

**BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION,	)	
	)	
Complainant,	)	
	)	Docket Nos. UE-111190
v.	)	
	)	
PACIFICORP D/B/A PACIFIC POWER,	)	
	)	
Respondent.	)	
_____	)	

**RESPONSIVE TESTIMONY OF DONALD W. SCHOENBECK**  
**ON BEHALF OF**  
**THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES**  
  
**REDACTED VERSION**

**January 6, 2012**

1 **I. INTRODUCTION AND SUMMARY**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 **A.** My name is Donald W. Schoenbeck, and my business address is 900 Washington Street,  
4 Suite 780, Vancouver, Washington 98660. I am employed by Regulatory and  
5 Cogeneration Services, Inc. (“RCS”), a utility rate and consulting firm.

6 **Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.**

7 **A.** I have been involved in the electric utility industry for over 35 years. For the majority of  
8 this time, I have provided consulting services for large industrial customers addressing  
9 regulatory and contractual matters. I have appeared before the Washington Utilities and  
10 Transportation Commission (the “Commission”) on many occasions since 1982. A  
11 further description of my educational background and work experience can be found in  
12 Exhibit No. \_\_\_\_ (DWS-2) attached to this testimony.

13 **Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

14 **A.** I am testifying on behalf of the Industrial Customers of Northwest Utilities (“ICNU”).  
15 ICNU is a non-profit trade association whose members are large industrial customers  
16 served by electric utilities throughout the Pacific Northwest, including PacifiCorp (the  
17 “Company”).

18 **Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?**

19 **A.** This testimony will address certain power supply matters. These items are the updating  
20 of power costs to take into account information provided by the Company in response to  
21 data requests, using forward prices from over a longer period of time for deriving power  
22 supply costs, and the use of an alternate power supply model instead of the internally  
23 developed Company model (“GRID”) in future proceedings. In addition, my associate

1 Michael C. Deen will also present additional power supply adjustments on behalf of  
 2 ICNU and the spreading of any Commission allowed revenue increase.

3 **Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS**  
 4 **PROCEEDING.**

5 **A.** The combined power supply-related adjustments addressed by ICNU will reduce  
 6 PacifiCorp’s proposed \$12.9 million revenue requirement by approximately \$10.1  
 7 million, as indicated by the following table. The conversion of the total western control  
 8 area (“WCA”) power supply cost shown under the column heading “Power Supply Cost”  
 9 to a Washington revenue requirement amount is based on a Washington allocation factor  
 10 (22.6%), the Company’s production factor adjustment (98.252%) and revenue sensitive  
 11 item adjustment (4.8%). ICNU recommends that the Commission require the Company  
 12 to perform a “compliance” filing to precisely determine the overall impact of all the  
 13 adjustments ordered by the Commission in this proceeding.

<b>ICNU Power Supply Related Adjustments (\$ in Millions)</b>				
<b>Number</b>	<b>Issue</b>	<b>WCA Power Supply Cost</b>	<b>WA Revenue Requirement</b>	<b>ICNU Witness</b>
1	PacifiCorp Updates	-12.5	-2.9	Schoenbeck
2	Contract Revenue	-9.4	-2.2	Schoenbeck
3	Coal Costs	-6.9	-1.6	Schoenbeck
4	Forward Market Prices	-4.2	-1	Schoenbeck
5	Power Supply Model	0	0	Schoenbeck
6	Sales Limits or Caps	-4.3	-1	Deen
7	Hydro Capability	-2.9	-0.7	Deen
8	OATT Revenues	-3.5	-0.8	Deen
9	Balancing/Others	0.3	0.1	Deen
10	Total:	-43.4	-10.1	

1 Below is a brief summary of each issue I will address.

- 2 • **PacifiCorp Updates:** The Company’s filing was based on a WCA net power  
3 supply cost of \$567.5 million. In response to data requests (“DR”)—  
4 particularly WUTC DR 91 and WUTC DR 101—the Company has provided  
5 updates in several areas including forward prices, wheeling charges, purchase  
6 power contracts and coal costs. These updates reduce the WCA net power  
7 costs by \$12.5 million and the claimed revenue increase by \$2.9 million.  
8 (ICNU disagrees with the coal cost update which will be addressed below).
  
- 9 • **Contract Revenue:** One of the contract updates PacifiCorp has included in  
10 its net power cost determination provided in response to WUTC DR 101 will  
11 provide a substantial amount of revenue to the Company. Recognizing the  
12 revenue from this contract reduces the Company’s claimed revenue  
13 requirement increase by \$2.2 million.
  
- 14 • **Coal Costs:** The majority of coal supplied to the Jim Bridger plant comes  
15 from an affiliated mine. Adequate time has not been provided to assess the  
16 reasonableness of the Company’s coal price updates. As a placeholder, ICNU  
17 recommends the updated price from the third party supplier be used as a price  
18 cap on the allowable Jim Bridger coal costs. This recommendation reduces  
19 the claimed revenue increase by \$1.6 million.
  
- 20 • **Forward Market Price Determination:** As it has done in the past, the  
21 Company’s power supply costs are based on a forward price curve for a single  
22 day. ICNU recommends the Commission require the Company to use the  
23 average forward prices over at least a one month period. This would be about  
24 20-22 trading days instead of the single day approach employed by the  
25 Company. In addition, ICNU recommends the Commission require the  
26 Company to perform a compliance filing which would include a final forward  
27 price update based upon the method ordered by the Commission in this  
28 proceeding. Based on the average forward prices from November 17 through  
29 December 16, 2011, this update would reduce the claimed revenue increase by  
30 about \$1.0 million.
  
- 31 • **Power Supply Model:** As in the past several proceedings, the Company’s  
32 GRID model was used to forecast the net power supply cost in this  
33 proceeding. ICNU recommends moving away from this model at the  
34 conclusion of this proceeding. ICNU recommends the Commission order the  
35 Company to use a power supply model developed and marketed by an  
36 independent third party—such as AURORA—in all future proceedings.

1 **Q. HAVE YOU PREPARED AN EXHIBIT THAT SUMMARIZES ALL OF ICNU'S**  
2 **PROPOSED ADJUSTMENTS IN THIS CASE?**

3 **A.** Yes. Attached as Exhibit No.\_\_(DWS-3) is a calculation of ICNU's overall revenue  
4 requirement recommendation, including all of ICNU's proposed adjustments related to  
5 power supply, and administrative and general expenses. Taken together, the ICNU  
6 adjustments reduce PacifiCorp's claimed increase by \$13.8 million, resulting in an  
7 decrease of \$0.8 million or just -0.3%. ICNU's overall recommendation in this case may  
8 be different, because ICNU will review the proposals of Staff and other parties. In  
9 addition, the fact that ICNU's witnesses have not addressed a specific issue should not be  
10 construed as support for the Company's position on that issue. ICNU's legal briefing  
11 will include ICNU's final recommendations in this case.

12 **II. POWER SUPPLY RELATED ADJUSTMENTS**

13 **PacifiCorp Updates**

14 **Q. HAVE YOU REVIEWED THE COMPANY'S TESTIMONY, EXHIBITS, AND**  
15 **WORKPAPERS REGARDING POWER COSTS IN THIS PROCEEDING?**

16 **A.** Yes. I have reviewed both the power cost testimony and supporting evidence provided  
17 by the Company in its initial filing as well as updates the Company has provided in  
18 responses to data requests. In particular, the Company provided revised WCA net power  
19 costs in response to Staff DR numbers 91 ("WUTC DR 91") and 101 ("WUTC DR  
20 101"). The revised power cost in response to WUTC DR 91 was provided around  
21 October 27, 2011. This response included an Excel file that showed the impact on the  
22 Company's net power cost from updating the forward price curves (from March 2011 to  
23 September 2011), including additional short-term purchases for the rate year (June 2012  
24 through May 2012), updated Mid-Columbia ("Mid-C") contract costs, updated wheeling

1 rates and updated coal costs for the Jim Bridger and Colstrip plants. As shown by  
2 Exhibit \_\_\_(DWS-4), the net impact of all these adjustments was a reduction in WCA  
3 power costs of \$15.9 million (from \$567.5 to \$551.6 million). In response to WUTC DR  
4 101, the Company provided a further updated WCA power cost around December 5,  
5 2011. Additional supplements to this data response were provided by the Company  
6 around December 7, 2011 and December 22, 2011. As shown by Exhibit \_\_\_(DWS-4),  
7 WUTC DR 101 updated the forward market prices to November 2011, revised the coal  
8 costs again and included a new contract for integration services for Seattle City Light’s  
9 (“SCL”) Stateline resource. The result of these updates was an increase in WCA net  
10 power costs of \$3.3 million. Taking the two data responses together, the forward price  
11 updates have decreased the WCA power costs by \$16.8 million while the coal prices  
12 updates have increased the WCA power costs by \$6.4 million. The contract updates and  
13 wheeling rate changes have reduced the WCA power supply costs by \$2.0 million. After  
14 including the system balancing adjustment (to calculate the impact of all the changes on  
15 the GRID result), the data responses have reduced the WCA power costs by \$12.5  
16 million. In total, all above updates lower the associated claimed revenue increase by  
17 about \$2.9 million.

18 **Q. DID THE COMPANY PROVIDE ADEQUATE WORKPAPERS TO SUPPORT**  
19 **ALL THE UPDATES IN ITS RESPONSES TO WUTC DR 91 AND WUTC DR**  
20 **101?**

21 **A.** No. The Company’s response to WUTC DR 91 included the forward prices for just two  
22 electricity markets—Mid-C and the California-Oregon border (“COB”)—and the forward  
23 gas price at the Chehalis generating station only. Market price information for other  
24 market locations—such as Four Corners and the Hermiston plant—used in the

1 determination were not provided. The data response did include documentation of the  
2 revised Mid-C contract costs, the additional short-term power transactions, and internet  
3 links to the sites for obtaining the revised wheeling rate charges. Significantly, however,  
4 the Company did not provide any documentation to support the change in coal prices or  
5 the ability to review the GRID input and output files used to quantify the claimed power  
6 cost changes.

7 Due to the lack of workpapers provided in response to WUTC DR 91, ICNU  
8 immediately requested that all documents and GRID files be provided to support the  
9 response to WUTC DR 101 on the day this request was filed with the Company (ICNU  
10 DR 11.1). The Company's initial response to WUTC DR 101 on December 5, 2011,  
11 again contained only limited documentation, but it did include the requested GRID files  
12 in response to ICNU DR 11.1 (available on December 6, 2011). As was the case with the  
13 WUTC DR 91 response, the Company provided no documents to support the revised coal  
14 prices in the initial response to WUTC DR 101 or ICNU DR 11.1. It was only in the  
15 Company's second supplemental response to WUTC DR 101 that some coal price files  
16 were provided. PacifiCorp could have emailed these responses, but the Company sent  
17 them via Federal Express. Due to the holidays, Federal Express delivered these files to  
18 the offices of RCS, Inc. on December 27, 2011—less than two weeks before ICNU  
19 testimony was due. There is no reason PacifiCorp should not have provided full and  
20 complete supporting documentation on a timely basis.

1 **Q. DO YOU AGREE WITH ALL THE COMPANY’S UPDATES TO ITS NET**  
2 **POWER SUPPLY COSTS?**

3 **A.** ICNU agrees with all of the updates except for the Jim Bridger coal cost. If a utility is  
4 going to be allowed or required to update its power costs after its initial filing, it is critical  
5 that parties be provided complete and timely materials well in advance of the due date for  
6 filing responsive testimony. Putting the coal issue aside for the moment, all other updates  
7 performed by the Company can be analyzed or compared to third party data to verify the  
8 reasonableness of the revised values and results on net power costs (“NPC”). For  
9 example, the market hub price updates can be compared with prices provided by third  
10 party providers to see if the Company’s manufactured price curves are relatively close to  
11 those of others. Similarly, the documentation provided with regard to the Mid-C  
12 contracts and wheeling charges was already known from participation in other  
13 proceedings or from verifying the third party source or documentation provided by the  
14 Company. Accordingly, for the remainder of this testimony, ICNU will address the  
15 Company’s WCA net power costs as contained in its response to WUTC DR 101. As  
16 shown by Exhibit \_\_\_(DWS-4), this is a WCA power cost of \$555.0 million, or \$12.5  
17 million below the Company’s filed case.

18 **Contract Revenue Adjustment**

19 **Q. DO THE COMPANY UPDATES HAVE ANY OTHER IMPACT ON THE**  
20 **CLAIMED REVENUE REQUIREMENT IN THIS PROCEEDING?**

21 **A.** Yes. In its filing, the Company had assumed the integration services it had been  
22 providing to SCL for the Stateline resource would not be extended or renewed upon  
23 expiration of this contract on December 31, 2011. See Exhibit \_\_\_ (RBD-1T), page 11,  
24 lines 10-16. Consequently, the Company included a pro forma revenue adjustment to



1 remove \$4.9 million of revenue associated with this contract from the test period. See  
2 Exhibit \_\_\_\_ (RBD-3), Tab 3, page 3.0.1. The Company's initial update for the SCL  
3 contract in its response to WUTC DR 101 only included the impact of this contract on the  
4 Company's net power supply cost. As this contract is providing integration services to  
5 SCL, the revenues associated with this contract must be taken into account in order to  
6 determine the allowed revenue increase in this proceeding. Confidential Exhibit \_\_\_\_  
7 (DWS-5C) is an excerpt of the Company's second supplemental data response to WUTC  
8 DR 101. This exhibit indicates a revenue projection attributable to this contract of \$9.4  
9 million for the rate year. Instead of removing \$4.9 million from the test period as the  
10 Company had done, \$4.5 million of revenue needs to be added to the test period to  
11 achieve the total amount of expected revenue under the new agreement ( $\$4.5 + \$4.9 =$   
12  $\$9.4$  million). The Washington allocated revenue requirement impact from incorporating  
13 the revenue from the new contract is \$2.2 million ( $\$9.4 \text{ million} \times 22.47\% \times 1.048 = \$2.2$   
14 million).

15 **Bridger Coal Costs**

16 **Q. PLEASE PROVIDE A BRIEF EXPLANATION OF HOW THE JIM BRIDGER**  
17 **COAL PLANT PROCURES ITS FUEL.**

18 **A.** The Bridger plant receives its fuel from two sources. As noted in the Company's  
19 testimony, about 31% of the coal needs come from a third party coal source, the Black  
20 Butte mine. The remaining need is satisfied from an affiliated source, the Bridger Coal  
21 Company ("BCC"). Through an affiliate, PacifiCorp owns 66.67% of BCC, while the  
22 remainder is owned by an affiliate of the Idaho Power Company.

1 **Q. HOW SHOULD THE BRIDGER COAL COST BE DETERMINED FOR RATE**  
2 **MAKING PURPOSES?**

3 **A.** The coal sourced from the Black Butte mine should be evaluated and assessed under the  
4 usual rate setting standard of whether or not the cost is prudent or reasonable. For the  
5 coal sourced from the Company affiliate however, a different standard is warranted. For  
6 affiliated coal costs the standard should be the lower of the market value or actual cost.  
7 By establishing the affiliated cost in this manner, ratepayers are protected from affiliate  
8 abuse by the Company paying an unreasonable price which would allow the affiliate and  
9 parent corporation to achieve above market profits.

10 **Q. IS MARKET PRICE INFORMATION READILY AVAILABLE FOR COAL**  
11 **NEAR THE BRIDGER FACILITY?**

12 **A.** No. There is no readily available source for coal costs near and around the Bridger  
13 facility. This makes it extremely difficult to ascertain the reasonableness of the  
14 Company's affiliated coal price for Bridger.

15 **Q. YOU STATED EARLIER THAT YOU OBJECTED TO THE COMPANY'S**  
16 **COAL COST UPDATES REFLECTED IN WUTC DR 91 AND DR 101. PLEASE**  
17 **EXPLAIN WHY THIS IS THE CASE.**

18 **A.** The Company provided limited workpapers associated with the coal cost updates less  
19 than two weeks before the testimony was due. The Bridger coal cost reflected in the  
20 updated filing is about 16% greater than the 2010 cost as reflected in the Company's  
21 FERC Form 1. In other words, to achieve the coal costs the Company is seeking for the  
22 Bridger plant in the updated filing for the rate year, it would have to experience 6.4% cost  
23 increases in each year of 2011, 2012, and 2013. This seems extraordinarily high and well  
24 above projected escalation rates. In addition, several of the workpaper files contained  
25 many "pasted values" instead of formulas. This makes it very difficult and time

1 consuming to track through and audit any changes in the Company's calculations. Given  
 2 the timing and lack of documentation, it was impossible to ascertain the reasonableness  
 3 of the Company's rate year coal price update for BCC when no readily available third  
 4 party source of market prices could be used as a measuring stick.

5 **Q. WHAT ANALYSIS HAD YOU UNDERTAKEN WITH RESPECT TO THE**  
 6 **COMPANY'S ORIGINAL CLAIMED COAL COSTS?**

7 **A.** We had examined the historical fuel costs as reflected in the FERC Form 1 filings of the  
 8 Company for the past several years, the Company's Excel spreadsheet files in support of  
 9 the claimed coal cost and the coal costs reflected in the Company's compliance filing in  
 10 UE-100749. In this assessment, the most critical factor was that in the last proceeding,  
 11 the cost of coal from BCC was less than the cost of coal supplied from the Black Butte  
 12 mine. That is not the instant case where the Company's claimed cost of BCC coal is  
 13 greater than projected Black Butte cost. Also, under the Company's updated cost  
 14 contained in WUTC DR 101, the one year escalation of BCC costs from the 2010  
 15 compliance filing is incredible at 21%. This is shown in the following table which also  
 16 presents a comparison of the projected cost of coal from the two Bridger sources at  
 17 various points in time.

Comparison of Coal Costs (\$/MMBTU)					
Source	2010 GRC (4/11 - 3/12)	2011 GRC As Filed (6/12 - 5/13)	2011 GRC WUTC 101 Update	Difference	Percent
<b>BBC</b>	\$1.66	\$1.91	\$2.00	\$0.34	21%
<b>Black Butte</b>	\$1.75	\$1.84	\$1.90	\$0.15	8%
<b>Blended</b>	\$1.69	\$1.89	\$1.97	\$0.28	16%
<b>Difference:</b>	-\$0.09	\$0.06	\$0.11	\$0.20	12%

1 **Q. WHAT IS THE ICNU RECOMMENDATION FOR ESTABLISHING THE COST**  
2 **OF BRIDGER COAL IN THIS PROCEEDING?**

3 **A.** At this time, I recommend that the updated price of coal from the Black Butte mine be  
4 used as the Bridger coal cost for ratemaking purposes. I fully understand that this is a  
5 very limited measure of market value but it does represent a significant source of coal  
6 already for the Bridger plant. This recommendation also satisfies the standard that the  
7 cost of coal from an affiliate be no higher than the market value. Under this  
8 recommendation, the coal cost for Bridger is \$1.895 per MMBTU. A value quite close to  
9 the original as filed blended cost of \$1.886 per MMBTU. Incorporating this  
10 recommendation into the Company's WUTC DR 101 GRID simulation lowers the WCA  
11 NPC by \$6.9 million. This lowers the Company's claimed revenue increase by about  
12 \$1.6 million. ICNU reserves the right to provide supplemental testimony on this issue,  
13 given the tardiness with which the Company provided workpapers in support of its coal  
14 cost update. The Commission should also not consider any justifications for this increase  
15 in PacifiCorp's rebuttal testimony, since the Company could have provided supporting  
16 documentation earlier in this proceeding.

17 **Forward Market Price Updates**

18 **Q. PLEASE DESCRIBE HOW THE COMPANY DOES ITS MARKET PRICE**  
19 **UPDATES.**

20 **A.** In performing a market price update, the Company's uses its "Official Forward Price  
21 Curve" ("OFFC") in effect at the time of the update for the various critical trading hubs  
22 (both electricity and gas). It is my understanding that while the Company has forward  
23 price curves for each trading day throughout the month, the OFFC—which undergoes  
24 greater review and approval—is compiled once each quarter or as required to determine

1 the Company's net power cost in a rate proceeding. Based on the OFFC, the Company  
 2 will update all contracts and transactions, including any mark-to-market adjustment,  
 3 affected by changes in market prices. In addition, the Company will also include any  
 4 additional short-term transactions it has executed. The following table shows the change  
 5 in average rate year prices at select trading hubs from the Company's OFFC. The table  
 6 below illustrates the significant drop in market prices since March 2011:

<b>PacifiCorp Forward Price Comparison</b>				
<b>June 2012 through May 2013</b>				
<b>(\$/MWh or \$/MMBTU)</b>				
<b>Market</b>	<b>Mar-11</b>	<b>Sep-11</b>	<b>Nov-11</b>	<b>Change</b>
<b>Mid-C HLH</b>	\$41.44	\$36.28	\$34.05	-\$7.40
<b>Mid-C LLH</b>	\$31.44	\$26.47	\$24.63	-\$6.81
<b>COB HLH</b>	\$46.11	\$40.79	\$37.86	-\$8.25
<b>COB LLH</b>	\$33.35	\$28.84	\$27.22	-\$6.14
<b>Sumas</b>	\$4.89	NA	\$4.05	-\$0.84
<b>AECO</b>	\$4.55	NA	\$3.78	-\$0.77

7 **Q. DO YOU HAVE ANY CONCERNS WITH THE MANNER IN WHICH THE**  
 8 **COMPANY PERFORMS ITS MARKET PRICE UPDATES?**

9 **A.** Yes, I have a concern with a single aspect of PacifiCorp's market update procedures.

10 The concern is PacifiCorp reliance on an OFFC from a single day to determine the  
 11 expected rate year costs. I am concerned that use of a single day raises the potential for  
 12 gaming and the Company's approach is quite different from the approach used by both  
 13 Puget Sound Energy ("PSE") and Avista. For many years, PSE and Avista have used the  
 14 average of three months of trading days to derive the market prices used in regulatory  
 15 filings. This has become the accepted method as a result of the rebuttal testimony and  
 16 accompanying analysis performed by Dr. Jeffrey Dubin on behalf of PSE in docket UE-

1 040641 and the resulting Commission order accepting this approach for PSE.<sup>1/</sup> The  
2 testimony stated that in a less than perfectly efficient market, an average of future prices  
3 could be used. Dr. Dubin’s accompanying analysis indicated little statistical difference  
4 between using averaging periods from one month up to six months for a given future  
5 period. Focusing on periods that were five months and seventeen months into the  
6 future—to reflect the typical start and end months of the rate year—Dr. Dubin concluded  
7 that the use of a three month averaging period was reasonable.

8 **Q. DO YOU BELIEVE THE COMPANY ENTERS INTO TRANSACTIONS IN**  
9 **MARKETS THAT ARE NOT “PERFECTLY EFFICIENT”?**

10 **A.** Yes, as measured by liquidity. There are several market hubs where readily available  
11 daily forward market price information is not readily available. For example, under the  
12 WCA power supply approach, forward price information is required for the COB and  
13 Four Corners market hubs. However, forward prices are not reported by the  
14 Intercontinental Exchange (“ICE”) at either of these locations due to illiquidity.

15 **Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THIS**  
16 **ISSUE?**

17 **A.** The Commission should require PacifiCorp to use the average of many trading days to  
18 derive the forward price curves. While ICNU prefers the use of three months of trading  
19 days, consistent with the method used by PSE and Avista, PacifiCorp’s expansive service  
20 territory requires far more electricity trading hubs than either PSE or Avista, in order to  
21 determine the net power supply costs for the Company. For this reason, the Commission  
22 should require that forward prices be determined using the average of all trading days

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<sup>1/</sup> WUTC v. PSE, Docket Nos. UE-040641 and UG-040640, Rebuttal Testimony of Dr. Jeffrey A. Dubin at 23:7-17 (Nov. 3, 2004); WUTC v. PSE, Docket Nos. UE-040641 and UG-040640, Order No. 06 ¶ 111 (Feb. 18, 2005).

1 from the most recent month or 30 day period. Typically, this would be 20-22 trading  
 2 days. Of course, ICNU would also support using three months as is done by PSE and  
 3 Avista. Either approach would give greater assurance to ratepayers than the Company's  
 4 single day method.

5 **Q. HAVE YOU PERFORMED ANY ANALYSIS SHOWING HOW THIS**  
 6 **RECOMMENDATION WOULD IMPACT THE COMPANY'S WCA NPC?**

7 **A.** Yes. The following table compares the forward market price average for the rate year at  
 8 select hubs from the Company initial filing and updates along with the ICNU  
 9 recommendation. The Company OFFCs were as of March 2011 ("As Filed" column),  
 10 September 2011 ("WUTC 91" column) and November 2011 ("WUTC 101" column).  
 11 The ICNU prices were derived from ICE forward prices from November 17 through  
 12 December 16, 2011 for the Mid-C hub and maintaining the Mid-C COB differential from  
 13 the Company's WUTC DR 101 OFFC in order to derive the ICNU COB prices.

<b>Forward Price Comparison - Rate Year Average</b>					
<b>(\$/MWh or \$/MMBTU)</b>					
<b>Market Hub</b>	<b>As filed</b>	<b>WUTC 91</b>	<b>WUTC 101</b>	<b>ICNU</b>	<b>ICNU - WUTC 101</b>
<b>Mid-C On peak</b>	\$41.44	\$36.28	\$34.05	\$32.51	-\$1.54
<b>Mid-C Off peak</b>	\$31.44	\$26.47	\$24.63	\$23.64	-\$0.99
<b>COB On Peak</b>	\$46.11	\$40.79	\$37.86	\$36.33	-\$1.54
<b>COB Off Peak</b>	\$33.35	\$28.84	\$27.22	\$26.23	-\$0.99
<b>Sumas</b>	\$4.89	NA	\$4.05	\$3.83	-\$0.22
<b>Chehalis</b>	\$5.23	\$4.57	\$4.34	\$4.10	-\$0.24

14 Using the illustrative ICNU market prices, the Company's WCA net power cost is  
 15 lowered by about \$4.2 million. This market price update lowers the Company's claimed  
 16 Washington increase by about \$1.0 million. ICNU recommends that the Commission

1 order the Company to perform a compliance filing in this proceeding using the most  
2 currently available forward prices from at least the most recent month. This final update  
3 will ensure the rates resulting from this proceeding are based on the most recent forward  
4 price information available. This final update can also include the most recent short-  
5 term transactions the Company has executed (both electric and gas) and final mark-to-  
6 market calculations, but the Company should not have the discretion to change any other  
7 contract or cost item that has not been previously approved by this Commission. It would  
8 be inappropriate to allow PacifiCorp to change rates based on contracts that have not  
9 been reviewed by the parties or the Commission.

**Power Supply Mode**

10 **Q. DO YOU HAVE ANY OTHER POWER COST RECOMMENDATIONS FOR**  
11 **THE COMMISSION TO CONSIDER?**

12 **A.** Yes. I believe that the Commission should order the Company to use a power supply  
13 model that has been developed and marketed by an independent third party vendor in all  
14 future proceeding before this Commission.

15 **Q. WHY?**

16 **A.** In this proceeding—as it has done in several prior proceedings—the Company has used  
17 its GRID model to project its net power cost for the rate year. This is an internally  
18 developed Company model with several significant short comings. The GRID model has  
19 been controversial in many jurisdictions, with parties litigating numerous GRID  
20 modeling problems that overstate net power costs. For example, the Company uses a  
21 screening process in order to determine the proper unit commitment as the internal  
22 dispatch logic was shown to be deficient. A more robust model would not require this



1 burdensome screening process. Similarly, the Company uses an external model to  
2 determine the hourly dispatch of its hydro resources instead of the GRID dispatch logic.  
3 PacifiCorp has resisted providing this model to ICNU, and instead only provides model  
4 runs to ICNU. (This pre-determined hourly dispatch is then directly inputted into the  
5 GRID model through a data file). Since the dispatch of hydro resources should be  
6 dependent upon market conditions, the use of the external hydro dispatch model  
7 necessitates an iterative process between GRID and the hydro model to capture any  
8 market price changes. Again, this iterative process is avoided if the model is actually  
9 determining the hydro dispatch and the marginal cost or market price simultaneously. In  
10 addition, the GRID model requires that hourly electricity market prices be directly  
11 inputted at several trading hubs. This requires the Company to manufacture market  
12 prices through an external process as well. The futility of this exercise—projecting  
13 hourly “real time” market prices up to seventeen months into the future—is shown by  
14 the simple fact that no third party vendor markets projected real-time prices. It simply  
15 cannot be done with any reasonable accuracy beyond just a couple of days. Further, as I  
16 previously noted, some of the electricity trading hubs are illiquid thereby requiring  
17 considerable “guestimating” in order to determine projected forward prices for the rate  
18 year.

19 Many of these model deficiencies can be overcome by simply using a different  
20 model. In my view, the GRID model is a very simplistic model that must be told how  
21 units should be run and what the market price already is, irrespective of the availability of  
22 the generating resources. For example, with the GRID model, a planned outage at a  
23 major resource has absolutely no impact on the market price during the outage hours.

1 This is far from the real world circumstances where outages at significant plants or  
2 transmission lines have an immediate impact on market prices.

3 **Q. ARE OTHER MODELS READILY AVAILABLE THAT CAN TAKE IN TO**  
4 **ACCOUNT VARYING MARKET CONDITIONS?**

5 **A.** Yes. There are several third party models being marketed which could be used to  
6 determine the Company's power supply cost through a more appropriate simulation  
7 process. For example, this Commission is very familiar with the AURORA model  
8 marketed by EPIS. This fundamental model is employed both by PSE and Avista for  
9 deriving power supply costs. As a fundamental model, AURORA will determine the  
10 hourly market price at each electricity hub based upon the marginal cost of serving that  
11 location at that particular hour. In so doing, it will use all available resources to serve the  
12 projected load in a least cost manner. This allows for a more consistent integration of all  
13 market drivers based upon a given series of loads and resource costs including forward  
14 gas prices. In my view, this would be a far superior method for deriving PacifiCorp's net  
15 power supply cost, instead of using the patched-together series of external models and  
16 considerable judgment required with GRID.

17 **Q. ARE YOU RECOMMENDING THAT THE COMPANY SHOULD BE**  
18 **REQUIRED TO USE THE AURORA MODEL?**

19 **A.** No. The Company should be allowed to select an independent model that it believes is  
20 most appropriate for modeling its system. However, the Commission should require that  
21 Staff and intervening parties be given access to the model at little or no cost and trained  
22 in its use, as is done with the Company's current GRID model and PSE's and Avista's  
23 AURORA model. This training should occur long before the Company is allowed to  
24 submit another rate filing using the new model.

1 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

2 A. Yes.