Oregon

Theodore R. Kulongoski, Governor

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June 23, 2008

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **Docket No. UE 199 – In the Matter of PACIFICORP, dba PACIFIC POWER 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service.**

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Direct Testimony.

/s/ Kay Barnes

Kay Barnes
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
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c: UE 199 Service List (parties)

PUBLIC UTILITY COMMISSION OF OREGON

UE 199

STAFF DIRECT TESTIMONY OF

Kelcey Brown
Lisa Schwartz

In the Matter of
PACIFICORP, dba PACIFIC POWER
2009 Transition Adjustment Mechanism
Schedule 200, Cost-Based Supply Service.

June 23, 2008

CASE: UE 199
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

DIRECT TESTIMONY

June 23, 2008

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Kelcey Brown. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301. I am a Senior Economist in the Electric and Natural Gas Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. My witness qualification statement is found in Exhibit Staff/101, Brown/1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. In this testimony I describe Staff's recommended adjustments to the power costs that PacifiCorp has included in its filed case, UE 199 Annual Transition Adjustment Mechanism (TAM). I recommend that the Commission require the Company to update its ancillary service revenue and Little Mountain steam sales revenue within the annual update, which are directly related to the corresponding expenses included in net variable power costs (NVPC) requested in this TAM proceeding. In addition, I recommend that the Commission require PacifiCorp includes the impact of the Chehalis gas plant on its net NVPC in the 2009 test year.

Q. PLEASE SUMMARIZE STAFF'S PROPOSED ADJUSTMENTS TO THE COMPANY'S FILED NVPC REQUEST.

A. Staff proposes seven adjustments to the requested NVPC as allocated to Oregon:

(1) A reduction of $12,566,029 to account for additional revenue associated with customer load growth;

(2) A reduction of $524,595 to account for changes in net ancillary service revenue;

(3) A reduction of $623,477 to account for increased revenue associated with the Little Mountain gas facility steam sales;

(4) A reduction of $189,093 for the wind integration charge associated with the PacifiCorp wind storage contracts with other parties;

(5) A reduction of $800,605 for the wind integration charge associated with PacifiCorp-owned wind facilities;

(6) A reduction of $2,922,698 to account for removing the new forced outage rate methodology PacifiCorp used for owned hydro facilities in UE 199 versus previous filings; and

(7) A reduction of $789,034 to account for a change in capacity factor for the Rolling Hills wind generation project.

Q. WHAT IS THE TOTAL REQUESTED ADJUSTMENT BY STAFF TO NVPC?

A. The total adjustment requested by Staff is $18,415,529 for the 2009 test year.

<u>Additional Load-Related Revenue</u>

Q. WHAT IS THE PURPOSE OF STAFF'S ADJUSTMENT RELATED TO THE ADDITIONAL REVENUE ASSOCIATED WITH CUSTOMER LOAD GROWTH?

A. When a utility realizes load growth it is logical that its total power costs will increase as a result. Concurrent to the increase in costs there is also a corresponding increase in revenue from customer sales. The Company's requested NVPC in this docket does not account for the additional power cost-related revenue the Company will collect from customer load growth.

Q. DO PGE AND IDAHO POWER MAKE THIS ADJUSTMENT IN THEIR ANNUAL POWER COST UPDATES?

A. Yes, both the PGE and Idaho Power annual power cost update mechanisms are limited to per kilowatt-hour changes in NVPC. The PGE and Idaho Power mechanisms eliminate the portion of the total change in power costs, due to customer load growth, in the same fashion as Staff's proposed adjustment. This is shown very clearly in PGE testimony, UE 197 PGE/200, Tooman-Tinker/2.[1]

Q. HOW HAS STAFF CALCULATED THIS ADJUSTMENT?

A. Using the previously approved NVPC in rates for Oregon ratepayers, $247,421,525[2] divided by current base rate sales of 13,470,754 MWh[3], times the increase in sales, 684,152 MWh (calculated by subtracting Company projected sales for 2009[4] minus current base rate sales). This provides the total $12.6 million in additional revenue (for calculation *See* Exhibit Staff/102, Brown/1-2).

Q. WHY IS IT NECESSARY TO MAKE THIS ADJUSTMENT WITHIN THE CURRENT TAM PROCEEDING?

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[1] Pursuant to OAR 860-014-0050(e), staff requests that the Commission take official notice of this document.

[2] *See* PPL101, Duvall/1

A. Staff's proposed adjustment will ensure that the Company does not over-collect the authorized level of NVPC because of customer load growth.

<u>**Updating "Other Revenue" Components Directly Related to NVPC**</u>

Q. WHAT IS STAFF'S PROPOSAL REGARDING UPDATING OTHER REVENUES THAT HAVE CORRESPONSING COST UPDATES INCLUDED IN THE ANNUAL NVPC ADJUSTMENT?

A. PacifiCorp has stated that it is updating costs associated with providing ancillary services and steam sales. According to information provided by the Company, the impact on NVPC within the 2009 test year is approximately $4.0 Million (*See* Exhibit Staff/103, Brown/1). Within PGE's UE 180 docketed case, the Commission recognized that there was a mismatch between costs and benefits associated with updating ancillary service costs and not updating the corresponding revenues and ordered PGE to update both costs and revenues associated with ancillary services. Staff recommends that in order to correct this inequality, and to be consistent with Commission policy, PacifiCorp needs to update both costs and revenues associated with these services on an annual basis.

Q. DOES PGE UPDATE THESE REVENUES WITHIN ITS ANNUAL AUT FILING?

A. No, PGE does not update these revenues within its annual AUT filing. The Commission ordered PGE to update these revenues in its annual PCAM filing, due to PGE's claim that they have difficulty in forecasting

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[3] *See* PPL/201, Ridenour/1

their revenues associated with ancillary services and the fact that PGE has a PCAM mechanism.

Q. DOES PACIFICORP HAVE A PCAM MECHANISM THAT WOULD BE ABLE TO CAPTURE THIS INEQUALITY?

A. No.

Q. WAS PACIFICORP ABLE TO PROVIDE AN ESTIMATED REVENUE AMOUNT FOR THESE SERVICES FOR THE 2009 TEST YEAR?

A. Yes, PacifiCorp was able to provide estimates for these revenues. PacifiCorp has provided budgeted revenue for the 2008 and 2009 test years, in addition to actual revenue for 2007 within the 1st supplemental response to OPUC data request # 29 (*See* Exhibit Staff/103, Brown/2).

Q. WHAT IS THE BASIS FOR STAFF'S ADJUSTMENT ASSOCIATED WITH ANCILLARY SERVICE REVENUE?

A. Consistent with the Commission's direction in the UE 180 order, Staff's adjustment is based on the cost impacts of providing ancillary services for the 2009 test year, and budgeted revenue provided by PacifiCorp for the 2009 test year. $5,986,273 - $4,000,000 = $1,986,273 and as allocated to Oregon $524,595 (*See* Exhibit Staff/103, Brown/1).

Q. WHAT IS THE BASIS FOR STAFF'S ADJUSTMENT FOR LITTLE MOUNTAIN STEAM SALES?

A. Staff's proposed adjustment of $623,477is based on actual revenue from the 2007 steam sales for Little Mountain, and estimated revenues for the 2009 test year that PacifiCorp based on GRID model output. Staff's

[4] OPUC DR 14, attachment 14-2 Staff Exhibit 103

adjustment is the difference between 2007, the test period for PacifiCorp's last filed general rate case, and the Company's provided estimates for 2009 revenue (*See* Exhibit Staff/104 Brown/1).

Q. ARE THESE REVENUES DIRECTLY ASSOCIATED WITH VARIABLE POWER COSTS?

A. Yes, specifically for the Little Mountain Steam sales, it is written in the contract that the recipient will pay market gas prices on a monthly basis for delivered steam. Staff will show that the increase in revenue is symmetrical to the increase in gas costs.

Q. WHAT WAS THE AVERAGE COST INCREASE THAT PACIFICORP REALIZED FOR THEIR NATURAL GAS FACILITIES?

A. In response to OPUC DR #10 (*See* Exhibit Staff/104, Brown/2) PacifiCorp states that natural gas costs are up 11% to 12% from the 2008 test year to the 2009 test year.

Q. WHAT PROOF DO YOU HAVE THAT THE ADDITIONAL REVENUE RECEIVED BY THE COMPANY IS DIRECTLY ASSOCIATED WITH THE INCREASE IN VARIABLE POWER COSTS AND NOT RECOVERY OF CAPITAL COSTS?

A. In response to OPUC data request #23, PacifiCorp states that their estimated revenues for the 2008 test year are $6,032,000, which shows that the increase in revenue for 2009 is approximately 11% higher ($6,683,000/$6,032,000-1), directly attributable to the increase in natural gas prices. (*See* Exhibit Staff/104, Brown/1)

Q. DO THESE LAST TWO ADJUSTMENTS RELATE TO THE COMMISSION DECISION MADE IN UE 191 ASSOCIATED WITH THE GP CAMAS CONTRACT ADJUSTMENT?

A. No, the Commission specifically ruled that the GP Camas contract would have been an adjustment associated with capital cost recovery and other major maintenance (Order No. 07-446 at page 22), more appropriately considered within a general rate case proceeding. Staff has shown that the adjustment associated with Little Mountain Steam sales and other ancillary services is directly associated with variable power costs, and not capital cost recovery, and therefore as directed by the commission in UE 180 needs to be updated on an annual basis within the TAM proceedings in order to match the costs and benefits of these services.

<u>Wind Integration Costs</u>

Q. WHAT ADJUSTMENTS IS STAFF PROPOSING TO THE WIND INTEGRATION COSTS?

A. Staff is proposing two adjustments to the wind integration costs included by PacifiCorp for the first time in the 2009 test year.

1. Staff is adjusting the PacifiCorp cost per MWh from $1.14/MWh to $.11/MWh using the methodology in Appendix J from PacifiCorp's acknowledged 2007 IRP and adjusted for inflation to 2009 dollars using the PacifiCorp method in the Company's modeling of wind integration, resulting in an adjustment of $800,605. (*See* Exhibit Staff/105, Brown/1-2 for calculations)

2. Staff is also making an adjustment for the wind integration charge associated with the storage contracts for wind facilities in the amount of $189,093. Staff will show that this cost, as included in the current TAM filing, would constitute a double recovery for PacifiCorp since it is currently receiving revenues for these services from the contract recipients.

Q. WHAT WAS PACIFICORP'S BASIS FOR ITS CALCULATION OF THE $1.14/MWH INTEGRATION CHARGE?

A. PacifiCorp conducted a study within the 2007 PacifiCorp IRP, Appendix J page 193, in order to determine the costs for load following services. Within the IRP, PacifiCorp discusses the study which led to the calculation of $1.14/MWh associated with a 2,000 MW portfolio of wind and the required incremental reserves of 43 MW for this portfolio (*See* Exhibit Staff/105, Brown/3-14).

Q. IS THE $1.14/MWH ASSOCIATED ONLY WITH THE 43 MW OF INCREMENTAL RESERVES THAT PACIFICORP IDENTIFIES AS BEING REQUIRED FOR A PORTFOLIO OF 2,000 MW OF WIND?

A. Yes.

Q. WHAT IS THE PORTFOLIO OF WIND CURRENTLY INCLUDED IN THE 2009 TAM FILING, NOT INCLUDING STORAGE CONTRACTS?

A. 701 MW.

Q. WHAT ARE THE INCREMENTAL RESERVES THAT WOULD BE REQUIRED FOR 701 MW AS SHOWN IN FIGURE J.3 OF APPENDIX J IN THE 2007 PACIFICORP IRP?

A. Using Figure J.3, Appendix J, Staff estimates that the incremental reserves would be approximately 5 MW (*See* Exhibit Staff/105, Brown/6). Staff's estimation of the 5 MW incremental reserves is based on a visual interpretation provided by the trend line within Figure J.3, a graph that plots Incremental Reserve Requirement vs. Installed Wind Capacity.

Q. WHAT IS THE COST ASSOCIATED WITH 5 MW OF INCREMENTAL RESERVES?

A. Using Appendix J, Figure J.4 trend line equation, and escalating this figure to 2009 dollars using the NPC report wind integration tab, the cost for providing 5 MW of incremental reserves is $.11/MWh (*See* Exhibit Staff/105, Brown/2).

Q. PACIFICORP HAS AN ANNUAL UPDATE FOR WIND GENERATION RESOURCES. IS IT APPROPRIATE TO INCLUDE A PRICE THAT WAS CALCULATED ON A FUTURE PORTFOLIO OF WIND RESOURCES?

A. No, because PacifiCorp has an annual update they should only be including costs associated with the test year portfolio of resources.

Q. WHAT ARE THE STORAGE CONTRACTS THAT STAFF HAS REFERENCED IN ITS RECOMMENDED ADJUSTMENT?

A. PacifiCorp models five storage agreements within the storage and exchange section of the net power cost report. These contracts are associated with the wind facilities cited as Foote Creek I, II, III, IV, and SCL State Line. PacifiCorp is the operator of these facilities, receiving intermittent power into its system and agreeing to provide firm power at scheduled times to the owner of the facilities, such as BPA and EWEB.

Q. WHAT IS AN EXAMPLE OF THE CHARGES THAT PACIFICORP IS CURRENTLY BILLING ON A MONTHLY BASIS?

A. Specifically, within the contract with BPA for Foote Creek II (FC II), PacifiCorp receives monthly revenue for three components: 1. directly assigned facility charge; 2. storage Charge per kWh; and 3. transmission Charge per kWh (*See* Exhibit Staff/106, Brown/3).

Q. WHAT IS INCLUDED IN THE STORAGE CHARGE?

A. According to the definition within the contract language for BPA FC II Storage Agreement, the storage charge is for Storage Services provided by PacifiCorp-Merchant (*See* Exhibit Staff/106, Brown/1-2).

Q. DOES PACIFICORP DEFINE WHAT THESE "STORAGE SERVICES" ARE?

A. Yes, as quoted from the BPA FC II contract, "Storage Services means the provision by PacifiCorp-Merchant to Bonneville of load control and load following services in providing a within-the-hour smoothing of Project output and in providing an hour-to-hour predictability of Scheduled Energy."

Q. DOES THIS MEAN THAT THE COST AND RECOVERY FOR PROVIDING WIND INTEGRATION SERVICES HAS BEEN INCLUDED IN THESE CONTRACTS SINCE THEIR INCEPTION?

A. Yes. This specific contract was negotiated in 1999 and it is currently in effect. Language in the other four contracts also demonstrates that PacifiCorp is providing this service as part of the storage contract.

Q. WHY SHOULD PACIFICORP NOT INCLUDE THIS CHARGE INTO THE GRID MODEL?

A. If PacifiCorp were allowed to include an additional wind integration charge into the GRID model for these wind storage contracts, ratepayers, as well as the contract recipients would be responsible for paying PacifiCorp for the same service, which would effectively provide PacifiCorp with double recovery for this service.

Hydro Forced Outage Rates

Q. DOES STAFF BELIEVE IT IS APPROPRIATE FOR PACIFICORP TO INTRODUCE A CHANGE IN ITS FORCED OUTAGE RATE METHODOLOGY IN THE TAM PROCEEDING?

A. No. This type of methodology change is more appropriate in a general rate case filing or special investigation, where Staff and other parties would have more time and resources to fully investigate the change that PacifiCorp is proposing in its modeling of hydro facilities. Staff and other parties, including PacifiCorp, are currently involved in a docketed case, UM 1355 Investigation into Forced Outage Rates for Electric Generating Units, which would be a more appropriate venue for this methodological change.

Q. WHAT IS THE CHANGE IN METHODOLOGY THAT PACIFICORP HAS DONE WITH RESPECT TO FORCED OUTAGE RATES ON HYDRO UNITS?

A. This docket is the first time PacifiCorp has modeled forced outages on its hydro facilities. Prior to the 2009 test year, PacifiCorp would estimate and model maintenance outages for the upcoming test year.

Q. DOES PGE OR IDAHO POWER INCLUDE FORCED OUTAGES ON THEIR HYDROELECTRIC GENERATING UNITS WHEN ESTIMATING NVPC?

A. No.

Q. HAS PACIFICORP MODELED FORCED OUTAGE RATES ON ITS HYDRO UNITS IN THE SAME MANNER THAT IT MODELS FORCED OUTAGE RATES ON THERMAL PLANTS?

A. No. Modeling forced outages on a thermal plant in the GRID model de-rates the plant for the entire year. For example, if the facility had a nameplate capacity of 100 MW and a 10% forced outage rate, the available capacity of the plant for the upcoming year would be set at 90 MW. PacifiCorp has modeled forced outages on its hydro plants by taking the four-year average of forced outages, coming up with an average number of hours for each month, and in the applicable test year modeling these hours within the VISTA hydro optimization model so that GRID shows the plant to be unavailable for the specific hours that PacifiCorp has said it will be out of service due to forced outages.

Q. IS THIS CONSISTENT WITH HOW FORCED OUTAGES OCCUR?

A. No. Forced outages occur randomly, which is why for thermal plants the plant is de-rated throughout the year. There is no way to predict which hours, or even which month the plant will be out of service.

Q. PLEASE EXPLAIN STAFF'S RECOMMENDED HYDRO ADJUSTMENT FOR FORCED OUTAGE RATES.

A. PacifiCorp's new methodology in computing forced outage rates on its owned hydro facilities yields a reduction in generation output of 154,000 MWh from UE 191. Staff multiplied this number times the average market price for purchased power, included in PacifiCorp's GRID model net power cost report, to calculate the avoided cost that this amount of energy would represent. 154,000 MWh times $71.86/MWh = $2,922,698 as allocated to Oregon using system generation factor 26.41%.

Q. WHY DOES STAFF USE AN AVERAGE PRICE FOR PURCHASED POWER WHEN CALCULATING ITS ADJUSTMENT?

A. PacifiCorp stated that the analysis to isolate the dollar impact of this change had not been done (*See* Exhibit Staff/107, Brown/1). Therefore, Staff used the average price for purchased power, which is a reasonable assumption of the avoided cost that PacifiCorp would have realized had this energy been included.

<u>Rolling Hills Wind Capacity Factor Adjustment</u>

Q. WHAT IS STAFF'S ADJUSTMENT FOR THE CAPACITY FACTOR ASSOCIATED WITH THE ROLLING HILLS WIND PROJECT?

A. Using the GRID model, provided by PacifiCorp for the 2009 TAM filing, Staff changed the capacity factor for the Rolling Hills Wind facility from approximately 31% to 38%. This resulted in a total change in NVPC of $772,456, and an increase of 60,941 MWh from the facility. This change in NVPC includes additional wind integration charges of $18,349. Staff has recommended adjustments to wind integration charges, therefore it is consistent to deduct the additional wind integration charges at the $1.14/MWh and add the wind integration charge at Staff recommended $.11/MWh (60,941 MWh * $.11/MWh = $6,704 * 26.41% = $1,771), which results in a total adjustment of $789,034.

Numerically illustrated: $772,456 + $18,349 - $1,771=$789,034

Q. HOW DOES STAFF SUPPORT THE ROLLING HILLS CAPACITY FACTOR ADJUSTMENT?

A. Support for the capacity factor adjustment is provided in Staff/200 testimony by Staff witness Lisa Schwartz. My testimony is in support of the monetary adjustment, and GRID calculation, associated with changing the capacity factor adjustment recommended in Staff/200 testimony.

<u>New Gas-Fired Resource</u>

Q. WHAT IS STAFF'S SUGGESTION WITH RESPECT TO THE PROPOSED CHEHALIS GAS PLANT THAT PACIFICORP INTENDS TO ACQUIRE SEPTEMBER 2008?

A. The Chehalis natural gas plant, a 520 MW plant, with regulatory approval would be purchased by PacifiCorp in September 2008. If the acquisition of the Chehalis plant is in fact completed, Staff recommends that this plant be included in the NVPC for the 2009 test year in this docket.

Q. WILL THIS PLANT BE IN SERVICE ON JANUARY 1, 2009 OF THE TEST YEAR?

A. Yes, if the transaction is completed as scheduled.

Q. DOES PACIFICORP HAVE PLANTS INCLUDED IN THE TEST YEAR THAT ARE NOT CURRENTLY PRODUCING POWER, BUT EXPECTED TO BE IN SERVICE BY JANUARY 1, 2009?

A. Yes, the wind facilities at Glenrock, Rolling Hills, and Seven Mile Hill are expected to be operational in December 2008.

Q. DOES PACIFICORP CURRENTLY HAVE PLANTS INCLUDED IN 2009 NVPC FOR WHICH FIXED COSTS WILL NOT BE INCLUDED IN RATES?

A. Yes, the fixed costs of the Lake Side gas power plant will not be included in rates for 2009. (See PPL/100, Duvall/6)

Q. WOULD THE FIXED COSTS FOR THE CHEHALIS GAS PLANT BE INCLUDED IN 2009 RATES IF PACIFICORP PURCHASED THE FACILITY IN SEPTEMBER 2008?

A. No.

Q. DOES STAFF HAVE A MONETARY ADJUSTMENT FOR INCLUDING THIS PLANT IN NVPC?

A. No, PacifiCorp has not provided an estimate of the inclusion of the Chehalis plant in the GRID model for the 2009 test year.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE MONETARY ADJUSTMENT?

A. Staff recommends that the Commission require PacifiCorp to provide a GRID run that shows the impact on NVPC for the 2009 test year, in order to adequately account for this resource. If PacifiCorp acquires the Chehalis plant as expected, the Commission should require the Company to include that impact in its final 2009 NVPC.

Q. HAS PACIFICORP PROVIDED THIS TYPE OF INFORMATION WITHIN ANOTHER PROCEEDING?

A. Yes. According to the Company it has prepared a net power cost study including the Chehalis plant for the Chehalis proceeding in Utah (Docket No. 07-035-93), which is based on a 2008 test year.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 199
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 23, 2008

WITNESS QUALIFICATION STATEMENT

NAME: Kelcey Brown

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist, Electric and Natural Gas Division, Resource and Market Analysis

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.

EDUCATION: All course work towards Masters in Economics
University of Wyoming

B.S. University of Wyoming
Major: Business Economics
Minor: Finance

EXPERIENCE: Since November 2007 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research and providing technical support on a wide range of cost, revenue and policy issues for electric utilities. I have actively participated in regulatory proceedings in Oregon, including UE 195, UE 198, and UE 200.

From June 2003 to November 2007 I worked as the Economic Analyst for Blackfoot Telecommunications Group, a competitive and incumbent telephone provider in Missoula, Montana. I conducted all long and short term sales and revenue forecasts, resource acquisition cost-benefit analysis, business case analysis on new products and build-outs, pricing, regulatory support, market research, and strategic planning support.

From May 2002 to August 2002 I worked as an intern at the Illinois Commerce Commission in Springfield, Illinois. I performed competitive market analysis, spot market monitoring and pricing review, and extensive research on locational marginal pricing and transmission system incentives for development.

CASE: UE 199
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 102

Exhibits in Support
of Direct Testimony

June 23, 2008

Oregon Load Growth Adjustment Calculation

			Source:
2009 Oregon retail sales	14,154,906	MWh	Pac response to Staff DR 14 (Attach OPUC 14-2)
Current base rate sales	13,470,754	MWh	UE 199, PPL/201, Ridenour/1
increase	684,152	MWh	
UE 191 Oregon NVPC	$247,421,525		UE 199, PPL/101, Duvall/1
UE 191 Oregon NVPC - $/MWh	$18.37		= $247,421,525 / 13,470,754
Increase	684,152	MWh	
UE 191 $/MWh	$18.37	$/MWh	
Adjustment	**$12,566,029**		

Adjustment: reduction in request due to Oregon Load increase

Docket: UE-199 / Oregon TAM 2008
OPUC Data Request 14

	2009												
	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	CY 2009
OREGON													
CALENDAR VIEW													
CLASS OF SERVICE													
ENERGY (MWH)													
RESIDENTIAL	605,772	482,370	522,294	391,339	379,685	376,036	409,879	401,009	337,388	398,759	534,332	661,995	5,500,858
COMMERCIAL	383,014	363,213	400,866	332,666	395,647	424,426	495,759	471,828	431,092	407,704	412,553	420,717	4,939,486
INDUSTRIAL	274,704	273,281	274,730	277,803	282,941	287,750	290,185	296,112	297,113	292,999	286,714	279,648	3,413,981
PUBLIC STREET LIGHTING	3,868	3,284	3,799	3,420	3,490	3,268	3,627	3,576	3,556	3,929	3,531	3,684	43,032
SALES TO PUBLIC AUTHORITIES	0	0	0	0	0	0	0	0	0	0	0	0	0
INTERDEPARTMENTAL	0	0	0	0	0	0	0	0	0	0	0	0	0
IRRIGATION	-243	-228	839	5,444	28,829	43,363	68,197	60,523	40,196	11,064	-206	-230	257,548
SALES TO ULTIMATE CUSTOMERS	1,267,114	1,121,920	1,202,528	1,010,672	1,090,592	1,134,843	1,267,647	1,233,049	1,109,346	1,114,456	1,236,924	1,365,814	14,154,906

CASE: UE 199
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 103

Exhibits in Support
of Direct Testimony

June 23, 2008

OPUC Data Request 29

Please provide a list of all entities to which PacifiCorp provides ancillary services, and the specific services provided to each entity. With respect to these services please provide the 2007 actuals, 2008 forecast, and 2009 forecast of costs and revenues for each service and for each entity, and where in this filing these revenues and costs are included. If the revenues are not included in this filing, but the costs are, where are the revenues accounted for in the company's rates and specifically how much is included in the projected 2009 rates.

1st Supplemental Response to OPUC Data Request 29

Without waiving the objection in PacifiCorp's original response to OPUC 29, the Company provides the following supplemental response.

The Company operates its portfolio of resources to serve its total obligation. It is not possible to identify which resources went to serve which obligation. As a result, it is not possible to isolate actual costs related to providing ancillary services to those entities. For the same reason, it is not possible to forecast the costs of such services. However, the GRID model may be used to estimate the change in net power costs if the Company were not obligated to provide such services. Based on the Commission authorized net power costs in the UE 191 proceeding, the net power costs would reduce by about $5.5 million. Based on the Company's filed net power costs in the current proceeding, the net power costs would reduce by about $4.0 million (this was stated incorrectly in the Company's original response to OPUC Data Request 29).

Please note the cost impact should not be compared with the revenue received because the Company is under regulation and obligated to provide such services under FERC regulated tariff rates.

Refer to Attachment OPUC 29 1st Supplemental for ancillary services revenues for 2007 and an updated budget of ancillary services revenues for 2008 and 2009. The budgeted figures are based on assumptions from 2007.

Docket: UE-199 / Oregon TAM 2008
OPUC Data Request 29 1st supplemental attachment

TRANSMISSION ANCILLARY SERVICE REVENUE
2007 ACTUAL RESULTS - 2008 & 2009 BUDGETED REVENUE

NOTE: Ancillary Service Revenue - Transmission reported in FERC acct. (456.1) Revenues from Trasmission of Electricity of Others . Imbalance reported in FERC Acct. (555) Purchased Power .
NOTE 1: The company does not budget for energy imbalances.

	Type of Service									
For the 12 months ended December 31, 2008, and 2009 - Budgeted $: Revenue - (Expense)	Scheduling System Control & Dispatch	Regulation & Frequency Response	Energy Imbalance	Operating Reserves-Spinning	Operating Reserves-Supplemental	Emergency Reserves	Primary Delivery Service	Distribution Substation Service	Meter Interrogation	Total
Transmission Customer										
Basin Electric Power Cooperative	$ -	$ 18,144	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,144
Bonneville Power Administration	25,200	109,896	-	94,608	-	-	178,932	49,248	-	457,884
Deseret Generation and Transmission	16,644	206,108	-	843,224	721,613	-		5,520	25,200	1,818,309
Flathead Electric Cooperative, Inc.	-	1,620	-	-	-	-	20,422	5,622	-	27,664
Iberdrola (formerly known as PPM Inc.)	-	-	-	169,200	171,200	-	-	-	-	340,400
Sempra Energy Trading Corp	-	20,100	-	-	-	-	-	-	-	20,100
Utah Associated Municipal Power	66,600	259,080	-	-	-	-	-	43,620	-	369,300
Utah Municipal Power Agency	36,000	71,340	-	-	-	-	-	-	-	107,340
Western Area Power Administration	-	-	-	-	-	-	33,432	2,700	-	36,132
	-	-	-	-	-	-	-	-	-	-
	$ 144,444	$ 686,288	$ -	$ 1,107,032	$ 892,813	$ -	$ 232,786	$ 106,710	$ 25,200	$ 3,195,273
For the 12 months ended December 31, 2008, and 2009 - Budgeted MWh										
Transmission Customer (Energy Received) Delivered										
Basin Electric Power Cooperative	-	113,400	-	-	-	-	-	-	-	113,400
Bonneville Power Administration	-	88,125	-	-	-	-	-	-	-	88,125
Deseret Generation and Transmission	-	1,288,175	-	2,268,548	1,943,742	-	-	-	-	5,500,465
Flathead Electric Cooperative, Inc.	-	10,125	-	-	-	-	-	-	-	10,125
Iberdrola (formerly known as PPM Inc.)	-	-	-	451,200	456,533	-	-	-	-	907,733
Sempra Energy Trading Corp	-	125,625	-	-	-	-	-	-	-	125,625
Utah Associated Municipal Power	-	-	-	-	-	-	-	-	-	-
Utah Municipal Power Agency	-	-	-	-	-	-	-	-	-	
Western Area Power Administration	-	-	-	-	-	-	-	-	-	
	-	-	-	-	-	-	-	-	-	-
	-	1,625,450	-	2,719,748	2,400,275	-	-	-	-	6,745,473

Merchant Function - Other revenue recorded in FERC Acct 456 - Other Electric Revenues

	2007	2008	2009	
Clark Storage and Irrigation Agreement (Load following, interest, & reserves)	$ 5,764,349	-	-	
Foote Creek Project	$ 2,224,156	$ 2,791,000	$ 2,791,000	**Total 2009 Revenue**
	$ 7,988,505	$ 2,791,000	$ 2,791,000	**5,986,273**

CASE: UE 199
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
of Direct Testimony

June 23, 2008

OPUC Data Request 23

For the Little Mountain gas generation facility, please provide any and all contracts associated with additional services that this facility provides in addition to electricity. If there is additional revenue associated with this facility, please provide the total revenue amount received from these additional contracts in 2007, projected 2008, and projected 2009. Where is this revenue included in the company's filing in this case?

Response to OPUC Data Request 23

Please refer to Attachment OPUC 23 for a copy of the Steam Supply Agreement. To the extent this requests seeks revenues for these this facility, PacifiCorp objects to this request as irrelevant because steam sales revenues are not included in the TAM, which is limited to an annual update of PacifiCorp's NVPC. This revenue is recorded in Other Electric Revenue (Account 456). In Order No. 07-446 (UE 191), the Commission found that the Camas contract adjustment, which also related to revenues included in Other Electric Revenue in UE 179, was outside the scope of the TAM proceeding.

Without waiving this objection, the Company provides the following response.

Actual steam sales revenues for Little Mountain recorded in 2007 were $4,322,329. Planned amounts for 2008 and 2009 are $6,032,000 and $6,683,000, respectively. As noted above, the revenue associated with this facility is not included in the TAM, which is limited to an annual update of PacifiCorp's NVPC.

OPUC Data Request 10

In an Excel spreadsheet, please (a) provide 5 years worth of actual fuel (gas and coal) costs, (b) 2008 approved test year costs, and the 2009 projected test year costs, on a $/MWh basis for each thermal facility, and $/MMBtu with respect to each facility on an annual basis. (c) Please describe in detail the reasons for increases or decreases in fuel costs for each facility for the 2009 test year versus the 2008 approved test period.

Response to OPUC Data Request 10

__Gas Costs__

a. Please refer to the Company's response to OPUC Data Request 4; specifically Attachment OPUC 4.

b. For 2008 approved test year costs, please refer to the Company's filing on November 15, 2007, provided here as Attachment OPUC 10 -1. For the 2009 projected costs please refer to Greg Duvall's Exhibit PPL/102 ("Net Power Cost Report") in the current proceeding.

c. Natural gas costs in test year 2009 for the Hermiston plant are 5.5% higher than those for 2008. This is due to pricing provisions in the full requirements natural gas supply contracts that dictate an annual contract price escalation of 5.5%. For the remaining plants, natural gas costs are up 11% to 12% from 2008 test year to 2009 test year as quantified in this response. This increase is indicative of the same market supply/demand fundamentals that have caused domestic natural gas prices to trend generally upward over the last three to five years. Average annual NYMEX futures prices are up 17% over the last three years and up 65% over the last five years.

   As PacifiCorp's practice has been to roll its natural gas price hedges gradually out through a three to five year period, the hedged prices for 2009 were locked in later, at higher prices, in the upward trending market than hedged prices for 2008.

__Coal Costs__

a.– c. The requested information for five years' worth of actual coal costs is provided in Attachment OPUC 10 -2. Approved test year 2008 costs and 2009 projected test year costs along with an analysis by plant of coal costs are provided in Confidential Attachment OPUC 10 -3. The confidential attachments are provided subject to the terms and conditions of the protective order in this proceeding.

CASE: UE 199
WITNESS: Kelcey Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

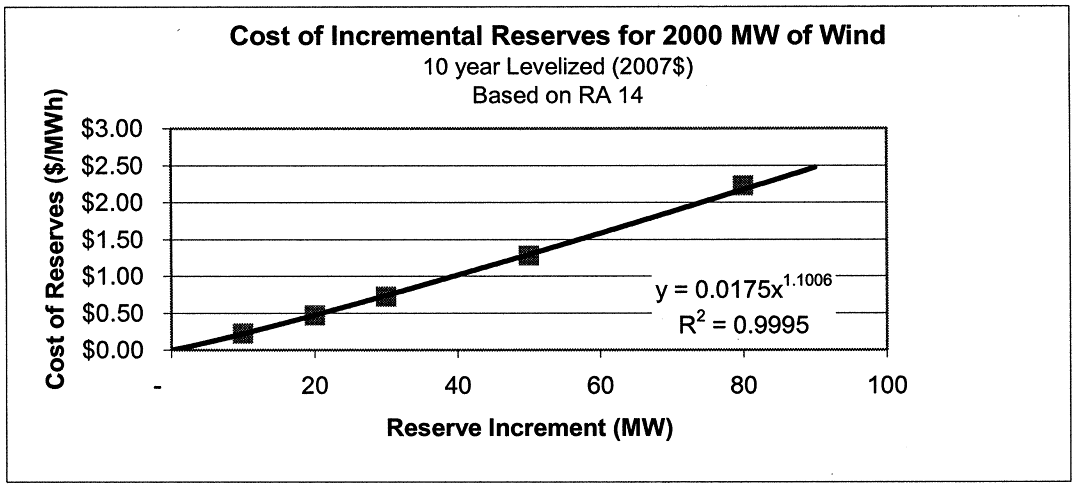
Exhibits in Support
of Direct Testimony

June 23, 2008

Staff's Wind Intregration Adjustment Calculation

Adjustment 1			Source:
Total Owned Wind Generation	2,247,932	MWh	GRID NPC report UE 199
PacifiCorp 2007 IRP, Appendix J	$1.14	$/MWh	GRID NPC report UE 199
Total cost	$3,278,604		
Total Owned Wind Generation	2,247,932	MWh	
Staff Estimated $/MWh	$0.11	$/MWh	
	$247,272		
Total Change	$3,031,331		
Oregon Allocated Adjustment	**$800,605**		
Adjustment 2			
Storage Contract Wind Generation	628,036	MWh	GRID NPC report UE 199
PacifiCorp 2007 IRP, Appendix J	$1.14	$/MWh	GRID NPC report UE 199
Total Adjustment	$715,961		
Oregon Allocated Adjustment	**$189,093**		

Staff Calculation Cost/MWh Wind Integration Costs



Source:
PacifiCorp 2007 IRP Study
Appendix J, Page 193

Trend Line Equation

coefficients	0.0175	1.1006
X =	5 MW	
Y =	$.0175*5^{1.1006}$	
Y =	$0.10	

Inflation Adjustment

Wind Integration Costs					
Year	CY GDP Deflator Annual Rate	CY CPI Annual Rate	CY Avg Inflation Annual Rate	Cummulative Adjustment	Wind Integration Costs
2007					$0.10
2008	2.2%	2.5%	2.3%	102.3%	$0.11
2009	1.8%	1.6%	1.7%	104.1%	$0.11
2010	1.8%	1.9%	1.8%	106.0%	$0.11
2011	2.0%	1.8%	1.9%	108.0%	$0.11
2012	2.1%	1.9%	2.0%	110.2%	$0.11

Source:
PacifiCorp Inflation Study
Inflation Forecast Dated 2008 03 01
GRID NPC report Wind Integration worksheet

APPENDIX J – WIND RESOURCE METHODOLOGY

This appendix summarizes the wind resource analyses used to help characterize wind resources included in PacifiCorp's IRP models. Specifically, the appendix covers (1) the expected cost of integrating various amounts of wind generation with other portfolio resources—reflecting a refinement and update of previous analysis conducted for PacifiCorp's integrated resource planning, (2) a resource screening effort to determine a base amount of wind resources to include in portfolios subjected to stochastic production cost simulation, and (3) the calculation of capacity planning contribution of wind resources, accounting for generation variability.

In addition to summarizing the results of its wind resource studies, this appendix briefly describes current efforts by organizations in the Pacific Northwest to assess wind integration implications. Finally, the last section of this appendix discusses the role of resource fuel type on the company's strategy for integrating wind resources. This discussion addresses an Oregon Public Utility Commission requirement to investigate this topic for the 2007 IRP.

A new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis, which allowed PacifiCorp to apply the same analytical approach to estimating the incremental reserve requirements for wind. The availability of hourly wind data for resources distributed across PacifiCorp service territories over comparable historical time horizons enabled analysts to include proxy wind resources with realistic operating characteristics into the analysis. Further, a development in techniques for estimating load carrying capability allowed analysts to estimate the capacity contributions of various wind combinations of wind developments that restricted interactions due to correlated generation from nearby plants. Analysts were able to improve the characterization of wind operations and interactions with the power system in the present analysis.

WIND INTEGRATION COSTS

Across all analyses, wind integration costs have generally been divided into two categories – incremental reserve requirements and system balancing costs. The former is related to the need for dynamic resources to be held in reserve, able to respond on a roughly ten minute basis to rapidly changing load/resource balance conditions. Since wind resource generation can be quite variable over time periods from about ten minutes to several hours, it will be necessary to increase the amount of reserves as the quantity of wind resources on the system increases. System balancing costs represent the difference in value between the energy delivered from wind resources compared to that delivered from less volatile resources. Consistent with previous studies, PacifiCorp reviewed both categories of wind integration costs: the incremental reserve requirement and the system balancing cost.

Incremental Reserve Requirements

Operating reserves are divided into categories based on purpose and on characteristics. Naming conventions for categorizing reserves by their intended purpose are not standard in the industry. Reserves held for responding to the sudden failure of generation or transmission equipment are usually called "contingency reserves". Reserves held to respond to changes in system frequency over a period of a few seconds will be referred to as "regulating reserves". Generation that can be brought on over a multiple-minute time period will be termed "load following reserves."

Wind projects are not expected to affect the need to hold contingency reserves, as there is no significant difference between wind generation and other types of generation with respect to sudden equipment failures, or other outages. The multiplicity of individual generators within a typical wind farm inherently makes them less susceptible to losing the entire output of the farm due to generator or turbine failures (but not transmission-related outages). Wind projects are subject to relatively rapid shutdown when wind speeds reach the cutout level. However, this has not been a significant problem in practice, as individual wind turbines do not tend to shut down simultaneously.

Similarly, regulating reserve requirements do not appear to be significantly affected by wind turbines[4]. The second-by-second variations in wind project output are found to be not significantly different from other generating units and the ambient fluctuations of the load. They are also not correlated with either load fluctuations, or distant wind projects.

Wind variations over periods of ten minutes to an hour are significant, and can cause operators to rapidly start up units on short notice within an hour. Fluctuations of the combined output of a collection of wind projects increases with the amount of total wind generation connected to the system.

For the 2007 IRP, a new methodology was developed to explicitly calculate the load following reserve requirement based on the uncertainty in load for the next hour on an operational basis. Operators have estimates of the behavior of loads for the next hour and move to bring on or back off resources as necessary to accommodate the expected change. Knowing that the actual load of the next hour will likely be different than the forecast and that there will be deviations within the hour, operators hold additional resources ready to respond should they underestimate the need for resources. (Generally, overestimates are not a problem, though it is an additional concern). Reserve levels are established to ensure that the shortfall can be met a minimum percentage of the time—generally around 95 percent. The methodology is graphically illustrated in Figure J.1, which shows how the load forecast changes from one hour to the next. Assuming that the range of actual outcomes for the next hour can be approximated by a normal distribution, the amount of additional reserve capability that is necessary to provide assurance of having adequate resources available at least 95 percent of the time can be calculated.

This methodology can be applied first to the system load alone and then again to the system load net of wind generation. The difference between the two results is the estimated incremental reserve requirement due to the wind resources.

[4] DeMeo, Grant, Milligan, and Schuerger, "Wind Plant Integration: Costs, Status, and Issues", IEEE Power & Energy Magazine, Vol 3 Number 6, Nov/Dec 2005, p. 41.

Figure J.1 – Load Following Reserve Requirement Illustration

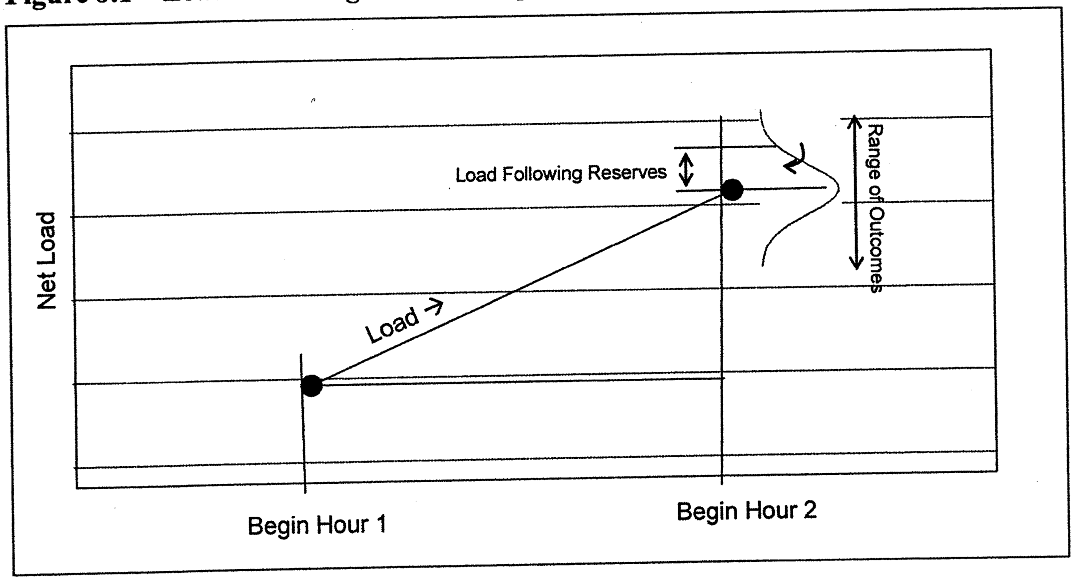
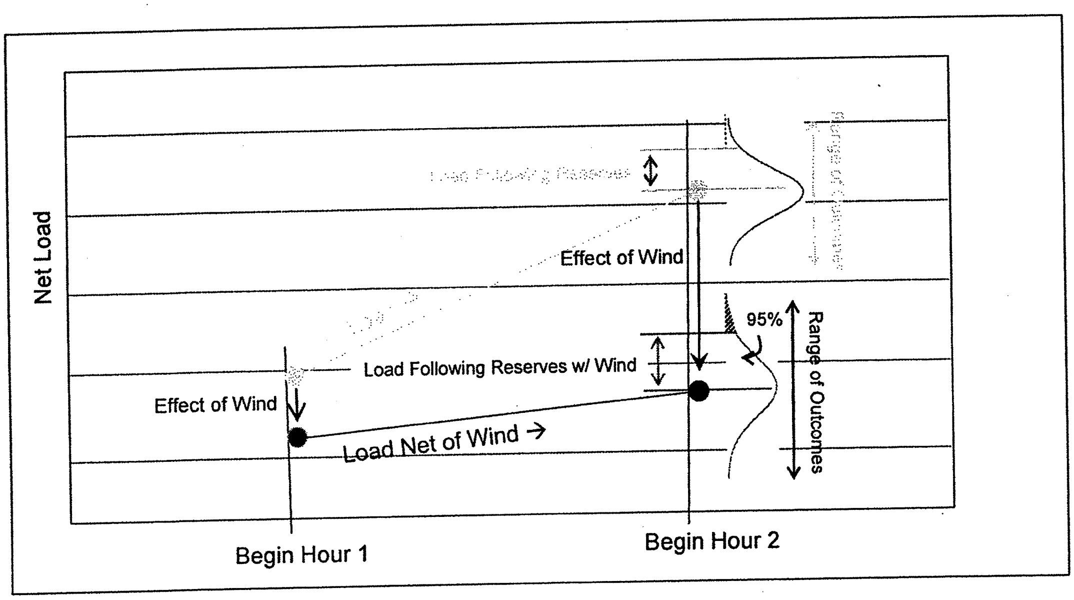


Figure J.2 shows the variability of the load forecast and the variability of the wind energy rolled together by performing the same analysis on the forecast of load net of wind energy. The expected value of load net of wind will be less than or equal to the load forecast for any given hour. However, the variability of load net of wind is greater than that of load alone. It is the difference of between the variability of load and the variability of load net of wind for a given hour that described the incremental reserves that should be attributed to wind resources.

Figure J.2 – Load Following Reserve Requirement for Load Net of Wind

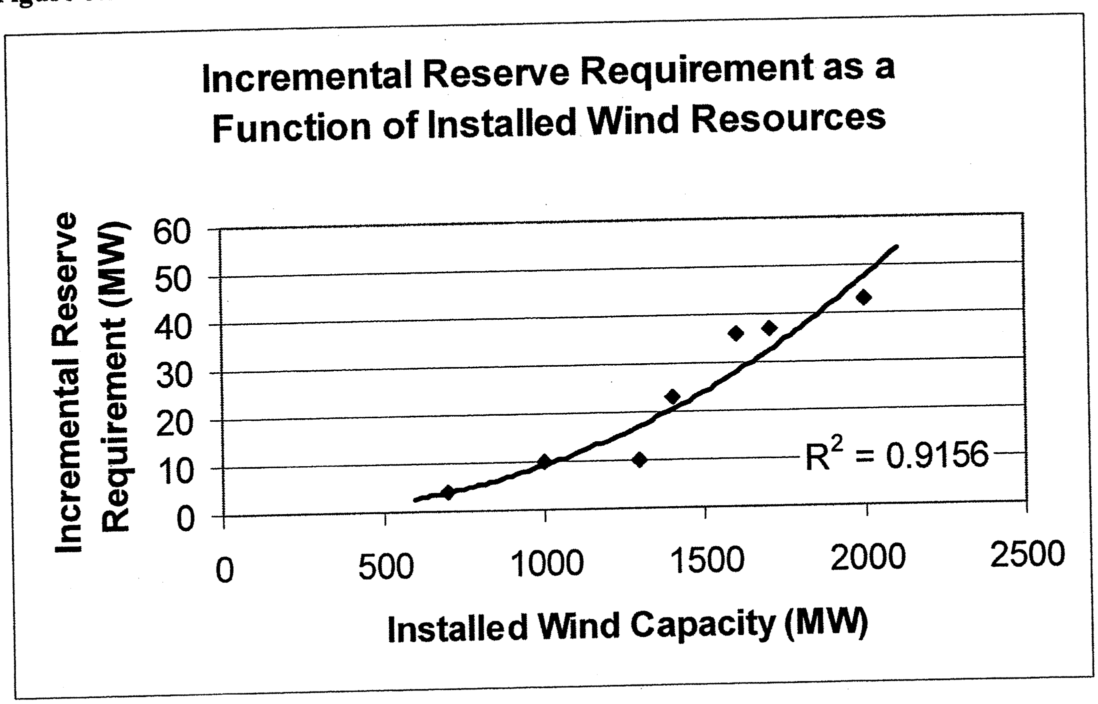


Early in the 2007 IRP process, the result of applying this methodology to the PacifiCorp system with an additional 1,400 megawatts of wind resources was an estimated 30 megawatts of additional reserve requirements. That amount of spinning reserve was added to the stochastic PaR model runs to simulate the additional cost.

In follow up analyses of the preferred portfolio, the company confirmed that using even the simplest forecast techniques greatly reduced the forecast error of both load and wind and consequently reduced the anticipated need for load following reserves. Figure J.3 displays the estimated incremental load following requirement calculated using PacifiCorp's updated load forecast and varying the level of wind resources following the build pattern of the preferred portfolio. For the 1,400 megawatt level of wind installation, the estimated need for incremental reserves is approximately 22 megawatts. For the preferred portfolio with 2,000 megawatts of wind resources, Figure J.4 shows an estimated need for 43 megawatts of additional load following reserves due to wind resources.

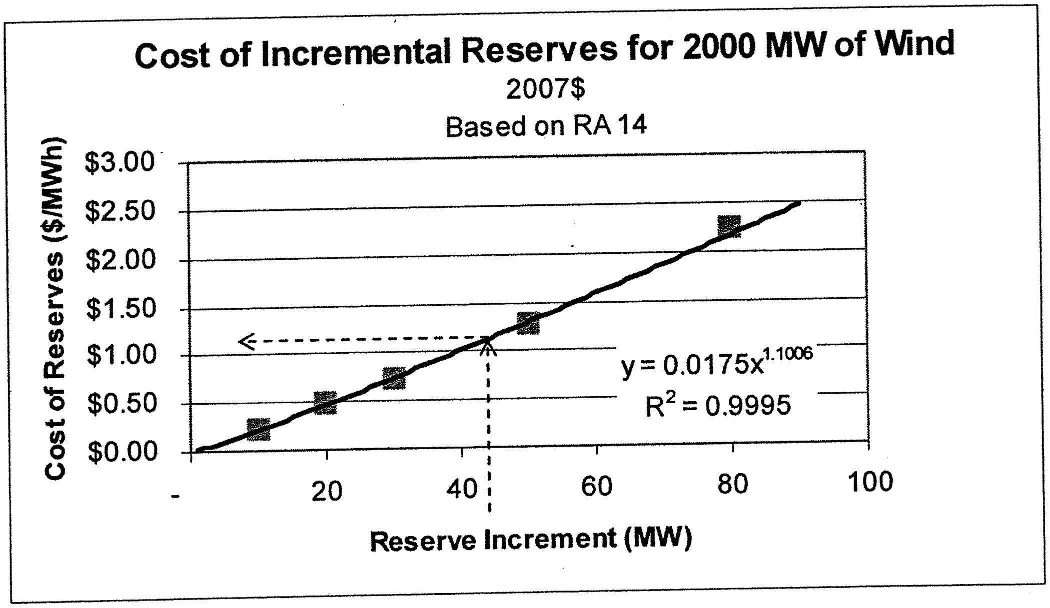
This analysis represents a reduction in the estimate of needed reserves compared with previous estimates. The major difference from prior studies is the development of a systematic method for estimating load following reserve requirements. The 2003 IRP study was based on the hourly variability of wind resources, whereas the current analysis is based on the hourly uncertainty in generation. It is further benefited by the more extensive operating data available since the 2003 study.

Figure J.3 – Incremental Reserve Cost Associated with Various Wind Capacity Amounts



By running the PaR model studies with and without the incremental load following reserves, the company can estimate the cost of the incremental reserves at varying levels. This can be converted to a unit cost by dividing the cost by the total amount of wind energy. Figure J.4 shows the results of those studies.

Figure J.4 – Operating Cost of Incremental Load Following Reserves



From Figure J.4, the unit cost of 43 megawatts of incremental reserves attributed to the 2,000 megawatts of wind capacity in the preferred portfolio is estimated to be $1.10 per megawatt hour of wind energy.

System Balancing Costs

System balancing costs represent the additional operating costs incurred as a result of adding wind generation to PacifiCorp's system. For the 2003 IRP, the system balancing costs associated with wind resources were evaluated by comparing one model run with wind resources specified with an hourly energy pattern to another run where the hourly wind energy was replaced by an equal amount of energy expressed as a flat annual shape. This methodology was repeated for the 2007 IRP preferred portfolio with the following modifications.

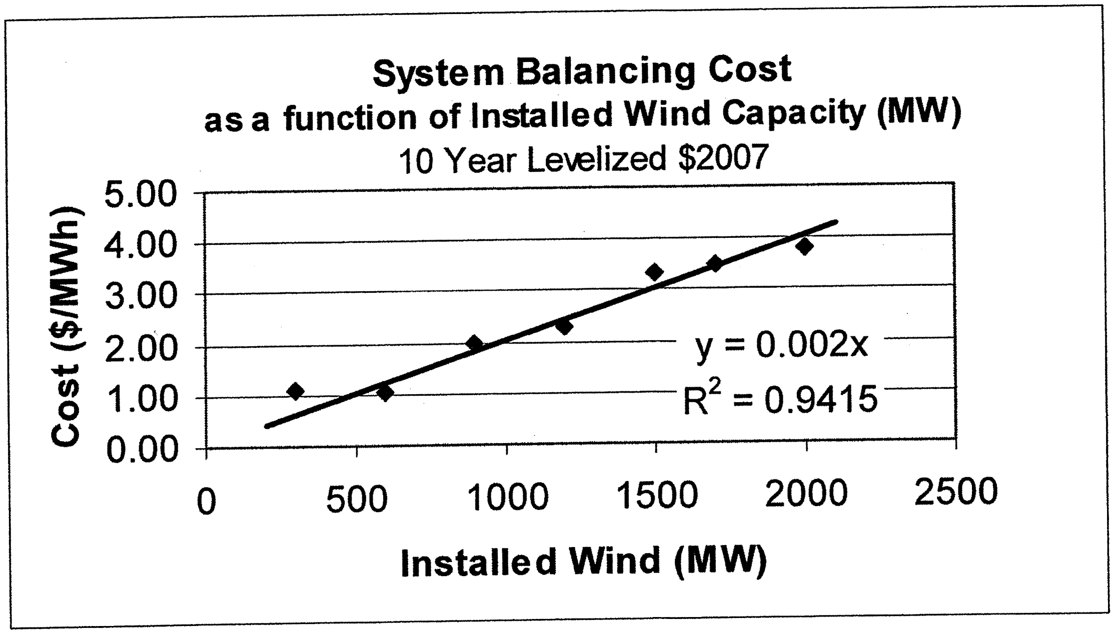
- First, the hourly wind patterns for the base study were substantially upgraded. Data from multiple Pacific Northwest sources, including PacifiCorp's actual wind energy, was modified for project size and mapped to the proxy wind resources by location. In the case of multiple "plants," some of the data was shifted by an hour or two to represent diversity within a wind area. The Wyoming projects were updated to a 40 percent capacity factor to be consistent with actual information coming from that area.

- The comparison to the annual block size was repeated for several sized accumulations of wind projects across PacifiCorp's system using the wind data and build patterns consistent with the preferred portfolio analysis.

Using the equivalent annual block against the hourly wind patterns confirmed earlier findings that as wind resources accumulate the system balancing costs also increase on a unit cost basis.

The 2007 IRP results are shown in Figure J.5. The results are similar to previous studies.

Figure J.5 – PacifiCorp System Balancing Cost



From Figure J.5 it can be seen that 2000 megawatts of wind capacity installed on PacifiCorp's system brings with it approximately $4.00 per megawatt-hour less than an equivalent amount of energy shaped as an annual base load resource

While some of the regional studies employed smaller sized energy blocks for similar comparisons, PacifiCorp continues to use the annual block-size approach. Equivalent energy generated at a constant rate for the entire year and priced at market is the competing resource that PacifiCorp uses in its resource economic evaluations.

Use of Wind Integration Cost Estimates in the 2007 IRP Portfolio Analysis

Wind integration costs for the purposes of the CEM runs were based on 2004 IRP results due to the timing of the needed analyses. In the PaR model, the system balancing costs are implicit as the wind resources are represented as hourly generation patterns from the quasi-historical data. The incremental load-following reserve requirement, calculated outside of the main IRP models, was added as a constraint in the stochastic PaR runs for the candidate and preferred portfolios in the 2007 IRP. (CEM does not model reserve requirements, and so was not affected by the analysis).

Because the hourly generation patterns of wind and the increased incremental reserves are modeled explicitly in the PaR model the PVRR includes both types of cost. The integration cost for the 2,000 megawatts of wind resources included in the preferred portfolio is estimated to be $5.10 per megawatt hour of wind energy.

PacifiCorp is continuing to explore methodologies to confirm and quantify wind variability with respect to the need for operating reserves. In particular, sub-hourly data is being captured to test the impact of deviations within the hour. Continued study of the impacts of integrating large quantities of wind in PacifiCorp's system is identified in the IRP action plan (See Chapter 8).

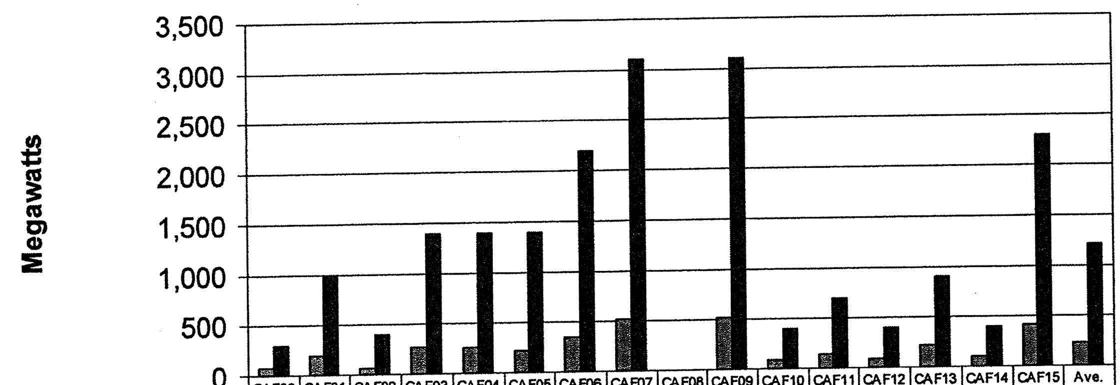
DETERMINATION OF COST-EFFECTIVE WIND RESOURCES

PacifiCorp used the CEM to help determine the quantity of wind considered reasonable given a range of alternative assumptions concerning future portfolio costs. The explicit costs of wind (capital and integration costs, less production tax credits and the value of renewable energy credits) were entered into the CEM. The results of the alternative future scenario CEM runs were examined to find a rough cost-effectiveness order for the proxy wind resource sites. Nearly all of the CEM runs found wind to be part of a cost-effective resource portfolio.

Fixed in each of the runs were the 400 megawatt MEHC acquisition commitments made to state commissions. In the "medium case" alternative future scenario (Alternative Future #11), the CEM added 700 nameplate megawatts of wind resources to the system, for a total of 1,100 megawatts of additional renewable resources by 2016.

Figure J.6 shows the cost-effective wind capacity amounts (both nameplate and capacity contribution) selected by the CEM for each of the 16 alternative future scenarios. The average for all the alternative future runs was over 1,200 megawatts (235 megawatt capacity contribution), or 1,600 megawatts including the 400 megawatt base assumption quantity. These results are consistent with the 1,400 megawatt determination for the level of cost-effective renewables reported in PacifiCorp's 2004 IRP.

Figure J.6 – Renewables Capacity Additions for Alternative Future Scenarios



	CAF00	CAF01	CAF02	CAF03	CAF04	CAF05	CAF06	CAF07	CAF08	CAF09	CAF10	CAF11	CAF12	CAF13	CAF14	CAF15	Ave.
Wind Capacity Contribution	82	196	60	277	259	215	354	514	0	514	85	148	95	222	99	410	235
Renewables Nameplate	300	1,000	400	1,400	1,400	1,400	2,200	3,100	-	3,100	400	700	400	900	400	2,300	1213

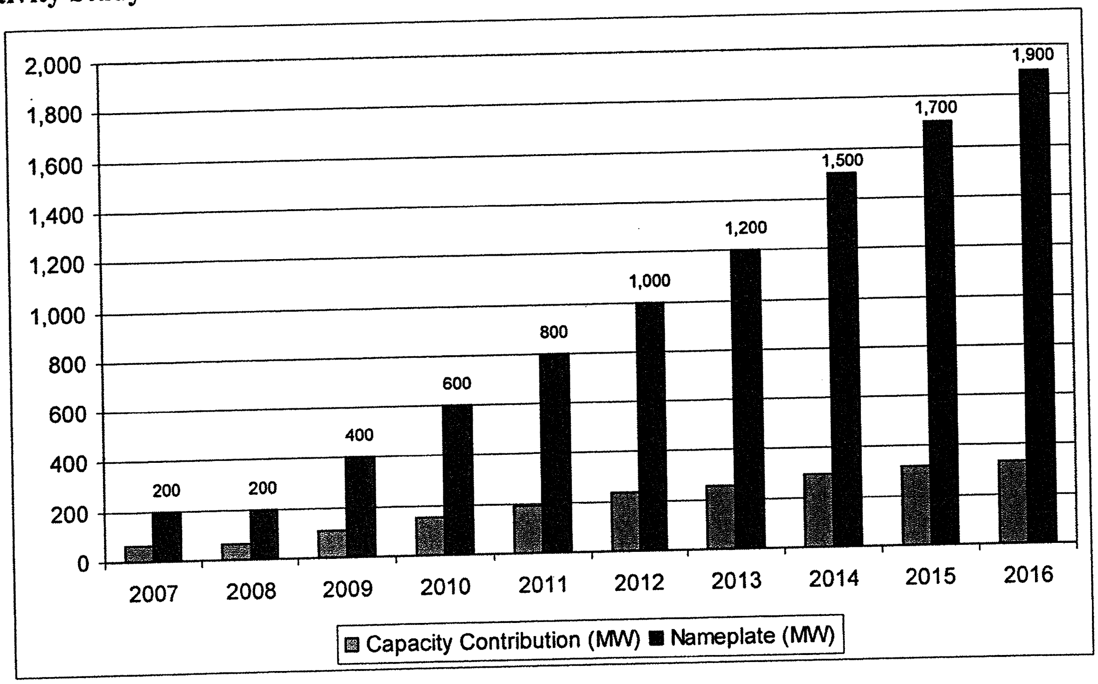
Wind Capacity Contribution ■ Renewables Nameplate

A CEM sensitivity run was performed to test the quantity of wind selected given the expiration of renewable production tax credits, but with otherwise favorable scenario conditions for wind development. These favorable conditions included a high CO_2 adder ($25/ton in 1990 dollars), high natural gas and electricity prices, and a high system-wide renewable sales percentage requirement attributable to renewable portfolio standards. See Chapter 6, Modeling and Risk Analysis Approach, for more details on scenario assumptions.

In this sensitivity, the CEM selected 1,900 megawatts of wind by 2016 (capacity contribution of 335 megawatts). Figure J.7 shows the cumulative annual resource addition pattern for 2008 through 2016. The sensitivity results indicate that given the assumed favorable scenario conditions, the expiration of the production tax credits results in 1,200 megawatts less wind capacity selected for the optimal portfolio.

Based on these results, PacifiCorp identified 1,000 to 1,600 megawatts of additional nameplate wind capacity for specifying proxy renewable resources to be included in portfolios subjected to stochastic production cost simulation.

Figure J.7 – Cumulative Capacity Contribution of Renewable Additions for the PTC Sensitivity Study



WIND CAPACITY PLANNING CONTRIBUTION

For planning purposes, most resources are assumed to contribute their nominal (or "nameplate") capacity to meeting the planning reserve margin level. It is recognized that wind resources cannot be depended on to contribute their full nameplate capacity to meeting planning reserve margin, since the probability of achieving that level on a peak hour is relatively low, and virtually zero for a large portfolio of diverse wind resources. Nevertheless, it was recognized that some level of capacity contribution attributed to wind projects is appropriate, and PacifiCorp has adopted the effective load carrying capability of wind projects as the standard. In short, the effective load carrying capability of a resource is the amount of incremental load the system can meet with the incremental resource without degrading the reliability of meeting load.

PacifiCorp used the stochastic PaR model to estimate the monthly load carrying capability of a wind resource using an analytical method based on the Z statistic.[5] The analytical method of estimating load carrying capability was necessary in order to compute the capacity contributions from a large number of wind projects and different combinations of projects. The result of this analysis as applied to the proxy (100-megawatt) wind resources is shown in Table J.1 below. Key observations from these results include the following.

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[5] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

- The incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area.
- The capacity contribution decline is greatest for projects with more variability of their on-peak contributions.
- The capacity contribution varies over the year, primarily due to expected on-peak generation.

Table J.1 – Incremental Capacity Contributions from Proxy Wind Resources

Regional Resource Additions (MW)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC OR	-100	1	18	28	17	25	35	37	27	22	14	5	5
	-200	0	8	16	7	14	24	28	18	12	5	0	0
	-300	0	0	3	0	3	14	19	10	2	0	0	0
	-400	0	0	0	0	0	3	10	1	0	0	0	0
SE WA	-100	19	14	33	13	13	10	12	7	10	14	16	16
	-200	8	2	20	2	1	0	2	0	0	3	5	4
	-300	0	0	8	0	0	0	0	0	0	0	0	0
	-400	0	0	0	0	0	0	0	0	0	0	0	0
EC NV	-100	18	20	32	32	23	28	27	23	21	23	19	28
	-200	15	17	29	26	20	24	23	20	17	20	17	24
	-300	13	14	25	20	16	20	20	18	13	16	14	21
	-400	10	12	21	14	13	17	16	15	9	13	12	17
SE ID	-100	26	37	59	35	31	32	25	32	22	32	38	32
	-200	20	31	53	29	26	27	21	28	17	26	32	26
	-300	14	24	47	24	22	22	17	24	13	21	25	20
	-400	8	17	41	18	17	17	13	20	8	16	18	14
WC UT	-100	13	10	25	31	35	27	20	26	26	24	20	19
	-200	10	9	21	27	31	24	18	22	22	20	17	16
	-300	7	7	17	22	26	20	15	18	18	16	14	13
	-400	4	6	13	17	21	17	12	15	13	13	11	10
SW WY	-100	33	27	36	33	30	30	23	24	25	31	24	34
	-200	27	24	29	27	26	25	20	21	22	26	21	28
	-300	21	20	22	21	21	21	18	18	19	21	18	22
	-400	16	16	15	16	16	16	15	16	16	16	15	16
	-500	10	12	8	10	11	11	13	13	13	11	13	10
	-600	5	8	1	4	6	7	10	10	9	6	10	4
	-700	0	5	0	0	2	2	7	7	6	1	7	0
SC MT	-100	42	34	35	24	26	26	27	26	28	32	42	33
	-200	34	27	26	19	23	21	24	23	24	28	33	26
	-300	26	20	18	14	19	16	21	20	21	23	25	18
	-400	18	14	10	9	15	11	18	18	18	19	17	11
SE WY	-100	35	26	30	25	22	19	13	15	18	23	44	37
	-200	30	21	24	21	18	16	11	13	15	18	43	32
	-300	25	16	19	17	14	12	9	10	11	13	43	27
	-400	20	12	13	13	10	9	7	8	7	9	42	23
	-500	15	7	7	9	6	6	5	6	3	4	41	18
	-600	9	2	2	5	2	3	3	3	0	0	40	13
	-700	4	0	0	1	0	0	1	1	0	0	39	8

REGIONAL STUDIES

Utilities are studying wind resources in order to quantify the full cost of integrating wind energy into existing systems. In March 2007, Northwest Power and Conservation Council released the Northwest Wind Integration Action Plan (the Action Plan). A joint product of the region's utility, regulatory, consumer and environmental organizations, the Action Plan addresses several major questions surrounding the growth of wind energy and suggests areas that need further consideration.

The Action Plan summarizes the results of wind integration cost studies performed by PacifiCorp (in its 2004 IRP), Avista, Idaho Power, Puget Sound Energy, and Bonneville Power. The report lists the key findings of these northwest studies. All of the studies find that the cost of integrating wind starts low as the variability of small quantities of wind generation is lost in the volatility of the system load, and grows as the amount of wind resource increases. Collectively the studies list the size of the control area in relation to the amount of wind, the geographic diversity of the wind locations, the amount of flexibility of the receiving utility, and the access to robust markets as key factors affecting the cost of integrating wind energy.

Table J.2 reproduces the data from the report. The Action Plan includes a summary of each of the study methodologies in its appendix B. PacifiCorp's estimate of wind integration costs ranked among the lowest of the wind integration costs. Only Bonneville Power ranked lower. PacifiCorp's low integration cost is likely the result of the opportunity to maximize the use of each of the key factors: a large system, wide geographic coverage allowing for dispersed wind sites, and a flexible system with multiple points of access to the energy markets.

Table J.2 – Wind Integration Costs from Northwest Utility Studies [6]

Utility	Peak Load (MW)	Wind Penetration ($/MWh of Wind Generation) 5%	10%	20%	30%
Avista	2,200	$ 2.75	$ 6.99	$ 6.65	$ 8.84
Idaho Power	3,100		$ 9.75	$11.72	$16.16
Puget Sound Energy	4,650	$ 3.73	$ 4.06		
PacifiCorp (2003-2004 IRP)	9,400	$ 1.86	$ 3.19	$ 5.94	
BPA (within-hour impacts only)	9,090	$ 1.90	$ 2.40	$ 3.70	$ 4.60

In the wake of the regional load peak of July 24, 2006, when wind turbines made only a small contribution to generating capacity at the time of the peak, the wind resource contribution to peak capacity is being reassessed by Northwest Resource Adequacy Forum (NWRA Forum) as Action #1 of the Action Plan.[7]

[6] Source: NWRA Forum, Northwest Wind Integration Action Plan, (March 2007 pre-publication version), page 31.
[7] NWRA Forum, Northwest Wind Integration Action Plan (March 2007, pre-publication version). See Action 1, p.48,

EFFECT OF RESOURCE ADDITION FUEL TYPE ON THE COMPANY'S COST TO INTEGRATE WIND RESOURCES

As the company installs larger volumes of wind resource generation, the cost to integrate these intermittent resources is anticipated to increase. This is because more non-wind resources must be held back to allow flexibility to follow the intra-hour volatility of the wind generation. Resources with greatest the dispatch flexibility that are not already in use to serve load are typically used for integration.

The hour to hour dispatch of non-wind resources is not a trivial decision. The company's owned hydro plants with storage capability and the Mid-Columbia hydro contracts, all of which have the highest flexibility, can often provide the needed flexibility. However, these hydro resources do not have enough volume to integrate all of the anticipated wind variability. Partially loaded gas turbines can provide additional flexibility. Due to its low cost, coal is normally fully utilized to serve load rather than backed off to provide wind integration.

It is flexible resources that are operating on the margin that influence the cost of wind integration. When evaluating the effect of the fuel type of resource additions on PacifiCorp's cost to integrate wind resources, it is most likely that the IRP natural gas-fired additions will have the most effect on integration costs.

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(p) "Partial Calendar Year" means the Days (1) from the Commencement Date through December 31, inclusive, of the same year, or (2) the Days from January 1 through the Day of the same year in which Storage Services are terminated hereunder, inclusive.

(q) "Planned Outage" refers to an interruption scheduled by FCII for one or more components of the Project, during which repairs, maintenance, or alterations to the Project will be made.

(r) "Point(s) of Delivery" are the point(s) where Scheduled Energy is delivered by PacifiCorp-Merchant to Bonneville as determined pursuant to section 7 of this Agreement.

(s) "Project" means the Foote Creek II Project consisting of wind turbines, tower structures, collection systems and controls, meters and interconnection equipment, as further described in Exhibit D, that Bonneville has caused to be installed at the Site.

(t) "Project Capacity" means the nominal capacity of the Project in megawatts (MW), as specified in Exhibit D.

(u) "Prudent Utility Practice" means those practices, methods, and equipment, as changed from time to time, that:

(1) when engaged in are commonly used in prudent electrical engineering and operations to operate electric equipment lawfully and with safety, reliability, efficiency, and expedition; or

(2) in the exercise of reasonable judgment considering the facts known when engaged in, could have been expected to achieve the desired result consistent with applicable law, safety, reliability, efficiency, and expedition.

Prudent Utility Practice is not limited to the optimum practice, method, selection of equipment, or act, but rather is a range of acceptable practices, methods, selections of equipment, or acts.

(v) "Scheduled Energy" means the Energy scheduled by PacifiCorp-Merchant to Bonneville pursuant to this Agreement.

(w) "Site" means the real property where all Project generation facilities are located, including the wind turbines, tower structures, down tower collection systems, and controls, which Site is approximately 25 miles southeast of Hanna Junction on Foote Creek Rim in the State of Wyoming.

(x) "Storage Charge" means the negotiated rate to be paid by Bonneville to PacifiCorp-Merchant for the Storage Services provided by PacifiCorp-Merchant.

(y) "Storage Services" means the provision by PacifiCorp-Merchant to Bonneville of load control and load following services in providing a within-the-hour smoothing of Project output and in providing an hour-to-hour predictability of Scheduled Energy.

(z) "Substation" means the PacifiCorp transmission function's 34.5/230 kV Foote Creek Substation located at or near the Site.

(aa) "System Emergency" means a condition on Bonneville's transmission system, at the Project, at the Substation, on the Foot Creek Line Extension, or on PacifiCorp's Transmission System used to deliver the Energy at the Points of Delivery, which condition is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(bb) "Transmission Charge" means the compensation to be paid by Bonneville to PacifiCorp-Merchant for delivering Energy at the Points of Delivery. PacifiCorp's Transmission Charge is determined pursuant to Exhibit A to this Agreement.

(cc) "Transmission Constraint" means a transmission condition that curtails the delivery of Energy to PacifiCorp-Merchant or the delivery of Scheduled Energy at the Points of Delivery.

(dd) "Transmission Losses" means the losses incurred by PacifiCorp-Merchant at the Substation, on the Foote Creek Line Extension, and the PacifiCorp Transmission System which, at the time of execution of this Agreement, were as specified in Exhibit B.

(ee) "Workday" means each day that both Bonneville and PacifiCorp-Merchant observe as a regular workday.

3. **EXHIBITS**
Directly Assigned Facilities Charges, Storage Charges, and Transmission Charges (Exhibit A), Sample Invoice (Exhibit B), Points of Delivery (Exhibit C), and Project Description (Exhibit D) are attached hereto and made a part of this Agreement.

4. **STORAGE SERVICES**

(a) PacifiCorp-Merchant shall cause the Energy from the Project to be taken into its control area and shall integrate such output into hourly MWh amounts for entry into its records utilizing standard electrical utility practices. PacifiCorp-Merchant shall provide the Storage Services to Bonneville.

(b) Scheduling between control areas for the Parties shall be in whole MW. Scheduled Energy shall be delivered to Bonneville 168 hours following PacifiCorp-Merchant's receipt of Energy. Calculations shall be carried out

Exhibit B
SAMPLE INVOICE

Month for Which Payment is Requested

1	Beginning Date	____________
2	Ending Date	____________

Energy During Month for Which Payment is Requested

3 Energy ____________ kWh
4 Loss Rate for Foote Creek Line Extension and Substation: 0.30 percent
5 Loss Rate for PacifiCorp Transmission System: 4.48 percent
6 Scheduled Energy [1.0 - (Line 4 + Line 5) x Line 3] ____________ kWh

Directly Assigned Facilities Charge

7 Directly Assigned Facilities Charge $3,222

Storage Charge

8 Storage Charge Rate ________ mills per kWh

9 Storage Charge (Line 8 × Line 3) **$** ____________

Transmission Charge

10 Transmission Charge Rate ________ mills per kWh

11 Transmission Charge (Line 10 × Line 3) **$** ____________

TOTAL PAYMENT REQUESTED **$** ____________
(Line 7 + Line 9 + Line 11)

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OPUC Data Request 6

Within PPL/100, Duvall/4 you state that the company has refined its hydro modeling to better reflect historical hydro availability. Please be specific about the effect this had over the previous TAM filing on total hydro availability, weekly modeling, total hydro power output on a MWh basis, and the dollar impact of this change. How does the current methodology compare to the previous methodology? What time period is taken into account when looking at the historical hydro availability, and how has this changed?

Response to OPUC Data Request 6

The normalized hydro generation for calendar year 2009 is approximately 440,000 MWh less than was filed for calendar year 2008 (UE-191). The analysis to isolate the dollar impact of this change has not been done.

This difference incorporates two types of change. First, as described in Mr. Duvall's testimony there are date-specific changes that occur in contracts and licenses. Contract/license changes between 2008 and 2009 account for approximately half of the total difference, 220,000 MWhs. The remaining portion of the difference is due to incorporation of forced outages for the modeled hydro, ongoing model improvements and stream flow verification. The model improvements are described in Attachment OPUC 6.

Of these model improvements, the only one that can be characterized as a change in methodology is the incorporation of normalized outages for the hydro system. The Company reviewed the 48-month outage record (calendar years 2003-2006); determined the average amount of outage per month in the normalized year; and set up an equivalent outage schedule that was repeated in each year of the model run. Previous study included only a forward looking schedule of planned outages that was not normalized; i.e. was not the same each year.