PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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August 30, 2011

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: UE 227 – PacifiCorp's 2012 Transition Adjustment Mechanism (TAM)
PacifiCorp's Surrebuttal Filing

Pursuant to the Prehearing Conference Memorandum issued April 19, 2011, PacifiCorp d/b/a Pacific Power) submits for filing an original and five copies of its Surrebuttal Testimony and Exhibits for the following witness:

- Surrebuttal Testimony and Exhibits of Gregory N. Duvall (Exhibits PPL/110 – PPL/112).
- Surrebuttal Testimony and Exhibits of Judith M. Ridenour (Exhibits PPL/305-307).
- Surrebuttal Testimony and Exhibits of Stefan A. Bird (Exhibits PPL/406 – PPL/408), containing confidential and highly confidential material.
- Surrebuttal Testimony and Exhibits of Frank C. Graves (Exhibits PPL/700 – PPL/702), containing confidential material.
- Surrebuttal Testimony of Andrea L. Kelly (Exhibit PPL/800).

Included with this filing are CDs containing the electronic workpapers.

Confidential information is provided pursuant to the Protective Order, Order No. 10-069. Highly confidential information is provided pursuant to the Modified Protective Order, Order No. 11-265.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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Please direct informal correspondence and questions regarding this filing to Joelle Steward, Regulatory Manager, at (503) 813-5542.

Very truly yours,

Andrea L. Kelly

Andrea L. Kelly
Vice President, Regulation

Enclosures
cc: UE 227 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 30th of August, 2011, I caused to be served, via email or overnight delivery, a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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Docket No. UE-227
Exhibit PPL/110
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Surrebuttal Testimony of Gregory N. Duvall

August 2011

Q. Are you the same Gregory N. Duvall who filed direct testimony and rebuttal testimony in this proceeding on behalf of PacifiCorp (the Company)?

A. Yes.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. I respond to the adjustments and proposals presented by Messrs. Ed Durrenberger and Brian Bahr on behalf of Commission Staff (Staff), Mr. Donald Schoenbeck on behalf of the Industrial Customers of Northwest Utilities (ICNU), Messrs. Robert Jenks and Gordon Feighner on behalf of the Citizens' Utility Board of Oregon (CUB), and Mr. Kevin Higgins on behalf of Noble Americas Energy Solutions, LLC (NAES). Specifically, I address the following issues:

- The load forecast;
- Liquidated damages;
- Market caps;
- Wind integration costs and modeling of Gadsby units 4, 5, and 6;
- Affiliate mine expenses; and
- The Bonneville Power Administration (BPA) wheeling credit.

Q. Do other PacifiCorp witnesses address certain issues raised by the parties?

A. Yes. Ms. Judith M. Ridenour presents the updated rates based on the updated load forecast presented by the Company in my July 29, 2011 rebuttal testimony and accepted by Staff in its August 16, 2011 rebuttal testimony; Mr. Stefan A. Bird responds to CUB's and ICNU's adjustments related to the Company's natural gas hedging; Mr. Frank C. Graves, from The Brattle Group also responds to CUB's and ICNU's natural gas hedging adjustments; and Ms. Andrea L. Kelly responds to CUB's testimony on past rate increases and the Company's cost control efforts.

Q. Are there adjustments by other parties that PacifiCorp is not discussing in surrebuttal testimony?

A. Yes. ICNU did not respond to my rebuttal testimony on the DC Intertie or Cal ISO adjustments, and to Rick Link's rebuttal testimony on forward price curves. On the other hand, Staff conceded its position on the DC Intertie and Call ISO adjustments through discovery. See Exhibit PPL/112. Staff also opposed ICNU's proposal on the forward price curves. Therefore, the Company does not address these issues further in surrebuttal testimony. Also, based on Mr. Higgins' rebuttal testimony, NAES and the Company appear to be in agreement on the issue of line losses, so I do not address that issue either.

Recommendation for Company's Net Power Costs for this Case

Q. In your rebuttal testimony, you recommended that the Commission set the Company's system NPC at $1.563 billion for the test period ending December 31, 2012. Has your NPC recommendation changed?

A. Yes. Based upon the Company's acceptance of Staff's proposal to update the load forecast and CUB's proposal on liquidated damages as I describe below, the Company has reduced its proposed system NPC to approximately $1.496 billion, a reduction of $67 million on a total company basis. These two adjustments reduce the proposed TAM increase by approximately $4.8 million to $58.7 million. The GRID study incorporating the updated load forecast as proposed by

Staff and accepted by the Company was provided as a workpaper supporting my rebuttal testimony.

Adjustments Accepted by the Company

Q. Has the Company agreed to accept any additional adjustments, either in whole or in part, proposed by the other parties beyond those discussed in your rebuttal testimony?

A. Yes.

Q. What is the first accepted adjustment that you will discuss?

A. The Company has agreed to adopt Staff's proposal to use the updated July 2011 load forecast that I presented in my rebuttal testimony to determine NPC in this proceeding.

Q. Do you agree with Staff that using the Company's updated load forecast for the 2012 TAM does not require a change to the TAM Guidelines that would require PacifiCorp to update loads in all future TAM proceedings?

A. No. Although Staff states that its proposal is "merely adjusting" the load forecast proposed in the Company's Initial Filing, Staff is proposing to adjust the forecast by using the Company's updated July 2011 load forecast which used more recent data than was available when the Company made its Initial Filing. Staff is not proposing to correct or change the load forecast from the Initial Filing based on information known at that time. I also note that Staff concedes that Staff's proposal is to "use PacifiCorp's updated forecast for 2012 loads for determining the net variable power costs in this case." Staff/300, Durrenberger/2, lines 13-15.

Q. Do you believe that this adjustment falls outside the TAM Guidelines?

A. Yes. As I stated in my rebuttal testimony, the TAM Guidelines do not provide for updating the load forecast after the Company's Initial Filing.

Q. How do you propose the Commission address the fact that the TAM Guidelines do not provide for updating the load forecast after the Initial Filing?

A. The Company intends to request that the Commission review this element of the TAM Guidelines in the Company’s next TAM filing concurrent with a general rate case to determine whether a load forecast update should be part of TAM proceedings in the future.

Q. Does the Company’s acceptance of Staff’s proposal also address ICNU’s proposed adjustment to account for additional fixed revenue attributable to increased sales levels?

A. Yes. Updating the load forecast reasonably addresses the concerns ICNU raises with respect to the expected level of sales in the test period and removes the underlying rationale for ICNU’s adjustment. For the reasons explained in the rebuttal testimony of William R. Griffith, ICNU’s proposed adjustment on loads represents a much more radical departure from the TAM Guidelines than Staff’s. In addition, ICNU’s load adjustment violates the matching principle.

Q. ICNU states that both Puget Sound Energy (PSE) and Avista Utilities (Avista) have fuel and purchase power cost mechanisms in Washington that take into account fixed cost contribution in some manner. Does this citation have any bearing on this case?

A. No. Mr. Schoenbeck's testimony is not substantiated with any citations or evidence supporting his claims that these mechanisms take into account fixed cost contribution or how they do so. Even if Mr. Schoenbeck had substantiated his assertion, this statement is irrelevant. The Company's TAM filing is governed by the TAM Guidelines, to which ICNU agreed only two years ago, not by policies determined by another commission for other utilities.

Q. What is the impact on the Company's requested increase as a result of incorporating the July 2011 load forecast in the rebuttal GRID run?

A. This adjustment reduced the rebuttal increase by $4.7 million on an Oregon allocated basis. Exhibit PPL/111 is an updated version of PPL/106 based on the updated load forecast and the Rebuttal Update NPC. This exhibit shows the corresponding change in allocation factors and the load change adjustment as a result of the updated load forecast. The use of the updated load forecast also impacts the rate design test year set forth in Judith Ridenour's testimony. The impact of the load forecast on total and Oregon allocated NPC will change in the Final Update depending on the impact of the forward price curve and contract updates.

Q. What is the second adjustment the Company is accepting based on the parties' rebuttal testimony?

A. The Company accepts CUB's proposal to use a four-year rolling average of settlements for liquidated damages related to forced outages at generation plants. This is also shown in Exhibit PPL/111. However, as I noted in my rebuttal testimony, because liquidated damages are addressed in general rate cases, including them in a stand-alone TAM raises the potential for double counting liquidated damages that are already included in rates.

Q. Is there a double count of liquidated damages in CUB's proposed adjustment?

A. Yes. Approximately $25,000 of the liquidated damages included in CUB's adjustment is already included in rates. This amount is associated with an outage at Jim Bridger unit 4 and was included in rates in Docket UE 217.

Q. What is the impact on NPC of CUB's adjustment with the double count removed?

A. CUB's adjustment with the double count removed reduces NPC by approximately $0.4 million on a system basis or $0.1 million on an Oregon basis.

Q. Do you have comments on other issues that have been resolved based on the parties' rebuttal testimony?

A. Yes. The Company supports CUB's suggestion that the Company continue to work with 2010 Wind Integration Study stakeholders to resolve conflict over the calculation of wind integration costs.

Company Responses to Contested Adjustments

Market Caps

Q. Staff continues to object to the Company's refined approach to calculating market caps. How do you respond to Staff's rebuttal testimony on this issue?

A. For the reasons explained in my rebuttal testimony and further in this surrebuttal testimony, the Company believes that its market cap approach is reasonable and has shown that the approach lowers NPC compared with the approach used in the last TAM proceeding. Based on Staff's concerns, however, it is apparent to the Company that parties would benefit from additional review and discussion of the Company's market cap calculation, which can occur in the next TAM proceeding. For this reason, the Company proposes that the Commission adopt the Company's market cap approach in this case on a non-precedential basis.

Q. What impact does this proposal have on NPC in this case?

A. Maintaining the Company's approach would not change NPC. On the other hand, as I explained in my rebuttal testimony, adopting Staff's proposal and rejecting the Company's market cap refinement would result in an increase to system NPC of approximately $10 million.

Q. Staff claims the Company's GRID results showing that NPC increase by approximately $10 million when using Staff's proposal is "anomalous." Do you agree with Staff's conclusion?

A. No. Staff indicates they compared the NPC report from previous TAM filings, presumably including the NPC from UE 216, with the NPC report from the current TAM filing. Based on this comparison, Staff found that the previous

GRID runs consistently contained greater system balancing sales and coal plant output than the GRID runs in the current TAM. Staff then attributed these differences in system balancing sales and coal generation to the change in approach to market caps.

Q. Is Staff's conclusion valid?

A. No. As discussed in my direct testimony, "[t]he increase in 2012 NPC is driven by a range of factors, including increases in the Company's total system load, changes in the Company's portfolio of wholesale purchase and sales contracts, and increases in coal costs." PPL/100, Duvall/5. These changes in inputs to GRID result in changes in the dispatch of the Company's resource portfolio. Two primary factors lead to the decrease in system balancing sales and coal generation in the 2012 TAM compared to prior TAMs. First, the Company's retail sales are higher and resource base is lower, resulting in approximately 2 million MWh less energy available to make system balancing sales when compared to the 2011 TAM. As I also noted in my direct testimony, "The 2012 test period in the current filing reflects a full year impact of the contracts that expired during the 2011 TAM test period." PPL/100, Duvall/6. Second, for the first time, the additional reserves necessary to integrate wind into the system were included in GRID rather than addressed outside of GRID. This latter change contributed to the reduction in coal generation, as well as the reduction in system balancing sales.

Q. Has the Company prepared a GRID run that removes the impact of changing the market caps between the 2011 TAM and 2012 TAM studies?

A. Yes. In order to remove any impact of changes in market caps, the Company performed a GRID run for 2012 using the previous market caps from the Company's 2011 TAM that Staff supports. The results of this study show that NPC increased by approximately $11 million based on factors other than market caps and therefore proving that the Company's prior analysis was not anomalous. Table 1 below summarizes the load and resources from the Company's NPC studies for the July updates and an additional study using the July update with the market caps from UE 216.

Table 1 - Impact of Different Market Caps

MWh	UE 227, July Update (Graveyard Market Cap) A	UE 227, July Update (UE 216 Market Caps) B	UE 227, July Update C
Retail load	62,391,256	62,391,256	62,391,256
Sales			
Other than System Balancing	4,588,501	4,588,501	4,588,501
System balancing	7,172,199	6,956,897	8,106,296
Total Sales	11,760,700	11,545,398	12,694,798
Purchases			
Other than System Balancing	8,272,522	8,305,720	8,361,026
System balancing	6,639,832	6,504,053	5,931,982
Total Purchases	14,912,354	14,809,773	14,293,008
Hydro	4,077,770	4,077,770	4,077,770
Coal	43,897,149	43,767,367	44,941,590
Gas	8,112,910	8,129,968	8,621,906
Wind & Geothermal	3,151,778	3,151,778	3,151,778

Q. Please explain Table 1.

A. The first column (Study A) shows the level of sales, purchases and generation from the study presented in my rebuttal testimony that uses the market caps developed based on the latest historical information. The only change in inputs between Study A and Study B is for market caps, where the market caps in Study A are replaced with the market caps used in the Company's 2011 TAM. Study B produces lower system balancing sales and coal generation than Study C, which uses the Company's new approach to market caps, proving the changes that Staff observed are not caused by changes to market caps and are not "anomalous".

Q. Does ICNU continue to object to the application of market caps in GRID?

A. Yes. ICNU asserts that there is no economic justification for imposing a market sales cap. This assertion ignores the information provided by the Company in its rebuttal testimony. It would be more accurate to assert that there is no economic justification to assume the Company could sell power at levels that exceeded what it has been able to achieve in the past.

Q. ICNU asserts that the Company's method is inappropriate, as it results in cap values that are substantially lower than the actual transactions the Company has executed at each trading hub. Is this correct?

A. No, ICNU's claim is not correct. The Company's method results in cap values that are equal to the actual transactions the Company has executed at each trading hub on an energy basis.

Q. Please explain.

A. Using the Company's old approach to market caps, ICNU attempts to support the claim by showing that the Company's method results in market caps that are lower than actual transactions in some hours using graveyard transactions in January 2006 at a particular hub. What ICNU's analysis shows, however, is that ICNU's claim that the Company's market caps are lower than the actual transactions is true for less than 10 percent of those hours. In the rest of the hours—over 90 percent of them—the Company's market caps are higher than the actual transactions. In over 90 percent of those hours, then, GRID will be able to model more transactions than the Company actually experienced.

This very example that ICNU uses to criticize the Company's application of average energy-based market caps where the Company was only able to sell in less than 10 percent of the hours can be used to support the use of market caps in GRID.

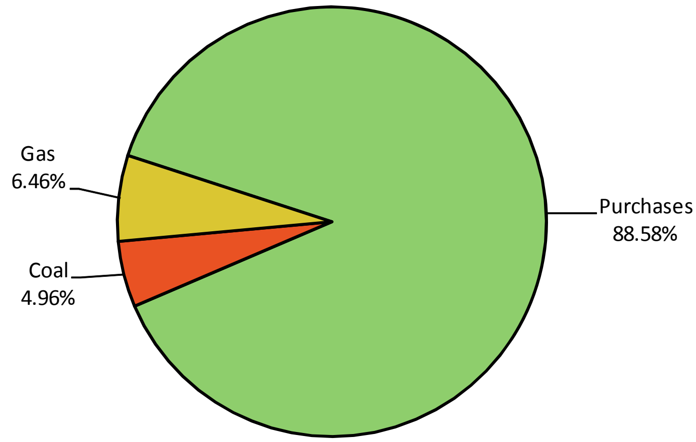
Q. ICNU argues that its adjustment of removing market caps only increases the amount of sales for a small fraction of what the Company could actually transact and therefore rejects your argument that removing market caps will result in increased trading transactions that are already reflected in the trading margin adjustment. How do you respond?

A. ICNU continues to compare actual system balancing sales volumes to those produced by GRID and draws inappropriate conclusions from this comparison. This issue was addressed in my rebuttal testimony, where I noted that the claim was irrelevant, that Staff made the same argument in UE 191, and the Commission in that case accepted the Company's explanation as to why actual system balancing sales volumes are greater than those modeled by GRID. (PPL/105, Duvall/20)

Q. Do you have evidence to support your claim that removing market caps will result in increased trading transactions that are already reflected in the trading margin adjustment?

A. Yes. The changes in dispatchable resources when market caps are removed occur mainly in market transactions, which is a fact that ICNU does not dispute. ICNU/100, Schoenbeck/24. Figure 1 identifies the composition of the total changes to the resource portfolio by categories when market caps are used. Figure 1 is based on ICNU's study presented with its rebuttal testimony, and shows about 90 percent of the increased sales that occur when market caps are removed are associated with increased purchases. This is arbitrage, and unless an equal amount of arbitrage is removed from GRID, there will be a double counting of arbitrage benefits. ICNU's proposal to remove market caps results in NPC that include trading margins in amounts that exceed what the Company has been able to achieve in the past.

Figure 1 - Sources of Increase in Sales without Market Caps



Source of Increased Sales in Without Market Caps (MWH)			
Purchases	**Coal**	**Gas**	**Total**
909,888	50,946	66,384	1,027,218
88.6%	5.0%	6.5%	100.0%

Q. ICNU states that other Pacific Northwest utilities such as Portland General Electric, PSE, or Avista do not employ market caps, and that the Company does not have market caps for purchases, and uses such statements to justify its proposal to remove Company's market caps for sales. How do you respond?

A. ICNU presents no basis supporting the relevance of these statements. Each of these utilities uses a different dispatch model than PacifiCorp and PacifiCorp models a much larger and more complex system than these other utilities. ICNU made no attempt to present evidence reconciling these differences or showing how modeling NPC for those utilities has any bearing on modeling NPC for the Company.

Nor has ICNU explained the relevance of a purchase cap to its critique of the Company's market cap. Without additional development or substantiation of these points, they do not support ICNU's proposal to remove market caps.

Wind Study Must-run Assumptions

Q. First, has Staff conceded its position on the must-run requirement for the Current Creek and Gadsby units?

A. Yes. See Exhibit PPL/112.

Q. Does ICNU's proposed adjustment to the must-run designation for the Gadsby units reduce PacifiCorp's wind integration costs below a reasonable level?

A. Yes. The Company's proposed wind integration charge in this case is $6.32 per MWh, including both intra- and inter-hour integration. The impact of adopting ICNU's adjustment would be to reduce the Company's wind integration charge to $5.70 per MWh. No party in this proceeding, including ICNU, is currently objecting to the overall level of wind integration costs included in NPC in this case. ICNU has provided no evidence showing that the Company's proposed overall level of wind integration costs is unreasonable, and my rebuttal testimony presented evidence showing that the Company's level of wind integration costs is reasonable when compared with relevant benchmarks. For example, my testimony showed that when BPA's intra-hour charge of $5.83 per MWh is combined with the Company's inter-hour charge of $0.70 per MWh, it results in a total charge of $6.53 per MWh, which is higher than the Company's proposed combined charge of $6.32 per MWh.

ICNU's objection to one technical modeling assumption used to support integrating wind should be discounted, given that all the evidence in the record shows that the overall level of wind integration proposed by the Company is reasonable.

Q. ICNU argues that past results should not be used in isolation to defend a GRID run and should instead be used to simulate expected operations. Are you using past results in isolation?

A. Not at all. ICNU misses the fundamental point of using a must-run designation for these units. Absent assuming a must-run status for some natural gas plants, reserves would be held on coal plants which are slow to respond and may not be sufficient to retain system reliability. In order to provide spinning reserves that can be responsive to the quick response needed to follow changes in wind output, the gas plants must be running, which is why the Company models Gadsby units 4-6 and Currant Creek as must-run units in GRID.

Q. Please explain how changes in the Company's hydro resources have required the Company to increasingly look to its natural gas fired resources for reserves.

A. Since late 2005, contracts with the Mid-Columbia hydroelectric facilities owned by Grant County and Chelan County have expired. In fact in October 2011, the Rocky Reach contract expires and for the first time, the Company is only left with one of the original four Mid-Columbia hydro-electric contracts for 2012. This one remaining Mid-Columbia contract is only 56 MW, or about 12-13 percent of the approximately 450 megawatts that were available to the Company prior to November 2005. These were flexible contracts that were used to hold spinning reserves and could increase or decrease generation relatively quickly. At the same time that these flexible contracts are expiring, the Company has added about 2,000 MW of new wind facilities that require additional spinning reserves that are quick to respond. With the loss of hydro resources, the next best type of facility that can provide quick responding reserves is natural gas fired generation.

Q. Is ICNU's reference to the operation of Gadsby units 4-6 from July 1, 2010 through June 30, 2011 a reasonable benchmark to support its adjustment?

A. No. ICNU has targeted a time period with high levels of hydro and wind generation and low market prices. It is not unexpected under these conditions that Gadsby units 4-6 would operate at lower capacity factors. Ironically, this example is counter to ICNU's own position that past results or operations should not be used in isolation to defend the results of a GRID simulation. Over history, Gadsby units 4-6 have operated as high as 39 percent capacity factor. The 32 percent capacity factor modeled in GRID as must-run units is reasonable.

Affiliate Mine Incentives

Q. How does Staff respond to your rebuttal testimony on affiliate mine incentives?

A. Staff provides citations to Commission cases that remove meals and entertainment, incentives, and donations from utility expenses. Staff claims that its proposal is consistent with Commission precedent that the entire amount of such expenses should not be included in rates.

Q. Do you agree that the precedent cited by Staff supports the proposed removal of these expenses from affiliate mine expenses?

A. No, I do not. All of the cases cited by Staff relate to utility, not affiliate, expenses. I understand that for affiliates, the relevant standard to determine the proper amount to be included in rates is the cost or market standard. As Staff has shown, the Company's affiliate coal costs are lower than market. It would be inappropriate to find that affiliate costs meet the lower of cost or market standard and then reduce those costs after the fact.

BPA Transmission Credit

Q. How does NAES respond to your testimony on BPA transmission credits?

A. NAES takes issue with my testimony that the Company may need to acquire additional transmission to deliver freed up generation to market in order to realize the transmission credits determined for the lost load. NAES argues that the Company has the opportunity to resell the 25 MW of BPA transmission that the transition adjustment calculation assumes is freed up.

Q. How do you respond?

A. NAES continues to assume that direct access loads will free up Company-controlled BPA transmission from Mid-Columbia to the direct access load and that the Company would then have an opportunity to sell that freed-up BPA transmission if it chose to do so. This position simply ignores my rebuttal testimony where I demonstrated that the value of freed-up transmission with BPA is minimal. I note that some loads do not use BPA transmission and some loads use a combination of BPA transmission and Company transmission. In these cases, NAES' proposal would be nothing more than a subsidy from other retail customers.

Q. NAES cites Noble Solutions Exhibit 201 to Mr. Higgins' testimony which indicates that the Company owns 636 MW of long-term point-to-point (PTP) BPA transmission rights from Mid-Columbia and a network integration agreement with BPA for 497 megawatts. Can the Company resell these BPA transmission rights when a customer goes to direct access?

A. With respect to network rights, the answer is no. In response to NAES Data Request 18 (d), where the Company was asked to explain why it is reasonable for PacifiCorp to continue paying Network Transmission rates for loads that have migrated to direct access, the Company wrote:

> PacifiCorp will continue to pay for Network Transmission service because there are no provisions in BPA OATT for elimination of Network Transmission rates for loads that make short-term elections to migrate to direct access. Load forecasts excluding these loads have no effect since billing is based on actual load not forecast load. The actual load is not reduced unless it meets the BPA OATT Section 31.7 Declared Customer-Served Load which is "limited to the resources and contracts specified in the Service Agreement on October 1, 2005." Since PacifiCorp did not enter into the Network Integration Transmission Service Agreement until November 1, 2009 well after the October 1, 2005 deadline, it has no load amount that qualifies.

With respect to PTP rights, the answer is the same as before: it can be sold only if it can be freed up, which is not likely.

Q. Do you agree with NAES's alternative proposal that the BPA credit adopted in UE 216 should continue to be applied?

A. No. After a thorough examination of the potential savings from freed-up transmission associated with direct access customers, the Company believes the

$0.50/MWh credit included in the stipulation from the prior TAM is not achievable and should not be included in the transition adjustment.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE-227
Exhibit PPL/111
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Gregory N. Duvall

Oregon Allocated TAM Costs

August 2011

Exhibit PPL/111
Duvall/1

PacifiCorp
CY 2012 TAM (Surrebuttal, August 2011)

		Total Company								Oregon Allocated			
	ACCT.	UE 216 Final TAM CY 2011	Filed TAM CY 2012	July Update CY 2012	Surrebuttal (August 2011) CY 2012	Factor	Factors CY 2011	Factors CY 2012	Surrebuttal Factors CY 2012	UE 216 Final TAM CY 2011	Filed TAM CY 2012	July Update CY 2012	Surrebuttal (August 2011) CY 2012
Sales for Resale													
Existing Firm PPL	447	25,965,364	26,081,862	25,857,080	25,857,080	SG	26.177%	25.623%	26.314%	6,796,976	6,682,858	6,625,263	6,804,026
Existing Firm UPL	447	25,490,589	25,490,583	25,490,583	25,490,583	SG	26.177%	25.623%	26.314%	6,672,694	6,531,357	6,531,357	6,707,586
Post-Merger Firm	447	425,569,012	479,326,113	432,331,358	450,655,477	SG	26.177%	25.623%	26.314%	111,401,573	122,815,936	110,774,646	118,585,377
Non-Firm	447	-	-	-	-	SE	24.283%	24.336%	24.796%	-	-	-	-
Total Sales for Resale		477,024,966	530,898,559	483,679,022	502,003,141					124,871,243	136,030,151	123,931,266	132,096,989
Purchased Power													
Existing Firm Demand PPL	555	50,413,276	2,798,085	3,057,680	3,057,680	SG	26.177%	25.623%	26.314%	13,196,727	716,943	783,458	804,597
Existing Firm Demand UPL	555	46,845,802	46,946,386	46,965,905	46,965,905	SG	26.177%	25.623%	26.314%	12,262,866	12,028,897	12,033,898	12,358,597
Existing Firm Energy	555	57,920,075	24,844,458	24,712,774	24,712,774	SE	24.283%	24.336%	24.796%	14,064,911	6,046,166	6,014,120	6,127,708
Post-merger Firm	555	353,358,225	573,790,087	572,860,870	533,749,221	SG	26.177%	25.623%	26.314%	92,498,892	147,020,087	146,781,997	140,450,645
Secondary Purchases	555	-		-	-	SE	24.283%	24.336%	24.796%	-	-	-	-
Seasonal Contracts	555	-		-	-	SSGC	0.000%	0.000%	0.000%	-	-	-	-
Other Generation Expense	555	38,906,526	3,726,876	3,636,631	3,636,631	SG	26.177%	25.623%	26.314%	10,184,595	954,924	931,800	956,942
Total Purchased Power		547,443,905	652,105,892	651,233,861	612,122,212					142,207,992	166,767,016	166,545,273	160,698,490
Wheeling Expense													
Existing Firm PPL	565	40,049,244	27,034,359	27,034,359	27,034,359	SG	26.177%	25.623%	26.314%	10,483,726	6,926,913	6,926,913	7,113,815
Existing Firm UPL	565	259,960	-	-	-	SG	26.177%	25.623%	26.314%	68,050	-	-	-
Post-merger Firm	565	102,100,510	102,329,448	102,898,595	102,898,595	SG	26.177%	25.623%	26.314%	26,726,940	26,219,492	26,365,322	27,076,712
Non-Firm	565	104,176	2,893,180	2,886,131	2,899,820	SE	24.283%	24.336%	24.796%	25,297	704,087	702,371	719,031
Total Wheeling Expense		142,513,890	132,256,988	132,819,085	132,832,774					37,304,013	33,850,491	33,994,606	34,909,558
Fuel Expense													
Fuel Consumed - Coal	501	631,194,105	711,634,271	712,588,017	708,843,890	SE	24.283%	24.336%	24.796%	153,274,821	173,183,855	173,415,959	175,762,891
Fuel Consumed - Coal (Cholla)	501	55,439,077	56,618,412	57,709,222	57,629,949	SSECH	24.812%	24.910%	25.371%	13,755,347	14,103,650	14,375,371	14,621,343
Fuel Consumed - Gas	501	5,410,856	10,850,156	8,735,448	7,499,287	SE	24.283%	24.336%	24.796%	1,313,935	2,640,502	2,125,865	1,859,502
Natural Gas Consumed	547	365,117,219	484,957,536	443,183,136	438,533,308	SE	24.283%	24.336%	24.796%	88,662,546	118,019,633	107,853,384	108,737,457
Simple Cycle Combustion Turbin	547	8,178,179	36,248,503	36,351,436	36,589,196	SSECT	22.403%	24.329%	24.788%	1,832,173	8,818,918	8,843,960	9,069,661
Steam from Other Sources	503	3,540,887	3,893,567	3,760,489	3,760,489	SE	24.283%	24.336%	24.796%	859,844	947,542	915,155	932,440
Total Fuel Expense		1,068,880,323	1,304,202,445	1,262,327,747	1,252,856,120					259,698,666	317,714,100	307,529,695	310,983,294
Net Power Cost		1,281,813,152	1,557,666,766	1,562,701,671	1,495,807,965					314,339,428	382,301,456	384,138,307	374,494,353
Liquidated Damages Adjustment					(405,489)	SG			26.314%				(106,700)
UE 216 Settlement Adjustment		(44,855,794)								(11,000,000)			
Total Net of Adjustments		1,236,957,358	1,557,666,766	1,562,701,671	1,495,402,475					303,339,428	382,301,456	384,138,307	374,387,653
Increase Absent Load Change											**78,962,027**	**80,798,879**	**71,048,225**
Oregon-allocated NPC Baseline in Rates from UE 216										303,339,428			303,339,428
$ Change due to load variance from UE-216 forecast										21,080,116			15,855,962
2012 Recovery of NPC in Rates										324,419,544			319,195,390
Increase Including Load Change											57,881,911	59,718,763	55,192,263
Add Other Revenue Change											3,745,661	3,745,661	3,508,274
Total TAM Increase											**61,627,572**	**63,464,424**	**58,700,537**
Variance from July 2011 Update													*(4,763,888)*

Docket No. UE-227
Exhibit PPL/112
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Gregory N. Duvall

Staff Response to Data Request 2.1

August 2011

August 29, 2011

TO: Katherine McDowell
Counsel for PacifiCorp

FROM: Ed Durrenberger
Program Manager, Rates and Regulation

OREGON PUBLIC UTILITY COMMISSION
UE 227
PacifiCorp's Second Set of Data Requests to OPUC
Due August 29, 2011
Data Request 2.1

Request:

2.1 Staff's surrebuttal testimony does not respond to PacifiCorp's rebuttal testimony on Staff's adjustments to the "must-run" requirements for Current Creek and Gadsby, Cal ISO expenses, or DC Intertie expenses. Please explain in Staff's current position on these adjustments.

Response:

Staff concedes their position on the "must –run" requirement for Current Creek and Gadsby.
Staff finds the PacifiCorp adequately rebuts the Staff position on the Cal ISO and DC Intertie expenses and concedes this adjustment as unnecessary.

Docket No. UE-227
Exhibit PPL/305
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Surrebuttal Testimony of Judith M. Ridenour

August 2011

Q. Are you the same Judith M. Ridenour who filed direct testimony and rebuttal testimony in this proceeding on behalf of PacifiCorp (the Company)?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your surrebuttal testimony?

A. I present updated exhibits showing the proposed rates and the impact of the proposed rate change on customers' bills based on the Company's surrebuttal position.

Updated Exhibits and Impacts

Q. What is the rate increase resulting from the Company's surrebuttal position?

A. The rate increase based on this surrebuttal filing is $58.7 million. This is a reduction of approximately $4.8 million from the Company's rebuttal filing and reflects the updated 2012 load forecast presented by Company witness Gregory N. Duvall in rebuttal and adopted by Staff in its rebuttal (*See* Staff/300, Durrenberger/3). It also reflects the adjustment for liquidated damages as discussed by Mr. Duvall in his surrebuttal testimony.

Q. Please describe the exhibits accompanying your testimony.

A. Exhibit PPL/306 shows the development of rates for Schedule 201 and Schedule 205 based on the updated forecast load for the rate design test year. This exhibit updates Exhibit PPL/301 and Exhibit PPL/302 from my direct testimony.

Exhibit PPL/307 shows the estimated effect of the proposed TAM price change based on the updated forecast load for the rate design test year. This exhibit updates Exhibit PPL/304 from my direct testimony.

Q. Are you presenting updated tariffs in this surrebuttal filing?

A. No. Tariffs with the final ordered rates will be provided in the compliance filing at the conclusion of this docket. Other than updated rates, the Company proposes no changes to the tariffs proposed in my direct testimony. Updated rates are shown in Exhibit PPL/306.

Q. What are the effects of the rates proposed in this surrebuttal filing?

A. The overall proposed rate increase is 5.1 percent on a net basis. The estimated monthly impact to the average residential customer using 950 kilowatt-hours per month is $4.00.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE-227
Exhibit PPL/306
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Judith M. Ridenour

Updated Rates for Schedule 201 and Schedule 205

August 2011

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues - Surrebuttal
Forecast 12 Months Ended December 31, 2012

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 4, Residential					
First Block kWh (0-1,000)	4,090,525,407	2.220 ¢	$90,809,664	2.604 ¢	$106,517,282
Second Block kWh (> 1,000)	1,497,695,207	3.032 ¢	$45,410,119	3.556 ¢	$53,258,042
	5,588,220,614		$136,219,783		$159,775,324
				Change	$23,555,541
Employee Discount					
First Block kWh (0-1,000)	*12,235,301*	*2.220 ¢*	*$271,624*	*2.604 ¢*	*$318,607*
Second Block kWh (> 1,000)	*5,916,095*	*3.032 ¢*	*$179,376*	*3.556 ¢*	*$210,376*
	18,151,396		*$451,000*		*$528,983*
		Discount	-$112,750	Discount	-$132,246
				Change	-$19,496
Schedule 23, Small General Service					
Secondary Voltage					
1st 3,000 kWh, per kWh	823,288,548	2.586 ¢	$21,290,242	3.033 ¢	$24,970,342
All additional kWh, per kWh	228,996,047	1.919 ¢	$4,394,434	2.251 ¢	$5,154,701
	1,052,284,595		$25,684,676		$30,125,043
				Change	$4,440,367
Primary Voltage					
1st 3,000 kWh, per kWh	660,596	2.505 ¢	$16,548	2.938 ¢	$19,408
All additional kWh, per kWh	200,603	1.859 ¢	$3,729	2.180 ¢	$4,373
	861,199		$20,277		$23,781
				Change	$3,504
Schedule 28, General Service 31-200kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	1,473,100,897	2.451 ¢	$36,105,703	2.875 ¢	$42,351,651
All additional kWh, per kWh	577,498,788	2.384 ¢	$13,767,571	2.796 ¢	$16,146,866
	2,050,599,685		$49,873,274		$58,498,517
				Change	$8,625,243
Primary Voltage					
1st 20,000 kWh, per kWh	10,806,912	2.271 ¢	$245,425	2.664 ¢	$287,896
All additional kWh, per kWh	10,802,696	2.210 ¢	$238,740	2.592 ¢	$280,006
	21,609,608		$484,165		$567,902
				Change	$83,737
Schedule 30, General Service 201-999kW					
Secondary Voltage					
1st 20,000 kWh, per kWh	189,165,886	2.695 ¢	$5,098,021	3.161 ¢	$5,979,534
All additional kWh, per kWh	1,049,091,298	2.337 ¢	$24,517,264	2.741 ¢	$28,755,592
	1,238,257,184		$29,615,285		$34,735,126
				Change	$5,119,841
Primary Voltage					
1st 20,000 kWh, per kWh	11,820,727	2.665 ¢	$315,022	3.126 ¢	$369,516
All additional kWh, per kWh	76,753,410	2.304 ¢	$1,768,399	2.702 ¢	$2,073,877
	88,574,137		$2,083,421		$2,443,393
				Change	$359,972
Schedule 41, Agricultural Pumping Service					
Secondary Voltage					
Winter, 1st 100 kWh/kW, per kWh	1,634,669	3.392 ¢	$55,448	3.979 ¢	$65,043
Winter, All additional kWh, per kWh	1,384,498	2.311 ¢	$31,996	2.711 ¢	$37,534
Summer, All kWh, per kWh	119,498,247	2.311 ¢	$2,761,604	2.711 ¢	$3,239,597
	122,517,414		$2,849,048		$3,342,174
				Change	$493,126
Primary Voltage					
Winter, 1st 100 kWh/kW, per kWh	9,069	3.285 ¢	$298	3.853 ¢	$349
Winter, All additional kWh, per kWh	48,026	2.238 ¢	$1,075	2.625 ¢	$1,261
Summer, All kWh, per kWh	438,524	2.238 ¢	$9,814	2.625 ¢	$11,511
	495,619		$11,187		$13,121
				Change	$1,934
Schedule 47, Large General Service, Partial Requirements 1,000kW and over					
Primary Voltage					
On-Peak, per on-peak kWh	77,843,379	2.321 ¢	$1,806,745	2.719 ¢	$2,116,561
Off-Peak, per off-peak kWh	52,684,370	2.271 ¢	$1,196,462	2.669 ¢	$1,406,146
	130,527,749		$3,003,207		$3,522,707
				Change	$519,500
Transmission Voltage					
On-Peak, per on-peak kWh	60,158,097	2.213 ¢	$1,331,299	2.592 ¢	$1,559,298
Off-Peak, per off-peak kWh	38,402,800	2.163 ¢	$830,653	2.542 ¢	$976,199
	98,560,897		$2,161,952		$2,535,497
				Change	$373,545

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Present and Proposed Rates and Revenues - Surrebuttal
Forecast 12 Months Ended December 31, 2012

		Present Schedule 201		Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
On-Peak, per on-peak kWh	398,965,559	2.410 ¢	$9,615,070	2.824 ¢	$11,266,787
Off-Peak, per off-peak kWh	217,810,379	2.360 ¢	$5,140,325	2.774 ¢	$6,042,060
	616,775,938		$14,755,395		$17,308,847
				Change	$2,553,452
Primary Voltage					
On-Peak, per on-peak kWh	972,802,054	2.321 ¢	$22,578,736	2.719 ¢	$26,450,488
Off-Peak, per off-peak kWh	605,530,990	2.271 ¢	$13,751,609	2.669 ¢	$16,161,622
	1,578,333,044		$36,330,345		$42,612,110
				Change	$6,281,765
Transmission Voltage					
On-Peak, per on-peak kWh	382,445,896	2.213 ¢	$8,463,528	2.592 ¢	$9,912,998
Off-Peak, per off-peak kWh	309,165,926	2.163 ¢	$6,687,259	2.542 ¢	$7,858,998
	691,611,822		$15,150,787		$17,771,996
				Change	$2,621,209
Schedule 15, Outdoor Area Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,990,380	2.319 ¢	$231,525	2.720 ¢	$271,936
	9,990,380		$231,525		$271,936
				Change	$40,411
Schedule 50, Mercury Vapor Street Lighting Service					
Secondary Voltage					
All kWh, per kWh	9,314,273	1.906 ¢	$177,685	2.236 ¢	$208,385
	9,314,273		$177,685		$208,385
				Change	$30,700
Schedule 51, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	17,431,141	3.008 ¢	$523,829	3.528 ¢	$614,523
	17,431,141		$523,829		$614,523
				Change	$90,694
Schedule 52, Street Lighting Service, Company-Owned System					
Secondary Voltage					
All kWh, per kWh	1,146,710	2.304 ¢	$26,420	2.702 ¢	$30,984
	1,146,710		$26,420		$30,984
				Change	$4,564
Schedule 53, Street Lighting Service, Consumer-Owned System					
Secondary Voltage					
All kWh, per kWh	9,017,061	0.984 ¢	$88,728	1.154 ¢	$104,057
	9,017,061		$88,728		$104,057
				Change	$15,329
Schedule 54, Recreational Field Lighting					
Secondary Voltage					
All kWh, per kWh	1,011,906	1.695 ¢	$17,152	1.988 ¢	$20,117
	1,011,906		$17,152		$20,117
				Change	$2,965
TOTAL Before Employee Discount			**$319,308,140**		**$374,525,539**
Employee Discount			-$112,750		-$132,246
TOTAL SCHEDULE 201	**13,327,140,976**		**$319,195,390**		**$374,393,294**
Schedule 33 kWh	104,951,114			**Change**	**$55,197,903**
Schedule 47 Unscheduled kWh	3,277,915				
Total Forecast kWH	13,435,370,005				

PACIFIC POWER
STATE OF OREGON
Other Revenues - Stand-Alone TAM Adjustment: Schedule 205 Proposed Rates and Revenues - Surrebuttal
Forecast 12 Months Ended December 31, 2012

Rate Schedule	Forecast Energy	Present Schedule 201 Revenues	Proposed Schedule 205 Rates	Proposed Schedule 205 Revenues
Schedule 4, Residential				
First Block kWh (0-1,000)	4,090,525,407	$90,809,664	0.024 ¢	$981,726
Second Block kWh (> 1,000)	1,497,695,207	$45,410,119	0.033 ¢	$494,239
	5,588,220,614	$136,219,783		$1,475,965
Employee Discount				
First Block kWh (0-1,000)	*12,235,301*	*$271,624*	*0.024 ¢*	*$2,936*
Second Block kWh (> 1,000)	*5,916,095*	*$179,376*	*0.033 ¢*	*$1,952*
	18,151,396	*$451,000*		*$4,888*
	Discount	-$112,750	Discount	-$1,222
Schedule 23, Small General Service				
Secondary Voltage				
1st 3,000 kWh, per kWh	823,288,548	$21,290,242	0.028 ¢	$230,521
All additional kWh, per kWh	228,996,047	$4,394,434	0.021 ¢	$48,089
	1,052,284,595	$25,684,676		$278,610
Primary Voltage				
1st 3,000 kWh, per kWh	660,596	$16,548	0.028 ¢	$185
All additional kWh, per kWh	200,603	$3,729	0.020 ¢	$40
	861,199	$20,277		$225
Schedule 28, General Service 31-200kW				
Secondary Voltage				
1st 20,000 kWh, per kWh	1,473,100,897	$36,105,703	0.027 ¢	$397,737
All additional kWh, per kWh	577,498,788	$13,767,571	0.026 ¢	$150,150
	2,050,599,685	$49,873,274		$547,887
Primary Voltage				
1st 20,000 kWh, per kWh	10,806,912	$245,425	0.025 ¢	$2,702
All additional kWh, per kWh	10,802,696	$238,740	0.024 ¢	$2,593
	21,609,608	$484,165		$5,295
Schedule 30, General Service 201-999kW				
Secondary Voltage				
1st 20,000 kWh, per kWh	189,165,886	$5,098,021	0.030 ¢	$56,750
All additional kWh, per kWh	1,049,091,298	$24,517,264	0.026 ¢	$272,764
	1,238,257,184	$29,615,285		$329,514
Primary Voltage				
1st 20,000 kWh, per kWh	11,820,727	$315,022	0.029 ¢	$3,428
All additional kWh, per kWh	76,753,410	$1,768,399	0.025 ¢	$19,188
	88,574,137	$2,083,421		$22,616
Schedule 41, Agricultural Pumping Service				
Secondary Voltage				
Winter, 1st 100 kWh/kW, per kWh	1,634,669	$55,448	0.037 ¢	$605
Winter, All additional kWh, per kWh	1,384,498	$31,996	0.025 ¢	$346
Summer, All kWh, per kWh	119,498,247	$2,761,604	0.025 ¢	$29,875
	122,517,414	$2,849,048		$30,826
Primary Voltage				
Winter, 1st 100 kWh/kW, per kWh	9,069	$298	0.036 ¢	$3
Winter, All additional kWh, per kWh	48,026	$1,075	0.025 ¢	$12
Summer, All kWh, per kWh	438,524	$9,814	0.025 ¢	$110
	495,619	$11,187		$125
Schedule 47, Large General Service, Partial Requirements 1,000kW and over				
Primary Voltage				
On-Peak, per on-peak kWh	77,843,379	$1,806,745	0.025 ¢	$19,461
Off-Peak, per off-peak kWh	52,684,370	$1,196,462	0.025 ¢	$13,171
	130,527,749	$3,003,207		$32,632
Transmission Voltage				
On-Peak, per on-peak kWh	60,158,097	$1,331,299	0.024 ¢	$14,438
Off-Peak, per off-peak kWh	38,402,800	$830,653	0.024 ¢	$9,217
	98,560,897	$2,161,952		$23,655

PACIFIC POWER
STATE OF OREGON
Other Revenues - Stand-Alone TAM Adjustment: Schedule 205 Proposed Rates and Revenues - Surrebuttal
Forecast 12 Months Ended December 31, 2012

Rate Schedule	Forecast Energy	Present Schedule 201 Revenues	Proposed Schedule 205 Rates	Proposed Schedule 205 Revenues
Schedule 48, Large General Service, 1,000kW and over				
Secondary Voltage				
On-Peak, per on-peak kWh	398,965,559	$9,615,070	0.026 ¢	$103,731
Off-Peak, per off-peak kWh	217,810,379	$5,140,325	0.026 ¢	$56,631
	616,775,938	$14,755,395		$160,362
Primary Voltage				
On-Peak, per on-peak kWh	972,802,054	$22,578,736	0.025 ¢	$243,201
Off-Peak, per off-peak kWh	605,530,990	$13,751,609	0.025 ¢	$151,383
	1,578,333,044	$36,330,345		$394,584
Transmission Voltage				
On-Peak, per on-peak kWh	382,445,896	$8,463,528	0.024 ¢	$91,787
Off-Peak, per off-peak kWh	309,165,926	$6,687,259	0.024 ¢	$74,200
	691,611,822	$15,150,787		$165,987
Schedule 15, Outdoor Area Lighting Service				
Secondary Voltage				
All kWh, per kWh	9,990,380	$231,525	0.025 ¢	$2,498
	9,990,380	$231,525		$2,498
Schedule 50, Mercury Vapor Street Lighting Service				
Secondary Voltage				
All kWh, per kWh	9,314,273	$177,685	0.021 ¢	$1,956
	9,314,273	$177,685		$1,956
Schedule 51, Street Lighting Service, Company-Owned System				
Secondary Voltage				
All kWh, per kWh	17,431,141	$523,829	0.033 ¢	$5,752
	17,431,141	$523,829		$5,752
Schedule 52, Street Lighting Service, Company-Owned System				
Secondary Voltage				
All kWh, per kWh	1,146,710	$26,420	0.025 ¢	$287
	1,146,710	$26,420		$287
Schedule 53, Street Lighting Service, Consumer-Owned System				
Secondary Voltage				
All kWh, per kWh	9,017,061	$88,728	0.011 ¢	$992
	9,017,061	$88,728		$992
Schedule 54, Recreational Field Lighting				
Secondary Voltage				
All kWh, per kWh	1,011,906	$17,152	0.019 ¢	$192
	1,011,906	$17,152		$192
TOTAL Before Employee Discount		**$319,308,140**		**$3,479,960**
Employee Discount		-$112,750		-$1,222
TOTAL SCHEDULE 201	**13,327,140,976**	**$319,195,390**		**$3,478,738**
Schedule 33 kWh	104,951,114			
Schedule 47 Unscheduled kWh	3,277,915			
Total Forecast kWH	13,435,370,005			

Docket No. UE-227
Exhibit PPL/307
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Judith M. Ridenour

Estimated Effect of Updated Proposed TAM Price Change

August 2011

TAM Price Change - Surrebuttal

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
Forecast 12 Months Ended December 31, 2012

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %[2]	Change Net Rates ($000)	Change Net Rates %[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	478,578	5,588,220	$560,344	$11,511	$571,855	$585,376	$11,511	$596,887	$25,032	4.5%	$25,032	4.4%	1
2	**Total Residential**			478,578	5,588,220	$560,344	$11,511	$571,855	$585,376	$11,511	$596,887	$25,032	4.5%	$25,032	4.4%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	74,901	1,053,146	$111,984	($1,745)	$110,239	$116,707	($1,745)	$114,962	$4,723	4.2%	$4,723	4.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,000	2,072,210	$159,821	$7,564	$167,385	$169,083	$7,564	$176,647	$9,262	5.8%	$9,262	5.5%	4
5	Gen. Svc. 201 - 999 kW	30	30	803	1,326,831	$94,782	$1,911	$96,693	$100,614	$1,911	$102,525	$5,832	6.2%	$5,832	6.0%	5
6	Large General Service >= 1,000 kW	48	48	212	2,886,720	$183,684	($10,248)	$173,436	$195,861	($10,248)	$185,613	$12,177	6.6%	$12,177	7.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	5	232,367	$15,090	($910)	$14,180	$16,039	($910)	$15,129	$949	6.6%	$949	7.0%	7
8	Agricultural Pumping Service	41	41	6,131	123,013	$14,091	($1,964)	$12,127	$14,617	($1,964)	$12,653	$526	3.7%	$526	4.3%	8
9	Agricultural Pumping - Other	33	33	2,007	104,951	$6,348	$66	$6,414	$6,348	$66	$6,414	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			94,059	7,799,238	$585,800	($5,326)	$580,474	$619,270	($5,326)	$613,944	$33,470	5.7%	$33,470	5.8%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,020	9,991	$1,293	$261	$1,554	$1,336	$261	$1,597	$43	3.3%	$43	2.8%	11
12	Street Lighting Service	50	50	247	9,314	$1,047	$228	$1,275	$1,080	$228	$1,308	$33	3.1%	$33	2.6%	12
13	Street Lighting Service HPS	51	51	726	17,431	$3,116	$678	$3,794	$3,212	$678	$3,890	$96	3.1%	$96	2.5%	13
14	Street Lighting Service	52	52	50	1,147	$130	$28	$158	$135	$28	$163	$5	3.7%	$5	3.1%	14
15	Street Lighting Service	53	53	263	9,017	$572	$134	$706	$588	$134	$722	$16	2.9%	$16	2.3%	15
16	Recreational Field Lighting	54	54	105	1,012	$87	$18	$105	$90	$18	$108	$3	3.6%	$3	3.0%	16
17	**Total Public Street Lighting**			8,411	47,912	$6,245	$1,347	$7,592	$6,441	$1,347	$7,788	$196	3.1%	$196	2.6%	17
18	**Total Sales to Ultimate Consumers**			581,048	13,435,370	$1,152,389	$7,532	$1,159,921	$1,211,086	$7,532	$1,218,618	$58,697	5.1%	$58,697	5.1%	18
19	**Employee Discount**				18,151	($450)	($9)	($459)	($471)	($9)	($480)	($21)		($21)		19
20	**Total Sales with Employee Discount**			581,048	13,435,370	$1,151,939	$7,523	$1,159,462	$1,210,616	$7,523	$1,218,139	$58,677	5.1%	$58,677	5.1%	20
21	AGA Revenue					$2,886		$2,886	$2,886		$2,886	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			581,048	13,435,370	$1,154,825	$7,523	$1,162,348	$1,213,502	$7,523	$1,221,025	$58,677	5.1%	$58,677	5.1%	22

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).
[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$18.56	$18.99	$0.43	2.32%
200	$27.39	$28.23	$0.84	3.07%
300	$36.18	$37.44	$1.26	3.48%
400	$45.01	$46.69	$1.68	3.73%
500	$53.80	$55.90	$2.10	3.90%
600	$62.60	$65.12	$2.52	4.03%
700	$71.42	$74.37	$2.95	4.13%
800	$80.22	$83.57	$3.35	4.18%
900	$89.04	$92.82	$3.78	4.25%
950	**$93.42**	**$97.42**	**$4.00**	**4.28%**
1,000	$97.84	$102.04	$4.20	4.29%
1,100	$109.16	$113.93	$4.77	4.37%
1,200	$120.49	$125.84	$5.35	4.44%
1,300	$131.81	$137.74	$5.93	4.50%
1,400	$143.15	$149.64	$6.49	4.53%
1,500	$154.47	$161.54	$7.07	4.58%
1,600	$165.78	$173.43	$7.65	4.61%
2,000	$211.10	$221.04	$9.94	4.71%
3,000	$324.36	$340.04	$15.68	4.83%
4,000	$437.62	$459.03	$21.41	4.89%
5,000	$550.88	$578.03	$27.15	4.93%

* Net rate including Schedules 91, 98, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
kW		Present Price		Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$66	$76	$69	$78	3.70%	3.22%
	750	$90	$99	$93	$103	4.09%	3.70%
	1,000	$113	$123	$118	$128	4.32%	3.98%
	1,500	$160	$170	$168	$177	4.58%	4.32%
10	1,000	$113	$123	$118	$128	4.32%	3.98%
	2,000	$207	$217	$217	$227	4.72%	4.52%
	3,000	$301	$311	$316	$325	4.87%	4.72%
	4,000	$380	$389	$398	$408	4.82%	4.70%
20	4,000	$409	$418	$427	$437	4.48%	4.38%
	6,000	$566	$576	$592	$601	4.52%	4.44%
	8,000	$724	$733	$756	$766	4.54%	4.48%
	10,000	$881	$890	$921	$930	4.56%	4.51%
30	9,000	$860	$870	$897	$906	4.24%	4.20%
	12,000	$1,096	$1,106	$1,144	$1,153	4.32%	4.29%
	15,000	$1,332	$1,341	$1,390	$1,400	4.38%	4.35%
	18,000	$1,568	$1,577	$1,637	$1,647	4.41%	4.39%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$65	$74	$67	$77	3.66%	3.20%
	750	$88	$97	$91	$101	4.06%	3.67%
	1,000	$110	$120	$115	$125	4.29%	3.96%
	1,500	$156	$165	$163	$173	4.57%	4.30%
10	1,000	$110	$120	$115	$125	4.29%	3.96%
	2,000	$202	$211	$211	$221	4.71%	4.50%
	3,000	$293	$302	$307	$316	4.87%	4.72%
	4,000	$369	$378	$387	$396	4.81%	4.69%
20	4,000	$397	$407	$415	$425	4.47%	4.37%
	6,000	$550	$559	$575	$584	4.51%	4.43%
	8,000	$702	$712	$734	$744	4.53%	4.47%
	10,000	$855	$864	$894	$903	4.54%	4.49%
30	9,000	$835	$845	$871	$880	4.23%	4.18%
	12,000	$1,064	$1,074	$1,110	$1,119	4.31%	4.27%
	15,000	$1,293	$1,302	$1,349	$1,359	4.36%	4.33%
	18,000	$1,521	$1,531	$1,588	$1,598	4.40%	4.37%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$401	$421	5.22%
	7,500	$602	$637	5.78%
	10,500	$804	$853	6.07%
31	9,300	$811	$855	5.32%
	15,500	$1,228	$1,300	5.86%
	21,700	$1,643	$1,743	6.12%
40	12,000	$1,042	$1,098	5.35%
	20,000	$1,580	$1,673	5.88%
	28,000	$2,106	$2,235	6.13%
60	18,000	$1,557	$1,641	5.37%
	30,000	$2,349	$2,487	5.88%
	42,000	$3,137	$3,329	6.13%
80	24,000	$2,060	$2,171	5.39%
	40,000	$3,112	$3,295	5.89%
	56,000	$4,163	$4,419	6.13%
100	30,000	$2,560	$2,698	5.39%
	50,000	$3,875	$4,103	5.89%
	70,000	$5,189	$5,508	6.14%
200	60,000	$5,040	$5,313	5.42%
	100,000	$7,669	$8,122	5.92%
	140,000	$10,297	$10,932	6.16%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$367	$386	5.28%
	7,500	$547	$579	5.90%
	10,500	$727	$772	6.22%
31	9,300	$739	$779	5.42%
	15,500	$1,112	$1,178	6.00%
	21,700	$1,482	$1,575	6.29%
40	12,000	$949	$1,000	5.44%
	20,000	$1,429	$1,515	6.02%
	28,000	$1,899	$2,018	6.30%
60	18,000	$1,418	$1,495	5.47%
	30,000	$2,124	$2,252	6.02%
	42,000	$2,828	$3,006	6.30%
80	24,000	$1,875	$1,977	5.49%
	40,000	$2,813	$2,983	6.03%
	56,000	$3,751	$3,988	6.31%
100	30,000	$2,329	$2,457	5.49%
	50,000	$3,502	$3,713	6.04%
	70,000	$4,675	$4,970	6.31%
200	60,000	$4,568	$4,822	5.55%
	100,000	$6,914	$7,335	6.08%
	140,000	$9,261	$9,848	6.35%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	30,000	$2,816	$2,962	5.20%
	50,000	$3,921	$4,156	5.99%
	70,000	$5,027	$5,350	6.44%
200	60,000	$5,081	$5,360	5.50%
	100,000	$7,292	$7,748	6.26%
	140,000	$9,502	$10,136	6.67%
300	90,000	$7,485	$7,897	5.51%
	150,000	$10,801	$11,479	6.28%
	210,000	$14,117	$15,061	6.68%
400	120,000	$9,792	$10,337	5.57%
	200,000	$14,213	$15,113	6.33%
	280,000	$18,635	$19,889	6.73%
500	150,000	$12,123	$12,801	5.59%
	250,000	$17,651	$18,771	6.35%
	350,000	$23,178	$24,741	6.75%
600	180,000	$14,455	$15,266	5.61%
	300,000	$21,088	$22,430	6.37%
	420,000	$27,720	$29,594	6.76%
800	240,000	$19,119	$20,195	5.63%
	400,000	$27,962	$29,747	6.38%
	560,000	$36,806	$39,299	6.78%
1000	300,000	$23,782	$25,125	5.64%
	500,000	$34,837	$37,065	6.40%
	700,000	$45,891	$49,005	6.79%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$2,764	$2,908	5.23%
	50,000	$3,850	$4,082	6.02%
	70,000	$4,937	$5,256	6.46%
200	60,000	$4,994	$5,269	5.51%
	100,000	$7,168	$7,617	6.27%
	140,000	$9,341	$9,965	6.68%
300	90,000	$7,353	$7,759	5.52%
	150,000	$10,614	$11,281	6.29%
	210,000	$13,874	$14,802	6.69%
400	120,000	$9,657	$10,194	5.56%
	200,000	$14,004	$14,889	6.32%
	280,000	$18,351	$19,584	6.72%
500	150,000	$11,955	$12,622	5.58%
	250,000	$17,388	$18,491	6.34%
	350,000	$22,821	$24,360	6.74%
600	180,000	$14,252	$15,050	5.60%
	300,000	$20,772	$22,093	6.36%
	420,000	$27,292	$29,136	6.76%
800	240,000	$18,847	$19,906	5.62%
	400,000	$27,540	$29,297	6.38%
	560,000	$36,234	$38,688	6.77%
1000	300,000	$23,442	$24,763	5.63%
	500,000	$34,309	$36,501	6.39%
	700,000	$45,176	$48,239	6.78%

* Net rate including Schedules 91, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$246	$271	$175	$259	$286	$175	5.33%	5.60%	0.00%
	5,000	$410	$435	$175	$432	$459	$175	5.33%	5.50%	0.00%
	7,000	$575	$600	$175	$605	$632	$175	5.33%	5.45%	0.00%
Three Phase										
20	6,000	$493	$542	$350	$519	$573	$350	5.33%	5.60%	0.00%
	10,000	$821	$871	$350	$865	$919	$350	5.33%	5.50%	0.00%
	14,000	$1,149	$1,199	$350	$1,211	$1,265	$350	5.33%	5.45%	0.00%
100	30,000	$2,463	$2,712	$1,504	$2,594	$2,864	$1,504	5.33%	5.60%	0.00%
	50,000	$4,105	$4,354	$1,504	$4,324	$4,593	$1,504	5.33%	5.50%	0.00%
	70,000	$5,746	$5,996	$1,504	$6,053	$6,323	$1,504	5.33%	5.45%	0.00%
300	90,000	$7,388	$8,136	$3,770	$7,782	$8,592	$3,770	5.33%	5.60%	0.00%
	150,000	$12,314	$13,062	$3,770	$12,971	$13,780	$3,770	5.33%	5.50%	0.00%
	210,000	$17,239	$17,987	$3,770	$18,159	$18,968	$3,770	5.33%	5.45%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$237	$261	$175	$250	$276	$175	5.37%	5.63%	0.00%
	5,000	$395	$419	$175	$416	$442	$175	5.37%	5.54%	0.00%
	7,000	$553	$577	$175	$583	$609	$175	5.37%	5.49%	0.00%
Three Phase										
20	6,000	$474	$522	$350	$499	$552	$350	5.37%	5.63%	0.00%
	10,000	$790	$838	$350	$832	$884	$350	5.37%	5.54%	0.00%
	14,000	$1,106	$1,154	$350	$1,165	$1,217	$350	5.37%	5.49%	0.00%
100	30,000	$2,369	$2,610	$1,494	$2,496	$2,758	$1,494	5.37%	5.63%	0.00%
	50,000	$3,949	$4,190	$1,494	$4,161	$4,422	$1,494	5.37%	5.54%	0.00%
	70,000	$5,528	$5,769	$1,494	$5,825	$6,086	$1,494	5.37%	5.49%	0.00%
300	90,000	$7,107	$7,831	$3,760	$7,489	$8,273	$3,760	5.37%	5.63%	0.00%
	150,000	$11,846	$12,570	$3,760	$12,482	$13,266	$3,760	5.37%	5.54%	0.00%
	210,000	$16,584	$17,308	$3,760	$17,475	$18,259	$3,760	5.37%	5.49%	0.00%

* Net rate including Schedules 91, 98, 290 and 297.

Pacific Power & Light Company
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$22,461	$23,821	6.05%
	500,000	$32,869	$35,135	6.89%
	700,000	$43,277	$46,449	7.33%
2,000	600,000	$44,572	$47,292	6.10%
	1,000,000	$64,078	$68,610	7.07%
	1,400,000	$84,170	$90,515	7.54%
4,000	1,200,000	$87,123	$92,561	6.24%
	2,000,000	$127,306	$136,370	7.12%
	2,800,000	$167,489	$180,179	7.58%
6,000	1,800,000	$129,939	$138,097	6.28%
	3,000,000	$190,214	$203,810	7.15%
	4,200,000	$250,490	$269,524	7.60%

Notes:

On-Peak kWh	64.69%
Off-Peak kWh	35.31%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing: Present Price	Monthly Billing: Proposed Price	Percent Difference
1,000	300,000	$21,505	$22,812	6.08%
	500,000	$31,427	$33,605	6.93%
	700,000	$41,348	$44,398	7.38%
2,000	600,000	$42,640	$45,254	6.13%
	1,000,000	$61,173	$65,530	7.12%
	1,400,000	$80,292	$86,392	7.60%
4,000	1,200,000	$83,237	$88,465	6.28%
	2,000,000	$121,475	$130,189	7.17%
	2,800,000	$159,713	$171,913	7.64%
6,000	1,800,000	$124,399	$132,242	6.30%
	3,000,000	$181,757	$194,827	7.19%
	4,200,000	$239,114	$257,413	7.65%

Notes:

On-Peak kWh	61.63%
Off-Peak kWh	38.37%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Pacific Power & Light Company
TAM Monthly Billing Comparison - Surrebuttal
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$21,181	$22,426	5.88%
	500,000	$30,591	$32,666	6.78%
	700,000	$40,001	$42,906	7.26%
2,000	600,000	$41,764	$44,255	5.96%
	1,000,000	$59,274	$63,425	7.00%
	1,400,000	$77,370	$83,182	7.51%
4,000	1,200,000	$81,259	$86,240	6.13%
	2,000,000	$117,451	$125,753	7.07%
	2,800,000	$153,643	$165,266	7.56%
6,000	1,800,000	$121,845	$129,316	6.13%
	3,000,000	$176,133	$188,585	7.07%
	4,200,000	$230,421	$247,855	7.57%

Notes:

On-Peak kWh	55.30%
Off-Peak kWh	44.70%

* Net rate including Schedules 91 and 290. Schedule 297 not included for kWh levels over 730,000.

Docket No. UE-227
Exhibit PPL/406
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Surrebuttal Testimony of Stefan A. Bird

August 2011

Q. Are you the same Stefan A. Bird who filed direct testimony and rebuttal testimony in this proceeding on behalf of PacifiCorp (the Company)?

A. Yes.

Purpose and Summary of Testimony

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the August 16, 2011 rebuttal testimony on the Company's hedging activities sponsored by Mr. Ed Durrenberger on behalf of the Oregon Public Utility Commission Staff (Staff), Messrs. Robert Jenks and Gordon Feighner on behalf of the Citizens' Utility Board of Oregon (CUB), and Mr. Donald Schoenbeck on behalf of the Industrial Customers of Northwest Utilities (ICNU). Specifically, my surrebuttal testimony:

- Concurs with Staff's conclusion that the Company's hedges in this proceeding were prudent given the information available at the time the hedge transactions were executed and recommends the Commission reject all of CUB's and ICNU's proposed adjustments related to hedging.
- Concurs with Staff's recommendation to enter into a series of workshops with interested parties to review the hedging process in detail and provide Staff and customer groups the opportunity for input into the Company's going forward risk management and hedging policies.
- Demonstrates that all of the contested hedges in this proceeding greater than 48 months of delivery were executed in compliance with the Company's risk management policy, which addresses and eliminates CUB's only remaining contested hedging issue in this proceeding.

- Demonstrates that there is no basis for a prudence disallowance based on ICNU's unsubstantiated assertions that the Company hedged too much or too far forward.

These conclusions are further supported by the surrebuttal testimony of third party expert, Mr. Frank C. Graves of the Brattle Group.

Staff

Q. Do you agree with Staff's conclusion that all of PacifiCorp's hedges in this proceeding were prudent and that the Commission should reject CUB's and ICNU's proposed adjustments related to hedging?

A. Yes.

Q. Do you agree with Staff's recommendation to enter into a series of workshops with parties to review the hedging process in detail and provide Staff and customer groups the opportunity for input into the Company's going forward risk management policy and hedging program?

A. Yes. If parties have concerns about the Company's approach to hedging, an ex ante review of the Company's risk management policy and hedging program is the appropriate response.

Q. Did the Company recently commence a similar ex ante review process at the Utah Commission?

A. Yes. In the recent stipulation settling the Company's 2011 Utah general rate case, the parties agreed to convene a collaborative process "to discuss appropriate changes to the Company's hedging practices to better reflect customer risk tolerances and preferences."[1] The Company agreed "to implement appropriate changes on a going-forward basis" resulting from the collaborative process. The Utah Stipulation lists a number of issues to be addressed in the collaborative process, including volume percentage limits and hedging time horizons, two key issues raised in this case.

Q. Because the Company manages its hedging program on a total system basis, is it good policy for Oregon to conduct a collaborative process on the Company's hedging program in tandem with Utah and potentially other states?

A. Yes. This would permit the Company to reflect and work to harmonize the interests and concerns of stakeholders throughout its jurisdictions, in a manner similar to the Company's integrated resource planning process. In the Utah Stipulation, the Company specifically agreed to work to resolve materially inconsistent policy changes sought in Utah and in other states.

Q. Do you agree with Staff that CUB does not clearly demonstrate its assertion that because PacifiCorp lacks a power cost adjustment mechanism (PCAM) in Oregon, hedging shifts risk from shareholders to customers?

A. Yes.

Q. Do you agree with Staff's comment that it is possible that PCAM's in PacifiCorp's other jurisdictions have affected the incentives for careful hedging?

A. No. The different net power cost regulatory recovery mechanisms across the

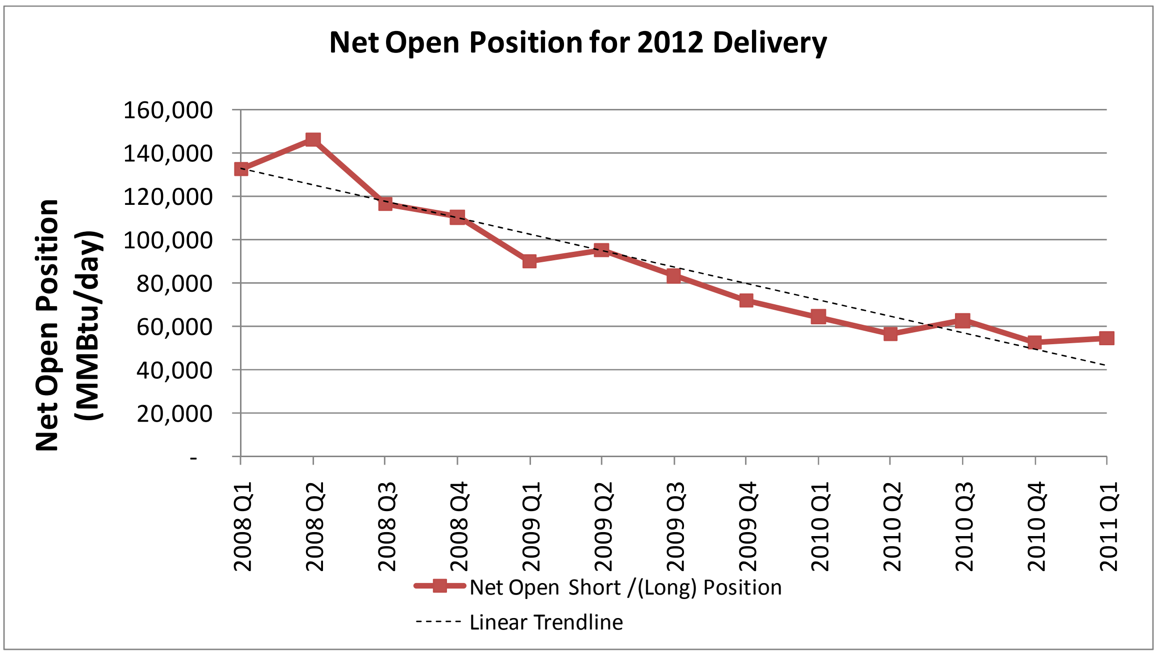
[1] The Utah Stipulation (July 28, 2011) is available at: http://www.psc.state.ut.us/utilities/electric/elecindx/2010/10035124indx.html

Company's six jurisdictions have not affected the Company's incentives for careful hedging. As Staff correctly notes, customers face significant risk in regard to commodity price volatility with or without the existence of a PCAM. PacifiCorp's risk management policy and hedging program are designed and implemented to mitigate this risk exposure to customers.

PacifiCorp's incentives for careful hedging arise from its fundamental commitment to customers, its obligation to serve, commodity price volatility that is out of the Company's control, the assumption that our customers are risk adverse and have a preference for stability, and the prudence standard for the Company to obtain cost recovery. The Company is committed to satisfying its customers' interests and is open to modifying its risk management policy and hedging program going forward if customers express a different risk preference. Staff's recommendation to enter into a series of workshops on the Company's hedging practices is an appropriate venue to consider any potential changes going forward.

Q. **How do you respond to Staff's general observation that the Company's hedges in this proceeding appear to be more sporadic than programmatic?**

A. The figure below shows the change in the Company's natural gas open position for the test period from the fourth quarter 2007 to the third quarter 2011 compared to a linear progression. The figure shows that the Company's net open position and associated risk for 2012 was reduced on a reasonably steady basis during that period, consistent with the Company's portfolio approach to hedging. However, the progression is not rigidly linear and this variability is the result of resource portfolio changes (*i.e.*, the 500 MW Chehalis facility was added in September 2008 resulting in increased gas requirements), market changes (volatility in the spread between forward electricity prices and forward natural gas prices resulting in reduced or increased gas requirements), reserve requirement changes (increasing with incremental wind assets and generally resulting in reduced gas requirements) and trader discretion within the confines of the limits in the risk management policy.



CUB

Q. Did CUB change its position regarding hedging issues in its rebuttal testimony?

A. Yes. CUB modified its position on hedging issues based on the Company's rebuttal testimony and conceded that it is prudent for the Company to contract for hedges that are up to 48 months out as compared to its opening testimony contesting hedges beyond 36 months.

Q. Why did CUB make this change?

A. As outlined in my rebuttal testimony, the Company's October and November 2006 updates to its risk management policy (2006 Policy) included an amendment to reflect a 48 month maximum effective transaction period for natural gas hedges, which reflected an improvement in market liquidity in the 37 to 48 month range. CUB's rebuttal testimony cites the 2006 Policy and acknowledges this change in market conditions.

Q. Does CUB have any other outstanding hedging concerns?

A. Yes. CUB continues to contest hedges that were made more than 48 months in advance of delivery.

Q. What is the basis for CUB's outstanding hedging concern?

A. CUB asserts that the Company's hedges greater than 48 months prior to delivery were executed out of compliance with Company policy.

Q. Please describe the hedges CUB contests.

A. For the test period, there are 58 hedges that extend into the 49 to 60 month period. On average, these hedges extend 2.3 months beyond the standard 48 month tenor.

Q. Does any other party share CUB's assertion?

A. Yes. ICNU makes the same assertion.

Q. Is CUB's and ICNU's assertion that these hedges were executed out of compliance with Company policy accurate?

A. No. All of the Company's hedges in this proceeding were executed in compliance with the Company's risk management policy.

Q. Please explain what was required for the Company to execute transactions over 48 months in compliance with the Company's risk management policy.

A. Under the Company's Front Office Procedures section entitled "Transaction Approvals and Authorization" (section 7.1 in the 2004 version and section 6.1 in the 2008 version), transactions in excess of 48 months require advance approval by the Commercial and Trading Senior Vice President (a job that subsumed the role of Trading and Origination Managing Director referenced in the 2004 version) or the Energy Trading Director, who reports to the Commercial and Trading Senior Vice President. See Exhibit PPL/407. The Front Office Procedures do not require written approval or specific analysis or documentation.

ICNU previously conceded in its rebuttal testimony that the Company's policies allowed for advance approval of transactions in excess of risk management policy limits.

Q. Did you approve these transactions in advance, as required by the Company's risk management policy and front office procedures?

A. Yes. In my capacity as Senior Vice President of Commercial and Trading, I gave advance approval for the use of standard market products to reduce the Company's hedging costs during this time period, even though in some circumstances the use of these products caused the hedges to extend beyond 48 months. Under my supervision, the Director of Trading also gave advanced approval of these transactions. As I explained in my rebuttal testimony, we authorized this approach because it was the most economic way to maintain compliance with the risk management policy that required incremental hedging as new months with large exposures rolled into the 48 month risk management horizon. With our advanced approval, these transactions were fully compliant with the Company's risk management policy.

Q. What is the basis of CUB's and ICNU's claim of non-compliance?

A. Both CUB and ICNU misinterpret the Company's response to ICNU 13.14 as evidence that the Company violated its risk management policy regarding the non-standard transactions in late 2007 and early 2008 that extended beyond 48 months.

ICNU 13.14 asked the Company to provide *all documents and analysis the Company considered in its review to execution each of the non-standard transaction* [emphasis added]. The Company's response to this question was that it did not have the requested information. CUB and ICNU both imply that this response is an admission of the Company's non-compliance with its risk management policy. But ICNU 13.14 did not ask for the evidence establishing that the transactions were compliant with the risk management policy. As noted above, this evidence is my sworn testimony that the Company's Director of Trading and I personally pre-approved these transactions as required by the Company's risk management policy front office procedures. Compliance with these policies and procedures did not require the pre-approval analysis or documentation requested in ICNU 13.14.

Q. Did customers benefit from the authorization of these non-standard transactions?

A. Yes. As noted in my rebuttal testimony, these transactions provided customers benefits from the reduced transaction costs associated with the use of standard market products.

Q. Does Staff agree that the non-standard nature of these hedges does not mean that they are noncompliant with the risk management policy or imprudent?

A. Yes. Staff correctly notes that the fact that these hedges required executive approval[2] does not make the actions imprudent and in fact makes the process more robust than it would be without this additional approval requirement.

ICNU

Q. Did ICNU change its position regarding hedging in its rebuttal testimony?

A. ICNU's adjustment has not changed. However, ICNU no longer asserts that the hedges between 37 and 48 months in advance were out of compliance with Company policy.

Q. In addition to the greater than 48 month hedge transactions issue discussed above, does ICNU contest any other hedging issue?

A. Yes. ICNU continues to promote an unsubstantiated after-the-fact programmatic hedging policy that results in their recommendation to arbitrarily reject a large portion of hedges in this proceeding that were executed greater than 36 months in advance of delivery.

[2] While Staff is correct in stating that certain hedges reflected in this case required my pre-approval, these are the hedges over 48 months, not 36 months as noted by Staff at Staff/300, Durrenberger/8.

Q. In ICNU/110, Schoenbeck/12, lines 3-7, Mr. Schoenbeck claims that the Company "has no documentation to support" the hedging transactions for which he seeks disallowance, which includes transactions in the 37 to 48 month period as well as transactions greater than 48 months that ICNU disputes. Is this correct?

A. No. The Company has documented each of these transactions, as is evident from the list of hedging transactions compiled in ICNU/103, Schoenbeck/9-10. In fact, the Company provides details on each transaction in the supporting workpapers provided to parties pursuant to the TAM Guidelines. *See* Order No. 09-274 at Appendix A, p 17 (Section A(3)(d)). In addition, the Company has provided its risk management policy and front office procedures documentation and has demonstrated that all transactions were executed in compliance with Company policy and procedures.

Q. Do you agree with ICNU that the relevant Company policy to address ICNU's issues regarding hedges greater than 36 months in advance is the Company's 2006 Policy?

A. Yes, I have attached the November 26, 2006 Risk Management Policy as Confidential/Highly Confidential Exhibit PPL/408. However, an understanding of the Company's current hedging practices is also important, both to show how the practices have evolved and adapted to current market conditions and to assess whether ex ante changes to the practices are warranted. In any event, the Company's overall approach and philosophy toward hedging have not changed materially since the time that the Company executed the hedges ICNU challenges in this case.

Q. Do you agree with ICNU's statement that the Company was trying to beat the market in 2007 while using the 2006 Policy?

A. No. As stated previously in my rebuttal testimony and the Company's IRP, also cited by ICNU, the Company hedges for the sole purpose of mitigating volatility, not to beat the market.

Q. How does ICNU support its claim that the Company was trying to beat the market?

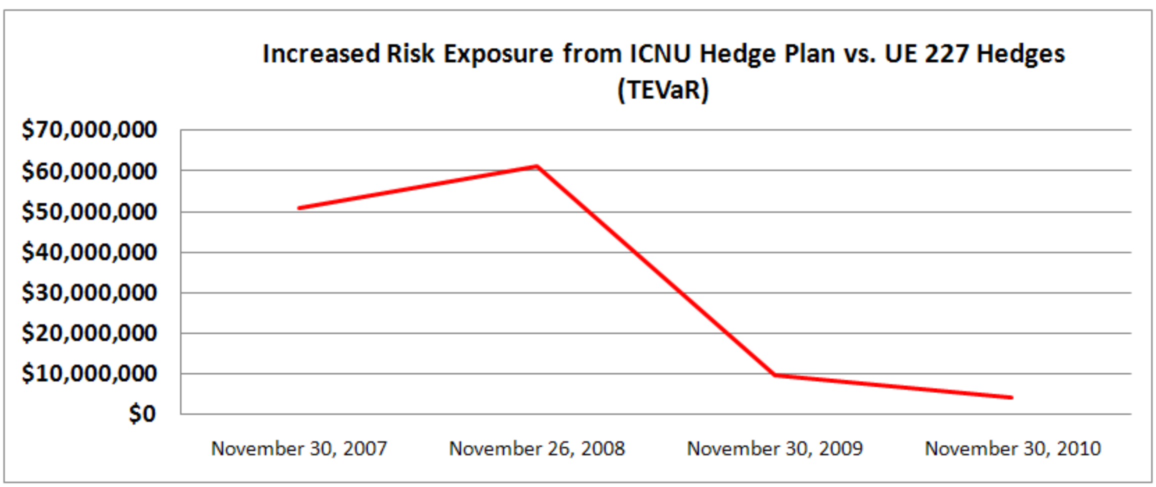
A. ICNU appears to support this claim by reference to my rebuttal testimony where I showed that third party experts were projecting even higher gas costs as support for why it was prudent to hedge.

Q. Does this reference support ICNU's claim?

A. No. The point of including this third party data in my testimony was to demonstrate that at the time these hedges were made, there was significant risk that natural gas prices might escalate. Staff's testimony relies upon a similar summary of the status of the market at the time these hedges were made to support Staff's conclusion that the hedges were prudent. All of the hedges were entered to mitigate the risk of price escalation and were executed at then current forward market prices. No hedges were executed to try to beat the market. Indeed, ICNU's hindsight hedging strategy effectively proposes that the Company should have tried to beat the market instead of hedging based on sound risk management principles. ICNU's hindsight proposal demands that the Company abandon sound risk management principles and instead increase its customer risk position in the face of elevated market risk and escalating forward prices.

Q. What incremental customer risk exposure would have resulted if the Company had instead adopted ICNU's proposed hedging plan?

A. The Company calculated time to expiry value-at-risk (TEVaR) with forward prices, volatilities and correlations known during the historical period from 2007 through 2010. The chart below shows the increased risk to customers that result from ICNU's hypothetical hedging plan as compared to the Company's actual hedges in UE 227. The results demonstrate ICNU's proposed hedging plan would have increased risk to customers as much as $60 million as of November 30, 2008. This increased risk results from a much larger net open position exposure in the face of escalating forward prices and high price volatility at the time.



Q. Do you agree with ICNU that past hedging benefits should not be considered in the decision in the current proceeding?

A. I agree that it is inappropriate to consider hedging gains or losses to determine if the hedges in any period were prudent. However, since ICNU is highlighting hedging losses in the current proceeding, it is disingenuous for ICNU to ignore the fact that customers have received benefits from the Company's hedging activity in prior proceedings. Given that commodity prices are volatile and unpredictable, one would reasonably expect that there will be hedging gains in some periods and hedging losses in others and that, in fact, is the Company's experience.

Q. Were any of the transactions in the current proceeding also included in the Company's previous TAM proceeding?

A. Yes. Approximately 20 percent of the natural gas hedge transactions in this proceeding—including all of the Company's hedges executed in 2007—also had settlement dates in the UE 216 test period. These hedges were uncontested in the Company's last rate case and are currently reflected in Oregon rates. ICNU's adjustment includes over one-half of the subset of hedges included in both UE 216 and this filing. ICNU has not explained this fact, nor justified why the Commission should remove multi-year hedges already in rates.

Q. Did the Company's hedging activities reduce net power costs in UE 216?

A. Yes. As shown in Mr. Duvall's Exhibit PPL/108, the Company's hedges provided $10.5 million in benefits to customers on a total company basis.

Q. What does ICNU conclude from its review of the Company's electricity hedging in this proceeding?

A. ICNU does not contest any of the Company's electricity hedges in this proceeding.

Q. What is the benefit to customers of the Company's electricity hedges in this proceeding?

A. $24.4 million based on the Rebuttal Update.

Q. Do you agree with Mr. Schoenbeck's observation that, as compared to the last TAM (UE 216), the test period in UE 227 reflects a significant decline in short term firm electricity sales, a significant decline in favorable net electric swap expense and a modest decline in natural gas swap expense?

A. Yes.

Q. Do these figures help explain the net hedging loss in UE 227?

A. Yes, however, it is important to understand what is driving these changes. The Company's risk management policy, hedging program and implementation of its policy were consistent in UE 216 and UE 227. What changed, and therefore what drives these results, is the Company's load and resource balance. These changes are described by Mr. Duvall in his surrebuttal testimony and are detailed in the workpapers in the Company's initial TAM filing.

In brief, the Company's natural gas requirements increased and the Company's available electric capacity decreased in the test period in UE 227. As a result, the Company's natural gas requirements as compared to its excess electricity sales was much greater in UE 227 than in UE 216. Given this starting position, under the Company's progressive portfolio hedge program, the Company's natural gas hedges occurred in advance of electricity hedges and in much greater volumes.

Q. What do you conclude from comparing those hedges the parties accept as prudent and those they challenge?

A. The Company has applied the same general risk management principles to all of its hedging practices, natural gas and electric, and in this case and in the last. Given this fact, it is difficult for me not to conclude that the parties' positions on whether or not the Company's hedges are prudent are inappropriately driven by opportunistic hindsight and not on sound risk management principles.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE-227
Exhibit PPL/407
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Stefan A. Bird

Relevant Portions of Front Office Procedures in 2004 and 2008 Versions for Transaction Approvals and Authorization

August 2011

PACIFICORP

Commercial & Trading Front Office

Procedures and Practices

Confidential and Proprietary

Approved October 18, 2004

7.1 Transaction Approvals and Authorization.

i. The Trading & Origination Managing Director shall ensure that all transactions are within approved limits and guidelines and comply with all rules and regulations of the applicable market.
ii. It is the responsibility of the traders and originators that no transaction is consummated unless it falls within the procedures set forth or referenced in this document.
iii. Only authorized personnel, as determined in writing and shown in Exhibit 6, shall enter a transaction on behalf of Front Office.
iv. Transactions must comply with the FERC Market Behavior Rules set forth in Section 13.1 and any other rules and regulations of the applicable power market.
v. Transactions are restricted to approved counterparties.
vi. Transactions must adhere to authorized credit limits.
vii. Transactions must adhere to authorized risk limits (position, VaR, and Incremental VaR).
viii. Traders and originators shall only transact approved products or must have approval from Risk Management, Credit, Legal, and the Energy Trading Director or Origination Director in advance of the transaction.
ix. Transactions must adhere to approved strategy guidelines.
x. Any transaction not clearly within the trader or originator's mandate to execute must be approved in advance by the Energy Trading Director or Origination Director.
xi. Any exceptions to this approval and authorization process must be recorded and reported to the Trading & Origination Managing Director immediately.
xii. Front Office will maintain a record of current procedures, approved products, approved counterparties, counterparty credit limits and trading strategies with pertinent associated supporting documents.
xiii. Authorized Signing Levels are included in Exhibit 7.

REDACTED

PACIFICORP ENERGY
A DIVISION OF PACIFICORP

Commercial and Trading

Front Office Procedures and Practices

Approved July 31, 2008

6 Procedures

The limitations on transactions and the front office authorizations required conform to the requirements contained in the *PacifiCorp Energy Risk Management Policy* and the *PacifiCorp Corporate Governance and Approvals Process.*

6.1 Transaction Approvals and Authorization.

i. The C&T senior vice president shall ensure that all transactions are within approved limits and guidelines and comply with all rules and regulations of applicable markets.
ii. It is the responsibility of the traders and originators to assure that no transaction is consummated unless it falls within the procedures set forth or referenced in this document.
iii. Only authorized personnel, as determined in writing and shown in Exhibit 2, shall enter a transaction on behalf of the front office.
iv. Transactions must comply with the FERC market behavior rules set forth in Section 12.1.1 and any other rules and regulations of the applicable power market.
v. Transactions are restricted to approved counterparties.
vi. Transactions must adhere to authorized credit limits.
vii. Transactions must adhere to authorized risk limits (position and value-at-risk)
viii. Traders and originators shall only transact approved products or must have approval from the PacifiCorp Energy president through the process outlined in the *PacifiCorp Energy Risk Management Policy.*
ix. Transactions must adhere to approved strategy guidelines.
x. Any transaction not clearly within the trader or originator's mandate to execute must be approved in advance by the either the trading or the origination director.
xi. Any exceptions to this approval and authorization process must be recorded and reported to the C&T senior vice president immediately.
xii. The front office will maintain a record of current procedures, approved products, approved counterparties, counterparty credit limits and trading strategies with pertinent associated supporting documents.
xiii. Authorized signing levels are referenced in Exhibit 3.

REDACTED

CONFIDENTIAL/
HIGHLY CONFIDENTIAL
Docket No. UE-227
Exhibit PPL/408
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Confidential/Highly Confidential Exhibit Accompanying Surrebuttal Testimony of Stefan A. Bird

Risk Management Policy (November 26, 2006)

August 2011

THIS EXHIBIT IS CONFIDENTIAL
SUBJECT TO
PROTECTIVE ORDER NO. 10-069
AND
HIGHLY CONFIDENTIAL
SUBJECT TO MODIFIED
PROTECTIVE ORDER NO. 11-265

REDACTED
Docket No. UE-227
Exhibit PPL/700
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Surrebuttal Testimony of Frank C. Graves

August 2011

Q. Please state your name and position.

A. My name is Frank C. Graves. I am a Principal at the economics consulting firm *The Brattle Group*, where I am also co-leader of the utility practice group.

Q. Please summarize your qualifications and experience briefly.

A. I specialize in regulatory and financial economics, especially for electric and gas utilities. I have assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. I have testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning (IRPs), the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions. I am the author of several publications in risk management and recently co-authored a white paper managing gas price volatility.[1] I received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975. A detailed resume and C.V. is attached as Exhibit PPL/701.

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[1] Frank C. Graves and Steven H. Levine, "Managing Natural Gas Price Volatility: Principles and Practices Across the Industry," *American Clean Skies Foundation*, November 2010.

Q. Have you previously testified for PacifiCorp (the Company) in regard to risk management and hedging?

A. Yes. I filed testimony on behalf of the Company before the Public Service Commission of the State of Utah in Docket No. 10-035-124. I also filed testimony in the Company's request for a power cost adjustment mechanism in Utah, Docket No. 09-035-15, some of which addressed risk management and hedging.

Q. What is the purpose of your testimony?

A. I have been asked to review the rebuttal testimonies of Mr. Ed Durrenberger of the Staff of the Public Utility Commission of Oregon (Staff), Messrs. Bob Jenks and Gordon Feighner on behalf of the Citizens' Utility Board of Oregon (CUB) and Mr. Donald Schoenbeck on behalf of the Industrial Customers of Northwest Utilities (ICNU) and to respond to the views on PacifiCorp's hedging policy.

Specifically, I have been asked to address Mr. Schoenbeck's recommendation that substantial hedging costs be disallowed because PacifiCorp, in Mr. Schoenbeck's view, executed "too many transactions too soon"[2] and Messrs. Jenks' and Feighner's recommendation that the costs of certain natural gas hedges that extend beyond 48 months be disallowed. I understand that Messrs. Jenks and Feighner have revised their position regarding hedges in the 37-48 month range, as CUB acknowledges the market now is more liquid than a few years ago.[3]

These intervenors' allegations or concerns are that such hedges were

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[2] ICNU/110, Schoenbeck/10.
[3] CUB/200, Jenks - Feighner/7.

inappropriate due to their tenor, which may involve reduced liquidity and greater exposure to mark-to-market valuation changes than shorter hedges.

Q. What are your general conclusions?

A. I believe that much of this criticism simply reflects hindsight frustration, rather than a finding that PacifiCorp's hedging practices were imprudent. Given the substantial reductions in natural gas prices that have occurred in the past three years due to the recession and shale gas developments, several of PacifiCorp's long-dated hedges entered in 2007-2009 are now out of the money and contribute to an increase in hedging costs in this proceeding. However, regret over realized prices is not an appropriate basis for concluding the hedges were unreasonable. I agree with Staff that "in the context of what was known at the time, … it was prudent…to enter into contracts to lock down long term supply at the then current market price of gas."[4] I disagree with Mr. Schoenbeck's adjustment for hedges over 36 months because PacifiCorp executed "too many transactions too soon," and CUB's view that all hedges over 48 months should be disallowed. I demonstrate that based on what was known and knowable at the time of transactions being questioned, PacifiCorp's hedging length and volumes were reasonable, even after prices began falling in mid-2008 (because risk indicators were still rising well into 2009).

I find that the proposed hedging strategy presented by ICNU as the basis for its adjustment in its rebuttal testimony has not been justified by any analysis other than that in hindsight it would have resulted in lower gas prices under the

[4] Staff/300, Durrenberger/10.

unique conditions of the last few years. The strategy proposed by ICNU would expose customers to additional risks compared to the hedging policies PacifiCorp has used and uses now. No evidence has been presented that reducing the percentage hedged or the tenor and timing of forward hedges (to shorter horizons) would be beneficial in general, so there is no risk management basis for accepting the adjustments.

In general, ICNU's and CUB's rebuttal criticisms of long-dated hedges ignore the fact that the incremental costs of hedging beyond 36 or 48 months (compared to shorter horizons) are in general minimal, especially when offset against the cost savings associated with the use of standard market products to which Mr. Stefan Bird has testified. Indeed, in some cases PacifiCorp's long-dated hedges were less costly in hindsight than shorter hedges that became available in subsequent months would have been. By seeking to disallow hedges beyond 36 months and 48 months, respectively, ICNU and CUB fail to take into account that the alternative to longer dated hedges is not no hedging but rather hedging somewhat later (and possibly adjusting other portfolio positions as well, to maintain risk limits). The difference between the costs of, for example, a hedge for January 2011 entered into in December of 2007 vs. one entered in January 2007 would be modest.

Hedging Too Much Too Soon

Q. ICNU argues that PacifiCorp executed too many hedges too far in advance and therefore was imprudent with respect to hedges beyond 36 months.[5] Messrs. Jenks & Feighner on behalf of CUB reject hedges beyond 48 months.[6] What is your response?

A. I disagree that there is any *per se* flaw or problem with hedging three to four years or more forward. Hedging does not change the expected costs of future supply; it just changes the range and shape of potential costs around that expected level. There is no intrinsically "best shape" to which those potential costs should be constrained; that is a matter of risk tolerances for non-commodity costs the unhedged risks could impose. For the same reason, there is no intrinsically "right" horizon of forward cover (as long as there is reasonable liquidity, as measured by bid-ask spreads and availability of a reasonable number of counterparties.) The relevant horizon depends on the extent of risk reduction and cost predictability that is desired for future periods, i.e., on the risk reduction goals desired by the beneficiaries of the hedging.

What the Company's risk reduction goals should be is certainly an appropriate topic for debate about customer needs and preferences, but it is not fair or reasonable to criticize a practice after the fact because it happens to have resulted in some currently out of the money hedges. In fact, as I explain later,

[5] ICNU/110, Schoenbeck/11. ICNU argues that selected volumes should be disallowed because the Company "hedged [redacted] of test year requirements by [redacted] and lacks documentation to support these transactions." [ICNU/110, Schoenbeck/12.] The allegation that the Company lacks documentation is addressed in the Surrebuttal testimony of Company witness Mr. Bird, so I address only the issue of hedging 37 or more months out.

[6] CUB/200, Jenks - Feighner/8.

such look-back assessments of hedging "success" or disappointment are not appropriate tests of hedging prudence, nor do they provide much guidance about desirable hedging practices.

Q. What specifically does ICNU witness Schoenbeck criticize?

A. Mr. Schoenbeck offers a view of prudence and alternative risk reduction goals that are not grounded in risk management metrics or any review of market conditions prevailing at the time of hedging:

> In my view, entering into transactions that have delivery periods beyond 48 months, or if too many transactions are executed too far in advance, it is imprudent.[7]

He suggests a disallowance of $64.8 million system wide, or $16.2 million Oregon[8], based on his opinion that hedge volume targets should have declined [redacted].[9] The risk management efficacy of this prescription is not addressed in Mr. Schoenbeck's testimony nor quantitatively supported in his workpapers. In my experience, it is unusual and ill-advised to see an adjustment this large and far-reaching with little or no analytical support of its purported economic benefits.

Q. ICNU acknowledges the benefits and costs of hedging.[10] If there are both benefits and costs, how do long-dated hedges help manage these tradeoffs?

A. As noted in Mr. Schoenbeck's rebuttal, companies that engage in hedging will

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[7] ICNU/110, Schoenbeck/11.
[8] ICNU/110, Schoenbeck/3.
[9] Confidential Exhibit ICNU/103, Schoenbeck/15.
[10] ICNU/110, Schoenbeck/12.

experience gains during some time periods and losses during others. Thus, hedging cannot be evaluated in terms of whether it captured such gains and avoided such losses, but in terms of how well it dampened exposures to large swings in natural gas prices. Long-dated hedges can play a useful role in this regard.

Looking at a few key events affecting natural gas during the past decade or so, there were high prices in 2000 – 2001, largely due to the western power crisis, followed by a general drop until around late 2005 when Hurricanes Katrina and Rita hit and pushed gas prices up to $8-10 or more per MMBtu. These abated down to around $5-6/MMBtu for a while, but dramatic global economic expansion and the rapid growth of oil and commodity prices in 2007-2008 caused another spike to around $12. (This was the context facing PacifiCorp at the time of the long-dated hedges criticized in this proceeding.) Then the financial crisis and resulting recession, combined with the shale gas revolution, pushed prices back down to much lower gas price levels today. This low cost pattern may last for a few years, but it is certainly plausible that there will be resurgence to high fuel and power prices once the economy picks up steam, tighter environmental regulations take effect, and perhaps inflation sets in.

The point is not that three-year, four-year, or even longer term hedges are good or bad, but that they can serve a purpose, if desired, of smoothing out long-wave variations in energy market conditions. This will feel like a benefit when the hedges are in-the-money (below current spot or replacement costs) but may be disappointing when they are more expensive. Unfortunately it is not possible to arrange to be exposed to just one of those two possible outcomes. Hedging inherently comes with the possibilities of both after the fact satisfaction and after the fact regret.

Q. Do you have an opinion on what the consequences would be of eliminating hedges beyond 36 or 48 months?

A. Yes. First, I note that if the concern is hedging beyond 36 or 48 months, then the most reasonable comparison is to determine the marginal transaction cost benefit or costs of waiting to hedge until delivery is 36 or 48 months or less ahead. The appropriate comparison or criticism is not to simply throw out cost recovery for such hedges as if nothing would have ever replaced them. PacifiCorp would still have had overall portfolio risk goals to satisfy on behalf of its customers and shareholders, and it would have had the possibility of entering somewhat shorter dated hedges a few months later. Those alternative hedges would likely have had little, if any incremental transaction-cost benefit associated with using slightly shorter dated market products.

Moreover, waiting to hedge with future, shorter dated positions would have increased risks, in addition to changing the realized costs. This occurs for two reasons. First, there is risk (likelihood) that forward prices will change over time while waiting to enter deferred hedges. This intrinsically happens from waiting, even if volatility levels do not change. But second, as is shown in Figure FCG – 4 below, the volatility levels in the market did increase through late 2009. This means that PacifiCorp and its customers would have been facing more and more future risk, the longer the Company waited to hedge.

Q. Some of the criticism for long-dated hedges centers on their alleged illiquidity. Is this a meritorious concern?

A. No. First, as witnesses for Staff and CUB both acknowledge, there is no evidence that markets were illiquid at the time of the transactions.[11] The market for natural gas contracts has become much more liquid in recent years. Specifically, contracts are generally available for well beyond a four-year horizon into the future. This is especially true of bilateral or customized contracts.

Even if the market for long-dated gas contracts were illiquid, that would not necessarily be bad for customers. It is possible to obtain "a good deal" in an illiquid market. Illiquidity should be analyzed in terms of what incremental costs it involves, rather than being used as a *per se* reason for dismissing all of the value of entire positions. For this reason, the fact that a hedge was long-dated does not in any way imply it will be harmful to consumers or is imprudent.

Q. Please comment on Mr. Schoenbeck's recommended hedging strategy on which his adjustment is based.

A. Mr. Schoenbeck reduces the volume hedged and the horizon over which gas hedging occurs. Specifically, Mr. Schoenbeck's strategy reduces the percentage of the Company gas needs (volumes) that is hedged during forward years 1, 2, 3 and 4 and eliminates hedging beyond year 4. In addition, Mr. Schoenbeck's strategy reduces the percentage hedged during April, May, and June to [redacted] of his recommended hedge percentage for other months.[12] Mr.

[11] Staff/300, Durrenberger/6-7; CUB/200, Jenks - Feighner/7.
[12] ICNU/103, Schoenbeck/15.

Schoenbeck's adjustment is based on the difference between the mark to market of the Company's hedging strategy and the strategy he proposes.[13]

Q. Do you have any comments on Mr. Schoenbeck's hedging strategy?

A. Yes. I have several comments. First, Mr. Schoenbeck's strategy does not calculate the benefits or costs associated with reducing hedge targets and waiting longer to hedge. He simply leaves more gas unhedged. Other than showing that his approach would have lower mark to market costs at this time, he offers no general justification for this recommendation. Second, he presents no analysis of how much risk his recommended strategy would impose on the Company or leave open for customers compared to the policy actually used, nor why the greater amount of risk exposure his plan likely entails is a preferred arrangement in general. It is simply a personal view point based on his after-the-fact review from a 2011 perspective. He does not consider how his strategy would have appeared in late 2007 and early 2008 in the face of then-increasing forward prices and volatilities.

I also disagree with Mr. Schoenbeck's recommendation to hedge a smaller percentage of the gas for deliveries in April, May and June than other months. This suggestion is unnecessary, because the Company's "net need" for gas to be hedged already takes the lower consumption of gas in the spring run-off months into account. He is effectively making two adjustments for the hydro season – both a lower quantity needed and a lower proportion of that to be hedged. He offers no theory or explanation for reducing the latter hedging percentage by [redacted]

[13] ICNU/100, Schoenbeck/3.

[redacted] in three months. In fact, the market volatility data I describe below do not support a belief that hydro run-off months are materially less risky than other months.[14] Thus, there is no reason to make an adjustment in hedging targets above and beyond recognizing the reduced expected gas demand in these months.

Q. Do you have any comments on application of ICNU's proposed hedging strategy to the Company on a going-forward basis?

A. Yes. ICNU's strategy is based upon fixed volumetric targets, and dictates a large open position in year one. The strategy is a step backward for PacifiCorp, which has moved to a more sophisticated and flexible TEVaR metric to set hedging targets. Under this approach, the Company's hedged position is not based upon fixed percentages, but rather is set in response to underlying market prices and volatilities. In addition, by reducing the overall volume hedged and leaving a large open position in year one, ICNU's strategy appears better designed for a local gas distribution company with gas storage (such as NW Natural)[15], not an electric company with a resource portfolio as large and complex as PacifiCorp's.

Q. Do witnesses for CUB offer any suggestions for alternative hedging goals or practices?

A. No. Messrs. Jenks and Feighner do not support hedges beyond 48 months, but they do not present any suggestion for an alternative approach. This means there

[14] I evaluated seasonality factors for all the series of broker volatility quotes from late 2007 to the present, and the monthly coefficients for April, May, and June averaged [redacted] with a range from [redacted] of the non-seasonal volatility. A coefficient of 1.0 would mean that these months do not have any expected difference in volatility from other months. Table FCG-A1 in the appendix included as Confidential Exhibit PPL/702 shows these monthly seasonality coefficients.

[15] Even though many gas distribution companies also rely on much more complex hedging strategies than the one proposed by ICNU.

is no basis for assuming the risks or even *ex post* costs of their preferred alternative would have been lower or more reasonable.

Known and Knowable at the Time

Q. ICNU has described PacifiCorp's hedging policies as imprudent, but has not offered a normative view of how to define prudence.[16] In your view, how should prudence be defined?

A. Any reasonable standards for prudence and cost recovery of a hedging policy should be forward looking. Hindsight comparisons based on a single period of recent history will not generally be informative because they are a single "snapshot" of just one of many possible outcomes that might have occurred. Historical analysis of hedging is useful <u>only if</u> the same kind of review can be applied on many occasions over a long period of time, with the same underlying risk conditions and hedging approach being used consistently throughout. For electricity and gas markets, this is a very strong condition to impose. If market conditions are not stationary, system configuration changes (e.g., more gas plants, more renewables on the system, different hydro runoff, etc.), or the company's hedging approach evolves, then hindsight snapshots are purely circumstantial views.

Instead of hindsight tests based on circumstantial *ex post* gains or losses, prudence should be evaluated by whether reasonable risk reduction goals were pursued, making good use of available information, with appropriate risk management techniques and controls for the type and timing of hedges applied.

[16] ICNU/110, Schoenbeck/11.

Q. Is a hindsight review contrary to a proper prudence analysis?

A. Yes. Prudence has to be judged on what was known and knowable at the time about prospective risk. Staff witness Durrenberger appears to agree with the assessment and states that: "… in the context of what was known at the time, specifically that natural gas prices were increasing every year and that domestic supplies of gas were forecast to be in decline, that it was prudent [for] PacifiCorp to enter into contracts to lock down long term supply at the then current market price of gas."[17]

Q. Mr. Durrenberger also notes that natural gas forward prices for 2011-12 delivery were increasing during the 2007-08 period and that at the time the energy companies on the west coast were planning the development of large, expensive import terminals for liquefied natural gas (LNG) to reduce exposure to future increases in gas prices. He finds that in this timeframe, forward gas prices "were a reasonable forecast of future prices of natural gas."[18] Do you agree?

A. Yes. During the 2007-08 time frame, natural gas production was expected to decline while increased importation of gas through LNG terminals was viewed as the likely solution to increasing prices and declining supply. For example, an April 2008 report from the National Energy Technology Laboratory on behalf of the Department of Energy forecast foresaw a decline in U.S. gas production of almost 2 Tcf per year (or approximately 10 percent from 2007 to 2015.)[19] The significant drops in gas and electricity demand that resulted from the financial

[17] Staff/300, Durrenberger/10.
[18] Staff/300, Durrenberger/8.
[19] DOE / NETL-2008/1320, "Natural Gas and Electricity Costs and Impacts on the Industry," Figure 1.

crisis and recession, as well as the rapid emergence of inexpensive shale gas that supplanted these prior expectations by 2009 and beyond were not foreseen or foreseeable at the time of the hedges in dispute in this case.

The fact that the market expected natural gas prices to rise or remain high is illustrated by the series of forward price strips shown in Figure FCG - 1. This shows that from approximately October 2007 to July 2008, PacifiCorp was looking at steadily increasing forward prices from that time through to 2011-12 deliveries. For instance, in Figure FCG – 1 the forward price curve as of November 2007 (green) is above the October 2007 strip (black), and the strip as of April 2008 (red) is above the November 2007 curve. July 2008 (purple) is yet higher, and it represents the peak after which the forward price of natural gas starts to decline.[20] This pattern of rising forward natural gas prices indicates market concerns about supply adequacy were growing stronger, which in turn supports long term forward hedging. In fact, the rise in forward prices means that hedges entered in late 2007 were generally cheaper than hedges entered over the first six months of 2008. Certainly, there was no evidence of a pending decline in gas prices in the forward curve until after July 2008.

[20] See also the illustration of the development in forward prices in Figure 3 of PPL/400, Bird/32.

Figure FCG - 1

[redacted]

Q. Did the volatility of gas prices evolve in a similar way throughout this time frame?

Yes. In addition to the forward price curve for natural gas increasing until mid-2008, volatility was also increasing. In fact, natural gas volatility rose for more than a year longer, through late 2009. This is evident in broker quotes (obtained from the Company) on volatilities associated with each future delivery month for each forward price curve from the fall of 2007 to the present. Brokers' quoted volatilities are derived from (or implied by) a standard financial model, the Black-

Scholes option model for pricing options on gas futures.[21] Volatility, usually expressed as the annualized standard deviation of prices, is a measure of how far from its expected value the price could become by the time the option has to be exercised. The larger the volatility, the higher the prices will be, and vice versa (everything else being equal). Thus, if we know the forward price of natural gas and the prices of options for that same time of delivery, we can derive the implied volatility.

Q. What do volatility quotes look like?

A. They are quoted as a percentage price uncertainty for each future month, where each value represents the standard deviation of how much that month's forward price currently tends to change per day in percentage (scaled up to an annualized equivalent value). There is a different percentage for each forward month, and the overall pattern of these monthly percentages is called the volatility term structure. The typical volatility term structure declines as the time to delivery increases, so that the short-term volatility is larger than the long-term (far out) volatility. This pattern is observed because short term risk factors (such as weather) often do not have much influence on long term expectations or risks. In addition, the term structure of volatility typically exhibits seasonal effects. I estimate the short-term, long-term and seasonal coefficients that best fit the quoted volatility data from the Company. The technical detail of the estimation is in Confidential Exhibit PPL/702 (Appendix A) to this testimony. Figure FCG – 2

[21] The Black-Scholes formula is a widely used mathematical (and equilibrium economic) relationship between the forward price of a security or commodity like natural gas, the current spot price, time to delivery, and the volatility of the price.

below shows an example of the quoted (black line) and fitted (red line) volatility describing market expectations as of October 2007.

Figure FCG - 2

[redacted]

I will focus on how these fitted parameters changed over the time frame from mid-2007 to late 2009 in my analysis of risk expectations facing PacifiCorp.

Q. How do you use the fitted volatility?

A. At each point in time, when PacifiCorp entered a hedge, the volatility conditions foreseen in the market would have shifted. For instance, the volatility quotes seen above in Figure FCG – 2 for October 1, 2007 were no longer applicable to the market in the subsequent months. Some examples of how volatility changed over time are seen in Figure FCG – 3 below.

Figure FCG - 3

[redacted]

To see if there is any general trend in such curves, I obtained a series of monthly updates to quoted volatilities from June 2007 through December 2009, for each of which I estimated the short-term, long term as well as monthly seasonality coefficients going forward for each transaction date. From this, I could observe how the volatility facing the Company was changing over time. The result is shown in Figure FCG – 4.

Figure FCG - 4

[redacted]

This figure clearly shows that both short and long term volatility rose, albeit unevenly, throughout almost all of this two year period. Indeed, short run volatility more than doubled, while the long term grew by a few percent.

Q. What are the implications of this price and volatility history for gas hedging practices throughout this timeframe?

A. Figures FCG – 1 and FCG - 4 demonstrate why it was reasonable for PacifiCorp to have hedged long-dated delivery periods throughout 2007, 2008 and 2009. The market forward curves in mid-07 through mid-08 were rising, while market volatility was rising for longer, from mid-07 to late ‘09. Therefore, long-dated hedges struck in late 2007 and early 2008 were increasingly in-the-money for several months after they were struck, and they helped avoid growing market volatility for nearly two more years. I note that this reduction in exposure to growing market volatility goes well beyond the time when the forward hedges would have been struck had the company entered into only 48 months long contracts.

Even though prices fell once the financial crisis began, there is no evidence that the natural gas market foresaw the large drop in natural gas prices.

Conclusion

Q. Given the disagreements with ICNU and to a lesser extent with CUB over the desirable extent and horizon of hedging to use, and the lack of a shared concept of prudence, how would you suggest these tensions be resolved?

A. Staff has suggested that PacifiCorp engage stakeholders in workshops that review the Company's hedging policy and provide input to the Company.[22] I agree with this suggestion. Workshops could be used to achieve a common understanding of the tradeoffs among benefits, costs, and risks, as well as constraints on alternative types and degrees of hedging. These could lead to an agreed upon set of goals, hedging practices, reporting, and standards of regulatory review.

Q. Does this conclude your testimony?

A. Yes.

[22] Staff/300, Durrenberger/12.

Docket No. UE-227
Exhibit PPL/701
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Frank C. Graves

Resume of Frank C. Graves

August 2011

Mr. Frank Graves is a Principal of *The Brattle Group* who specializes in regulatory and financial economics, especially for electric and gas utilities. He has assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. He also provides consulting and expert witness support for commercial litigation matters, such as contract disputes and securities fraud proceedings. He has testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning (IRPs), the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions.

In the area of financial economics, he has assisted and testified for companies in regard to contract damages estimation, securities litigation suits, special purpose audits, tax disputes, risk management, and cost of capital estimation.

He received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975.

AREAS OF EXPERTISE

- *Utility Planning and Operations*
- *Regulated Industry Restructuring*
- *Market Competition*
- *Electric and Gas Transmission*
- *Financial Analysis*

EXPERIENCE

Utility Planning and Operations

- Air quality and other power plant environmental regulations are being tightened considerably in the period from about 2014-2018. Mr. Graves has co-developed a market and financial model for determining what power plants are most likely to retire vs. retrofit with new environmental controls, and how much this may alter their profitability. This has been used to help several power market participants assess future capacity needs, as well as to adjust their price forecasts for the coming decade.

- Merchant power plant development and financing depends in part on obtaining a long term power purchase agreement. Mr. Graves directed a study of what pricing points and risk-sharing terms should be attractive to potential buyers of long-term power supply contracts from a large baseload facility.

- Many utilities are pursuing smart meters and time-of-use pricing to increase customer ability to consume electricity economically. Mr. Graves has led a study of the costs and benefits of different scales and timing of installation of such meters, to determine the appropriate pace. He has also evaluated how various customer incentives to increase conservation and demand response might be provided over the internet, and how much they might increase the participation rates in smart meter programs.

- Wind resources are becoming a critical part of the generation expansion plans and contracting interests of many utilities, in order to satisfy renewable portfolio standards and to reduce long run exposure to carbon prices and fuel cost uncertainty. Mr. Graves has applied *Brattle*'s risk modeling capabilities to simulate the impacts of wind resources on the potential range of costs for portfolios of wholesale power contracts designed to serve retail electricity loads. He has also assessed the amount and costs of additional ancillary services that may be required to successfully integrate large quantities of wind generation on the transmission grid.

- The potential introduction of environmental restrictions or fees for CO_2 emissions has made generation expansion decisions much more complex and risky. He helped one utility assess these risks in regard to a planned baseload coal plant, finding that the value of flexibility in other technologies was high enough to prefer not building a conventional coal plant.

- Mr. Graves helped design, implement, and gain regulatory approvals for a natural gas procurement hedging program for a western U.S. gas and electric utility. A model of how gas forward prices evolve over time was estimated and combined with a statistical model of the term structure of gas volatility to simulate the uncertainty in the annual cost of gas at various times during its procurement, and the resulting impact on the range of potential customer costs.

- Generation planning for utilities has become very complex and risky due to high natural gas prices and potential CO2 restrictions of emission allowances. Some of the scenarios that must be considered would radically alter system operations relative to current patterns of use. Mr. Graves has assisted utilities with long range planning for how to measure and cope with these risks, including how to build and value contingency plans in their resource selection criteria, and what kinds of regulatory communications to pursue to manage expectations in this difficult environment.

- Several utilities with coal-fired power plants have faced allegations from the U.S. EPA that they have conducted past maintenance on these plants which should be deemed "major modifications", thereby triggering New Source Review standards for air quality controls. Mr. Graves has helped one such utility assess limitations on the way in which GADS data can be used retrospectively to quantify comparisons between past actual and projected future emissions. For another utility, Mr. Graves developed retrospective estimates of changes in emissions before and after repairs using production costing simulations. In a third, he reviewed contemporaneous corporate planning documents to show that no increase in emissions would have been expected from the repairs, due to projected reductions in future use of the plant as well as higher efficiency. In all three cases, testimony was presented.

- The U.S. Government is contractually obligated to dispose of spent nuclear fuel at commercial reactors after January 1998, but it has not fulfilled this duty. As a result, nuclear facilities that are shutdown or facing full spent fuel pools are facing burdensome costs and risks. Mr. Graves prepared developed an economic model of the performance that could have reasonably been expected of the government, had it not breached its contract to remove the spent fuel.

- Capturing the full value of hydroelectric generation assets in a competitive power market is heavily dependent on operating practices that astutely shift between real power and ancillary services markets, while still observing a host of non-electric hydrological constraints. Mr. Graves led studies for several major hydro generation owners in regard to forecasting of market conditions and corresponding hydro schedule optimization. He has also designed transfer pricing procedures that create an internal market for diverting hydro assets from real power to system support services firms that do not yet have explicit, observable market prices.

- Mr. Graves led a gas distribution company in the development of an incentive ratemaking system to replace all aspects of its traditional cost of service regulation. The base rates (for non-fuel operating and capital costs) were indexed on a price-cap basis (RPI-X), while the gas and upstream transportation costs allowances were tied to optimal average annual usage of a reference portfolio of supply and transportation contracts. The gas program also included numerous adjustments to the gas company's rate design, such as designing new standby rates so that customer choice will not be distorted by pricing inefficiencies.

- An electric utility with several out-of-market independent power contracts wanted to determine the value of making those plants dispatchable and to devise a negotiating strategy for restructuring the IPP agreements. Mr. Graves developed a range of forecasts for the delivered price of natural gas to this area of the country. Alternative ways of sharing the potential dispatch savings were proposed as incentives for the IPPs to renegotiate their utility contracts.

- For an electric utility considering the conversion of some large oil-fired units to natural gas, Mr. Graves conducted a study of the advantages of alternative means of obtaining gas supplies and gas transportation services. A combination of monthly and daily spot gas supplies, interruptible pipeline transportation over several routes, gas storage services, and "swing" (contingent) supply contracts with gas marketers was shown to be attractive. Testimony was presented on why the additional services of a local distribution company would be unneeded and uneconomic.

- A power engineering firm entered into a contract to provide operations and maintenance services for a cogenerator, with incentives fees tied to the unit's availability and operating cost. When the fees increased due to changes in the electric utility tariff to which they were tied, a dispute arose. Mr. Graves provided analysis and testimony on the avoided costs associated with improved cogeneration performance under a variety of economic scenarios and under several alternative utility tariffs.

- Mr. Graves has helped several pipelines design incentive pricing mechanisms for recovering their expected costs and reducing their regulatory burdens. Among these have been Automatic Rate Adjustment Mechanisms (ARAMs) for indexation of operations and maintenance expenses, construction-cost variance-sharing for routine capital expenditures that included a procedure for eliciting unbiased estimates of future costs, and market-based prices capped at replacement costs when near-term future expansion was an uncertain but probable need.

- For a major industrial gas user, he prepared a critique of the transportation balancing charges proposed by the local gas distribution company. Those charges were shown to be arbitrarily sensitive to the measurement period as well as to inconsistent attribution of storage versus replacement supply costs to imbalance volumes. Alternative balancing valuation and accounting methods were shown to be cheaper, more efficient, and simpler to administer. This analysis helped the parties reach a settlement based on a cash-in/cash-out design.

- The Clean Air Act Amendments authorized electric utilities to trade emission allowances (EAs) as part of their approach to complying with SO_2 emissions reductions targets. For the Electric Power Research Institute (EPRI), Mr. Graves developed multi-stage planning models to illustrate how the considerable uncertainty surrounding future EA prices justifies waiting to invest in irreversible control technologies, such as scrubbers or SCRs, until the present value cost of such investments is significantly below that projected from relying on EAs.

- For an electric utility with a troubled nuclear plant, Mr. Graves presented testimony on the economic benefits likely to ensue from a major reorganization. The plant was to be spun off to a jointly-owned subsidiary that would sell available energy back to the original owner under a contract indexed to industry unit cost experience. This proposal afforded a considerable reduction of risk to ratepayers in exchange for a reasonable, but highly uncertain prospect of profits for new investors. Testimony compared the incentive benefits and potential conflicts under this arrangement to the outcomes foreseeable from more conventional incentive ratemaking arrangements.

- Mr. Graves helped design Gas Inventory Charge (GIC) tariffs for interstate pipelines seeking to reduce their risks of not recovering the full costs of multi-year gas supply contracts. The costs of holding supplies in anticipation of future, uncertain demand were evaluated with models of the pipeline's supply portfolio that reveal how many non-production costs (demand charges, take-or-pay penalties, reservation fees, or remarketing costs for released gas) would accrue under a range of demand scenarios. The expected present value of these costs provided a basis for the GIC tariff.

- Mr. Graves performed a review and critique of a state energy commission's assessment of regional natural gas and electric power markets in order to determine what kinds of pipeline expansion into the area was economic. A proposed facility under review for regulatory approval was found to depend strongly on uneconomic bypass of existing pipelines and LDCs. In testimony, modular expansion of existing pipelines was shown to have significantly lower costs and risks.

- For several electric utilities with generation capacity in excess of target reserve margins, Mr. Graves designed and supervised market analyses to identify resale opportunities by comparing the marginal operating costs of all this company's power plants not needed to meet target reserves to the marginal costs for almost 100 neighboring utilities. These cost curves were then overlaid on the corresponding curve for the client utility to identify which neighbors were competitors and which were potential customers. The strength of their relative threat or attractiveness could be quantified by the present value of the product of the amount, duration, and differential cost of capacity that was displaceable by the client utility.

- Mr. Graves specified algorithms for the enhancement of the EPRI EGEAS generation expansion optimization model, to capture the first-order effects of financial and regulatory constraints on the preferred generation mix.

- For a major electric power wholesaler, Mr. Graves developed a framework for estimating how pricing policies affect the relative attractiveness of capacity expansion alternatives. Traditional cost-recovery pricing rules can significantly distort the choice between two otherwise equivalent capacity plans, if one includes a severe "front end load" while the other does not. Price-demand feedback loops in simulation models and quantification of consumer satisfaction measures were used to appraise the problem. This "value of service" framework was generalized for the Electric Power Research Institute.

- For a large gas and electric utility, Mr. Graves participated in coordinating and evaluating the design of a strategic and operational planning system. This included computer models of all aspects of utility operations, from demand forecasting through generation planning to financing and rate design. Efforts were split between technical contributions to model design and attention to organizational priorities and behavioral norms with which the system had to be compatible.

- For an oil and gas exploration and production firm, Mr. Graves developed a framework for identifying what industry groups were most likely to be interested in natural gas supply contracts featuring atypical risk-sharing provisions. These provisions, such as price indexing or performance requirements contingent on market conditions, are a form of product differentiation for the producer, allowing it to obtain a price premium for the insurance-like services.

- For a natural gas distribution company, Mr. Graves established procedures for redefining customer classes and for repricing gas services according to customers' similarities in load shape, access to alternative gas supplies, expected growth, and need for reliability. In this manner, natural gas service was effectively differentiated into several products, each with price and risk appropriate to a specific market. Planning tools were developed for balancing gas portfolios to customer group demands.

- For a Midwestern electric utility, Mr. Graves extended a regulatory *pro forma* financial model to capture the contractual and tax implications of canceling and writing off a nuclear power plant in mid-construction. This possibility was then appraised relative to completion or substitution alternatives from the viewpoints of shareholders (market value of common equity) and ratepayers (present value of revenue requirements).

- For a corporate venture capital group, Mr. Graves conducted a market-risk assessment of investing in a gas exploration and production company with contracts to an interstate pipeline. The pipeline's market growth, competitive strength, alternative suppliers, and regulatory exposure were appraised to determine whether its future would support the purchase volumes needed to make the venture attractive.

- For a natural gas production and distribution company, he developed a strategic plan to integrate the company's functional policies and to reposition its operations for the next five years. Decision analysis concepts were combined with marginal cost estimation and financial *pro forma* simulation to identify attractive and resilient alternatives. Recommendations included target markets, supply sources, capital budget constraints, rate design, and a planning system. A two-day planning conference was conducted with the client's executives to refine and internalize the strategy.

- For the New Mexico Public Service Commission, he analyzed the merits of a corporate reorganization of the major New Mexico gas production and distribution company. State ownership of the company as a large public utility was considered but rejected on concerns over efficiency and the burdening of performance risks onto state and local taxpayers.

Regulated Industry Restructuring

- For several utilities facing the end of transitional "provider of last resort" (or POLR) prices, Mr. Graves developed forecasts and risk analyses of alternative procurement mechanisms for follow-on POLR contracts. He compared portfolio risk management approaches to full requirements outsourcing under various terms and conditions.

- For a large municipal electric and gas company considering whether to opt-in to state retail access programs, Mr. Graves lead an analysis of what changes in the level and volatility of customer rates would likely occur, what transition mechanisms would be required, and what impacts this would have on city revenues earned as a portion of local electric and gas service charges.

- Many utilities experienced significant "rate shock" when they ended "rate freeze" transition periods that had been implemented with earlier retail restructuring. The adverse customer and political reactions have lead to proposals to annual procurement auctions and to return to utility-owned or managed supply portfolios. Mr. Graves has assisted utilities and wholesale gencos with analyses of whether alternative supply procurement arrangements could be beneficial.

- The impacts of transmission open access and wholesale competition on electric generators risks and financial health are well documented. In addition, there are substantial impacts on fuel suppliers, due to revised dispatch, repowerings and retirements, changes in expansion mix, altered load shapes and load growth under more competitive pricing. For EPRI, Mr. Graves co-authored a study that projected changes in fuel use within and between ten large power market regions spanning the country under different scenarios for the pace and success of restructuring.

- As a result of vertical unbundling, many utilities must procure a substantial portion of their power from resources they do not own or operate. Market prices for such supplies are quite volatile. In addition, utilities may face future customer switching to or from their supply service, especially if they are acting as provider of last resort (POLR). This problem is a blending of risk management with the traditional least-cost Integrated Resource Planning (IRP). Regulatory standards for findings of prudence in such a hybrid environment are often not well understood or articulated, leaving utilities at risk for cost disallowances that can jeopardize their credit-worthiness. Mr. Graves has assisted several utilities in devising updated procurement mechanisms, hedging strategies, and associated regulatory guidelines that clarify the conditions for approval and cost recovery of resource plans, in order to make possible the expedited procurement of power from wholesale market suppliers.

- Public power authorities and cooperatives face risks from wholesale restructuring if their sales-for-resale customers are free to switch to or from supply contracting with other wholesale suppliers. Such switching can create difficulties in servicing the significant debt capitalization of these public power entities, as well as equitable problems with respect to non-switching customers. Mr. Graves has lead analyses of this problem, and has designed alternative product pricing, switching terms and conditions, and debt capitalization policies to cope with the risks.

- As a means of unbundling to retain ownership but not control of generation, some utilities turned to divesting output contracts. Mr. Graves was involved in the design and approval of such agreements for a utility's fleet of generation. The work entailed estimating and projecting cost functions that were likely to track the future marginal and total costs of the units and analysis of the financial risks the plant operator would bear from the output pricing formula. Testimony on risks under this form of restructuring was presented.

- Mr. Graves contributed to the design and pricing of unbundled services on several natural gas pipelines. To identify attractive alternatives, the marginal costs of possible changes in a pipeline's service mix were quantified by simulating the least-cost operating practices subject to the network's physical and contractual constraints. Such analysis helped one pipeline to justify a zone-based rate design for its firm transportation service. Another pipeline used this technique to demonstrate that unintended degradations of system performance and increased costs could ensue from certain proposed unbundlings that were insensitive to system operations.

- For several natural gas pipeline companies, Mr. Graves evaluated the cost of equity capital in light of the requirements of FERC Order 636 to unbundle and reprice pipeline services. In addition to traditional DCF and risk positioning studies, the risk implications of different degrees of financial leverage (debt capitalization) were modeled and quantified. Aspects of rate design and cost allocation between services that also affect pipeline risk were considered.

- Mr. Graves assisted several utilities in forecasting market prices, revenues, and risks for generation assets being shifted from regulated cost recovery to competitive, deregulated wholesale power markets. Such studies have facilitated planning decisions, such as whether to divest generation or retain it, and they have been used as the basis for quantifying stranded costs associated with restructuring in regulatory hearings. Mr. Graves has assisted a leasing company with analyses of the tax-legitimacy of complex leasing transactions by reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent of defeasance, and compliance with prevailing guidelines for true-lease status.

Market Competition

- Mr. Graves has testified on the quality of retail competition in Pennsylvania and on whether various proposals for altering Default Service might create more robust competition.

- Regulatory and legal approvals of utility mergers require evidence that the combined entity will not have undue market power. Mr. Graves assisted several utilities in evaluating the competitive impacts of potential mergers and acquisitions. He has identified ways in which transmission constraints reduce the number and type of suppliers, along with mechanisms for incorporating physical flow limits in FERC's Delivered Price Test (DPT) for mergers. He has also assessed the adequacy of mitigation measures (divestitures and conduct restrictions) under the DPT, Market-Based Rates, and other tests of potential market power arising from proposed mergers.

- A major concern associated with electric utility industry restructuring is whether or not generation markets are adequately competitive. Because of the state-dependent nature of transmission transfer capability between regions, itself a function of generation use, the quality of competition in the wholesale generation markets can vary significantly and may be susceptible to market power abuse by dominant suppliers. Mr. Graves helped one of the largest ISOs in the U.S. develop market monitoring procedures to detect and discourage market manipulations that would impair competition.

- Vertical market power arises when sufficient control of an upstream market creates a competitive advantage in a downstream market. It is possible for this problem to arise in power supply, in settings where the likely marginal generation is dependent on very few fuel suppliers who also have economic interests in the local generation market. Mr. Graves analyzed this problem in the context of the California gas and electric markets and filed testimony to explain the magnitude and manifestations of the problem.

- The increased use of transmission congestion pricing has created interest in merchant transmission facilities. Mr. Graves assisted a developer with testimony on the potential impacts of a proposed line on market competition for transmission services and adjacent generation markets. He also assisted in the design of the process for soliciting and ranking bids to buy tranches of capacity over the line.

- Many regions have misgivings about whether the preconditions for retail electric access are truly in place. In one such region, Mr. Graves assisted a group of industrial customers with a critique of retail restructuring proposals to demonstrate that the locally weak transmission grid made adequate competition among numerous generation suppliers very implausible.

- Mr. Graves assisted one of the early ISOs with its initial market performance assessment and its design of market monitoring tests for diagnosing the quality of prevailing competition.

Electric and Gas Transmission

- Substantial fleets of wind-based generation can impose significant integration costs on power systems. Mr. Graves assisted in assessing what additional amounts and costs for ancillary services would be needed for a large Western utility.

- For a utility seeking FERC approval for the purchase of an affiliate's generating facility, Mr. Graves analyzed how transmission constraints affecting alternative supply resources altered their usefulness to the buyer.

- As part of a generation capacity planning study, he lead an analysis of how congestion premiums and discounts relative to locational marginal prices (LMPs) at load centers affected the attractiveness of different potential locations for new generation. At issue was whether the prevailing LMP differences would be stable over time, as new transmission facilities were completed, and whether new plants could exacerbate existing differentials and lead to degraded market value at other plants.

- Mr. Graves assisted a genco with its involvement in the negotiation and settlement of "regional through and out rates" (RTOR) that were to be abolished when MISO joined PJM. His team analyzed the distribution of cost impacts from several competing proposals, and they commented on administrative difficulties or advantages associated with each.

- For the electric utility regulatory commission of Colombia, S.A., Mr. Graves led a study to assess the inadequacies in the physical capabilities and economic incentives to manage voltages at adequate levels. The *Brattle* team developed minimum reactive power support obligations and supplement reactive power acquisition mechanisms for generators, transmission companies, and distribution companies.

- Mr. Graves conducted a cost-of-service analysis for the pricing of ancillary services provided by the New York Power Authority.

- On behalf of the Electric Power Research Institute (EPRI), Mr. Graves wrote a primer on how to define and measure the cost of electric utility transmission services for better planning, pricing, and regulatory policies. The text covers the basic electrical engineering of power circuits, utility practices to exploit transmission economies of scale, means of assuring system stability, economic dispatch subject to transmission constraints, and the estimation of marginal costs of transmission. The implications for a variety of policy issues are also discussed.

- The natural gas pipeline industry is wedged between competitive gas production and competitive resale of gas delivered to end users. In principle, the resulting basis differentials between locations around the pipeline ought to provide efficient usage and expansion signals, but traditional pricing rules prevent the pipeline companies from participating in the marginal value of their own services. Mr. Graves worked to develop alternative pricing mechanisms and service mixes for pipelines that would provide more dynamically efficient signals and incentives.

- Mr. Graves analyzed the spatial and temporal patterns of marginal costs on gas and electric utility transmission networks using optimization models of production costs and network flows. These results were used by one natural gas transmission company to design receipt-point-based transmission service tariffs, and by another to demonstrate the incremental costs and uneven distribution of impacts on customers that would result from a proposed unbundling of services.

Financial Analysis

- Holding company utilities with many subsidiaries in different states face differing kinds of regulatory allowances, balancing accounts with differing lags and allowed returns for cost recovery, possibly different capital structures, as well as different (and varying) operating conditions. Given such heterogeneity, it can be difficult to determine which subsidiaries are performing well vs. poorly relative to their regulatory and operational challenges. Mr. Graves developed a set of financial reporting normalization adjustments to isolate how much of each subsidiary's profitability was due to financial, vs. managerial, vs. non-recurring operational conditions, so that meaningful performance appraisal was possible.

- Many banks, insurance firms and capital management subsidiaries of large multinational corporations have entered into long term, cross border leases of properties under sale and leaseback or lease in, lease out terms. These have been deemed to be unacceptable tax shelters by the IRS, but that is an appealable claim. Mr. Graves has assisted several companies in evaluating whether their cross border leases had legitimate business purpose and economic substance, above and beyond their tax benefits, due to likelihood of potentially facing a role as equityholder with ownership risks and rewards. He has shown that this is a case-specific matter, not per se determined by the general character of these transactions.

- Many utilities have regulated and unregulated subsidiaries, which face different types and degrees of risk. Mr. Graves lead a study of the appropriate adjustments to corporate hurdle rates for the various lines of business of a utility with many types of operations.

- A company that incurred Windfall Tax liabilities in the U.K. regarded those taxes as creditable against U.S. income taxes, but this was disputed by the IRS. Mr. Graves lead a team that prepared reports and testimony on why the Windfall Tax had the character of a typical excess profits tax, and so should be deemed creditable in the U.S. The tax courts concurred with this opinion and allowed the claimed tax deductions in full.

- For a defendant in a sentencing hearing for securities' fraud, Mr. Graves prepared an analysis of how the defendant's role in the corporate crisis was confounded by other concurrent events and disclosures that made loss calculations unreliable. At trial, the Government stipulated that it agreed with Mr. Graves' analysis.

- For the U.S. Department of Justice, Mr. Graves prepared an event study quantifying bounds on the economic harm to shareholders that had likely ensued from revelations that Dynegy Corporation's "Project Alpha" had been improperly represented as a source of operating income rather than as a financing. The event study was presented in the re-sentencing hearing of Mr. Jamie Olis, the primary architect of Project Alpha.

- Mr. Graves has assisted leasing companies with analyses of the tax-legitimacy of complex leasing transactions. These analyses involved reviewing the extent and quality of due diligence pursued by the lessor, the adequacy of pre-tax returns, the character, time pattern, and degree of risk borne by the buyer (lessor), the extent, purpose and cost of defeasance, and compliance with prevailing guidelines for true-lease status.

- For a utility facing significant financial losses from likely future costs of its Provider of Last Resort (POLR) obligations, Mr. Graves prepared an analysis of how optimal hindsight coverage would have compared in costs to a proposed restructuring of the obligation. He also reviewed the prudence of prior, actual coverage of the obligation in light of conventional risk management practices and prevailing market conditions of credit constraints and low long-term liquidity.

- Several banks were accused of aiding and abetting Enron's fraudulent schemes and were sued for damages. Mr. Graves analyzed how the stock market had reacted to one bank's equity analyst's reports endorsing Enron as a "buy," to determine if those reports induced statistically significant positive abnormal returns. He showed that individually and collectively they did not have such an effect.

- Mr. Graves lead an analysis of whether a corporate subsidiary had been effectively under the strategic and operational control of its parent, to such an extent that it was appropriate to "pierce the corporate veil" of limited liability. The analysis investigated the presence of untenable debt capitalization in the subsidiary, overlapping management staff, the adherence to normal corporate governance protocols, and other kinds of evidence of excessive parental control.

- As a tax-revenue enhancement measure, the IRS was considering a plan to recapture deferred taxes associated with generation assets that were divested or reorganized during state restructurings for retail access. Mr. Graves prepared a white paper demonstrating the unfairness and adverse consequences of such a plan, which was instrumental in eliminating the proposal.

- For a major electronic and semiconductor firm, Mr. Graves critiqued and refined a proposed procedure for ranking the attractiveness of research and development projects. Aspects of risk peculiar to research projects were emphasized over the standards used for budgeting an already proven commercial venture.

- In a dispute over damages from a prematurely terminated long-term power tolling contract, Mr. Graves presented evidence on why calculating the present value of those damages required the use of two distinct discount rates: one (a low rate) for the revenues lost under the low-risk terminated contract and another, much higher rate, for the valuation of the replacement revenues in the risky, short-term wholesale power markets. The amount of damages was dramatically larger under a two-discount rate calculation, which was the position adopted by the court.

- The energy and telecom industries have been plagued by allegations regarding trading and accounting misrepresentations, such as wash trades, manipulations of mark-to-market valuations, premature recognition of revenues, and improper use of off-balance sheet entities. In many cases, this conduct has preceded financial collapse and subsequent shareholder suits. Mr. Graves lead research on accounting and financial evidence, including event studies of the stock price movements around the time of the contested practices, and reconstruction of accounting and economic justifications for the way asset values and revenues were recorded.

- Dramatic natural gas price increases in the U.S. have put several natural gas and electric utilities in the position of having to counter claims that they should have hedged more of their fuel supplies at times in the past. Mr. Graves developed testimony to rebut this hindsight criticism and risk management techniques for fuel (and power) procurement for utilities to apply in the future to avoid prudence challenges.

- As a means of calculating its stranded costs, a utility used a partial spin-off of its generation assets to a company that had a minority ownership from public shareholders. A dispute arose as to whether this minority ownership might be depressing the stock price, if a "control premium" was being implicitly deducted from its value. Using event studies and structural analyses, Mr. Graves identified the key drivers of value for this partially spun-off subsidiary, and he showed that value was not being impaired by the operating, financial and strategic restrictions on the company. He also reviewed the financial economics literature on empirical evidence for control premiums, which he showed reinforced the view that no control premium de-valuation was likely to be affecting the stock.

- A large public power agency was concerned about its debt capacity in light of increasing competitive pressures to allow its resale customers to use alternative suppliers. Mr. Graves lead a team that developed an Economic Balance Sheet representation of the agency's electric assets and liabilities in market value terms, which was analyzed across several scenarios to determine safe levels of debt financing. In addition, new service pricing and upstream supply contracting arrangements were identified to help reduce risks.

- Wholesale generating companies intuitively realize that there are considerable differences in the financial risk of different kinds of power plant projects, depending on fuel type, length and duration of power purchase agreements, and tightness of local markets. However, they often are unaware of how if at all to adjust the hurdle rates applied to valuation and development decisions. Mr. Graves lead a Brattle analysis of risk-adjusted discount rates for generation; very substantial adjustments were found to be necessary.

- A major telecommunications firm was concerned about when and how to reenter the Pacific Rim for wireless ventures following the economic collapse of that region in 1997-99. Mr. Graves lead an engagement to identify prospective local partners with a governance structure that made it unlikely for them to divert capital from the venture if markets went soft. He also helped specify contracting and financing structures that create incentives for the venture to remain together should it face financial distress, while offering strong returns under good performance.

- There are many risks associated with operations in a foreign country, related to the stability of its currency, its macro economy, its foreign investment policies, and even its political system. Mr. Graves has assisted firms facing these new dimensions to assess the risks, identify strategic advantages, and choose an appropriate, risk-adjusted hurdle rate for the market conditions and contracting terms they will face.

- The glut of generation capacity that helped usher in electric industry restructuring in the US led to asset devaluations in many places, even where no retail access was allowed. In some cases, this has led to bankruptcy, especially of a few large rural electric cooperatives. Mr. Graves assisted one such coop with its long term financial modeling and rate design under its plan of reorganization, which was approved. Testimony was provided on cost-of-service justifications for the new generation and transmission prices, as well as on risks to the plan from potential environmental liabilities.

- Power plants often provide a significant contribution to the property tax revenues of the townships where they are located. A common valuation policy for such assets has been that they are worth at least their book value, because that is the foundation for their cost recovery under cost-of-service utility ratemaking. However, restructuring throws away that guarantee, requiring reappraisal of these assets. Traditional valuation methods, *e.g.*, based on the replacement costs of comparable assets, can be misleading because they do not consider market conditions. Mr. Graves testified on such matters on behalf of the owners of a small, out-of-market coal unit in Massachusetts.

- Stranded costs and out-of-market contracts from restructuring can affect municipalities and cooperatives as well as investor-owned utilities. Mr. Graves assisted one debt-financed utility in an evaluation of its possibilities for reorganization, refinancing, and re-engineering to improve financial health and to lower rates. Sale and leaseback of generation, fuel contract renegotiation, targeted downsizing, spin-off of transmission, and new marketing programs were among the many components of the proposed new business plan.

- As a means of reducing supply commitment risk, some utilities have solicited offers for power contracts that grant the right but not the obligation to take power at some future date at a predetermined price, in exchange for an initial option premium payment. Mr. Graves assisted several of these utilities in the development of valuation models for comparing the asking prices to fair market values for option contracts. In addition, he has helped these clients develop estimates of the critical option valuation parameters, such as trend, volatility, and correlations of the future prices of electric power and the various fuel indexes proposed for pricing the optional power.

- For the World Bank and several investor-owned electric utilities, Mr. Graves presented tutorial seminars on applying methods of financial economics to the evaluation of power production investments. Techniques for using option pricing to appraise the value of flexibility (such as arises from fuel switching capability or small plant size) were emphasized. He has applied these methods in estimating the value of contingent contract terms in fuel contracts (such as price caps and floors) for natural gas pipelines.

- Mr. Graves prepared a review of empirical evidence regarding the stock market's reaction to alternative dividend, stock repurchase, and stock dividend policies for a major electric utility. Tax effects, clientele shifting, signaling, and ability to sustain any new policies into the future were evaluated. A one-time stock repurchase, with careful announcement wording, was recommended.

- For a division of a large telecommunications firm, Mr. Graves assisted in a cost benchmarking study, in which the costs and management processes for billing, service order and inventory, and software development were compared to the practices of other affiliates and competitors. Unit costs were developed at a level far more detailed than the company normally tracked, and numerical measures of drivers that explained the structural and efficiency causes of variation in cost performance were identified. Potential costs savings of 10-50 percent were estimated, and procedures for better identification of inefficiencies were suggested.

- For an electric utility seeking to improve its plant maintenance program, Mr. Graves directed a study on the incremental value of a percentage point decrease in the expected forced outage rate at each plant owned and operated by the company. This defined an economic priority ladder for efforts to reduce outage that could be used in lieu of engineering standards for each plant's availability. The potential savings were compared to the costs of alternative schedules and contracting policies for preventive and reactive maintenance, in order to specify a cost reduction program.

- Mr. Graves conducted a study on the risk-adjusted discount rate appropriate to a publicly-owned electric utility's capacity planning. Since revenue requirements (the amounts being discounted) include operating costs in addition to capital recovery costs, the weighted average cost of capital for a comparable utility with traded securities may not be the correct rate for every alternative or scenario. The risks implicit in the utility's expansion alternatives were broken into component sources and phases, weighted, and compared to the risks of bonds and stocks to estimate project-specific discount rates and their probable bounds.

PROFESSIONAL AFFILIATIONS

- IEEE Power Engineering Society
- Mathematical Association of America
- American Finance Association
- International Association for Energy Economics

TESTIMONY

Rebuttal report on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 07-876C, No. 07-875C, No. 07-877C, August 5, 2011.

Direct Testimony on rehearing regarding the allowance of swaps in Rocky Mountain Power's fuel adjustment cost recovery mechanism, on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, July 2011.

Comments and Reply Comments on capacity procurement and transmission planning on behalf of New Jersey Electric Distribution Companies before the State of New Jersey Board of Public Utilities in the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning, NJ BPU Docket No. EO11050309, June 17, 2011; July 12, 2011.

Rebuttal testimony regarding Rocky Mountain Power's hedging practices on behalf of Rocky Mountain Power before the Public Service Commission of the State of Utah, Docket No. 10-035-124, June 2011.

Expert and Rebuttal reports regarding contract termination damages, on behalf of Hess Corporation before the United States District Court for the Northern District of New York, Case No. 5:10-cv-587 (NPM/GHL), April 29, 2011, May 13, 2011.

Expert and Rebuttal reports on spent fuel removal at Rancho Seco nuclear power plant, on behalf of Sacramento Municipal Utility District before the U.S. Court of Federal Claims, No. 09-587C, October 2010, July 1, 2011.

Rebuttal testimony on the Impacts of the Merger with First Energy on retail electric competition in Pennsylvania, on behalf of Allegheny Power before the Pennsylvania Public Utility Commission, Docket Numbers A-2010-2176520 and A-2010-2176732, September 13, 2010.

Expert and Rebuttal reports on the interpretation of pricing terms in a long term power purchase agreement, on behalf of Chambers Cogeneration Limited Partnership before the Superior Court of New Jersey, Docket No. L-329-08, August 23, 2010, September 21, 2010.

Expert and Rebuttal reports on spent fuel removal at Trojan nuclear facility, on behalf of Portland General Electric Company, The City of Eugene, Oregon, and PacifiCorp before the United States Court of Federal Claims No. 04-0009C, August 2010, June 29, 2011.

Rebuttal and Rejoinder testimonies on the approval of its Smart Meter Technology Procurement and Installation Plan before the Pennsylvania Public Utility Commission on behalf of West Penn Power Company d/b/a Allegheny Power, Docket Number M-2009-2123951, October 27, 2009, November 6, 2009.

Supplemental Direct testimony on the need for an energy cost adjustment mechanism in Utah to recover the costs of fuel and purchased power, on behalf of Rocky Mountain Power before the Public Service Commission of Utah, Docket No. 09-035-15, August 2009.

Expert and Rebuttal reports on spent nuclear fuel removal on behalf of Yankee Atomic Electric Company, Connecticut Yankee Atomic Power Company, Maine Yankee Atomic Power Company before the United States Court of Federal Claims, Nos. 98-126C, No. 98-154C, No. 98-474C, April 24, 2009, July 20, 2009.

Expert report in regard to opportunistic under-collateralization of affiliated trading companies, on behalf of BJ Energy, LLC, Franklin Power LLC, GLE Trading LLC, Ocean Power LLC, Pillar Fund LLC and Accord Energy, LLC before the United States District Court for the Eastern District of Pennsylvania, No. 09-CV-3649-NS, March 2009.

Rebuttal report in regard to appropriate discount rates for different phases of long-term leveraged leases, on behalf of Wells Fargo & Co. and subsidiaries, Docket No. 06-628T, January 15, 2009.

Oral and written direct testimony regarding resource procurement and portfolio design for Standard Offer Service, on behalf of PEPCo Holdings Inc. in its Response to Maryland Public Service Commission, Case No. 9117, October 1, 2008 and December 15, 2008.

Direct testimony regarding considerations affecting the market price of generation service for Standard Service Offer (SSO) customers, on behalf of Ohio Edison Company, *et al*., Docket 08-125, July 24, 2008.

Direct testimony in support of Delmarva's "Application for the Approval of Land-Based Wind Contracts as a Supply Source for Standard Offer Service Customers," on behalf of Delmarva Power & Light Company before the Public Service Commission of Delaware, July 24, 2008.

Oral direct testimony in regard to the Government's performance in accepting spent nuclear fuel under contractual obligations established in 1983, on behalf of plaintiff Dairyland Power Cooperative before the United States Court of Federal Claims (No. 04-106C), July 17, 2008.

Direct testimony for Delmarva Power & Light on risk characteristics of a possible managed portfolio for Standard Offer Service, as part of Delmarva's IRP filings (PSC Docket No. 07-20), March 20, 2008 and May 15, 2008.

Oral direct testimony regarding the economic substance of a cross-border lease-to-service contract for a German waste-to-energy plant on behalf of AWG Leasing Trust and KSP Investments, Inc before U. S. District Court, Northern District of Ohio, Eastern Division, Case No. 1:07CV0857, January 2008.

Direct testimony regarding portfolio management alternatives for supplying Standard Offer Service, on behalf of Potomac Electric Power Company and Delmarva Power & Light Company before the Public Service Commission of Maryland, Case No. 9117, September 14, 2007.

Direct testimony in regard to preconditions for effective retail electric competition, on behalf of New West Energy Corporation before the Arizona Commerce Commission, Docket No. E-03964A-06-0168, August 31, 2007.

Direct and rebuttal testimonies regarding the application of OG&E for an order of commission granting preapproval to construct Red Rock Generating Facility and authorizing a recovery rider, on behalf of Oklahoma Gas & Electric Company (OG&E) before the Corporation Commission of the State of Oklahoma, Case No. PUD 200700012, January 17, 2007 and June 18, 2007.

Testimony in regard to whether defendant's role in accounting misrepresentations could be reliably associated with losses to shareholders, on behalf of defendant Mark Kaiser before U.S. District Court of New York SI:04Cr733 (TPG).

Rebuttal testimony on proposed benchmarks for evaluating the Illinois retail supply auctions, on behalf of Midwest Generation EME L.L.C. and Edison Mission Marketing and Trading before the Illinois Commerce Commission Docket Number 06-0800, April 6, 2007.

Direct and rebuttal testimonies on the shareholder impacts of Dynegy's Project Alpha for the sentencing of Jamie Olis, on behalf of the U.S. Department of Justice before the United States District Court, Southern District of Texas, Houston Division, Criminal Number H-03-217, September 12, 2006.

Direct and rebuttal testimony on the need for POLR rate cap relief for Metropolitan Edison and Pennsylvania Electric and the prudence of their past supply procurement for those obligations, on behalf of FirstEnergy Corp before the Pennsylvania Public Utility Commission, Docket Nos. R-00061366 and R-00061367, August 24, 2006.

Direct testimony regarding Deutsche Bank Entities' opposition to Enron Corp's amended motion for class certification, on behalf of the Deutsche Bank Entities before the United States District Court, Southern District of Texas, Houston Division, Docket No. H-01-3624, February 2006.

Expert and Rebuttal reports regarding the non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract, on behalf of Pacific Gas and Electric Company before the United States Court of Federal Claims, Docket No. 04-0074C, into which has been consolidated No. 04-0075C, November 2005.

Direct testimony regarding the appropriate load caps for a POLR auction, on behalf of Midwest Generation EME, LLC before the Illinois Commerce Commission, Docket No. 05-0159, June 8, 2005.

Affidavit regarding unmitigated market power arising from the proposed Exelon – PSEG Merger, on behalf of Dominion Energy, Inc. before the Federal Energy Regulatory Commission, Docket No. EC05-43-000, April 11, 2005.

Expert and rebuttal reports and oral testimonies before the American Arbitration Association on behalf of Liberty Electric Power, LLC, Case No. 70 198 4 00228 04, December 2004, regarding damages under termination of a long-term tolling contract.

Oral direct and rebuttal testimony before the United States Court of Federal Claims on behalf of Connecticut Yankee Atomic Power Company, Docket No. 98-154 C, July 2004 (direct) and August 2004 (rebuttal), regarding non-performance of the U.S. Department of Energy in accepting spent nuclear fuel under the terms of its contract.

Direct, supplemental and rebuttal testimony before the Public Service Commission of Wisconsin, on behalf of Wisconsin Public Service Corporation and Wisconsin Power and Light Company, Docket No. 05-EI-136, February 27, 2004 (direct), May 4, 2004 (supplemental) and May 28, 2004 (rebuttal) in regard to the benefits of the proposed sale of the Kewaunee nuclear power plant.

Testimony before the Public Utility Commission of Texas on behalf of CenterPoint Energy Houston Electric LLC, Reliant Energy Retail Services LLC, and Texas Genco LP, Docket No. 29526, March 2004 (direct) and June 2004 (rebuttal), in regard to the effect of Genco separation agreements and financial practices on stranded costs and on the value of control premiums implicit in Texas Genco Stock price.

Rebuttal and additional testimony before the Illinois Commerce Commission, on behalf of Peoples Gas Light and Coke Company, Docket No. 01-0707, November 2003 (rebuttal) and January 2005 (additional rebuttal), in regard to prudence of gas contracting and hedging practices.

Rebuttal testimony before the State Office of Administrative Hearings on behalf of Texas Genco and CenterPoint Energy, Docket No. 473-02-3473, October 23, 2003, regarding proposed exclusion of part of CenterPoint's purchased power costs on grounds of including "imputed capacity" payments in price.

Rebuttal testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Ameren Energy Generating Company and Union Electric Company, Docket No. EC03-53-000, October 6, 2003, in regard to evaluation of transmission limitations and generator responsiveness in generation procurement.

Rebuttal testimony before the New Jersey Board of Public Utilities on behalf of Jersey Central Power & Light Company, Docket No. ER02080507, March 5, 2003, regarding the prudence of JCP&L's power purchasing strategy to cover its provider-of-last-resort obligation.

Oral testimony (February 17, 2003) and expert report (April 1, 2002) before the United States District Court, Southern District of Ohio, Eastern Division on behalf of Ohio Edison Company and Pennsylvania Power Company, Civil Action No. C2-99-1181, regarding coal plant maintenance projects alleged to trigger New Source Review.

Expert Report before the United States District Court on behalf of Duke Energy Corporation, Docket No. 1:00CV1262, September 16, 2002, regarding forecasting changes in air pollutant emissions following coal plant maintenance projects.

Direct testimony before the Public Utility Commission of Texas on behalf of Reliant Energy, Inc., Docket No. 26195, July 2002, regarding the appropriateness of Reliant HL&P's gas contracting, purchasing and risk management practices, and standards for assessing HL&P's gas purchases.

Direct and rebuttal testimonies before the Public Utilities Commission of the State of California on behalf of Southern California Edison, Application No. R. 01-10-024, May 1, 2002, and June 5, 2002, regarding Edison's proposed power procurement and risk management strategy, and the regulatory guidelines for reviewing its procurement purchases.

Rebuttal testimony before the Texas Public Utility Commission on behalf of Reliant Resources, Inc., Docket No. 24190, October 10, 2001, regarding the good-cause exception to the substantive rules that Reliant Resources, Inc. and the staff of the Public Utility Commission sought in their Provider of Last Resort settlement agreement.

Direct testimony before the Federal Energy Regulatory Commission (FERC) on behalf of Northeast Utilities Service Company, Docket No. ER01-2584-000, July 13, 2001, in regard to competitive impacts of a proposed merchant transmission line from Connecticut to Long Island.

Direct testimony before the Vermont Public Service Board on behalf of Vermont Gas Systems, Inc., Docket No. 6495, April 13, 2001, regarding Vermont Gas System's proposed risk management program and deferred cost recovery account for gas purchases.

Affidavit on behalf of Public Service Company of New Mexico, before the Federal Energy Regulatory Commission (FERC), Docket No. ER96-1551-000, March 26, 2001, to provide an updated application for market based rates.

Affidavit on behalf of the New York State Electric and Gas Corporation, April 19, 2000, before the New York State Public Service Commission, *In the Matter of Customer Billing Arrangements*, Case 99-M-0631.

Supplemental Direct and Reply Testimonies of Frank C. Graves and A. Lawrence Kolbe (jointly) on behalf of Southern California Edison Company, Docket Nos. ER97-2355-00, ER98-1261-000, ER98-1685-000, November 1, 1999, regarding risks and cost of capital for transmission services.

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August 29, 2011

REDACTED
Docket No. UE-227
Exhibit PPL/702
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Exhibit Accompanying Surrebuttal Testimony of Frank C. Graves

Appendix A – Estimating the Volatility Term Structure

August 2011

APPENDIX A: ESTIMATING THE VOLATILITY TERM STRUCTURE

Appendix A explains how I obtain the components of the volatility term structure such as the near-term, the long-term and the seasonal volatility. I obtained broker quotes from the Company on volatilities and then estimated the components of the volatility term structure, which determine the relationship between volatility, quote date, and delivery time. These quoted volatilities are derived from (or implied by) a standard financial model, the Black-Scholes option model for pricing options on gas futures. Figure FCG-A1 below presents one such set of quotes as they described the market for gas contracts at RockOpal at the beginning of October 2007.

Figure FCG-A1

[redacted]

These volatilities will change over time, but they also have some patterns or recurring structure. Typically, the term structure of annualized volatilities is declining, whereby the high, near-term volatility decays to a steadier lower long-term volatility. The decline occurs because many near term risks generally do not affect the long term. While near term risks reflect current market conditions, the long term risk is more a reflection of beliefs about long run marginal costs. This does not mean that there is less cumulative risk in the long run than in the short run. Instead, the declining shape indicates how much the forward price of a given delivery month is likely to change over the coming month, not how much it could change over the entire time to delivery. This higher sensitivity to short run risks also means that the volatility quoted for a given month, say September, will depend on how far ahead in time September is at the time of the quote. Finally, there are seasonal variations in risk corresponding to different typical supply and demand conditions of the market.

All of these patterns can be seen in Figure FCG – A1. It is clear from the figure that the volatility declines over time, so that the near-term volatility is much larger than the more distant volatility. The bumps along the way reflect seasonality.

The declining term structure, seasonality, and sensitivity to pending time to delivery, can be used to compare risk conditions over time. However, in order to evaluate how volatility expectations in the market have changed over time, the broker quotes must be normalized for seasonality and time to delivery. I have done this by fitting an exponentially declining curve with monthly seasonality to the quoted volatilities, so that the squared error (the difference between the estimated and the actual volatility) is as small as possible. The separation of the short and long term factors from the seasonality also allows me to compare volatilities over time in a manner that is not feasible with the raw volatility quotes (which would be confounded by differences in dates of purchase).[1]

The process of estimating the components of the volatility curves is best illustrated in steps. First, I determine the declining exponential curve that best fits the quoted volatility. This is shown in Figure FCG – A2 below, where the red curve indicates the best fitting curve.

[1] See for example, Chapter 8 in L. Clewlow and C. Strickland (2000), "Energy Derivatives: pricing and Risk Management" and Electric Power Research Institute (EPRI) Technical Brief W03581 for a derivation of the mathematics of this approach.

Figure FCG – A2

[redacted]

To obtain the fitted curve in Figure FCG – A2, I estimated the near-term and the long-term volatility. The near-term volatility is initial volatility at the y-axis, while the long-term volatility is the volatility in distant future. I will focus on how these parameters changed over the time frame from mid-2007 to late 2009 in my analysis of risk expectations facing PacifiCorp.

In addition to the exponentially declining pattern in the quoted volatility, there is also a series of bumps along the path, which are month-to-month or seasonal effects. To determine the effect of the monthly seasonality, I estimated monthly seasonality factors, which are expressed as a percentage of the overall volatility, so that a coefficient of 100% indicates no seasonality, while a higher coefficient indicates a relatively higher volatility during that month. Figure FCG – A3 below illustrates the effect of adding monthly seasonality factors to the fitted curve. As can be seen from the figure, the fit improves substantially when seasonality it taken into account.

Figure FCG – A3

[redacted]

Going through these steps results in an estimate of the short-term, long-term and seasonal volatilities, which can be used to evaluate the risk conditions and the development in risk conditions over time.

In addition to improving the statistical fit, the monthly coefficients are useful for understanding whether certain delivery months have more or less risk than others. The table below summarizes these coefficients for all the volatility series I evaluated. The last three rows of this table show the averages and the range of values within any given month. The variation is fairly modest. Winter months tend to have slightly higher volatility, while the spring months are the lowest, but only about 93% on average of the non-seasonalized volatility.

[redacted]

Docket No. UE-227
Exhibit PPL/800
Witness: Andrea L. Kelly

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Surrebuttal Testimony of Andrea L. Kelly

August 2011

Q. Please state your name, business address and position with PacifiCorp (the Company).

A. My name is Andrea L. Kelly. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am employed by PacifiCorp as Vice President of Regulation.

Q. Describe your education and professional background.

A. I hold a Bachelor's degree in Economics from the University of Vermont and an MBA in Environmental and Natural Resource Management from the University of Washington. After graduate school, I joined the Staff of the Washington Utilities and Transportation Commission. In 1995, I became employed by PacifiCorp as a Senior Pricing Analyst in the Regulation Department and advanced through positions of increasing responsibility. From 1999 through 2005, I led major strategic projects at PacifiCorp including the Multi-State Process and the regulatory approvals for the MidAmerican Energy Holdings Company (MEHC)-PacifiCorp transaction. In March 2006, I was appointed Vice President of Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes, I have appeared as a witness on behalf of PacifiCorp in the states of California, Idaho, Oregon, Utah, Washington, and Wyoming.

Purpose of Surrebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. My testimony responds to the rebuttal testimony of the Citizens' Utility Board of Oregon (CUB) with respect to past rate increases and the Company's cost control efforts. Specifically, my surrebuttal testimony:

- Provides additional background related to past rate increases that have been approved by the Commission since the acquisition of PacifiCorp by MEHC in March of 2006;
- Demonstrates that the existence of the Transition Adjustment Mechanism (TAM) has allowed the Company to avoid annual general rate cases in Oregon;
- Discusses the scope of this proceeding, which is to determine the appropriate level of net power costs in rates for calendar year 2012; and
- Provides additional information regarding how the Company is working with its customers to manage disconnections.

History of Past Rate Increases

Q. Please describe PacifiCorp's rate activity since its acquisition by MEHC.

A. Rate activity over the past five and one-half years generally falls into three categories: (1) general rate cases; (2) TAM proceedings; and (3) miscellaneous filings. I will discuss each category below.

Q. Please describe the general rate cases that PacifiCorp has filed in Oregon since 2006.

A. Since the March 2006 close of the transaction, the Company has filed three general rate cases in Oregon: the first in Docket UE 179 for rates effective January 1, 2007; the second in Docket UE 210 for rates effective February 2, 2010; and the third in Docket UE 217 for rates effective January 1, 2011. Each of these dockets was resolved through Commission adoption of either an all-party stipulation or, in the case of Docket UE 210, a contested stipulation. The Company managed its costs in a manner that allowed it to avoid filing a general rate case in Oregon for rates effective in 2008, 2009 and this year for 2012.

As discussed in the testimony in support of these stipulations, the key driver for general rate increases has been investment in the system to respond to emerging energy policies in the states in which PacifiCorp operates. These energy policies include renewable portfolio standards, clean air regulations, generation portfolio diversity, and the need for additional transmission to move remote generation to load centers. The general rate increases have not been driven by increases in controllable costs such as administrative and general, and operations and maintenance expenses. And while all parties acknowledge that the size of last year's rate increase was unfortunate in light of the economic downturn, all of the Company's investments were found prudent and beneficial to customers over the long term.

Q. Over this period, has the Company overearned?

A. No. The Company has not earned its authorized rate of return in any year since the acquisition. The Company's results of operations reports filed annually with the Commission show that the Company's return on equity (ROE) in Oregon ranged from a high of 9.0 percent in 2007 to a low of 5.8 percent most recently in 2010. [1]

Q. Please describe the second category of rate activity, TAM proceedings.

A. TAM proceedings result from an annual, non-discretionary filing to establish the

[1] ROE levels reflected on a type 1 basis, which include Commission ordered regulatory adjustments.

appropriate level of net power costs in rates for the upcoming calendar year and are used to establish the transition adjustment for customers choosing direct access. Net power cost increases in the past five years have been driven by increases in fuel costs and the loss of low-price legacy wholesale sales and purchase contracts. These cost drivers are not completely within the control of the Company. The upward pressure on net power costs has been mitigated by the acquisition of very low variable cost wind resources.

Q. Have the TAM proceedings also been resolved through settlement among the parties?

A. Yes. In all but one proceeding - UE 191 for rates effective January 1, 2008 - the TAM proceedings have been resolved by settlement among the parties.

Q. Absent the TAM proceedings, would the Company have been able to avoid the filing of general rate cases for the three years discussed above?

A. No. Given the upward pressure on net power costs that are not within the Company's control, absent the TAM proceedings, the Company would have been forced to file general rate cases. Although CUB posits that elimination of the TAM would create an incentive to manage costs, the very nature of net power costs is that they are driven by customer demand and market forces. Ironically, one of the best ways for the Company to manage net power cost volatility is through a comprehensive and well-constructed hedging policy and yet these actions are also under attack in this proceeding by CUB and the Industrial Customers of Northwest Utilities (ICNU). Mr. Gregory N. Duvall's rebuttal testimony demonstrates that the Company's hedging practices have reduced customer exposure to net power cost volatility in every year from 1999 to 2010 and, further, have reduced total system net power costs by approximately $118 million from 2008 through 2011.

Q. Please explain the third category of rate activity -- miscellaneous filings -- that have impacted customer rates in Oregon.

A. These filings are generally driven by state-specific mandates and allow the Company to recover its costs of complying with the mandates. For example, Oregon's renewable portfolio standard (RPS) allows for deferral and recovery of costs related to compliance with the law. Another annual impact to the Company's customers resulted from tax filings under Senate Bill 408, which has now been repealed. There have also been costs associated with additional conservation spending, independent evaluators for the Company's requests for proposals, intervenor compensation, costs related to the implementation of direct access and the Klamath dam removal surcharge. For residential customers, there was also a dramatic elimination of benefits from the Bonneville Power Administration related to the Northwest Power Act.

Q. Why is this background important to consider when evaluating CUB's claims that the Company has not managed its costs?

A. It demonstrates that the opposite is true. The Company has prudently invested considerable sums of capital into its system to meet the current and future policy requirements of Oregon and the other states in which it operates. The Company has one of the largest portfolios of renewable resources of all utilities in the United States, which is consistent with the legislative intent of the RPS. The later year requirements of the RPS cannot be met without investment in incremental renewable generation resources and transmission infrastructure to deliver the resources to load.

The Company has avoided general rate cases in Oregon in three of six years by controlling its controllable costs. While the Company understands that the size and timing of last year's rate increase was unfortunate in light of economic conditions in the state, it also made every effort to avoid a general rate case this year despite a continuing need for capital investments. Past rate increases also do not change the facts and circumstances in this TAM--a proceeding that is exclusively related to establishing the appropriate level of net power costs in rates for calendar year 2012.

Scope of TAM Proceedings

Q. Please briefly discuss the intended scope of the Company's TAM proceedings.

A. As noted in the TAM Guidelines adopted in Order No. 09-274:

> Pacific Power's Transition Adjustment Mechanism (TAM) is an annual filing with the objective to update the forecast net power costs to account for changes in market conditions, with the final forecast update close to the direct access window to capture costs associated with direct access, and to correctly identify the proper amount for the transition adjustment….When filed on a stand-alone basis, the TAM is intended to be narrower and more streamlined than when the TAM is filed in or processed concurrently with a general rate case.

As noted in the Company's rebuttal testimony, these guidelines were developed to allow for an orderly and streamlined processing of the TAM and provide clear direction related to the scope of the proceeding and the update process.

Q. Are CUB's complaints about PacifiCorp's general rate levels inappropriate in a TAM proceeding?

A. Yes. The Company's relatively limited response to CUB's arguments on this subject reflected the Company's desire to maintain the narrow scope of the TAM, rather than a lack of engagement in CUB's concerns. However, given the criticism, I do provide some rate comparisons later in this testimony.

Additional Information on Customer Disconnects

Q. CUB presents statistics on PacifiCorp's number of disconnection notices and arrearages as support for its contention that PacifiCorp's rates are becoming unaffordable. How do you respond?

A. CUB's analysis relates to disconnection *notices*, not actual disconnections. The number of actual disconnections in Oregon has decreased in recent years from approximately 24,500 in 2008 to 12,500 in 2009 to 7700 in 2010. While the Company's 2011 disconnections are trending up somewhat, they are not anywhere near 2008 levels.

Q. What has PacifiCorp done to help customers respond to the challenging economic conditions?

A. The Company is dedicated to assisting customers in this tough economy by managing balances with payment arrangements, providing energy assistance resources for eligible customers, and supporting energy conservation. These efforts have been effective, and the Company's percentage of net write-offs for uncollectibles is lower than the electric industry standard. In 2009, the industry average for write-offs as a percent of retail revenue was 0.65 percent. For PacifiCorp in Oregon it was 0.54 percent in 2009 and 0.45 percent in 2010.

Q. How do PacifiCorp's average Oregon rates compare against other utilities throughout the region and the nation?

A. Favorably. The Company's average retail rate in Oregon, including the January 1, 2011 rate increase, is 8.44 cents per kWh. The average retail rate for the Pacific Region for the 12 months ended 2010 was 12.82 cents per kWh, and for the United States was 9.96 cents per kWh.

Q. How has PacifiCorp's customer satisfaction fared during recent years?

A. Recent customer surveys have shown that customer satisfaction with PacifiCorp remains quite high and continues to improve, despite the recession and the most recent rate increases. These survey results are illustrative:

J.D. Power released the results for its 2011 residential customer satisfaction study on July 13, 2011. Pacific Power improved from a 7th place ranking in 2010 to 6th place in 2011 among 13 West region large utilities. This places Pacific Power in the 2nd quartile.

The American Customer Satisfaction Index released the results of its 2011 energy utility residential customer satisfaction research. Pacific Power, Rocky Mountain Power and MidAmerican Energy Company, ranked together as MidAmerican, received a 1st quartile national ranking for the fourth consecutive year. Twenty-five investor-owned utilities were included in the rankings.

E Source announced its 2011 rankings of electric and gas utility interactive voice response systems on July 19, 2011. Pacific Power improved from a 10th place national ranking in 2009 to 8th place in 2011. The company ranks at the top of the 1st quartile nationally among 96 utilities.

TQS scores for the Company's largest customers have consistently exceeded 90 percent for overall customer satisfaction.

The proof of PacifiCorp's commitment to customer service is reflected in these results. The Company strives to both control costs and provide excellent customer service.

Q. Has the Company agreed to additional adjustments in surrebuttal that mitigate the proposed TAM increase?

A. Yes. As discussed in the surrebuttal testimony of Mr. Duvall, the Company has agreed to Staff's proposal to use the updated load forecast that was presented in the Company's rebuttal filing. The Company has also agreed to CUB's adjustment to reflect a four-year average of liquidated damages. Together, these reduce the proposed TAM increase by $4.8 million, based on the rebuttal update filing.

Q. What is the residential customer impact for the proposed increase as a result of the surrebuttal?

A. For an average residential customer using 950 kWh per month, the filing will result in a monthly increase of $4.00.

Q. Is this an "exorbitant" increase as CUB suggests?

A. No.

Q. Does this conclude your testimony?

A. Yes.