that meet the relevant criteria. We accordingly determine that the Commission should approve and adopt the unopposed Multiparty Settlement in full resolution of the issues related to natural gas rate design.

F. Service Quality Issues

357 We address two issues under this heading:

- Proposed settlement re meter and billing performance standards.
- Whether Service Quality Index (SQI)-9, Disconnection Ratio, should be eliminated.

1. Meter and Billing Performance Standards

358 Staff raised concerns in PSE's 2007 general rate case related to meter and back-billing issues. The Commission resolved these issues by approving and adopting a partial settlement that included the establishment of meter and billing performance standards.[445] Mr. Roger Kouchi, testifying for Staff in this proceeding, proposed that the existing meter and billing performance standards be modified to require identification and correction of 100 percent of stopped meter and unassigned energy usage issues for natural gas and electric meters within six months and four months, respectively. Staff's original proposal retained the interim thresholds in the existing performance standards and added reporting requirements.

359 In PSE's pre-filed rebuttal testimony, the Company stated that it was agreeable to including the identification of the meter issue in the performance standards. The Company, however, proposed that 80 percent of the meter issues would be resolved within six months. PSE also proposed to remove the interim thresholds. The Company agreed to certain of Staff's proposed revisions to the reporting requirements.

360 On February 15, 2012, Staff and PSE filed a Partial Settlement Re: Meter and Billing Performance Standards (Partial Settlement) addressing these issues.[446] The Partial Settlement provides the Parties' proposed resolution to meter and billing performance issues by:

- Requiring a one-time investigation of certain zero consumption accounts.
- Revising the existing meter and billing performance standards in a manner that directly addresses the length of retroactive bills.
- Requiring customer notification when an account reaches 180 days of zero consumption.
- Modifying the reporting requirements related to the Company's meter and billing performance.

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[445] *WUTC v Puget Sound Energy, Inc*., Dockets UE-072300 and UG-072301, Order 12 (October 8, 2008).

[446] Exh. No. SP-1.

361 While Staff is of the view that the performance standards approved in 2008 have been effective given that the number of back-bills decreased by 49 percent and the average duration of the back-bills decreased by 30 percent since 2009, there were still 176 electric and gas back-bills longer than 24 months and 607 longer than 12 months, as of 2011.[447] The revised standards are expected to increase the Company's attention on reducing the longer duration back-bills. In addition, the parties testify, the proposed revisions to the performance standards benefit customers in the following ways:

- The agreement to investigate meters that have recorded zero consumption for 12 months or longer will identify meter problems that have not been previously been identified by the Company's ZCON and Data-Raker tools.
- The agreement to notify customers whose meters have recorded zero consumption for at least 180 days will alert those customers they may have a meter problem and give them the information they need to address the problem with the Company.
- The revised performance standards for stopped meters and unassigned energy usage, will, over-time, reduce the average length of back-bills.
- Modifying the reporting requirements to annual and the elimination of the interim performance standards will allow for increased efficiencies and a better tool for Staff to review the Company's annual progress toward meeting the long term goals of reducing the length of back-bills.[448]

362 Messrs. DeBoer and Kouchi testify that the settlement thus focuses on changes to the performance standards that support Commission Staff and the Company's mutual goal to reduce the number of lengthy back-bills in an efficient and cost-effective

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[447] Joint Testimony of Tom DeBoer and Roger Kouchi, Exh. No. SP-2T at 6:8-13. Ms. Zana Jones testifies for PSE that the Company actually has a very high percentage of timely-issued customer bills. She says that based on January through June 2011 data, 99.88 percent of the Company's bills did not involve a back-bill. Z. Jones, Exh. No. ZDJ-1T at 15:3-5. This condition is consistent with circumstances at the time of the earlier settlement in Dockets UE-072300 and UG-072301. *Id.* at 3:10-13. PSE had, at that time, approximately 1.8 million natural gas and electric meters in service. *Id.*

[448] DeBoer and Kouchi, Exh. No. SP-2T at 6:14-7:4.

manner.[449] Staff and PSE believe that the revised meter and performance standards outlined in the Partial Settlement are consistent with their shared interest in resolving these ongoing service quality concerns.[450]

363 The Settling Parties-Gas' testify that the Partial Settlement meets key concerns of both the Company and Commission Staff regarding reducing the length of retroactive-bills, while still recognizing that equipment breaks and some customers do not notify the Company immediately upon moving in, and that the Company does not have complete control over how quickly all of these issues can be identified without significantly increasing costs that would ultimately be borne by all ratepayers.[451]

364 *Commission Determination:* It appears from both the tenor and substance of the settling parties' joint testimony that the proposed settlement terms will promote the public interest by affording additional and improved meter and billing performance protections for customers. Considering that PSE's evidence demonstrates its considerable success in terms of metering and billing as to the vast majority of its customers, the Company's willingness to work cooperatively with Staff to improve services at the margins of these performance measures, where some problems persist, is laudable. We therefore determine that the Commission should approve and adopt the Partial Settlement in full resolution of the meter and billing performance issues in this proceeding.

2. Service Quality Index (SQI)-9: Disconnection Ratio

365 The Service Quality Index program, in its entirety, was established originally to ensure that customer service did not decline following the merger of Puget Sound Power & Light Company and Washington Natural Gas.[452] One of the performance measures, SQI-9: Disconnection Ratio, established a cap for the number of

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[449] *Id.* at 3:13-15.

[450] *Id.* at 3:16-18.

[451] *Id.* at 4:17-23.

[452] *In re: Application of Puget Sound Power & Light Company and Washington Natural Gas Company*, Dockets UE-951270 and UE-960195, Fourteenth Supp. Order Accepting Stipulation; Approving Merger at 13 (February 5, 1997).

disconnections per 1,000 customers for nonpayment of amounts due when the Commission's disconnection policy would permit service curtailment. The SQI-9 ratio was set originally at .030, meaning that automatic penalties would take effect if the Company exceeded 30 disconnections per 1,000 customers. Later, in 2009, the Commission approved a request by the Company to increase the annual benchmark from .030 to .038, thereby, allowing 38 disconnections per 1,000 customers when Commission rules permit.[453]

366 On June 15, 2010, PSE filed an application to eliminate SQI-9: Disconnection Ratio, which Staff supported. On August 10, 2010, the Commission granted PSE's application on an interim basis. The Commission stated that permanent elimination of the benchmark would be considered in PSE's next general rate proceeding, which is this case.[454]

367 Mr. Kouchi testifies that Staff continues to support elimination of SQI-9 because it interferes with public policies underlying existing Commission rules to the detriment of the general body of ratepayers.[455] Ms. Susan McLain, for PSE, agrees that SQI-9 or "any disconnection benchmark" can have unintended consequences that are adverse to customer and Company interests.[456] She testifies:

> Such a benchmark can result in inequitable treatment because some customers eligible to be disconnected for nonpayment are, in fact, disconnected each month while others are not – simply because the quota of allowed disconnects has been met.[457]

368 Mr. Kouchi testifies similarly that SQI-9 results, in practice, in inequitable and unfair treatment of customers as PSE limits disconnects to those within the allowed

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[453] *WUTC v Puget Sound Energy, Inc*., Dockets UE-072300 and UG-072301, Order 14 (November 13, 2009).

[454] *WUTC v Puget Sound Energy, Inc*., Dockets UE-072300 and UG-072301, Order 16 (August 10, 2010).

[455] Kouchi, Exh. No. RK-1T at 3:1-2. McLain, Exh. No. SML-7T at 8:4-8.

[456] McLain, Exh. No. SML-1T at 50:9-18.

[457] *Id.* at 50:12-15.

disconnection ratio and increases expenses for all customers who are burdened with higher rates to recover the uncollectible revenues.[458] Mr. Kouchi also testifies:

> Existing rules already offer thorough and meaningful protections for customers facing disconnection. Allowing the Company to eliminate SQI-9 will have no effect on those existing protections. Rather than limiting PSE's ability to disconnect customers for non-payment; the rules prescribe specific steps PSE must follow before it can disconnect a customer. The rules also recognize that energy service is essential to the public health and welfare by providing a specific mechanism for disconnected customers to resume service without the burden of first having to repay their prior obligation.[459]
>
> Public Counsel and the Energy Project did not file testimony on PSE's proposal to eliminate SQI-9. However, their cross-examination shows they oppose the request because they view SQI-9 as a means to protect low-income customers during difficult economic times.

369 Public Counsel and the Energy Project did not file testimony on PSE's proposal to eliminate SQI-9. However, they address and oppose the request in their Initial Briefs because they view SQI-9 as a means to protect low-income customers during difficult economic times.[460]

370 *Commission Determination:* Public Counsel and the Energy Project both argue that SQI-9 does not impose a hard cap on disconnections. If PSE exceeds the standard, however, even having complied with all Commission rules protecting customers from disconnection and extending to customer various bill payment options to avoid disconnection (*e.g.*, levelized payments; payment plans), the Company faces significant penalties of up to $1.5 million annually.[461] Thus, as a practical matter the SQI standard does impose a cap and "some customers eligible to be disconnected for

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[458] Kouchi, Exh. No. RK-1T at 7:21-8:2.

[459] *Id.* at 9:17-10:1.

[460] Public Counsel Initial Brief ¶¶138-44; Energy Project Initial Brief at 11-13.

[461] *WUTC v Puget Sound Energy, Inc.*, Dockets UE-011570 and UG-011571, Updated Appendix1 to Exhibit J, in Compliance with Order 17, Dockets UE-072300 and UG-072301 (November 29, 2010).

nonpayment are, in fact, disconnected each month while others are not – simply because the quota of allowed disconnects has been met."[462]

371 It appears, then, that SQI-9 – Disconnection Ratio has had unanticipated consequences in its application that make its continuance contrary to the public interest. The evidence shows that PSE's adherence to the SQI-9 requirements is discriminatory in effect. If the measure had not been suspended during 2010, for example, PSE would have disconnected 68,341 customers rather than the total number of 70,500 who met all criteria for disconnection.[463] Thus, 2,159 customers who should be disconnected for non-payment would have effectively received an undeserved benefit by not being disconnected, while 68,341 customers experienced the consequences of non-payment. Those customers who should be disconnected in accordance with PSE's tariff and the Commission's rules, but are not disconnected because the SQI-9 cap has been reached, continue to impose costs on PSE which, due to continuing non-payment, must be borne by customers who are paying their bills. This, too, is inequitable and discriminatory in effect.

372 Our decision is influenced significantly by the fact that there are carefully considered protections in place for customers facing disconnection, such as:[464]

- Customers have the right to receive a bill stating the amount owed and the date payment is due.
- Customers have the right to have billing and service disputes investigated by PSE and Staff, and may not be disconnected while these investigations are pending.
- Customers have the right to advance, written notice of PSE's intent to disconnect service for non-payment of bills.

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[462] McLain, Exh. No. SML-1T at 50:12-15.

[463] The 2010 Annual Puget Sound Energy SQI and Electric Service Reliability Report filed with the Commission on March 31, 2011, shows a 32 percent increase in the number of disconnections for nonpayment from 53,500 in 2009 (2.97 percent of the total customer base) to 70,500 in 2010 (3.92 percent of the total customer base). Exh. No. RK-2 at 3.

[464] *See* WAC 480-90-128, -173, -178; WAC 480-100-128, -173, -178.

Our rules also require PSE to reconnect customers who pay a reconnection charge and one-half the allowed deposit amount. PSE may not require payment of an unpaid prior balance before reconnecting service, but may seek collection through other means.[465] These rules operate independently of SQI-9 and there is no evidence that the operation of the Disconnection Ratio has influenced the Company to be any more or less diligent in working with customers to help them avoid disconnection and ensure they are afforded the protections required by the Commission's rules. Accordingly, based on the evidence above and the partial settlement presented to us, we approve the elimination of SQI-9.

G. Low-Income Customer Bill Assistance

373 The Energy Project recommends increasing PSE's low-income bill assistance program funding from .51 percent to .665 percent of the Company's total annual operating revenues,[466] because the current funding level does not allow many of the customers in PSE's service territory who are eligible for assistance to receive it. The proposal is based on a comparison of PSE's low-income funding to similar programs by Avista, Seattle City Light, Snohomish PUD, three utilities in California, and three utilities in New England. [467] The Energy Project also cites decreased federal Low-Income Home Energy Assistance Program funding available at the state level.[468] The Energy Project argues that increased assistance funding should become effective immediately when new rates go into effect.[469]

374 The Company takes no position on The Energy Project's proposal, except to argue that if the Commission approves the increase, the increase in ratepayer funding should take place as part of PSE's ongoing annual true-up compliance filing in August, as provided for in the original settlement terms for low-income bill assistance. [470]

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[465] *See* WAC 480-90-123 and WAC 480-100-123.

[466] Howatt, Exh. No. JGH-1T at 20. Based on 2010 operating revenues, this would increase low-income bill assistance from $15.5 million to $20.2 million.

[467] *Id*. at 11:10-19.

[468] Initial Brief of The Energy Project, at 2-3.

[469] *Id*. at 4.

[470] PSE Initial Brief ¶ 173 (citing *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 and UG-011571, Twelfth Supp. Order, App. A (June 20, 2002)).

375 Staff recommends that the Commission approve the increase considering that it is relatively minor and would impose little impact on the remaining customers that fund the program.[471] Staff cautions, however, that The Energy Project's justification for the increase was based upon a comparison to other utilities that does not account explicitly for factors such as customer demographics and economic conditions specific to PSE's service territory. Staff therefore recommends that the Commission caution parties that proposals for future increases should include more detailed analysis of these factors.[472]

376 *Commission Determination:* The customer testimony heard at our public comment hearings in PSE's service territory,[473] written comments from customers,[474] and additional evidence in the record[475] make us keenly aware of the struggle PSE's customers face as they balance their needs for goods and services against their financial resources. This situation is significantly worse for the area's low-income residents especially in the context of the sluggish economic recovery and PSE's request for frequent rate increases. No party objects to increasing funding for PSE's low-income bill assistance program. We find reasonable the Energy Project's proposal to increase the funding for PSE's low-income bill assistance program. We direct the Company to file for the increase as part of its ongoing annual true-up compliance filing on August 31, 2012.

377 We also find reasonable Staff's recommendation to require that parties proposing increases for low-income bill assistance funding in future PSE rate cases present more detailed analyses of the economic conditions and customer demographics within the utility's service territory. The comparative evidence presented in this case, though informative, did not contain such relevant economic and demographic information. Such evidence will be useful in assisting the Commission to determine the merit of a proposed change in funding levels.

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[471] Staff Initial Brief ¶226.

[472] *Id.* at ¶227.

[473] *See generally* TR. 56 - 101; 563-609.

[474] Exh. No. B-6 (compilation of written Public Comments).

[475] *See* Howatt, Exh. No. JGH-1T, *passim*; Exh. No. B-15 (Census Bureau data on poverty in the state of Washington).

H. Prudence Issues

1. Lower Snake River

378 The Lower Snake River Wind Project (LSR) is located in southeast Washington and encompasses over 124,000 acres of leased lands in Garfield and Columbia Counties. LSR covers four wind resource areas and includes enough acreage and wind potential for a 1250 MW development.[476] PSE acquired the wind development rights to LSR in two separate transactions with RES America Developments, Inc., beginning in November 2008, and recently completed Phase 1 of the Lower Snake River Wind Project (LSR-1), in which it has 100 percent ownership.[477]

379 LSR-1 adds 343 MW nameplate capacity of wind energy to PSE's existing portfolio.[478] The project is located on the western edge of Garfield County and connects to PSE through BPA's transmission system. It consists of 149 Siemens 2.3 MW wind turbines spread over nearly 2,160 acres of leased land straddling U.S. Highway 12.[479] LSR-1 became operational on February 29, 2012, a few months ahead of the original schedule of April 2012.[480]

380 Mr. Roger Garratt and Ms. Aliza Seelig are PSE's principal witnesses on the subject of LSR-1. They testify in detail concerning the quantitative, qualitative and business analyses PSE conducted in connection with the Company's 2009 IRP (Integrated Resource Plan) and 2010 RFP (Request for Proposals) processes that are central to its resource acquisition decision making.[481] PSE identified LSR-1 as the renewable resource with the lowest reasonable cost and lowest reasonable risk.[482]

381 Mr. Garratt relates that after the RFP comparative analysis identified LSR-1 as the preferred resource to acquire to meet its renewable resource need, the Company's

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[476] *Id.* at 38:15-19.

[477] Garratt, Exh. No. RG-1HCT at 29:13-15; 37:6-8.

[478] Garratt, Exh. No. RG-1HCT at 3.

[479] Id. at 41-44.

[480] Garratt, Exh. No. RG-13HC at 22, Table 6.

[481] *See generally*, Garratt, Exh. Nos. RG-1HCT and RG-28CT; Seelig, Exh. Nos. AS-1HCT and AS-4HCT.

[482] Garratt, Exh. No. RG-1HCT at 55:3-4.

Energy Management Committee (EMC), on April 22, 2010, approved a request to put before the Board of Directors a proposal to construct LSR-1.[483] On May 5, 2010, PSE's Board of Directors approved the Company's recommendation to construct LSR-1.[484]

382 Mr. Garratt states that PSE's construction of LSR-1 is a valuable step in acquiring the necessary electric supply resources to meet PSE's renewable portfolio standard (RPS) requirements under the EIA.[485] He testifies that the principal benefits of this new resource are that:[486]

- LSR-1 meets the Company's renewable resource need to satisfy the 2016 RPS benchmark.
- PSE considered LSR-1 as part of the 2010 RFP renewable resource evaluation process, and this process demonstrated LSR-1 to be the lowest reasonable cost, lowest reasonable risk alternative at the time.
- Renewable generation ownership provides long-term wind resource value and avoids the liquidity and credit requirements that typically accompany many long-term power purchase agreements.
- LSR-1 meets the requirements for the Treasury Grant program that provides $321,108,000 nominal benefit to customers ($18/MWh).
- The project takes advantage of sales tax exemption which provides $45,737,000 nominal savings, inclusive of taxes and AFUDC (allowance for funds used during construction), to customers.
- LSR-1 presented a viable opportunity for near-term renewable energy project that helps satisfy energy needs and renewable portfolio standard requirements.
- Synergies between LSR-1 and Hopkins Ridge operations allow cost savings on infrastructure and personnel.

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[483] Garratt, Exh. No. RG-1HCT at 57:3-10.

[484] *Id.* at 57:13-14.

[485] Codified at RCW 19.285.

[486] *Id.* at 87:13-88:13.

- Expansion into Garfield County enjoys local community support.

- As a self-build option, PSE controls development and construction that saves developer premium, maintains flexibility and provides additional development experience.

Mr. Garratt testifies that current state and federal tax incentives that may not be available in the future materially affected the Company's decision to acquire additional wind generation in advance of need for the associated environmental credits.[487]

383 Commission Staff supports PSE's request for determinations that its acquisition and development of LSR-1 satisfies the Commission's used and useful and prudence requirements, and that its costs should be allowed in rates.[488] According to Mr. David Nightingale, the project is used and useful, in part, because it will be operational to provide power to the Company's service territory during the rate year associated with this proceeding.[489] In his discussion of prudence, he describes analyses that address the question of benefits to ratepayers that are tangible and have been quantified by PSE and verified during his review of relevant documents.

384 Ms. Mary Decker for NWEC and Mr. Ezra D. Hausman for the Sierra Club provide additional testimony in support of PSE's development of LSR-1.[490] Sierra Club argues generally in its Initial Brief in favor of wind generation.[491] NWEC is more specific, arguing for example that "PSE has invested in early acquisition of wind resources to take advantage of significant federal incentives, secure compliance with

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[487] *See* Garratt, Exh. No. RG-28CT at 19:18-20:19.

[488] *See generally* Nightingale, Exh. Nos. DN-1HCT and DN-2T. Staff's analysis is informed by and follows the Commission's recent Policy and Interpretive Statement on the early acquisition of renewable energy resources. *In the Matter of the Washington Utilities and Transportation Commission's Inquiry on Regulatory Treatment for Renewable Energy Resources*, Docket UE-100849, Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities (January 3, 2011) ("Renewable Policy Statement").

[489] Nightingale, Exh. No. DN-1HCT at 8:1-2. Indeed, the facility began delivering power on February 29, 2012. There is no dispute that this is the appropriate in-service date to use when determining the cost and accounting treatment for LSR-1n rates.

[490] *See generally* Decker, Exh. No. MWD-1T; *See also* Hausman, Exh. No. EDH-1T at 4, 23-25.

[491] Sierra Club Initial Brief ¶¶41-43.

state RPS, and reduce its exposure to the substantial financial risks associated with fossil-fuel-fired electricity generation."[492]

385 Public Counsel and ICNU assert that LSR-1 is neither used and useful nor prudent. Their contentions are grounded in the idea that PSE acquired and developed LSR-1 several years in advance of any need for such a renewable resource to meet mandatory RPS. Mr. Scott Norwood recommends that the Commission disallow $55 million in LSR costs based on an estimate of the additional cost expected to be incurred due to PSE's early wind addition.[493] Public Counsel argues that "[t]his partial disallowance will allow PSE a reasonable level of cost recovery for the plant while also recognizing the excessive costs imposed on customers by the early pursuit of this self-build option."[494]

386 Mr. Norwood testifies that while the actual cost impact on customers of PSE's LSR-1 investment is much larger than his recommended disallowance, what he proposes "conservatively reflects the estimated additional cost expected to be incurred due to early wind additions based on the Company's estimates at the time the decision was made to select LSR-1."[495] According to Mr. Norwood, his recommendation allows PSE to recover requested operations and maintenance costs, depreciation, property taxes, insurance, and related wheeling and wind integration costs, and debt financing costs for the project, plus a modest return on equity.[496]

387 Public Counsel[497] makes three principal arguments in support of its contention that LSR-1 does not meet the Commission's prudence standard:

- PSE failed to establish a need for LSR-1.

- PSE failed to show that LSR-1 is cost effective.

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[492] NWEC Initial Brief ¶31.

[493] Norwood, Exh. No. SN-1CT at 7:13-8:1.

[494] Public Counsel Initial Brief ¶9.

[495] *Id.* at 8:5-13.

[496] *Id.*

[497] ICNU co-sponsored Mr. Norwood, but does not address these issues in detail in its Initial Brief, relying instead on Public Counsel's advocacy. *See* ICNU Initial Brief ¶3.

- PSE's Board was not properly informed and involved.

Public Counsel argues, in addition, that LSR-1 is not used and useful because it does not provide net benefits to customers before 2016 at the earliest.

388 The EIA,[498] established RPS that require electric utilities in Washington with more than 25,000 customers to use qualifying renewable energy to serve at least 15 percent of their electric load by 2020, with benchmarks of 3 percent and 9 percent that take effect in 2012 and 2016, respectively, to demonstrate progress. Public Counsel's argument that PSE failed to establish a need for LSR-1 begins with the point that PSE has no need for new renewable resources in 2012 to meet RPS requirements.[499] This is undisputed. PSE acknowledges that at the time the Company decided to build LSR-1, it was "well-positioned to meet the near-term RPS benchmark in 2012."[500] PSE determined, however, that it required additional renewable resources to meet the mandated levels in both 2016 and 2020.[501]

389 PSE decided to build LSR-1, in large part, to meet the RPS benchmark for 2016. The Company says its decision to construct the project in advance of this need was prudent due to the following significant costs savings realized by PSE:[502]

- A $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.[503]

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[498] Codified at RCW 19.285. The EIA resulted from the passage by voters in November 2006 of Initiative Measure No. 937.

[499] Public Counsel Initial Brief ¶14.

[500] PSE Initial Brief ¶124.

[501] *Id.;* Garratt, Exh. No. RG-1HCT 18:8-11.

[502] PSE Initial Brief ¶125.

[503] Garratt, Exh. No. RG-1HCT 25:7-9.

- A $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.[504]

- A depressed resource development market that has created downward price pressure on wind turbine generators, which generally comprise 60-75% of the total cost to build a wind project.[505]

PSE projects that the construction of LSR-1 in 2012 provides net present value (NPV) benefits that are $190 million higher than the construction of a similarly sized renewable energy plant in 2016.[506]

390 Public Counsel does not dispute these facts, but argues they do not establish that LSR-1 was cost effective because the analysis showing these net present value benefits was not presented to the PSE Board of Directors during the May 5, 2010, meeting at which the Board approved going forward with LSR-1 or included in the direct testimony and exhibits provided by Ms. Seelig and Mr. Garratt.[507] While this may be true with respect to PSE's ultimate NPV calculation, the nominal benefits underlying this analysis were presented to the Board of Directors, as is clear from Mr. Garratt's prefiled direct testimony and exhibits.[508]

391 PSE presented evidence demonstrating its early evaluation of the cost effectiveness of LSR-1 and other available renewable resources in its 2009 IRP. After completing 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 three quantitative models to identify the cost-effective level of renewable resources that it could add to meet its needs as identified in the 2009 IRP:

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[504] *Id.* at 25:9-10.

[505] *Id.* at 3:16–4:5.

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

[507] Public Counsel Reply Brief ¶7.

[508] Garratt, Exh. No. RG-1HCT at 25:2-11; Exh. No. RG-13HC at 27 (Approval of LSR Wind Project Phase 1, presentation to PSE Board of Directors, May 5, 2010).

- A simple discounted cash flow analysis.
- A re-run of the 2009 IRP in the Portfolio Screening Model II (the PSM II Model) used during the 2009 IRP.
- 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.[509]

392 Given the need for resources shown by its early analyses, the Company issued an "All Sources" RFP in January 2010. PSE received 64 proposals from 55 respondents. Renewable resources accounted for 31 of the proposals and 21 of the 31 were for wind.[510] The timing of the 2010 RFP cycle made it possible to compare PSE's self-build renewable resource (*i.e.*, LSR-1) to more than 30 other renewable resource proposals. In fact, PSE specifically postponed the Board of Directors decision on whether or not to proceed with LSR-1 to allow sufficient time for PSE to evaluate LSR-1 with the renewable resource proposals submitted in response to the 2010 RFP.[511] In addition to LSR-1, PSE evaluated two other self-build projects during the 2010 RFP including a combined-cycle gas turbine project and a simple-cycle gas turbine peaking plant project with two different technology options.[512]

393 PSE evaluated all proposals using a "fatal flaw" array of qualitative and quantitative analyses to screen out the least competitive offers.[513] The remaining short-list of proposals was subjected to further due diligence using a dynamic simulation of the PSE system within the Western Interconnection.[514] The model selected various combinations of available additional resources under several scenarios and simulated 20 years of operation to find the lowest revenue requirement that satisfies the RPS and capacity needs of PSE.[515] In particular, the modeling examined the impact of

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[509] Seelig, Exh. No. AS-1HCT 21:6-15.

[510] *Id.* at 4:11-5:2.

[511] *Id.* at 7:8-16.

[512] *Id.*

[513] *Id.* at 8:2-7.

[514] *Id.* at 3: 9-17 and Selig, Exh. No. AS-3HC at 157-160.

[515] Seelig, Exh. No. AS-3HC at 42.

Section 1603 Treasury grant and state sales tax incentives, and prices for wind turbines that the Company states were15 percent below 2008 prices and falling.[516]

394 These analyses determined there were significant cost benefits to acquiring wind in advance of the RPS, including energy production and REC sales revenues.[517] They also found that LSR was among the lowest cost alternatives and presented the lowest overall risk of construction and ability to secure the federal and state tax incentives.[518]

395 Mr. Norwood criticizes PSE's quantitative analyses in terms of both methods and assumptions. He also testifies concerning several mistakes that, in his view, discredit and undermine PSE's decision to construct LSR-1. Public Counsel devotes significant portions of its Initial and Reply Briefs to this subject.

396 PSE systematically addresses these criticisms through its witnesses' testimonies and in its own Initial and Reply Briefs, also at considerable length. Staff provides us with detailed testimony in support of LSR-1 and thoroughly briefs the issues.[519] While we do not need to discuss each of these point-counterpoint discussions in detail, we summarize here several key disputed points in the record.

397 Mr. Norwood asserts that an error in the 2009 Business as Usual (2009 BAU) market price scenario in PSE's re-run of the 2009 IRP "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

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[516] The cumulative discount from the federal and state incentives is 35.4 percent: 30 percent from Treasury grants and 5.4 percent from sales tax exemption. Nightingale, Exh. No. DN-1HCT at 17:15-16.

[517] Seelig, TR. 344:2-13.

[518] Nightingale, Exh. No. DN-1THC, pages 21-22. Other renewable proposals suffered from one or more significant qualitative risks: 1) Incomplete planning and permitting; 2) Lack of available transmission; 3) Lack of wind study to substantiate resource claims; 4) Lack of long-term agreements with dependent operations or fuel supply; 5) Improper wind turbine placement that would require project redesign; and 6) Lack of wind turbine site suitability and construction and start dates that made it unlikely the project would meet Treasury grant deadlines. Seelig, Exh. No. AS-3HC at 42.

[519] The Sierra Club argues generally in support of PSE's acquisition of wind energy. Sierra Club Initial Brief ¶¶41-43.

response to its 2010 RFP."[520] However, the Company corrected this error and reran the BAU market price scenario, which demonstrated it was inconsequential. The corrected analysis demonstrates that the early construction of 600 MW of renewable energy to capture the Section 1603 Treasury Grant remained the most cost-effective solution based on the need defined in the 2009 IRP.[521]

398 Mr. Norwood testifies that PSE overstated its renewable energy need to meet the benchmark targets for the RPS because PSE failed to consider the REC banking provisions of the RPS.[522] This ignores the fact that, at the time PSE's Board of Directors authorized the construction of LSR-1, PSE had contractual commitments to sell most of its surplus RECs in the 2011–2015 period to counterparties in order to provide significant monetary benefits to customers.[523] Thus, PSE did not project significant REC surplus over the 2011-2015 period and considered the RPS's banking provisions generally as a hedge against wind generation uncertainty, wind curtailment policies, and load uncertainty. It was not, at that time, considered as a mechanism to substitute for renewable generation to meet requirements of the state mandated RPS.[524]

399 Mr. Norwood asserts that "PSE assumed in all scenarios that wind projects placed in service after 2013 would not be eligible for PTCs [Production Tax Credits]."[525] In his view, this incorrect assumption created a significant capital cost advantage for early wind generation projects, such as LSR-1, when compared to wind projects that were projected to enter service after 2013.[526] PSE's analyses assumed that PTCs would not be available for projects placed in service after December 31, 2012, because the federal legislation creating wind PTCs does not extend to projects placed in service after December 31, 2012. Even so, PSE conducted sensitivity analyses that considered the possibility that legislation would extend PTCs through 2016 and

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[520] Norwood, Exh. No. SN-1CT at 33:1-3.

[521] Seelig, Exh. No. AS-4HCT at 12:8–14:9.

[522] Norwood, Exh. No. SN-1CT at 33:4 – 35:18.

[523] Seelig, Exh. No. AS-4HCT at 14:10-16.

[524] *Id.* at 16:6-15.

[525] Norwood, Exh. No. SN-1CT at 36:6-10.

[526] *Id.*

through 2020. These analyses confirmed PSE's recommendation to construct or acquire renewable energy need in advance of the RPS target deadlines.[527]

400 Mr. Norwood criticizes the carbon price assumptions PSE used in its Trends Scenario in its re-run of the 2009 IRP analysis.[528] These prices were those indicated by a March 2008 EPA (Environmental Protection Agency) analysis of proposed carbon legislation and were the prices available to PSE at the time it re-ran the 2009 IRP analysis.[529] Moreover, when updated CO_2 price forecasts became available in October 2009, after PSE completed its re-run of the 2009 IRP, PSE used the updated estimates in its analyses of the projects proposed in response to the 2010 RFP.[530]

401 Public Counsel criticizes PSE's "end effects" analysis on various bases, focusing particularly on its assumption that wind resources that are retired after the 20 year evaluation period will not be replaced. Mr. Norwood testifies that "by failing to replace units that are required during the end-effects period, PSE's method creates a mismatch between the level of wind in the end-effects evaluation period as between the 'early wind' and 'no early wind' scenarios."[531]

402 Public Counsel argues that "PSE in rebuttal acknowledges that the end-effects methodology recommended by Mr. Norwood is a reasonable approach."[532] This is misleading in two respects. Ms. Seelig actually testifies at the cited page and line of her rebuttal that, "[r]eplacing resources after the end of a planning horizon is *an alternative way to handle end effects*."[533] Contrary to Public Counsel's argument, this is not an endorsement of Mr. Norwood's approach. Indeed, Ms. Seelig goes on to criticize the replacement method because it "does not solve the mismatch in the level of wind resources during the end effects period when comparing alternative

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[527] Seelig, Exh. No. AS-4HCT at 16:16–20:14.

[528] Norwood, Exh. No. SN-1CT at 39:20-22.

[529] Seelig, Exh. No. AS-4HCT at 21:5-18.

[530] *Id.* at 20:7–28:22.

[531] Norwood, Exh. No. SN-1CT, p. 41:18-42:8.

[532] PSE Initial Brief ¶32 (citing Seelig, Exh. No. AS-4HCT at 32:6-7).

[533] Seelig, Exh. No. AS-4HCT at 32:6-7 (emphasis added).

portfolios."[534] She explains that, using the same methodology as included in the Company's end effects analyses of resources since 2003:

> PSE's end effect calculation, as described above, is thorough and treats all portfolios consistently. PSE's end effects calculation includes all the costs of resources assumed during the 20-year planning horizon, the remaining rate base cost at the end of the planning horizon, and any portfolio benefit from the book life beyond the planning horizon.[535]

Public Counsel's assertion is also misleading because it ignores Ms. Seelig's testimony that: "Mr. Norwood does not propose an alternative end effects calculation. Rather he shows an analysis that essentially removes PSE's calculation of end effects."[536] She explains this point at length, offering details that we do not need to recount here.[537]

403 Mr. Norwood testifies 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."[538] Mr. Norwood's REC purchase analysis used PSE's $8 per REC price based on the conservative sale price PSE used for its own excess RECs.[539] However, all of the unbundled REC bids in the 2010 RFP were higher than $8/MWh. 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.[540] 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.[541]

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[534] Seelig, Exh. No. AS-4HCT at 32:10-12.

[535] *Id.* at 32:13-18.

[536] *Id.* at 34:7-8.

[537] *Id.* at 34:9-35:9.

[538] Norwood, Exh. No. SN-1CT at 43:4-6.

[539] Norwood, Exh. No. SN-CT at 43:4-15; Seelig, Exh. No. AS-4HCT at 39:18-22.

[540] Seelig, Exh. No. AS-4HCT at 36:8-37:5.

[541] *Id.* at 35:7-40:2.

404 Ms. Decker testifies for NWEC that the core mandate of the RPS requirement in the EIA focuses on long-run physical compliance with annual targets, requiring sufficient generating resources or REC contracts to be in place as of January 1 of each target year.[542] The REC carry-over provision was not intended to allow utilities to delay compliance with the law; rather, it allows utilities some flexibility to respond to uncertain load growth or other needs. Thus, Ms. Decker demonstrates, even if it might have been feasible for PSE to meet its obligations under the EIA by purchasing unbundled RECs or by relying on carry-over provisions, such a strategy offered PSE only temporary compliance and carried the risk that a later acquisition of eligible renewable resources would come at a significantly higher price.[543]

405 Mr. Norwood asserts 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.[544] In fact, PSE conducted a discounted cash flow analysis in January 2010 that both evaluated a "No Early Wind" scenario, and included an estimate of the market value benefit of wind energy relative to the incremental operating and transmission cost of wind projects.[545] 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.[546] 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.[547]

406 *Commission Determination:* After we consider all of the discrete points of disputed facts discussed above, we find the weight of the evidence balances in PSE's favor in

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[542] Decker, Exh. No. MWD-1T at 3:19-4:13.

[543] *Id.*

[544] Norwood, Exh. No. SN-1CT at 43:17–44:9.

[545] Seelig, Ex. No. AS-4HCT at 41:6-43:15.

[546] *Id.*

[547] Seelig, Exh. No. AS-4HCT at 40:4–43:15.

each instance. Without burdening our Order with further detailed discussion of the record concerning LSR-1, it is sufficient to observe at this juncture that the 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. The record establishes, in addition, that PSE's qualitative and commercial analyses undertaken in connection with in its 2010 RFP process, supported PSE's conclusion that LSR-1 was the renewable resource alternative that presented the lowest reasonable cost and risk.[548]

407 There is substantial evidence in the record showing that PSE kept its Board of Directors informed and involved in the consideration and construction of LSR-1.[549] Public Counsel identifies several items he contends should have been disclosed to the Board, but fails to establish that they would have affected the Board's evaluation of LSR-1 or would have influenced the Board to make different decisions.[550]

408 Overall, the Commission's prudence standard is a reasonableness standard:

> The Commission has consistently applied a reasonableness standard when reviewing the prudence of decisions relating to power costs, including those arising from power generation asset acquisitions. The test the Commission applies to measure prudence is what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.[551]

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

[549] *See* Garratt, Exh. Nos. RG-1HCT at 16:1-14, 35:15-36:2, 37:11-16, 46:1-10, 48:5-49:2, 55:15-57:15, 73:9-20; RG-7HC, RG-12C; RG-13HC; *See also* Seelig, Exh. Nos. AS-1HCT at 3:18-4:4, 11:1-12:2, 19:1-20:14.

[550] Public Counsel Initial Brief ¶64.

[551] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 19 (April 7, 2004) (footnotes and related citations omitted).

409 There is no single set of factors by which the Commission evaluates prudence but the Commission typically focuses on four factors:[552]

1) *The Need for the Resource:* The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.

2) *Evaluation of Alternatives:* The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.

3) *Communication With and Involvement of the Company's Board of Directors:* The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.

4) *Adequate Documentation:* The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.

410 Today, it is important amplify on the second factor above, evaluation of alternatives, in the context of acquisition of renewable resources. In such acquisitions, PSE and other utilities are required to take into account in mandatory RPS benchmarks that require them to obtain renewable resources sufficient to meet certain minimum percentages of their power needs at specific points in time.

411 Public Counsel argues that "PSE has not cited any regulatory decision from Washington or other jurisdictions which approved the placement of a resource into

[552] *Id.* at ¶ 20; *WUTC v. Puget Sound Power & Light Co.,* Docket UE-921262*, et al.*, Nineteenth Supplemental Order at 11 (September 27, 1994).

rates four years or more in advance of need, under any theory."[553] This may be true to the extent Public Counsel means a decision in an adjudicatory or rulemaking proceeding, but this is misleading because it ignores that we are considering the matter with respect to a specific resource acquisition for the first time in this case. The Commission did, however, expressly address the question of early acquisition in its 2011 Decoupling Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities (Renewable Resource Policy Statement) 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: [554]

> 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.[555]

412 The Renewable Resource Policy Statement 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

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[553] Public Counsel Initial Brief ¶14.

[554] *In the Matter of the Washington Utilities and Transportation Commission's Inquiry on Regulatory Treatment for Renewable Energy Resources*, Docket UE-100849, Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities at ¶52 (January 3, 2011).

[555] Renewable Resource Policy Statement ¶52.

> facility earlier may secure a more productive (and therefore more cost-effective) facility.[556]

The record establishes that PSE invested significant time and effort considering these factors as it evaluated the question whether to develop LSR-1. While Public Counsel and ICNU, through Mr. Norwood, invest significant resources in critiquing PSE's analyses, the record demonstrates that PSE's decision to construct or acquire renewable resources in advance of RPS target deadlines was cost-justified.

413 In sum, PSE established by substantial competent evidence its need for LSR-1 and its cost effectiveness, its careful and extensive evaluation of alternatives, extensive interaction and communication by responsible PSE personnel with the Energy Management Committee and the Board of Directors, and adequate documentation of the decision-making process, much of which is now included in the record of this proceeding. We find and conclude for these reasons that PSE's development of LSR-1 was prudent.

414 "In determining the fair value of company property for rate making purposes, *i.e., establishing the appropriate rate base*, we must determine whether the property is 'used and useful for service in this state.'"[557] While the relevant statute, by its terms, limits the used and useful question to determinations of rate base, the Commission also said in the order from which the preceding quote is drawn that it "must find a resource to be used and useful in this State before its *costs* may be recovered in rates."[558] The Commission notes in this connection that "'[c]osts' include

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[556] *Id.* ¶53.

[557] *WUTC v. PacifiCorp*, Docket No. UE-050684, Order No. 04, ¶48 (April 17, 2006) (emphasis altered) (citing RCW 80.04.250). The cited statute provides in part:

> The commission shall have power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state and shall exercise such power whenever it shall deem such valuation or determination necessary or proper under any of the provisions of this title. In determining what property is used and useful for providing electric, gas, or water service, the commission may include the reasonable costs of construction work in progress to the extent that the commission finds that inclusion is in the public interest.

[558] *WUTC v. PacifiCorp*, Docket No. UE-050684, Order No. 04, ¶ 50 (April 17, 2006) (emphasis added).

expenditures needed to operate the facility, depreciation and a return on the investment."[559]

415 In the Renewable Resource Policy Statement 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.[560]

416 It is not disputed that PSE constructed LSR-1 to satisfy the RPS requirements that commence in 2016. It follows that this "[e]arly acquisition of a renewable resource is 'useful' in that it will meet the RPS . . . in the future." LSR-1 also is "used" both in the traditional meaning of the term and as the definition is stated in the Renewable Resource Policy Statement. LSR-1 became operational on February 29, 2012, and is today providing capacity and energy to PSE's customers. These are the sorts of direct benefits the Commission has found support a determination that plant is used and

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[559] *Id.* at footnote 71.

[560] Renewable Resource Policy Statement ¶¶55-56. Of course, under the Administrative Procedure Act, policy statements are advisory only and are non-binding. *See Washington Education Ass'n v. Washington State Public Disclosure Comm'n*, 150 Wn.2d 612, 622, 80 P.3d 608 (2003). They simply set forth the "current approach" of the agency. RCW 34.05.010(15). Accordingly, as elaborated upon later, parties cannot simply rely on a policy statement as if it were a binding rule, and parties are free to advocate policies different from those articulated in such a statement.

useful.[561] In addition, PSE's analytical models demonstrate that the construction of LSR-1 will, over the life of the project, provide benefits that have a measurable net present value to ratepayers. Additional potential direct benefits are available in the form of off-system sales of electricity produced by the LSR-1 facilities and the sales of RECs pending PSE's need to retain them to meet the RPS requirements.

417 Public Counsel apparently misreads the Commission's policy guidance that "the utility must show that the resource produces benefits that offset the cost of early acquisition" to mean a showing of quantifiable benefits that completely offset the facility's cost of early acquisition at every moment of its life.[562] Such a policy, if implemented through interpretation of the used and useful requirements, would preclude utilities from undertaking many long-term resource acquisitions. Such resources would rarely, if ever, be cost-effective if compared only 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.[563]

418 Having found LSR-1 both prudent and used and useful, we determine further that PSE should be authorized to recover in rates the capital and operating costs of LSR as discussed in other parts of this Order.

2. Colstrip

419 Colstrip is a four-unit, mine mouth, coal-fired electricity-generating facility operated by PPL Montana, LLC (PPL) in Colstrip, Montana, about 120 miles southeast of Billings. Colstrip is capable of producing up to 2,094 megawatts (MW) of electricity

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[561] "We interpret the phrase 'used and useful for service in this state' to mean benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource to customers) and/or indirectly . . . Under either circumstance, the Company must demonstrate a quantifiable benefit to Washington ratepayers. *When a facility is actually used to provide service, its costs and benefits can be readily identified* and allocated appropriately." *WUTC v. PacifiCorp*, Docket No. UE-050684, Order No. 04, ¶¶ 50, 51 (April 17, 2006) (emphasis added).

[562] Public Counsel Initial Brief ¶¶81, 82.

[563] PSE Initial Brief ¶148.

from four generating units. PSE has a 50 percent interest in Units 1 and 2, which are each rated at 307 MW of net generating capacity, and a 25 percent interest in Units 3 and 4, which are each rated at 740 MW of net generating capacity. In total, Colstrip provides about 20 percent of PSE's overall energy needs.[564]

420 The Sierra Club raises concerns about the costs of compliance Colstrip faces considering current and pending environmental regulations. Sierra Club couches its concerns in terms of "prudence," but does not specifically challenge prudence at this time, or request any adjustment with respect to PSE's treatment of Colstrip costs in rates.[565] At this juncture, Sierra Club recommends that the Commission order:

> 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. The study should include a full analysis of the range of risks for future costs at Colstrip from environmental retrofits due to state and federal regulations, increasing coal prices, costs and risks associated with the rehabilitation, maintenance, expansion, and continued operation of storage ponds for combustion waste, and the risks associated with future carbon emissions costs.[566]

Sierra Club argues that if the Commission does not require PSE to conduct a forward-looking study, it should find in this Order that prior submission of such an evaluation for review and comment will be a key consideration in all future prudence reviews of the Company's rate requests for the Colstrip units.[567]

421 Sierra Club argues in the alternative that if the Commission elects to rely solely on the IRP process to consider future environmental compliance and other costs at Colstrip,

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[564] M. Jones, Exh. No. MLJ-1T at 2:12-3:7.

[565] Dr. Hausman testifies, however, that the Commission "should condition any requested recovery of Colstrip costs in this proceeding, by requiring the Company to fully evaluate all aspects of the future costs and risks at Colstrip." Hausman, Exh. No. EDH-1T at 21:1-9. Dr. Hausman does not explain how such a condition could be imposed as a practical matter, or squared with legal and policy constraints establishing the bounds of ratemaking practice in Washington.

[566] Sierra Club Initial Brief ¶44.

[567] *Id.* ¶46.

it should direct PSE to allow parties to conduct discovery and access confidential information in the context of that process. Sierra Club envisions an IRP process that, in effect, would accomplish the same goal as the study it envisions, stating that an IRP review of Colstrip should include:

> Detailed cost inputs for potential future regulations, including cost sensitivities for the following regulations that are major potential contributors to the cost of Colstrip: MACT Rule compliance; Regional Haze Rule compliance; coal combustion residual regulations; greenhouse gas regulations; and updates to NAAQS standards. PSE should also include non-regulatory costs such as: increased costs of coal at the Rosebud mine; potential future costs associated with an alternative source of coal, including infrastructure costs; upcoming major capital improvements or repairs such as boiler overhauls or major component replacements.[568]

422 Mr. Story testifies for PSE that the Commission has already recognized the Sierra Club's concerns and identified the appropriate forum for consideration of these issues in its letter accepting the Company's 2011 IRP.[569] Indeed, in response specifically to Sierra Club's comments during the IRP process, the Commission said in its 2011 IRP Acknowledgement letter that:

> PSE provides a useful critique of its modeling of a "no northwest coal" scenario. We agree with PSE's commitment to study the modeling of this scenario. We also conclude additional modeling of Colstrip scenarios in PSE's next IRP would be useful.
>
> PSE should model a scenario without Colstrip that includes results showing how PSE would choose to meet its load obligations without Colstrip in its portfolio and estimates of the impact on Net Present Value (cost) of its portfolio and rates.
>
> PSE should conduct a broad examination of the cost of continuing the operation of Colstrip over the 20-year planning horizon, including a range of anticipated costs associated with federal EPA regulations on coal-fired generation.

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[568] *Id.* ¶45.

[569] Story, Exh. No. JHS-18T at 52:10-4.

> We also note that the Company acknowledges that carbon dioxide (CO2) costs are one of the key inputs for modeling, along with load forecasts (demand), wholesale power prices and natural gas prices. We find the inclusion of several levels of CO2 costs to be appropriate, and further acknowledge that such modeling is required by our rules in WAC 480-100-238(2)(b) to consider the environmental effects of future generation resources. In its analysis of CO2 prices, the Company modeled three different levels of prices (low, moderate, and high) and developed scenarios based on the variability of this key assumption along with others (base case, base case plus CO2, and "green world"). We note that the regional and national discussion regarding setting a price for CO2 remains unsettled, and therefore significant uncertainty still exists for developing a preferred mix of electric resources. We find the Company's description of the risks associated with CO2 pricing to be relevant and find its analysis of the various scenarios to be useful.

PSE argues that because this analysis will be done in PSE's IRP process, there is no need for the Commission to order further analysis as part of this proceeding.[570]

423 Sierra Club states that while these directions from the Commission are very helpful, the organization is concerned that an IRP evaluation of Colstrip will not provide an adequate forum to address in rigorous detail the extent and nature of costs related to coal fired generation. Nor, Sierra Club contends, is the general rate case process adequate to the task because:

> Under typical rate base practices, no prudence review of these substantial costs is allowed until the utility seeks to include the pollution controls in rate base, which in turn only occurs after the controls are built and operational (*i.e.,* used and useful). The Commission would similarly be precluded from taking an *a priori* look at non-capital operating expenses because those expenses would not be sufficiently known and measurable until after they were incurred.[571]

424 Sierra Club argues the Commission should open a new docket to study Colstrip, allow for intervention, and provide parties with full discovery rights.[572] Sierra Club, in

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[570] Story, Exh. No. JHS-18T at 52:10-4.

[571] Sierra Club Initial Brief ¶33.

[572] *Id.* ¶19.

effect, argues that a separate, full adjudicative proceeding under the Administrative Procedure Act is required for a thoroughgoing review of Colstrip's future as part of PSE's resource mix.

425 *Commission Determination:* Considering the requirements set out in the Commission's letter acknowledging the Company's 2011 IRP that require PSE to thoroughly study Colstrip, we determine that it would be duplicative for the Commission to order such analysis here. Nor do we see the need at this time to establish a separate process, such as initiating an adjudicative proceeding.

426 Our determination, however, is conditional. We understand Sierra Club's concerns with respect to the availability of important information that it, or other interested persons, might require to participate meaningfully in the context of PSE's next IRP. PSE may regard some of this information as being confidential. We expect those who participate in PSE's next IRP to work cooperatively together to make such information available as needed. If there are problems in this regard, they may be brought to the Commission and alternative means may be ordered to ensure the Commission has available the information and analyses it requires with respect to Colstrip.

3. Uncontested Asset Acquisitions

a. Klamath Peaker Five-Year Purchase Power Agreement

427 In March 2010, PSE entered into a fifty month contract with Iberdrola Renewables for 100 MW of winter capacity and energy associated with the so-called Klamath Peakers.[573] The contract term is from January 1, 2012, through February 29, 2016, and was contingent on Iberdrola securing firm BPA network transmission on a long-term basis and PSE securing transmission from the Klamath Facilities to BPA's John Day substation, each on or before August 15, 2011. These contingencies were met.[574]

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[573] These facilities are located in Klamath Falls, Oregon, adjacent to the 536 MW Klamath Cogeneration Facility, also owned by Iberdrola Renewables. The Klamath Peakers commenced commercial operation on May 17, 2002, and have operated since then as a single fuel (natural gas) peaking power generation facility.

[574] PSE assumed in the prefiled rate year power costs that the transmission would be acquired from BPA at a higher cost than was secured with Portland General Electric Company. The lower

428 Mr. Garratt testifies in detail concerning the prudence of this PPA.[575] He says in summary that PSE determined that the Klamath Peaker PPA offered significantly more favorable economics than any other alternative offered in the 2010 RFP, as also discussed by Ms. Seelig.[576] As a winter seasonal PPA, the contract provides PSE with valuable capacity during those months in which PSE is most in need of capacity.[577] Mr. Garratt and Ms. Seelig also testify that PSE reevaluated the Klamath Peaker PPA prior to finalizing it.[578] According to Ms. Seelig, both quantitative and qualitative analyses demonstrated that it was the lowest cost capacity resource available to meet PSE's capacity need compared to the most recent offers.[579]

429 Mr. Nightingale examined in detail PSE's acquisition of the Klamath Peaker PPA.[580] He concludes that PSE satisfied all prudence factors and that the decision to acquire the Klamath Seasonal PPA was made appropriately by PSE management. It follows, he testifies, that the Klamath Seasonal PPA acquisition was a reasonable and prudent choice for PSE when that decision was made.[581]

430 No other party addresses this issue.

431 *Commission Determination:* We determine on the basis of the undisputed record on this issue that PSE's execution of a fifty month contract with Iberdrola Renewables for 100 MW of winter capacity and energy associated with the Klamath Peakers was prudent.

Portland General Electric Company transmission rates results in a $1.1 million rate year power cost decrease. Mills, Exh. No. DEM-8CT at 10:7-11:4.

[575] Garratt, Exh. No. RG-1HCT at 89:1-94:2.

[576] *Id.* at 93:15-18 (citing Seelig, Exh. No. AS-1HCT [at 59:14-60:8]).

[577] *Id.* at 93:18-20.

[578] *Id.* at 93:20; Seelig, Exh. No. AS-1HCT at 62:13-64:5.

[579] *Id.*

[580] Nightingale, Exh. No. DN-1HCT at 33:4-36:17.

[581] *Id.* at 36:19-37:4.

b. PPL Energy Project PPA

432 At the same time it evaluated and entered into the Klamath Peaker PPA, PSE also evaluated and selected a second proposal identified in Mr. Garratt's and Ms. Seelig's testimonies as the PPL Energy Project PPA. This contract provides for delivery to PSE's system of 100 MW of firm power at a fixed price.[582] PSE states that it limits PSE's exposure to fluctuations in the market.[583] The Company determined that this contract offered the lowest levelized cost of any resource evaluated and had fewer associated risks.[584] Among other attractive features, PPL Energy agreed to accept any carbon risk for the term of the contract and the price includes firm transmission to PSE's system for the entire contract capacity.[585]

433 *Commission Determinations:* PSE does not expressly request a prudence determination with respect to this resource. Staff apparently did not evaluate it or, at least, offered no testimony with respect to it. Nor does any other party address the subject. We accordingly make no determination with respect to the prudence of the Company's decision to enter into the PPL Energy Project PPA one way or the other. The question, if raised, is reserved for another day.

I. Decoupling

434 Mr. DeBoer testifies for PSE on the topic of conservation and "the financial disincentives that PSE faces as it pursues conservation."[586] He reviews various approaches that have been proposed for dealing with barriers to conservation, including those outlined in the Commission's *Decoupling Policy Statement on Regulatory Mechanisms, Including Decoupling, To Encourage Utilities To Meet or Exceed Their Conservation Targets* issued in November 2010 (Decoupling Policy

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[582] Seelig, Exh. No. AS-1HCT at 60:11-20.

[583] Seelig, Exh. No. AS-1HCT at 60:11-20.

[584] Seelig, Exh. No. AS-1HCT at 60:11-20.

[585] Seelig, Exh. No. AS-1HCT at 60:11-20.

[586] DeBoer, Exh. No. TAD-1T at 2:6-7.

Statement).[587] According to Mr. DeBoer, "mechanisms such as decoupling do not address PSE's concern that expenses per customer are growing faster than revenue per customer—and that conservation exacerbates this problem."[588]

435 Mr. DeBoer's direct testimony also includes an overview of PSE's proposed Conservation Savings Adjustment (CSA) Rate, which he testifies would "mitigate the negative financial effects that conservation has on its ability to recover certain of its fixed costs."[589] Staff and other parties urge through their witnesses' response testimonies that the CSA Rate proposal should be rejected because it does not follow the Commission's guidance in the Decoupling Policy Statement. Mr. DeBoer testifies in rebuttal to these contentions that: "PSE's proposal should be judged solely on its merits and the facts presented in this fully adjudicated general rate case, not on the basis of [a] statement of policy which by its very terms is not intended to be binding or inflexible."[590]

436 We agree that PSE's CSA Rate proposal should be evaluated on its own merits and do so in a separate section of this Order. We mention the CSA Rate proposal here because Mr. DeBoer recommends it directly in connection with his testimony rejecting "mechanisms such as decoupling." Given this juxtaposition, the Commission referred to the CSA Rate proposal in Bench Request No. 3, which directed Commission Staff, and invited all other parties, to inform the record with a discussion of "the critical elements that a full decoupling proposal should contain, consistent with the Decoupling Policy Statement."

437 PSE filed an objection to Bench Request No. 3, apparently misreading our purpose in issuing it and attaching to it significance it does not have vis-à-vis the Company's CSA Rate proposal. We have carried PSE's objection with this case so far, but now overrule it for the reasons discussed below.

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[587] UTC Docket U-100522, Investigation Into Energy Conservation Incentives, *Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, To Encourage Utilities To Meet or Exceed Their Conservation Targets* (November 4, 2010).

[588] DeBoer, Exh. No. TAD-1T at 2:13-16.

[589] *Id.* at 10:16-19.

[590] DeBoer, Exh. No. TAD-4T at 5:19-22.

1. Bench Request No. 3

438 The Commission's issuance of its Decoupling Policy Statement in November 2010 was a milestone in what NWEC's witness, Mr. Cavanagh, described during our evidentiary hearing as "a 30-year conversation with this Commission" on the subject.[591] The utilities we regulate, including PSE, have participated in this conversation. They have urged, particularly in recent years, that the Commission either adopt decoupling in rule or approve it in individual general rate proceedings to solve their claimed inability to recover fully their fixed costs so long as a portion of these are included in and recovered via volumetric rates. The utilities have consistently argued that without decoupling, they face a financial "disincentive" to conservation, which they nevertheless are required by statute to implement to the extent it is cost-effective to do so. The Commission, in the Decoupling Policy Statement, affirmatively invited the utilities it regulates to file decoupling proposals as part of a general rate case.[592] In light of this, the Commission was surprised that in the general rate case filed by Avista in May 2011[593] and in this case file by PSE in in June 2011, neither utility included a full decoupling proposal.

439 The Commission, first in *Avista* and later in *PSE,* elected to be proactive on this question and issued bench requests in both proceedings. The requests were substantially similar, stating:

> In the Decoupling Policy Statement, the Commission examined several lost margin recovery mechanisms and stated its policy preference for full decoupling. The Commission expressed interest in considering a full decoupling mechanism for electric and natural gas utilities in the context of a general rate case, so as to "allow a utility to either recover revenue declines related to reduced sales volumes or, in the case of sales volume increases, refund such revenues to its customers."

440 The Commission's bench request in *Avista* observed that "Avista's filing includes a proposal for a lost margin recovery mechanism for electrical sales (*i.e.,* Energy

[591] Cavanagh, TR. 428:11-12.

[592] Decoupling Policy Statement ¶28 (internal cites omitted).

[593] *See WUTC v. Avista Utilities,* Dockets UE-110876 and UG-110877, Order 06 (December 16, 2011).

Efficiency Load Adjustment) and continuation of its current limited "decoupling" mechanism on the gas side." Similarly, in its bench request in *PSE*, the Commission observed that "PSE's filing includes a proposal for a Conservation Savings Adjustment (CSA) Rate 'to mitigate the negative financial effects that conservation has on its ability to recover certain of its fixed costs.'"[594] Both bench requests continue with a directive to Staff, as follows:

> In the interest of having a more complete record concerning the issues raised by [the Company's] proposal, the Commission requests that Staff examine full decoupling, as discussed in the Decoupling Policy Statement, as an option for [the Company]. In response to this Bench Request, Staff should provide the Commission with a discussion of the critical elements that a full decoupling proposal should contain, consistent with the Decoupling Policy Statement, including consideration of lost sales revenues that are potentially offset by avoided costs and other benefits. It should also indicate whether, based on the information it supplies the Commission, it believes that the Commission could make a final decision on a decoupling proposal by the end of this rate proceeding or whether more process may be necessary or desirable.[595]

441 Although we directed these bench requests to Staff, we invited the Companies and all other parties to respond, if they wished. PSE's response was to file an objection to our bench request on October 10, 2011, five days after the Commission served it.

2. PSE's Objection to Bench Request No. 3

442 We consider at the threshold PSE's objection to our bench request, an objection it renews in its Initial Brief.[596] PSE complains that the Commission, by issuing this

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[594] DeBoer, Exhibit TAD-1T at 10:8-10.

[595] While the Commission expects Staff to provide an analysis of PSE's proposal in light of the our Decoupling Policy Statement, we are neither directing Staff to, nor preventing it from, advocating full decoupling or another alternative. Staff's response may be in the form of testimony, or may be presented in another form (*e.g.*, a narrative discussion), as Staff deems appropriate.

[596] PSE Initial Brief ¶159 (citing Puget Sound Energy, Inc.'s Objection to Bench Request No. 3 (October 10, 2011)).

bench request is "influencing the nature and content of evidence entered into the record in this proceeding." PSE argues the bench request:

- Improperly communicates that the Policy Statement only allows for full electric decoupling; effectively pre-judging PSE's CSA proposal and biasing the record.

- 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.

- 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.

- Suggests that the Commission has a policy preference for full decoupling that is inconsistent with the language of the Policy Statement, which allows for options other than full decoupling.

PSE argues that "[b]y directing parties to focus their attention on full decoupling as opposed to fairly evaluating PSE's CSA proposal, the Commission exceeds its statutory authority."[597]

443 We agree with only one assertion in PSE's objection. The Commission issued its bench request expressly to influence the nature and content of evidence entered into the record in this proceeding by making it more thorough. As Bench Request No. 3 states, we issued it "in the interest of having a more complete record concerning the issues raised by PSE's [CSA] proposal," including whether full decoupling, as discussed in the Decoupling Policy Statement, might be an option for PSE.

444 We did not direct parties to focus attention exclusively on full decoupling, suggest it is the only type of regulatory mechanism the Commission would consider to address fixed cost recovery, pre-judge PSE's CSA proposal or bias the record against it.

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[597] PSE Initial Brief ¶159.

Directing the Commission Staff and inviting all parties to enhance the record in this proceeding by giving the Commission a broader perspective on the issues pertinent to questions of fixed cost recovery is not tantamount to "directing parties" to not fairly evaluate PSE's CSA proposal. The Commission is squarely within its statutory authority to conduct a full investigation and develop a complete record to inform its decisions whenever a hearing is required as a prerequisite to its decisions, as is this, and every, general rate case proceeding.

445 We deny PSE's objection to Bench Request No. 3.[598]

3. Full Decoupling

446 The Commission recognized in its Decoupling Policy Statement that a properly constructed full decoupling mechanism designed to balance both lost and found margin from any source between general rate cases, could benefit both a utility and its ratepayers.[599] The Commission explained that:

> By reducing the risk of volatility of revenue based on customer usage, both up and down, such a mechanism can serve to reduce risk to the company, and therefore to investors, which in turn should benefit customers by reducing a company's debt and equity costs. This reduction in costs would flow through to ratepayers in the form of rates that would be lower than they otherwise would be, as the rates would be set to reflect the assumption of more risk by ratepayers.[600]

447 The Commission also said in its Decoupling Policy Statement that it would consider a full decoupling mechanism for electric and natural gas utilities in the context of a general rate case. Because the utilities the Commission regulates were proponents of decoupling both in proceedings before the Commission over a number of years and in connection with certain legislation introduced during the 2010 session, the

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[598] Our Notice of Bench Request, issued in this proceeding on October 5, 2011, was inadvertently left unnumbered. We refer to it as Bench Request No. 3 because it is, in sequence, the third bench request issued in these dockets.

[599] Decoupling Policy Statement ¶27.

[600] *Id.*

Commission expected these utilities to propose decoupling mechanisms in their next general rate case filing following issuance of the Decoupling Policy Statement.[601]

448 As previously mentioned, Avista filed a general rate case in May 2011[602] and PSE filed this case the following month, yet neither utility's filing included a full decoupling proposal.

449 NWEC filed testimony supporting implementation of a full decoupling mechanism for PSE. Its proposal is essentially that those portions of PSE's nonproduction fixed costs that are recovered in variable charges tied to customer usage would be included in the decoupling mechanism. According to Mr. Cavanagh, this is approximately $500 million out of PSE's roughly $2.1 billion revenue requirement.[603] The proposal is for a true-up mechanism that can move rates either up or down, depending on total consumption, with a rate cap of three percent a year on the upside and no constraint on down side reductions. Mr. Cavanagh testifies that, "the mechanism doesn't add costs to Puget's revenue requirement, it simply provides that the revenue requirement . . . will be recovered independent of fluctuations in sales."[604]

450 NWEC's proposal responds to and incorporates many elements discussed in the Commission's Decoupling Policy Statement.[605] Commission Staff also discussed the

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[601] *Id.* ¶28. Indeed, this is indicated by the Commission direction that, "[a] utility's request for a full decoupling mechanism must be made in its direct testimony of its rate case filing," including at a minimum various elements specified in the policy statement.

[602] *See WUTC v. Avista Utilities*, Dockets UE-110876 and UG-110877, Order 06 (December 16, 2011).

[603] Cavanagh, TR. 431:15-432:6.

[604] *Id.*

[605] NWEC's proposal also includes some features that are inconsistent with the guidance offered by the Policy Statement. First, though the Policy Statement states a preference for an earnings test (Decoupling Policy Statement ¶28), Mr. Cavanagh advocates otherwise. He argues, among other things, that such a test would inhibit a company's incentive to control costs. Cavanagh, Exh. RCC-1T at 15. Second, while the Policy Statement favors a mechanism based on revenue "per class" of customer (Decoupling Policy Statement ¶28), the NWEC proposal would base is operation on revenue "per customer." Additionally, in response to the Decoupling Policy Statement suggestion that a potential reduction in ROE in connection with the adoption of a decoupling mechanism should be analyzed, Mr. Cavanagh advocates that there should be no reduction in ROE with the adoption of the decoupling proposal. Mr. Cavanagh argued that any impact on ROE should be considered by evaluating a mechanism after five years of operation.

mechanics of a full decoupling mechanism in its response to the Commission's Bench Request on decoupling, although Staff did not propose that the Commission adopt such a mechanism. NWEC notes that "Staff and the Coalition appear largely to agree on how many elements of a decoupling mechanism should be structured for PSE."[606]

451 PSE opposes the NWEC mechanism, arguing via Mr. DeBoer's rebuttal testimony that it does not adequately address the financial consequences of PSE's energy efficiency programs.[607] Mr. DeBoer makes a similar point in his direct testimony where he estimates PSE's sales volumes and associated revenues with and without conservation. Asserting that sales volumes are not keeping pace with costs, he concludes that decoupling does not address the Company's earnings issues.[608]

452 PSE also argues that one premise of the NWEC proposal – that any increased level of electricity consumption is undesirable – is flawed.[609] Mr. DeBoer testifies:

> The primary focus of the 2012 Washington State Energy Strategy, the state's formal energy policy, is the reduction in our state's dependence on fossil fuels, primarily in the transportation sector. This will require the use of other forms of transportation "fuel," with electricity being the most touted alternative. PSE finds that removing the throughput incentive would be counterproductive to aligning electric utilities' financial incentive with this goal.[610]

Cavanagh, Exh. No RCC-1T at 21:1-4. Other than these differences, the policy advocated by NWEC is essentially congruent with the policy we endorsed in the Decoupling Policy Statement.

[606] NWEC Initial Brief ¶14, footnote 1 (citing Prefiled Cross-Answering Testimony of Ralph C. Cavanagh, Exh. RCC-6T at 3).

[607] De Boer, Exh. No. TAD-4T at 6-9.

[608] De Boer, Exh. No. TAD-1T at 17:10-18:2. Mr. De Boer testifies that if PSE's verified conservation savings since the test year in its 2004 general rate case are added to its actual weather-normalized energy sales over time, the Company's electric use-per-customer would have grown at an annual average rate of 0.9 percent. Without conservation, the growth would have been at an average annual rate of 1.2 percent. Mr. De Boer implies by this that conservation exacerbates earnings erosion resulting from the fact that PSE's growth in use-per-customer lags behind its growth in expense-per-customer.

[609] De Boer, Exh. No. TAD-4T at 9.

[610] *Id.* at 9:19-10:5 (citing Washington State Energy Policy, Core Solutions for Economy, Jobs and Climate, Department of Commerce; available at www.commerce.wa.gov/energystrategy).

Mr. DeBoer acknowledges in this connection that there is an emphasis in Washington's energy policy on promoting efficient use, but there is not, to his knowledge any expressed support in that policy for the removal of any throughput incentive.[611] He concludes by testifying that while state energy policy is silent as to what specific ratemaking mechanisms should be used to achieve energy efficiency, he does not believe the state would support mechanisms such as NWEC's proposal that is, in Mr. DeBoer's view, "counterproductive to the primary focus of its energy policy, increasing energy efficiency and reduction in greenhouse gas emissions in the transportation sector."[612]

453 *Commission Determination:* We commend NWEC for its proposal and Staff for providing a detailed response to Bench Request No. 3. Yet, while NWEC affirmatively recommends that we approve and require PSE to implement full decoupling, as discussed in Mr. Cavanagh's testimony, we determine we should not do so in the face of PSE's staunch opposition to the idea.[613] Despite PSE's strong advocacy in favor of decoupling at other times, the Company argues in this case that NWEC's decoupling proposal, which largely follows the guidance of the Decoupling Policy Statement, "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."[614] PSE renews its objection to Bench Request No. 03 in its Initial Brief and argues definitively that "the Commission should not impose upon PSE a mechanism it did not request."[615]

454 We observe that PSE's rejection of decoupling, couched in terms of the mechanism's failure to address increasing costs per customer, sacrifices the opportunity to recover revenues that may be lost to the negative impacts of the economy, weather, and the ratepayer's investment in conservation. We are surprised by PSE's response and must wonder why the Company made this sacrifice. It appears that PSE wants more

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[611] *Id.* at 10:7-13.

[612] *Id.* at 10:14-19.

[613] We note that other parties also oppose NWEC's proposal. *See* Public Counsel Initial Brief ¶¶4, 114-121; ICNU Initial Brief ¶¶93-112; Kroger Initial Brief at 9-11.

[614] PSE Initial Brief ¶160 (citing DeBoer, TR. 525:4-17).

[615] *Id.* ¶159.

than decoupling has to offer, namely the freedom to recover incremental revenue to offset new investments between rate cases. In other words, PSE rejects the opportunity to recover most of its lost revenue because the mechanism does not address the incremental impacts of regulatory lag, a problem decoupling was never intended to fix.

455 In prior testimony, workshops and discussions, PSE and others have promoted decoupling as a mechanism that severs sales from revenues, thus breaking down a utility's so-called financial disincentive to conservation. It was never intended to supplant other tools that deal with demonstrated earnings attrition. Implementation of decoupling to remove any financial disincentive to conservation in a fair and balanced manner was the motivation behind our Policy Statement. NWEC's proposal is consistent in intent and general design with this purpose. Surprisingly, PSE has rejected another opportunity to address effectively the arguable adverse impacts of conservation on earnings.[616]

456 In summary, PSE's opposition to full decoupling militates strongly against our accepting NWEC's recommendation regardless of the merit we might find on a close examination of its details. We determine that the Commission should not require PSE to implement full decoupling on this record.[617]

J. Conservation Savings Adjustment Rate Proposal

1. PSE's Proposal

457 PSE proposes a new tariff schedule it calls the Conservation Savings Adjustment (CSA) Rate "to mitigate the negative financial effects that conservation has on its

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[616] In its last rate case, PSE walked away from the Commission's financial incentive program, which rewarded the Company for exceeding its conservation targets. *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 ¶50 (April 2, 2010).

[617] The Commission remains open to proposals for a full decoupling mechanism, even to one that may vary somewhat from what is described in our Policy Statement. As the Commission noted in the Policy Statement, the guidance provided "does not imply that the Commission would not consider other mechanisms in the context of a general rate case . . ." Decoupling Policy Statement ¶34. In other words the Policy Statement set forth the principles the Commission believed important to the design of such a mechanism and the issues it expected to be addressed in any decoupling filing. It was not intended to set forth immutable doctrine on this issue or to negatively imply that we would be receptive to nothing else.

ability to recover certain of its fixed costs."[618] The CSA would allow PSE to recover the revenue it regards as being "lost" due to customers conserving electricity or gas pursuant to the Company's conservation programs. The CSA would be an ongoing annual rider for both electric and gas operations. Mr. Piliaris testifies that:

> [T]he CSA Rate methodology is implemented in the following steps. First, for a given calendar year, [assuming normal weather,] PSE calculates the amount of applicable Company-sponsored conservation savings that is not reflected in base rates in each month and for each affected rate group. Next, PSE calculates the per-unit impact of these conservation savings on the utility's ability to recover costs for each rate group to which the CSA rates apply. PSE then multiplies the applicable conservation savings for each group by its corresponding per-unit cost impact in each month. PSE then sums these amounts across the months within the year to calculate the amount to be recovered through the CSA Rates.[619]

458 Mr. DeBoer describes the operation of the proposed CSA as follows:

> For each calendar year, PSE first calculates the amount of unrecovered costs resulting from the load-reducing effects of Company-sponsored energy efficiency. PSE proposes to recover 75 percent of this amount in the following CSA Rate year, beginning each May 1st. PSE proposes to recover the remaining 25 percent in a subsequent CSA Rate filing, subject to a true-up and other conditions.[620]

459 He states that even though the Company is confident in measuring the effects of its energy efficiency programs, holding back recovery of 25 percent "should provide ample assurance to PSE's customers that the costs being recovered in CSA Rate have been adequately reviewed before being fully recovered."[621] In addition, PSE proposes that recovery of the withheld 25 percent of revenue be conditioned upon third-party verification of the savings used to derive the CSA Rate and be subject to an earnings

[618] DeBoer, Exh. No. TAD-1T at 10:8-10.

[619] Piliaris, Exh. No. JAP-1T at 33:1-13.

[620] DeBoer, Exh. No. TAD-1T at 21:6-10.

[621] *Id.* at 21:20-22.

test.[622] Under the proposed earnings test, lost margins for any given year would only be recoverable to the extent that the Company failed to achieve its authorized rate of return.

460 As a separate recovery mechanism, the CSA would not add revenues to the overall requested revenue requirement upon which base rates will be determined in this proceeding. However, the Company forecasts that the CSA, if approved, will allow PSE to recover $9.8 million in additional electric revenues and $2.0 million in additional gas revenues for the rate year that begins in May, 2012.[623]

2. Opposition to the CSA

461 The Commission's Decoupling Policy Statement addressed three specific mechanisms to encourage conservation: limited decoupling for gas utilities only, full decoupling for gas or electric utilities, and direct conservation incentives. PSE's proposed CSA mechanism does not fit any of these categories. As PSE notes in its Initial Brief, however,

> The guidance provided in [the Decoupling] 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.[624]

While the CSA also does not propose an attrition adjustment as a means to protect the company from lost margin, the quoted language reflects more generally the well-understood point that the Decoupling Policy Statement, like any interpretive or policy statement, is not binding and cannot be relied upon as establishing any binding

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[622] *Id.* at 22:1-16.

[623] Piliaris, Exh. No. JAP-1T at 38 and 39, Tables 4 and 5. The average monthly bill for a typical residential electric customer would increase by 31 cents, or by 0.3 percent as a result of the proposed Electric CSA Rate. The proposed Gas CSA Rate would increase the average monthly bill for a typical natural gas residential customer by 11 cents, or by approximately 0.1 percent. *Id.* at 40:1-6, 41:1-8.

[624] PSE Initial Brief ¶155, footnote 313 (quoting Decoupling Policy Statement ¶34).

requirements.[625] Commission Staff acknowledges that the Policy Statement is not binding and that other mechanisms not described in the Policy Statement can be proposed. Staff recognizes, too, that the Commission is "obligated to give [such a] proposal its full and fair consideration."[626] Staff also observes, however, that whether a proposal falls under one or more of the three mechanisms discussed in the Decoupling Policy Statement, or has attributes in common with them, the elements and criteria the Commission set forth as its current opinion, approach and likely course of action should be addressed by any party advocate.[627]

462 Staff, Public Counsel and other parties argue that PSE's CSA proposal should be rejected because it does not follow, and in some respects is directly contrary to, the policy guidance set forth in the Decoupling Policy Statement. While such discussion is useful to the analysis of the CSA, the analysis must not stop there. As noted above, we remain open to other ideas not specifically discussed to in our Policy Statement. Accordingly, we discuss PSE's CSA proposal in the broader context of decoupling because that is the context in which PSE raised it. We also discuss it in connection with Staff's testimony and advocacy related to attrition adjustments and a ratemaking process proposal. However, we evaluate the merits of the CSA proposal without regard to whether, or to what extent, it comports with or departs from the principles discussed in the Decoupling Policy Statement. In other words, our discussion here focuses on the parties' arguments opposing the CSA on grounds independent of the Commission's Policy Statement on Decoupling.

463 Staff, Public Counsel, ICNU, NWIGU, and Kroger all zealously criticize the CSA for numerous reasons, and it is unnecessary for us to catalogue and respond to them all. Rather, we need focus only on three sets of criticisms: the actual functioning of the mechanism as it relates to calculation of revenues due to conservation; the fact that

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[625] PSE Initial Brief ¶156 (citing *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")).

[626] 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.").

[627] Staff Initial Brief ¶184 (citing RCW 34.05.230(1)).

the CSA fails to account only for lost revenues, ignoring "found" revenues; and the consumer confusion that could result.

464 The CSA mechanism is complex. It does not include any calculation of the Company's actual costs on which the proposed rate will be based. Instead, "costs" are calculated by first estimating conservation savings and then applying the Company's existing rates to those savings to determine the "cost" to be recovered.[628] Apparently, the Company does not actually allocate between fixed and variable costs for this calculation. Rather, all of PSE's costs other than its power costs and gas commodity costs, and any costs recovered through the fixed basic charge for the respective service, would be reflected in and recovered through the CSA rate to the extent they are arguably under recovered due to load lost to conservation.[629]

465 PSE uses the savings estimates from its energy efficiency programs to estimate conservation-related load reduction for the CSA. These estimates are based on the Regional Technical Forum or other engineering sources.[630] They are used for program planning and conservation target setting under RCW 19.285.040(1)(e). Such estimates have been acceptable for those purposes because cost-effectiveness calculations have shown them to be conservative enough to conclude that particular measures, on average, contribute savings to the program.[631] Ms. Deborah Reynolds testifies for Staff that, "these energy savings estimates are really intended to be used for forecasting and as a guide for making a decision about which plant to purchase, where plant A is conservation and plant B is a gas plant[.]"[632] Public Counsel and Staff argue that these savings estimates are not rigorous enough for ratemaking.[633]

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[628] Piliaris, Exh. No. JAP-1T at 35:4-43:10.

[629] *See* TR. 661:7-670:8 (colloquy between Commissioner Oshie and Mr. Piliaris).

[630] Reynolds, Exh. No. DJR-1T at 31:11-16.

[631] *Id.* at 30:4-16 and 31:8-17.

[632] Reynolds, TR. 772: 7-11.

[633] Public Counsel Initial Brief ¶104; Staff Initial Brief ¶202. We note that the same concerns have been raised in other proceedings and we will examine them in due course.

466 PSE's witness Mr. Robert Stolarski agreed on cross-examination that the accuracy of the savings estimates is critical to getting the CSA rate correct.[634] Nevertheless, PSE acknowledged that the CSA does not take into account actual customer behavior with conservation measures.[635] Nor does the Company reevaluate savings estimates from prior periods reflected in the CSA calculation.[636]

467 Mr. Stolarski testifies that the savings estimates are subject to extensive "Evaluation, Measurement and Verification" (EM&V) that, "on average", ensures that the estimates are "precise."[637] However, Staff argues, this ignores that an independent third party review of PSE's savings estimates and EM&V practices makes several recommendations for needed improvements, especially with respect to tracking and reporting practices and measure installation verification.[638]

468 Verification on the natural gas side of PSE's operations also is problematic. Mr. Stolarski testified on cross-examination, for example, that if an industrial manufacturer installs a high-efficiency boiler and is expected to achieve a certain amount of savings, but then after installation its productivity is cut in half, say for economic reasons, the CSA does not carve out the differences in the drivers behind those two different savings. In other words, as NWIGU argues:

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[634] Stolarski, TR. 696:19-22.

[635] *Id.* 733:10-17.

[636] *Id.* 737:10-738:11.

[637] Stolarski, Exh. No. RWS-1T at 4:19-24 and Stolarski, TR. 734:2-6.

[638] Staff Initial Brief ¶201. *See* Stolarski, Exh. No. RWS-12 at 13-18 (SBW Consulting, Independent Third Party Review of PSE's 2010-2011 Electric Conservation Energy Savings). This report states, for example, that:

- "PSE has multiple databases and spreadsheets" that "can result in confusion on what verified savings values are."
- "The status of data quality functions that are built into the PSE systems" is not clear.
- "Many savings verification and measure inspection processes are not currently documented."
- "Third-party program implementers do not appear to have any PSE-imposed guidelines or requirements for their verification processes."

> [I]f unpredicted changes happen after the equipment is installed, such as a downturn in the economy, there is no mechanism for going back to review the customer's actual gas use to determine how much of a decline in use is attributable to economic factors and how much is attributable to the conservation measure.[639]

469 Another problem NWIGU discusses is that the estimated conservation savings from a conservation program would continue to be reflected in the CSA mechanism year after year, in addition to any new conservation savings, until new rates are set.[640] This takes no account of whether the conservation program upon which the estimate is based continues to produce conservation savings year after year. Thus, the CSA rate on customers' bills would grow continuously each year until reset following a general rate case.[641]

470 Parties also criticize the CSA because it fails to take into account increased revenues, sometimes referred to as "found margin."[642] In other words, it is a one-way mechanism, in contrast to the stated preference in the Decoupling Policy Statement for a mechanism that works both ways – resulting in increased rates if electricity sales and revenues decline, but decreased rates if sales and revenues increase.[643]

471 Finally, parties question whether PSE is correct in arguing that customers will be encouraged to conserve even more when they see the "true cost" of their energy use.[644] Mr. Piliaris acknowledged this price elasticity argument is qualitative and unsupported by any quantitative evidence in the record.[645] Even PSE's qualitative argument is questionable. As Mr. Piliaris acknowledged, it may be difficult to explain to customers that their rates are actually going up because they conserved more and then expect them to keep conserving even though additional conservation

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[639] NWIGU Initial Brief at 9 (citing Stolarski, TR 721:11-15).

[640] TR 649:22 to 650:2; 651:22-652:15 (colloquy between Commissioner Goltz and Mr. Piliaris).

[641] *Id.*

[642] *See, e.g.*, Public Counsel Initial Brief ¶97; ICNU Initial Brief ¶¶97-98.

[643] Decoupling Policy Statement ¶¶11, 27-28.

[644] *See* Exh. No. JAP-24CT at 24:9-18.

[645] TR 672:1-9 (colloquy between Commissioner Jones and Mr. Piliaris).

will once again cause rates to rise.[646] This point is underscored by testimony from members of the public. Ms. Anita Plaschka of Graham, for example, submitted written comments, stating that, "In 2005 we reduced our use of electricity by about 40% and we were overjoyed that our monthly payment was reduced. Seven years later we are now paying more than before we cut our usage nearly in half."[647] In a similar vein, Dee Shaw of Lacey testified during our public comment hearing in Olympia, as follows:

> I'm a single occupant. I purchased a heat pump in 2002, but was told it was not the month PSE was offering a rebate. I got no credit for the large purchase I did a refinance on my home for. I programmed my thermostat for 60 degrees at night when—and when I'm not at home, and 68 degrees when I am home. I also purchased a new energy efficient hot water heater and set it at a low energy setting. I'm down to showering about every three to four days. I'm only doing laundry every two weeks. I'm using the dishwasher once every two and a half to three weeks. I unplug my microwave, DVD player and computer when not in use. I use CFL bulbs on lights I absolutely need to have on, but have Christmas lights in each room, which are the primary sources of light. I don't turn my porch light on. I'm not sure how I can cut back even further. I live like a miser because I cannot afford for my PSE bill to go up. I've just been informed my power bills will be $216 more this year than last year, and I'm using less energy than last year.[648]

Mr. Piliaris testified that it would be difficult to explain the CSA customers such as Ms. Plaschka and Ms. Shaw.[649] Indeed, we find this testimonial response by customers who are conserving, yet experiencing higher rates and overall costs, reason enough to question PSE's suggestions that "more accurate price signals" are a benefit the CSA rate would provide.

472 *Commission Determination:* While the Company's claims that its conservation efforts cause earnings erosion may be justified, we decline to adopt the Company's CSA as a solution. We adhere to the principles we expressed in our Decoupling

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[646] TR 652:22-653:3; 654:7-15 (colloquy between Commissioner Goltz and Mr. Piliaris).

[647] Exh. No. B-6, Attachment "UTC—Comments from Database Electric 111048" at 48.

[648] TR.582:11-583:9.

[649] TR 654:7-655:1(colloquy between Commissioner Goltz and Mr. Piliaris).

Policy Statement that such a mechanism should work both ways – taking into account lost revenues as well as new revenues. Though the proposed CSA would limit somewhat the downside of the one-way nature of the mechanism by including an earnings test, we nevertheless find other reasons to decline to adopt the CSA.

473 We find that the proposed methods for measuring load loss due to conservation and the level of cost under recovery related to this load are not precise enough. The CSA would create a surcharge to customers for the impact of Company-sponsored conservation on Company revenues, as determined by two factors: PSE's conservation savings estimates and its estimate of fixed costs. No matter how well-suited the engineering estimates of savings may be for their intended purposes, we do not find them suitable for the purpose of determining rates. Moreover, the Company's description of the fixed cost to be recovered by the CSA is not sufficiently detailed to allow us to conclude that this element of the surcharge is reliably measured.

474 We also find that the operation of the CSA mechanism, as proposed, would produce unacceptable effects. For example, the CSA would result in double recovery of some "lost revenue." The Company is seeking recovery based on conservation efforts since January 2010. Since 2010 is the test year in this case, at least some of these losses are already reflected in the weather-normalized historic test year sales used to develop pro forma revenue at present rates, as PSE's witness conceded during our evidentiary hearing.[650]

475 Furthermore, the CSA would carry over conservation results from year to year, in the absence of an intervening rate case, whether or not these results persisted between periods. Even though the Company would conduct EM&V studies for its current year program, it would not conduct similar studies for prior periods to test the continued veracity of its savings estimates, even though it would use those unverified results to make rates. As pointed out in hearing, past year savings estimates are subject to many influences that affect actual results. As noted by Staff, conservation savings are estimates only. Whether such savings persist from year to year is an important issue to be resolved and it has not been proven here.

[650] Piliaris, TR. 638:14 – 639:6.

476 In a similar vein, the Company's CSA mechanism would calculate expected revenues by multiplying accumulated conservation savings by the fixed costs attributed to kWh or therm sold. In natural gas operations, the variable costs associated with natural gas commodities would not be included in the calculation of fixed costs, as they are subject to full recovery in the PGA.

477 On the other hand, the calculation of fixed costs for electric operations is more complicated. For example, PSE is allowed a PCA, but it does not include all costs associated with electric generation. Furthermore, the PCA contains risk bands that allocate power costs that deviate from a baseline according to pre-determined allocation of risk, whether to ratepayers or the Company. These recovery bands do not allow PSE full recovery of its power costs when costs exceed the baseline. These are but two examples of how difficult it can be to ascertain fixed costs in PSE's electric operations.

478 This problem of measuring fixed costs is clearly demonstrated by Mr. Piliaris's responses to questions from the Bench. He could not verify, for example, whether the salaries and other costs attributable to certain employees engaged in power generation are accounted for through the PCA or as a fixed cost to be contained in the CSA.[651]

479 Furthermore, he testified that PSE does not disaggregate its rates into variable and fixed costs per customer.[652] We find this lack of clarity compelling. The CSA mechanism ostensibly is intended to compensate the Company for fixed costs associated with sales reductions due to conservation. For purposes of ratemaking, both components of the calculation (*i.e.,* conservation kWhs multiplied by fixed cost per kWh) must be clearly ascertainable to reach a revenue requirement and the rate necessary to achieve that requirement. If the fixed costs are unverifiable in this record and the conservation savings cannot be reasonably known from year to year, the CSA cannot be demonstrated to create a fair, just and reasonable rate.

480 Another problem is that the CSA would result in annual, automatic rate increases for both electric and natural gas service.[653] This feature of the CSA that would allow the

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[651] TR. 666:2-667:14 (colloquy between Commissioner Oshie and Mr. Piliaris).

[652] TR. 669:10-21 (colloquy between Commissioner Oshie and Mr. Piliaris).

[653] Piliaris, Exh. No. JAP-1T at 32:12-35:2.

Company to recover revenues related to conservation measures on a cumulative basis, with no future end point, does not ensure that the Company would not accumulate CSA revenues beyond the "short-term." The mechanism would lead only to cumulative cost increases for customers, at the class level, unless and until the Company files a general rate case.

481 Further, the CSA would send a confusing message. When asked how he would explain a "conservation savings" item on a bill, PSE's witness Piliaris responded, "It's tough."[654] This was reinforced by the public testimony cited above.

482 We determine for these reasons that PSE's CSA Rate proposal should be rejected.

K. Attrition

483 PSE contends that over the past several years the Company has not been able to earn its authorized return on equity. Mr. Gaines testifies that this inability is persistent and that the trend in its under-earning is worsening. Ms. Harris testifies that the Company's regulated return on equity was only 4.8 percent during calendar year 2010, rather than its allowed rate of 10.1 percent.[655] Mr. Gaines offers historic perspective, saying that while PSE's authorized equity returns have been over 10 percent during recent periods, the Company's actual earnings fell from 9.1 percent in 2007, to 4.8 percent in 2010.[656] PSE adjusts this figure for 2010 to 6.4 percent, taking into account warmer weather, increased conservation and poor economic conditions. Thus, PSE claims its achieved rate of return on equity fell 370 basis points short of its allowed return during the test year.[657]

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[654] TR. 654:14.

[655] Harris, Exh. No. KJH-1T at 8:10-13.

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

[657] Gaines, Exh. No. DEG-1T at 23:4-24:7 (asserting that in 2010 PSE achieved a rate of return to equity of 6.4 percent, which is less than its 10.1 percent allowed return). We note that PSE adjusts for warmer weather, increased conservation and poor economic conditions. It follows that PSE is claiming attrition of 3.5 percent for 2010, attributable apparently to its rapid pace of high capital investment.

484 PSE, for reasons not explained in the record, resists labeling this experience as "attrition."[658] Staff nevertheless describes the issue using this term, and urges us to reject the Company's claim.[659] Staff contends that the Company's presentation of trends in actual, per-books, earnings is not sufficient to prove earnings attrition in the rate year. Staff notes that in 1988 the Commission examined whether actual per-books results are a reliable gauge of financial performance. At that time the Commission determined they were not reliable and consequently amended its rules to require utilities to adjust their financial reporting to reflect normalized results.[660] Moreover, Staff says that "actual results" are affected by weather and other factors and are not an accurate gauge of financial performance.

485 Staff also objects to PSE's evaluation of earnings on a combined basis saying this precludes examining remedies specific to the gas or electric business line.[661] Mr. Elgin testifies that PSE's per book results calculated for the period ending September 30, 2011, show actual earnings of 7.03 percent and 7.31 percent, respectively, for electric and natural gas operations. Mr. Elgin expresses Staff's perspective that these results indicate "the alleged attrition is not so bad."[662] The Company responds that these results represent attrition of return on equity of more than 200 basis points and this is indeed evidence of bad attrition.[663]

486 While Staff takes issue with the reliability of the unadjusted, actual earnings performance upon which PSE relies to demonstrate attrition and does not regard PSE's actual under-earnings problem to be as severe as the Company claims, Staff does not dispute that the Company faces earnings pressure. Staff acknowledges that certain aspects of the Company's circumstances may, indeed, give rise to attrition in

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[658] We note that the term "attrition," though it has a more formal definition, is often loosely applied to any situation in which a rate-regulated business fails to achieve its allowed earnings.

[659] Elgin, Exh. No. KLE-1T at 64:2, 73:12 – 74:12. Mr. Elgin defines attrition as "the erosion of a company's rate of return over time when the historical test period relationship in revenues, expenses and rate base accepted by the Commission in a rate case does not hold during a future rate year."

[660] *Id*. at 75:21-76:7.

[661] *Id.* at 74:16-77:10.

[662] Elgin, Exh. No. KLE-1T at 76:18-22.

[663] Olson, Exh. No.CEO-10T at 11:10-15.

allowed earnings. Staff, like PSE, cites ongoing costs associated with infrastructure additions, replacements and additions as an example.

487 Considering that the Company bears the burden of proof in general rate cases, Staff argues that PSE could have presented an attrition study to demonstrate earnings erosion in the rate year and could have proposed an adjustment based on such a study to increase revenue to address the situation. Staff says an attrition study must include trend analysis to determine whether there is a strong probability that during the rate year the utility will not experience the test period relationship among revenues, expenses and rate base. A proper study, in Staff's view, must identify the impact of attrition on rate of return.[664]

488 The Company responds that an attrition study of the kind described by Staff is not necessary to understand the Company is failing to earn its allowed return.[665] PSE says that it has not filed an attrition study in this case, is not making an attrition claim, and is not requesting an attrition adjustment.[666] Observing that an attrition study may not be the "simple and effective tool" characterized by Staff, the Company points to what it considers to be an uneven history of Commission decisions concerning attrition. PSE says that it is unable to discern from past Commission decisions just what is needed in an attrition study for it to be consistent with Commission policy and practice.[667] In particular, PSE says that while the Commission has confined its acceptance of attrition to periods of high inflation, it believes earnings attrition can occur during periods of low inflation if unit cost for new plant is higher than system average unit costs.[668] Turning generally to "proof of attrition," the Company says that frequent rate cases with approved rate increases are themselves historical proof that the Company is experiencing attrition.[669]

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[664] Elgin, Exh. No. KLE-1T at 77:4-10.

[665] Gaines, Exh. No. DEG-14T at 23:12-14.

[666] *Id*. at 24:8-25:5.

[667] Story, Exh. No. JHS-18T at 55:6-57:22; 59:16-60:2.

[668] *Id*. at 57:25-59:13. Mr. Story testifies that this is just the situation PSE is now facing.

[669] Story, Exh. No. JHS-18T, at 60:3-20.

489 *Commission Discussion:* As PSE makes abundantly clear, it has not put before us in this general rate case a request for an attrition adjustment. Thus, we face no need to make a determination whether one is needed to address the Company's more general claim of under-earning relative to its authorized return. We nevertheless find it appropriate to discuss the subject because an attrition adjustment is one among several possible responses the Commission could make to address a demonstrated trend of under earning due to circumstances beyond the Company's ability to control. This form of adjustment was available to utilities during the early 1980's in an environment of exceptional inflation and high interest rates; it is equally available today if shown to be a needed response to the challenges posed by PSE's current intensive capital investment program to replace aging infrastructure.

490 Earnings attrition is not an issue new to regulation nor are various regulatory solutions to the problem. The phenomenon is well documented and examined in regulatory texts.[670] It has been addressed variously by state utility commissions since the early 1960s.[671] The formal definition of "attrition" in the context of utility ratemaking is limited to circumstances in which key assumptions that underlie ratemaking theory fail to hold in reality. Regardless whether an historical or budgeted test-period is used, the relationship between rate base, expenses and revenues is used to represent the future and to set prospective rates adequate to allow a reasonable return. Ratemaking rests on the key assumption that the test-period relationships will accurately represent relationships in the future. If this assumption fails, cost of service may increase more rapidly than revenues and the rates approved based on test period conditions may not be adequate to achieve the allowed level of return under future conditions.[672]

491 The regulatory texts focus on two conditions as common sources of earnings attrition: high general inflation, and high levels of plant additions. The latter is especially

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[670] Robert L. Hahne and Gregory E. Aliff, *Accounting for Public Utilities* at 8.01-8.12 (Matthew Bender, Publication 16, Release 28, October 2011); Charles F. Phillips, Jr., *The Regulation of Public Utilities. Theory and Practice* at 386-90 (Public Utility Reports Inc., 1988).

[671] 1 Leonard Saul Goodman, *The Process of Ratemaking* at 290-92, 636-38 (Public Utility Reports, Inc. 1998).

[672] While it is theoretically possible, the regulatory literature does not address "negative attrition" - circumstances where rates produce over-earning because of a change in the relationship among expenses, revenues, and rate base.

relevant if new plant is more costly than plant being replaced, or more costly than the average cost of plant included in rates. In such circumstances, the texts identify a number of potential remedies. The Commission already employs a number of these mechanisms, as discussed at various points in this Order. The texts identify remedies that we use, or are open to considering, as follows:

- Pro-forma adjustment of test-year data to reflect known and measurable changes in conditions or costs incurred subsequent to the end of the test-year.

- Use of plant accounts (rate base) measured at the end, or subsequent to the end of the test-year rather than the test-year average.

- Inclusion of Construction Work in Progress (CWIP) in rate base providing a return on investment prior to when the new plant goes into service.

- Comprehensive expense adjustments based on an overall measurement of the projected shortfall of earnings in the rate year (*e.g.,* attrition allowance based on an attrition study). [673]

- Upward adjustment to the equity share in the capital structure.

Unfortunately, the literature provides little in the way of detailed guidance about how these remedies should be calculated or implemented. Nor do we find readily available any comprehensive analyses of the effectiveness and fairness of these individual measures when applied in real-world circumstances. Considering this, we are reluctant to be at all prescriptive in terms of establishing parameters defining how, or stating criteria by which, such remedies might be fashioned and judged. We emphasize that the Commission remains open to, and will consider fairly, specific proposals supported by adequate evidence showing them to be an appropriate response to PSE's economic and financial circumstances including, if demonstrated, under earnings due to attrition.

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[673] Such an "attrition allowance" usually is based on a combination of trended historical analysis showing, for example, erosion of earnings coupled with some analysis of why such historical trends likely will continue into the rate year. Such historical analysis is what distinguishes an attrition adjustment from the use of a future test year.

L. Expedited Rate Case Proposal

492 Periods characterized by significant inflation, extreme volatility in natural gas and energy prices, or significant requirements for plant replacement and additions to plant confront regulated utilities, Commission Staff and other participants in the regulatory process, and the Commission with difficult challenges. The Washington Commission historically has shown its willingness and ability to meet such challenges. The Commission is flexible when carrying out its statutory duties that are fundamentally defined by its obligation to ensure that utility rates are fair, just, reasonable and sufficient on a continuing basis.

493 Faced with extremely high rates of inflation during the 1980's, for example, the Commission approved attrition adjustments to mitigate the earnings erosion that was beyond the ability of the utilities to control. During the western energy crisis in 2000 and 2001, the Commission authorized interim rates, authorized deferral mechanisms for extraordinary power costs and approved hypothetical capital structures with equity shares higher than actual equity in setting rates to promote financial strength. In PSE's case, the Commission approved the PCORC (Power Cost Only Rate Case) mechanism allowing the Company to seek approval for major production plant additions to rate base between rate cases and a PCA (Power Cost Adjustment) mechanism, the baseline of which could be adjusted between rate cases in PCORC proceedings.

494 PSE presented evidence in this case showing that it continues to face the need for unusually high levels of capital investment to replace aging infrastructure, as it has for the past several years.[674] The Company also has made significant capital investments in wind power projects, such as LSR-1 in this case, to meet RPS mandated by state law.[675] These ongoing capital investments may exacerbate the impacts of regulatory lag beyond a level that is appropriate to achieve its well-understood and generally accepted benefit as an incentive for regulated companies to operate efficiently and control their costs.

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[674] McLain, Exh. No. SML-1T.

[675] RCW 19.285.

495 Although PSE complains about this problem through several witnesses' testimony, the Company does not make any specific proposal to address it broadly.[676] Dr. Olson, however, is almost harshly critical of the Commission's continued use of a historic test year as a starting point when adjusting rates. However, the Company did not request use of one on this rate case, nor did it request one prospectively.[677]

496 While Staff rejects Dr. Olson's suggestion, it outlines in response what it describes as "an expedited form of general rate relief using a simple and straight-forward process to update the test period relationships between rate base and net operating income."[678] The process would utilize the type of financial information required by Commission basis reports.[679] It could be filed in early March, following a general rate case, which Staff believes would allow time for a decision by September that coincides with the winter heating season when PSE generates 70 percent of its annual net operating income.[680] The case, as Staff envisions it, would contain only restating adjustments, such as temperature normalization. PSE would not be allowed to request a change in rate of return, except to update debt costs.[681]

497 Staff identifies what it apparently regards as the principal benefits of its proposal as follows:

- Rates would be based upon known costs, not budgets.

- Rates would capture changes to test year customer growth and load, including any changes that result from conservation.

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[676] To the extent PSE's proposed CSA Rate addresses regulatory lag, it does so narrowly, focusing only on the problem insofar as it relates specifically to conservation efforts.

[677] Because use of an historic test year is embodied in a Commission rule, WAC 480-07-510(1), any proposal for a future test year would have to either involve a petition to revise that rule or have to be a filing using both a future and an historic test year.

[678] *Id.* at ¶ 41.

[679] WAC 480-90-257 (gas) and WAC 480-100-257 (electric).

[680] Elgin, Exh. No. KLE-1T at 82:21-83:8.

[681] *Id.* at 81:5-22.

- Rates changes would be implemented to maximize the impact on financial results.

- This process provides for more streamlined and less contentious rate proceedings.[682]

498 The Company, for its part, states that:

> PSE appreciates Commission Staff's acknowledgement of the need to address regulatory lag and attrition in some fashion. 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.[683]

499 Staff disagrees, saying that Mr. Elgin "described the process with sufficient specificity as to timing, supporting data and allowed adjustments."[684] Staff encourages PSE to "take the initiative to implement Staff's proposal as soon as this case is completed."[685] Staff says it is willing to meet with PSE to confirm mutual expectations of this filing if that will facilitate the process.

500 Public Counsel's reaction to Staff proposal is that it is "an interesting proposal worth consideration."[686] Public Counsel, however, expresses some preliminary reservations about the justification for exploring this type of option at this time. In Public Counsel's view, PSE's claims of regulatory lag "ring hollow in the face of the relentless rounds of general rate case filings pursued since 2001 with virtually no

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682 Staff Initial Brief ¶ (citing Elgin, Exh. No. KLE-1T at 8:7-17; *See* Schooley, Exh. No. TES-1T at 8:12-10:5 for a description of the particular regulatory difficulties presented currently by PSE that could be alleviated by Staff's proposal).

683 PSE Initial Brief ¶161 (citing Elgin, Exh. No. KLE-1T 80:17-81:2; Story, Exh. No. JHS-18T 60:20-61:10).

684 Staff Initial Brief ¶ 46 (citing Schooley, Exh. No. TES-1T at 7:11-8:3 and Elgin, Exh. No. KLE-1T at 82:21-83:8).

685 *Id.* (citing Elgin, TR. 861:25-862:5).

686 Public Counsel Initial Brief ¶ 123.

break between rate effective dates and the next filing."[687] Public Counsel also points to the well-established benefits of regulatory lag.

501 Another concern for Public Counsel is that Staff's proposal "may be prompted as much by rate case fatigue as by the merits of the proposal itself."[688] While recognizing the pressures on the Commission's resources imposed by frequent rate case filings, including at least 36 energy rate cases filed with the Commission since 2000, it is not clear in Public Counsel's view that the appropriate response is to expedite the process for such requests. Public Counsel is concerned this could make requests for rate increases even more frequent and easier to obtain. "As proposed, the new approach does not appear to offer any definitive trade-off that would result in a reduced frequency of rate filings in return for streamlining. There must be benefits for both customers and companies in any new approach."[689]

502 Having raised these preliminary concerns, Public Counsel also says that there are several aspects of Staff's proposal that require further development:

> These include the type of adjustments that would be permitted pursuant to the expedited process, the plausibility of maintaining a narrow scope of issues that could be addressed in an expedited proceeding, and whether such an expedited rate proceeding is appropriate for other utilities at this time.[690]

Public Counsel believes it would be premature to adopt a "streamlined ratemaking" framework on this record, but that it would be an appropriate topic for a collaborative process, if the Commission wishes to review a more well-developed proposal.[691]

503 ICNU is flatly opposed to Staff's proposal because, in its view, the proposal "is designed to address problems that have not been shown to exist."[692] ICNU raises four specific objections:

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[687] *Id.*

[688] *Id.* ¶ 124.

[689] *Id.*

[690] *Id.* ¶125 (citing Exh. No. ACC-5T, pp. 9-16 (Crane)).

[691] *Id.*

- There is no evidence that the Company is experiencing any regulatory lag considering that PSE has a power cost adjustment mechanism, files numerous deferred accounts, has an automatic storm damage deferral, recovers its conservation costs in separate tariff riders, and has been filing near annual general rate cases.

- PSE has not filed an attrition study or provide evidence "demonstrating that attrition exists, and, second, quantifying its impact on the rate of return."[693]

- Staff's proposal is not fully developed, as is demonstrated by the fact that PSE opposes its adoption at this time.[694]

- There are a large number of unknown issues regarding Staff's proposal, including what (if any) issues would be appropriate to review on an expedited basis, whether it would apply to other utilities, how to conduct discovery, and what the cost baselines should be.

504 ICNU concludes for these reasons that "Staff's proposal is not yet ready for prime time, and should be more thoroughly vetted and reviewed before the Commission seriously considers any new form of expedited rate case."[695]

505 *Commission Discussion:* We are not called upon to make any specific determination in connection with Staff's proposal for "an expedited form of general rate relief." We nevertheless find it worthy of comment.

506 As suggested by the preceding discussion, the Commission recognizes the dynamic nature of the financial and economic tides that affect utilities, including PSE, and its customers. The Commission strives to maintain reasonable and appropriate flexibility

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[692] ICNU Initial Brief ¶113.

[693] Elgin, KLE-1T at 80:5-13.

[694] ICNU Initial Brief ¶113 (citing TR. 544:2—545:12 (DeBoer/Commissioner Jones).

[695] *Id.*

in its regulatory process to address this ebb and flow. We appreciate Staff's willingness to bring forward the outline of a proposed process mechanism to help address the particular problems associated with PSE's current position in a cycle of capital investment that places unusually high demands on utilities from time to time as they face the need to maintain and replace significant amounts of aging infrastructure.

507 Again, however, we have no specific proposal before us. If PSE accepts Staff's invitation "to meet with PSE to confirm mutual expectations" for a filing along the lines Staff suggests, or the Company on its own initiative makes such a filing, we certainly will give it fair consideration. Alternatively, Staff and PSE may enter into a broader discussion with other interested participants in the regulatory process and bring forward for consideration specific proposals that may satisfy a range of both common and diverse interests. In this connection, the Commission would be particularly interested in proposals that might break the current pattern of almost continuous rate cases. This pattern of one general rate case filing following quickly after the resolution of another is overtaxing the resources of all participants and is wearying to the ratepayers who are confronted with increase after increase. This situation does not well serve the public interest and we encourage the development of thoughtful solutions.

M. Proposed PCA Study

508 Commission Staff requests a review of PSE's PCA mechanism and PCORC, stating that a separate proceeding, in Staff's view, is the best way to address the subject, rather than this proceeding which already has many complicated and probably contentious issues.[696] PSE disagrees,[697] arguing that it presented an analysis of the symmetry of the PCA sharing bands in its 2006 general rate proceeding[698] as well in the last, and now, this, rate case.[699]

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[696] Schooley, Exh. No. TES-1T at 11:3-8.

[697] PSE Initial Brief ¶12.

[698] *Id.* (citing *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-060266, *et al.*, Order 08 ¶¶ 16-34 (Jan. 5, 2007)).

[699] *Id.* (citing *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).

509 PSE points out that no party responded substantively to the Company's 2008 study or the testimony PSE provided in this case. As for the PCORC, PSE states that 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.[700]

510 Staff disputes PSE's argument that it has ignored the Commission's instruction in the 2009 general rate case to more broadly examine the PCA. Staff states that its response is Mr. Schooley's recommendation in this case for a separate proceeding to review the PCA mechanism. Staff argues this is a reasonable approach given the complexity and contentiousness of the existing case.[701]

511 *Commission Determination:* Staff, and others who may take an interest, have had ample opportunity in this case and prior cases to address directly any issues concerning the PCA and PCORC mechanisms. Absent some showing that these mechanisms are not functioning as intended, are no longer needed, or should be modified to better accomplish their intended results, we will not order a special proceeding to review them at this time.

FINDINGS OF FACT

512 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

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

[701] Schooley, Exh. No. TES-1T at 11:3-8. Mr. Schooley's testimony is as follows:

> Staff also requests the Commission commence a separate proceeding to review PSE's Power Cost Adjustment and Power Cost Only Rate Case mechanisms for potential revisions. Company witness Aladin addresses the PCA and does not recommend any specific changes to the mechanism. A separate proceeding, in Staff's view, is the best way to address the subject, rather than this proceeding which already has many complicated and probably contentious issues.

513 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical and gas companies.

514 (2) Puget Sound Energy, Inc., (PSE) is a "public service company," an "electrical company" and a "gas company," as those terms are defined in RCW 80.04.010 and as those terms otherwise are used in Title 80 RCW. PSE is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

515 (3) The following investments by PSE were prudent and their costs are found to be reasonable for recovery in rates:

- Phase 1 of the Lower Snake River wind project.

- PSE's fifty month contract with Iberdrola Renewables for 100 MW of winter capacity and energy associated with the so-called Klamath Peakers.

516 (4) PSE demonstrates by substantial competent evidence that its current rates are insufficient to yield reasonable compensation for the electric and gas services it provides in Washington.

517 (5) The record supports a capital structure and costs of capital, which together produce an overall rate of return of 7.80 percent, as set forth in the body of this Order in Table 7.

518 (6) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments identified in Appendices A and B to this Order are reasonable, results in our findings that PSE's electric revenue deficiency is $63,319,369 and its natural gas revenue deficiency is $13,389,128, as set forth in detail in Tables 7 - 10 in the body of this Order.

519 (7) PSE requires relief with respect to the rates it charges for electric service and gas service provided in Washington State so that it can recover its natural gas service and electric service revenue deficiencies.

520 (8) The following Settlement stipulations were shown to resolve in the public interest the issues they present:

- Multiparty Settlement Re: Electric Rate Spread, Electric Rate Design and Renewable Energy Credit Tracker, filed on January 17, 2012.

- Multiparty Settlement Re: Natural Gas Rate Spread and Natural Gas Rate Design, filed on January 17, 2012.

- Partial Settlement Re: Meter and Billing Performance Standards, filed on February 15, 2012.

These Settlement stipulations are attached respectively to this Order as Appendices C, D and E and are incorporated into the body of this Order by this reference.

521 (9) The rates, terms, and conditions of service that result from this Order are fair, just, reasonable, and sufficient.

522 (10) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

523 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

524 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

525 (2) PSE failed to show that the rates it proposed by tariff revisions filed on June 13, 2011, which were suspended by prior Commission order, are fair, just or reasonable. These as-filed rates accordingly should be rejected.

526 (3) PSE carried its burden to prove that its existing rates for electric service and natural gas service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

527 (4) PSE requires relief with respect to the rates it charges for electric service and natural gas service provided in Washington State.

528 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under PSE's tariffs that govern its rates, terms, and conditions of service for providing natural gas and electricity to customers in Washington State.

529 (6) The costs of PSE's investments found on the record in this proceeding to have been prudently made and reasonable should be allowed for recovery in rates.

530 (7) PSE should have the opportunity to earn an overall rate of return of 7.80 percent based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 9.80 percent on an equity share of 48 percent.

531 (8) PSE should be authorized and required to make a compliance filing to recover its revenue deficiency of $63,319,369 for electrical service provided to its customers in Washington.

532 (9) PSE should be authorized and required to make a compliance filing to recover its revenue deficiency of $13,389,128 for natural gas service provided to its customers in Washington.

533 (10) The Commission should approve and adopt the following Settlement stipulations in full resolution of the issues they present:

- Multiparty Settlement Re: Electric Rate Spread, Electric Rate Design and Renewable Energy Credit Tracker, filed on January 17, 2012.

- Multiparty Settlement Re: Natural Gas Rate Spread and Natural Gas Rate Design, filed on January 17, 2012.

- Partial Settlement Re: Meter and Billing Performance Standards, filed on February 15, 2012.

534 (11) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.

535 (12) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.

536 (13) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

537 (14) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

538 (1) The proposed tariff revisions PSE filed on June 13, 2011, which were suspended by prior Commission order, are rejected.

539 (2) The Commission approves and adopts the following Settlement stipulations in full resolution of the issues they present:

- Multiparty Settlement Re: Electric Rate Spread, Electric Rate Design and Renewable Energy Credit Tracker, filed on January 17, 2012.

- Multiparty Settlement Re: Natural Gas Rate Spread and Natural Gas Rate Design, filed on January 17, 2012.

- Partial Settlement Re: Meter and Billing Performance Standards, filed on February 15, 2012.

540 (3) PSE is authorized and required to file tariff sheets that are necessary and sufficient to effectuate the terms of this Final Order, including determinations of a revenue deficiency of $63,319,369 for electrical service and a revenue deficiency of $13,389,128 for natural gas service. PSE must file the required tariff sheets at least two business days prior to their stated effective date, which shall be no sooner than May 14, 2012.

541 (4) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

542 (5) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective May 7, 2012.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

UNCONTESTED ISSUES – ELECTRIC

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UNCONTESTED ISSUES – ELECTRIC

Adjustment	NOI	Rate Base	Revenue Requirement
Actual Results of Operations	$117,427,311	$4,100,870,913	328,105,050
Adjustment 20.03-LSR Prepaid Transmission	(726,665)	110,846,093	15,098,953
Adjustment 20.05-Wild Horse Solar	179,073	(3,370,636)	(712,015)
Adjustment 20.06- ASC 815 (formerly SFAS 133)	108,519,513		(174,820,278
Adjustment 20.08-Remove Tenaska	30,284,100	(56,496,129)	(55,885,387)
Adjustment 20.09-Chelan Payments	(4,607,243)	135,630,302	24,464,649
Adjustment 21.01-Temperature Normalization	12,971,429		(20,896,415)
Adjustment 21.02-Revenues and Expenses	1,352,073		(2,178,132)
Adjustment 21.03-Pass Through Rev/Exp	(306,445)		493,670
Adjustment 21.07-General Plant Depreciation	688,453	(233,769)	(1,138,442)
Adjustment 21.08-Normalize Injuries and Damage	(725,618)		1,168,939
Adjustment 21.09-Bad Debts	1,638,181		(2,639,039)
Adjustment 21.12-Excise Tax & Filing Fee	(200,979)		323,769
Adjustment 21.14-Interest on Customer Deposits	(47,149)		75,955
Adjustment 21.16-Deferred G/L on Property Sales	(1,028,316)		1,656,573
Adjustment 21.17-Property and Liability	(124,477)		200,527

Ins.			
Adjustment 21.18-Pension Plan	(1,199,984)		1,933,123
Adjustment 21.19-Wage Increase	(1,512,830)		2,437,104
Adjustment 21.20-Investment Plan	(83,624)		134,715
Adjustment 21.21-Employee Insurance	(11,276)		18,165

APPENDIX B

UNCONTESTED ISSUES - NATURAL GAS

APPENDIX B
UNCONTESTED ISSUES - NATURAL GAS

Adjustment	NOI	Rate Base	Revenue Requirement
12.01 Water Heater Depreciation	4,071,209	(2,218,846)	(6,829,199)
12.02 Reclass Bare to Wrapped Steel	(195,347)	(97,673)	302,062
12.03 Contract Charges	640,161	0	(1,030,042)
13.01 Temperature Normalization	6,651,267	0	(10,702,130)
13.02 Revenues and Expenses	16,913,083		(27,213,765)
13.03 Pass-Through Revenue & Expense	154,724	0	(248,957)
13.07 General Plant Depreciation	384,999	(113,067)	(633,668)
13.08 Injuries & Damages	(54,310)	0	87,387
13.09 Bad Debt	1,574,431	0	(2,533,317)
13.12 Excise Tax & Filing Fee	(49,256)	0	79,255
13.14 Interest on Customer Deposits	(21,705)	0	34,924
13.16 Deferred G/L on Property Sales	(92,595)	0	148,989
13.17 Property & Liability Insurance	35,752	0	(57,526)
13.18 Pension Plan	(582,788)	0	937,727
13.19 Wage Increase	(769,423)	0	1,238,030
13.21 Employee Insurance	(5,476)		8,811

APPENDIX C

Multiparty Settlement Re: Electric Rate Spread, Electric Rate Design and Renewable Energy Credit Tracker

APPENDIX D

Multiparty Settlement Re: Natural Gas Rate Spread
and
Natural Gas Rate Design

APPENDIX E

Partial Settlement Re: Meter and Billing Performance Standards