**Exhibit No. \_\_\_ (JMW-1T)**

**Docket UE-130617**

**Witness: Juliana Williams**

**Redacted Version**

**BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

|  |  |
| --- | --- |
| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**  **Complainant,**  **v.**  **PUGET SOUND ENERGY, INC.,**  **Respondent.** | **DOCKET UE-130617** |

**TESTIMONY OF**

**JULIANA WILLIAMS**

**STAFF OF**

**WASHINGTON UTILITIES AND**

**TRANSPORTATION COMMISSION**

***Prudence and Accounting Treatment of Ferndale Generating Station and Major Hydroelectric Plant Additions***

**August 14, 2013**

**CONFIDENTIAL PER PROTECTIVE ORDER**

**Redacted Version**

**TABLE OF CONTENTS**

I. INTRODUCTION 1

II. SCOPE AND SUMMARY OF TESTIMONY 2

III. COMMISSION POLICY ON PRO FORMA RATE BASE ADJUSTMENTS….…5

IV. COMPANY’S REQUESTED PRO FORMA RATE BASE ADJUSTMENTS…...9

V. PRUDENCE STANDARD………………………………………………………...17

VI. APPLICATION OF PRUDENCE STANDARD TO THE SNOQUALMIE

PROJECT, BAKER PROJECT AND FERNDALE PLANT……………………...19

A. Snoqualmie Project 19

1. Application of the Prudence Standard – Snoqualmie Project 21

a. The Need for the Resource; Evaluation of Alternatives;

Cost 21

b. Participation of the Company’s Board of Directors 23

c. Documentation of the Company’s Decision-making

Process 24

d. Conclusion on the Snoqualmie Project Acquisition

Prudence 24

B. Baker Project 25

1. Application of the Prudence Standard – Baker Project 26

a. The Need for the Resource; Evaluation of Alternatives;

Cost 26

b. Participation of the Company’s Board of Directors 30

c. Documentation of the Company’s Decision-making

Process 31

d. Conclusion on the Baker Project FSC and LBP

Acquisition Prudence 31

C. Ferndale Plant 32

1. Application of the Prudence Standard – Ferndale 33

a. The Need for the Resource; Evaluation of Alternatives;

Cost 33

b. Participation of the Company’s Board of Directors 37

c. Documentation of the Company’s Decision-making

Process 37

d. Greenhouse Gas Emissions Performance Standard 38

e. Conclusion Prudence of the Ferndale Plant Acquisition 39

VII. OTHER ISSUES 42

A. Energy Independence Act Eligibility for Hydroelectric

Efficiency Improvements 42

B. FERC Relicensing Process 44

C. Consideration of Future Alternative Resource Acquisition 45

**List of Exhibits**

Exhibit JMW-2, Staff Adjustment 4 – Snoqualmie Falls Hydroelectric Redevelopment Project;

Exhibit JMW-3, Staff Adjustment 5 – Snoqualmie Falls Hydroelectric Redevelopment Project Deferral;

Exhibit JMW-4, Staff Adjustment 6 – Baker River Hydroelectric Project Relicensing Upgrades;

Exhibit JMW-5, Staff Adjustment 8 – Ferndale Plant Purchase

Exhibit JMW-6, Staff Adjustment 9 – Ferndale Plant Deferral

Exhibit JMW-7, Portland General Electric’s Dispatchable Standby Generation tariff

Exhibit JMW-8, Staff conversations with Portland General Electric staff regarding their Dispatchable Standby Generation program

1. **INTRODUCTION**

**Q. Please state your name and business address.**

A. My name is Juliana M. Williams.  My business address is The Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, Washington 98504.

**Q. By whom are you employed and in what capacity?**

A. I am employed by the Washington Utilities and Transportation Commission (“Commission”) as a Regulatory Analyst in the Conservation and Energy Planning Section of the Regulatory Services Division.

**Q. How long have you been employed by the Commission?**

A. I have been employed by the Commission since May 2012.

**Q. Would you please state your educational and professional background?**

A. I graduated from Whitman College in 2007 with a Bachelor of Arts degree in Geology. I graduated from the University of Maryland in 2011 with a Master of Public Policy degree, with a concentration in Energy Policy.

Prior to my employment with the Commission, I held various policy research and analysis positions with a clean energy developer, multiple think tanks and environmental non-profit organizations. In 2012, I attended the New Mexico State University’s “The Basics – Practical Regulatory Training,” as well as other sector-specific trainings.

**Q. What are your responsibilities at the Commission?**

A. My responsibilities at the Commission include the review and analysis of resource acquisition prudence, electric utility compliance filings regarding integrated resource planning and the energy conservation and renewable portfolio standards of the Energy Independence Act, energy conservation program implementation and evaluation, and low-income and reliability issues.

**Q. Have you previously testified before the Commission?**

A. Yes. I testified before the Commission in Docket UE-130043 regarding the prudence of PacifiCorp’s acquisition of major hydroelectric resource additions. I have also presented Staff recommendations to the Commission at open public meetings, participated in Commission rulemakings and supported Staff testimony in other cases before the Commission.

1. **SCOPE AND SUMMARY OF TESTIMONY**

**Q. Please explain the purpose of your testimony.**

A. My testimony addresses the appropriate ratemaking treatment of pro forma rate base additions, including Puget Sound Energy’s (PSE or Company) request for a prudence determination regarding its acquisition of the Ferndale Generating Station (Ferndale Plant); the Company’s recent renovation of and upgrades to the Snoqualmie Falls Hydroelectric Redevelopment Project (Snoqualmie Project); and the addition of a generator and other equipment for the Lower Baker Hydroelectric Project (Baker Project). My testimony addresses the propriety of including these resources in rate base (Adjustments 4, 6 and 8) and the deferrals associated with these projects (Adjustments 5, 7 and 9).

The relevant Company witnesses for the Ferndale Plant are David E. Mills, Roger Garratt, Michael Mullally, Aliza Seelig[[1]](#footnote-1) and Katherine J. Barnard. The relevant Company witnesses for the hydroelectric projects are Roger Garratt, Paul K. Wetherbee, Douglas S. Loreen, and Katherine J. Barnard.

**Q. Have you prepared any exhibits in support of your testimony?**

A. Yes. I have prepared the following exhibits in support of my testimony:

* Exhibit JMW-2 shows Staff Adjustment 4 – Snoqualmie Falls Hydroelectric Redevelopment Project;
* Exhibit JMW-3 shows Staff Adjustment 5 – Snoqualmie Falls Hydroelectric Redevelopment Project Deferral;
* Exhibit JMW-4 shows Staff Adjustment 6 – Baker River Hydroelectric Project Relicensing Upgrades;
* Exhibit JMW-5 shows Staff Adjustment 8 – Ferndale Plant Purchase;
* Exhibit JMW-6 shows Staff Adjustment 9 – Ferndale Plant Deferral;
* Exhibit JMW-7 is the tariff for Portland General Electric’s Dispatchable Standby Generation tariff; and
* Exhibit JMW-8 outlines Staff conversations with Portland General Electric staff regarding their Dispatchable Standby Generation program.

**Q. Please summarize your conclusions on the issues addressed in your testimony.**

A. Staff recommends establishing a cut-off date for allowing into rate base plant expenditures as of the filing date of this case, for prudently acquired resources placed into service before the close of discovery. Staff recommends the Commission find that PSE acted prudently in upgrading the Snoqualmie Project Diversion Dam and Power Plant 2. Staff expects PSE to place the Snoqualmie Project Power Plant 1 and the Recreational and Cultural Improvements into service prior to August 29, 2013; the discovery cut-off for this case. Provided PSE can demonstrate that Power Plant 1 and the Recreational and Cultural Improvements are in service prior to August 29, 2013, Staff recommends including Snoqualmie Project costs in rate base as of April 25, 2013, the filing date of this case.

Staff agrees with the Company that costs associated with the Snoqualmie Project Diversion Dam and Power Plant 2 are eligible for deferral under RCW 80.80.060. However, Staff recommends the removal of all deferred costs associated with Power Plant 1, because it is not yet in service, which is a requirement for deferral.

My testimony also recommends the Commission find that PSE acted prudently in upgrading the Baker Project, and to include in rate base the costs of the Baker Project as of April 25, 2013. Staff rejects PSE’s deferral of costs associated with the Baker Project powerhouse, because it was placed into service after April 25, 2013.

My testimony recommends that the Commission find that PSE acted prudently in acquiring the Ferndale Plant and to include the costs of that acquisition in rate base.

1. **COMMISSION POLICY ON PRO FORMA RATE BASE ADJUSTMENTS**

**Q. Please explain the general approach for Staff’s recommendation regarding cost recovery for the new projects you have identified.**

A. A Power Cost Only Rate Case (PCORC) establishes rates based on expected rate year expenditures, and is thus forward-looking in nature. The Company proposes multiple pro forma rate base adjustments that are based on forward-looking estimates of final costs. Staff seeks to balance the Company’s request to recover investments in plant that will be used and useful for service by the beginning of the rate year with the requirement that pro forma adjustments be known and measurable.

**Q. What is the definition of a pro forma adjustment?**

A. As defined by WAC 480-07-510(3)(e)(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.”

Although this rule applies specifically to general rate cases rather than PCORCs, this definition of pro forma adjustment is an accepted ratemaking principle and should therefore be applicable to a PCORC.

**Q. What concepts underlie this definition of pro forma adjustments?**

A. There are two basic concepts: the “known and measurable” concept and the “offset by other factors” concept.

**Q. Please explain the “known and measurable” concept.**

A. The known and measurable concept requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during or after the test year, but the effect of which will be in place when new rates go into effect.[[2]](#footnote-2)

The actual amount of the change must also be *measurable*. Costs that are documented by actual expenditure, invoice, contract or other specific obligation usually meet this test. Amounts that will not meet this test include estimates, projections, products of a budget forecast, or some similar exercise of judgment concerning future revenue, expense or rate base. The Commission has acknowledged limited exceptions to this requirement, such as the use of forward costs of gas in power cost projections, but requires a high degree of analytical rigor for such exceptions.[[3]](#footnote-3)

**Q. Please explain the “offset by other factors” concept.**

A. This concept requires that all factors affecting the known and measurable change must be considered in determining the pro forma level of revenue, expense or rate base. An offsetting factor is one that mitigates the impact of the known and measurable event. If all offsetting factors are not taken into account, the known and measurable change would be overstated or understated, creating a mismatch in the relationship of revenues, expenses and rate base.[[4]](#footnote-4) The Commission has stated that “Pro forma rate base adjustments often are not considered to be appropriate because the offsetting factors are extremely difficult to measure. That is, it is not possible to properly match revenues, expenses, and other relationship that constitute the entire business operation.”[[5]](#footnote-5)

**Q. Please describe the “used and useful” standard.**

A. In order for a resource to be included in rate base for ratemaking purposes, the resource must be “used and useful for service” in Washington State.[[6]](#footnote-6) The Commission has stated that the phrase “used and useful for service in this state” means “to benefit the ratepayers of Washington, either directly (*e.g*., flow of power from a resource to customers) and/or indirectly (*e.g*., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits).”[[7]](#footnote-7) The Commission also has stated that “the [c]ompany must demonstrate tangible and quantifiable benefits to Washington of resources in the system before we will include the resources in rates.”[[8]](#footnote-8)

**Q. Has the Commission adopted a consistent practice in establishing a timeframe for acceptable pro forma adjustments?**

A. No. For example, in one case, the Commission has rejected pro forma plant additions,[[9]](#footnote-9) and in another case the Commission accepted pro forma plant additions that for plant that was projected to be placed into service well into the rate year.[[10]](#footnote-10) In the latter example, the Commission endorsed, in principle, the establishment of an “in-service cut-off date” for consideration of pro forma plant additions.[[11]](#footnote-11) However, in that same case, the Commission also stated, “Our decision here should not be taken as precedent for other capital additions that present different facts and circumstances.”[[12]](#footnote-12)

Even more recently, the Commission outlined the following principles for pro forma rate base additions (emphasis added):

Increases in rate base and in expense and revenue items ideally are audited before they are approved for recovery in rates. They, at least, should be auditable by Staff within a reasonable time after a company files a general rate case and well before the date set for Response Testimony. In all but exceptional cases,any rate base addition or pro forma adjustment to expense *must satisfy the known and measurable requirement at the time the company makes its filing*.[[13]](#footnote-13)

**Q. Has the Commission identified any exceptional cases to the requirement that pro forma adjustments be known and measurable at the time the company makes its filing?**

A. Yes. In PSE’s most recent general rate case, the Commission allowed in rate base the first phase of the Lower Snake River Wind Project (LSR), because the plant’s in-service date was prior to the close of the record and the Company was in a period of “intensivecapital investment.”[[14]](#footnote-14) In that determination, the Commission recognized “the appropriateness of forward looking adjustments for production assets.”[[15]](#footnote-15)

**Q. Has the Commission identified any criteria for exceptions to the known and measurable requirement for pro forma rate base additions?**

A. In previous PSE PCORCs, the Commission has allowed pro forma rate base additions because of “the materiality of the resource acquisition and the fact that offsetting factors were captured through the power supply and production factor adjustments.”[[16]](#footnote-16) However, the Commission has not provided explicit guidelines as to what constitutes a “material investment.”

**IV. COMPANY’S REQUESTED PRO FORMA RATE BASE ADJUSTMENTS**

**Q. What is the test period for this case?**

A. The test period for this case is October 1, 2011, to September 30, 2012. Therefore, any requested rate base additions that were placed into service after the test period are considered pro forma adjustments.

**Q. What pro forma rate base additions does the Company propose to include in rate base?**

A. The Company proposes three pro forma rate base additions, as described by Company witnesses Mullally, Garratt, Wetherbee and Loreen.

* Ferndale Plant, in-service November 15, 2012;
* Baker River Hydroelectric Project (Baker Project), which includes:
  + Lower Baker Floating Service Collector (“FSC”), in-service February 14, 2013;
  + Lower Baker Unit 4 Powerhouse (“LBP”), in-service July 25, 2013;
* Snoqualmie Falls Hydroelectric Redevelopment Project (“Snoqualmie Project”), which includes:
  + Diversion Dam, in-service October 31, 2012;
  + Power Plant 1, projected in-service August 15, 2013;
  + Power Plant 2, in-service April 17, 2013;
  + Recreational and Cultural Improvements, projected completion September 2013.[[17]](#footnote-17)

**Q. Please explain Staff’s approach for evaluating these pro forma rate base adjustments in the context of the policy discussion in Section III of your testimony.**

A. Staff’s approach is to identify three key characteristics of an acceptable pro forma rate base addition. First, the pro forma rate base additions should be known and measurable as of the filing of the case. Second, there should be no offsetting factors (or the adjustment takes all offsetting factors into account). Third, the rate base addition must be in service, providing electricity (or other benefits) to serve customers.

A resource may be operational yet fail to meet the known and measurable criteria if activities such as testing, commissioning, or close-out costs are not completed. Moreover, including a generating rate base addition into the power cost model should sufficiently capture the significant offsetting factors, recognizing that some offsetting factors for newly constructed plants may not be captured due to the lack of operational history.

Finally, of course, the Company must be prudent in acquiring the project. Among the prudence criteria, which I discuss in further detail below in Section V, is an evaluation of whether the Company acquired the resource in a cost-effective manner.[[18]](#footnote-18) Staff cannot evaluate the cost-effectiveness of a project if construction on the project is incomplete and, therefore, the total costs are not yet known and measurable.

**Q. Please summarize how Staff applied these principles to the pro forma plant additions PSE proposes to include in rate base in this case.**

A. Staff made a compromise in applying these principles. Had Staff strictly applied these principles, Staff would recommend the Commission reject both the Company’s Baker Project and Snoqualmie Project pro forma plant adjustments, because those projects are not yet in-service, or were placed into service after the filing of this case.

However, given the forward-looking nature of the PCORC and Staff’s expectation that both of these facilities will be fully in-service prior to the rate year, Staff recommends the following compromise:

1. The Commission should include in the power cost model prudently-acquired resources that are in-service as of August 29, 2013, the discovery cut-off for this case, so as to capture offsetting factors.
2. For each such resource, the Commission should allow into rate base only those costs that are known and measurable as of April 25, 2013, the filing date for this case.
3. If any pro forma rate base addition fails to be in-service by August 29, 2013, the Commission should remove the related adjustment to the power cost model and remove all costs associated with the resource from rate base.

Additionally, Staff evaluated the major components within each project separately to address the varied in-service dates. Staff puts forward this compromise reluctantly. The Company created this situation by filing the PCORC when it did, while several resources for which the Company seeks recovery are incomplete, which made it very difficult for Staff to conduct a proper review and audit.

**Q. What is the basis for the element of Staff’s compromise approach that uses the date the Company filed its case as the known and measurable “cut-off date” for consideration of a pro forma rate base addition?**

A. This element of the compromise is consistent with the Commission’s statement that pro forma rate base additions be “auditable by Staff within a reasonable timeframe after the company files a general rate case.”[[19]](#footnote-19) Although the Commission made this statement in the context of a general rate case, it is even more critical in a PCORC, where the review period is shorter.

As of the filing of a case, a company is able to include known and measurable expenditures to that date. Using the filing date of a rate case as a cut-off for costs allows Staff full use of the time allowed by the procedural schedule to evaluate adjustments without burdening the process, record and Commission’s limited resources with later-filed evidence and updates.

This cost cut-off date is also consistent with the Commission’s policy that exceptions to the known and measureable standard have a “high degree of analytical rigor.”[[20]](#footnote-20) Allowing PSE to pursue pro forma plant adjustments for plant that is completed and placed into service after the filing of this case is tantamount to requiring Staff to conduct a continual audit during the pendency of the proceeding. This is an unreasonable and unnecessary expectation that compromises Staff’s ability to perform a thorough analysis of the proposed adjustments, and, in turn, fully assist the Commission in its evaluation of the issues.

**Q. Why is it appropriate to use the discovery cut-off, August 29, 2013, as the “cut-off date” for including a resource in the power cost model?**

A. The Commission has in the past allowed recovery of resources that were in-service after the filing of the case, and in the case of Hopkins Ridge, in service after the close of the record.[[21]](#footnote-21) However, one of Staff’s roles in a rate case is making a recommendation to the Commission on the prudence of resource acquisition. Staff cannot deem a resource prudent that is not in-service. Unforeseen events, such as occurred in the Coyote Springs II example I discussed earlier, can delay the in service date of a resource and can escalate costs for a resource, and this can impact the prudence analysis. After the close of discovery, Staff no longer has sufficient time to review and audit expenditures on rate base, and therefore cannot fully assist the Commission after the close of discovery.

For example, using the compliance filing as a cut-off date also fails to provide sufficient time for Staff to review prudence along with every other change reflected in the compliance filing. Should the Commission decide to allow such an approach, Staff could not conduct a full review.

**Q. Which of the Company’s proposed pro forma plant additions were in service prior to the filing of this case on April 25, 2013?**

A. The Ferndale Plant, and the Baker Project FSC, the Snoqualmie Project Diversion Dam, and Snoqualmie Project Power Plant 2 project components were all in service prior to April 25, 2013.

The Ferndale Plant was an existing operating plant was when PSE acquired it in November 2012, and the Ferndale Plant has been providing service to PSE’s customers as a Company facility since then. PSE placed the Baker Project FSC into service in February 2013; PSE placed the Snoqualmie Project Diversion Dam into service in in October 2012; and PSE placed the Snoqualmie Project Power Plant 2 into service in April 2013.

**Q. Were the capital costs for Ferndale, Baker Project FSC and Snoqualmie Project Diversion Dam and Power Plant 2 known and measurable as of April 25, 2013?**

A. Yes, for the most part. All costs related to the acquisition of Ferndale were known and measurable as of April 25, 2013. For the Baker Project FSC, the Company projected to incur $1,427,309 in commissioning and final close-out costs after April 25, 2013.[[22]](#footnote-22) Similarly, the Company projected to incur $2,742,604 in estimated costs for Snoqualmie Project Power Plant 2 after April 25, 2013.

**Q. Which of the Company’s proposed pro forma plant additions did PSE place in service subsequent to the filing of this case on April 25, 2013?**

A. PSE placed the Baker Project LBP into service in July 2013.

**Q. Which of the Company’s proposed pro forma plant additions does PSE project will be in service by the start of the rate year?**

A, PSE projects the Snoqualmie Project Power Plant 1 to be in service on August 15, 2013. PSE projects the Snoqualmie Project Recreational and Cultural Improvements to be completed in September 2013. FERC required PSE to construct these recreational and cultural items as a condition of the relicensing.

**Q. What capital costs for Baker Project LBP and Snoqualmie Falls Power Plant 1 and Recreational and Cultural Improvements were known and measurable as of April 25, 2013?**

A. For the LBP, as of April 25, 2013, PSE had spent $95,194,977,[[23]](#footnote-23) including AFUDC, out of a projected budget of $102,186,383.[[24]](#footnote-24) For Snoqualmie Project Power Plant 1, PSE had spent $123,186,065,[[25]](#footnote-25) out of a projected budget of $135,912,803.[[26]](#footnote-26) And, for the Snoqualmie Project Recreational and Cultural Improvements, PSE had spent $10,650,989[[27]](#footnote-27) out of a projected budget of $12,594,683.[[28]](#footnote-28)

**Q. Please summarize Staff’s recommended rate base adjustments based on Staff’s recommended August 29, 2013, “in-service cut-off date” and April 25, 2013 “known and measurable cost cut-off date.”**

A. Staff’s recommendation is in three parts:

1) The Ferndale Plant, the Baker Project FSC, the Snoqualmie Project Diversion Dam and Power Plant 2 were in service prior to April 25, 2013, and therefore qualify for full recovery in rate base.

2) The Baker Project LBP was in service as of July 25, 2013. The known and measurable costs for this project as of April 25, 2013, may be included in rate base.

3) If the Snoqualmie Project Power Plant 1 and the Recreation and Cultural Improvements are completed by August 29, 2013, the known costs as of April 25, 2013 may be included in rate base and power output from Power Plant 1 should be included in the power cost model. If these projects are not completed by August 29, the Commission should disallow rate base recovery in this PCORC and the Power Plant 1 power output should be removed from the power cost model. Staff excludes all other costs beyond this date, including projected project closeout costs.

**Q. Is the Company disadvantaged unfairly by excluding from rate base at this time costs it incurred subsequent to April 25, 2013?**

A. No. Because the PCORC is forward-looking, Staff is recommending a compromise that allows inclusion of generating resources into the power cost model and of known and measurable costs into rate base, despite the fact that several resources were not in-service by the filing of the case. This is favorable to PSE, because a strict interpretation of the known and measurable principle and used and useful would lead to the disallowance of both Baker Project and Snoqualmie Project. Furthermore, the Company will have another opportunity to request recovery of costs incurred after April 25, 2013, in its next PCORC filing, which is anticipated in early 2014.

1. **PRUDENCE STANDARD**

**Q. What is the relevant standard to assess the Company’s acquisition of the Ferndale Plant, and the upgrades to Baker Project and Snoqualmie Project?**

A. The Commission applies a “prudence” standard when it determines whether a specific resource acquisition decision by a utility is appropriate, and that ratepayers can be required to support that resource through rates. Overall, the 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.[[29]](#footnote-29)

**Q. What factors does the Commission use to evaluate the prudence of a utility’s electric resource acquisition?**

A. There is no single set of factors. However, the Commission generally has focused on the following four factors:

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.[[30]](#footnote-30)
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.[[31]](#footnote-31)
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 as appropriate.[[32]](#footnote-32)
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.[[33]](#footnote-33)

Although the Commission typically has applied these factors to a utility’s acquisition of new major resources such as the Ferndale Plant, in my opinion, it is likewise appropriate to consider these factors when evaluating the prudence of major upgrades to existing resources, such as the Snoqualmie and Baker Projects. Additionally, the Ferndale Plant must also meet the state Greenhouse Gas Emissions Performance Standard in order to be considered prudent.[[34]](#footnote-34)

1. **APPLICATION OF PRUDENCE STANDARD TO THE SNOQUALMIE PROJECT, BAKER PROJECT AND THE FERNDALE PLANT**

**A. Snoqualmie Project**

**Q. Please briefly describe the Snoqualmie Project.**

A. The Snoqualmie Project is a run-of-the-river hydroelectric project located on the Snoqualmie River in King County, Washington. The project consists of a Diversion Dam and two powerhouses (Plants 1 and 2), built in 1898 and 1910, respectively. Power Plant 1 includes an underground powerhouse and tailrace tunnel, built near the bottom of the 268-foot-high falls. The Power Plant 2 powerhouse is located below Snoqualmie Falls.

The original license from the Federal Energy Regulatory Commission (FERC) for this project expired in 1993, and the project was allowed to operate until the issuance of a new license. FERC issued PSE a new license in 2004, which authorized an increase in installed capacity from the 44.4MW previously authorized, to 54.4MW. [[35]](#footnote-35) FERC amended PSE’s new license in 2005 and 2009. Some of the major changes made by these amendments include reducing the height of the diversion dam, changing the channel alignment to provide greater flood protection, replacing only one unit in Power Plant 1 instead of all five, and reconfiguring and increasing the installed capacity of Power Plant 2.[[36]](#footnote-36) The 2004 license also required significant improvements to recreational and cultural resources at the facility.[[37]](#footnote-37)

**Q. What information did you evaluate in conducting your analyses in this case?**

A. I reviewed the direct testimony and exhibits of PSE witnesses Garratt, Wetherbee, Loreen, and Barnard, and PSE’s responses to data requests from Staff. These documents included FERC licenses, applicable settlement agreements and orders, approvals of parties to the settlement agreements, economic analyses, request for proposal criteria and analyses, proof of project in-service dates, and other related documents.

**Q. Is the Snoqualmie Project used and useful for service in Washington?**

A. In part. The Snoqualmie Project Power Plant 2 was placed into service again on April 17, 2013.[[38]](#footnote-38) This plant provides direct benefits to ratepayers through its location within PSE’s service territory. Therefore, the upgrades to the plant are used and useful for service. PSE expects to place Power Plant 1 into service on August 15, 2013, and expects to complete the Recreational and Cultural Improvements in September 2013. [[39]](#footnote-39) Although Power Plant 1 and the Recreational and Cultural Improvements are not considered used and useful for service yet, Staff believes it is likely PSE will place these resources in service prior to the start of the rate year.

**1. Application of the Prudence Standard – Snoqualmie Project**

1. **The Need for the Resource; Evaluation of Alternatives; Cost**

**Q. Did the Company adequately support the need for Snoqualmie Project, and show that it was an appropriate investment to acquire to meet that need?**

A. Yes. The Company has demonstrated the need for the facility in its 2005 PCORC. The Commission previously has determined that PSE’s decision to pursue relicensing of the Snoqualmie Project as well as the costs related to the relicensing process were prudent.[[40]](#footnote-40) No additional facts have been presented that would change that determination. FERC approved amendments to the license in 2005 and again in 2009. These amendments did not change the generating capacity of the facility or the ability of the facility to provide electricity to PSE’s customers. The upgrades are required for the Snoqualmie Project to continue to generate electricity in compliance with the Company’s current FERC license.

**Q. How did PSE evaluate the Snoqualmie Project?**

A. PSE conducted economic analyses throughout the relicensing process. The Company presented an “Assessment of New FERC License and Alternative” to its Board of Directors in July 2004, immediately after the issuance of the new license, comparing the costs to implement the license with other alternatives.[[41]](#footnote-41) This analysis showed that accepting the new license was the lowest cost option. The Company also re-evaluated the economics for the project and multiple design options in preparation for and in response to the license amendments issued in 2009. Again, the analyses showed that accepting the amended license was the lowest cost option.[[42]](#footnote-42)

Once the Company accepted the amended license, it issued a Request for Proposals (“RFP”) for the construction work and invited three pre-screened contractors to submit bids, due the specialized nature of the underground work. The Company received three proposals for the work and evaluated these proposals based on the construction plans and schedules, qualifications of the bidding team, cost, interview performance and experience constructing similar projects. The proposal selected by PSE was the lowest cost bid and was deemed to sufficiently minimize risks.[[43]](#footnote-43)

**Q. Was the cost of the Snoqualmie Project reasonable?**

A. It is unclear whether all of the costs of the Snoqualmie Project are reasonable, because final costs are unknown. Power Plant 1 is not yet in-service and construction on it and the Recreational and Cultural Improvements is ongoing. As of April 25, 2013, PSE spent $287,784,738 out of a total budget of $305,197,775, or approximately 94 percent of the current budget.[[44]](#footnote-44) The Company initially estimated in 2009 that the capital expenditures for the project would be $240.0 million.[[45]](#footnote-45) The most recent budget projects total capital expenditures to total just over $272 million.[[46]](#footnote-46) The increase of approximately $32 million, or 13 percent, from the initial budget forecast to the most recent budget is largely due to unexpected and unforeseeable field conditions, such quality of bedrock and the river channel, and wetter than average weather conditions that complicated construction.[[47]](#footnote-47)

Although Staff is generally uncomfortable with cost overruns of this magnitude, Staff has found no evidence of mismanagement and accepts that the bulk of the budget changes made during construction of the project were appropriate given factors that were out of the Company’s control. Staff expects that the final cost of the project will be reasonable once construction is completed.

**b. Participation of the Company’s Board of Directors**

**Q. Did PSE’s Board of Directors make the final decision to build the Snoqualmie Project?**

A. No. However, it may be reasonable for upper management to provide final approval for this type of project, rather than the Board of Directors. Following receipt of detailed project analysis, Paul Weigand, Vice President of Power Generation and Chair of PSE’s Energy Management Committee, gave final approval of the project on May 28, 2009.[[48]](#footnote-48) Staff reviewed PSE’s Controller’s Manual – Invoice/Payment Approval (CTM-7) and accepts that the final approval for the reconstruction of the Snoqualmie Project was made at the appropriate level for this type of project, pursuant to Company policy.[[49]](#footnote-49)

1. **Documentation of the Company’s Decision-making Process**

**Q. Did PSE meet the documentation requirement for the acquisition of the Snoqualmie Project?**

A. Yes. PSE provided adequate contemporaneous records of its decision-making process and supporting analysis in this case, as cited above.

1. **Conclusion on Snoqualmie Project Acquisition Prudence**

**Q. What is your conclusion regarding the prudence of PSE’s upgrade of the Snoqualmie Project?**

A. Based on the documentation provided by the Company on Snoqualmie Project to date, Staff recommends that the Commission find that the Diversion Dam and Power Plant 2 are used and useful for service in the rate year. However, Staff is unable to recommend that Power Plant 1 and the Recreational and Cultural Improvements are “used and useful” or that the acquisition of the resource by PSE was prudent because final costs are not known and measurable. However, Staff expects that all elements of the project will be placed into service prior to the discovery cutoff, and has seen no evidence of imprudence in the expenditures made to date. Therefore, as discussed earlier, under the condition that PSE demonstrates that the project is in-service by August 29, 2013, Staff recommends that the $287,784,738 spent by April 25, 2013, be included in rate base as prudently incurred expenses. Inclusion in rate base of expenditures incurred after April 25, 2013, should occur in a later proceeding after the final totals are known and measurable.

**B. Baker Project**

**Q. Please briefly describe the Baker Project.**

A. The Baker Project is one of the two hydroelectric developments that compose FERC Project No. 2150. The Baker Project is located on the Baker River in Skagit and Whatcom Counties in northwestern Washington. The Baker Project began commercial operations in 1925 and consists of a concrete arch dam, a single unit powerhouse and a fish barrier dam and trap.

In 2008 FERC granted PSE a new license for operation of the Baker Project for a term of 50 years.[[50]](#footnote-50) The FERC license order incorporates the terms of a comprehensive settlement agreement[[51]](#footnote-51) which, among other things, requires PSE to construct a new 30 MW powerhouse and a downstream migratory fish collection facility.[[52]](#footnote-52) The LBP was constructed in an underground facility to mitigate the landscape instability that previously damaged the facility. The FSC is a 130-foot-by-60-foot barge “designed to attract, sort, and safely transfer juvenile salmon for transport downstream around Lower Baker Dam,” and includes a series of submerged screens, water pumps, fish-holding chambers, a fish-evaluation station, equipment-control rooms and a fish-loading facility.[[53]](#footnote-53)

**Q. What information did you evaluate in conducting your analyses in this case?**

A. I reviewed the direct testimony and exhibits of PSE witnesses Garratt, Wetherbee, Loreen, and Barnard, and PSE’s responses to data requests from Staff.  These documents included FERC licenses, applicable settlement agreements and orders, approvals of parties to the settlement agreements, economic analyses, request for proposal criteria and analyses, proof of project in-service dates, and other related documents.

**Q. Are the Baker Project FSC and LBP used and useful for service in Washington?**

A. Yes. PSE placed the FSC into service on February 14, 2013,[[54]](#footnote-54) and PSE placed the LBP into service on July 25, 2013.[[55]](#footnote-55)

**1. Application of the Prudence Standard – Baker Project**

**a. The Need for the Resource; Evaluation of Alternatives; Cost**

**Q. Did the Company adequately support the need for the Baker Project FSC and LBP, and show that it was an appropriate investment to acquire to meet that need?**

A. Yes. The Company demonstrated the need for the facility in its 2006 general rate case. In that case, the Commission determined that PSE’s decision to relicense the Baker River Project was prudent.[[56]](#footnote-56) No additional facts have been presented that would change that determination. The Baker Project FSC and LBP were included in the terms of the settlement agreement PSE entered into as part of the FERC relicensing process. Thus, the FSC and LBP are required for the Baker Project to continue to generate electricity in compliance with the Company’s current FERC license.

**Q. How did PSE evaluate the Baker Project FSC and LBP?**

A. PSE conducted economic analyses for the FSC and LBP throughout the Baker River Project relicensing process. The business case for relicensing the Baker River Project is described in internal PSE memoranda dated April 15, 2004,[[57]](#footnote-57) and November 12, 2004.[[58]](#footnote-58) The Company’s consideration of alternative courses of action was also documented in testimony and exhibits submitted by Company witness Kris Olin in PSE’s 2006 general rate case.[[59]](#footnote-59) In that case, the Commission determined that PSE’s decision to relicense the Baker River Project was prudent.[[60]](#footnote-60) The Company performed an updated economic analysis in November 2008 reflecting the specific terms and conditions of the FERC license that was issued for the Baker River Project in October 2008.[[61]](#footnote-61) These analyses are sufficient to demonstrate that retention of this project was consistently the economically favorable course of action.

Once the project was relicensed, the Company issued two separate RFPs for technical design and construction work for the LBP and the FSC. Regarding the LBP, PSE solicited bids from three pre-screened contractors capable of performing the specialized work. The Company received two complete proposals and evaluated these proposals based on the construction plans and schedules, qualifications of the bidding team, cost, interview performance and experience constructing similar projects. The proposal selected by PSE was rated highest in all categories.[[62]](#footnote-62) The Company then negotiated a project-specific construction contract with the selected contractor team.

Regarding the Floating Surface Collector, PSE solicited bids from four pre-screened contractors capable of performing the specialized work. The Company received four proposals and evaluated these proposals based on the construction plans and schedules, qualifications of the bidding team, cost, interview performance and experience constructing similar projects. The proposal selected by PSE rated higher than all the bidders in nearly all categories.[[63]](#footnote-63) The Company then negotiated a project-specific construction contract with the selected contractor team.

**Q. Was the cost of the Baker Project FSC and LBP reasonable?**

A. It is unclear whether all of the costs of the FSC and LBP are reasonable, because final costs are unknown. Although PSE placed the FSC into service on February 14, 2013, PSE has indicated that the Company team and the contractor are continuing to work through the project “punch list.”[[64]](#footnote-64) As of April 25, 2013, PSE spent $56,867,149 out of a total budget of $58,294,458, or 98 percent of the current budget for the FSC. By comparison, the Company initially estimated in April 2011 that the capital expenditures for the FSC would be $53.1 million.[[65]](#footnote-65) The most recent budget projects total capital expenditures to total $54.5 million. This cost overrun of $1.4 million, or 3 percent, is within an acceptable margin, and the reasons for deviations from budget described by Company witness Loreen[[66]](#footnote-66) are reasonable. It is also worth noting that the final budget for the FSC represents a significantly lower cost than a similar Floating Surface Collector at Upper Baker, which is substantially the same design.

Regarding the LBP, although PSE placed this facility into service on July 25, 2013, the expenditures to date and the final project budget remain estimates. As of April 25, 2013, PSE spent $95,194,977 out of a total budget of $102,186,383, or approximately 93 percent of the current budget. By comparison, the Company initially estimated that the capital expenditures for the project would be $83 million.[[67]](#footnote-67) The most recent budget projects total capital expenditures to total approximately $94 million.[[68]](#footnote-68) The increase of approximately $11 million, or roughly 13 percent, from the initial budget forecast to the most recent budget is due to the reasons discussed by Company witness Loreen.[[69]](#footnote-69) PSE identified that $3.3 million[[70]](#footnote-70) of the over budget estimate was due to unforeseeable landslide slope stabilization measures at the site.[[71]](#footnote-71) Adding the cost of the unforeseeable slope stabilization costs to the budget reduces the remaining overage to approximately $7.7 million, or 9% over original budget.

Staff has found no evidence of mismanagement and accepts that the changes made during construction of the project were generally appropriate given factors that were out of the Company’s control and a normal range of variances for projects of this nature and complexity.

**b. Participation of the Company’s Board of Directors**

**Q. Did PSE’s Board of Directors make the final decision to the build Baker Project FSC and LBP?**

A. No. However, it may be reasonable for upper management to provide final approval for this type of project, rather than the Board of Directors. Following receipt of detailed project analyses, Paul Weigand, Senior Vice President of Power Generation and Chair of PSE’s Energy Management Committee, gave final approval of the Baker Project LBP construction and Booga Gilbertson, Vice President of Operational Services gave final approval of the Baker Project FSC.[[72]](#footnote-72) Staff reviewed PSE’s Controller’s Manual – Invoice/Payment Approval (“CTM-7”) and accepts that the final approval for the reconstruction of Baker Project was made at the appropriate level for this type of project, pursuant to Company policy.[[73]](#footnote-73)

1. **Documentation of the Company’s Decision-making Process**

**Q. Did PSE meet the documentation requirement for the acquisition of the Baker Project FSC and LBP?**

A. Yes. PSE provided adequate contemporaneous records of its decision-making process and supporting analysis in this case, as cited above.

1. **Conclusion on Baker Project FSC and LBP Acquisition Prudence**

**Q. What is your conclusion regarding the prudence of PSE’s acquisition of the Baker Project FSC and LBP?**

A. Based on the documentation provided by the company on the Baker Project FSC and LBP, particularly documentation demonstrating that both facilities were placed into service prior to the filing of my testimony, Staff recommends that the Commission find that the FSC and the LBP are used and useful for service in the rate year. However, because final costs for those projects are not known and measurable, Staff does not believe that all costs should be included in rates at this time. Staff recommends that the $56,867,149 spent for the FSC by April 25, 2013, and the $95,194,977 spent for the LBP by April 25, 2013, or a total of $152,062,126, be included in rate base as prudently incurred expenses. Inclusion in rate base of expenditures incurred after April 25, 2013, should occur in a later proceeding after the final totals are known and measurable.

**C. Ferndale Plant**

**Q. Please briefly describe the Ferndale Plant.**

A. The Ferndale Plant is a combined-cycle combustion turbine electric generating resource located west of Ferndale, Washington, in Whatcom County. The plant began operations in April 1994, though not under PSE’s ownership. The plant consists of two General Electric 7EA combustion turbines and one steam turbine.[[74]](#footnote-74) The rated output is 245 MW summer baseload (270 MW when duct-firing is used), and up to 290 MW winter baseload when duct-firing is used. The plant is designed to run on natural gas and fuel oil and has on-site fuel oil tanks, to allow continued operation in the event of gas supply interruptions. The facility also is capable of delivering steam to the adjacent oil refinery. Previously, this plant was owned by the Tenaska Partners, and PSE purchased output from the facility under a PURPA contract through December 2011.[[75]](#footnote-75)

**Q. What information did you evaluate in conducting your analyses in this case?**

A. I reviewed the direct testimony and exhibits of Company witnesses Michel Mullally, Roger Garrett and Aliza Seelig, as well as responses to various data requests. These documents included RFP analyses, presentations to PSE’s Board, contracts and other related documents.

**Q. Is Ferndale used and useful for service in Washington?**

A. Yes. When PSE acquired the Ferndale Plant on November 15, 2012, the facility was operational. The Ferndale Plant is providing power to PSE customers in Washington State. [[76]](#footnote-76)

1. **Application of the Prudence Standard – Ferndale**

**a. The Need for the Resource; Evaluation of Alternatives; Cost**

**Q. Did the Company demonstrate that it has a need for additional resources as called for in the first prudence factor mentioned above?**

A. Yes. The Company’s 2011 Integrated Resource Plan (2011 IRP), identified a need for additional resources to meet the forecast load demand based on the Company’s 2010 demand forecast.[[77]](#footnote-77) The Company updated the load forecast multiple times to reflect more current information during the analysis of proposals from the 2011 Request For Proposals for All Generation Sources (RFP) process.[[78]](#footnote-78)

**Q. How did these revised load forecasts affect the projected need for resources during the RFP evaluation process and the ultimate acquisition of resources?**

A. PSE updated the 2011demand forecast just before the 2011 IRP was filed, which reduced PSE’s short-term capacity need to 385 MW in 2012 and 1,317 MW in 2017. Further updates in November 2011 and April 2012 reflected lower growth, avoidance of retiring gas plants and short-term hedges acquired by PSE. By April 2012, PSE’s expected capacity had shrunk to 138 MW in 2012 and 866 MW in 2017.[[79]](#footnote-79) The majority of the remaining need for capacity in the short term, 2012 to 2017, was due to expiring power purchase agreements. Updating the forecasted demand during the RFP process provided the Company with the most current and relevant information upon which to base its decisions. Specifically, the updated demand forecast prevented the Company from potentially acquiring additional capacity sooner than it needed. The Ferndale Plant, in combination with one other resource, was determined to be the best resource for meeting the Company’s final updated resource need.

**Q. Does PSE’s RFP process evaluate all proposals against alternatives, including the cost for PSE to build the resource itself?**

A. Yes. The PSE’s RFP process compares external proposals to the anticipated costs of self-build similar resources, which are approximated quantitatively in the portfolio model as generic resources.

**Q. How many proposals did PSE receive in response to its RFP?**

A. The Company received 29 proposals from the RFP process and two additional proposals during the RFP evaluation process. The proposals included nine renewable resources with a total capacity of 454 MW, 11 thermal resource proposals with a total of 3,124 MW, and nine proposals for other resources such as market power purchase agreements, energy storage, and hydro, with a combined capacity of 2,631 MW.

**Q. How did PSE evaluate the RFP proposals?**

A. The Company used a standard two-phase process to evaluate RFP proposals, which was also used in prior prudence cases before the Commission.[[80]](#footnote-80)

The first phase in PSE’s RPF evaluation process screens out proposals that appear to be relatively high-risk, based on qualitative analysis; high-cost, based on modeling the financial effect of adding each proposed resource to the portfolio; or subject to significant feasibility constraints, such as unproven generation technology.[[81]](#footnote-81) The screening process involves both qualitative and quantitative analysis to rank and then select a candidate short-list of proposals for further examination and due diligence in the second phase of the selection process. [[82]](#footnote-82)

The second phase of PSE’s evaluation of proposals examines the candidate short list in more depth, including a qualitative evaluation of the remaining proposals as well as dynamic quantitative optimizing modeling of all the resources under each of five economic scenarios.[[83]](#footnote-83) The optimization model dynamically selects resources at different times over the 20 year planning horizon to find the lowest net present value revenue requirement (NPVRR) in each of five economic scenarios.[[84]](#footnote-84)

**Q. What were the results of PSE’s RFP evaluation process?**

A. Phase one of the RFP evaluations resulted in PSE selecting the 10 most promising offers for further scrutiny. In phase two, PSE combined the quantitative results of the optimization modeling with the qualitative analysis of the 10 remaining offers[[85]](#footnote-85) to select the three lowest risk and lowest cost proposals for negotiations, called the “short list.”[[86]](#footnote-86)

After PSE notified applicants regarding their proposal status, three replacement proposals were submitted to PSE with revised pricing by June 22, 2012.[[87]](#footnote-87) The revised proposals constituted material changes to the proposals that had been evaluated to create the short list. Therefore, as required by WAC 480-107-075(4), PSE suspended contract finalization and re-ranked the projects according to the revised project proposal.

Using the same methods, PSE re-evaluated the 10 candidate offers including the three revised offers. This re-evaluation resulted in a new set of preferred lowest cost and lowest risk projects.

**Q. What was the final recommendation to the Board resulting from the RFP evaluation process?**

A. PSE’s Energy Management Committee recommended to the Board on September 27, 2012, that the acquisition of Ferndale Plant and Centralia Coal PPA provided the lowest cost and lowest risk combination and were best tailored to meet PSE’s projected needs.[[88]](#footnote-88)

**Q. Did PSE perform additional due diligence regarding the Ferndale Plant prior to executing the purchase agreement?**

A. Yes. The due diligence process prior to acquisition of the Ferndale Plant is well documented by Mr. Mullally in his Exhibit No. MM-1HCT, pages 38 to 50.

**Q. Was the process and analysis performed by the Company appropriate, given the circumstances and information available?**

A. Yes. The Company appropriately adapted its analysis and conclusions regarding the most beneficial, lowest cost and lowest risk resources through the RFP evaluation process. The final cost of acquiring Ferndale was XXXXX or XXXXX.[[89]](#footnote-89)

**b. Participation of the Company’s Board of Directors**

**Q. Did Company management or the Board of Directors participate in the decision to acquire the Ferndale Plant?**

A. Yes. PSE’s Board of Directors considered PSE’s Energy Management Committee’s recommendations on September 27, 2012. The Board of Directors received extensive documentation regarding the evaluations performed by the Company.[[90]](#footnote-90) The Board passed a resolution approving management’s proposal to pursue final negotiations for the purchase of the Ferndale Plant, with certain price and other conditions.[[91]](#footnote-91) The sales contract was within the limits and conditions set by the Board.

**c. Documentation of the Company’s Decision-making Process**

**Q. Did the Company provide adequate contemporaneous documentation to support its decision to acquire the Ferndale Plant?**

A. Yes. PSE provided extensive documentation of its decision-making process and supporting analysis in this case, as cited above and in the testimony of Witnesses Mullally, Garratt and Seelig.

**d. Greenhouse Gas Emissions Performance Standard**

**Q. What is the Greenhouse Gas Emissions Standard?**

A. The Greenhouse Gas Emissions Performance Standard states, “No electrical company may enter into a long-term financial commitment unless the baseload electric generation supplied under such a long-term financial commitment complies with the greenhouse gases emissions performance standard.”[[92]](#footnote-92)As it applies in the case of the Ferndale Plant acquisition, the GHG performance standard is “one thousand one hundred pounds of greenhouse gases per megawatt-hour.”[[93]](#footnote-93) All electric generation facilities or power plants fueled exclusively by renewable resources, as defined in RCW 19.280.020, are deemed to be in compliance with the standard.[[94]](#footnote-94)

**Q. Does the Ferndale Plant meet the Greenhouse Gas Emissions Performance Standard?**

A. Yes. In Docket UE-121594, the Commission determined that the Ferndale Plant is a baseload generation plant and that it “complies with the greenhouse gas emissions performance standard,” subject to certain conditions.[[95]](#footnote-95)

**e. Conclusion on Prudence of the Ferndale Plant Acquisition**

**Q. What do you conclude regarding the prudence of PSE’s acquisition of the Ferndale Plant?**

A. Based on the documentation provided by the Company, I recommend that the Commission determine that PSE’s acquisition of the Ferndale Plant was prudent, and that the full cost of the plant be placed into rate base.

1. **RATE BASE ADJUSTMENTS**

**Q. What is the scope of this section of your testimony?**

A. In this section, I describe Staff’s proposed changes to the relevant Rate Base Adjustments proposed by the Company.

Q. Please describe Staff’s Adjustment 4, Snoqualmie Falls Hydroelectric Redevelopment Project.

A. Staff’s Adjustment 4, as shown in Exhibit No. JMW-2, represents the costs associated with Snoqualmie Project Power Plant 1, Power Plant 2, and Diversion Dam, as of April 25, 2013. Staff does not include any costs after that date. As discussed in Staff witness Mr. Mickelson’s testimony, Staff used the rate period of December 1, 2013 to November 30, 2014, to determine the Average of Monthly Averages (“AMA”) of plant balance, accumulated depreciation, deferred income tax liability, and operating expenses.

Q. Please describe Staff’s Adjustment 5, Snoqualmie Falls Hydroelectric Redevelopment Project deferral

A. Staff’s Adjustment 5, as shown in Exhibit No. JMW-3, represents the deferral of costs as of April 25, 2013, associated with Snoqualmie Project Power Plant 2 and the diversion dam. Staff agrees with the Company that in general, the project is eligible for deferral under RCW 80.80.060 and is a renewable resource as defined by RCW 19.285.030(1). However, Power Plant 1 is not eligible for deferral at this time because it was not in service by April 25, 2013, and RCW 80.80.060((6) states that the “deferral begins with the date on which the plant begins commercial operation.”

Q. Please describe Staff Adjustment 6 - Baker River Hydroelectric Project Relicensing Upgrades

A. Staff’s Adjustment 6, as shown in Exhibit No. JMW-4, represents the costs associated with the Baker Project FSC and LBP as of April 25, 2013. Staff does not include any costs after that date. As discussed in Mr. Mickelson’s testimony, Staff used the rate period to determine the “AMA” plant balances, accumulated depreciation, deferred income tax liability, and operating expenses.

Q. Please describe Staff Adjustment 7 - Baker River Hydroelectric Project Relicensing Upgrades Deferral.

A. Staff Adjustment 7 removes this project in its entirety. The Baker Project LBP did not begin operation until July 24, 2013. Because it was not in service by April 25, 2013, it is not eligible for deferral at this time.

Q. Please describe Staff Adjustment 8 - Ferndale Plant Purchase

A. Staff Adjustment 8, as shown in Exhibit No. JMW-5, represents the costs PSE incurred to the purchase the Ferndale Plant on November 15, 2012. As discussed in Mr. Mickelson’s testimony, the rate period was used to determine the “AMA” of plant balance, accumulated depreciation, deferred income tax liability, Asset Retirement Cost and Asset Retirement Obligation (ARC/ARO) liabilities, and operating expenses. Additionally, Staff updated the Discounted Present Value of the ARC/ARO from $1,564,370 to $1,562,307 per PSE’s Response to Commission Staff Data Request 39.

Q. Please describe Staff Adjustment 9 - Ferndale Deferral

A. Staff Adjustment 9, as shown in Exhibit No. JMW-6, represents the deferral on costs for the purchase of the Ferndale plant on November 15, 2012. Staff agrees with the Company that the project[[96]](#footnote-96) is eligible for deferral under RCW 80.80.060 and meets the Greenhouse Gas Emissions Performance Standard. Staff updated the Discounted Present Value of the ARC/ARO from $1,564,370 to $1,562,307 per PSE’s Response to Commission Staff Data Request 39. Staff removed property taxes because PSE now has a separate tracker for property taxes, per the Commission’s order in Docket UE-130137.

1. **OTHER ISSUES**

**A. Energy Independence Act Eligibility for Hydroelectric Efficiency Improvements**

**Q. In addition to requests for cost recovery and determinations of prudence, did PSE make any other requests in relation to the upgrades the Company performed at the Baker Project and Snoqualmie Project?**

A. Yes. The Company requested that the Commission recognize the incremental power produced by the Baker Project and Snoqualmie Project as a result of the upgrades as an eligible renewable resource under the Washington Energy Independence Act (EIA).[[97]](#footnote-97)

**Q. What factors does the Commission consider in determining whether an upgraded hydropower facility is an eligible renewable resource?**

A. To be considered an eligible renewable resource, a hydro facility must meet four criteria: (1) the efficiency improvements must have been completed after March 31, 1999; (2) the facility must be owned by a qualifying utility; (2) the facility must be located in the Pacific Northwest; and (4) the efficiency upgrades must not result in any new water impoundments or diversions.[[98]](#footnote-98)

**Q. Does the Commission need to address PSE’s request for the Baker and Snoqualmie Projects to be recognized as eligible renewable resources under the EIA in the current docket?**

A. No, because the Commission is expected to address the Company’s request in Docket UE-131072. In the Staff Memorandum presented at the July 26, 2013, Open Meeting, Staff recommended that the Commission issue an order accepting the Company’s amended annual renewable portfolio standard (RPS) compliance report, and recognize the Baker and Snoqualmie Projects as eligible renewable resources for EIA compliance.[[99]](#footnote-99) A Commission order accepting Staff’s recommendation is expected before the end of August.

**Q. Why should the Commission address the Company’s request in the annual RPS filing, rather than in this case?**

A. The Commission has established a practice of considering resource eligibility for EIA compliance in the annual RPS filings. All other EIA eligibility determinations the Commission has made were issued in the orders proceeding from the initial 2012 RPS filings.[[100]](#footnote-100) Because the EIA requires both the annual RPS report and Commission determination of resource eligibility, the two requirements are best considered in the same context.

**B.** **FERC Relicensing Process**

**Q. What is the issue regarding the FERC relicensing process?**

A. When a utility conducts its initial economic analysis to determine whether it is more cost-effective to pursue relicensing of a hydroelectric facility versus decommissioning it, the utility determines the cost of supplying replacement power equivalent to the amount of power produced by the hydroelectric facility. In theory, this can create a “ceiling” up to which the utility could spend on relicensing the facility and still have a cost-effective resource. Staff is concerned that this could reduce the incentive for a utility to minimize costs.

Most other intervening parties in FERC relicensing processes seek conditions and amendments that increase the cost of operating hydroelectric facilities. The more costly it is to implement the requirements of the FERC license, the greater the return the Company earns on those investments. With the exception of FERC, there is rarely a party advocating to minimize costs on behalf of the ratepayers, yet FERC primarily seeks to balance intervener interests.

**Q. What does Staff recommend?**

A. Staff recommends the Commission take a more proactive role in the FERC relicensing processes for utilities under its jurisdiction. Staff does not recommend a specific method of engagement, but options could include becoming an intervener, engaging with other regulatory bodies in the review of project designs, or other courses of action.

**C. Consideration of Future Alternative Resource Acquisition**

**Q. Are processes allowed other than using an RFP for acquiring resources to meet the Company’s forecast demand?**

A. Yes. The Commission’s rules explicitly recognize this. WAC 480-107-001(1) states: “[t]he rules in this chapter do not establish the sole procedures utilities must use to acquire new resources.” Further, “[u]tilities may construct electric resources, operate conservation programs, purchase power through negotiated contracts, or take other action to satisfy their public service obligations.”

These non-RFP allowed methods for acquiring resources were acknowledged on page 9 of Mr. Mullally’s Exhibit No. MM-3HC. This exhibit was prepared in the context of the Company’s evaluation of self-build, power purchase agreements, and transmission rights to the Mid-C outside of the RFP process.

**Q. Are there other recently developed proven methods, outside of the RFP process, to acquire new capacity resources?**

A. Yes. For example, Portland General Electric Company (PGE) has developed 89 MW capacity of peaking generation capacity and expects to have 104 MW of capacity by the end of 2013.[[101]](#footnote-101) PGE accomplished this through a relatively new program described in their Dispatchable Standby Generation, DSG, tariff schedule 200.[[102]](#footnote-102) PGE actively recruits small standby generators, typically 500 kW and larger, to provide a system of distributed peaking capacity for up to 400 hours per year.[[103]](#footnote-103)

This peak power displaces or delays the need for PGE to acquire an equivalent amount of peaking resources. Kelly Cox, PGE’s Manager of Customer Specialized Programs indicates that the benefits to the Company are at least threefold:

***Cost-effectiveness***: They have found this peaking resource to be more cost-effective than purchasing capacity of a simple-cycle combustion turbine resource.

***Reduced non-spinning reserves***: The DSG resources provide all of the non-spinning reserves for the PGE system which provides a significant savings to the Company.

***Grid reliability increases***: The DSG also increases reliability. When a feeder heats up due to heavy loading, a DSG resource can temporarily reduce the overloading on that circuit.[[104]](#footnote-104)

**Q. Has PSE pursued similar Dispatchable Standby Generation capacity?**

A. No. The company currently relies only on the RFP, unsolicited proposals, and tariff schedule 91 for qualifying resources under 5 MW.[[105]](#footnote-105) The company has not pursued DSG.

**Q. Should PSE consider implementation of a program similar to the PGE Dispatchable Standby Generation system and other distributed energy programs?**

A. Yes. Based on the experience of PGE, PSE should immediately evaluate the benefits and costs of developing a similar Dispatchable Standby Generation system in its service territory. The company should also conduct deeper evaluation of other promising distributed demand response opportunities such as fixed battery storage technology, time-of-use pricing and direct load control programs.

**Q. What do you recommend regarding DSG programs for PSE?**

A. I recommend the Commission order PSE to evaluate the PGE DSG program and provide a report to the Commission of their conclusions and recommendations by December 1, 2014, regarding the financial and technical feasibility of implementing a similar DSG program in PSE’s territory.

**Q. Does this conclude your testimony?**

A. Yes.

1. Aliza Seelig’s testimony is now sponsored by PSE witness Cara Peterman. [↑](#footnote-ref-1)
2. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶26 (April 2, 2010). [↑](#footnote-ref-2)
3. *Id.* [↑](#footnote-ref-3)
4. *Utilities and Transp. Comm’n v. Avista Corp.,* Dockets UE-090134, UG-090135 and UG-060518, Order 10 at ¶46 (December 22, 2009). [↑](#footnote-ref-4)
5. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶26 (April 2, 2010). [↑](#footnote-ref-5)
6. RCW 80.04.250. This section also permits the Commission to include construction work in progress (CWIP) in rate base, which is not in service. PSE has not requested any CWIP to be included in rate base in this case. [↑](#footnote-ref-6)
7. *Utilities and Transp. Comm’n v. PacifiCorp, d/b/a Pacific Power & Light Co.,* Docket UE-050684, Order 04 at ¶ 50 (April 17, 2006). [↑](#footnote-ref-7)
8. *Id.* at ¶ 68. [↑](#footnote-ref-8)
9. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Order 08 at ¶49-52 (January 5, 2007). [↑](#footnote-ref-9)
10. *Utilities and Transp. Comm’n v. Avista Corp.,* Dockets UE-090134, UG-090135 and UG-060518, Order 10 at ¶80-81 (December 22, 2009). [↑](#footnote-ref-10)
11. *Id.,* at ¶71. [↑](#footnote-ref-11)
12. *Id., at* ¶80-81 (emphasis added). [↑](#footnote-ref-12)
13. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶33 (April 2, 2010). [↑](#footnote-ref-13)
14. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 at ¶306-307 (May 7, 2012) [↑](#footnote-ref-14)
15. *Id., at* ¶306. [↑](#footnote-ref-15)
16. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶31 (April 2, 2010). [↑](#footnote-ref-16)
17. Douglas Loreen, Email communication, July 30, 2013. [↑](#footnote-ref-17)
18. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶20 (April 7, 2004). [↑](#footnote-ref-18)
19. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶33 (April 2, 2010). [↑](#footnote-ref-19)
20. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶26 (April 2, 2010). [↑](#footnote-ref-20)
21. For PSE, these include LSR-1 (Docket UE-111048) and Hopkins Ridge (Docket UE-050870). [↑](#footnote-ref-21)
22. Difference between Barnard, Exhibit No. KJB-WP 04.06-9.07 Baker Adj & Deferral SUPP, “Hydro Summary” Tab, cell E:17 and PSE Response to Commission Staff Data Request 43, Attachment B, “Hydro Summary Update” Tab, cell E:17. [↑](#footnote-ref-22)
23. PSE Response to Commission Staff Data Request 43, Attachment B, “Hydro Summary Update” Tab, cell E:13. [↑](#footnote-ref-23)
24. Barnard, Exhibit No. KJB-WP 04.06-9.07 Baker Adj & Deferral SUPP, “Hydro Summary” Tab, cell E:13. [↑](#footnote-ref-24)
25. PSE Response to Commission Staff Data Request 46, Attachment A, “Summary Table” Tab, cell H:6. [↑](#footnote-ref-25)
26. PSE Response to Commission Staff Data Request 46, Attachment A, “Snoq Budgets” Tab, cell H:7. [↑](#footnote-ref-26)
27. PSE Response to Commission Staff Data Request 46, Attachment A, “Summary Table” Tab, cell H:9. [↑](#footnote-ref-27)
28. PSE Response to Commission Staff Data Request 46, Attachment A, “Snoq Budgets” Tab, cell H:13. [↑](#footnote-ref-28)
29. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.,* Docket UE-031725, Order 12 at ¶19 (April 7, 2004) (footnotes and related citations omitted). [↑](#footnote-ref-29)
30. *Utilities and Transp. Comm’n v. Puget Sound Power & Light Co.,* Docket UE-921262*, et al.,* Nineteenth Supplemental Order at 11 (September 27, 1994). [↑](#footnote-ref-30)
31. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶20 (April 7, 2004). [↑](#footnote-ref-31)
32. *Id.*  [↑](#footnote-ref-32)
33. *Id.* at ¶20. [↑](#footnote-ref-33)
34. RCW 80.80.040(1) [↑](#footnote-ref-34)
35. Exhibit No. PKW-1CT, at page 12, lines 2-10. [↑](#footnote-ref-35)
36. FERC Project No. 2493-084, Order Amending License, ¶5-10 (June 1, 2009). [↑](#footnote-ref-36)
37. FERC Project No. 2493-006, Order Issuing New License, Article 417 (June 29, 2004). [↑](#footnote-ref-37)
38. Exhibit PKW-1CT, at page 17, lines 9-10. [↑](#footnote-ref-38)
39. PSE Response to Commission Staff Data Request 46, Attachment A, “Snoq Budgets” Tab, at cell E:6. [↑](#footnote-ref-39)
40. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.,* Docket UE-050870, Order 04at ¶30 (October 20, 2005). [↑](#footnote-ref-40)
41. PSE Response to Commission Staff Data Request 23, Attachment A. [↑](#footnote-ref-41)
42. PSE Response to Commission Staff Data Request 23, Attachment B. [↑](#footnote-ref-42)
43. PSE Response to Commission Staff Data Request 26, Attachment C. [↑](#footnote-ref-43)
44. Including AFUDC. [↑](#footnote-ref-44)
45. Excluding AFUDC. *See* Wetherbee, Exhibit No. PKW-1CT, at page 17, lines 3-5. [↑](#footnote-ref-45)
46. PSE Response to Commission Data Request 46, Attachment A, at “Snoq Budgets” Tab, cell F:14. [↑](#footnote-ref-46)
47. PSE 1st Supplemental Response to Commission Staff Data Request 56, Attachment A, [↑](#footnote-ref-47)
48. PSE Response to Commission Staff Data Request 24, Attachment B. [↑](#footnote-ref-48)
49. PSE Response to Commission Staff Data Request 25, Attachment D. [↑](#footnote-ref-49)
50. Wetherbee, Exhibit No. PKW-1CT, at page 3, lines 18-19. [↑](#footnote-ref-50)
51. PSE response to Commission Staff Data Request 022, Attachment B. [↑](#footnote-ref-51)
52. FERC Project Nos. P-2150-033, 027, Order on Offer of Settlement, Issuing New License, and Dismissing Amendment Application as Moot, (October 17, 2008). [↑](#footnote-ref-52)
53. Wetherbee, Exhibit PKW-1CT, at page, 6 lines 16-22. [↑](#footnote-ref-53)
54. Exhibit No. PKW-1CT, at page 6, lines 4-6. [↑](#footnote-ref-54)
55. PSE Supplemental Response to Commission Staff Data Request 035. [↑](#footnote-ref-55)
56. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Order 09 (January 5, 2007) ¶165. [↑](#footnote-ref-56)
57. PSE response to Commission Staff data request 023, Attachment C. [↑](#footnote-ref-57)
58. PSE response to Commission Staff data request 023, Attachment D. [↑](#footnote-ref-58)
59. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Exhibit Nos. KO-1HCT, KO-5HC and KO-6HC (February 15, 2006). [↑](#footnote-ref-59)
60. *Utilities and Transp. Comm’n v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Order 09 (January 5, 2007) ¶165. [↑](#footnote-ref-60)
61. PSE response to Commission Staff Data Request 23, Confidential Attachment E. [↑](#footnote-ref-61)
62. PSE response to Staff data request 026, Attachment A. [↑](#footnote-ref-62)
63. PSE response to Staff data request 026, Attachment E. [↑](#footnote-ref-63)
64. Exhibit No. DSL-1T, page 13 at lines 18-19. [↑](#footnote-ref-64)
65. Exhibit No. DSL-1T, page 13 at lines 5-6. [↑](#footnote-ref-65)
66. Exhibit No. DSL-1T, page 13 at lines 9-15. [↑](#footnote-ref-66)
67. Exhibit No. DSL-1T, page 15 at line 14. [↑](#footnote-ref-67)
68. PSE Response to Commission Staff Data Request 55Attachment 1, Detail tab, cell CC:338. [↑](#footnote-ref-68)
69. Exhibit No. DSL-1T, page 16 at lines 1-5. [↑](#footnote-ref-69)
70. PSE Response to Commission Staff Data Request 55Attachment 1, Comparison List tab, cell E:78. [↑](#footnote-ref-70)
71. Staff observed this mitigation measure during a site visit on July 17, 2013. [↑](#footnote-ref-71)
72. PSE Supplemental Response to Commission Staff Data Request 24. [↑](#footnote-ref-72)
73. PSE Response to Commission Staff Data Request 25, Attachment D. [↑](#footnote-ref-73)
74. Mullally, Exhibit No. MM-1HCT at page 43, line 3. [↑](#footnote-ref-74)
75. Mullally, Exhibit No. MM-1HCT at page 38, lines 4-5. [↑](#footnote-ref-75)
76. Odom, Exhibit No. LEO-1CT, at page 16, line 5. [↑](#footnote-ref-76)
77. The 2011 IRP filed on May 30, 2011 was included in this Docket as Garratt, Exhibit No. RG-3. [↑](#footnote-ref-77)
78. Mullally, Exhibit No. MM-3HC at 4. This is shown graphically on Mullally, Exhibit MM-3HC, page 91. [↑](#footnote-ref-78)
79. Mullally Exhibit No. MM-3HC at 6. [↑](#footnote-ref-79)
80. The same RFP process was used in Docket UE-090704, involving the acquisition of Mint Farm, and Docket UE-111048, involving the LSR-1. [↑](#footnote-ref-80)
81. Mullally Exhibit No. MM-3HCT, at page 20. [↑](#footnote-ref-81)
82. Mullally Exhibit No. MM-3HCT, at pages 48-58. [↑](#footnote-ref-82)
83. Seelig, Exhibit No. AS-1HCT, at pages 16-21. [↑](#footnote-ref-83)
84. Mullally, Exhibit No. MM-3HCT at pages 22-23; Seelig Exhibit No. AS-1HCT at pages 10-13. For a further description of the optimization model, also called the Portfolio Screening Model III or PSM 3, see Garratt, Exhibit No. RG-3 at pages 351-355. [↑](#footnote-ref-84)
85. Some proposals contained multiple offers. [↑](#footnote-ref-85)
86. Mullally Exhibit Nos. MM-1HCT at 23:16 to 24:5 and MM-3HCT at 39-41. [↑](#footnote-ref-86)
87. Mullally, Exhibit No. MM-1HCT at 25:3-8. [↑](#footnote-ref-87)
88. Mullally Exhibit No. MM-1HCT, at page 31- 32, and Garratt Exhibit RG-5HC, at page 158 and RG-6HC. [↑](#footnote-ref-88)
89. Mullally Exhibit No. MM-4HC, at page 3. [↑](#footnote-ref-89)
90. Garratt Exhibit No. \_\_ (RG-6HC). [↑](#footnote-ref-90)
91. Garratt, Exhibit No. \_\_ (RG-6HC), pages 6-8. [↑](#footnote-ref-91)
92. RCW 80.80.060(1) [↑](#footnote-ref-92)
93. RCW 80.80.040(1)(a). According to the statute, this is the applicable standard until the Washington Department of Commerce (formerly the Department of Community, Trade and Economic Development) develops a different standard. RCW 80.80.040(1)(b) and 80.80.050. [↑](#footnote-ref-93)
94. RCW. 80.80.040(4). [↑](#footnote-ref-94)
95. *Application of Puget Sound Energy, Inc.,* Docket UE-121594, Order 02 (11/2/2012) at 1. [↑](#footnote-ref-95)
96. PSE is not seeking to defer costs associated with the Recreational and Cultural Improvements in this case. [↑](#footnote-ref-96)
97. Mills, Exhibit DEM-1CT, at page 5, lines 21-23. [↑](#footnote-ref-97)
98. RCW 19.285.030(11)(b). See also the testimony of Wetherbee, Exhibit PKW-1CT, at page 19 lines 13-20. [↑](#footnote-ref-98)
99. See Docket UE-131072, Staff memorandum (July 26, 2013). [↑](#footnote-ref-99)
100. In Puget Sound Energy’s case, see Docket UE-120802, Order 01, ¶ 43. [↑](#footnote-ref-100)
101. Williams, Exhibit No. JMW-8. [↑](#footnote-ref-101)
102. Williams, Exhibit No. JMW-7. [↑](#footnote-ref-102)
103. Four hundred hours per year is set in current PGE tariff and contracts, but likely will be reduced to 50 hours per year due to recently adopted rules by United States Environmental Protection Agency. Williams, Exhibit No. JMW-8. [↑](#footnote-ref-103)
104. *Id*. [↑](#footnote-ref-104)
105. PSE response to Commission Staff Data Request 34. [↑](#footnote-ref-105)