

**BEFORE THE WASHINGTON  
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY,

Respondent.

---

In the Matter of the Petition of

PACIFIC POWER & LIGHT  
COMPANY,

For an Order Approving Deferral of  
Costs Related to Colstrip Outage.

---

In the Matter of the Petition of

PACIFIC POWER & LIGHT  
COMPANY,

For an Order Approving Deferral of  
Costs Related to Declining Hydro Generation.

---

DOCKETS UE-140762 and  
UE-140617 (*consolidated*)

DOCKET UE-131384  
(*consolidated*)

DOCKET UE-140094  
(*consolidated*)

**PACIFIC POWER'S OPENING BRIEF**

**January 22, 2015**

## TABLE OF CONTENTS

I.	INTRODUCTION .....	1
II.	LEGAL STANDARDS .....	3
III.	COST OF CAPITAL .....	4
A.	Pacific Power’s Proposed ROE is Reasonable .....	6
1.	Mr. Strunk’s recommended 10.0 percent ROE is based on objective estimates derived from well-established models. ....	6
2.	The cost of equity has not declined since the Company’s last rate case. ....	8
3.	The current interest rate environment supports a higher ROE. ....	10
4.	The Company’s risk profile does not support a lower ROE.....	11
5.	Mr. Parcell’s objective models and analysis support a higher cost of equity. ....	12
6.	Mr. Hill’s recommendations lack credibility.....	14
7.	Mr. Gorman’s inconsistent recommendations in other jurisdictions undermine his credibility. ....	15
8.	The Commission should increase Pacific Power’s ROE if a hypothetical capital structure is adopted. ....	15
B.	The Company’s Actual Capital Structure is Reasonable.....	16
1.	The Company’s actual equity ratio properly balances safety and economy. ....	16
2.	Mr. Gorman’s shifting justification for a hypothetical equity ratio should be rejected. ....	18
3.	If the Commission adopts a hypothetical capital structure, it should also adopt hypothetical debt costs.....	20
C.	The Credit Metrics under Staff’s, Public Counsel’s, and Boise’s Cost of Capital Proposals Demonstrate the Unreasonableness of Their Recommendations.....	20
IV.	NET POWER COSTS .....	21
A.	The Company’s Updated Coal Costs are Reasonable and Unrebutted.....	22
B.	Pacific Power Should Recover its Out-of-State QF PPAs under the WCA .....	23
1.	Out-of-state QF PPAs serve and benefit Washington customers. ....	23
2.	Out-of-state QF PPA prices conform to PURPA’s avoided cost requirement and full cost recovery is consistent with PURPA.....	25
3.	Situs assignment results in interstate subsidization and violates PURPA’s customer indifference requirement. ....	27

4.	Market re-pricing of QF PPAs violates PURPA. ....	27
5.	Situs assignment of the Company’s out-of-state QFs is inconsistent with the current approach for Avista and past approach for Pacific Power. ....	29
6.	Discrimination against out-of-state QF PPAs violates the Commerce Clause. ....	30
7.	The Company’s proposed alternatives are reasonable approaches to allocation of out-of-state QF PPA costs. ....	32
a.	The Washington re-pricing alternative responds to concerns about different state QF policies in Oregon and California.....	32
b.	The load decrement alternative addresses inequities inherent to situs assignment of QF PPA costs. ....	33
C.	The Commission Should Reject Boise’s Speculative Imputation of EIM Benefits .....	33
1.	The E3 Report was never intended to be used for ratemaking and the assumptions underlying the report do not match the NPC pro forma period in this case.....	34
2.	Boise’s inter-regional dispatch benefit double counts transactions already modeled in GRID and relies on inapplicable transmission assumptions....	35
3.	Boise’s intra-regional dispatch benefit has no relation to the potential intra-regional dispatch benefits that may occur through the EIM. ....	36
4.	Boise’s flexibility reserves adjustment is based on erroneous calculations and flawed assumptions. ....	37
5.	The E3 Report undermines Boise’s “within-hour dispatch” adjustment....	37
6.	Boise’s allocation of EIM costs and benefits to Washington is flawed. ...	38
D.	Pacific Power’s Proposed RRTM is Reasonable and Furthers State Energy Policy .....	39
E.	The Commission Should Reject Staff’s Proposed PCAM .....	41
F.	Boise’s Thermal Plant Outage Adjustments are Meritless.....	42
1.	The Chehalis outage was not anomalous and not the result of imprudence. ....	42
2.	The Colstrip outage was not the result of imprudence and the replacement power costs are known and measurable.....	44
G.	The Commission Should Approve the Replacement Power Costs Associated with Less-than-Normal Hydro Generation .....	45

H.	Boise’s Inter-Hour Integration Adjustment is Baseless.....	45
I.	The Company Agrees with Boise’s BPA NITS Adjustment, But Not its Calculation.....	46
V.	PRO FORMA CAPITAL ADDITIONS.....	46
VI.	WAGES AND LABOR.....	48
A.	Public Counsel’s Adjustment to the Company’s Post-Test Year Wage Increase Should Be Rejected.....	48
B.	Public Counsel’s Proposed Adjustment to Current FTE Count is Unsupported ...	49
C.	Public Counsel’s Proposed Adjustment to Pension and OPEB Expenses Violates the Matching Principle and Should be Rejected.....	50
VII.	IHS GLOBAL INSIGHTS .....	50
VIII.	INSURANCE EXPENSE.....	52
IX.	DEFERRALS .....	53
X.	END OF PERIOD RATE BASE.....	54
XI.	RESIDENTIAL RATE DESIGN .....	55
A.	The Company’s Recommended Basic Charge is Reasonable .....	55
B.	The Commission Should Affirm the Company’s Two-Tier Rate Design .....	58
XII.	CONCLUSION.....	60

**TABLE OF AUTHORITIES**

	<b>Page(s)</b>
<b>CASES</b>	
<i>Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.</i> , 461 U.S. 402 (1983).....	28
<i>Bluefield Water Works &amp; Improvement Co. v. Pub. Serv. Comm’n of W. Va.</i> , 262 U.S. 679 (1923).....	3
<i>City of Phila. v. N.J.</i> , 437 U.S. 617 (1978).....	30, 32
<i>Fed. Power Comm’n v. Hope Natural Gas Co.</i> , 320 U.S. 591 (1944).....	3, 7
<i>Freehold Cogen. Assoc., L.P. v. Bd. of Reg. Comm’rs of New Jersey</i> , 44 F.3d 1178 (3d Cir. 1995).....	33
<i>Indep. Energy Producers Ass’n v. Cal. Pub. Utils. Comm’n</i> , 36 F.3d 848 (9th Cir. 1994) .....	25
<i>Jones v. Califano</i> , 576 F.2d 12 (2d Cir. 1978-).....	6
<i>Middle S. Energy, Inc. v. Ark. Pub. Serv. Comm’n</i> , 772 F.2d 404 (8th Cir. 1985) .....	31
<i>New England Power Co. v. N.H.</i> , 455 U.S. 331 (1982).....	31, 32
<i>N.Y. v. FERC</i> , 535 U.S. 1 (2002).....	24, 27
<i>Or. Waste Sys., Inc. v. Dep’t of Env’tl. Quality of State of Or.</i> , 511 U.S. 93 (1994).....	30
<i>People’s Org. for Wash. Energy Res. v. WUTC</i> , 104 Wn.2d 798 (1985) .....	3
<i>Pub. Utils. Comm’n of R.I. v. Attleboro Steam &amp; Elec. Co.</i> , 273 U.S. 83 (1927).....	31
<i>Quill Corp. v. N.D.</i> , 504 U.S. 298 (1992).....	30
<i>State ex rel. Utils. Comm’n v. N.C. Power</i> , 338 N.C. 412, 450 S.E.2d 896 (1994).....	26

<i>United Haulers Ass’n, Inc. v. Oneida-Herkimer Solid Waste Mgmt. Auth.</i> , 550 U.S. 330 (2007).....	30
--	----

<i>Vergeyle v. Employment Sec. Dep’t</i> , 28 Wn. App. 399 (1981).....	6
---	---

**STATUTES**

U.S. Const. art. I, § 8, cl. 3 .....	30
--------------------------------------	----

16 U.S.C. §§ 824a-3(b), (d).....	25, 26, 28
----------------------------------	------------

16 U.S.C. § 824a-3(m)(7).....	25
-------------------------------	----

RCW 19.285.050(2).....	40
------------------------	----

RCW 80.28.010.....	3
--------------------	---

RCW 80.28.020.....	3
--------------------	---

**RULES**

18 C.F.R. § 292.101(b)(6) .....	25
---------------------------------	----

18 C.F.R. §§ 292.304(b)(2) .....	26
----------------------------------	----

18 C.F.R. §§ 292.304(b), (d) .....	28
------------------------------------	----

WAC 480-107-075(3).....	33
-------------------------	----

**FEDERAL ENERGY REGULATORY COMMISSION ORDERS**

<i>Am. Ref-Fuel Co., et al.</i> , 105 F.E.R.C. ¶ 61,004 (Oct. 1, 2003).....	25
--	----

<i>Assoc. of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Operator, Inc., et al.</i> , 148 F.E.R.C. ¶ 61,049 (Oct. 16, 2014).....	17, 19
---	--------

<i>Coakley, et al. v. Bangor Hydro-Elec. Co.</i> , 147 F.E.R.C. ¶ 61,234 (June 19, 2014) .....	11
---	----

<i>N.Y. State Elec. &amp; Gas Corp.</i> , 71 F.E.R.C. ¶ 61,027 (Apr. 12, 1995).....	28
--	----

<i>Re So. Cal. Edison Co.</i> , 70 F.E.R.C. ¶ 61,215 (Feb. 23, 1995).....	26
--	----

<i>So. Cal. Edison Co., et al.</i> , 71 F.E.R.C. ¶ 61,269 (June 2, 1995) .....	25
---	----

**WASHINGTON UTILITIES & TRANSPORTATION COMMISSION ORDERS**

<i>Re Amending and Repealing Rules in WAC 480-108 Relating to Electric Companies- Interconnection With Electric Generators</i> , Docket UE-112133, General Order R-571 (July 18, 2013).....	55, 56
<i>Re Puget Sound Energy</i> , Docket UE-070725, Order 05 (Aug. 31, 2010) .....	54
<i>WUTC v. Avista</i> , Dockets UE-991606, <i>et al.</i> , Third Supp. Order (Sept. 29, 2000) .....	3, 4, 55
<i>WUTC v. Pacific Power</i> , Dockets UE-140762, <i>et al.</i> , Order 07 (Dec. 5, 2014) .....	22, 23
<i>WUTC v. PacifiCorp</i> , Dockets UE-050684, <i>et al.</i> , Order 04 (Apr. 17, 2006) .....	<i>passim</i>
<i>WUTC v. PacifiCorp</i> , Dockets UE-061546, <i>et al.</i> , Order 08 (June 21, 2007) .....	28, 41, 42
<i>WUTC v. PacifiCorp</i> , Docket UE-100749, Order 06 (Mar. 25, 2011) .....	<i>passim</i>
<i>WUTC v. PacifiCorp</i> , Docket UE-100749, Order 07 (May 12, 2011).....	6
<i>WUTC v. PacifiCorp</i> , Docket UE-130043, Order 05 (Dec. 4, 2013).....	<i>passim</i>
<i>WUTC v. Puget Sound Energy</i> , Dockets UE-060266, <i>et al.</i> , Order 08 (Jan. 5, 2007) .....	22, 56
<i>WUTC v. Puget Sound Energy</i> , Dockets UE-090704, <i>et al.</i> , Order 11 (Apr. 2, 2010) .....	3, 14
<i>WUTC v. Puget Sound Energy</i> , Dockets UE-111048, <i>et al.</i> , Order 08 (May 7, 2012) .....	5, 6, 22, 54
<i>WUTC v. Puget Sound Energy</i> , Dockets UE-121697, <i>et al.</i> , Order 07 (June 25, 2013) .....	9
<i>WUTC v. Puget Sound Energy</i> , Dockets UG-040640, <i>et al.</i> , Order 06 (Feb. 18, 2005) .....	16, 17, 19

<i>WUTC v. Puget Sound Power and Light</i> , Cause No. U-87-1262-T, 87 P.U.R.4th 53 (Sept. 30, 1987).....	44
<i>WUTC v. Verizon Nw. Inc.</i> , Docket UT-040788, Order 11 (Oct. 15, 2004) .....	6, 29
<i>WUTC v. Wash. Nat. Gas Co.</i> , Cause No. U-80-111, 44 P.U.R.4th 435 (Sept. 24, 1981) .....	54
<i>WUTC v. Wash. Water Power Co.</i> , Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615 (Nov. 9, 1983) .....	25, 26
<b>OTHER REGULATORY ORDERS</b>	
<i>Re N.C. Power</i> , Docket E-22, SUB 333, 1993 WL 216264 (Feb. 26, 1993) <i>aff'd sub nom.</i> <i>N.C. Power</i> , 450 S.E.2d 896.....	26
<b>OTHER AUTHORITIES</b>	
IHS Economics and Country Risk Accolades, <a href="http://www.ihs.com/products/global-insight/accuracy-accolades.aspx">http://www.ihs.com/products/global-insight/accuracy-accolades.aspx</a> .....	51
James C. Bonbright, Albert L. Danielsen, & David R. Kamerschen, <i>Principles of Public Utility Rates</i> , 111-12 (2d ed. Public Utilities Reports 1988).....	3
<i>PacifiCorp's 2013 Electric Integrated Resource Plan</i> , Docket UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013).....	1
Roger A. Morin, <i>New Regulatory Finance</i> , 24 (1st ed. Public Utilities Reports 2006).....	4
Washington Economic and Revenue Forecast Council November 2014 Meeting Report, <a href="http://www.erfc.wa.gov/forecast/documents/rev20140219_color.pdf">http://www.erfc.wa.gov/forecast/documents/rev20140219_color.pdf</a> .....	51



## I. INTRODUCTION

1 Pacific Power & Light Company (Pacific Power or the Company), a division of PacifiCorp, submits this brief in support of its request for a revenue requirement increase of \$30.4 million, or 9.9 percent overall.<sup>1</sup> The Company is currently facing significant changes resulting from state and federal mandates related to the environment, renewable resources, distributed generation, conservation, and energy efficiency. These mandates limit the Company's power supply choices, increase costs, and reduce loads. The Washington Utilities and Transportation Commission (Commission) recently recognized this period of "major changes in the utility industry," and acknowledged the corresponding challenges for regulated utilities like Pacific Power:

State policies for renewable portfolio standards, greenhouse gas reduction and mandatory conservation programs have created additional logistical challenges for utilities, and forthcoming federal environmental regulations may restrain the use of coal.<sup>2</sup>

2 Washington State has been a leader in responding to environmental concerns by steadily moving toward requiring more renewable resources and less carbon-intensive energy supplies. Similar energy policies are being promoted by federal agencies, notably the Environmental Protection Agency (EPA) in its recent proposed rules under Sections 111(b) and 111(d) of the Clean Air Act. To adapt to this rapidly evolving landscape, Pacific Power needs supportive regulatory treatment from this Commission.

3 In this case, the Company presented several proposals to better position it to constructively respond to changing state and national energy policies:

---

<sup>1</sup> The Company's rebuttal filing requested a revenue requirement increase of \$31.9 million. Dalley, Exh. No. RBD-3T 1:16. After rebuttal testimony was filed, the Company accepted Staff's proposal to include only those pro forma major capital additions placed in service as of the Company's rebuttal filing. This reduced the Company's revenue requirement by approximately \$1.5 million from the rebuttal filing. *See* Final Issues List at 17 (Dec. 11, 2014); Dalley, RBD-10CX (Pacific Power's 1<sup>st</sup> Supplemental Response to Public Counsel Data Request 130).

<sup>2</sup> Ball, Exh. No. JLB-8CX 3 (*PacifiCorp's 2013 Electric Integrated Resource Plan*, Docket UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013)).

- Pacific Power seeks a return on equity (ROE) of 10.0 percent, an increase from its currently authorized ROE of 9.5 percent. The Company's recommendation is based on objective modeling, appropriately recognizes current capital market conditions, and properly accounts for the Company's risk profile.
- Pacific Power proposes to set rates using PacifiCorp's actual capital structure, including its actual equity ratio. The evidence demonstrates that this appropriately balances economy and safety and is reasonable and comparable to other electric utilities. The use of the actual capital structure also results in an economical overall rate of return (ROR) due, in part, to the fact that the Company's actual equity ratio has resulted in the lowest cost of long-term debt of any investor-owned utility (IOU) in Washington.
- Pacific Power proposes including an allocated share of power purchase agreements (PPAs) with qualifying facilities (QFs) in California and Oregon in Washington net power costs (NPC). The Company's proposal is consistent with the Public Utility Regulatory Policies Act (PURPA) and the U.S. Constitution and appropriately recognizes the benefits provided to Washington customers by out-of-state QFs.
- Pacific Power proposes a Renewable Resource Tracking Mechanism (RRTM) to recover the variable costs associated with the increased renewable development required by Washington's Energy Independence Act (EIA). This proposal is consistent with the EIA's cost-recovery provisions.
- Pacific Power proposes reflecting in rates pro forma capital additions in service by the date of the Company's rebuttal testimony filing, end-of-period (EOP) rate base balances, and escalation of non-labor operations and maintenance (O&M) and administrative and general (A&G) expenses to better reflect costs anticipated in the rate effective period.
- Pacific Power proposes an increase in its monthly basic customer charge to \$14.00 to better reflect the fixed costs of providing utility service and to address state energy policies, including those encouraging greater distributed generation (DG) and increased conservation and energy efficiency. The Company also proposes the continued use of its two-tier residential rate design to decrease revenue volatility, send appropriate price signals to customers, and mitigate impacts on low-income customers.

4

In response to the Company's proposed revenue requirement increase, parties recommend the following: Staff—overall increase of \$6.1 million; Public Counsel—overall increase of \$1.2 million;<sup>3</sup> and Boise White Paper LLC (Boise)—overall decrease of \$2.7 million. If adopted, the parties' positions do not provide sufficient revenues to provide the Company a reasonable opportunity to recover the costs to serve its Washington customers, including a

---

<sup>3</sup> Ramas, Exh. No. DMR-1CTr 5:11-21 (Public Counsel recommends a revenue requirement increase of \$11.2 million, but also provides the revenue requirement resulting from the removal of out-of-state QF PPA costs, which is a revenue requirement increase of \$1.2 million).

reasonable return on investment. Pacific Power respectfully requests that the Commission approve its proposed rate increase of \$30.4 million.

## II. LEGAL STANDARDS

5 In a general rate case, the Commission determines whether the rates proposed by the utility are fair, just, reasonable, and sufficient.<sup>4</sup> To meet this standard, rates must include compensation necessary to provide safe and reliable electric service<sup>5</sup> and “a rate of return sufficient to maintain [the utility’s] financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk”<sup>6</sup> and support the utility’s creditworthiness.<sup>7</sup> Because rates must allow a utility to recover its costs, which includes both operating expenses and capital costs.<sup>8</sup> As Staff’s witnesses correctly recognized, a utility’s return on its capital investment is a component of the cost to serve customers.<sup>9</sup>

6 The Commission’s duty in a general rate case 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.”<sup>10</sup> It is just “as important in the eyes of the law” that rates provide “reasonable compensation” for a utility as it is that rates are just and reasonable for customers.<sup>11</sup>

---

<sup>4</sup> RCW 80.28.020.

<sup>5</sup> RCW 80.28.010.

<sup>6</sup> *WUTC v. Avista Corp.*, Dockets UE-991606, *et al.*, Third Supp. Order ¶ 324 (Sept. 29, 2000); *WUTC v. PacifiCorp*, Dockets UE-050684, *et al.*, Order 04 ¶ 235 (Apr. 17, 2006).

<sup>7</sup> See *Fed. Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n of W. Va.*, 262 U.S. 679, 692-693 (1923). *People’s Org. for Wash. Energy Res. v. WUTC*, 104 Wn.2d 798, 811 (1985) (en banc) (rates must “compensate [] investors for the risks assumed”) (quoting *Hope*, 320 U.S. at 605).

<sup>8</sup> James C. Bonbright, Albert L. Danielsen, & David R. Kamerschen, *Principles of Public Utility Rates*, 111-12 (2d ed. Public Utilities Reports 1988) (emphasis added).

<sup>9</sup> Twitchell, TR. 657:6-18 (Staff includes a utility’s authorized rate of return as part of the cost to serve); Ball, TR. 539:9-12 (agrees ROE is part of revenue requirement).

<sup>10</sup> *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704, *et al.*, Order 11 ¶ 18 (Apr. 2, 2010).

<sup>11</sup> *People’s Org. for Wash. Energy Res.*, 104 Wn.2d at 808, 810-11.

### III. COST OF CAPITAL

7 The Company recommends an ROR of 7.67 percent, based on the following cost of capital components, which appropriately balance safety and economy:<sup>12</sup>

<b>Component</b>	<b>Percent of Total</b>	<b>Percent Cost</b>	<b>Weighted Average</b>
Short-Term Debt	0.19%	1.73%	0.00%
Long-Term Debt	48.06%	5.19%	2.50%
Preferred Stock	0.02%	6.75%	0.00%
Common Stock Equity	51.73%	10.00%	5.27%
	100.00%		7.67%

8 If the Commission adopts a hypothetical capital structure with more debt and less equity, then the Company's debt and equity costs would increase because of the additional leverage. This is reflected in the Company's alternative recommendation, with a higher overall ROR:

<b>Component</b>	<b>Percent of Total</b>	<b>Percent Cost</b>	<b>Weighted Average</b>
Short-Term Debt	0.19%	2.11%	0.00%
Long-Term Debt	50.69%	5.80%	2.94%
Preferred Stock	0.02%	6.75%	0.00%
Common Stock Equity	49.10%	10.28%	5.05%
	100.00%		7.99%

9 The Company's recommended ROR of 7.67 percent will allow it to maintain its financial integrity, attract capital on reasonable terms, and receive a return comparable to other enterprises of corresponding risk.<sup>13</sup> Nationally, the average approved ROR for the first three quarters of 2014 is 7.75 percent.<sup>14</sup> Recently authorized RORs for PacifiCorp in Utah and Wyoming of 7.57 percent and 7.41 percent, respectively, support an increase in Pacific Power's Washington ROR, currently set at 7.36 percent.<sup>15</sup>

10 Staff, Boise, and Public Counsel contest the Company's proposed ROE and recommend a hypothetical capital structure with 49.1 percent equity. Staff's ROE/ROR recommendation is

<sup>12</sup> Roger A. Morin, *New Regulatory Finance*, 24 (1st ed. Public Utilities Reports 2006) (to produce optimal investment rates at the minimum price to customers, the Commission should set the Company's authorized return equal to its actual cost of capital).

<sup>13</sup> *WUTC v. Avista Corp.*, Dockets UE-991606, *et al.*, Third Supp. Order ¶ 324 (Sept. 29, 2000); *WUTC v. PacifiCorp*, Dockets UE-050684, *et al.*, Order 04 ¶ 235 (Apr. 17, 2006).

<sup>14</sup> Williams, Exh. No. BNW-16T 13; Parcell, Exh. No. DCP-29CX 5.

<sup>15</sup> Williams, TR. 174:15-22.

9.0 percent/7.07 percent, Public Counsel's is 8.9 percent/7.01 percent, and Boise's is 9.3/7.20 percent. Each of the proposed ROEs is so extreme that it falls outside of the bell curve of ROE determinations made for vertically-integrated electric utilities in 2013 and 2014,<sup>16</sup> which average at or near 10.0 percent.<sup>17</sup> Notably, Mr. Hill's recommended ROR of 7.01 percent is less than any authorized ROR from any state regulatory commission this year.<sup>18</sup>

11 The parties' base their recommendations on the erroneous and unsupported conclusion that the Company has less risk than comparable utilities and that a more leveraged capital structure would not materially impact its risk profile or capital costs. They also ignore that, on average, the Company has earned nearly 600 basis points less than its authorized ROR since 2006, less than comparable utilities in Washington.<sup>19</sup> As Staff witness Jeremy Twitchell testified at hearing:

I think it's a general point of agreement that [the Company] hasn't been earning that fair return. And staff is sensitive to that fact. Staff does feel that there is a strong public interest in the Company being able to meet its costs for rating reasons, for debt reasons, and so we don't have to do a rate case every year.<sup>20</sup>

12 In its most recent cost of capital determination for Puget Sound Energy (PSE), the Commission made clear that under-earning was a relevant consideration.<sup>21</sup> In the PSE case on remand, Staff testified that PSE's current ROR of 7.77 percent should not be reduced because PSE was still not achieving its authorized return. This concern is equally relevant to Pacific

---

<sup>16</sup> Strunk, Exh. No. KGS-19; Strunk Exh. No. KGS-17T 8 n. 6.

<sup>17</sup> Parcell, Exh. No. DCP-29CX 1; Parcell, Exh. No. DCP-23CX (Public Utilities Fortnightly calculated average authorized ROEs for 2014 as 9.9 percent); Strunk, Exh. No. KGS-17T 8 Table 1. In 2014, Fitch specifically noted that the Company's current Washington ROE of 9.5 percent is "lower than the sector average of around 10%."

Williams, Exh. No. BNW-16T 8:6-12.

<sup>18</sup> Williams, TR. 174:9-14.

<sup>19</sup> Dalley, Exh. No. RBD-3T 8 Table 1 (including 2013 earnings), 8:6-9; *see* Dalley, Exh. No. RBD-1T 5 Table 1.

<sup>20</sup> Twitchell, TR. 642:2-8.

<sup>21</sup> *WUTC v. Puget Sound Energy*, Dockets UE-111048, *et al.*, Order 08 ¶ 91 (May 7, 2012) ("[W]e 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"), reversed on other grounds, *Indus. Customers of Nw. Utils. v. WUTC*, Thurston County Superior Case Nos. 12-2-01576-2 and 13-2-01582-7 (consolidated), Order Granting in Part and Denying in Part Petition for Judicial Review (July 5, 2014).

Power’s cost of capital. In setting rates, the Commission “should strive for equality of treatment”<sup>22</sup> and “may not treat similar situations in dissimilar ways.”<sup>23</sup>

**A. Pacific Power’s Proposed ROE is Reasonable**

**1. Mr. Strunk’s recommended 10.0 percent ROE is based on objective estimates derived from well-established models.**

13 Mr. Strunk’s recommended 10.0 percent ROE is based on several well-established and previously-relied-upon methodologies: two Discounted Cash Flow (DCF) models (analysts’ growth rate and yield-plus-growth), capital asset pricing model (CAPM) and risk premium model, and comparable earnings (CE) analysis. Mr. Strunk verified the reasonableness of his results and overall recommendation by comparing both to allowed returns from other states.

14 In this case, Mr. Strunk considered all model results but recommended greater reliance on the DCF yield-plus-growth model, CAPM and risk premium models, and CE analysis, in light of current risks associated with interest rates and the volatility of capital markets. While the Commission has often looked to the DCF model to determine ROE,<sup>24</sup> it has also been clear that it “value[s] each of the methodologies used to calculate the cost of equity and do[es] not find it appropriate to select a single method as being the most accurate or instructive.”<sup>25</sup>

15 As an initial step in his analysis, Mr. Strunk developed a proxy group of 24 comparable utilities that have similar risk profiles to PacifiCorp.<sup>26</sup> The differences between the witnesses’ proxy groups are not material in this case, as Mr. Parcell uses the same proxy group and Mr. Gorman’s proxy group is largely the same.<sup>27</sup>

---

<sup>22</sup> *Vergeyle v. Employment Sec. Dep’t*, 28 Wn. App. 399, 404 (1981), *rev. den.*, 95 Wn.2d 1021 (1981), *disapproved on other grounds by Davis v. Employment Sec. Dep’t*, 108 Wn.2d 272 (1987). *See also WUTC v. Verizon Nw. Inc.*, Docket UT-040788, Order 11 ¶ 140 (Oct. 15, 2004).

<sup>23</sup> *Vergeyle*, 28 Wn. App. at 404 (quoting *Jones v. Califano*, 576 F.2d 12, 20 (2d Cir. 1978)) (internal quotations omitted).

<sup>24</sup> *See, e.g., WUTC v. PacifiCorp*, Dockets UE-050684, *et al.*, Order 04 ¶ 261 (Apr. 17, 2006).

<sup>25</sup> *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 91 (Mar. 25, 2011); *WUTC v. PacifiCorp*, Docket UE-100749, Order 07 ¶ 22 (May 12, 2011) (different methods can be more useful “depending on the economic and capital market conditions at a specific time”); *WUTC v. Puget Sound Energy*, Dockets UE-111048, *et al.*, Order 08 at n. 77 (May 7, 2012).

<sup>26</sup> Strunk, Exh. No. KGS-1T 7:17-20.

<sup>27</sup> Strunk, Exh. No. KGS-17T 25:15-26:2.

16 Mr. Strunk’s CAPM and risk premium models indicate an ROE of 9.73 percent and 10.07 percent, respectively.<sup>28</sup> Mr. Strunk reasonably relied on a forward-looking market risk premium, because in the current interest rate environment a historical market risk premium fails to accurately reflect investor’s forward-looking expectations.<sup>29</sup> Since 2006, the market risk premium has steadily increased, as the risk-free rate declined more than the allowed returns, indicating that historical data is less reliable. Importantly, however, Mr. Strunk’s analysis did not use forecast interest rates—he applied a forward-looking risk premium to current rates.<sup>30</sup>

17 Mr. Strunk’s CE method indicates an ROE of 9.97 percent for PacifiCorp’s utility peers and 16.2 percent for unregulated industrial firms with similar risk.<sup>31</sup> The CE method is consistent with the well-established principle in applied finance that past returns influence investors’ forward-looking expectations.<sup>32</sup> The CE method addresses the requirement in *Hope* that the ROE “be commensurate with returns on investments in other enterprises having corresponding risks.”<sup>33</sup> In the current uncertain interest rate environment, the CE method is reasonable because it is less sensitive to fluctuations in interest rates.<sup>34</sup>

18 Mr. Strunk’s two DCF models indicate an ROE of 9.0 percent and 10.1 percent, as of the time of his rebuttal testimony.<sup>35</sup> Mr. Strunk’s first model uses analysts’ forecast earnings growth rates and estimated sustainable growth rates.<sup>36</sup> Mr. Strunk did not artificially cap his growth rates at short-term gross domestic product (GDP) growth forecasts, given the empirical evidence that utilities’ earnings have historically grown faster than GDP on average.<sup>37</sup>

---

<sup>28</sup> Strunk, Exh. No. KGS-18.

<sup>29</sup> Strunk, Exh. No. KGS-1T 15:1-20.

<sup>30</sup> Strunk, Exh. No. KGS-17T 23:3-12.

<sup>31</sup> Strunk, Exh. No. KGS-18.

<sup>32</sup> Strunk, Exh. No. KGS-17T 20:21-21:6; Parcell, Exh. No. DCP-1T 34:1-4.

<sup>33</sup> *Hope*, 320 U.S. at 603.

<sup>34</sup> Parcell, TR. 344:2-6.

<sup>35</sup> Strunk, Exh. No. KGS-18.

<sup>36</sup> Strunk, Exh. No. KGS-1T 11:12-14.

<sup>37</sup> Strunk, Exh. No. KGS-17T 31:1-32:12 (NERA studies indicate that utility growth rates exceed GDP growth rates by five percent).

19 In his second DCF model, yield-plus-growth, Mr. Strunk relied on the dividend yield and expected earnings growth for the electric utility industry as a whole.<sup>38</sup> This analysis resulted in an expected ROE of 10.1 percent.<sup>39</sup> Mr. Strunk testified that investor expectations are influenced by expected returns for the industry as a whole and that the yield-plus-growth model provides an important data point for determining the reasonable cost of equity for the Company.<sup>40</sup>

20 Finally, Mr. Strunk used allowed returns in other jurisdictions to verify the reasonableness of his model results and overall recommendation. Data from Regulatory Research Associates (RRA) indicates that the average authorized ROE for the first nine months of 2014 was 10.0 percent, including the Virginia generation cases.<sup>41</sup> Although parties criticize the inclusion of the Virginia cases in the national averages, Mr. Strunk testified that investor (as opposed to regulatory) analysts examine all national data, Virginia included.<sup>42</sup> Excluding the Virginia cases and all non-integrated utilities, the average ROE was 9.92 percent.<sup>43</sup> Similarly, data compiled by Public Utilities Fortnightly indicates that ROEs for electric utilities have averaged 9.9 percent in 2014.<sup>44</sup> These allowed returns confirm the reasonableness of Mr. Strunk's 10.0 percent recommendation.

## 2. The cost of equity has not declined since the Company's last rate case.

21 The Commission last set Pacific Power's ROE at 9.5 percent in December 2013. The record in this case demonstrates that equity costs have increased since then with new risks associated with utility stock volatility and interest rates caused by Federal Reserve policy.<sup>45</sup>

22 Mr. Parcell testified that "PacifiCorp's cost of equity is less than in prior years."<sup>46</sup> Yet, Mr. Parcell's own analysis contradicts this conclusion and indicates that equity costs are actually

---

<sup>38</sup> Strunk, Exh. No. KGS-1T 12:17-21.

<sup>39</sup> Strunk, Exh. No. KGS-18.

<sup>40</sup> Strunk, Exh. No. KGS-17T 20:6-15.

<sup>41</sup> Parcell, Exh. No. DCP-29CX 1.

<sup>42</sup> Strunk, TR. 191:21-192:2.

<sup>43</sup> Strunk, Exh. No. KGS-17T 8 Table 1.

<sup>44</sup> Parcell, Exh. No. DCP-23CX (Public Utilities Fortnightly calculated average authorized ROEs for 2014 as 9.9 percent).

<sup>45</sup> Strunk, Exh. No. KGS-17T 11:4-12:9.



higher now than in 2013. Mr. Parcell's modeling results and recommended ROE range for the Company are consistently higher compared to his modeling results for PSE, which were based on market conditions in 2013—indicating that equity costs have increased since 2013.<sup>47</sup>

23 Mr. Gorman claimed that industry authorized ROEs are decreasing and that, consistent with this trend, the Commission should reduce Pacific Power's ROE.<sup>48</sup> Undercutting Mr. Gorman's position, however, is the fact that his recommended ROE for the Company increased 10 basis points since the Company's 2013 rate case.<sup>49</sup> Mr. Gorman's testimony in the PSE remand proceeding also indicates that equity costs are increasing, as his recommended ROE range increased between April 2013 and November 2014.<sup>50</sup>

24 Mr. Hill testified explicitly in the PSE remand proceeding that "my most recent cost of capital estimate prepared for the Public Counsel in the on-going PacifiCorp rate proceeding indicates that the current cost of equity capital is in the same range as that determined for the target 2013 time period in the [PSE remand] case."<sup>51</sup> Despite acknowledging that equity costs are in the same range in 2013 and now, however, Mr. Hill recommends an ROE for Pacific Power that is a full 60 basis points less than Pacific Power's current ROE and his recommended 9.5 percent ROE for PSE in 2013.<sup>52</sup> Given that Mr. Hill agrees that equity costs have remained constant, there is no basis for his proposed ROE reduction.

25 In addition to the results of each expert's own analysis and recommendations, industry data also indicates that authorized ROEs have not declined from 2013 through the first three quarters of 2014. Industry data indicates that the average authorized ROE for January through

---

<sup>46</sup> Parcell, Exh. No. DCP-1T 40:1-2.

<sup>47</sup> Parcell, Exh. No. DCP-26CX 28:9-13, 25:12-14; Parcell, Exh. No. DCP-1T 36:9-13, 33:11-14; Parcell, TR. 285:2-24; Parcell, TR. 294:17-295:2 (proxy groups substantially the same).

<sup>48</sup> Gorman, Exh. No. MPG-1T 66:1-7.

<sup>49</sup> Gorman, TR. 226:1-13.

<sup>50</sup> *Id.* at 227:9-13; Gorman, Exh. No. MPG-26CX 4:7-9 (as of November 2014 recommends 9.3 percent ROE, with a range of 9.0 to 9.6 percent); Gorman, Exh. No. MPG-26CX 3:19-22 (as of April 2013 recommended ROE of 9.3 percent with a range of 8.4 to 9.3 percent).

<sup>51</sup> Hill, Exh. No. SGH-21CX 54:16-19; *see also* Hill, TR. 256:17-257:8. Like Messrs. Gorman and Parcell, Mr. Hill's proxy group was substantially the same for both PacifiCorp and PSE. Hill, Exh. No. SGH-21CX 55:1-2.

<sup>52</sup> *WUTC v. Puget Sound Energy*, Dockets UE-121697, *et al.*, Order 07 ¶ 49 (June 25, 2013).

September 2014 was 10.0 percent, compared to 10.02 percent for 2013—a change of only two basis points.<sup>53</sup> Industry data related to integrated utilities similar to PacifiCorp (excluding generation-, transmission-, and distribution-only businesses) demonstrates that the average authorized ROE was 9.92 percent for 2013 and January through October 2014.<sup>54</sup>

### 3. The current interest rate environment supports a higher ROE.

26 Parties argue that current interest rates indicate that equity costs remain low.<sup>55</sup> Interest rates are similar to the 2013 level when the Commission set Pacific Power’s ROE at 9.5 percent, however, and the risk associated with future interest rates has increased.

27 Mr. Gorman acknowledged that bond yields in April 2013 were “nearly comparable to where they are today.”<sup>56</sup> According to Mr. Gorman’s testimony, the average A-rated utility bond yield was 4.48 percent in 2013 compared to 4.44 percent in 2014, a change of just four basis points.<sup>57</sup> Mr. Hill testifies that interest rates from 2013 to 2014 were “very similar”<sup>58</sup> and that the “current expectation with regard to long-term interest rates is the same as it has been for some time, i.e., that they are expected to move slightly higher in the future[.]”<sup>59</sup>

28 With the end of the Federal Reserve’s quantitative easing stimulus program, there is now more risk that interest rates will increase. As Mr. Strunk testified, investor expectations are what matters for setting the Company’s ROE, and investors expect higher interest rates.<sup>60</sup> Mr. Hill also testified that interest rates are likely to increase as the economy improves, and his testimony here and in the recent Avista case demonstrates that the economic outlook has improved.<sup>61</sup>

---

<sup>53</sup> Parcell, Exh. No. DCP-29CX 1; *see also* Hill, Exh. No. SGH-23CX 2 (average ROE for 2012 were generally 10 percent); Parcell, Exh. No. DCP-26CX 60 (Edison Electric Institute data shows average 2013 ROE of 9.99 percent); Strunk, Exh. No. KGS-17T 9:22 – 10:4 (FERC-approved ROEs “comparable [to] and, in several cases, above prior base ROE decisions over the past several years.”).

<sup>54</sup> Strunk, Exh. No. KGS-17T 8 Table 1.

<sup>55</sup> *See e.g.* Hill, Exh. No. SGH-1CT 13:13-19.

<sup>56</sup> Gorman, Exh. No. MPG-26CX 4:15-19.

<sup>57</sup> Gorman, Exh. No. MPG-15.

<sup>58</sup> Hill, Exh. No. SGH-21CX 55:5-13.

<sup>59</sup> Hill, Exh. No. SGH-1CT 18:10-12.

<sup>60</sup> Strunk, TR. 339:18-24.

<sup>61</sup> Hill, Exh. No. SGH-22CX 18:7-19; Hill, Exh. No. SGH-1CT 17:3-10.

29 Mr. Gorman acknowledges that “there is additional risk in long-term interest rate markets created by [the] Federal Reserve stimulus policy.”<sup>62</sup> Given this increased risk, Mr. Gorman recommends reliance on his risk premium results and claims that he gave greater weight to the high end of his results.<sup>63</sup> To the contrary, Mr. Gorman gave less weight to the high end of his risk premium results than in prior cases.<sup>64</sup> Weighting Mr. Gorman’s risk premium results consistent with his past approach increases his ROE range to 9.22 to 10.04 percent, with a mid-point of 9.63 percent.

30 The Federal Energy Regulatory Commission (FERC) has also recently approved a base level ROE for transmission service provided by ISO New England at a level above the mid-point of the DCF analysis. Rather than mechanically applying its established methodology and reducing the utilities’ ROE in response to the current interest rate market, as parties recommend here, the FERC increased ROE to account for the increased risk associated with current interest rates.<sup>65</sup>

#### 4. The Company’s risk profile does not support a lower ROE.

31 The parties recommend that the Commission authorize an ROE at the low end of the reasonable range to account for what they claim is PacifiCorp’s lower risk profile compared to the proxy group companies.<sup>66</sup> Mr. Parcell claims that PacifiCorp has less risk because of its “above average debt ratings.”<sup>67</sup> Similarly, Mr. Hill also supports his low-end ROE recommendation by claiming that PacifiCorp has a “*slightly* higher bond rating” than the proxy group companies.<sup>68</sup> But this argument is undermined by the fact that the parties all used bond

---

<sup>62</sup> Gorman, Exh. No. MPG-1T 39:17-18; Gorman, TR. 217:14-20.

<sup>63</sup> Gorman, TR. 346:16-347:24; Gorman, TR. 217:21-218:2.

<sup>64</sup> Gorman, TR. 218:19-219:20.

<sup>65</sup> *Coakley, et al. v. Bangor Hydro-Elec. Co., et al.*, 147 F.E.R.C. ¶ 61,234, ¶¶ 142-53 (June 19, 2014); Parcell, Exh. No. DCP-23CX 2 (“As FERC explained, if ROEs were tied too closely to current interest rates, investors would simply choose to put their money elsewhere.”).

<sup>66</sup> See e.g. Parcell, Exh. No. DCP-1T 4:1-5; Hill, Exh. No. SGH-1CT 5:3-11.

<sup>67</sup> Parcell, Exh. No. DCP-1T 39:3.

<sup>68</sup> Hill, Exh. No. SGH-1CT 5:6-7 (emphasis added).

ratings as a basis to determine the proxy companies with similar risk profiles. At hearing, Mr. Hill admitted that he did not base his low-end ROE on PacifiCorp's bond rating.<sup>69</sup>

32 Mr. Parcell also claims that PacifiCorp will have less risk in Washington if a power cost adjustment mechanism (PCAM) is implemented.<sup>70</sup> Mr. Parcell admitted that some of the utilities in his proxy group already have PCAMs.<sup>71</sup> Mr. Strunk testified that any risk mitigation related to a PCAM is already included in the ROE estimates because PCAMs are so common that they do not factor into equity investor return expectations.<sup>72</sup>

33 Mr. Hill also claims that the Company has less risk because it has a "higher common equity ratio than the electric utility sample group."<sup>73</sup> But Mr. Hill incorrectly relies on holding company capital structures to support his claim. Equity ratios for the operating companies included in Mr. Strunk's proxy group average 51.82 percent equity, higher than in PacifiCorp's capital structure.<sup>74</sup> In addition, the market-based equity ratios, which Mr. Hill relies upon in the de-levering of the proxy group beta, show an average equity ratio for the proxy group that is higher than PacifiCorp's 51.73 percent.<sup>75</sup>

#### **5. Mr. Parcell's objective models and analysis support a higher cost of equity.**

34 Mr. Parcell recommends an ROE of just 9.0 percent, a 50 basis point reduction in Pacific Power's currently authorized ROE.<sup>76</sup> An examination of Mr. Parcell's concurrent testimony in this case and in the PSE case, however, makes clear that his primary CE model supports an ROE for Pacific Power of 10.0 percent, consistent with Mr. Strunk's recommendation.<sup>77</sup>

---

<sup>69</sup> Hill, TR. 254:8-14.

<sup>70</sup> Parcell, Exh. No. DCP-1T 39:5-6.

<sup>71</sup> Parcell, Exh. No. DCP-21CX.

<sup>72</sup> Strunk, TR. 301:20-25, 331:14-23.

<sup>73</sup> Hill, Exh. No. SGH-1CT 5:6-7.

<sup>74</sup> Williams, TR. 170:22-171:19.

<sup>75</sup> Hill, Exh. No. SGH-3 5 (Mr. Hill uses the formula book equity ratio times the market-to-book ratio to calculate the market value equity ratio, which is implicit in the "Market Value Debt (1-t) / Eq." column of his exhibit).

<sup>76</sup> Parcell, Exh. No. DCP-1T 2:22.

<sup>77</sup> Strunk, Exh. No. KGS-15.

35 In the PSE remand case, Mr. Parcell recommends an ROE of 9.5 percent, based on the same models and a substantially similar proxy group.<sup>78</sup> Mr. Parcell testified to the reasonableness of PSE's currently authorized ROE of 9.8 percent, a full 80 basis points higher than his recommended ROE for Pacific Power.<sup>79</sup> Mr. Parcell's PSE recommendation relied extensively on his CE results, which were the only modeling results that supported the high end of his reasonable range (including PSE's current 9.8 percent ROE).<sup>80</sup> At hearing, Mr. Parcell testified that if he excluded his CE results, his PSE recommendation would be less than nine percent.<sup>81</sup>

36 At hearing, Mr. Parcell was unable to explain any basis for recommending a lower ROE for Pacific Power, other than the fact that his PSE testimony analyzed 2013.<sup>82</sup> But the record evidence shows that equity costs are the same or higher now than in 2013. Mr. Parcell's failure to provide any justification for his artificially low ROE recommendation for Pacific Power was compounded by the fact that his CE modeling results produced materially higher ROEs for Pacific Power.<sup>83</sup> For PSE, Mr. Parcell's analysis indicates ROEs of 8.3 percent to 10.3 percent,<sup>84</sup> while for Pacific Power, his same analysis indicates ROEs of 9.4 percent to 10.3 percent.<sup>85</sup>

37 Mr. Parcell's Pacific Power CE results indicate a significantly higher equity cost than his recommended 9.0 percent ROE. Mr. Parcell admitted that half of his ROE period averages used to determine his CE range were higher than 9.8 percent and all of his 16 ROE period averages are greater than this recommended 9.0 percent ROE.<sup>86</sup> In fact, 10 of his 16 period averages

---

<sup>78</sup> Parcell, Exh. No. DCP-26CX 7:3-4, 16:18-23, 39; Parcell, TR. 294:13-295:2. Mr. Parcell used 35 proxy companies in his PSE testimony, 21 of which he also included in the proxy group (of 24 companies) used in his Pacific Power testimony.

<sup>79</sup> Parcell, Exh. No. DCP-26CX 7:4-6.

<sup>80</sup> *Id.* at 30:15-17 (CE results are the only results that support a 9.5 percent ROE); Parcell, TR. 275:23-25.

<sup>81</sup> Parcell, TR. 286:8-16.

<sup>82</sup> *Id.* at 283:2-11.

<sup>83</sup> *See e.g.* Parcell, Exh. No. DCP-26CX 30:16 (CAPM results for PSE are 6.7 percent); Parcell, Exh. No. DCP-1T 38:17 (CAPM results for PacifiCorp are 7.3 percent); Parcell, TR. 285:2-24.

<sup>84</sup> Parcell, Exh. No. DCP-26CX 28:14-19 (projected ROEs within a range of 8.7 to 10.4 percent).

<sup>85</sup> Parcell, Exh. No. DCP-1T 36:14-19 (projected ROEs within a range of 9.5 to 11.1 percent).

<sup>86</sup> Parcell, Exh. No. DCP-25CX; Parcell, Exh. No. DCP-1T 36:9-13; Parcell, Exh. No. DCP-12.

produced ROEs greater than 10 percent, and the simple average of his period averages results in an ROE of 10.01 percent, with a median of 10.05 percent.<sup>87</sup>

38 To arrive at his recommended ROE for the Company, Mr. Parcell had to artificially cap his CE results at 9.5 percent, despite the fact that only two of his 16 period averages produced ROE results less than 9.5 percent.<sup>88</sup> Notably, Mr. Parcell did not cap his CE results in his PSE testimony.<sup>89</sup> At hearing, Mr. Parcell justified the cap by pointing to the market-to-book ratios.<sup>90</sup> But the market-to-book ratios in both his Pacific Power and PSE testimonies were substantially the same.<sup>91</sup>

39 Mr. Parcell's ROE recommendation for Pacific Power is based on the arbitrary exclusion of certain results and the artificial reduction of his range of modeling outcomes. Without this manipulation, Mr. Parcell's ROE recommendation would be at least 9.5 percent to 9.8 percent, but more likely closer to Mr. Strunk's ROE recommendation of 10.0 percent.

#### **6. Mr. Hill's recommendations lack credibility.**

40 Mr. Hill relies largely on his DCF results, which he describes as the "most reliable indicator of the current" ROE.<sup>92</sup> But the Commission rejected Mr. Hill's DCF results in the last fully litigated case in which he testified because they "rely on growth estimates that are obscure and not subject to replication."<sup>93</sup> Mr. Hill acknowledged at hearing that his DCF methodology here was unchanged.<sup>94</sup> Given that the Commission has previously rejected the exact same methodology Mr. Hill used in this case, his recommendations should be given little weight.

---

<sup>87</sup> Parcell, Exh. No. DCP-12.

<sup>88</sup> Parcell, Exh. No. DCP-1T 38:15-25; Parcell, Exh. No. DCP-12.

<sup>89</sup> Parcell, Exh. No. DCP-26CX 30:14-22.

<sup>90</sup> Parcell, TR. 278:17-22, 280:6-17; Parcell, Exh. No. DCP-25CX 1.

<sup>91</sup> Parcell, Exh. No. DCP-1T 36:11-12; Parcell, Exh. No. DCP-26CX 28:10-11.

<sup>92</sup> Hill, Exh. No. SGH-1CT 57:3.

<sup>93</sup> *WUTC v. Puget Sound Energy*, Dockets UE-090704, *et al.*, Order 11 ¶ 299 (Apr. 2, 2010); Hill, TR. 246:24-25, 248:16; Hill, Exh. No. SGH-1CT 42:8-16 (admitting growth rate estimates not based on publicly available growth rate data).

<sup>94</sup> Hill, TR. 246:24-25, 248:14-16.

41 In addition, Mr. Hill's testimony originally supported an ROR for Pacific Power of 7.32 percent and used the higher cost of debt associated with Pacific Power's alternative cost of capital recommendation. Almost two months after filing testimony, and after Mr. Hill served discovery on Pacific Power's rebuttal testimony that expressly referenced Mr. Hill's use of a 5.80 percent cost of debt, Mr. Hill claimed that his use of this cost of debt was mistaken and changed his proposed ROR to 7.01 percent.<sup>95</sup> At hearing, Mr. Hill could not explain the mistake or his failure to revise his testimony until well after he had conducted discovery on Pacific Power's rebuttal testimony.<sup>96</sup>

**7. Mr. Gorman's inconsistent recommendations in other jurisdictions undermine his credibility.**

42 Mr. Gorman recommends an ROE of 9.3 percent for Pacific Power in this case. In April 2014, Mr. Gorman recommended an ROE of 9.4 percent for PacifiCorp in Utah.<sup>97</sup> And because Mr. Gorman also supported the Company's actual capital structure in Utah, the overall ROR recommended by Mr. Gorman in that state was 21 basis points higher than his recommendation here.<sup>98</sup> Mr. Gorman admits that the Company's credit rating is based on its consolidated operations.<sup>99</sup> Therefore, to the extent that the Company's credit rating reflects risk, the risk is generally the same in every state. There is no principled basis for Mr. Gorman to recommend a lower ROE and ROR in Washington than in other PacifiCorp states.<sup>100</sup>

**8. The Commission should increase Pacific Power's ROE if a hypothetical capital structure is adopted.**

43 PacifiCorp's financial profile would be riskier if the Company actually carried the 49.1 percent equity recommended by the parties.<sup>101</sup> To account for this, the Company's ROE should increase if the Commission adopts a hypothetical capital structure. Based on well-

---

<sup>95</sup> *Id.* 239:17-20, 243:3-9.

<sup>96</sup> *Id.* 240:11-245:1.

<sup>97</sup> Gorman, Exh. No. MPG-24CX 2:22-23.

<sup>98</sup> Gorman, TR. 229:13-21, 232:16-20.

<sup>99</sup> *Id.*, TR. 228:3-7.

<sup>100</sup> Gorman, Exh. No. MPG-23CX; Gorman, TR. 228:8-12.

<sup>101</sup> Strunk, Exh. No. KGS-1T 21:13-19.

established techniques, Mr. Strunk testified that the imputation of a higher debt ratio would raise the Company's cost of equity 28 basis points, resulting in a recommended ROE of 10.28 percent.<sup>102</sup>

44 Although Mr. Gorman does not support Mr. Strunk's increased ROE, Mr. Gorman's testimony in the PSE remand case acknowledges that a credit downgrade of one to two notches should be accompanied by an increase in the ROE of 20 to 25 basis points, nearly the same adjustment recommended by Mr. Strunk.<sup>103</sup> Mr. Hill agrees in principle with Mr. Strunk that the Company's ROE should be increased if the Commission approves a hypothetical capital structure with more debt.<sup>104</sup> But he recommends only an eight-basis-point adjustment, based on his unsupported assumption of the Company's greater market-to-book ratio for its regulated operations in Washington.<sup>105</sup>

#### **B. The Company's Actual Capital Structure is Reasonable**

45 The capital structure established by the Commission for ratemaking purposes must balance the economy of lower-cost debt versus the safety of higher-cost equity.<sup>106</sup> Consistent with these standards, the Company proposes adoption of its actual capital structure with 51.73 percent equity.

##### **1. The Company's actual equity ratio properly balances safety and economy.**

46 The Company's proposed capital structure is based upon the average of the five quarters ended December 31, 2014, and the equity ratio is consistent with the equity levels that the Company expects for the foreseeable future.<sup>107</sup> The Company's current equity level is safe because it maintains the Company's credit rating and ensures continued access to low-cost

---

<sup>102</sup> *Id.*; Strunk, TR. 314:22-315:1.

<sup>103</sup> Gorman, Exh. No. MPG-26CX 6:20-7:6. Mr. Gorman testified in support of his proposed decoupling adjustment and recommended a 20 to 25 basis point ROE reduction to account for the lower risk resulting from decoupling.

<sup>104</sup> Hill, TR. 316:23-317:5.

<sup>105</sup> Hill, Exh. No. SGH-1CT 26:13-19, 58:4-6; Strunk, Exh. No. KGS-17T 18:9-15.

<sup>106</sup> *WUTC v. Puget Sound Energy*, Dockets UG-040640, *et al.*, Order 06 ¶ 27 (Feb. 18, 2005).

<sup>107</sup> Williams, Exh. No. BNW-1T 4:17-18; Williams, TR. 315:21-22.



capital, particularly during a period of significant capital expenditures.<sup>108</sup> The Company's actual capital structure is also economical because it results in a reasonable overall ROR and the lowest debt costs of any IOU in Washington.<sup>109</sup>

47 The evidence presented in this case demonstrates that imputing a more leveraged capital structure is not reasonable. First, the Company demonstrated that in five of the six credit ratios used by Standard & Poor's (S&P), the Company's metrics are now weaker than the median A and A- rated utilities.<sup>110</sup> Imputing additional debt and lowering the Company's cash flows will further weaken the Company's ratios, making it clear that the Company could not maintain its current credit rating if it were actually capitalized at 49.1 percent equity.<sup>111</sup>

48 Second, while industry averages should not be used to *establish* the Company's capital structure,<sup>112</sup> as with ROEs, they can corroborate the reasonableness of the Company's actual capitalization. The evidence shows that similarly rated electric utilities have equity ratios similar to PacifiCorp. As noted above, the equity ratios for the operating companies included in Mr. Strunk's proxy group average 51.82 percent equity.<sup>113</sup> Mr. Hill claims that the appropriate comparison is to the capital structure of the holding companies in the proxy group.<sup>114</sup> But this is comparable to using the capital structure of Berkshire Hathaway Energy for ratemaking purposes, an approach the Commission has never used.<sup>115</sup>

49 Mr. Parcell cites to rate case decisions from 2013 and claims that there are "several decisions . . . where an electric utility had an equity ratio of less than 50 percent and had single A ratings."<sup>116</sup> However, the average common equity ratio of the A-rated utilities cited by

---

<sup>108</sup> Williams, Exh. No. BNW-1T 16:10-22.

<sup>109</sup> *Id.* at 12 Table 5.

<sup>110</sup> Williams, Exh. No. BNW-16T 10:14-16, 11.

<sup>111</sup> Williams, TR. 175:1-8.

<sup>112</sup> *WUTC v. Puget Sound Energy*, Dockets UG-040640, *et al.*, Order 06 ¶ 30 (Feb. 18, 2005).

<sup>113</sup> Williams, TR. 170:22-24.

<sup>114</sup> Hill, TR. 255:3-18.

<sup>115</sup> See *e.g. Assoc. of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, 148 F.E.R.C. ¶ 61,049, ¶ 190 (Oct. 16, 2014) (using operating company's actual capital structure if operating company issues own debt, has own credit rating, and has a capital structure within a reasonable range).

<sup>116</sup> Parcell, Exh. No. DCP-1T 46:13-16; Parcell, Exh. No. DCP-16.

Mr. Parcell is 51.24 percent, which is much closer to the Company's actual equity of 51.73 percent than Mr. Parcell's 49.1 percent recommendation.<sup>117</sup> Importantly, Mr. Parcell was also unable to identify a single other case where he recommended a hypothetical capital structure.<sup>118</sup>

50           Moreover, the majority of authorized equity ratios for integrated electric utilities from January 2009 through October 2014 were greater than 49.1 percent.<sup>119</sup> Of the total 42 rate cases decided in 2013 that included an equity ratio determination, approximately one-half of the cases had an equity ratio greater than the Company's actual ratio—meaning that the Company's actual equity ratio is roughly the median value for 2013.<sup>120</sup> And in the first nine months of 2014, the average authorized equity ratio was 50.52 percent.<sup>121</sup> Given this evidence, which was not considered in prior cases, the Commission should approve the use of the Company's actual capital structure for ratemaking purposes.

**2. Mr. Gorman's shifting justification for a hypothetical equity ratio should be rejected.**

51           In the Company's last three litigated rate cases in Washington, Mr. Gorman has recommended a 49.1 percent equity ratio. In each case, Mr. Gorman's rationale has changed. In the 2010 rate case, the Commission adopted Mr. Gorman's recommended equity ratio because he provided the "most reasonable approach for calculating the equity component . . . by ascertaining the equity used to support plant investment."<sup>122</sup> Mr. Gorman failed to perform this same analysis in either the 2013 case or in this case.

52           Instead, in the 2013 rate case, Mr. Gorman supported his recommended equity ratio by claiming that it is safe because it "has been reviewed by credit ratings agencies" and has contributed to PacifiCorp's current rating levels.<sup>123</sup> Yet Mr. Gorman now acknowledges that the

---

<sup>117</sup> Williams, Exh. No. BNW-16T 3:13-20.

<sup>118</sup> Parcell, Exh. No. DCP-17CX 1.

<sup>119</sup> Strunk, Exh. No. KGS-17T 14:1-5.

<sup>120</sup> Williams, Exh. No. BNW-1T 8:10-14.

<sup>121</sup> Parcell, Exh. No. DCP-29CX 4.

<sup>122</sup> *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 42 (Mar. 25, 2011).

<sup>123</sup> Gorman, Exh. No. MPG-27CX 15:4-5.

Company's credit rating is based on its actual, not hypothetical, capitalization.<sup>124</sup> Moreover, the evidence in this case indicates that the investment community has commented negatively on the Commission's use of a hypothetical capital structure.<sup>125</sup>

53 In this case, Mr. Gorman now supports his recommended equity ratio by claiming that PacifiCorp would not suffer a ratings downgrade if it were actually capitalized at 49.1 percent because the Company's S&P adjusted debt ratio is lower than that of other utilities with similar bond ratings.<sup>126</sup> Mr. Gorman's approach is too simplistic, comparing only equity ratios and adjusted debt ratios (which are not even used by S&P) and concludes that, based solely on these metrics, PacifiCorp could increase its debt without suffering a downgrade.<sup>127</sup> Mr. Williams' more robust analysis demonstrates that Mr. Gorman's analysis is incorrect.<sup>128</sup>

54 In a case decided in October 2014 (which Mr. Gorman failed to produce in discovery), FERC soundly rejected a similar proposal from Mr. Gorman.<sup>129</sup> In that case, Mr. Gorman recommended that FERC cap MISO transmission operator's equity ratios at 50 percent, based on Mr. Gorman's claim that the industry average equity ratio was 48.8 percent.<sup>130</sup> FERC dismissed Mr. Gorman's recommendation, observing that it "has never dictated a utility's capital structure based on how much common equity it *needs* to attract capital and maintain good credit ratings."<sup>131</sup> FERC also concluded that "it is reasonable to assume that individual utilities are subject to different risk factors, have different investment needs, and may pursue different business strategies, all of which could affect capitalization decisions."<sup>132</sup>

---

<sup>124</sup> Gorman, Exh. No. MPG-24CX 2:26-31.

<sup>125</sup> Williams, TR. 179:10-12.

<sup>126</sup> Gorman, Exh. No. MPG-1T 14:3-25.

<sup>127</sup> Williams, Exh. No. BNW-16T 10:6-11:6. *See WUTC v. Puget Sound Energy*, Dockets UG-040640, *et al.*, Order 06 ¶ 35 (Feb. 18, 2005) ("ratings agencies consider a host of factors" when determining a company's credit rating, not just the equity ratio).

<sup>128</sup> Williams, Exh. No. BNW-16T 10:14-16.

<sup>129</sup> Gorman, TR. 214:4-215:9.

<sup>130</sup> *Assoc. of Bus. Advocating Tariff Equity, et al. v. Midcontinent Indep. Sys. Operator, Inc., et al.*, 148 F.E.R.C. ¶ 61,049, ¶ 13 (Oct. 16, 2014).

<sup>131</sup> *Id.* at ¶ 193 (emphasis in original).

<sup>132</sup> *Id.* at ¶ 194.

**3. If the Commission adopts a hypothetical capital structure, it should also adopt hypothetical debt costs.**

55 Mr. Williams testified that if the Company was actually capitalized at 49.1 percent equity, the additional leverage would cause a credit rating downgrade of two notches (to a BBB rating) and increased debt costs.<sup>133</sup> Mr. Williams analyzed the debt issuances of BBB-rated utilities going back to 2006, when the Commission first adopted a hypothetical capital structure for Pacific Power.<sup>134</sup> Based on this comparative analysis, Mr. Williams concluded that the Company's debt costs would be 5.80 percent, an increase of 61 basis points, if it were actually capitalized using the hypothetical capital structure. Mr. Williams verified the reasonableness of this conclusion by reviewing the debt costs of PSE and Avista, both of which have lower credit ratings and higher debt costs.<sup>135</sup> The Company's recommended ROR using the hypothetical capital structure and the corresponding increase in debt and equity costs is 7.99 percent, 32 basis points greater than the Company's recommendation based on its actual capitalization.<sup>136</sup>

**C. The Credit Metrics under Staff's, Public Counsel's, and Boise's Cost of Capital Proposals Demonstrate the Unreasonableness of Their Recommendations**

56 Messrs. Parcell, Hill, and Gorman all claim that a 49.1 percent hypothetical equity ratio is reasonable because the Company could actually be capitalized at that level and maintain its current credit rating. But the evidence demonstrates otherwise:

- None of the parties' credit metric analyses consider their revenue requirement adjustments in the case.<sup>137</sup> Boise recommends a rate decrease, which Mr. Gorman ignored entirely.<sup>138</sup> The Company's cash flows and credit metrics will be negatively affected by any reduction to the Company's rate proposal.
- All of the parties' analyses assume that the Company will actually earn its authorized ROR.<sup>139</sup> This assumption is unsupported given the Company's historical earnings.<sup>140</sup>

---

<sup>133</sup> Williams, Exh. No. BNW-1T 11:11-14; Williams, TR. 167:19-168:3.

<sup>134</sup> Williams, Exh. No. BNW-1T 12:1-12; Williams, TR. 171:7-19.

<sup>135</sup> Williams, Exh. No. BNW-1T 12 Table 5.

<sup>136</sup> *Id.* 12:13-13:2.

<sup>137</sup> Williams, Exh. No. BNW-16T 5:19-20, 15:6-7.

<sup>138</sup> Mullins, Exh. No. BGM-1CT 6 Table 1.

<sup>139</sup> *See* Williams, Exh. No. BNW-16T 15:9-10.

<sup>140</sup> Dalley, Exh. No. RBD-3T 8 Table 1.

- None of the parties count debt at the level imputed by ratings agencies and investors.<sup>141</sup>
- Messrs. Parcell and Hill rely only on an outdated and incomplete metric, the pre-tax interest coverage ratio, to assess the impact of their ROR recommendations.<sup>142</sup> Mr. Hill's analysis showed a stronger credit metric under his revised ROR of 7.01 percent than under his original ROR of 7.32 percent, a facially unreasonable result. In addition, Mr. Parcell acknowledges that the benchmark ratios he used were from 2004 and are obsolete.<sup>143</sup> Under the outdated metrics used by Mr. Parcell, Mr. Hill's analysis demonstrates that the Company would be downgraded.<sup>144</sup>
- Mr. Gorman ignores five of the seven ratios used by S&P to establish the Company's credit rating.<sup>145</sup>
- Unlike the rating agencies, the parties do not account for the financing costs associated with construction work in progress (CWIP).<sup>146</sup>
- Mr. Hill's claim that the Company's historical equity ratios demonstrate that the Company could maintain its credit rating with 49.1 percent equity is without merit.<sup>147</sup> The Company's equity ratio increased in 2008 response to the need for major capital additions and the financial crisis.<sup>148</sup>

#### IV. NET POWER COSTS

57 Pacific Power is requesting pro forma west control area NPC of approximately \$592.7 million, or \$135.6 million on a Washington-allocated basis, for the 12 months ending March 31, 2016. Pacific Power is also requesting an RRTM to permit full recovery of the variable costs of renewable resources under the Energy Independence Act (EIA). The parties propose a \$10 million reduction in Washington-allocated NPC, disallowing the costs of Pacific Power's out-of-state QF PPAs. Boise recommends additional NPC adjustments, primarily by imputing benefits related to the PacifiCorp's participation in the Energy Imbalance Market (EIM) with the California Independent System Operator Corporation (CAISO). In addition,

<sup>141</sup> Williams, Exh. No. BNW-16T 16:5-7; Strunk, Exh. No. KGS-17T 41:10-16.

<sup>142</sup> Williams, Exh. No. BNW-16T 5:17-18, 8:21-24.

<sup>143</sup> Parcell, TR. 297:8-298:9; Strunk, Exh. No. KGS-17T 41:7-8; Parcell, Exh. No. DCP-22CX.

<sup>144</sup> Strunk, Exh. No. KGS-17T 41:18-19 (Mr. Hill's pre-tax coverage ratio corresponds to a BBB-ratings bracket on Mr. Parcell's benchmark ratios).

<sup>145</sup> Williams, Exh. No. BNW-16T 17:12-16.

<sup>146</sup> *Id.* at 5:20-21, 15:14-15.

<sup>147</sup> Hill, Exh. No. SGH-1CT 23 Table II.

<sup>148</sup> Williams, TR. 169:18-170:12.

none of the other parties supports the RRTM, although Staff has responded with a proposal for a PCAM.

**A. The Company’s Updated Coal Costs are Reasonable and Unrebutted**

58 The Company’s rebuttal testimony reflects a west control area NPC increase of approximately \$23.9 million, or \$5.4 million on a Washington-allocated basis, compared to the original filing. This increase is largely attributable to changes in coal prices and increased volumes at the Jim Bridger plant, which is served by coal from the Black Butte mine and the captive Bridger Coal Company (BCC) mine.<sup>149</sup>

59 The updated Black Butte coal costs result from a request for proposals (RFP) that was issued in June 2014, which produced an agreement in November 2014 with increased prices and volumes.<sup>150</sup> The updated BCC coal costs are from a July 2014 mine plan that reflects lower volumes and corresponding higher per-ton prices.<sup>151</sup> The results of the June 2014 RFP demonstrate the reasonableness of the new Black Butte and BCC prices, which are generally comparable to each other and are less than other market alternatives.<sup>152</sup>

60 The Company updated its coal costs consistent with Commission precedent and prior cases.<sup>153</sup> The Commission has routinely “allowed, and even required” these types of fuel cost updates so that NPC reflect the costs that are “reasonably expected to be actually incurred during short and intermediate periods following the conclusion” of a case.<sup>154</sup> Here, the Commission made clear that it “should not ignore evidence that a significant increase in the Company’s power costs during the rate year will result from increased fuel supply costs, if these costs are shown to

---

<sup>149</sup> Crane, Exh. No. CAC-1CT 2:13-15; 3:6-12. The Company’s rebuttal testimony also updates coal prices for the Colstrip plant as a result of an updated operating plan for the Rosebud mine. *Id.* at 11:6-13.

<sup>150</sup> *Id.* at 4:12-5:16; Declaration of Cindy A. Crane in Support of Pacific Power’s Response in Opposition to Motion to Strike at ¶¶ 5-6.

<sup>151</sup> Crane, Exh. No. CAC-1CT 5:19-6:10.

<sup>152</sup> *Id.* at 4:1-10, 10:6-19.

<sup>153</sup> Duvall, Exh. No. GND-4T 9:17-12:4.

<sup>154</sup> *WUTC v. Puget Sound Energy*, Dockets UE-060266, *et al.*, Order 08 at ¶ 102 (Jan. 5, 2007); *WUTC v. Puget Sound Energy*, Dockets UE-111048, *et al.*, Order 08 at ¶ 220 (May 7, 2012); *WUTC v. Pacific Power*, Dockets UE-140762, *et al.*, Order 07 ¶ 4 (Dec. 5, 2014).

have become reliably known and measurable during the pendency of the Company’s current general rate case.”<sup>155</sup> The updated coal costs are the result of an RFP, a new contract, and a new mine plan and are “reliably known and measurable.” The Company’s update to NPC is reasonable, and no party challenged it through supplemental testimony or at hearing.

**B. Pacific Power Should Recover its Out-of-State QF PPAs under the WCA**

61 Pacific Power proposes to include in Washington rates an allocated share of the costs of the Company’s California and Oregon QFs PPAs. Under the current west control area inter-jurisdictional allocation methodology (WCA), only the costs of QFs that are physically located in Washington are included in rates. In response to the Commission’s decision in Pacific Power’s 2013 general rate case rejecting the same proposal, Pacific Power also provided two alternative recommendations—the Washington re-pricing alternative and the load decrement alternative.

**1. Out-of-state QF PPAs serve and benefit Washington customers.**

62 Like all generation in Washington, Oregon, and California, the Company uses its out-of-state QF PPAs to serve Washington load and balance its west control area.<sup>156</sup> The provision of energy and capacity is a direct benefit to Washington customers.<sup>157</sup> There is no dispute that the Company’s out-of-state QFs actually serve Washington. Staff’s testimony states that “the Commission has acknowledged these resources serve WCA customers,”<sup>158</sup> and Boise makes the same concession.<sup>159</sup> As the federal district court in *North Dakota v. Heydinger* recently

---

<sup>155</sup> *WUTC v. Pacific Power*, Dockets UE-140762, *et al.*, Order 07 ¶ 4 (Dec. 5, 2014) (“The Commission has routinely during the past decade allowed, and even required, power cost updates related to changes in fuel supply costs late in general rate proceedings, even at the compliance stage.”).

<sup>156</sup> *WUTC v. PacifiCorp*, Docket UE-130043, Order 05 ¶ 98 (Dec. 4, 2013) (hereinafter “Order 05”).

<sup>157</sup> *WUTC v. PacifiCorp*, Dockets UE-050684 *et al.*, Order 04 ¶ 50 (Apr. 17, 2006) (resources can provide “benefits to ratepayers in 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.”); *id.* at n. 72 (indirect benefits can include avoided costs, off-system sales revenues, or other system-wide benefits).

<sup>158</sup> Gomez, Exh. No. DCG-1CT 15:10-13.

<sup>159</sup> Mullins, Exh. No. BGM-1CT 25:18-26:2.

observed, “all of a utility’s resources are matched to all of a utility’s load, regardless of state boundaries.”<sup>160</sup>

63 While Staff and Boise contend that service to Washington is immaterial,<sup>161</sup> Staff acknowledges “that a facility’s costs should be allocated to the customers that benefit from that facility.”<sup>162</sup> Because the out-of-state QFs are providing energy and capacity to Washington customers, principles of cost causation require Washington customers to pay the prudent and reasonable costs of these resources.<sup>163</sup>

64 In addition, the out-of-state QF PPAs provide multiple indirect benefits to Washington. First, the out-of-state QFs, which are primarily wind and hydro renewable resources, will provide 806,799 MWh of emission-free generation during the rate year.<sup>164</sup> Washington energy policy promotes the reduction of carbon emissions, both within the state and regionally, as a substantial benefit to Washington residents.<sup>165</sup> The out-of-state QF PPAs provide these benefits, which are not supplied by market purchases or other alternative resources necessary to serve this load.<sup>166</sup>

65 Second, the out-of-state QFs also provide system diversity benefits. Staff acknowledges that resource diversity reduces Pacific Power’s operational risk.<sup>167</sup> Boise agreed: “Portfolio diversification is one of the fundamental principles relied on by utilities . . . to develop a least-cost, least-risk portfolio,” and it agreed that the Company benefits from a diverse fuel supply.<sup>168</sup>

---

<sup>160</sup> 15 F.Supp.3d 891, 917 (D. Minn. 2014); *see also See N.Y. v. FERC*, 535 U.S. 1, n.5 (2002) (“[e]nergy flowing onto a power network or grid *energizes the entire grid*, and consumers then draw undifferentiated energy from that grid. As a result . . . any activity on the interstate grid affects the rest of the grid. *Amici* dispute the States’ contentions that electricity functions the way water flows through a pipe or blood cells flow through a vein and can be controlled, directed and traced as these substances can be, calling such metaphors inaccurate and highly misleading.”) (emphasis in original) (internal quotations omitted).

<sup>161</sup> Gomez, Exh. No. DCG-1CT 10:16-17; Mullins, Exh. No. BGM-1CT 25:18-26:2. At hearing Staff was even more explicit, testifying that whether the QFs provide benefits simply does not matter. Gomez, TR. 555:19-24.

<sup>162</sup> Ball, Exh. No. JLB-7CX 1.

<sup>163</sup> Duvall, Exh. No. GND-4T 21:19-22:7.

<sup>164</sup> Duvall, Exh. No. GND-1CT 8:26, 9:10-15.

<sup>165</sup> Duvall, Exh. No. GND-4T 5:6-6:14; Dalley, Exh. No. RBD-3T 2:18-5:8.

<sup>166</sup> Duvall, Exh. No. GND-4T 18:17-21.

<sup>167</sup> Twitchell, Exh. No. JBT-1T 12:22-13:4; Gomez, TR. 556:3-5.

<sup>168</sup> Mullins, Exh. No. BGM-1CT 57:11-21; *see also* Duvall, Exh. No. GND-4T 19:10-14.



66 Third, the out-of-state QFs provide system reliability benefits. Boise’s trade group, the Industrial Customers of Northwest Utilities (ICNU),<sup>169</sup> has testified about the benefits provided by QFs, including system reliability resulting from the smaller, distributed nature of QFs, which result in greater reliability as compared to larger centralized generators.<sup>170</sup>

**2. Out-of-state QF PPA prices conform to PURPA’s avoided cost requirement and full cost recovery is consistent with PURPA.**

67 Congress passed PURPA specifically to encourage the development of small, renewable facilities and diversify the nation’s generation mix.<sup>171</sup> Section 210 of PURPA imposes a federal obligation on utilities to purchase the energy and capacity from QFs at rates that are just and reasonable to consumers, not discriminatory, and equal to the utilities’ avoided costs.<sup>172</sup>

68 When QFs are priced at avoided cost rates, “consumers are not forced to subsidize QFs because they are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.”<sup>173</sup> PURPA is also designed to make utilities indifferent to QF transactions by requiring full cost recovery for QF PPAs. Section 210(m)(7)(A) of PURPA requires FERC to “ensure that an electric utility that purchases electric energy or capacity from a [QF] . . . recovers all prudently incurred costs associated with the purchase.”<sup>174</sup>

69 FERC has been clear that states cannot set an avoided cost price that includes an “adder” intended to encourage renewable development.<sup>175</sup> Neither can a state discourage renewable

---

<sup>169</sup> See *WUTC v. PacifiCorp*, Docket UE-131384, Petition to Intervene of Boise White Paper, L.L.C. ¶ 6 (Jan. 13, 2014) (“Boise directly participated in PacifiCorp’s most recent general rate case and has participated, as a member of the Industrial Customers of Northwest Utilities, in other PacifiCorp rate proceedings, including UE-991832, UE-032065, UE-050684, UE-060669, UE-061546, UE-080220, UE-090205, UE-100749, and UE-111190.”).

<sup>170</sup> Duvall, Exh. No. GND-4T 19:4-8.

<sup>171</sup> *WUTC v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615, 622 (Nov. 9, 1983) (“The Supreme Court in *American Paper Institute, Inc. v American Electric Power Corp.*, *supra*, begins with the premise that ‘§210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.’”); *So. Cal. Edison Co., et al.*, 71 F.E.R.C. ¶ 61,269, 62,079 (June 2, 1995).

<sup>172</sup> See 16 U.S.C. §§ 824a-3(b), (d) (rates for purchases by utilities must be at the avoided cost).

<sup>173</sup> *Indep. Energy Producers Ass’n v. Cal. Pub. Utils. Comm’n*, 36 F.3d 848, 858 (9th Cir. 1994); 16 U.S.C. §§ 824a-3(b), (d); 18 C.F.R. § 292.101(b)(6).

<sup>174</sup> 16 U.S.C. § 824a-3(m)(7).

<sup>175</sup> *So. Cal. Edison Co., et al.*, 71 F.E.R.C. at 62,080; *Am. Ref-Fuel Co., et al.*, 105 F.E.R.C. ¶ 61,004, 61,007 (Oct. 1, 2003) (a QF’s environmental attributes cannot be considered when determining avoided costs).

development by setting prices below a utility's avoided costs.<sup>176</sup> In a 1994 case, the Supreme Court of North Carolina addressed whether the North Carolina Utilities Commission (NCUC) violated PURPA in its rate treatment of a QF PPA approved by the Virginia State Corporation Commission (VSCC).<sup>177</sup> In that case, the NCUC allowed the multi-jurisdictional utility to recover its full avoided costs, but disallowed an adder based on a state law that allowed the VSCC to account for "intangible environmental and societal benefits associated with QF power."<sup>178</sup> The court affirmed the NCUC's order, concluding that the disallowance "does not violate PURPA to the extent it only excludes the amount *above* avoided costs."<sup>179</sup>

70 In a 1983 case, *WUTC v. Washington Water Power Company*, the Commission took the same approach as the NCUC.<sup>180</sup> The issue was whether recovery of the full Washington-allocated costs of a QF located in Idaho was just and reasonable. The Commission observed, "In reaching this ultimate determination, the commission must make the underlying determination whether the proposed purchase agreement is based on a proper methodology to calculate the avoided cost as defined by federal and state laws and rules."<sup>181</sup> The Commission concluded that the "amount to be paid under the [PPA] is in excess of properly determined avoided cost."<sup>182</sup> Thus, the Commission disallowed cost recovery of the amounts that exceeded the avoided cost price.

71 Here, all of the out-of-state QF PPAs have avoided cost prices adopted by Oregon and California.<sup>183</sup> No party has challenged those avoided cost prices or claimed that they are excessive or illegal. Without a finding that the Company's out-of-state QF PPAs were priced

---

<sup>176</sup> 16 U.S.C. §§ 824a-3(b); 18 C.F.R. §§ 292.304(b)(2).

<sup>177</sup> *State ex rel. Utils. Comm'n v. N.C. Power*, 338 N.C. 412, 450 S.E.2d 896 (1994).

<sup>178</sup> *Re N.C. Power*, Docket E-22, SUB 333, 1993 WL 216264 (Feb. 26, 1993) *aff'd sub nom. N.C. Power*, 450 S.E.2d 896. FERC has since made clear that laws like Virginia's that inflate avoided cost prices to further state policies are contrary to PURPA. *See Re So. Cal. Edison Co.*, 70 F.E.R.C. ¶ 61,215, 61,676 (Feb. 23, 1995).

<sup>179</sup> *N.C. Power*, 450 S.E.2d at 900 (emphasis in original).

<sup>180</sup> *WUTC v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615 (Nov. 9, 1983).

<sup>181</sup> *Id.*, 56 P.U.R.4th at 617.

<sup>182</sup> *Id.*, 56 P.U.R.4th at 624. Staff contends that the fact the Commission rejected the tariff in its entirety meant that the Commission did not re-price the contract. Gomez, TR. 597:8-12. As the order expressly states, however, rejection of the tariff did reflect the utility's avoided costs.

<sup>183</sup> Duvall, Exh. No. GND-1CT 9:3-9.

above avoided costs—a conclusion with no evidentiary support in the record—there is no legal basis under PURPA for the Commission to disallow cost recovery.

**3. Situs assignment results in interstate subsidization and violates PURPA’s customer indifference requirement.**

72 The parties’ rationale for situs assignment is that each state should pay for the costs associated with QFs physically located in that state.<sup>184</sup> To be consistent with PURPA, however, this approach requires that each state consume only the QF electricity generated in that state. As the Commission, parties, and courts have acknowledged, electricity generated by out-of-state QFs indisputably serves loads in Washington.<sup>185</sup> Because Washington customers currently consume far more QF power than Washington produces, situs assignment results in Washington customers receiving QF power-related benefits for which they do not pay.<sup>186</sup> Unless a state consumes only the QF power that it produces, situs assignment means that states with the most QFs will pay more than avoided costs for their QF power and states like Washington with relatively few QFs will pay less than avoided costs. Both scenarios violate PURPA’s requirement of customer indifference.

**4. Market re-pricing of QF PPAs violates PURPA.**

73 In the last rate case, the Commission priced energy and capacity used to serve Washington customers at market rates.<sup>187</sup> In this case, Staff, Public Counsel, and Boise all recommend that the Commission continue to re-price out-of-state QFs at current market prices.<sup>188</sup> But no party claims that current market prices reflect Pacific Power’s avoided costs, either today or at the time that the QFs executed their PPAs. On the contrary, the evidence in this case demonstrates that the market prices used for re-pricing are less than Pacific Power’s

---

<sup>184</sup> See e.g. Order 05 ¶ 111.

<sup>185</sup> *Id.* at ¶ 98; Gomez, Exh. No. DCG-1CT 15:10-13; Mullins, Exh. No. BGM-1CT 25:18-26:2; *N.Y. v. FERC*, 535 U.S. at 7 (“any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce”).

<sup>186</sup> See Duvall, Exh. No. GND-4T 16:8-16.

<sup>187</sup> Order 05 ¶ 98.

<sup>188</sup> Gomez, Exh. No. DCG-1CT 16:12-14; Mullins, Exh. No. BGM-1CT 23:11-18; Ramas, Exh. No. DMR1-CT 4:8-5:11.

avoided costs in two critical respects—current market prices fails to account for the vintage of the QF PPAs and market prices fail to account for the capacity value provided by the QFs.

74 The use of *current* market prices to re-price the out-of-state QF PPAs is contrary to FERC’s regulations allowing QFs to obtain PPAs based on avoided cost prices determined *at the time the QF contracts with the utility*.<sup>189</sup> “[I]f rates are based on avoided cost estimates at the time the obligation is incurred, the rates are consistent with PURPA’s requirements even if they differ from avoided costs at the time of delivery.”<sup>190</sup> At hearing, Staff recognized that the vintage of the contract mattered and it was inapt to compare older contracts to current market prices.<sup>191</sup> In a previous Pacific Power case, the Commission rejected a proposal to re-price an allegedly imprudent 20-year-old sales contract using current market prices, agreeing with Staff “that the fact the contract is below-market today is not relevant to whether it was prudent 20 years ago.”<sup>192</sup>

75 Market prices also compensate Pacific Power for only the energy component of its avoided cost price.<sup>193</sup> The Commission has recognized that avoided costs must account for both energy and capacity, to the extent both are avoided as a result of the QF PPA.<sup>194</sup> The Company’s avoided cost prices reflected in the Company’s current Schedule 37 explicitly include both an energy and capacity component, consistent with the Commission’s conclusion that QF transactions have allowed Pacific Power to defer capacity additions.<sup>195</sup> In this case, Staff testified that wind resources provide capacity to serve the Company’s peak load.<sup>196</sup> In fact, the Company’s west control area wind resources—including the out-of-state wind QFs—contributed

---

<sup>189</sup> See e.g., 16 U.S.C. §§ 824a-3(b), (d); 18 C.F.R. §§ 292.304(b), (d); *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 413-18 (1983).

<sup>190</sup> *N.Y. State Elec. & Gas Corp.*, 71 F.E.R.C. ¶ 61,027, 1995 WL 216781, \*14 (Apr. 12, 1995).

<sup>191</sup> Gomez, TR. 561:15-18, 563:3-6.

<sup>192</sup> *WUTC v. PacifiCorp*, Dockets UE-061546, et al., Order 08 ¶ 123 (June 21, 2007).

<sup>193</sup> Duvall, Exh. No. GND-4T 14:19-15:2.

<sup>194</sup> *Wash. Water Power*, 56 P.U.R.4th at 623 (“Both sets of rules [Commission’s rules and FERC’s rules] provide that in determining the [avoided cost] price if the purchase allows the company to defer additions of capacity, the price to be paid should include capacity costs as well as energy costs.”)

<sup>195</sup> Gomez, Exh. No. DCG-6CX 2.

<sup>196</sup> Twitchell, Exh. No. JBT-1T 15:21-16:6.

25.4 percent of their nameplate capacity to meet the Company's peak load.<sup>197</sup> Staff also agreed that hydro resources, the other predominant out-of-state QF generator, provide significant capacity benefits.

**5. Situs assignment of the Company's out-of-state QFs is inconsistent with the current approach for Avista and past approach for Pacific Power.**

76 The Commission allows Avista to recover its out-of-state QF PPA costs in Washington rates.<sup>198</sup> Staff attempts to justify this disparate treatment by explaining that while “[c]ost-causation is a commission’s primary consideration in accepting an allocation method that best reflects the cost of serving the customers under its state jurisdiction,” the Commission “may apply discretion when allocating costs.”<sup>199</sup> At hearing, Staff admitted that Avista’s Idaho QF PPAs had significantly higher avoided cost prices as compared to its Washington QF PPAs<sup>200</sup> and that both Washington and Idaho QF PPAs were priced higher than current market prices.<sup>201</sup> Other than the fact that Avista’s QFs had a smaller impact on its overall rates,<sup>202</sup> Staff never articulated a reasonable basis for allowing recovery of higher priced out-of-state QF PPAs for Avista while simultaneously testifying in this case that cost causation *requires* situs assignment for Pacific Power.<sup>203</sup> Disparate treatment of Pacific Power and Avista is contrary to the Commission’s duty to regulate “consistently with laws, rules, and pertinent prior decisions” to provide “certainty, consistency, and fairness to both utility companies and their customers.”<sup>204</sup>

77 As described in the Company’s response to Bench Request Number 5, under all of the inter-jurisdictional allocation methodologies—except the WCA—used before and after the

---

<sup>197</sup> Duvall, Exh. No. GND-4T 16:4-7.

<sup>198</sup> Gomez, TR. 561:4-6 (Avista’s Washington rates include allocated costs of five QFs located in Idaho).

<sup>199</sup> Gomez, Exh. No. DCG-1CT 13:6-15.

<sup>200</sup> Gomez, TR. 562:5-13; Gomez, Exh. No. DCG-9CX.

<sup>201</sup> *Id.* at 562:18-21.

<sup>202</sup> Gomez, Exh. No. DCG-1CT 13:16-17:5.

<sup>203</sup> In both its pre-filed testimony and at hearing, Staff claimed that the Commission has previously situs assigned Avista’s QF PPA costs, relying on the *Washington Water Power* case. *See e.g.* Gomez, Exh. No. DCG-1CT n. 24. As outlined above, this interpretation of the order is incorrect.

<sup>204</sup> *WUTC v. Verizon Nw. Inc.*, Docket UT-040788, Order 11 ¶ 140 (Oct. 15, 2004).

merger of Pacific Power and Utah Power, QF PPAs were system allocated.<sup>205</sup> This is true for the pre-WCA allocation methodologies used in Washington and the allocation methodologies used in the Company’s other jurisdictions. Thus, contrary to Staff’s testimony at hearing, the historical norm for Washington and for PacifiCorp has been system allocation, not situs assignment.<sup>206</sup> Indeed, there is no evidence in the record that another commission has ever allocated QF PPAs on a situs basis, for PacifiCorp or any other utility.

**6. Discrimination against out-of-state QF PPAs violates the Commerce Clause.**

78 The parties’ recommended disallowance of out-of-state QF PPAs, based exclusively on the fact that the QFs are located outside of Washington, violates the Commerce Clause of the U.S. Constitution.<sup>207</sup> Courts have interpreted the “dormant” Commerce Clause to implicitly restrain state authority,<sup>208</sup> prohibiting states from taking action that discriminates against or unduly burdens interstate commerce.<sup>209</sup> A regulation is discriminatory if it differentiates between in-state and out-of-state economic interests in a manner that benefits the former and burdens the latter.<sup>210</sup> Facially discriminatory regulations are subject to strict scrutiny and are virtually *per se* invalid.<sup>211</sup>

79 In *New England Power Company v. New Hampshire*, the United States Supreme Court held that a New Hampshire Public Utilities Commission (NHPUC) order precluding a generator, New England Power Company, from selling its hydroelectric power outside New Hampshire was “precisely the sort of protectionist regulation that the Commerce Clause declares off-limits to the

---

<sup>205</sup> Bench Request No. 5 at 1.

<sup>206</sup> At hearing, Staff testified that prior to 2004 QF PPAs were situs assigned under the Revised Protocol. Gomez, TR. 558:9-12, 574:6-575:6. This misunderstanding likely arises from the fact that under the Revised Protocol PPAs executed before June 2004 were included in the Embedded Cost Differential (ECD) calculation, as explained in Bench Request No. 5. Despite this fact, the QF PPA costs for those QFs were still system allocated, it was only a small portion that was situs assigned as part of the ECD.

<sup>207</sup> U.S. Const. art. I, § 8, cl. 3.

<sup>208</sup> *United Haulers Ass’n, Inc. v. Oneida-Herkimer Solid Waste Mgmt. Auth.*, 550 U.S. 330, 338 (2007).

<sup>209</sup> *Quill Corp. v. N.D.*, 504 U.S. 298, 312 (1992).

<sup>210</sup> *Or. Waste Sys., Inc. v. Dep’t of Env’tl. Quality of State of Or.*, 511 U.S. 93, 99 (1994).

<sup>211</sup> *City of Phila. v. N.J.*, 437 U.S. 617, 624 (1978) (“where simple economic protectionism is effected by state legislation, a virtually *per se* rule of invalidity has been erected”).

states.”<sup>212</sup> Because the “transmission of electric current from one state to another . . . is interstate commerce,”<sup>213</sup> the Court determined that the NHPUC order unconstitutionally placed “direct and substantial burdens on transactions in interstate commerce.”<sup>214</sup>

80           Applying the Court’s *New England Power* analysis, in *Middle South Energy, Inc. v. Arkansas Public Service Commission*, the U.S. Court of Appeals for the Eighth Circuit found that the Arkansas Public Service Commission (APSC) unconstitutionally interfered with a utility’s contracts with an out-of-state generating plant.<sup>215</sup> The contracts at issue involved the financing of the plant and the subsequent purchase of electricity from the plant. In seeking to “close its borders to high-cost electricity,” Arkansas illegally instituted a preference for its citizens “gained at the expense of out-of-state customers.”<sup>216</sup> Similar to *New England Power*, the Eighth Circuit found that the “APSC’s action would constitute a direct and substantial burden on interstate commerce” because of the integrated nature of the electrical grid, which “represents commerce that is interstate in a most basic form.”<sup>217</sup>

81           The differential treatment of out-of-state QF PPAs, based exclusively on the fact that the QFs are located outside of Washington, is discriminatory on its face.<sup>218</sup> Pacific Power uses the out-of-state QFs to serve Washington load and out-of-state QF PPAs are the only resources that serve Washington customers that are denied cost recovery based on their geographic location. Like in *New England Power* and *Middle South Energy*, the electricity generated by the out-of-state QF PPAs flows into the interconnected, interstate transmission grid and is used to serve Washington customers, as recognized by the Commission and the parties.<sup>219</sup>

---

<sup>212</sup> *New England Power Co. v. N.H.*, 455 U.S. 331, 339 (1982) (“The [NHPUC] has made clear that its order is designed to gain an economic advantage for New Hampshire citizens at the expense of New England Power’s customers in neighboring states.”).

<sup>213</sup> *Pub. Utils. Comm’n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 86 (1927), *abrg’d on other grounds by Quill Corp.*, 504 U.S. 298.

<sup>214</sup> *New England Power Co.*, 455 U.S. at 339.

<sup>215</sup> *Middle S. Energy, Inc. v. Ark. Pub. Serv. Comm’n*, 772 F.2d 404 (8th Cir. 1985).

<sup>216</sup> *Id.* at 417.

<sup>217</sup> *Id.*

<sup>218</sup> *See Gomez*, TR. 558:19-22.

<sup>219</sup> Order 05 ¶ 98.

82 By denying cost recovery of out-of-state QF PPAs, situs assignment unconstitutionally “places direct and substantial burdens on transactions in interstate commerce,”<sup>220</sup> effectively blocking the flow of interstate commerce at Washington’s borders.<sup>221</sup> It discriminates against QFs based on their geographic location, discriminates against customers by setting rates that differ from avoided cost, and discriminates against Pacific Power by unduly burdening the Company’s participation in interstate commerce.

**7. The Company’s proposed alternatives are reasonable approaches to allocation of out-of-state QF PPA costs.**

**a. The Washington re-pricing alternative responds to concerns about different state QF policies in Oregon and California.**

83 The Company’s Washington re-pricing alternative re-prices each California and Oregon QF PPA at the Washington avoided cost rates in effect at the time the PPA was executed.<sup>222</sup> Because the Commission-approved avoided cost prices result in customer indifference, re-pricing the out-of-state QF PPAs at Washington avoided cost prices will also result in customer indifference.<sup>223</sup> This proposal ensures that Washington rates reflect only the policy decisions made by Washington and that customers are not impacted by policy decisions made in Oregon and California. The alternative decreases Pacific Power’s filing by \$2.2 million.<sup>224</sup>

84 As explained in the Company’s response to Bench Request 3, the Company’s re-pricing alternative is based on the same calculation that Staff, and ultimately the Commission, relied upon in the Company’s last rate case to demonstrate the relative level of Washington’s avoided cost prices.<sup>225</sup> The only difference is that the Company escalated the avoided cost prices into the rate year when the Washington avoided cost schedule used for re-pricing did not have prices into the rate year.<sup>226</sup> Escalating the vintage avoided cost rates into the pro-forma period captures

---

<sup>220</sup> *New England Power Co.*, 455 U.S. at 339.

<sup>221</sup> *City of Phila.*, 437 U.S. at 624.

<sup>222</sup> Duvall, Exh. No. GND-1CT 13:20-14:22; Bench Request No. 3.

<sup>223</sup> Duvall, Exh. No. GND-4T 25:8-17.

<sup>224</sup> *Id.* at 13:9-11.

<sup>225</sup> Order 05 ¶ 113; Bench Request No. 3.

<sup>226</sup> Bench Request No. 3.



expected increases in forward prices from the time the QF PPAs were executed. No party challenged the Company's re-pricing methodology in pre-filed testimony.

85           The Company's re-pricing methodology addressed only QF PPA prices and did not adjust for other QF PPA terms, including the length of the QF PPA. WAC 480-107-075(3) allows a utility to execute a Washington QF PPA for any term up to 20 years.<sup>227</sup> An assumption that the prices in the Company's California and Oregon QF PPAs should be re-opened every five years, based on the length of the standard QF PPA in Washington, is inconsistent with this rule specifically allowing longer QF PPA terms. It is also inconsistent with PURPA, which prohibits a utility from re-opening QF PPA prices during a PPA's term.<sup>228</sup>

**b.       The load decrement alternative addresses inequities inherent to situs assignment of QF PPA costs.**

86           The Company also proposed a load decrement approach to out-of-state QF PPAs. The proposal starts from the premise that the Oregon and California QFs serve customers only in those states, consistent with the Commission's situs assignment. The retail load of those states is reduced to account for the load served by the native QF. The reduced load is then used to determine allocation factors under the WCA.<sup>229</sup> This proposal would decrease the Company's filing by \$3.9 million.<sup>230</sup> This proposal ensures that the full impact of treating QF PPAs as situs resources is reflected in Washington revenue requirement and mitigates the cross-state subsidies inherent in a situs approach (where Washington pays for less QF power than it consumes).<sup>231</sup>

**C.       The Commission Should Reject Boise's Speculative Imputation of EIM Benefits**

87           Boise proposes to reduce Washington-allocated NPC by more than \$5 million based on the Company's participation in the EIM, while also including certain EIM-related costs. Boise

---

<sup>227</sup> See e.g. Duvall, Exh. No. GND-1CT 14:16-22.

<sup>228</sup> See e.g. *Freehold Cogen. Assoc., L.P. v. Bd. of Reg. Comm'rs of New Jersey*, 44 F.3d 1178, 1192 (3d Cir. 1995).

<sup>229</sup> Duvall, Exh. No. GND-1CT 12:10-13:19.

<sup>230</sup> Duvall, Exh. No. GND-4T 13:12-16.

<sup>231</sup> *Id.* at 27:6-10.

agrees this adjustment is subject to a stricter standard, requiring “a high degree of analytic rigor.”<sup>232</sup>

88 The EIM became operational in November 2014. The Company excluded both the costs and potential benefits of the EIM because it is the first market of its kind in the West and the extent of the benefits that will be realized during the rate year is highly uncertain.<sup>233</sup> In support of a similar approach in Oregon, Boise’s witness (on behalf of Boise’s trade association ICNU) agreed, “at this time, the costs and benefits associated with the EIM are difficult to predict with certainty,” so “it is reasonable to offset EIM costs and benefits in 2015 NPC.”<sup>234</sup>

**1. The E3 Report was never intended to be used for ratemaking and the assumptions underlying the report do not match the NPC pro forma period in this case.**

89 Boise’s adjustment relies on the E3 Report to “quantify the NPC impacts of the EIM in the rate period.”<sup>235</sup> The E3 Report, however, was never intended to be used to quantify near-term benefits for ratemaking purposes. Rather, as Boise admitted, the report was a planning document to verify the cost-effectiveness of the EIM.<sup>236</sup>

90 Further, the assumptions underlying the E3 Report are fundamentally inconsistent with this case. The E3 Report was issued in March 2013 and is limited by the data and assumptions available at that time.<sup>237</sup> Eight months after the E3 Report was issued, the Commission specifically recognized that “it is too early in the process for the Company to project the exact impacts that the EIM will have on [PacifiCorp’s] strategy and its ratepayers.”<sup>238</sup>

---

<sup>232</sup> Mullins, TR. 742:25-743:3.

<sup>233</sup> Duvall, Exh. No. GND-4T 30:19-31:9.

<sup>234</sup> *Id.* at 32 n. 45; Mullins, TR. 708:11-20.

<sup>235</sup> Mullins, Exh. No. BGM-1CT 31:18-19. At hearing, Boise’s witness claimed that he had relied on the E3 Report as a “starting point” and that the proposed EIM adjustment was based on independent analysis. Mullins, TR. 713:4. However, Boise’s pre-filed testimony is clear that the basis of the EIM adjustment was the E3 Report. Indeed, Boise’s inter-regional dispatch benefit and flexibility reserve savings were taken directly from the E3 Report. Mullins, Exh. No. BGM-1CT 42 Table 6; Mullins, TR. 731:4-5.

<sup>236</sup> Duvall, Exh. No. GND-4T 33:15-23; Mullins, TR. 715:1-12; Mullins, Exh. No. BGM-11CX 18.

<sup>237</sup> Duvall, Exh. No. GND-4T 31:13-14.

<sup>238</sup> Ball, Exh. No. JLB-8CX 9.

91 The E3 Report also focuses on estimated potential EIM benefits expected in 2017, which was selected “to represent likely system conditions within the first several years after the EIM becomes operational,” not the conditions existing in the early stage of EIM operation.<sup>239</sup> This means that the report used forecasted loads, fuel prices, generators, and transmission expected in 2017.<sup>240</sup> The NPC pro forma period in this case ends March 31, 2016, and has no overlap with the base period in the E3 Report.

92 Boise relies on the E3 Report’s allocation of benefits between PacifiCorp and CAISO, even though the report states explicitly that it “provides a high-level estimate of how these benefits might be apportioned among the ISO and PacifiCorp systems,” and that it is “not intended to be a methodology for allocating costs and benefits.”<sup>241</sup> The report is clear—the actual “benefits that would flow to” PacifiCorp “might be different from the assumptions used here.”<sup>242</sup>

**2. Boise’s inter-regional dispatch benefit double counts transactions already modeled in GRID and relies on inapplicable transmission assumptions.**

93 Boise’s EIM adjustment includes benefits resulting from increasing transactions between CAISO and PacifiCorp. The Company’s NPC in this case reflects significant transactions between PacifiCorp and CAISO at the California-Oregon-Border (COB) market, which use the same transmission capacity the E3 Report used to determine the inter-regional dispatch benefits.<sup>243</sup> The benefits Boise seeks to impute are already captured in GRID.

94 In addition, Boise’s adjustment relies on assumptions in the E3 Report that have yet to materialize.<sup>244</sup> The E3 Report assumed five-minute dynamic transfer capabilities between CAISO and PacifiCorp at the California-Oregon Intertie (COI). To date, however, the transfer

---

<sup>239</sup> Mullins, Exh. No. BGM-5 4, 7.

<sup>240</sup> *Id.* at 42; Duvall, Exh. No. GND-4T 33:17-22.

<sup>241</sup> Mullins, Exh. No. BGM-5 13, 34.

<sup>242</sup> *Id.* 34.

<sup>243</sup> Duvall, Exh. No. GND-4T 37:7-15.

<sup>244</sup> Mullins, Exh. No. BGM-5 19 (initial reliance on existing transmission contract rights “will prevent achievement of full benefits at EIM startup”).

capability has been limited to 15-minute transfers, which are less valuable than dynamic transfers and do not correlate to the E3 Report.<sup>245</sup>

**3. Boise’s intra-regional dispatch benefit has no relation to the potential intra-regional dispatch benefits that may occur through the EIM.**

95 Boise also imputed benefits related to intra-regional dispatch because the EIM will enable “more optimal generation and transmission dispatch in the PacifiCorp area.”<sup>246</sup> The E3 Report estimated these benefits by determining the benefits to CAISO when it transitioned from zonal to nodal pricing.<sup>247</sup> The Company’s NPC already includes these benefits, however, because GRID employs nodal dispatch and assumes perfectly efficient operations, just like the CAISO model.<sup>248</sup> To the extent intra-regional benefits are realized through the EIM, those benefits will simply bring actual operations more in line with the perfectly efficient dispatch modeled in GRID.<sup>249</sup>

96 Boise calculated its adjustment by removing all market caps from GRID, assuming unlimited system balancing sales at COB and Mid-Columbia markets.<sup>250</sup> Boise proposed removal of market caps in the Company’s last rate case,<sup>251</sup> which the Commission rejected after concluding that this would make GRID more inaccurate.<sup>252</sup> Here, Boise claimed that the value of removing the market caps is a “proxy under the assumption that the GRID model without market caps will more closely mimic the [CAISO] model.”<sup>253</sup> But Boise presented no evidence substantiating this assumption. At hearing, Boise’s witness agreed that GRID used nodal pricing and optimal dispatch and that it was already similar to the CAISO model.<sup>254</sup>

---

<sup>245</sup> Duvall, Exh. No. GND-4T 36:20-37:6.

<sup>246</sup> Mullins, Exh. No. BGM-5 23.

<sup>247</sup> Duvall, Exh. No. GND-4T 38:16-39:3.

<sup>248</sup> *Id.* at 39:11-21.

<sup>249</sup> *Id.* at 40:3-5.

<sup>250</sup> *Id.* at 40:8-20; Mullins, Exh. No. BGM-16CX 1.

<sup>251</sup> Mullins, TR. 737:13-15; Mullins, Exh. No. BGM-16CX.

<sup>252</sup> Order 05 ¶ 154.

<sup>253</sup> Mullins, TR. 736:11-15.

<sup>254</sup> *Id.* at 734:20-735:8; Mullins, Exh. No. BGM-11CX 9:2-4 (admitting in testimony before Wyoming Public Service Commission that CAISO will optimize just like GRID).

**4. Boise’s flexibility reserves adjustment is based on erroneous calculations and flawed assumptions.**

97 Under the EIM, PacifiCorp’s required flexibility reserves are expected to decrease as the reserves requirements can be spread over the entire EIM footprint.<sup>255</sup> The extent of the savings is linked to the transmission capacity between PacifiCorp and CAISO. Thus, like Boise’s inter-regional dispatch benefit, the flexibility reserve savings calculated by Boise is overstated because of the current lack of dynamic transfer capabilities between PacifiCorp and CAISO.<sup>256</sup>

98 Boise’s adjustment is also overstated because it assumes that the Company can achieve 100 percent of the flexibility savings resulting from EIM participation.<sup>257</sup> Boise’s adjustment assumes 98 MW of reserve savings, which are the total reserve savings estimated in the E3 Report.<sup>258</sup> The E3 Report, however, assumed that PacifiCorp could achieve only 80 percent of the total savings, or 78 MW.<sup>259</sup> At hearing, Boise’s witness was asked about this error, which he refused to acknowledge.<sup>260</sup> Boise’s witness’s intransigence is notable given that only two months ago he testified before the Public Service Commission of Wyoming, repeatedly and unequivocally, that the reserve savings estimated in the E3 Report are only 78 MW.<sup>261</sup> If Boise’s witness did, in fact, intend to model a 98 MW reduction in reserves, he failed to justify his position considering that it is directly contrary to the E3 Report and his own prior testimony.<sup>262</sup>

**5. The E3 Report undermines Boise’s “within-hour dispatch” adjustment.**

99 The one component of Boise’s EIM adjustment that was not based explicitly on the E3 Report is the “within-hour dispatch” adjustment. Boise claims that this adjustment is necessary because the E3 Report was performed on an hourly basis and therefore excluded these benefits,

---

<sup>255</sup> Duvall, Exh. No. GND-4T 41:13-16.

<sup>256</sup> *Id.* at 42:7-9.

<sup>257</sup> *Id.* at 42:12-14.

<sup>258</sup> Mullins, Exh. No. BGM-1CT 42 Table 6.

<sup>259</sup> Mullins, Exh. No. BGM-5 26-27; Duvall, Exh. No. GND-4T 41:21-42:4.

<sup>260</sup> Mullins, TR. 733:13-15.

<sup>261</sup> Mullins, Exh. No. BGM-11CX 10:6-9 (“The E3 study forecasts that the company’s load-following-reserve requirement was declining by approximately 78 MW as a result of integrating with the Cal ISO through the EIM.”); *id.* at 64:24-65:6 (confirming during commissioner questioning that E3 Report estimated 78 MW reserve savings).

<sup>262</sup> Mullins, TR. 733:13-15.

but noted that they may be substantial.<sup>263</sup> But Boise fails to note that the E3 Report also indicated that the use of hourly dispatch in the analysis “introduces two potentially offsetting modeling inaccuracies,” the within-hour dispatch benefits Boise imputes and an offsetting inaccuracy that may overestimate the potential benefits because dispatch changes that are feasible on an hourly basis may not be feasible on a sub-hourly basis.<sup>264</sup> Thus, the E3 Report concludes that the within hour benefits Boise imputes may well be entirely offset, resulting on no additional benefits at all.

**6. Boise’s allocation of EIM costs and benefits to Washington is flawed.**

100 There are several problems in Boise’s Washington allocation of EIM costs and benefits. First, Boise relied on a PacifiCorp system-wide factor to allocate EIM costs and benefits to Washington.<sup>265</sup> This overstates EIM benefits to Washington because, under the WCA, Washington does not pay a system-wide share of the Company’s generation costs.<sup>266</sup> Boise’s approach is also fundamentally inconsistent with the WCA, which isolates the costs of PacifiCorp’s west control area and is premised on the assumption that the east-side resources are not beneficial to Washington.

101 Second, the allocation factors used by Boise imply significantly greater EIM benefits than even the E3 Report estimates. Boise estimated that the Washington-allocated EIM benefits will be \$5.1 million, which, based on the allocation factors used by Boise, implies total Company EIM benefits of \$64 to \$67 million<sup>267</sup>—an amount that far exceeds the high-end estimated benefits of \$54 million in the E3 Report.<sup>268</sup>

---

<sup>263</sup> Mullins, Exh. No. BGM-1CT 43:9-15.

<sup>264</sup> Mullins, Exh. No. BGM-5 16-17.

<sup>265</sup> Mullins, TR. 718:6, 722:3-18, 741:5-10.

<sup>266</sup> *Id.* at 720:22-722:18.

<sup>267</sup> Boise uses the SE (7.5698 percent) and SG (7.9057 percent) factors to allocate benefits and costs, respectively. Mullins, TR. 718:6, 741:5-10. Dividing \$5.1 million by the SE and SG factors results in total Company benefits of \$64 and \$67 million.

<sup>268</sup> Mullins, Exh. No. BGM-1CT 33 Table 3.

102 Third, Boise allocated the benefits of inter-regional dispatch benefits between the east and west control areas based on the load in each control area.<sup>269</sup> This benefit, however, is related to more efficient dispatch of resources, not load. The east control area has significantly more dispatchable resources that will be bid into the EIM and therefore will realize greater benefits.<sup>270</sup>

103 Fourth, Boise allocates 100 percent of the flexibility reserve savings to the west control area, even though the east control area has more wind resources and therefore a larger share of the Company's total reserves.<sup>271</sup> Given that the flexibility reserve savings in the E3 Report are based on the Company's total system, it makes no sense to assume that all of those savings will accrue to the benefit of only the west control area.

**D. Pacific Power's Proposed RRTM is Reasonable and Furthers State Energy Policy**

104 In its 2013 rate case, the Company proposed a PCAM that would have allowed the Company to recover all of its prudently incurred NPC. The Commission rejected the Company's proposal, but indicated its openness to consider a PCAM that incorporates the proper balance between the Company and customers.<sup>272</sup> In response, the Company proposed a more narrowly tailored mechanism in this case, the RRTM. While the Company did not propose and does not support Staff's PCAM in this case, the RRTM can be complementary to a properly designed PCAM, and the two mechanisms should not be viewed as mutually exclusive.

105 The RRTM would allow the Company to collect or credit the differences between the value of resources eligible for the renewable portfolio standard (RPS) included in Washington rates and the actual value of the resources used to serve customers.<sup>273</sup> The RRTM is narrowly focused on resources that are eligible for compliance with Washington state energy policy.<sup>274</sup> The RRTM furthers Washington state energy policy and promotes renewable development by

---

<sup>269</sup> *Id.* at 35:19-20.

<sup>270</sup> Duvall, Exh. No. GND-4T 37:16-38:14; Duvall, Exh. No. GND-7.

<sup>271</sup> Duvall, Exh. No. GND-4T 42:15-22.

<sup>272</sup> Order 05 ¶ 173.

<sup>273</sup> Duvall, Exh. No. GND-1CT 38:5-18.

<sup>274</sup> Duvall, Exh. No. GND-4T 53:2-5.

mitigating the cost-recovery concerns that arise due to the inherent variability of many renewable resources.<sup>275</sup> By allowing full cost recovery of RPS-eligible resources, the RRTM is consistent with the cost-recovery provision of the EIA, which entitles utilities to “recover all prudently incurred costs associated with compliance” with the RPS.<sup>276</sup>

106           Given that RPS-eligible resources are largely intermittent, the RRTM also focuses on resources that exhibit significant variability outside the Company’s control.<sup>277</sup> Since 2006, the Company added 405 MW of new wind resources in the west control area. The new resources are largely sited in the same geographic location. When the wind changes, the generation from these resources increases or decreases in unison, which causes significant, unpredictable changes in market prices.<sup>278</sup> Since 2007, the forecast wind generation has exceeded the actual wind generation by over 500,000 MWh, resulting in cumulative under-recovery of \$34.8 million in NPC.<sup>279</sup>

107           Staff has specifically recognized the expanded role of renewable generation in the Company’s portfolio.<sup>280</sup> And parties have recognized the difficulty of forecasting wind generation. In the Company’s 2013 rate case, Boise’s witness testified that, “[f]orecasting normalized annual generation for large-scale wind projects in the United States is very much a science still in development . . . it is clear that wind power resources can display a high level of variability in inter-annual generation.”<sup>281</sup>

108           Parties criticize the RRTM because the wind variability is valued using market prices.<sup>282</sup> Market variability must be accounted for in the RRTM because it is an integral component of the cost variability associated with intermittent wind resources and is the most accurate way to

---

<sup>275</sup> *Id.* at 53:9-16.

<sup>276</sup> RCW 19.285.050(2).

<sup>277</sup> Duvall, Exh. No. GND-4T 53:2-5.

<sup>278</sup> Duvall, Exh. No. GND-1CT 41:7-14.

<sup>279</sup> *Id.* at 41:15-42:4.

<sup>280</sup> Gomez, Exh. No. DCG-10CX 9:16-18.

<sup>281</sup> Duvall, Exh. No. GND-4T 57:12-16.

<sup>282</sup> *See e.g.* Twitchell, Exh. No. JBT-1T 10:1-4.



calculate the NPC impact of variations in wind generation. Moreover, like wind generation, market prices are outside the Company's control, as Staff has previously testified.<sup>283</sup>

109 Parties are also critical of the narrow focus of the RRTM and argue that it could enable NPC over-recovery. As described above, the narrow focus of the RRTM is intended to capture the variability resulting from only those resources that are RPS-eligible and promote state energy policy. Parties have in the past supported narrowly tailored cost-recovery mechanisms focusing on only those resources that exhibit significant variability.<sup>284</sup> In addition, Pacific Power agreed to cap its cost recovery under the RRTM at its actual NPC.<sup>285</sup>

110 Parties further object to the lack of dead bands and sharing bands in the RRTM. But this approach is reasonable given the EIA's cost recovery mandate and the RRTM's narrow focus. As the Company explained, even the most efficient system operation cannot entirely mitigate the risks and costs associated with the variability and unpredictability of wind.

#### **E. The Commission Should Reject Staff's Proposed PCAM**

111 Staff has recommended a PCAM in this case that is "virtually identical" to Avista's Energy Recovery Mechanism (ERM), including asymmetrical sharing bands "[t]o reflect asymmetry of power cost distribution."<sup>286</sup> The Commission previously rejected a PCAM proposed by the Company specifically because it was modeled on the ERM and failed to account for "PacifiCorp's unique circumstances."<sup>287</sup> The Commission has been clear that PCAMs need to be specifically tailored to each utility's unique operational circumstances and current market conditions.<sup>288</sup> The Commission has also found that asymmetrical variability is largely due to

---

<sup>283</sup> Duvall, Exh. No. GND-4T 56:12-15 (Staff testified that the "Company has no control of either the sales prices or purchase prices related to economy market energy transactions it needs to make in order to address hydro-generation variability or short-term changes in customer load.").

<sup>284</sup> *WUTC v. PacifiCorp*, Dockets UE-061546, *et al.*, Order 08 ¶ 62 (June 21, 2007) ("... ICNU recommends that the Commission approve a PCAM that is focused narrowly on variability in hydro-generation[.]").

<sup>285</sup> Duvall, Exh. No. GND-4T 59:1-10.

<sup>286</sup> Gomez, Exh. No. DCG-7CX 1; Gomez, Exh. No. DCG-1CT 21:17-19, 22:20-22.

<sup>287</sup> *WUTC v. PacifiCorp*, Dockets UE-050684, *et al.*, Order 04 ¶ 91 (Apr. 17, 2006); *WUTC v. PacifiCorp*, Dockets UE-061546, *et al.*, Order 08 ¶ 59 (June 21, 2007).

<sup>288</sup> *WUTC v. PacifiCorp*, Dockets UE-050684, *et al.*, Order 04 ¶ 91 (Apr. 17, 2006); *WUTC v. PacifiCorp*, Dockets UE-061546, *et al.*, Order 08 ¶ 83 (June 21, 2007).

hydro variability<sup>289</sup> and that “PacifiCorp is less reliant on hydroelectric power than Avista and PSE, which may suggest a differently structured PCAM.”<sup>290</sup> In the last case, the Company presented un rebutted evidence that its power cost distribution is symmetrical, which Staff agreed is relevant when designing the bands.<sup>291</sup>

112 At hearing in this case, Staff was unable to articulate how it accounted for the Company’s unique circumstances in designing its PCAM.<sup>292</sup> Staff has presented no evidence that Pacific Power’s “unique circumstances” now warrant a PCAM that is “virtually identical” to the ERM.

113 Moreover, Staff’s proposal is insufficient to address the Company’s consistent NPC under-recovery. Accounting for changing loads, Staff’s testimony indicates that between 2007 and 2013, the Company under-recovered \$303 million in Washington-allocated NPC.<sup>293</sup> Under Staff’s proposed PCAM, the Company would have recovered only 28 percent of that amount.<sup>294</sup> A PCAM with such a limited impact is insufficient to address the Company’s consistently poor NPC recovery in Washington. In addition, without the RRTM, the PCAM would disallow approximately three-quarters of NPC under-recovery from renewable resources, in contravention of the EIA’s mandate of 100 percent cost recovery.

#### **F. Boise’s Thermal Plant Outage Adjustments are Meritless**

##### **1. The Chehalis outage was not anomalous and not the result of imprudence.**

114 In November 2013, one of the three units at Chehalis experienced an outage caused by the failure of a generator step-up transformer. Boise argues that this outage is not “representative of plant operations in the rate period” and should be excluded from the four-year average.<sup>295</sup> But in the Company’s 2010 rate case, Boise’s NPC witness through its trade group, ICNU, testified

---

<sup>289</sup> *WUTC v. PacifiCorp*, Dockets UE-061546, *et al.*, Order 08 ¶ 85 (June 21, 2007); *WUTC v. PacifiCorp*, Docket 130043, Responsive Testimony of Michael C. Deen, Exh. No. MCD-1CT 28:21-23 (June 21, 2013).

<sup>290</sup> *WUTC v. PacifiCorp*, Dockets UE-050684, *et al.*, Order 04 ¶ 93 (Apr. 17, 2006).

<sup>291</sup> Order 05 ¶ 167.

<sup>292</sup> Gomez, TR. 566:25-569:9.

<sup>293</sup> Gomez, Exh. No. DCG-5C.

<sup>294</sup> Gomez, TR. 571:6-11.

<sup>295</sup> Mullins, Exh. No. BGM-1CT 50:13-14.

that an outage should be excluded as anomalous only if it exceeds 28 days.<sup>296</sup> The Chehalis outage was less than 28 days.<sup>297</sup>

115 Boise also claims that the outage was the result of imprudence because the plant had experienced similar types of outages in prior years, one in 2006 before the Company owned the plant and one in 2011.<sup>298</sup> Boise's conclusions are solely based the opinion of Mr. Mullins, who has no training or experience in plant operations and maintenance.<sup>299</sup> The root cause analysis conducted on the outage—the only evidence upon which Boise's witness relies—did not attribute the outage to imprudence or operator error.<sup>300</sup>

116 The Company's expert, Mr. Dana Ralston, who has 28 years of experience in plant operations and maintenance, testified that the plant was operated consistent with standard industry practices, that the Company's actions following the 2011 outage were reasonable, and that the two prior outages would not have caused the Company to operate the plant differently.<sup>301</sup> In fact, following the 2011 outage, the Company installed monitoring equipment on the generator step-up transformers specifically to allow the Company to assess the risk of future failures—an action that exceeds standard industry practice.<sup>302</sup>

117 Boise claims that in the month leading up to the 2013 failure, the monitoring equipment indicated a problem and that it was "very clear" that the Company was "operating [the plant] in alarm status for a very long period of time."<sup>303</sup> This is not true. Whenever the data indicated an abnormality, the Company took immediate action to determine whether remedial steps were necessary, including the removal of the unit from service.<sup>304</sup> Contrary to Boise's claims, the

---

<sup>296</sup> *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 139 (Mar. 25, 2011).

<sup>297</sup> Mullins, Exh. No. BGM-1CT 50:11-13.

<sup>298</sup> *Id.* at 51:3-4.

<sup>299</sup> Mullins, TR. 749:18-21, 757:10-758:6.

<sup>300</sup> *Id.* at 749:22-750:2.

<sup>301</sup> Ralston, Exh. No. DMR-2T 4:20-5:5, 6:5-16, 6:21-7:22, 8:1-10.

<sup>302</sup> *Id.* at 4:18-5:5, 6:11-12.

<sup>303</sup> Mullins, TR. 750:24-751:4.

<sup>304</sup> Ralston, Exh. No. DMR-2T 5:6-17.

monitoring equipment never indicated that a failure was imminent or that the transformer's operation was critical in the time leading up to the 2013 failure.<sup>305</sup>

**2. The Colstrip outage was not the result of imprudence and the replacement power costs are known and measurable.**

118 Boise recommends that the Commission deny the Company's deferral petition for the Colstrip Unit 4 outage in 2013 for several reasons. Boise claims that the outage was the result of imprudent plant operation,<sup>306</sup> an opinion completely at odds with the root cause analysis. That analysis concluded that the plant operator, "did everything according to standard industry practice . . . Nothing they did or could have done, could have prevented this failure."<sup>307</sup> The expert's report continues, "In the future we would recommend that they . . . continue to operate and protect their units as they have been doing."<sup>308</sup>

119 Boise also claims that the replacement power costs cannot be accurately quantified and that the Company did not update the estimated replacement power costs included in its deferral application.<sup>309</sup> Boise ignores the extensive evidence presented in the Company's direct case detailing the actual replacement power costs incurred by the Company.<sup>310</sup> And, contrary to Boise's general claims, the Commission has previously approved recovery of replacement power costs resulting from a Colstrip outage.<sup>311</sup> While Boise also criticizes the Company for omitting from its deferral petition the fact that replacement power costs will be offset by a reduction in Colstrip fuel expenses, it is undisputed that the Company's replacement power costs specifically account for decreased variable expenses resulting from the outage.<sup>312</sup>

---

<sup>305</sup> *Id.* at 5:18-21; Mullins, Exh. No. BGM-7C 10.

<sup>306</sup> Mullins, Exh. No. BGM-1CT 65:14.

<sup>307</sup> Mullins, Exh. No. BGM-4C 47.

<sup>308</sup> *Id.*

<sup>309</sup> Mullins, Exh. No. BGM-1CT 63:19-23.

<sup>310</sup> Siore, Exh. No. NCS-9 5.

<sup>311</sup> *WUTC v. Puget Sound Power and Light*, Cause No. U-87-1262-T, 87 P.U.R.4th 53, 55 (Sept. 30, 1987) (replacement power cost recovery allowed "because no imprudence on the part of the company has been shown").

<sup>312</sup> Mullins, Exh. No. BGM-1CT 64:13-15; Siore, Exh. No. NCS-9 5.

**G. The Commission Should Approve the Replacement Power Costs Associated with Less-than-Normal Hydro Generation**

120 Based on the expectation that hydro generation in 2014 would vary significantly from forecast amounts included in rates, the Company filed a deferral application for the replacement power costs resulting from the expected abnormal weather conditions.<sup>313</sup> As of November 2014, hydro generation was 7.6 percent less than expected, a variance resulting in replacement power costs of \$2.4 million.<sup>314</sup>

121 Parties recommend the Commission reject the Company's petition because they contend that, as of the time that the parties filed testimony, hydro generation was not abnormal and that it is inappropriate to defer only one component of NPC between rate cases.<sup>315</sup> Between the filing of the parties' testimony and the Company's rebuttal, however, the variance had more than doubled and the variance has remained high. The Commission has specifically allowed recovery of individual NPC variations between rate cases, *e.g.*, recovery of replacement power costs for thermal plant outages discussed above. Without the deferral, the Company would have no way to recover the costs associated with low hydro generation because the Company uses a single year of median hydro generation levels to set rates, not an average.<sup>316</sup> Therefore, anomalous years are not reflected in an average calculation.

**H. Boise's Inter-Hour Integration Adjustment is Baseless**

122 Boise recommends an adjustment to remove the inter-hour wind and load integration costs that are modeled outside of GRID.<sup>317</sup> Boise incorrectly claims that the Company's use of hourly wind shaping in GRID internalizes these costs to the GRID results and that accounting for these costs outside of GRID double-counts the costs. The inter-hour wind integration costs are the result of the differences between how the Company commits its resources (based on forecast

---

<sup>313</sup> Duvall, Exh. No. GND-4T 59:14-17.

<sup>314</sup> *Id.* at 61:1-11.

<sup>315</sup> Gomez, Exh. No. DCG-1CT 16-18; Ramas, Exh. No. DMR-1CTr 42-44; Mullins, Exh. No. BGM-1CT 67-68:7.

<sup>316</sup> Duvall, Exh. No. GND-4T 60:11-21.

<sup>317</sup> Mullins, Exh. No. BGM-1CT 50:3-7.

wind) and how the Company actually dispatches the resources (based on actual wind).<sup>318</sup> The Company's inter-hour integration costs reflect the costs resulting from the difference between commitment and dispatch, costs that are not double-counted because they are not a part of GRID. Boise also claims that this is the first time that the Company included inter-hour costs for load integration.<sup>319</sup> This claim is incorrect; the Company included these costs in the last two cases.<sup>320</sup>

**I. The Company Agrees With Boise's BPA NITS Adjustment, But Not its Calculation**

The Company accepts, in concept, an adjustment proposed by Boise related to network integration transmission service (NITS) provided to PacifiCorp by the Bonneville Power Administration (BPA). But Boise's modeling of the adjustment is flawed because it results in nearly a quarter of the system peaks occurring on Sundays, which is inconsistent with historical peaks, and Boise ignores weather.<sup>321</sup> Instead, the Company proposed calculating the NITS expense based on the historical 2013 expenses, adjusted to account for the October 2013 rate increase.<sup>322</sup> The Company's approach is reasonable, straightforward, and conservative given that BPA has projected another significant rate increase mid-way through the rate year.<sup>323</sup>

**V. PRO FORMA CAPITAL ADDITIONS**

123 To mitigate regulatory lag and provide a more reasonable opportunity to recover costs incurred during the rate effective period, the Company proposed a pro forma adjustment for new plant expected to be in service before March 2015, valued at \$250,000 or more on a Washington-allocated basis. The Company's direct case included narrative descriptions of each project, including detailed cost information, which the Company updated through discovery. In its responsive testimony, Staff proposed to limit the pro forma capital additions to projects that were placed in service on or before the date the Company filed rebuttal testimony, November 14,

---

<sup>318</sup> Duvall, Exh. No. GND-4T 48:5-19.

<sup>319</sup> Mullins, Exh. No. BGM-1CT 49:8-13.

<sup>320</sup> Duvall, Exh. No. GND-4T 50:14-51:4.

<sup>321</sup> *Id.* at 65:1-17.

<sup>322</sup> *Id.* at 66:1-8.

<sup>323</sup> *Id.* at 65:9-15.

2014.<sup>324</sup> To minimize the number of litigated issues at hearing, the Company accepted Staff's proposal in the final issues list, reducing the Company's case by \$1.5 million.<sup>325</sup> Each of the 17 projects included in the Company's proposal for pro forma capital additions are now used and useful and the final costs are known and measurable.<sup>326</sup>

124 Public Counsel proposed an August 31, 2014 cut-off for new capital additions.<sup>327</sup> The Company's acceptance of Staff's position effectively addresses Public Counsel's stated concerns regarding projects with uncertain in-service dates or final budgets.<sup>328</sup>

125 Boise proposes to exclude all of the Company's proposed pro forma capital additions with the exception of the Merwin project.<sup>329</sup> Boise specifically challenges four projects: (1) the Jim Bridger Unit 1 Cooling Tower Replacement Project; (2) the Union Gap Substation Upgrade; (3) the Selah Substation Capacity Relief; and (4) the Fry Substation Project.<sup>330</sup> The Company removed two of these projects, the Selah Substation Capacity Relief and the Fry Substation Project, based on the November 14, 2014 cut-off.

126 Boise objects to the Jim Bridger Unit 1 cooling tower, claiming that "the costs and timing of this project appear uncertain."<sup>331</sup> That project, however, went into service in May 2014, shortly after the Company filed its case.<sup>332</sup> There is no uncertainty regarding the final costs of the project or the project's in service date.<sup>333</sup>

127 Boise argues that the costs for the first sequence of work on the Union Gap Substation Upgrade should be excluded because it is not really three distinct and separate sequences, and the project will not be finally completed until summer 2015.<sup>334</sup> Contrary to Boise's assertions, each

---

<sup>324</sup> Erdahl, Exh. No. BAE-1T 9:2-4.

<sup>325</sup> Dalley, TR. 389:7-16.

<sup>326</sup> Siores, Exh. No. NCS-11 at 8.4.2.

<sup>327</sup> Siores, Exh. No. NSC-10T 16:2-3.

<sup>328</sup> Ramas, Exh. No. DMR-1CTr 15:10-14.

<sup>329</sup> Mullins, Exh. No. BGM-1CT 11:8-11.

<sup>330</sup> *Id.* at 12:4-8.

<sup>331</sup> *Id.* at 12:12.

<sup>332</sup> Ralston, Exh. No. DMR-1T 4:7-9; Siores, Exh. No. NCS-10T 18:19-19:3.

<sup>333</sup> Siores, Exh. No. NCS-10T 18:19-23.

<sup>334</sup> Mullins, Exh. No. BGM-1CT 14:13-18.

of the three sequences of work for the Union Gap Substation Upgrade provides distinct known and measurable benefits to Washington customers.<sup>335</sup> The first sequence included replacing two existing transformers and moving another transformer. At hearing, the Company affirmed that the first sequence is “complete in totality.”<sup>336</sup>

128 Boise also argues that the costs should be more properly characterized as transmission costs and allocated to Washington accordingly rather than situs-assigned as distribution costs.<sup>337</sup> The Company correctly classified the project as distribution because the assets at issue support distribution level voltages.<sup>338</sup>

## VI. WAGES AND LABOR

129 The Company proposes to include in Washington rates a post-test year wage increase, using known and measurable increases that have occurred or are expected to occur through March 2016. The Company also proposed to use its full-time-equivalent (FTE) employee levels based on the historical test year to determine labor expenses and to include in rates pension and other post-employment benefit (OPEB) expenses based on the historical test year.

### A. Public Counsel’s Adjustment to the Company’s Post-Test Year Wage Increase Should Be Rejected

130 Public Counsel claims that the Company’s post-test year wage increase proposal is essentially equivalent to the use of a future test period and recommends limiting the post-test year wage increases to those increases in effect by December 31, 2014.<sup>339</sup> But the Company’s proposal is consistent with Commission precedent approving similar pro forma adjustments for the Company’s wage and salary expenses.<sup>340</sup> For example, in the Company’s most recent rate case, the Commission approved post-test year pro forma adjustments to wages for the 12-month

---

<sup>335</sup> Vail, Exh. No. RAV-2T 2:18-19.

<sup>336</sup> Vail, TR. 458:18-21.

<sup>337</sup> Mullins, Exh. No. BGM-1CT 14:19-20, 15:1-3.

<sup>338</sup> Vail, Exh. No. RAV-2T 5:4-11.

<sup>339</sup> Ramas, Exh. No. DMR-1CTr 20:20-22.

<sup>340</sup> *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶¶ 226-235 (Mar. 24, 2011).



period following the historical test year.<sup>341</sup> Although the Company's pro forma adjustments in this case extend farther, the adjustments are known and measurable and consistent with the approach used by Avista in its most recent rate cases.<sup>342</sup> The adjustment relies on union contracts, as well as known, committed, or planned increases for the non-union workforce.<sup>343</sup>

**B. Public Counsel's Proposed Adjustment to Current FTE Count is Unsupported**

131 Public Counsel proposes an adjustment to the Company's test year labor costs based on the difference between the average test year employee complement and the actual FTE employee complement as of June 2014, a difference of 66.5, or a reduction of 1.24 percent.<sup>344</sup> The Company demonstrated that the reductions in staffing it is currently experiencing are temporary. The Company requires a basic minimum level of staffing to ensure that its business operates smoothly.<sup>345</sup> The FTE employee numbers presented in this case reflect careful consideration of the number of employees needed to manage business and departmental responsibilities without compromising the Company's ability to continue to provide safe, reliable, and cost-effective service.<sup>346</sup> The Company continues to actively recruit to fill vacancies, and the most recent data available before hearing shows that the Company added employees in November 2014.<sup>347</sup>

132 In fall 2014, the Company completed an updated business plan showing 5,377 employees for the end of 2015.<sup>348</sup> The test period average FTE complement of 5,375 closely approximates the budgeted FTE complement.<sup>349</sup> In addition, the Company uses contract employees to backfill vacancies, and the expenses associated with retaining contract employees are roughly comparable to the expenses of the FTE employees.<sup>350</sup> Public Counsel's proposal would prevent

---

<sup>341</sup> See generally Order 05.

<sup>342</sup> See e.g. *WUTC v. Avista*, Docket UE-120436, Direct Testimony of Elizabeth M. Andrews, Exh. No. EMA-1T 28-29 (Apr. 2, 2012). Avista also used this approach in its 2014 rate case. See e.g. *WUTC v. Avista*, Docket UE-140188, Direct Testimony of Elizabeth M. Andrews, Exh. No. EMA-1T 50-51 (Feb. 5, 2014).

<sup>343</sup> Wilson, Exh. No. EDW-2T 2:4-6.

<sup>344</sup> Ramas, Exh. No. DMR-3r 13.

<sup>345</sup> Stuver, TR. 493:8-22.

<sup>346</sup> Stuver, TR. 493:3-14.

<sup>347</sup> *Id.* at 499:2-5.

<sup>348</sup> *Id.* at 495:23-25.

<sup>349</sup> *Id.* at 495:25, 496:1.

<sup>350</sup> *Id.* at 496:15-25, 497:1.

the Company from recovering expenses that are likely to be incurred regardless of whether the Company permanently fills all the current FTE employee vacancies.

**C. Public Counsel’s Proposed Adjustment to Pension and OPEB Expenses Violates the Matching Principle and Should be Rejected**

133 Public Counsel recommends adjustments to the Company’s pension and OPEB expenses based on updated actuarial assumptions provided in a 2014 report from Towers Watson. Public Counsel argues that these adjustments are consistent with reflecting other known and measurable changes in this case.<sup>351</sup> But Public Counsel’s adjustment inappropriately singles out one element of labor expense and ignores other elements of labor expense that may offset the reduction. The Company’s wage and labor proposals in this case are consistent with its prior rate case filings, in which pension and OPEB expenses, as well as other labor-related expenses, are based on the historical test year. In the 2010 case, the Commission approved the Company’s pro forma wage adjustment while noting the Company “did not adjust changes in workforce levels, employee benefits and incentives, or pensions.”<sup>352</sup> In this case, it is inappropriate to adjust pension and OPEB expenses without reviewing changes to other components of labor expenses, such as health-care benefit costs, which have increased since the historical test period.<sup>353</sup>

**VII. IHS GLOBAL INSIGHTS**

134 To better reflect the costs to serve customers anticipated in the rate effective period, the Company proposes escalating non-labor O&M and A&G expenses using indices prepared by IHS Global Insight.<sup>354</sup> IHS Global Insight assesses electric utility costs for materials and services (excluding labor) and develops escalation factors broken out by FERC Uniform System of Accounts functional subcategory.<sup>355</sup> The individual indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses.<sup>356</sup>

---

<sup>351</sup> Ramas, Exh. No. DMR-1CTr 27:4-12.

<sup>352</sup> *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 226 (Mar. 25, 2011).

<sup>353</sup> Siors, Exh. No. NCS-10T at 6:3-6.

<sup>354</sup> Dalley, Exh. No. RBD-1T 9:8-13, 10:20-22; Dalley, Exh. No. RBD-3T 7:11-23, 11:19-21.

<sup>355</sup> Siors, Exh. No. NCS-1T 19:5-9.

<sup>356</sup> *Id.* at 19:9-11.

The Company proposes applying the IHS Global Insights indices, by FERC function, to the Company's historical expense levels.<sup>357</sup>

135 While Staff challenges the reliability of the IHS Global Insights indices, they are widely-used and reliable.<sup>358</sup> IHS Global Insights is a national economic forecasting consulting company, winning accolades for its accuracy.<sup>359</sup> Washington's Economic and Revenue Forecast Council relies on IHS Global Insight data to develop economic forecasts for the state.<sup>360</sup>

136 Staff also argues that use of the IHS Global Insights indices deviates too far from the Commission's historical test year.<sup>361</sup> Boise takes the same position, although it concedes the Commission "has taken some latitude with regard to the application of a historic test period."<sup>362</sup> Public Counsel also claims that the use of IHS Global Insights indices is appropriate only when using a future test year.<sup>363</sup> At hearing, however, Staff agreed that the Commission uses a modified historical test year.<sup>364</sup> Public Counsel similarly criticized the Company's proposal as "more consistent with a future test year than with a historic test year approach."<sup>365</sup> Yet, like Staff, Public Counsel also supports numerous pro forma adjustments to the historical test year.<sup>366</sup> And even though Boise challenges the use of IHS Global Insights indices, Boise relied on a similar escalation factor to support its recommended EIM adjustment.<sup>367</sup>

---

<sup>357</sup> Dalley, Exh. No. RBD-1T 10:22-23.

<sup>358</sup> Ball, Exhibit JLB-1T 18:1-17; Dalley, Exh. No. RBD-3T 13:5-6.

<sup>359</sup> Dalley, Exh. No. RBD-3T 12:20-21, 13:5-6; *see* IHS Economics and Country Risk Accolades, <http://www.ihs.com/products/global-insight/accuracy-accolades.aspx> (last visited Jan. 21, 2015) (listing forecasting awards from Bloomberg Markets, Consensus Economics, MarketWatch, Reuters, USA Today, The Sunday Times, and The Wall Street Journal).

<sup>360</sup> *See* Economic Revenue Forecast Council, November 2014 Meeting Report, [http://www.erfc.wa.gov/forecast/documents/rev20140219\\_color.pdf](http://www.erfc.wa.gov/forecast/documents/rev20140219_color.pdf) (last visited Jan. 21, 2015).

<sup>361</sup> Ball, Exh. No. JLB-1T 16:1-4 (contending IHS indices escalate O&M costs "to a future test year level").

<sup>362</sup> Mullins, Exh. No. BGM-8T 11:9-11; Mullins, Exh. No. BGM-1CT 18:2-19.

<sup>363</sup> Ramas, Exh. No. DMR-1Tr 30:11-15.

<sup>364</sup> Ball, TR. 544:5-545:4.

<sup>365</sup> Ramas, Exh. No. DMR-1Tr 10:17-19.

<sup>366</sup> *Id.* at 20:20-22 (supporting pro forma wage adjustment); *id.* at 23:17-18 (supporting pro forma workforce level adjustment); *id.* at 27:1 (supporting pro forma pension and OPEB adjustment); *id.* at 15:10-14 (supporting numerous pro forma capital additions).

<sup>367</sup> Mullins, TR. 717:14-17, 718:18-25, 719:1-720:15 (using similar escalation factor to adjust E3 Report dollar figures from 2012 to rate year).

137 Parties are also concerned that the use of IHS Global Insights indices fails to account for changes in revenue that will occur after the test period.<sup>368</sup> The Company's load forecast shows only 0.2 percent load growth expected between the test year and the rate year, so any changes in the Company's revenues will be substantially less than the changes in costs.<sup>369</sup>

### VIII. INSURANCE EXPENSE

138 The Company proposes that the insurance expense reflect the historical six-year average of actual expenses. The Company's filing conforms to an agreement from the Company's 2011 rate case, which the Commission approved in the Company's 2013 rate case.<sup>370</sup> The expenses included in the historical average are known and measurable and their inclusion is consistent with the Commission's approved method for determining the historical average expense.<sup>371</sup>

139 Staff and Public Counsel propose adjustments to the 2012 expenses used to calculate the six-year historical average, which are intended to remove expenses they consider anomalous.<sup>372</sup> The Company demonstrated that a prudent utility maintains liability insurance for the types of events described by Staff and Public Counsel as "anomalies."<sup>373</sup> Both adjustments should be rejected as inconsistent with the fundamental purposes of using a historical average to normalize test year expenses.<sup>374</sup> In fact, Public Counsel testified that averages are intended to "normalize the costs that may have a high level of variability from year to year."<sup>375</sup> Although Staff proposes removing "anomalous" events from this historical average, Staff includes anomalous events in hydro forecasting, stating that "[n]ormal is defined by a long-term average which includes all

---

<sup>368</sup> Ball, Exh. No. JLB-1T 17:1-3 (asserting an escalation of costs is incomplete without recognition for the same period's revenues."); Ramas, Exh. No. DMR-1Tr 30:13-15 (calling it inappropriate to escalate select components of revenue requirement equation while leaving others, such as revenues, at historical level).

<sup>369</sup> Duvall, Exh. No. GND-1CT 16 Table 3.

<sup>370</sup> Siors, Exh. No. NCS-10T 7:4-7.

<sup>371</sup> Stuver, TR. 483:18-486:3 (Commission uses accrual, rather than cash-basis).

<sup>372</sup> Staff recommends replacing the total 2012 expense level with the 2007 expense. Ball, Exh. No. JLB-1T 13-15. Public Counsel recommends removing two incidents from the 2012 amount. Ramas, Exh. No. DMR-1CTr 31-35.

<sup>373</sup> Siors, TR. 465:8-466:5.

<sup>374</sup> Siors, Exh. No. NCS-10T 8:18-22.

<sup>375</sup> Ramas, Exh. No. DMR-1CTr 33:21-22.

extreme events.”<sup>376</sup> Removing data from the historical average, as Staff and Public Counsel recommend, frustrates the underlying purposes behind the six-year average.

## IX. DEFERRALS

140 There are three contested deferrals, and the arguments on the merits of the Colstrip and hydro deferral are addressed above. This section addresses the merits of the Merwin deferral and the parties’ recommendations that the Commission disallow interest on all of the deferrals.<sup>377</sup>

141 The Merwin project is necessary to allow fish to bypass the Company’s three Lewis River dams located in Washington.<sup>378</sup> Because of this project, customers will continue to benefit from emission-free, low-cost hydro generation, which is reflected in the Company’s NPC in this case.<sup>379</sup> The fish collector went into service on March 28, 2014, and the Company’s deferral requests amortization of the full revenue requirement associated with the project.<sup>380</sup> Staff supports amortization of a portion of the deferred amounts, but recommends that the Commission disallow recovery of the return on the project.<sup>381</sup> Public Counsel and Boise recommend that the Commission deny amortization of the deferred amounts in their entirety, claiming that it is unreasonable to defer the revenue requirement associated with a single project between rate cases.<sup>382</sup> The Commission should approve recovery of the deferred revenue requirement because it represents the actual costs incurred by the Company to serve customers. The project has been in service since March 2014, and no party challenges the prudence of the project.<sup>383</sup> Allowing the deferral mitigates regulatory lag and is good regulatory policy.

---

<sup>376</sup> Gomez, Exh. No. DCG-1CT 18:5-6.

<sup>377</sup> See e.g. Ball, Exh. No. JLB-1T 13:1-12.

<sup>378</sup> Tallman, Exh. No. MRT-1T 2:22-3:3.

<sup>379</sup> *Id.* at 4:12-16.

<sup>380</sup> Siores, Exh. No. NCS-10T 24:9-12.

<sup>381</sup> Ball, Exh. No. JLB-1T 13:1-12.

<sup>382</sup> Ramas, Exh. No. DMR-1CT 45-47.

<sup>383</sup> Siores, Exh. No. NCS-10T 25:6-9.

142 The Commission should also allow recovery of interest on the deferrals. Interest represents the time value of money and reasonably compensates Pacific Power for the financing costs incurred to serve customers.<sup>384</sup> The cost of service includes a fair return on investment.<sup>385</sup>

143 Staff relies on a recent Avista order to demonstrate that the Commission has approved no-interest deferrals in the past.<sup>386</sup> At hearing, Staff admitted that Avista did not request interest, and Staff was unable to point to a single other instance where the Commission disallowed interest on an approved deferral.<sup>387</sup> The Commission regularly allows recovery of a reasonable carrying charge on deferred amounts, either for the benefit of customers or the utility.<sup>388</sup>

144 Parties claim that interest on the Merwin deferral will result in double-recovery by the Company because the asset will be included in rate base.<sup>389</sup> This concern is unwarranted because the deferral only tracks the revenue requirement from the date of the petition until the costs associated with Merwin are incorporated into base rates beginning on the effective date of rates in this case.<sup>390</sup>

## X. END OF PERIOD RATE BASE

145 The Company's filing in this case reflects the use of electric plant in service balances at EOP levels, consistent with the Company's prior filing and the Commission's order in the last rate case.<sup>391</sup> Boise is the only party that objects. The Commission has recognized that the use of EOP rate base is an "appropriate regulatory tool under one or more of the following conditions: (a) abnormal growth in plant; (b) inflation and/or attrition; (c) as a means to reduce regulatory lag; (d) failure of utility to earn its authorized rate of return over an historical period."<sup>392</sup> In the

---

<sup>384</sup> *Id.* at 21:16-19.

<sup>385</sup> Ball, TR. 539:9-12; Twitchell, TR. 657:6-18.

<sup>386</sup> Ball, Exh. No. JLB-1T 28:14-19.

<sup>387</sup> Ball, TR. 541:19-542:6.

<sup>388</sup> *See e.g.* Gomez, TR. 573:1-11 (proposed PCAM includes interest in deferred amounts, like Avista's ERM); *Re Puget Sound Energy*, Docket UE-070725, Order 05 ¶ 24 (Aug. 31, 2010) ("It is appropriate . . . that ratepayers have the benefit of interest during the period PSE holds these ratepayer funds . . . in a deferral account.").

<sup>389</sup> *See e.g.* Ball, Exh. No. JLB-1T 29:9-10; Mullins, Exh. No. BGM-1CT 68-71.

<sup>390</sup> Siores, Exh. No. NCS-10T 25:10-19.

<sup>391</sup> Dalley, Exh. No. RBD-3T 10:20-23; Order 05 ¶ 184 (approving the use of end-of-period rate base).

<sup>392</sup> *WUTC v. Wash. Nat. Gas Co.*, Cause No. U-80-111, 44 P.U.R.4th 435, 438 (Sept. 24, 1981); *see also WUTC v. Puget Sound Energy*, Dockets UE-111048, *et al.*, Order 08 ¶ 97 (May 7, 2012).

Company's last rate case, the Commission approved the use of EOP rate base specifically to "address at least some of the impacts of regulatory lag on PacifiCorp."<sup>393</sup>

146 Here, the Company proposed using EOP rate base to minimize regulatory lag by reflecting rate base balances that are anticipated during the rate year.<sup>394</sup> It is undisputed that the Company has historically under-earned in Washington.<sup>395</sup> Because "one or more" of the Commission's conditions has been clearly satisfied in this case, the Commission should approve the use of end-of-period rate base.

## XI. RESIDENTIAL RATE DESIGN

### A. The Company's Recommended Basic Charge is Reasonable

147 Consistent with Commission precedent, the Company's recommended monthly basic charge of \$14.00<sup>396</sup> is intended to recover a reasonable portion of the Company's fixed costs through the fixed component of the residential rate.<sup>397</sup> Based on its cost of service (COS) study, the Company's proposed basic charge includes the fixed costs related to local distribution and retail service costs.<sup>398</sup> The Company limited its recommended basic charge to \$14.00 to allow the Company to collect one-half of the fixed costs that are necessary to provide service regardless of the customer's usage.<sup>399</sup>

148 The Company's recommended basic charge will also mitigate cost-shifting from increased DG resulting from state policies.<sup>400</sup> The Commission observed that the growth in DG should not compromise a utility's ability to recover its fixed costs nor unreasonably shift costs.<sup>401</sup>

---

<sup>393</sup> Order 05 ¶ 184.

<sup>394</sup> Dalley, Exh. No. RBD-3T 11:8-15.

<sup>395</sup> *Id.* at 8 Table 1.

<sup>396</sup> For low income customers on Schedule 17, the Company recommends a basic charge of \$8.75. Steward, Exh. No. 13T 2:6-9.

<sup>397</sup> See e.g. *WUTC v. Avista*, Dockets UE-991606, *et al.*, Third Suppl. Order ¶ 416 (Sept. 29, 2000).

<sup>398</sup> Steward, Exh. No. JRS-1T 19:1-18; Steward, Exh. No. JRS-13T 26:1-15.

<sup>399</sup> Steward, Exh. No. JRS-1T 19:1-18; Steward, Exh. No. JRS-13T 27:19-28:5.

<sup>400</sup> See e.g. *Re Amending and Repealing Rules in WAC 480-108 Relating to Electric Companies-Interconnection With Electric Generators*, Docket UE-112133, Interpretive Statement Concerning Commission Jurisdiction and Regulation of Third-Party Owners of Net Metering Facilities (July 30, 2014); Steward, Exh. No. JRS-13T 24:5-7 (60 percent growth in DG from 2013 through October 2014); Twitchell, TR. 631:2-14 (address DG now).

<sup>401</sup> *UTC Report on the Potential for Cost-Effective Distributed Generation in Areas Served by Investor Owned Utilities in Washington State*, Docket UE-110667 at 5, 29 (October 7, 2011).

The Company's proposal will better position the Company to respond to the market transformation resulting from state energy policy.<sup>402</sup> The Company's recommended basic charge also sends appropriate price signals to customers and does not diminish incentives to conserve and use energy efficiently. Under the Company's proposal, 89 percent of a typical monthly bill will be related to energy charges, a level consistent with Commission direction.<sup>403</sup>

149 Staff recommends including only transformer costs, resulting in a \$13.00 basic charge, which is comparable to the Company's proposal.<sup>404</sup> Staff testified that utilities are at risk of under-recovery of fixed costs when fixed costs are recovered through volumetric charges and that as DG grows, "such under-recovery has the potential to materially weaken the utility's financial integrity and its ability to attract investor capital[.]"<sup>405</sup> Staff further testified that the Company's declining residential load has contributed to the Company's inability to recover its authorized revenue requirement.<sup>406</sup> Staff supports its recommended basic charge in light of the EIA's mandatory conservation requirements.<sup>407</sup> Staff also observed that a higher basic charge is reasonable for utilities without a decoupling mechanism and may actually be preferable given the controversy surrounding recently approved mechanisms for other electric utilities.<sup>408</sup>

150 Public Counsel and The Alliance for Solar Choice (TASC) argue that the basic charge should include only the small portion of distribution costs that vary as a result of a new customer.<sup>409</sup> But Public Counsel admits that all distribution costs are fixed and do not vary with customer usage.<sup>410</sup> Given the agreement that all distribution costs are fixed, it is unreasonable to recover these costs through a variable energy rate.

---

<sup>402</sup> Steward, Exh. No. JRS-13T 23:19-24:13.

<sup>403</sup> *Id.* at 30; *id.* at 31:12-14 (small users will still have 77 percent of bill be variable); *WUTC v. Puget Sound Energy*, Dockets UE-060266, *et al.*, Order 08 ¶ 139 (Jan. 5, 2007).

<sup>404</sup> Twitchell, Exh. No. JBT-1T 26:13-20.

<sup>405</sup> Twitchell, Exh. No. JBT-1T 23:1-17 (quoting article by a former New York State Public Service Commissioner).

<sup>406</sup> *Id.* at 23:18-24.

<sup>407</sup> *Id.* at 23:25-26.

<sup>408</sup> *Id.* at 24:12-25:2; *see also* Watkins, Exh. No. GAW-10CX (decoupling mechanisms mitigate need for increased basic charge).

<sup>409</sup> Watkins, Exh. No. GAW-1T 27:1-20; Fulmer, Exh. No. MEF-1Tr 6:19-7:13.

<sup>410</sup> Watkins, Exh. No. GAW-6T 18:18-22.



151 Public Counsel also argues that all distribution costs should be excluded from the basic charge calculation because distribution costs are classified as demand related for purposes of COS studies.<sup>411</sup> But because residential customers pay no demand charge, it is reasonable to recover a portion of the fixed distribution costs through the basic charge.<sup>412</sup>

152 Public Counsel also argues that risk associated with declining loads caused by conservation and efficiency is nothing new requiring a higher basic charge at this time.<sup>413</sup> On the contrary, the Company has implemented robust conservation measures to meet Washington conservation targets, and new regulations under Section 111(d) may require significant conservation and energy efficiency on the part of utilities like Pacific Power.<sup>414</sup>

Similarly, Public Counsel asserts that Pacific Power's *residential* Washington loads have been increasing and are expected to continue to increase in the near future.<sup>415</sup> Public Counsel never actually analyzed temperature normalized data or historical or forecast Washington *residential* loads to support its conclusion.<sup>416</sup> In fact, Pacific Power's temperature normalized residential sales decreased 5.1 percent between 2010 and 2013.<sup>417</sup> And the NPC residential sales forecast in the Company's last two cases shows declining residential sales.<sup>418</sup> Even the 2013 IRP Update relied on by Public Counsel shows that the Company's overall residential retail sales forecast has decreased due to increased energy efficiency.<sup>419</sup>

---

<sup>411</sup> *Id.* at 19:12-23.

<sup>412</sup> Steward, Exh. No. JRS-13T 27:16-28:5.

<sup>413</sup> Watkins, Exh. No. GAW-1T 23:12-18.

<sup>414</sup> Twitchell, Exh. No. JBT-1T 23:25-26, 25:3-7; *see also* Gorman, Exh. No. MPG-25CX 3-4 (Fitch report anticipates significant impact on retail loads due to energy efficiency).

<sup>415</sup> Watkins, Exh. No. GAW-6T 16:28-17:21.

<sup>416</sup> Watkins, TR. 689:3-9 (relied on total Company sales, not residential sales); *id.* at 690:14-691:8 (relied on total Company residential sales, not Washington); *id.* at 689:10-13; *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 218 (Mar. 25, 2011) (adopting temperature normalization to estimate test year sales because many of PacifiCorp's customers use electricity for space heating and temperature may have a significant impact on customer usage).

<sup>417</sup> PacifiCorp State of Washington Results of Operations 2010, pages 3.1.5-3.1.6; PacifiCorp State of Washington Results of Operations 2011, pages 3.1.3-3.1.4; PacifiCorp State of Washington Results of Operations 2012, pages 3.1.3-3.1.4; PacifiCorp State of Washington Results of Operations 2013, pages 3.1.3-3.1.4.

<sup>418</sup> Duvall, Exh. No. GND-1CT 16 Table 3; Watkins, Exh. No. GAW-12CX 2.

<sup>419</sup> Watkins, Exh. No. GAW-11CX 3; Watkins, TR. 692:5-11 (IRP Update shows declining peak load only).

**B. The Commission Should Affirm the Company’s Two-Tier Rate Design**

153 The Company’s recommended residential rate design includes its existing steeply inverted two-tier, inclining rate blocks and increases rates for all residential customers, regardless of usage. This sends an accurate price signal regarding the higher cost of service.<sup>420</sup> Staff recommends a new three-tier inverted rate block design for residential customers that would increase the size of the first block from 600 to 800 kWh, set a second block from 801 to 1,700 kWh, and add a new third block for usage over 1,700 kWh. Staff’s three-tier rate design is based on national customer usage data, not data specific to Pacific Power’s Washington customers.<sup>421</sup> Given the region’s historically aggressive energy efficiency efforts and building codes, national data is not reflective of typical customer usage for the Company.<sup>422</sup> Staff’s reliance on national data is particularly perplexing given that, in the last case, Staff agreed to defer consideration of its proposed three-tier rate design pending the collection of additional Pacific Power data, which Staff agreed would be a “good outcome.”<sup>423</sup> Here, Staff did not to consider the Pacific Power’s data when designing its rates.<sup>424</sup>

154 Staff’s proposed rate design also sends confusing price signals and encourages increased consumption for nearly one-half of the Company’s residential customers, even though Staff agrees that costs are increasing.<sup>425</sup> Staff justifies its proposal by concluding that it will encourage efficiency savings by targeting high-usage customers through significantly higher rates in the newly proposed third tier.<sup>426</sup> But Staff admitted that it is possible that lower rates will result in higher usage, a result corroborated by Staff’s own elasticity analysis and the studies

---

<sup>420</sup> Steward, Exh. No. JRS-13T 41:5-12; Steward, Exh. No. JRS-1T 24:18-20.

<sup>421</sup> Twitchell, TR. 606:8-20.

<sup>422</sup> Steward, Exh. No. JRS-13T 44:6-20; *id.* at 45 Table 14 (national data overstates customer’s basic needs usage by 33 percent); Twitchell, Exh. No. JBT-1T 28:1-9.

<sup>423</sup> Order 05 ¶¶ 247-249; Twitchell, TR. 605:3-14; Twitchell, Exh. No. JBT-10CX; Twitchell, Exh. No. JBT-9CX.

<sup>424</sup> Twitchell, TR. 605:23-606:1.

<sup>425</sup> Steward, Exh. No. JRS-13T 35:11-20; Twitchell, Exh. No. JBT-1T 29:3-4 (rates reduced for usage between 600 and 1,700 kWh per month); Ball, Exh. No. JLB-1T 7 (Staff recommends an overall rate increase of \$7.7 million).

<sup>426</sup> Twitchell, Exh. No. JBT-1T 27:18-19.

on which Staff relied to design its rates.<sup>427</sup> Accounting for the different revenue requirement, the Company's recommended rate design results in greater estimated energy savings, as calculated using Staff's methodology.<sup>428</sup>

155 Without evidentiary support, Staff contends that it targeted energy savings for only high-end users because customers that use less than 2,000 kWh per month have limited capacity for energy savings.<sup>429</sup> The Company has energy efficiency programs targeted at all levels of usage, however, as recognized by Staff.<sup>430</sup> In the long-term, there is room for efficiency at lower usage levels due to more efficient lighting and appliances.<sup>431</sup>

156 Staff's proposal will also increase the Company's revenue volatility by shifting recovery of significant fixed costs to the new third tier.<sup>432</sup> The only expenses that will vary in the near term as usage declines are NPC, which account for only 31 percent of the costs that will be recovered in Staff's new third tier.<sup>433</sup> Revenue volatility will be further compounded because the new third tier is weather sensitive.<sup>434</sup> Seventy-two percent of bills with usage greater than 1,700 kWh occurred during the winter.<sup>435</sup> Thus, the vast majority of the customer bills that would be impacted by the new third tier are winter bills, indicating that Staff's proposal would have a significant adverse impact on these users.

157 Staff's proposal would also disproportionately affect low-income customers. Eighty-five percent of the Company's low-income customers on Schedule 17 have usage that exceeds 1,700 kWh during the winter.<sup>436</sup> The median energy usage for Schedule 17 customers during

---

<sup>427</sup> Twitchell, TR. 612:13-16, 613:13-16; Twitchell, Exh. No. JBT-1T 25 n. 32; Twitchell, Exh. No. JBT-12CX 13; Steward, Exh. No. JRS-13T 38:9-39:13; Steward, Exh. No. JRS-21 (Staff's elasticity analysis applied to all usage levels indicates greater usage when price declines).

<sup>428</sup> Steward, Exh. No. JRS-13T 39:3-13.

<sup>429</sup> Twitchell, Exh. No. JBT-1T 28:1-13.

<sup>430</sup> Steward, Exh. No. JRS-13T 43:12-44:5; Twitchell, TR. 616:15-20 (light bulb measures highly effective).

<sup>431</sup> Twitchell, Exh. No. JBT-1T 31:10-13; JRS-13T 44:1-5.

<sup>432</sup> Steward, Exh. No. JRS-13T 40:3-17.

<sup>433</sup> *Id.* at 40:18-41:4.

<sup>434</sup> *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 ¶ 218 (Mar. 25, 2011); Steward, Exh. No. JRS-13T 40:3-17,

<sup>435</sup> Table 14 (56 percent of Pacific Power customers rely on electric heat).

<sup>435</sup> Steward, Exh. No. JRS-13T 36:1-9.


<sup>436</sup> *Id.* at 37:1-11.

December, January, and February of the test period exceeds 1,700 kWh per month—indicating that more than one-half of the low-income customers on Schedule 17 will be affected by the new third tier for these three months.<sup>437</sup> In the Company’s last case, the parties and the Commission expressed concern over the potential impact of Staff’s new third tier on the most vulnerable of Pacific Power’s customers.<sup>438</sup> Staff’s proposal here has done nothing to address the impact on low-income customers, despite the evidence that these customers will be disproportionately impacted.

## XII. CONCLUSION

158 For the reasons stated above, the Company respectfully requests that the Commission approve its requested \$30.4 million revenue requirement increase, its proposed RRTM and \$14.00 monthly customer charge, and the amortization of amounts deferred related to an extended outage at the Colstrip generating plant, low hydro conditions, the Merwin Fish Collector, and depreciation expense.

159 Respectfully submitted this 22<sup>nd</sup> day of January, 2015.



---

Katherine A. McDowell  
McDowell Rackner & Gibson PC  
419 SW 11<sup>th</sup> Ave., Suite 400  
Portland, OR 97205  
Telephone: (503) 595-3924  
Facsimile: (503) 595-3928  
Email: [katherine@mcd-law.com](mailto:katherine@mcd-law.com)

Sarah K. Wallace  
Assistant General Counsel  
Pacific Power

---

<sup>437</sup> Bench Request No. 6.

<sup>438</sup> Order 05 ¶ 250.