PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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July 29, 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 Rebuttal and Update 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 Rebuttal Testimony and Exhibits for the following witness:

- Rebuttal Testimony and Exhibits of Gregory N. Duvall (Exhibit PPL/105 – PPL/109), containing confidential material.
- Rebuttal Testimony and Exhibits of Stefan A. Bird (Exhibits PPL/400 – PPL/405), containing confidential and highly confidential material.
- Rebuttal Testimony and Exhibits of Rick T. Link (Exhibits PPL/500 – PPL/502), containing confidential and highly confidential material.
- Rebuttal Testimony and Exhibits of William R. Griffith (Exhibits PPL/600 – PPL/602).

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 29th of July, 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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REDACTED
Docket No. UE-227
Exhibit PPL/105
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Rebuttal Testimony of Gregory N. Duvall

July 2011

Q. Are you the same Gregory N. Duvall who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (the Company)?

A. Yes.

Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony has two parts: a Transition Adjustment Mechanism (TAM) update section, consistent with the TAM Guidelines adopted by the Commission in Order No. 09-271, and a rebuttal section responding to the parties' proposed adjustments.

First, in the TAM update section, I provide contract, fuel, and forward price updates to the Company's March 17, 2011 filing (Initial Filing). In addition, I explain the reasonableness of the Company's revised system net power costs (NPC) of $1.563 billion, a number that reflects the TAM updates and adjustments for the test period of the 12 months ending December 31, 2012.

Second, in the rebuttal section of my testimony, I respond to the adjustments and criticism of the Company's NPC 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).

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

A. Yes. Mr. Stefan A. Bird responds to CUB's and ICNU's adjustments related to the Company's natural gas hedging; Mr. Rick T. Link responds to ICNU's adjustments and proposals related to the forward price curve; and Mr. William R. Griffith responds to ICNU's proposed adjustment to recognize non-NPC revenue in the TAM.

Recommendation for Company's Net Power Costs for this Case

Q. In your direct testimony, you recommended that the Commission set the Company's system NPC at $1.558 billion for the test period ending December 31, 2012. Has your NPC recommendation changed?

A. Yes. The Company has increased its recommended system NPC to $1.563 billion or $25.05 per MWh.

Q. Why have you increased your system NPC recommendation to $1.563 billion?

A. First, consistent with the TAM Guidelines, the Company updated the Initial Filing with (1) the most recent forward price curve and (2) new power, fuel, and transportation/transmission contracts and updates to existing contracts. Second, the Company has reviewed the proposed adjustments from Staff and intervenors. As discussed below, the Company has reflected certain of these adjustments in NPC. These factors result in a net increase to system NPC of $5.0 million.

Q. Please explain the change in NPC from the Initial Filing on an Oregon-allocated basis.

A. As illustrated in Exhibit PPL/106, on an Oregon-allocated basis, the Company's forecast normalized NPC for calendar year 2012 are approximately $384 million. This results in a $1.8 million increase from the Initial Filing.

Q. Does total Company NPC of $1.563 billion produce a reasonable result in this case?

A. Yes. As stated above, under the TAM Guidelines, the updated NPC reflect the most recent information available to the Company in the determination of 2012 NPC.

NPC Updates

Q. Please describe how the Company updated NPC.

A. Section B of the TAM Guidelines sets forth the elements of NPC that the Company will update in its Rebuttal Filing: the most recent forward price curve and new power, fuel, and transportation/transmission contracts, and updates to existing contracts.[1] The Company has updated NPC in this filing to reflect the most recent official forward price curve dated June 30, 2011. This update also includes prices for indexed contracts, mark-to-market value of natural gas and power swaps, as well as reshaped hydro generation. The Company also updated NPC to reflect new power, fuel, and transmission/transportation contracts and updates to existing contracts. Exhibit PPL/107 provides a summary of the impact on total Company NPC for each of the items.

Adjustments Accepted by the Company

Q. Please describe the adjustments proposed by Staff, CUB, or ICNU that the Company has accepted.

A. The Company has accepted the following proposed adjustments:

- Bear River Normalization: Because of the significant change in weather conditions impacting the Bear River project, the Company accepts Staff's

[1] *See* Order No. 09-274 at Appendix A at pp. 2-3.

and ICNU's proposed update to the modeling of Bear River median generation to include flood control years. This adjustment reduces system NPC by $2.1 million.

- Calculation of the Transition Adjustment: The Company accepts NAES' proposal to continue to apply the changes to the Schedule 294 and 295 rates that were adopted in Paragraph 15 of the stipulation adopted in Order No. 08-543 in UE 199 and in Paragraph 15(a) of the stipulation adopted in Order No. 09-432 in UE 207. The Company does not agree, however, to NAES' Bonneville Power Administration (BPA) transmission credit proposal.

Q. Are there additional proposals from parties that the Company is adopting?

A. Yes. Staff argues that the proposed BPA rate increase should not be included in the TAM unless the rate is adopted by BPA during the course of the TAM. Staff proposes an adjustment of $22,000, Oregon allocated. Staff states: "Should the rate change be adopted during the course of the TAM Staff will revise this adjustment accordingly."[2]

Q. How do you respond?

A. The Company agrees with Staff that this updated rate should not be included in the TAM unless it is adopted by BPA prior to the final updates. Although my direct testimony in this case stated that the Company had incorporated the new proposed wind integration charge, that testimony was inaccurate, therefore the adjustment is not necessary. The NPC in the Initial Filing reflected the current $1.29/kW-month charge, not the proposed $1.32/kW-month charge.

[2] *See* Staff/100, Durrenberger/4, lines 13-15.

Nonetheless, BPA issued it Record of Decision (ROD) revising the charge on July 26, 2011. However, the Company had already finalized NPC for the update filing by this time. The Company is in the process of reviewing the new ROD and will incorporate the new charges in the November update, consistent with Staff's position.

Company Responses to Contested Adjustments

Hedging

Q. What is the purpose of your rebuttal testimony on hedging?

A. My rebuttal testimony supports the rebuttal testimony of Mr. Bird, which provides an overview of the Company's risk management policy and hedging program and demonstrates that there is no basis for CUB's and ICNU's proposed prudence disallowance related to the Company's hedging program. Specifically, I demonstrate that, over the course of the last several years, the Company's hedging program has reduced both the volatility and overall level of NPC.

The Company's Hedging Program Reduces Volatility

Q. How does the Company's hedging strategy benefit Oregon customers?

A. The Company's hedging strategy mitigates the volatility of NPC and protects against large swings in NPC as a result of unforeseeable changes in wholesale market prices for electricity and natural gas. Mr. Bird's testimony discusses Staff's 2005 Natural Gas Procurement Study, and its finding that PacifiCorp's hedging program reduced volatility by 82 percent from 1999-2004. Using the same methodology employed in that study for the period 2005-2010, I demonstrate that the Company's hedging of natural gas reduced the volatility of gas prices by 50 percent, and reduced the volatility of wholesale power prices by 52 percent as shown in Tables 1 and 2.[3]

Table 1 – Natural Gas

	PacifiCorp		Market Index			
Hub/Pricing Point	Average ($/MMBtu)	Coefficient of Variation	Average ($/MMBtu)	Coefficient of Variation	Increase (decrease) in Price	Reduction (increase) in Volatility
Rockies	$5.91	0.19	$4.97	0.42	16%	56%
AECO	$3.41	0.09	$5.18	0.35	-52%	73%
Sumas	$7.44	0.18	$5.67	0.40	24%	56%
Henry Hub	$4.97	0.26	$6.39	0.41	-29%	36%
Overall	$5.12	0.17	$5.68	0.35	-11%	50%

Table 2 - Power

	PacifiCorp		Market Index			
Hub/Pricing Point	Average	Coefficient of Variation	Average	Coefficient of Variation	Increase (decrease) in Price	Reduction (increase) in Volatility
4C HLH	$65	0.18	$57	0.37	13%	52%
4C LLH	$46	0.15	$39	0.36	14%	58%
MID-C HLH	$59	0.18	$51	0.33	14%	46%
MID-C LLH	$47	0.25	$41	0.38	13%	34%
Overall	$57	0.16	$49	0.34	13%	52%

Q. Has the Company developed additional analysis on the issue of NPC volatility and hedging?

A. Yes. The Company's 2011 Integrated Resource Plan (IRP) addresses this issue and demonstrates that the Company's portfolio approach to hedging, which is both comprehensive and integrated from a power/natural gas standpoint, reduces the volatility of NPC. First, the IRP demonstrated that the "less hedged portfolio

[3] The coefficient of variation is the standard deviation of a sample divided by its average. It allows for apples to apples comparisons of volatility, as it standardizes the scale of the samples.

shows a wider distribution of outcomes representing a higher risk to price changes. Similarly, the more hedged portfolio shows a narrower distribution." Second, the analysis showed that "[t]he 'hedge only power' portfolio shows a much wider distribution due to the severe reduction in the natural offset between power and natural gas in the reference portfolio. The 'hedge only natural gas' has a similar distribution."[4]

Historical Benefits of Hedging in Company's Net Power Costs

Q. Have you analyzed the historical impact of the Company's hedging program on NPC in Oregon rates?

A. Yes. I have prepared Exhibit PPL/108 which sets forth the impact of the Company's hedging program on NPC in Oregon rates.

Q. Please summarize the results of your analysis.

A. From January 1, 2008, when rates from UE 191 went into effect, through the end of December 2011 when rates from this case will become effective, customers will have received $118 million in lower system NPC as a result of the Company's hedging program. It would be unfair to accept the substantial benefits of the hedging program from 2008 through 2011, and then disallow the costs of it going forward when nothing material has changed in the Company's approach or circumstances.

Q. On a volumetric basis, how much of the natural gas usage in the 2012 GRID NPC study is hedged in the Rebuttal Update?

A. Approximately [redacted] percent. This is lower than the hedging volume recommendations of both CUB and ICNU and undermines their claim that the

[4] PacifiCorp 2011 IRP, Docket LC 52, Appendix G at 165 (Mar. 31, 2011).

Company has over hedged with respect to natural gas.

Q. How do customers benefit from the Company's hedge program in years where hedges are unfavorable, such as in the test year?

A. The purpose of the Company's hedge program is to reduce the volatility of NPC. Absent the Company's hedge program, NPC would be subject to potentially large swings from year to year depending upon the volatility of the spot market. I previously demonstrated that the volatility of natural gas and wholesale electric prices were cut in half as a result of the Company's hedging program.

Retail Load Forecast

Q. Do parties challenge the Company's retail load forecast used in the Initial Filing?

A. Yes. Staff and ICNU propose adjustments based on challenges to the Company's load forecast. However, as discussed below, both Staff and ICNU mix and match different vintages of load forecasts to justify their recommendations, an approach that fails to recognize that each vintage of load forecast is derived using the best actual historic and forecast data available at the time the forecast is developed.

Q. What is Staff's argument related to the retail load forecast?

A. Staff argues that the retail load forecast in the 2012 TAM is overstated. Staff claims that the Company's 2011 IRP projects retail load growth for the 2011-2012 period of 2.3 percent, but the Company used a 7.5 percent increase. However, Staff erroneously calculates the 7.5 percent increase by comparing the October 2009 forecast for 2011 used in UE 216, the 2011 TAM (October 2009 forecast) against the November 2010 forecast for 2012 used in this TAM (November 2010 forecast). Staff did not quantify its adjustment and indicated it may quantify the impact at a later time. The Company reserves the right to rebut any quantification that Staff may propose in the future.

Q. What did ICNU propose with respect to the retail load forecast?

A. ICNU also objects to the Company's retail load forecast as being overstated, similarly citing the 7.5 percent figure on a total system basis and 7.1 percent for Oregon. However, ICNU's proposal for addressing this issue is to impute non-NPC related fixed margin revenue into this proceeding using the same forecast that it criticizes as overstated. Mr. Griffith explains why the methodology of ICNU's adjustment is one-sided and inappropriate in an NPC-only proceeding and is contrary to the TAM Guidelines, to which ICNU stipulated. I address the reasonableness of the Company's retail load forecast in this case.

Q. Can you clarify the sources of the 2.3 percent increase in retail loads and the 7.5 percent increase in retail loads cited by Staff and ICNU?

A. Yes. The 2.3 percent figure approximates the load growth between 2011 and 2012 that was forecast in the Company's 2011 IRP, which was developed in October 2010 (October 2010 forecast).

As discussed above, the 7.5 percent figure cited by Staff compares the October 2009 forecast for 2011 against the November 2010 forecast for 2012.

Q. What is the difference between the October 2010 forecast and the November 2010 forecast?

A. After completing the October 2010 forecast, the Company received new and more accurate information regarding the continuation of a load increase by a large industrial customer in Utah. As noted in the 2011 IRP, this was originally assumed for 2011 only.[5] The November 2010 forecast extended this load increase through 2012. This change resulted in an increase in the load forecast of 458 GWh, 52 average megawatts – an increase of 0.8 percent.

Q. Why is it erroneous to compare growth rates using different vintages of load forecasts?

A. It ignores the fact that new forecasts are based on the best available actual historical data and forecast data. Importantly, the October 2009 forecast was developed using actual historical load data through July 2009, while the November 2010 forecast was developed using actual historical load data through July 2010. Chart 1 shows the actual historical data on a total company basis, contrasted with the October 2009 forecast and the November 2010 forecast. Chart 2 provides this contrast for Oregon.

[5] PacifiCorp 2011 IRP, Docket LC 52, Appendix A at 9 (Mar. 31, 2011).

Chart 1

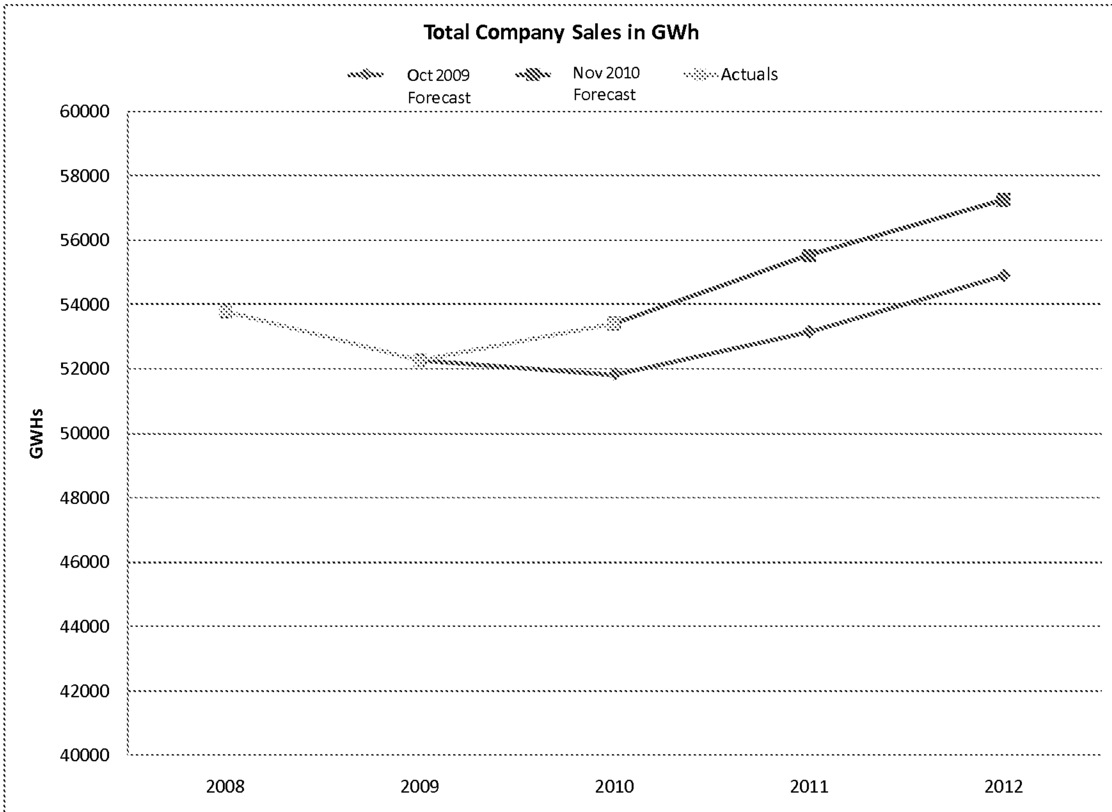
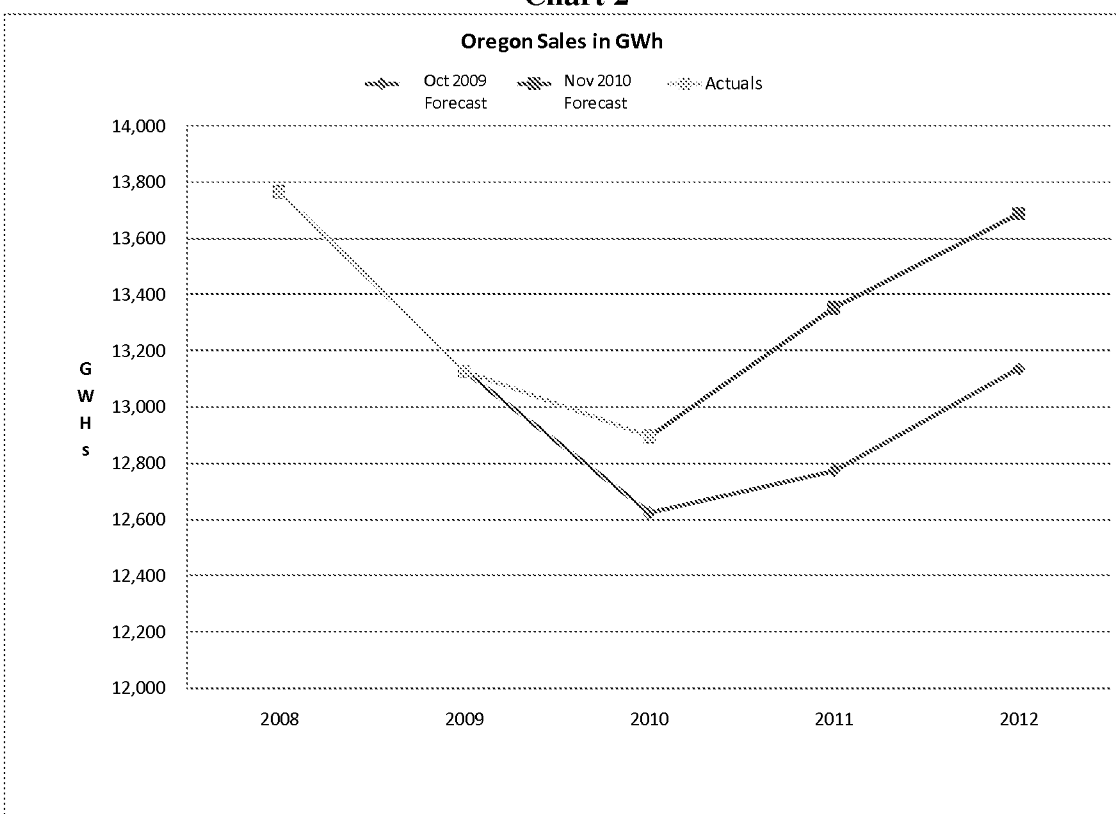


Chart 2



Q. Please explain.

A. As noted above, the October 2009 forecast was created in the midst of the recession, with the knowledge of actual historical loads through July 2009. At that time, loads had been declining and the Company's view was that it was unlikely to see much, if any, recovery from the recession during 2010. The October 2009 forecast therefore incorporated a small decrease between 2009 and 2010 on a system basis, with recovery beginning in 2011 and 2012. For Oregon, the Company assumed loads would continue to fall in 2010 with recovery beginning in 2011. As shown above, this forecast was understated for 2010. Loads in 2010 were several percentage points higher than what the Company had forecast, both on a system basis and for Oregon.

Appropriately, the November 2010 forecast incorporated these higher actual 2010 loads as a starting point and had the benefit of actual historical load data through July 2010. Doing otherwise - as Staff and ICNU recommend - would ignore what has actually occurred. The Company uses the same process for developing all of its load forecasts, so any differences in forecasts reflect the information that was available to the Company at the time it developed the forecast.

Q. Please quantify and explain why 2010 actual sales were higher than the amount forecast in October 2009.

A. On a total Company basis, 2010 actual sales were 1,594 GWh, or three percent higher than the October 2009 forecast for 2010. Approximately 86 percent (1,371 GWh) of this variance was attributable to economic recovery in the industrial segments, primarily in Utah (517 GWh), Wyoming (387 GWh), and Idaho (398 GWh). A significant portion of the remaining variance was due to higher sales in the residential class, mainly in Oregon (287 GWh).

Q. What is the retail load growth between 2011 and 2012 in the November 2010 forecast?

A. As shown in the charts above, the Company's filing incorporates a 3.1 percent growth on a total Company basis, and 2.5 percent growth on an Oregon basis between 2011 and 2012. For Oregon, this load growth is identical to that contained in the 2011 IRP forecast. On a total Company basis, the difference is discussed above.

Q. Do you think that this level of retail load growth is reasonable for 2012?

A. Yes. Based on the information that was available to the Company in November 2010, this level of growth is reasonable based on projected expansion by new and existing customers in extracting industries, growth in data centers, and economic development in the Company's service territory as the economy recovers.

Q. In addition to the change in the starting point between the October 2009 forecast and the November 2010 forecast, are there other differences between the forecast assumptions?

A. Yes. For the commercial class, there was an upward adjustment in the November 2010 forecast to reflect the addition and expansion of large data centers in Utah and Oregon – certain of which are already on-line and operating. For the industrial class, additional growth is attributable to recovery by existing large industrial customers and an updated outlook for new loads by customers in the extractive industry in Utah and Wyoming, as well as increased growth attributable to a small number of very large industrial customers.

Q. How does the Company forecast usage by its largest customers on the system?

A. The Company conducts regular discussions with its largest customers to seek information regarding each customer's business trends and expectations over the coming years. Given the economic uncertainties facing these customers, expectations on future usage and timing of expansions can change fairly often.

Q. Does the Company have a more recent load forecast than the one included in the Initial Filing?

A. Yes. The Company updated its load forecast in July 2011. As seen in Table 3 below, the July 2011 load forecast is 1,765 GWh lower than the November 2010 forecast. The updated load forecast is based on the revised information received from industrial and commercial customers and the most recent economic conditions.

Table 3

Difference Between November 2010 and July 2011 Forecasts

	Total MWh	OR MWh	WA MWh	CA MWh	UT MWh	ID MWh	WY MWh
July 2011 Forecast for CY 2012	55,481,640	13,435,370	4,107,990	851,260	23,837,760	3,379,350	9,869,910
Nov 2010 Forecast for CY 2012	57,246,690	13,686,920	4,155,920	830,990	24,864,100	3,431,560	10,277,200
July 2011 Forecast minus Nov 2010 Forecast	(1,765,050)	(251,550)	(47,930)	20,270	(1,026,340)	(52,210)	(407,290)
RES - Forecast Difference	(285,957)	(69,800)	(1,392)	10,215	(179,918)	(4,836)	(40,226)
COM - Forecast Difference	(481,259)	(154,602)	(1,537)	4,657	(351,166)	12,560	8,828
IND - Forecast Difference	(939,772)	19,961	(44,830)	6,258	(492,416)	(55,743)	(373,002)

Q. What are the drivers of the reduction in the July 2011 forecast?

A. The following changes from the November 2010 forecast are reflected in the July 2011 forecast.

- In Utah, the forecast related to a small number of large industrial and commercial customers has been reduced.
- In Wyoming, the majority of the reduction is similarly attributed to a revised forecast for a few industrial customers.
- In Oregon, the majority of the load reduction is attributable to the timing of load increases related to data centers.

Overall, the reduction to the forecast for the large customers discussed above represents 77 percent of the reduction for the Company. In addition, approximately 825 GWh of the industrial load reduction is attributed to certain industrial customers' plans to displace their retail loads with their on-site generation due to low wholesale market prices as compared to the retail rate. The remainder of the difference reflects lower forecasts of residential customer sales, which is reflective of 2011 results to date. Table 3 details the changes between the November 2010 forecast for 2012 and the July 2011 forecast for 2012.

Q. Why did the Company not adopt this updated forecast in its Rebuttal Filing?

A. The TAM Guidelines do not provide for updating the load forecast after the Company's Initial Filing.

Q. Would the Company support reflecting the updated forecast in its Final Update?

A. Yes, as long as the Commission modifies the TAM Guidelines to require the Company to update loads in its Rebuttal Filing in all future TAM proceedings. It would be inappropriate to reflect this lower load forecast but not allow the Company to update for higher load forecasts in the future.

Q. Has the Company quantified the impact of the July 2011 forecast on the Rebuttal Update?

A. Yes. This updated forecast would reduce the rebuttal update increase by $4.6 million, resulting in an overall Oregon increase of $58.8 million.

Q. Do you have any other comments on a change to the TAM Guidelines to accommodate updates to the load forecast after the Initial Filing?

A. Yes. I believe the Commission could consider whether any such update should be subject to a materiality threshold either on a MWh basis or a total dollar basis.

Market Caps

Q. Has the Company applied market caps in previous TAM proceedings?

A. Yes. Since implementation of the GRID model, the Company has applied market caps to wholesale sales modeled in GRID to reflect reasonable limits on market depth.

Q. Why are market caps necessary?

A. Without market caps, GRID would allow unlimited sales at every market at any time of the day or night. The historical level of short-term firm (STF) transactions shows that unlimited sales do not occur in actual operation. To appropriately reflect this fact in normalized NPC, the Company's market cap approach first determines the market depth or potential amount of sales transactions that the Company could enter into. Such a market depth is defined by the average level of STF sales transactions that the Company was able to enter into in the 48-month historical base period. The average historical level of STF transactions is then reduced by the actual STF transactions included in the normalized NPC study in this case, which determines the market caps. That is, the market caps are defined by the potential level of transactions, net of transactions that the Company has entered into.

Q. Has this Commission evaluated the market cap issue previously?

A. Although the Company has applied market caps since implementation of the GRID model, the issue has not been fully litigated before this Commission. ICNU proposed removing market caps two years ago, in Docket UE 207, and that case was resolved via settlement. ICNU did not object to market caps in the following proceeding, Docket UE 216.

Q. What occurred in the time period between UE 207 and UE 216 related to market caps?

A. On February 18, 2010, the Public Service Commission of Utah rejected a proposal by Mr. Randall Falkenberg, ICNU's witness in UE 207 and UE 216, to eliminate market caps.[6]

Q. Have any of PacifiCorp's commissions ever approved an adjustment removing market caps?

A. No.

Q. Is Staff objecting to the concept of market caps?

A. No. Staff proposes to restore the market cap methodology previously used in TAM proceedings. Staff states that this change would reduce system NPC by $6.0 million. ICNU proposes eliminating market caps entirely, resulting in a $5.6 million reduction to system NPC.

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[6] *Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah,* Docket 09-035-23, Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates at 27 (Feb. 18, 2010).

Q. Staff argues that the Company has not justified the change in its market cap approach. How do you respond?

A. As in all previous TAM filings, the Company has implemented market caps to reflect reasonable limits on market depth. The only change is that the Company refined its measurement of market depth and applied the resulting market caps to sales in all hours, not just sales in the graveyard hours. This refinement <u>reduced</u> the overall impact of market caps and <u>lowered</u> NPC, as compared to the market caps used in prior Oregon cases.

Q. Staff argues that the Company did not demonstrate that the modeling of market caps included in the Initial Filing produces a more reasonable or accurate representation of the actual surplus sales. How would reverting to the prior approach to market caps affect NPC?

A. Applying the same approach to determine market caps used in prior proceedings would increase system NPC by approximately $10 million.

Q. Please explain how the Company's approach to market caps in this proceeding reduces NPC as compared to the Company's previous approach, when under this approach the Company limits sales during all hours and the former approach limited sales only during graveyard hours.

A. The data used to determine the market depth in the current proceeding include all short-term firm transactions in the historical base period, while the data used to determine the graveyard-hour market caps in the previous cases included only spot transactions. As a result, compared with the previous market caps, the current market caps allow significantly higher amount of sales transactions during graveyard hours while slightly limiting sales transaction in all other hours.

Q. ICNU calls into question the logic within the Company's market cap modeling, because there are time periods when GRID modeled no transactions in active trading hubs. Does this indicate a flaw in the Company's modeling?

A. No. There may not be transactions modeled in every hour because the Company does not have excess generation to sell or the Company's transmission rights do not allow transfer of energy from one location to another during the relevant time period. This is irrelevant to the market liquidity issue addressed by market caps.

Q. ICNU argues that PacifiCorp's activity for the six hubs modeled by GRID is a small percentage of the market. What is your response to this argument?

A. I disagree. While it is true that PacifiCorp is only one of many parties active in these markets, that does not invalidate the evidence of market liquidity upon which the Company's market caps are based. The historical data that the Company used to determine the market depth shows that the Company's ability to sell in these markets is limited, and the Company's market caps appropriately reflect this fact.

Q. ICNU claims that the level of transactions modeled in GRID does not come close to historical actual levels. How do you respond?

A. ICNU's claim is irrelevant. ICNU makes the same argument that was resolved in the Company's 2008 TAM filing, UE 191, where Staff proposed an adjustment for trading margins based on the differences between the GRID generated volume of transactions and the actual volume of transactions. As explained by the Company in UE 191:

> This is a characteristic of any deterministic hourly production dispatch model that balances and optimizes a forecast test year on an hourly basis. The GRID model produces a lower volume of transactions because it balances loads and resources on an hourly basis with perfect foresight. Even with a stochastic model, the volumes may still be lower than actual results because a model can only capture the variation determined by the given statistical properties. On an actual basis, system balancing is a long process that involves numerous updates of load and resource balances due to changes in load forecasts, the availability of thermal units, hydro conditions, etc., up to the actual time of delivery. Additionally, products available in the market are not always a good fit to balance resource requirements, which also leads to higher actual volumes. As a result, actual balancing generates higher volumes than GRID or other deterministic models.[7]

Q. How did the Commission address this issue in UE 191?

A. In its decision, the Commission accepted the Company's explanation, did not adopt Staff's adjustment, and accepted the Company's calculation of trading margin for the case. In the current case, the Company again included the short-term firm (STF) trading margin. As a result, any adjustments to increase the volume of transactions modeled in GRID, especially through increased market purchases, would double count the value that has been included through the STF trading margin.

Q. Has Staff or ICNU provided any new information that would show that the Company would be able to make additional sales in the test period above historical levels in the hours in which market caps are applied?

A. No.

[7] *See* Exhibit PPL/204, Widmer/16, lines 9-21.

DC Intertie

Q. Please explain Staff's and ICNU's proposed adjustment to costs associated with the DC Intertie.

A. Staff argues that the expense associated with the DC Intertie agreement does not contain corresponding benefits for Oregon customers, is not used and useful and therefore should be disallowed. ICNU also argues that costs associated with the DC Intertie should be excluded from NPC on the basis that while the agreement is used by the Company, the low level of activity does not justify the inclusion of these costs. The proposed adjustment would result in a $4.8 million decrease to total Company NPC.

Q. Please provide some background on the DC Intertie contract.

A. The DC Intertie contract was executed 17 years ago on May 26, 1994, to provide deliveries of 200 MW of power from Southern California Edison at the Nevada Oregon Border market hub (NOB) under Amendment 1 to the Winter Power Sales Agreement (WPSA). The WPSA was executed on December 14, 1993 and provided up to 422 MW of power to be delivered to the Company's west control area. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222 MW of power into the west control area. The agreement provided that if the Company procured additional transmission rights by June 1, 1993, then it could import the remaining 200 MW to its system. The Company secured the remaining 200 MW of transmission rights by acquiring 200 MW of transmission capacity on the DC Intertie. The Company terminated the

WPSA effective January 1, 2002, but the DC Intertie contract remained effective by its terms.

Q. How does the DC Intertie contract benefit the Company's customers today?

A. The agreement takes advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest. The contract provides a valuable means of securing capacity and energy from California entities to meet retail loads. Loads in California are relatively low in the winter when loads in the Company's west control area and the rest of the Pacific Northwest are at their highest.

Q. Is there evidence that the Company can reasonably expect to use the DC Intertie in the rate effective period, even though GRID does not model transactions at NOB?

A. Yes. The Company made over 200 power purchase transactions at NOB each year for the past five years. The DC Intertie is used to transfer this power to load. There is no reason to believe this historical trend will not continue into the future.

Q. Can you quantify the benefit of those transactions as it compares with the cost of the contract?

A. The cost of the DC Intertie contract is $1.99 per kilowatt-month, which compares to over $8 per kilowatt-month that the Company paid to BPA under the peak purchase contract.

Q. What would be the result if the DC Intertie were not available to the Company?

A. If the DC Intertie were not available to the Company, then it would have to be replaced with a new 200 MW resource. Without a new 200 MW resource, the Company could not serve peak loads. Acquiring a new 200 MW transmission resource would cost customers significantly more than the cost of the DC Intertie.

Q. If the contract costs more than the dollar benefit of the transactions that use the contract, why is it appropriate to include the full costs of the DC Intertie agreement in rates?

A. In making their proposals, Staff and ICNU focus on energy deliveries under the contract rather than the capacity deferral and diversity benefits of the contract. It would be inappropriate to penalize the Company for prudently acquiring transmission rights 17 years ago by disallowing costs today based on hindsight and only looking at the energy value of a resource that can facilitate the delivery of both capacity and energy. By purchasing these transmission rights, the Company has purchased assurance that it can reliably serve its retail customers loads. Staff's and ICNU's proposals are based on a limited energy-only view of this contract, which is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds under an insurance policy. The costs associated with this contract are modest in light of the benefit to the Company's overall transmission strategy and hedge against changes in the market.

Q. How should the Commission judge the prudence of this contract?

A. Prudence should always be judged based on the information that was known at the time the contract was executed. It would not be reasonable to judge a 17-year old contract based on information that is available today that was not available 17 years ago.

Cal ISO Fees

Q. Please describe Staff's and ICNU's adjustments to Cal ISO fees.

A. Staff and ICNU recommend removal of the Cal ISO wheeling expenses and fees. They claim that the Cal ISO system capability is not modeled in GRID and there is no offsetting benefit reflected in the filing. The proposed adjustment would result in a $4.3 million reduction to system NPC.

Q. Is Staff's and ICNU's claim that the Cal ISO system capability is not modeled in GRID a valid concern?

A. No. In actual operations, the Company does not use the Cal ISO system capability. The Cal ISO fees are incurred when the Company transacts with the Cal ISO at market hubs that are modeled in GRID, such as the California Oregon Border, Four Corners, Mona and Palo Verde. The benefit of wholesale sales and purchases at these locations are already reflected in GRID.

Q. Will the Company enter into transactions with the Cal ISO in the rate effective period?

A. Yes. Staff stated in response to the Company Data Request 1.5 that Staff does not dispute whether the Company engages in Cal ISO transactions, and ICNU stated in response to the Company Data Request 1.11 that ICNU does not dispute this fact either. The responses to these data requests are included as Exhibit PPL/109.

Q. Is ICNU correct that the Company would not have entered into these transactions unless there was a clear profit margin at the time of the transaction?

A. No. The Company enters into transactions with the Cal ISO to serve load, not to earn a margin. The Company will enter into transactions with the Cal ISO if the Cal ISO is the Company's most economic option to serve load at that time. As a result, eliminating the Cal ISO as a counterparty will require the Company to enter into higher-priced transactions to serve load, thereby increasing NPC.

Q. If it is clear that the Company will engage in transactions with the Cal ISO in the future, what is the basis for the parties' adjustment?

A. Staff and ICNU claim that the benefits associated with the Cal ISO transactions are not reflected in NPC.

Q. Are they correct?

A. No. As previously described, all of the benefits of transacting with the Cal ISO are modeled in GRID. In general, when the Company's flexibility is removed or restricted, the costs of serving load increase. Removing the Cal ISO as a counterparty would limit the Company's ability to fully utilize the market and cause NPC to increase. The retooling of GRID that would be required to remove Cal ISO as a counterparty would result in increased costs elsewhere, because the Company would need to find a way to replace the transactions it makes with the Cal ISO. The premise of the parties' adjustment that there would be a net benefit that would offset Cal ISO expenses or even reduce NPC is wrong. The benefit of doing business with the Cal ISO is to avoid doing something more expensive in order to serve load. If the Commission were to disallow Cal ISO fees as a legitimate expense, the Company would be forced to find alternatives to doing business with the Cal ISO.

Q. How are Cal ISO transactions modeled in the filing?

A. Cal ISO transactions are reflected in the system balancing sales and purchases where no counterparties are explicitly identified. This is because the Company transacts with the Cal ISO in the real-time and day-ahead markets since those are the only markets in which the Cal ISO transacts. System balancing sales and purchases capture all transactions necessary to balance the system. Historic trends and the Company's actual verifiable experience demonstrate that the Company regularly transacts with the Cal ISO in order to serve load in a reliable and cost-effective manner. Cal ISO expenses are an ongoing and regular expense incurred by the Company in the normal course of business and should be recovered in NPC.

Wind Integration

CUB's Proposal to Use the BPA Wind Integration

Q. What is the first wind integration adjustment you address?

A. I address CUB's proposal to use BPA's wind integration charge as a proxy for the Company's wind integration costs. CUB claims that because stakeholders who participated in the Company's public process to analyze the 2010 Wind Integration Study (Wind Study) were not satisfied with the outcome, the Company should use BPA's wind integration charge of $5.83 per MWh to calculate NPC in this case. This compares to the Company's wind integration charge of approximately $6.32 per MWh in the Company's Initial Filing. CUB did not quantify this adjustment.

Q. Please provide some background on the Wind Study.

A. The Commission required the Company in Order No. 10-066 to complete a Wind Study by August 2, 2010. The Company initiated its public participation process with a public stakeholder meeting on February 26, 2010 to discuss the general framework and methodology for the Wind Study. The Company provided its draft 2010 Wind Study methodology paper on April 16, 2010, a revised draft methodology study on April 28, 2010, and a third draft methodology study on May 19, 2010 based on comments received from stakeholders and the Company's technical advisor The Brattle Group. The Company filed a motion with the Oregon Commission to extend the Wind Study due date to September 1, 2010 to accommodate more stakeholder study review time, and allot the Company additional time to investigate and validate modeling results.

Q. Did the Oregon Commission's imposed timeframe play a factor in your decision to hire the technical advisor The Brattle Group?

A. Yes. Because of the limited time the Company had to produce an updated Wind Study, the Company selected a technical advisor rather than forming a technical advisory committee. Use of a technical advisory committee would necessarily add a significant amount of time in order to accommodate the numerous scheduling issues that would arise when attempting to bring together multiple parties from different time zones and working constraints. The Company believes that its technical advisor, The Brattle Group, provided a thorough and objective independent review of the Wind Study. In the action plan for the 2011 IRP, the Company indicated it will form a technical review committee as part of its next wind integration study.

Q. Does the Company believe that its Wind Study results are accurate and complete?

A. Yes. The Wind Study verifiably depicts the Company's costs of integrating wind into its system.

Q. How do you respond to CUB's point that some stakeholders were not satisfied with the Wind Study?

A. The Company carefully considered all recommendations made by stakeholders who participated in the Wind Study process and as necessary consulted with The Brattle Group to evaluate whether any given recommendation might improve the study design and overall validity of the study results. There were numerous instances where the Company agreed with the recommendations submitted by stakeholders and incorporated them into the Wind Study.

It is neither feasible nor practical to expect that the Company would have incorporated all of the stakeholder recommendations as the process moved forward. All of the stakeholders did not agree with all aspects of the Wind Study, making it impossible to incorporate the views and opinions of all of those who participated in the process. While there were instances where the Company did not agree with the recommendations made by stakeholders, at no time did the Company intentionally suppress the views and criticisms of any of the stakeholders with the intentions of driving the Wind Study to a predetermined outcome.

Finally, I note that the only entities referenced by CUB—the Renewable Northwest Project and Mr. Randall Falkenberg—are not participating in this case. The Company therefore has no opportunity to conduct discovery on or respond to their arguments, so it would be improper to disallow costs based on CUB's representations of their concerns.

Q. Are BPA's wind integration costs directly comparable to the Company's wind integration costs included in NPC?

A. No. BPA imposes its charge for intra-hour integration of wind integration (*i.e.*, the integration costs between the scheduled generation to be delivered to BPA and the actual generation by the wind projects). The charge does not include the Company's inter-hour wind integration costs, which are approximately $0.70 per MWh. When BPA's intra-hour charge is combined with the Company's inter-hour charge, it results in a total charge of $6.53 per MWh, which is higher than the Company's proposed combined charge for intra- and inter-hour integration of $6.32 per MWh.

Q. Is the Company aware of any other available wind integration studies from an Oregon electric utility?

A. Yes. Portland General Electric (PGE) recently filed the preliminary results of its wind integration study. According to its results, PGE estimates wind integration costs of approximately $14.46 per MWh to integrate 850 MW of wind on its system. In comparison, the Company's wind integration costs are less than half this amount and are for a much higher level of wind generation.

Q. Does CUB present any evidence showing that the Company's wind integration charge is inaccurate?

A. No. CUB's only argument is that some stakeholders were not satisfied with the study.

Wind Study Must-Run Assumptions

Q. Do Staff and ICNU agree with the Company's must-run settings as applied to Gadsby units 4-6 and Currant Creek in GRID?

A. No. Staff argues that the Company has provided no evidence that the Gadsby units 4-6 and Currant Creek units currently operate on a must-run basis to provide regulating reserves for wind or that they will actually operate in this manner in 2012. ICNU contests the must-run settings for Gadsby units 4-6, but does not contest the must-run setting for Currant Creek. Staff's adjustment would result in a $1.1 million decrease to total-Company NPC, while ICNU's adjustment would result in a $2.9 million decrease to total-Company NPC.

Q. Is applying the must-run setting to these units appropriate?

A. Yes. While it is true that a must-run setting forces Gadsby units 4-6 and Currant Creek to operate in all hours, the must-run setting also ensures that these gas units are committed and able to carry reserves replicating the Company's real time operations. When the must-run setting is applied, units are committed and required to run at minimum levels, leaving GRID with the option to use the remaining capacity (the capacity differential between the minimum and the maximum rating) for reserves.

Q. Staff and ICNU argue that the Company does not operate the Gadsby units 4-6 as must-run facilities. How do you respond?

A. While the start-up data indicates that Gadsby units 4-6 tend to cycle and that one of the Currant Creek CTs cycles, albeit less frequently than the Gadsby units, the start-up data in and of itself does not show how generation from these units with must-run settings in GRID over the test period compare to historical generation data. Relative to generation in 2009, the period of historical data reviewed when the use of must-run settings were first implemented in the Wind Study, the average capacity factors for Gadsby units 4-6 and Currant Creek in GRID compare well to the average capacity factors derived from historical operational data. Over the test period in the Company's filed NPC, with must-run settings turned on, GRID yields a 32 percent average capacity factor for Gadsby units 4-6 and a 53 percent capacity factor for Currant Creek. In 2009, Gadsby units 4-6 were operated at a 33 percent capacity factor and Currant Creek was operated at a 65 percent capacity factor. As such, the must-run settings applied in GRID result in generation that is consistent with actual operational practice.

Liquidated Damages

Q. Please explain CUB's proposed adjustment related to liquidated damages.

A. CUB recommends an adjustment to incorporate a four-year rolling average of the Company's settlements for liquidated damages related to forced outages at generation plants.

Q. How do you respond?

A. The Company is not philosophically opposed to the new methodology proposed by CUB to reflect a four-year rolling average for liquidated damages. However, the Company does not agree that this adjustment should be introduced in a stand-alone TAM filing. First, the adjustment is not consistent with the TAM Guidelines. Second, liquidated damage payments are incorporated in the Company's revenue requirement in general rate case proceedings if the Company receives the payment during the base year. Liquidated damages are typically not recorded in the Federal Energy Regulatory Commission (FERC) accounts that are listed in the TAM Guidelines. In order to avoid double counting with payments already reflected in base rates, CUB should recommend this new methodology in a TAM filed concurrently with a general rate case.

Affiliate Mine Incentives

Q. Please explain Staff's proposed adjustment related to employee costs at the Bridger Plant.

A. Staff proposes to remove from NPC 50 percent of incentives, 50 percent of employee meals and gifts, and 100 percent of donations associated with the Bridger Coal Company and Deer Creek Mine. Staff argues that this proposal is consistent with Commission policy on these adjustments. Staff's adjustment reduces system NPC by $1.8 million.

Q. Do you agree that these adjustments are consistent with Commission policy?

A. No. Staff has not presented any justification or basis for the Commission to find the identified costs to be imprudent.

Q. Do the costs referenced by Staff provide benefits to customers?

A. Yes. As Staff concedes, affiliate coal costs are lower than market costs, undermining Staff's proposal to disallow costs associated with operating the mines.

NAES Adjustments

BPA Transmission Credit

Q. What has NAES proposed with respect to the BPA Transmission Credit?

A. NAES proposes that the Schedule 294 and 295 transition adjustment calculations be modified to include a credit for the resale of BPA transmission in the same amount as the 25 MW load decrement used in computing the transmission adjustment. Alternatively, if this proposal is not adopted, NAES recommends that the BPA credits adopted in the Docket UE 216 stipulation continue to be applied in the 2012 TAM.

Q. What had the Commission previously found with respect to the BPA transmission credit?

A. As Mr. Higgins discussed in his testimony, the Commission rejected proposals to recognize a BPA transmission credit in Order No. 04-516 in Docket UM 1081.

Q. Why does NAES raise this issue in this case?

A. NAES argues that circumstances are different today than when the Commission issued its order in UM 1081. NAES states that in 2004 the Company was contractually precluded from reselling its BPA wheeling rights, but that is no longer the case.

Q. Do you agree that this changed circumstance supports including a BPA transmission credit in the calculation of transition adjustments?

A. No. The Commission's decision in UM 1081 was not based solely on the fact that the Company was precluded from reselling its BPA transmission rights. The Company also argued that even if it "could avoid a purchase as a result of direct access load loss, it could neither avoid purchasing transmission nor resell the freed up transmission to capture any value."[8]

Q. Is it still the case that the Company does not obtain value from freed up transmission services?

A. Yes. Depending on the location of the lost load and the existing transmission arrangements with BPA and the Company's transmission function, the value of freed up transmission with BPA is minimal. In addition, the Company may need to acquire additional transmission in order to deliver the freed up generation to market in order to realize the transition credits determined for the lost load.

Q. Has the Company provided information to NAES on its actual experience with the transmission that might be freed up as a result of direct access load loss?

A. Yes. The Company has exchanged emails with Mr. Greg Bass of NAES and provided a response to an NAES data request on the subject. This information supports the Company's position that other customers would have to subsidize the imputed value of freed-up transmission in the transition adjustment. While the transmission services that the Company acquires from BPA to serve some of the sites in Oregon may be impacted by customers electing direct access, among

[8] *See* Order No. 04-516 at 6.

those sites, there was limited Point to Point (PTP) access that the Company could release on a seasonal basis. In addition, the sites to which BPA PTP transmission connects may not directly reach the load pockets of the direct access customers.

Q. What is your proposal with respect to the BPA Transmission Credit?

A. I recommend that the Commission reject NAES' proposal to include a BPA Transmission Credit in the calculation of the transition adjustment.

Line Losses

Q. What is NAES' proposal regarding the line loss percentages used to calculate the Schedule 294 and 295 transition adjustments?

A. NAES proposes that the line losses charged to Oregon's electric service suppliers (ESS) in the Company's Open Access Transmission Tariff (OATT) be the same as those used in the calculation of the transition adjustment. NAES argues that having different loss factors used in the state direct access arena and the federal OATT arena creates disadvantages in the pricing of direct access service for certain delivery voltages.

Q. Is NAES participating in the Company's transmission rate case before the FERC?

A. Yes. The Company filed its transmission rate case with FERC on May 26, 2011. NAES filed a protest in that proceeding on June 16, 2011, and the Company responded to that protest on July 1, 2011.

Q. What are NAES' central arguments with respect to the Company's proposed revisions to the OATT?

A. First, NAES argues that the Company's proposed Schedule 10 in the OATT should differentiate between distribution delivery at primary and secondary voltage. Second, NAES argues that there is a discrepancy between the line losses charged to an ESS through the OATT and those used in Oregon rates.

Q. With respect to NAES' first argument, why does the Company's OATT Schedule 10 not differentiate between distribution delivery at primary and secondary voltage?

A. Schedule 10 does not differentiate between distribution delivery at primary and secondary voltage because the Company does not provide secondary delivery service under its wholesale transmission rates, so it is not appropriate to include a secondary voltage loss factor in OATT Schedule 10. Secondary delivery voltage is related to retail service, which is not jurisdictional transmission service provided under the Company's OATT.

Q. With respect to NAES' second argument, why are the line losses in the OATT different from those used in Schedules 220, 294, and 295?

A. This issue is largely a matter of the timing of the Company's OATT filing and the timing of this filing. The current OATT loss factors set forth in OATT Schedule 10 are based on a 1995 loss study which was the most current study available at the time Schedule 10 was last updated. Oregon Schedules 220, 294 and 295 reflect more recent loss studies from 2007 reflecting a state-specific loss analysis including lower voltage levels associated with service at the state retail level. As part of its transmission rate case filing at the FERC, the Company included a proposed updated Schedule 10 and loss study with respect to its transmission losses over facilities at 46 kV.

Q. What is the Company's position on NAES' proposal?

A. While loss factors in state rate cases have been updated with the most recent factors from the 2007 loss study, the OATT Schedule 10 loss factor has not been updated with those most recent loss factor results. Until the loss factors in the OATT are approved by FERC in the Company's rate case, the Company does not have the authority to change them. The Company proposes that the current OATT-approved loss factors be reflected in Schedule 220, as described by Mr. Griffith, and be used to set the transition adjustments in Schedules 294 and 295 until FERC approves an OATT with updated loss factors. In this approach an ESS is held harmless by differences between line loss factors in the OATT and in the retail tariff because what they are credited for under the retail tariff will equal what they are charged for by the transmission provider.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Docket No. UE-227
Exhibit PPL/106
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Allocated Net Power Costs to Oregon

July 2011

PacifiCorp
CY 2012 TAM
July Update

	ACCT.	Total Company: UE 216 Final TAM CY 2011	Total Company: Filed TAM CY 2012	Total Company: **July Update CY 2012**	Factor	Factors CY 2011	Factors CY 2012	Oregon Allocated: UE 216 Final TAM CY 2011	Oregon Allocated: Filed TAM CY 2012	Oregon Allocated: **July Update CY 2012**
Sales for Resale										
Existing Firm PPL	447	25,965,364	26,081,862	**25,857,080**	SG	26.177%	25.623%	6,796,976	6,682,858	**6,625,263**
Existing Firm UPL	447	25,490,589	25,490,583	**25,490,583**	SG	26.177%	25.623%	6,672,694	6,531,357	**6,531,357**
Post-Merger Firm	447	425,569,012	479,326,113	**432,331,358**	SG	26.177%	25.623%	111,401,573	122,815,936	**110,774,646**
Non-Firm	447	-	-	**-**	SE	24.283%	24.336%	-	-	**-**
Total Sales for Resale		477,024,966	530,898,559	**483,679,022**				124,871,243	136,030,151	**123,931,266**
Purchased Power										
Existing Firm Demand PPL	555	50,413,276	2,798,085	**3,057,680**	SG	26.177%	25.623%	13,196,727	716,943	**783,458**
Existing Firm Demand UPL	555	46,845,802	46,946,386	**46,965,905**	SG	26.177%	25.623%	12,262,866	12,028,897	**12,033,898**
Existing Firm Energy	555	57,920,075	24,844,458	**24,712,774**	SE	24.283%	24.336%	14,064,911	6,046,166	**6,014,120**
Post-merger Firm	555	353,358,225	573,790,087	**572,860,870**	SG	26.177%	25.623%	92,498,892	147,020,087	**146,781,997**
Secondary Purchases	555	-		**-**	SE	24.283%	24.336%	-	-	**-**
Seasonal Contracts	555	-		**-**	SSGC	0.000%	0.000%	-	-	**-**
Other Generation Expense	555	38,906,526	3,726,876	**3,636,631**	SG	26.177%	25.623%	10,184,595	954,924	**931,800**
Total Purchased Power		547,443,905	652,105,892	**651,233,861**				142,207,992	166,767,016	**166,545,273**
Wheeling Expense										
Existing Firm PPL	565	40,049,244	27,034,359	**27,034,359**	SG	26.177%	25.623%	10,483,726	6,926,913	**6,926,913**
Existing Firm UPL	565	259,960	-	**-**	SG	26.177%	25.623%	68,050	-	**-**
Post-merger Firm	565	102,100,510	102,329,448	**102,898,595**	SG	26.177%	25.623%	26,726,940	26,219,492	**26,365,322**
Non-Firm	565	104,176	2,893,180	**2,886,131**	SE	24.283%	24.336%	25,297	704,087	**702,371**
Total Wheeling Expense		142,513,890	132,256,988	**132,819,085**				37,304,013	33,850,491	**33,994,606**
Fuel Expense										
Fuel Consumed - Coal	501	631,194,105	711,634,271	**712,588,017**	SE	24.283%	24.336%	153,274,821	173,183,855	**173,415,959**
Fuel Consumed - Coal (Cholla)	501	55,439,077	56,618,412	**57,709,222**	SSECH	24.812%	24.910%	13,755,347	14,103,650	**14,375,371**
Fuel Consumed - Gas	501	5,410,856	10,850,156	**8,735,448**	SE	24.283%	24.336%	1,313,935	2,640,502	**2,125,865**
Natural Gas Consumed	547	365,117,219	484,957,536	**443,183,136**	SE	24.283%	24.336%	88,662,546	118,019,633	**107,853,384**
Simple Cycle Combustion Turbines	547	8,178,179	36,248,503	**36,351,436**	SSECT	22.403%	24.329%	1,832,173	8,818,918	**8,843,960**
Steam from Other Sources	503	3,540,887	3,893,567	**3,760,489**	SE	24.283%	24.336%	859,844	947,542	**915,155**
Total Fuel Expense		1,068,880,323	1,304,202,445	**1,262,327,747**				259,698,666	317,714,100	**307,529,695**
Net Power Cost		1,281,813,152	1,557,666,766	**1,562,701,671**				314,339,428	382,301,456	**384,138,307**
Settlement Adjustment		(44,855,794)						(11,000,000)		
Total Net of Settlement Adjustment		1,236,957,358						303,339,428		
Increase Absent Load Change									78,962,027	**80,798,879**
Oregon-allocated NPC Baseline in Rates from UE 216								303,339,428		
$ Change due to load variance from UE-216 forecast								21,080,116		
2012 Recovery of NPC in Rates								324,419,544		
Increase Including Load Change									57,881,911	**59,718,763**
Add Other Revenue Change									3,745,661	**3,745,661**
Total TAM Increase									61,627,572	**63,464,424**
Variance										*1,836,852*

Exhibit PPL/106
Duvall/1

Docket No. UE-227
Exhibit PPL/107
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

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Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

July 2011 Updates to Net Power Costs

July 2011

Oregon TAM 2012 (March 2011 Filing)		NPC ($) =	1,557,666,766
		$/MWh =	$ 24.96

Oregon TAM 2012 (July 2011 Filing):

		Impact ($)	NPC ($)
Correction, one-off			
1	Correct Hunter station service	(115,088)	
2	Correct Ponderosa PTP wheeling	(432,283)	
Update, one-off			
1	Update for Small QFs	560,727	
2	Update termination date of Grant 10 aMW contract	(756,222)	
3	Update PGE Cove expense	225,000	
4	Update Douglas PUD pro-forma	63,878	
5	Update fixed and variable cost for Black Hills	197,932	
6	Update to 1106 OFPC	6,498,724	
7	Update Condit Dam decommssion date	3,064,177	
8	Update Monsanto interruptible contract cost	(198,946)	
9	Update APS PTP transmission rate	42,700	
10	Update Idaho PTP transmission rate	166,200	
11	Update Chehalis lateral pipeline cost	(53,196)	
12	Update for Woodland Tap wheeling	792,528	
13	Update commercial operation date for Pioneer Wind I QF	(4,437,689)	
14	Update coal contracts	4,767,513	
15	Update Kennecott Generation Incentive	(2,969,213)	
Adopted, one-off			
1	Bear River, median with flood control years	(2,053,421)	
	Total Adjustments from Updated =	5,363,317	
	System balancing impact of all adjustments	(328,412)	
	Total Adjustments from March 2011 Filing =	5,034,905	
	Oregon TAM 2011 NPC		**1,562,701,671**
Other			
	July 2011 load forecast, screened	(66,893,706)	
	Market capacity methodology from UE 216, screened	10,212,194	

Exhibit PPL/108
Gregory N. Duvall

Docket No. UE-227
Exhibit PPL/108
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Summary of Hedging Benefits in Oregon Rates

July 2011

Hedging Benefit / (Loss)

		Docket No.					
		UE 227 (Initial Filing)	UE 216	UE 207	UE 199	UE 191	Total
Rate Effective Date		1/1/2012	1/1/2011	1/1/2010	1/1/2009	1/1/2008	
Hedging Transactions as Filed							
STF Electricity Sales (MWh)		338,600	933,200	3,326,400	7,573,200	25,402,000	
STF Purchases (MWh)		219,600	183,200	873,000	1,630,920	18,629,400	
STF Electricity Sales Revenues	a	19,492,890	49,762,710	200,938,594	494,493,683	1,558,049,324	
STF Electricity Purchases Expenses	b	11,254,500	8,261,900	53,436,872	110,907,248	1,135,734,720	
Net Electric Swaps Expenses	c	(18,103,677)	(137,553,763)	(133,804,370)	(56,815,555)	-	
Natural Gas Physical Expenses	d	-	(96,034)	(341,941)	(341,334)	-	
Natural Gas Swaps Expenses	e	122,778,948	145,785,200	85,043,418	128,010,147	34,409,413	
Net Impact on NPC	f = b + c + d + e - a	96,436,881	(33,365,407)	(196,604,615)	(312,733,177)	(387,905,191)	
Transactions at Market							
STF Electricity Sales Revenues	g	12,890,452	27,503,871	136,127,957	370,852,631	1,429,680,306	
STF Electricity Purchases Expenses	h	8,683,763	4,666,971	1,016,504	93,699,324	1,052,565,742	
Net Impact on NPC	i = h - g	(4,206,689)	(22,836,900)	(135,111,452)	(277,153,307)	(377,114,564)	
Differences, at Market vs. as Filed							
STF Electricity Sales Revenues	i = g - a	(6,602,438)	(22,258,839)	(64,810,637)	(123,641,052)	(128,369,018)	
STF Electricity Purchases Expenses	j = h - (b + c)	15,532,941	133,958,834	81,384,002	39,607,631	(83,168,978)	
Natural Gas Expenses	k = 0 - (d + e)	(122,778,948)	(145,689,166)	(84,701,477)	(127,668,813)	(34,409,413)	
Total Hedging Benefit (loss)	l = j + k - i	(100,643,570)	10,528,507	61,493,162	35,579,870	10,790,626	
Amount in Rate Effective Period	m, weighted		10,528,507	61,493,162	35,579,870	10,820,190	**118,421,729**

Exhibit PPL/109
Gregory N. Duvall

Docket No. UE-227
Exhibit PPL/109
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Gregory N. Duvall

Responses to PacifiCorp Data Requests

July 2011

Request:

1.5 See Staff/100, Durrenberger/7, lines 12-16. Does Mr. Durrenberger dispute that PacifiCorp engages in Cal ISO transactions in actual operations?

Response:
I am not disputing whether or not PacifiCorp actually engages in Cal ISO transactions. The TAM is a forecast of net variable power costs for the upcoming calendar year of 2012 and the forecast does not indicate that there are any transactions with Cal ISO that would provide benefits to customers thereby justifying the corresponding expenses that have been included in the filing.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 227

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 1.11

July 11, 2011

Data Request No. 1.11:

See ICNU 100/Schoenbeck/25, lines 7-9. Does Mr. Schoenbeck dispute that the Company engages in Cal ISO transactions in actual operations?

Response to Data Request No. 1.11:

No.

Exhibit PPL/400
Stefan A. Bird

REDACTED
Docket No. UE-227
Exhibit PPL/400
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Rebuttal Testimony of Stefan A. Bird

July 2011

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

A. My name is Stefan A. Bird. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232. I am Senior Vice President, Commercial and Trading, for PacifiCorp Energy, a division of PacifiCorp.

Q. Please describe your educational and business background.

A. I hold a B.S. in mechanical engineering from Kansas State University. I joined PacifiCorp Energy and assumed my current position in January 2007. From 2003 to 2006, I served as president of CalEnergy Generation U.S., an owner and operator of Qualifying Facility and merchant generation assets, including geothermal and natural gas-fired cogeneration projects across the United States. From 1999 to 2003, I was vice president of acquisitions and development for MidAmerican Energy Holdings Company (MEHC). From 1989 to 1997, I held various positions at Koch Industries, Inc., including energy marketing, financial services, corporate acquisitions, project engineering and maintenance planning in the Americas and Europe.

In my current position I oversee the Company's Commercial and Trading organization which is responsible for dispatch of the Company's owned and contracted generation resources, procurement of new generation resources, and wholesale purchases and sales of natural gas and electricity to balance the Company's load and resources. I am also responsible for PacifiCorp's load and revenue forecast, integrated resource plan (IRP) and net power costs modeling.

Q. Please specifically describe your experience in electric utility risk management, hedging and natural gas procurement.

A. I have over 20 years of experience in the energy field with a concentration in managing the commercial and financial aspects of large scale electricity and natural gas commodity risk. I began analyzing and developing strategies to manage natural gas risk in 1992 in the Gulf Coast following the acquisition of an interstate pipeline company and the deregulation of the natural gas market. The start-up electricity services company I helped develop in 1994 traded the first NYMEX electricity futures contract and was at the time one of the three largest electricity trading companies in the United States. As a developer for MidAmerican Energy Holdings Company and as president of CalEnergy, I negotiated short-term and long-term contracts and developed and executed risk management strategies to manage natural gas procurement and electricity sales for generation assets distributed across the United States. For the past four and a half years at PacifiCorp, I have been a member of the Risk Oversight Committee and I oversee all of the Company's wholesale electricity purchases and sales, natural gas procurement and risk management activity to comply with the risk management policy and manage risk on behalf of our customers.

Q. Do the witnesses for CUB and ICNU have any direct experience in electric utility risk management, hedging and natural gas procurement?

A. Not based upon the experience referenced in the qualifications filed with their testimony in this docket.

Q. What is the purpose of your testimony?

A. My rebuttal testimony responds to the opening testimony of the Citizens' Utility Board of Oregon (CUB) presented by Messrs. Robert Jenks and Gordon Feighner and the Industrial Customers of Northwest Utilities (ICNU) presented by Mr. Donald Schoenbeck with respect to the Company's hedging activities. My rebuttal testimony addresses the Company's hedging strategy and practices and demonstrates that these practices are prudent and reasonable. Specifically, my rebuttal testimony:

- Provides an overview of the Company's risk management policy and hedging program;
- Demonstrates that the Company's hedging activities associated with the test period in this case were consistent with the risk management policy and hedging program;
- Discusses prior regulatory and third-party review of the Company's risk management policy and hedging program; and
- Demonstrates that there is no basis for a prudence disallowance based on contentions that the Company hedged too much or hedged too far forward.

In support of these conclusions, the rebuttal testimony of Company witness Mr. Gregory N. Duvall quantifies the impact of the Company's risk management policy and hedging program on net power costs in Oregon rates and demonstrates that the risk management policy and hedging program have reduced the volatility and overall level of the Company's net power costs.

Overview of Company's Risk Management Policy and Hedging Program

Q. What is the purpose of the Company's risk management policy and hedging program?

A. The goals of the Company's risk management policy and hedging program are to: (1) ensure that reliable power is available to serve customers; (2) reduce net power cost volatility; and (3) protect customers from significant risks. The Company's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed and updated as necessary.

Q. What are the main components of the Company's risk management policy?

A. As outlined in the Company's risk policy, the main components of the Company's risk management of fuel and power price volatility are value-at-risk (VaR) measurements and VaR limits, position limits, and stop-loss limits. These limits force the Company to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility.

Q. What is the purpose of the Company's hedging program?

A. The hedging program supplements and is subordinate to the Company's risk management policy by specifying separate to-expiry VaR calculation and targets. As stated in the Company's most recent IRP: "Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes….Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes."[1]

The Company has a large short position in natural gas because of its ownership of gas-fired electric generation, requiring it to purchase large quantities of natural gas to generate power for its customers. The hedge program has targets for the Company to purchase natural gas well in advance of when it is required to reduce the size of this short position. Likewise, on the power side, the Company either purchases or sells power in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Q. Please identify the documents that govern the Company's hedging activities.

A. The primary governance of the Company's hedging activities is in the Company's Confidential Risk Management Policy, and Highly Confidential Appendices, which are attached as Confidential/Highly Confidential Exhibit PPL/401. The hedging program is also governed by the Company's Confidential Front Office Procedures and Practices, Exhibit 10, also included in Confidential Exhibit PPL/401. The documents expressly state that the risk management policy governs in the event of a conflict between it and the front office procedures and practices.

Q. Does the Company hedge its separate power or natural gas positions or its net energy position?

A. The Company hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions.[2] The Company's 2011 IRP analysis shows that a "hedge only power" or "hedge only natural gas" approach results in higher

[1] PacifiCorp 2011 IRP, Docket LC 52, Appendix G at 161-162 (Mar. 31, 2011).
[2] *Id*. at 170.

risk (*i.e.*, a wider distribution of outcomes).[3] There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics.

Q. Can you explain why this is such a critical factor for electric utilities?

A. Yes. Assume the Company has a 500 MW natural gas-fired generation plant with a heat rate of 8 MMBtu/MWh (*i.e.*, requires 8 MMBtu of natural gas to create 1 MWh of electricity). In the first example, assume natural gas prices for a forward period are $4.00/MMBtu and electricity prices are $40/MWh. Under these conditions, it would be economic to dispatch the natural gas plant, as the cost to produce the electricity is $32/MWh ($4.00/MMBtu multiplied by 8 MMBtu/MWh) which is less than the electricity market price. Therefore, the Company would hedge the fuel requirements by purchasing 4,000 MMBtu of natural gas (500 MW multiplied by 8 MMBtu/MWh) and sell 500 MW of electricity. In the second example assume natural gas prices fell to $3.50/MMBtu and electricity prices fell to $26/MWh. Under these conditions it would not be economic to dispatch the natural gas plant, as the cost to produce the electricity is $28/MWh ($3.50/MMBtu multiplied by 8 MMBtu/MWh) which is greater than the available electricity market price. Therefore, the Company would not hedge the fuel requirements.

Q. What is your conclusion from these examples?

A. Electricity prices are just as important as natural gas prices in determining the volume of natural gas hedges for an electric utility with natural gas fired

[3] *Id.* at 170.

generation such as the Company. Neither CUB nor ICNU considered this important factor in their testimony and recommendations in this case.

Q. How is the Company's hedging program structured?

A. Since 2003, the Company's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. Highly Confidential Exhibit PPL/402 provides a tabular representation of the Company's current progressive portfolio hedging approach as a percentage of net power costs. In May 2010, the Company moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency to the Company's combined natural gas and power exposure by period. It enhances the progressive approach to hedging that the Company has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically results in reducing hedge requirements as commodity price volatility decreases and increasing hedge requirements as correlations among commodities diverge, all the while maintaining the same risk exposure.

Q. Have the Company's risk management policy and hedging program changed in response to the development of shale gas and the decreasing price of natural gas?

A. Yes. The Company's risk management policy has been actively reviewed by its internal risk oversight committee and updated every year for several years running to reflect best practices and respond to changing market conditions. In addition, as mentioned above, the hedging program was modified in May 2010 with the institution of the TEVaR metric. The result of these program changes in combination with changes in the market (such as reduced volatility to which the Company's program automatically responds), has been a significant decrease in the Company's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis. These hedges have decreased from a peak forward hedge percentage of approximately [redacted] percent in 2008 (a period reflecting high volatility) to approximately [redacted] percent in 2011 (a period reflecting lower volatility).

Q. ICNU contends that many of the gas hedges in this proceeding fell outside the guidelines for pre-approved transactions because the hedge horizon was longer than 36 months. Is this contention correct?

A. No. As noted above, the Company's risk management policy ultimately governs the Company's hedging program. The Company amended its risk management policy in October 2006 to move to a 48-month transaction tenor. The risk management policy was further amended in November 2006 and this version, which maintained the 48-month tenor, was operative during the time of the transactions ICNU now challenges.

The confusion on this point is likely a result of the Company producing various versions of its risk management policy in response to one data request (ICNU 7.3) and its front office procedures and practices in response to another data request (ICNU 2.18). The Company's supplemental response to ICNU Data

Request 2.18 clarifies that the two documents must be reviewed together, with the risk management policy expressly governing in the event of any conflict between the two.

Q. Do the hedges in this case include some transactions that extend beyond 48 months?

A. Yes. The Company purchased certain natural gas swaps in late 2007 and 2008 which extended beyond 48 months forward. The Company made an exception to its normal policy for these transactions, which reduced hedging costs through the use of standard market products. In forward markets at that time, there was greater liquidity in standard tenor products such as November-March or April-October than for individual months. As such, rather than incur a higher cost due to low liquidity, the Company opted to transact the more standard winter strip. By doing so, the Company avoided the illiquidity cost of an individual month and the continued illiquidity and higher costs by hedging with individual months as they rolled into the policy defined hedging horizon.

Q. Why did the Company purchase a relatively high volume of long-dated natural gas swaps in 2007 and 2008?

A. The Company entered into the 2007 and 2008 longer dated hedges to mitigate the risk of unfavorable prices and maintain compliance with its risk management policy as large open positions rolled into the period within 48 months of delivery. The Company's risk management policy at the time set absolute limits on short positions measured in MMBtu per day, for each forward month or quarter through 48 months. In addition, the Company's risk management policy also contained value-at-risk limits, calculated based on power and natural gas open positions, power and natural gas market prices and volatilities which were elevated in the 2007-2008 period, and commodity correlations.

At the time these hedges were transacted, there was an elevated risk of future price escalation reflected by then current high market volatility. Third party expert forecasters at the time also projected the risk of even higher prices consistent with then current views of continued economic growth, likely carbon legislation and the need for more expensive LNG to replace declining conventional natural gas supply to satisfy growing demand. The global economic crisis and shale gas revolution that subsequently developed was not anticipated by the market and most third party experts. Since that time the Company has continued to update its risk management policy and hedge program to reflect larger position limits consistent with its natural gas generation resource expansion and incorporate a more dynamic hedge program with the replacement of volume percentage based targets with TEVaR-based targets.

Regulatory Review of Company's Risk Management Policy and Hedging Program

Q. Has the Oregon Commission previously reviewed the Company's risk management policy and hedging program?

A. Yes. As part of the Commission's 2005 Natural Gas Procurement Study, the Commission Staff met with representatives of the Company to discuss natural gas procurement strategies. The report notes:

> PacifiCorp cited reliability and risk management as the primary goals of their purchasing strategies. The company communicated to staff that it uses at least a three year horizon for supply and acts as a market participant in their purchasing practices. The company represents it

> transacts at prevailing market prices. PacifiCorp can, and sometimes does, use financial instruments as a part of their natural gas purchasing strategies. The company's natural gas costs for 2006 have been, at least partially, hedged by fixed price purchases executed as far back as 1994 for the Hermiston plant and 2003 for the Utah plants. The result of the hedging is that PacifiCorp's hedged cost of natural gas for 2006 is below current market prices.[4]

Staff also conducted an "opportunity cost" analysis for the years 1999 through 2004 that compared the Company's overall procurement strategies over simply purchasing identical quantities from the identical hubs at prevailing market index prices. Based on this analysis, the report concluded:

> Overall, when the entire portfolio is considered, PacifiCorp achieved an 82 percent reduction in volatility and a fifteen percent decrease on average in the per therm price of natural gas over the time period analyzed.[5]

The pages of the report pertinent to PacifiCorp are reflected in Exhibit PPL/403.

Q. Has the Company updated the analysis contained in the Oregon Staff's natural gas procurement report?

A. Yes. Mr. Duvall's rebuttal testimony presents the results of a similar analysis conducted for the years from 2005 through 2010. This analysis demonstrates that, during the most recent six-year period, the Company's power and natural gas hedging activity decreased net power costs volatility by 50 percent and 52 percent, respectively.

Q. Has any party to a PacifiCorp general rate case or TAM filing previously proposed to disallow the Company's hedging costs?

A. No. I understand that in the Company's net power costs deferral arising from the Western energy crisis, Docket UM 995, ICNU challenged certain power costs on

[4] *See* Exhibit PPL/403 at p. 56.
[5] *Id.* at p. 58.

the basis that the Company should have hedged more of its market exposure.[6] The Commission rejected this argument, but in the concurring opinion of the Commission chair, directed electric utilities to more comprehensively examine and plan for risk in the future.[7] PacifiCorp's current risk management policy is informed by these events.

Q. Was the Company's risk management policy and hedging policy recently evaluated comprehensively by an independent third party?

A. Yes. In October 2009, the Division of Public Utilities (DPU) in Utah completed a comprehensive, third-party evaluation of the Company's risk management policy and hedging program. The DPU's Blue Ridge Report affirmatively concluded that the Company's risk management policy and hedging program adhered to generally accepted industry standards:

> Overall, Blue Ridge found that the Company's commercial trading and risk management programs (and the related hedging programs) are well-documented and controlled and adhere to generally accepted standards found elsewhere in the industry. The Company has well-stated goals and strategy that is aimed at mitigating price volatility. In addition, our review of the Company's internal documents showed that the Company is self-monitoring compliance with accepted commercial trading and risk management procedures through its own internal audit function.

While the Company's risk management policy and hedging program have continued to be refined and improved, the fundamentals of the risk management policy and the hedging program have not changed since the time of the DPU's Blue Ridge Report. The report is provided as Exhibit PPL/404.

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[6] *See* Order No. 02-469 at 16.

[7] *Id*. at 76.

Q. Did the Blue Ridge Report address policy issues related to hedging?

A. Yes. The Blue Ridge Report noted:

> The question has been asked, "Why hedge?" The answer lies in one fundamental statement: prices and supplies for energy commodities (crude oil, natural gas, electricity, etc.) can and have been extremely volatile. The benefit of hedging is that when prices are rising (either rapidly in the short term or gradually in the long term), a hedged portfolio of supply should mitigate the effect of those increases. However, the opposite is also true. When prices fall suddenly, a hedged portion of the supply can cost the utility and its customers the difference between the prices that were available at the current time versus the hedged prices for that supply. This cost (when netted against any gains) along with the administrative costs associated to operate and manage the trading operations is considered the insurance premium associated with a hedged portfolio.
>
> * * * * *
>
> [H]aving a "no hedge" policy clearly exposes consumers to significant (and likely) price swings. Assuming that an upward price trend continues (despite recent price levels and short-term price forecasts), consumers are very likely to pay higher prices for energy absent some level of hedging and price volatility mitigation.

Q. Has the National Regulatory Research Institute (NRRI) provided guidance related to natural gas hedging by utilities?

A. Yes. The DPU also sponsored a presentation by NRRI to the Utah Commission in June 2009. The NRRI Report[8] indicates that, for many years, state commissions have conveyed that the failure to engage in hedging (*i.e.*, buying natural gas in the day-ahead market or spot price) may be imprudent.

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[8] Docket No. 09-035-21, Gas Hedging Presentation to The Public Service Commission of Utah Technical Conference, Ken Costello, The National Regulatory Research Institute (June 3, 2009), available at: http://www.psc.utah.gov/utilities/electric/09docs/0903521/TechConf%206-3-09/Gas%20Hedging.ppt%20(UT%20PSC).pdf

Q. Does the NRRI Report provide guidance on standards for determining the prudence of a utility's hedging costs?

A. Yes. The NRRI Report states that "Second-guessing and micromanaging should be avoided." It explains that "Second-guessing is contrary to the traditional prudence standard, and in addition, creates distorted incentives for utility hedging." Instead, it recommends that, "[a]ccording to the prudence standard, a commission should maintain authority to evaluate the reasonableness of (1) a hedging strategy ex ante, and (2) the execution of the strategy." The NRRI Report suggests that a Commission could set an *ex ante* standard by, for example, defining an acceptable level of risk tolerance to price volatility.

Q. Does the Company agree with the NRRI Report's recommended approach to Commission review of the prudence of the Company's risk management policy and hedging program?

A. Yes. The Company welcomes *ex ante* direction from the Commission on the Company's risk management policy and hedging program. However, the Company agrees that second-guessing the Company's risk management policy and hedging program is contrary to the prudence standard. This is especially true given the fact that CUB and ICNU second-guess the risk management policy and hedging program based upon a single year of net losses and a subset of the Company's hedges—and fail to consider the *ex ante* risk reduction benefits to customers and net savings to customers of hedging on a multi-year, all-in basis.

Overall Response to Hedging Adjustments

Q. Please summarize CUB's and ICNU's hedging adjustments.

A. While CUB and ICNU propose different approaches, they each seek to disallow a large amount of the Company's net power costs related to the Company's hedging activities in the test period. However, a set of incorrect assumptions and facts provide the foundation for these proposed adjustments, including:

(1) The Company did not follow its risk management policy;

(2) The Company hedged too much of its open position, compared to other utilities; and

(3) The Company hedged over too long a time horizon, given the lack of liquidity in the forward markets (between 36 and 48 months).

I addressed and corrected the first issue above, and correct the record on the remaining two issues below.

Q. Is there another threshold flaw in the approach of CUB and ICNU?

A. Yes. While CUB and ICNU purport to support a portfolio approach to the Company's hedging, they attempt to isolate the Company's natural gas swaps from other aspects of the Company's portfolio. It is inappropriate and unfair to propose to disallow natural gas swaps in isolation from other hedges when the Company has an integrated hedging program designed to take full advantage of the natural offsets between its long power and short natural gas positions.

As discussed above, power and natural gas prices are correlated and the positions for each commodity are inextricably linked to spark spreads. Spark spreads represent the difference in the market price of power and the market price of natural gas converted to power through a gas-fueled power plant. Further, the price of power in on-peak hours is often established by a gas-fired plant on the margin. Because power and natural gas commodity prices are highly-interrelated, it is appropriate and necessary to report and manage the risk exposures from these commodities in a combined fashion. Separate management of these commodities increases the risk of over or under hedging or increases the overall risk profile of the Company by hedging in a manner that ignores or reduces natural offsetting positions. A hedging program that ignores this correlation and relationship will naturally be less effective than the current program. This is further demonstrated in the Company's recent 2011 IRP discussion on appropriate hedging strategies.

Q. Did the hedging program incur losses for the test period?

A. Yes. As set forth in PPL/108, Duvall/1, net power costs in the Company's initial filing reflect approximately $100.6 million of forecast hedging losses.

Q. Why did the Company incur these forecast losses?

A. The forecast hedging losses in the test period are a function of unforeseen declining forward prices, not the volume of the hedges, the time horizon of the hedges or the hedging instruments used. Hedging protects customers from the risk that net power costs in rates could be significantly higher if prices moved unfavorably in the test period that is used to set rates. To get this protection, customers must forego potentially lower net power costs that could result if prices moved favorably in the test period. As ICNU acknowledges, it is unlikely that a company can "beat the market" through its hedging program.

Effectiveness of the Company's Hedging Program

Q. Should the Commission judge the effectiveness of the hedging program on the basis of whether it has made or lost money for customers?

A. No. The goal of the hedging program is to reduce volatility in the Company's net power costs primarily due to changes in market prices. Consistent with the findings in the Commission's 2005 Natural Gas Procurement Study, Mr. Duvall demonstrates that the Company's hedging program has significantly reduced net power cost volatility. In addition, the Company's risk management policy and hedging program has been thoroughly reviewed and validated by an independent third party expert retained by the Utah DPU, on the basis that it was well-documented and controlled, and adhered to generally accepted industry standards.

Q. Nevertheless, can you demonstrate that the Company's hedging program has reduced net powers costs for Oregon customers over the last several years?

A. Yes. Mr. Duvall sponsors an exhibit that demonstrates that the Company's hedging activity since Oregon Docket UE 191 has reduced net power costs by approximately $118.4 million.

Hedging Volumes

Q. Please respond to the claims of intervenors that the Company is hedged at too high a percentage compared to other utilities.

A. The Company's hedging program progresses at gradually increasing levels approaching the time of delivery. This graduated approach provides diversity and flexibility to the hedging program. At the time of delivery, the Company is generally [redacted] percent hedged. This limits the Company's exposure to the volatility of the spot market. By the end of the fourth year on a rolling basis the Company is [redacted] (following the expiration of the 15-year Hermiston natural gas supply hedge in July 2011). The Company's portfolio approach to progressive hedging from [redacted] percent at the time of delivery to [redacted] by the end of the fourth year provides the risk diversification benefits of dollar cost averaging during this rolling four year period and avoids concentrated exposure to short periods of price changes. In fact, the Company's TEVaR-based hedge program is consistent with the spirit of the progressive approach advocated by CUB in its opening testimony, but the Company's TEVaR-based program is more effective in delivering the progressive risk mitigation approach desired by CUB than can be accomplished by using CUB's simple volume percentage targets.

Q. At what percentage is the Company's open position for natural gas hedged for the test period in the 2012 GRID NPC Rebuttal Update study?

A. Mr. Duvall's testimony shows that the Company's natural gas position is approximately [redacted] percent hedged in the 2012 GRID NPC study in the rebuttal filing in this case. The GRID study reflects all of the Company's actual hedges for the forecast test period, which also comply with the TEVaR targets. The volume percentage of hedging is lower in the Company's normalized GRID net power costs than is reflected in its daily risk management operations model that is used to measure and report daily compliance with the risk management policy. The difference is due to different assumptions and modeling methodology. With normalized inputs and a static point forecast for all assumptions, GRID optimizes the Company's natural gas plants and runs them at a higher capacity factor, thus increasing the forecast natural gas requirements. In contrast, the Company's risk management operations model is updated daily with numerous inputs and does not rely on a static forecast but rather incorporates volatility to forecast power and natural gas requirements, which results in a lower forecast natural gas supply requirement than forecast in GRID. Since the forecast natural gas requirement is higher in GRID, the hedge percentage of forecast natural gas requirements is smaller.

Q. Please respond to the claims of intervenors that the Company hedged its natural gas exposure at too high a percentage compared to other utilities.

A. On a normalized basis—which is the basis for forecasting net power costs—the Company's hedged position is less than the percentage limits proposed by intevenors. This demonstrates that there is no basis for the adjustments in this case that claim that the Company is overhedged.

Q. Please respond more specifically to ICNU's recommended hedging parameters.

A. ICNU's recommended hedging parameters would decrease the sophistication and effectiveness of the Company's hedging strategy.

ICNU recommends that PacifiCorp hedge at 80 percent in year one, reducing the volume by 20 percent each year through year four. ICNU does not provide any evidence in support of these particular targets. ICNU recommends hard, volumetric targets, which would reduce the flexibility, responsiveness and transparency of PacifiCorp's current TEVaR targets.

In addition, ICNU argues that PacifiCorp should be hedged at a substantially lower level during the second quarter of each year "when abundant hydro is available to displace the vast majority if not all the gas-fired generation in the Pacific Northwest region."[9] PacifiCorp's hedge program currently takes into account market conditions such as abundant Pacific Northwest hydro. Modifying the hedge program further would be double counting this impact.

Q. CUB cites the testimony of Dr. Lori Schell on behalf of the Utah Office of Consumer Services (OCS) in the Company's most recent Utah general rate case in support of CUB's position that the Company was over-hedged for the Utah test period. Similarly, ICNU notes that several parties in Utah have challenged the Company's hedging costs. Please respond.

A. The Utah general rate case refers to a different test period than in this case. Even if the test periods did align, the hedging issues in the Utah general rate case, among other items, were recently settled. As a part of that settlement, the parties agreed on a process to review the Company's hedging practices on a *prospective* basis to determine whether the risk management policy and hedging program should be revised in some manner. PacifiCorp is agreeable to a similar process in Oregon to address CUB's and ICNU's concerns.

In addition, I understand that the pre-filed testimony of a witness of another party in another state cannot provide the foundation for CUB's proposed adjustment, especially when the testimony has been made moot by a settlement. Moreover, Dr. Schell's testimony cannot fairly be evaluated without also

[9] ICNU/100, Schoenbeck/16.

considering the testimony filed in that case by the Company's expert, Mr. Frank Graves, of The Brattle Group, attached as Confidential Exhibit PPL/405.

Based on The Brattle Group's work with electric utilities for many years, it has access to information about electric industry standards on the scope of hedging programs, which is otherwise difficult to obtain given the confidential nature of the underlying data. Mr. Graves' expert opinion is that electric companies with combined natural gas/power hedging programs often hedge at higher volume levels than natural gas-only companies (which rely heavily upon gas storage) and that the Company's program, including its hedging volumes and hedging horizon (discussed in more detail below), fully comports with industry standards. As such, the degree of hedging boils down to a subjective preference level of risk tolerance, and there is certainly nothing objectively imprudent about the extent of the Company's hedging program.

Q. How do natural gas distribution companies differ from electric utilities with respect to their hedging needs and practices?

A. There are significant physical and financial differences in the hedging issues faced by natural gas companies and electric utilities. First, natural gas companies are only concerned with the natural gas commodity (and its transportation); they do not have to worry about the value of that natural gas once converted to electricity, or how purchased power might substitute for (or increase) gas usage. In contrast, electric utilities are more concerned about the spark spread between gas and electricity than the price of gas itself (for which they may be sellers, as well as buyers). Second, the volume of gas that electric utilities need also tends to be more of a peaking requirement that can be variable throughout the year, depending on the cost of other fuels. Third, electric utilities also hedge much more than just their fuel costs, because they must buy and sell significant quantities of power to balance their system supply against load. Fourth, spot electric prices are both extremely volatile and asymmetrical in terms of price distribution, resulting in price spikes often at times of high demand. For all of these reasons, the hedging requirements of electric companies are generally more complex than for gas distribution companies and may result in an electric utility hedging more volume for a longer time horizon.

Q. CUB also points to a previous Commission order, Order No. 07-200, lowering Avista's hedging volume as support for its adjustment. Please comment.

A. For several reasons, this case provides no support for CUB's adjustment disallowing hedging costs in this case for transactions beyond a 36 month horizon.

First, in Oregon Avista is a natural gas local distribution company, not an electric utility. Consistent with my observations above, the Commission's gas procurement study specifically distinguished natural gas and electric utilities, noting at pp 5-6 that:

> The natural gas purchasing strategies of Oregon's electric utilities and large industrial natural gas consumers differ from those of Oregon's LDCs. This is due to both the nature of their businesses (natural gas for peaking generators versus serving load, industrial production) and their peak demand times (e.g. summer vs. winter).

Second, Staff commenced its investigation into Avista's gas procurement and hedging practices primarily because of concerns that are not implicated by PacifiCorp's risk management policy and hedging program, including "lax internal monitoring and controls," "inadequate research and analysis of market intelligence," and "lack of management attention and control."[10] Additionally, Avista was pursuing a different hedging strategy in Oregon than in its other state jurisdictions, because its purchase gas adjustment mechanism in Oregon allowed for only 90 percent recovery of its purchase gas costs.[11] The governance and operation of PacifiCorp's risk management policy has never been challenged, and this policy does not vary based on state-specific cost recovery mechanisms.

Third, under the Stipulation in that case, Avista agreed to hedge at the 70 percent level for one year only, in return for an agreement that permitted it 100 percent recovery of its purchase gas costs.

Finally, CUB claims that in adopting the Stipulation in Order No. 07-200, the Commission indicated that Avista "was engaging in a natural gas strategy that was imprudent because it was too reliant on hedging." There is no such statement or finding anywhere in the Order.

Hedge Horizon

Q. Do you agree with CUB's recommendation that the Company should restrict hedging to up to 36 months?

A. No. The hedge program is based on the premise of hedging forward as long as there is sufficient liquidity. Although CUB asserts that "[t]here are real questions about the liquidity of the market in a timeframe greater than 36 months",[12] CUB presents no data or evidence to support this assertion. Ironically, CUB supports

[10] *See* Order No. 06-610, Appendix A at pp. 13-14.
[11] *Id.* at 9.
[12] *See* CUB/100, Jenks – Feighner/10, lines 21-22.

this position by citing to information developed in NW Natural's Encana transaction—a thirty-year gas supply hedge which CUB supported as being in the best interests of customers.

Q. ICNU also alleges that PacifiCorp hedged too much, too far out in time. Does it provide any specific evidence to support these contentions?

A. No. While ICNU alleges that PacifiCorp's hedges are more extensive than NW Natural's, at the same time it acknowledges that NW Natural hedges for up to five years (longer than PacifiCorp), and entered the 2010-2011 prompt year 77 percent hedged, which is higher than the [redacted] percent natural gas hedged percentage reflected in the net power cost study in this case (further, if NW Natural's percentage excludes its gas storage, the 77 percent number would be understated).

In any event, as explained above, comparisons to gas distribution companies are of limited value in determining the reasonableness of PacifiCorp's hedging. Notably, ICNU makes no comparison to Portland General Electric Company's hedging practices, which according to its most recent Integrated Resource Plan, appear to be similar to PacifiCorp's in the context of progressively hedging over its hedging horizon, however its hedging horizon is slightly longer at five years compared to PacifiCorp's four-year horizon.

Q. Is there adequate liquidity in the market in the period 36 to 48 months from delivery?

A. Yes.

Q. Are multiple counter-parties available during the Company's four-year hedge horizon?

A. Yes. Confidential Figure 1 shows the number of credit-worthy counterparties with whom the Company currently transacts natural gas hedges. While the market liquidity does diminish somewhat further from the time of delivery as indicated by the number of available counterparties, there is sufficient liquidity in the 36- to 48-month period (*i.e.*, year 4) for the Company to hedge its natural gas exposure. The Company recognizes the market constraints in this period through its hedging target levels, which are much lower in year 4 than in year 1.

Confidential Figure 1

[redacted]

Q. Why is the year 4 bar partially shaded in Confidential Figure 1?

A. In year 4 the Company currently has [redacted] credit-worthy counterparties; however, [redacted] have indicated they only transact beyond [redacted] after specific transactions have been approved by their management.

Q, Is there a more direct measure of liquidity?

A. Yes. The price spread between the ask price to sell and the bid price to buy is a more direct indicator of liquidity. This spread can be viewed as a surrogate for the transaction costs of hedging, with wider bid ask spreads indicating reduced market liquidity and higher transaction costs to hedge and narrow bid ask spreads indicating enhanced market liquidity and reduced transaction costs to hedge.

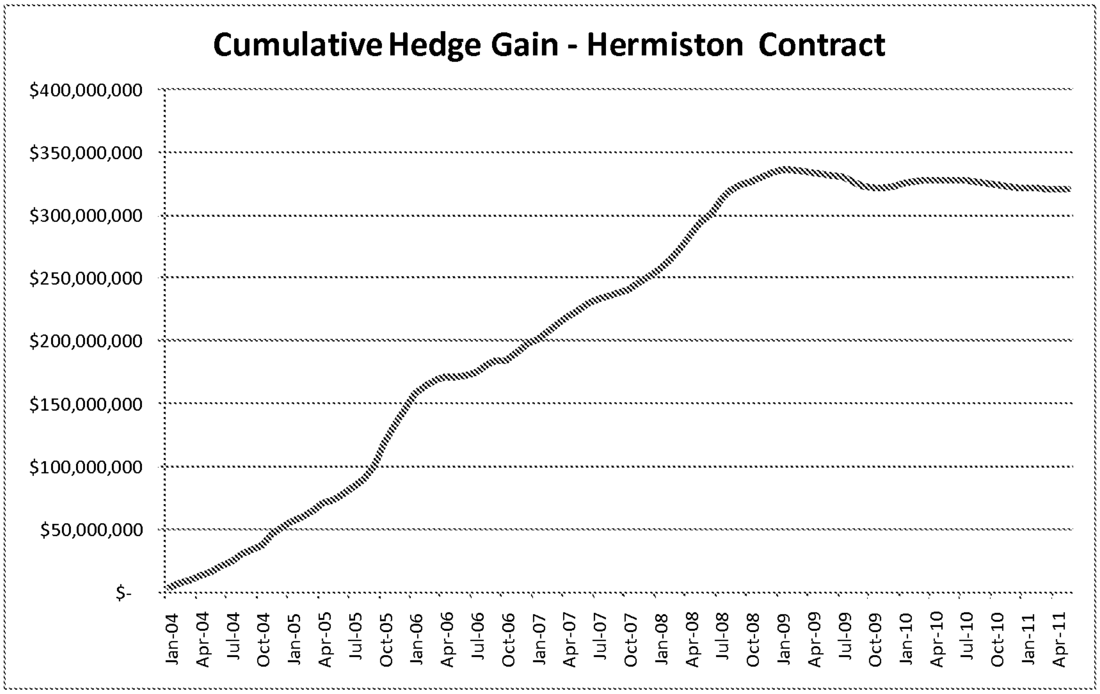
Q. What are the bid ask spreads for the Company's hedging periods?

A. The Company does not record nor have access to comprehensive bid ask spread data. However, the Company estimates based on its experience that it has paid as little as $0 per MMBtu in bid ask spread "transaction costs" to purchase natural gas in year 1 and as much as $0.10 per MMBtu in year 4. These costs are insignificant compared to the volatile natural gas market prices.

Q. Have the Company's customers benefitted from the Company's long-term hedging of its natural gas supply?

A. Yes. The Company hedged 100 percent of the fuel for the Hermiston natural gas fired plant with a 15-year supply agreement. At times the hedge was favorable and at times unfavorable compared to spot prices. Overall, the long term supply agreement was very favorable. As shown in Figure 2 the Hermiston gas hedge yields a cumulative benefit to customers of $320 million from January 2004 through May 2011.

Figure 2



Q. How is this long-term transaction consistent with PacifiCorp's risk management policy?

A. The risk management policy sets the parameters for pre-approved hedging transactions. The policy retains the flexibility for the Company's management to specially approve transactions outside of these pre-approval limits, such as the Hermiston gas supply contract.

Q. Has the Company reduced the amount of its hedges in year four in response to current conditions in the natural gas markets?

A. Yes, as noted above, the Company's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis, has decreased by approximately [redacted] percent between 2008 and 2011. Hedging flexibly in this manner over a 36- to 48-month period is a reasonable and prudent practice, especially for an electric utility such as the Company.

Foresight of Falling Natural Gas Prices

Q. During the period when the Company was executing hedges 36 to 48 months in advance for the test period, should the Company have foreseen the decrease in natural gas prices for the test period in this case?

A. No. Spot natural gas prices were very high during this time period. Neither the forward price curves at the time the hedges were transacted, nor third party spot price forecasts indicated a significant expected future drop in natural gas prices. If natural gas prices had remained high as then reflected in forward market prices or even higher as then forecast by PIRA, the Company's hedges in the test period, especially those in the 36- to 48-month category, would have been deep in the money.

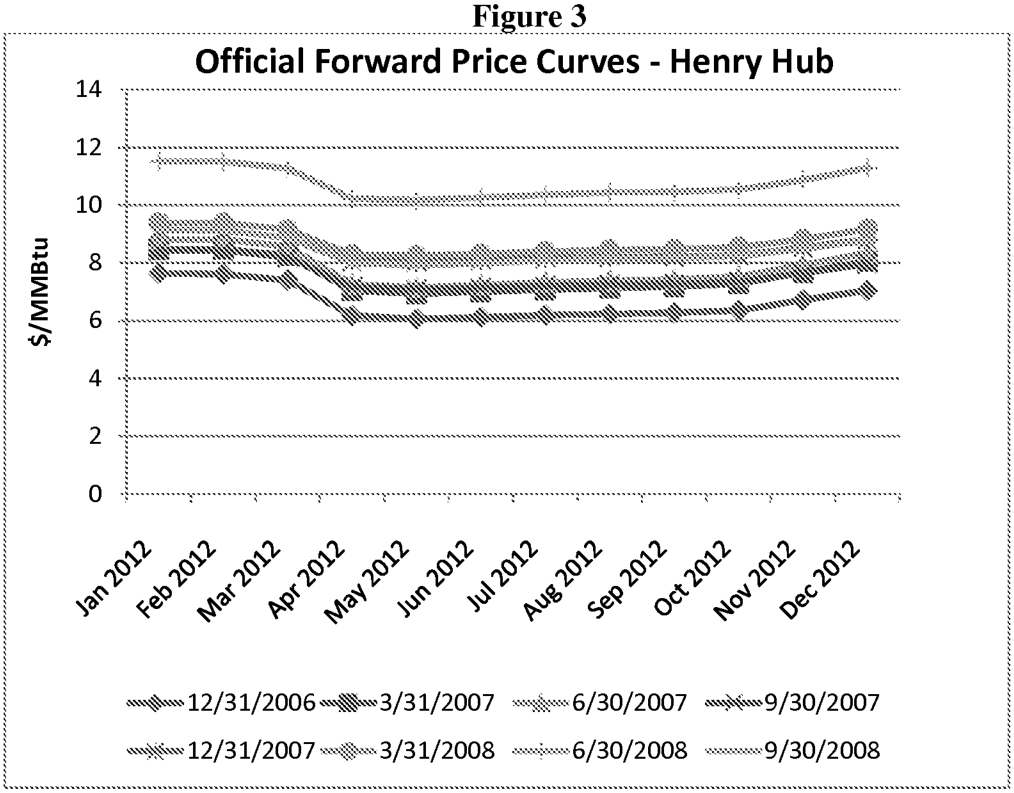
Q. Please explain the distinction between a forward price curve and a spot price forecast.

A. A forward price curve indicates the price at which a market participant can enter into a transaction today for natural gas that will be delivered (if physical) or settled (if financial) and paid for at a specified date in the future. These are fair market prices in that they are arrived at between willing buyers and willing sellers. Therefore, these prices reflect the views of the buyers and sellers of the true value of the deal. In contrast, a spot price forecast is an opinion, or speculation, of the level prices will settle at the time of delivery. For example, a forward price curve that indicates a $5.00 per MMBtu price for August 2012 may differ from an energy expert's spot price forecast published today of $5.50 per MMBtu because the forward price curve reflects the price the company can lock in today for that future date whereas the spot price forecast represents the price an energy expert believes will be the prevailing market price in August 2012 for natural gas deliveries or settlements in August 2012.

Q. At the time the 36- to 48-month natural gas hedges in this case were transacted, what did the forward price curves show with respect to natural gas prices in the test period?

A. Figure 3 shows the Company's official forward price curve as of each quarter in 2007 and 2008 for natural gas delivered in the test period. These prices are consistent with the prices paid by the Company for the natural gas hedges in this case.

Figure 3



Q. Is it apparent that the market in general, as reflected in the forward price curves shown in Figure 3, anticipated the precipitous drop in natural gas prices?

A. No. The forward price curves shown in Figure 3 did not indicate the drop in natural gas prices that occurred in the subsequent months and years. If the market in general had known or anticipated such a drop in prices, the forward price curves would have reflected that knowledge or anticipation in the form of declining prices in the future. In contrast, as Figure 3 shows, the market consistently reflected rising natural gas prices through mid-2008.

Q. If the test period market instead reflected 2008 forward market price levels, what would be the value of the Company's test period hedges?

A. In that scenario, the Company's swap transactions in the current proceeding would have significantly decreased net power costs. Figure 4 below duplicates ICNU's adjustment for gas financial hedging strategy at ICNU/103, Schoenbeck/15, replacing the market prices used in the Company's direct case with market prices from the Company's June 2008 Official Forward Price Curve (which was used in the July Update filing of the Company's 2009 TAM filing in UE 199). This analysis shows significant benefits associated with the Company's hedges under then-projected market prices. In this scenario, ICNU's adjustment would increase the Company's net power costs by $43.7 million, and only allow into rates $76.9 million out of the total $120.5 million in hedging benefits.

Figure 4

Transaction Year	Pacificorp MTM Adj	ICNU Adjustment	Recommended MTM Amount
2007	-$20.4	$20.4	$0.0
2008	-$49.8	$23.3	-$26.5
2009	-$36.3	$0.0	-$36.3
2010	-$14.0	$0.0	-$14.0
Total:	-$120.5	$43.7	-$76.9

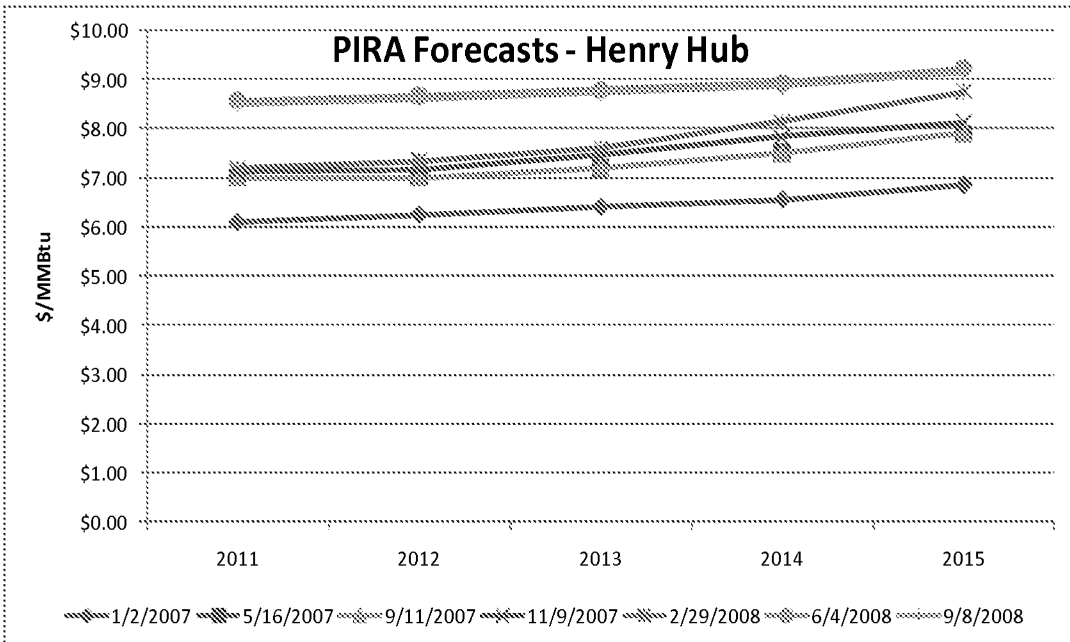
Q. At the time the hedges in this case were transacted, what did spot price forecasts show with respect to natural gas prices in the test period?

A. The Company subscribes to a forecasting service provided by PIRA, a well-known and respected company that provides forecasts of many commodities, including natural gas. PIRA's 2007 and 2008 forecasts of 2011 and 2012 Henry Hub natural gas spot prices, shown in Figure 5, increased from approximately $6 per MMBtu in early 2007 to approximately $9 per MMBtu in mid-2008 before decreasing to approximately $8 per MMBtu in late 2008. These spot price forecasts were slightly but not significantly lower than the forward market price curves for each of the contemporaneous time periods. However, spot price forecasts only represent a speculative view of expected prices; there is no legal recourse if forecasted prices fail to materialize. Spot price forecasts only serve as price indicators and carry a high degree of price uncertainty that often has more upward than downward price risk due to the asymmetrical nature of commodity prices. Contracts, however, are based on forward prices that bind counterparties to stipulated prices and delivery schedules with payments made at time of delivery.

Q. Is it apparent that PIRA, as reflected in its spot price forecast shown in Figure 5, anticipated the precipitous drop in natural gas prices?

A. No. Notably, PIRA's spot price forecast continued to climb for the delivery period 2011 through 2015.

Figure 5



Conclusion

Q. Please summarize your rebuttal testimony on the intervenors' hedging adjustments.

A. The Company respectfully requests that the Commission allow full recovery of the Company's forecast hedging costs in this case. These costs were incurred in compliance within a well-defined risk management policy and hedging program that has been independently verified. When measured on a multi-year, all-in basis, the Company's hedge program has reduced the volatility of net power costs in rates and provided significant benefits to customers. There is no basis for a prudence disallowance simply because hedges increase net power costs in this case. Nor is there any basis for a prudence disallowance because some parties use hindsight to allege that the Company hedged too much or hedged too far forward. The premise of each of these arguments is that the Company should have predicted in 2007-2009 that gas prices would decrease for the test period. This premise is undermined by the evidence of actual market forward price curves and third party spot price forecasts during the time that the Company transacted the hedges in this case. Although the Company believes its current risk management policy and hedge program reflect industry best practices and reasonable risk tolerances, the Company welcomes Commission feedback particularly in regard to going forward risk tolerances, any other aspect of the Company's risk management policy and hedge program, and any type of reporting that the Commission may desire.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit PPL/401
Stefan A. Bird

CONFIDENTIAL/
HIGHLY CONFIDENTIAL
Docket No. UE-227
Exhibit PPL/401
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

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

Risk Management Policy (January 13, 2010)
and Front Office Practices and Procedures, Exhibit 10 (May 13, 2010)

July 2011

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

Exhibit PPL/402
Stefan A. Bird

HIGHLY CONFIDENTIAL
Docket No. UE-227
Exhibit PPL/402
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Highly Confidential Exhibit Accompanying Rebuttal Testimony of Stefan A. Bird

TEVar Targets

July 2011

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

Exhibit PPL/403
Stefan A. Bird

Docket No. UE-227
Exhibit PPL/403
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Stefan A. Bird

**Public Utility Commission of Oregon's Natural Gas Procurement Study
Relevant Portions**

July 2011

Public Utility Commission of Oregon Natural Gas Procurement Study

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Executive Summary

This study on natural gas utility (LDC, or local distribution company) natural gas procurement was conducted under the Public Utility Commission of Oregon (OPUC or the Commission) 2004 Objective of establishing regulatory incentives and policies to promote least-cost energy resource development, specifically the examination of whether utility strategies for purchasing natural gas are reasonably designed to achieve rate stability at the lowest possible cost.

The study had four purposes, which are listed below with OPUC staff (staff) observations and findings:

1) Provide background information on natural gas markets, prices, and hedging instruments and techniques, including studies performed by and for other jurisdictions.

Staff's findings are:

- Hedging, defined broadly, is entering in to a transaction that reduces financial risk.
- Liberty Consulting, in their study for the Kentucky Public Service Commission, found that:
  - LDC staff responsible for the implementation of hedging plans should be knowledgeable about the futures market to know when the plan should be changed;
  - Hedging positions should be managed by a qualified LDC employee or an agent working in the interest of the LDC, not a commodities broker;
  - All parties should acknowledge that hedging programs will incur legitimate costs; and
  - The objective for any hedging program should be clearly defined.
- The Illinois Commerce Commission (ICC), in their study of hedging, found that:
  - The ICC is not opposed to hedging or liable to second guess legitimate risk management activities when hedged natural gas costs turn out to be higher than spot market prices;

- Hedging does not guarantee lower costs, but does reduce exposure to price volatility; and
- The use of hedging may distort price signals to customers.

➢ The Arizona Corporation Commission, in their study of natural gas procurement, found that:

- LDCs should pursue longer term, fixed price supply options;
- The Arizona Commission should adopt language that if a contract is prudent and reasonable at the time it is entered into, the utility should be permitted an opportunity to recover those gas costs; and
- The Arizona Commission should recognize price stability as one of the goals of the natural gas procurement process.

2) Analyze the results of Oregon LDC natural gas purchasing strategies over the past five years.

Staff conducted a study of the three Oregon LDCs natural gas purchasing strategies for the five Purchased Gas Adjustment (PGA) Years 1999/2000 through 2003/2004. The three LDCs reported the following breakdowns of purchasing strategies:

Table E.1. Avista Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	**99/00**	**00/01**	**01/02**	**02/03**	**03/04**
Hedged Volumes	37	34	36	36	36
Jackson Prairie Volumes	1	1	1	1	1
First-of-the-Month (FOM) Volumes	62	65	63	63	63
Total	**100**	**100**	**100**	**100**	**100**

Table E.2. Cascade Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	**99/00**	**00/01**	**01/02**	**02/03**	**03/04**
Physical with Fixed Price from Supplier	96.1	95.6	97.7	98.7	99.1
Storage	3.9	4.4	2.3	1.3	0.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Table E.3. NW Natural Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	99/00	00/01	01/02	02/03	03/04
Without Hedge	7.0	9.3	7.2	4.5	1.7
With Hedge[1]	41.9	66.1	49.5	54.7	82.2
Fixed Price[2]	31.1	8.2	30.2	27.0	3.3
Storage	20.0	16.4	13.1	13.9	12.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

The PGA mechanisms of Cascade and NW Natural use forecast base commodity gas costs as a baseline by which their actual commodity costs are compared. If the actual commodity costs differ from the base commodity costs, 67 percent of the difference, either positive or negative, are debited or credited, respectively, to the PGA. The remaining costs or credits are charged to shareholders.

Avista has been on the Gas Benchmark Mechanism (GBM) tariff since 1999.[3] The GBM fixes the price paid by all Oregon customers for the commodity portion of the natural gas costs to five cents per dekatherm (0.5 cents/therm) above the weighted average index price of natural gas sold. Avista weights their gas purchases by supply basin, and the weights are 50 percent AECO, 25 percent Sumas, and 25 percent Rockies. The GBM sunsets on March 31, 2005.

Staff analyzed the total cost of gas, which is the filed total gas cost rate embedded in customer rates plus deferrals, demand costs, and storage costs.

Table E.4. Oregon LDC Total Cost of Gas, PGA Years 1999/2000 through 2003/2004 ($/therm).

PGA Year	Avista ($)	% Change	Cascade ($)	% Change	NW Natural ($)	% Change
1999/2000	0.39990	-	0.34515	-	0.33899	-
2000/2001	0.57217	43.1	0.52270	51.4	0.46370	36.8
2001/2002	0.55802	(2.5)	0.61940	18.5	0.58638	26.5
2002/2003	0.56175	0.7	0.58834	(5.0)	0.49716	(15.2)
2003/2004	0.71292	26.9	0.59731	1.5	0.55959	12.6
5-Year Increase	**0.31302**	**78.3**	**0.25216**	**73.1**	**0.22060**	**65.1**

[1] Price with a supplier is tied to an index, but a financial transaction (swap or option) with a separate counterparty fixes the price.
[2] Price was fixed with a supplier for some period of time.
[3] See Public Utility Commission of Oregon Order No. 99-521 and Avista Utilities Oregon Tariff Schedule 464.

Staff conducted an analysis of LDC purchasing strategies versus the market for the three Oregon LDCs. Staff analyzed the opportunity cost of choosing the overall procurement strategy over simply purchasing identical quantities from the LDC's respective hubs at the market index price, represented as the percent of market spent on natural gas as a result of the purchasing strategies for each PGA year studied.

In order to balance analytical rigor with the practicality of the data provision burden placed on the three LDCs, staff chose a monthly market framework for the cost of hedging analysis. The monthly market framework was also useful because a large portion of LDC purchases during the period were made under contracts in which the price of natural gas was fixed for the entire month or tied to a monthly market index, such as the FOM index.

This analysis was not intended to be a down-to-the-dollar precise accounting of the effects of each strategy. Some amount of precision is lost when using monthly data instead of daily data. For example, monthly data does not have the detail of daily spot transactions. In addition, using the FOM price may not be entirely representative of daily price movements within a month, and may not be as accurate as reported historical average hub prices. Because only a small percentage of LDC purchases took place at a daily level of granularity, staff concluded that, overall, the lack of daily data is not an issue in reporting generalized results, but that any interpretation of the results should be mindful of the nature of the data.

Staff's findings are:

- The analysis of each LDC's total cost of gas showed that NW Natural had the lowest total cost of gas in four of the five years studied and also had the lowest five year increase.

- The PGA mechanisms currently in place for Cascade and NW Natural encourage hedging to fix prices and as a result both LDCs have hedged nearly all of their natural gas supply.

- For the time period studied, Avista Energy purchased gas for Avista, and Avista was unable to verify Avista Energy's actual costs of natural gas.

- Even though NW Natural and Cascade have employed different purchasing strategies, the companies experienced similar results in their respective markets. However, NW Natural's purchasing strategies resulted in a lower percent of market spent on natural gas and lower purchase price volatility as compared to Cascade.

- For the five PGA years studied, Cascade and NW Natural have, on average, produced results that come very close to the natural gas market.

Cascade, for the years studied, spent 2.6 percent over the market, on average, but the majority of that figure is accounted for by the 2001/2002 PGA year. NW Natural, for the years studied, spent 4.5 percent *under* the market, on average. NW Natural's results were also affected by the 2001/2002 PGA year, and overall for the study period, their purchasing strategies performed better than the market.

- For Cascade and NW Natural, their purchasing strategies resulted in 30 and 35 percent overall reductions in price volatility, respectively, when compared to market price. However, when broken down by hub, both LDCs saw results in which a reduction in volatility was achieved with a large increase in price or both price and volatility increased.

- The LDC purchasing strategies softened the impact on customers of the price spike that began in April 2000 and ended in August 2001. Though NW Natural experienced a doubling of their weighted average settlement price between September and November 2000, and Cascade's weighted average settlement price tripled during the same period, the two LDCs combined to spend over $160 million less than if they had purchased at the weighted average market index. Including storage costs, Cascade's purchases for the PGA year were at 70.1 percent of the market, and NW Natural's were at 57.1 percent of the market.

- With hedging, the deviation between market prices and purchasing strategy costs can represent a significant portion of annual revenue. For example, in the 2001/2002 PGA year, the difference between market prices and purchase costs was 21.7 percent of annual revenue for Cascade and 30.8 percent for NW Natural. However, over the five year study period, the representation of the deviation as a percentage of annual revenues for all three LDCs was very small, ranging from 1.1 percent to 1.8 percent.

- Using a monthly analysis of the purchasing strategies, the LDCs were unable to take advantage of the price trough that occurred directly after the price spike. The inability to take advantage of the price trough is because both LDCs used long-term contracts with locked-in prices during this period of time.

- The use of hedging may not necessarily result in the lowest possible price, but does reduce price volatility and can mitigate harm to customers from extreme price spikes.

- The natural gas purchasing strategies of Oregon's electric utilities and large industrial natural gas consumers differ from those of Oregon's LDCs. This is due to both the nature of their businesses (natural gas for peaking generators vs. serving load, industrial production) and their peak demand times (e.g. summer vs. winter).

- For the five Oregon LDC PGA years studied, PacifiCorp has, on average, produced results better than the natural gas market. Over the study period, the company spent 14.7 percent less than the market, even with the inclusion of their performance in 2001/2002. PacifiCorp was also able to reduce both purchase price and price volatility for their total purchases.

- For the five Oregon LDC PGA years studied, PGE has, on average, produced results better than the natural gas market. Over the study period, the company spent 32.6 percent less than the market, even with the inclusion of their performance in 2001/2002. PGE was also able to reduce both purchase price and price volatility at the three hubs at which they purchased natural gas.

3) *Compare the regulatory treatment of Oregon LDC natural gas purchasing strategies to treatments used by other commissions in the United States.*

Staff designed and distributed a survey to gauge the regulatory treatment of natural gas purchasing strategies in other jurisdictions. The natural gas procurement survey was sent to the 50 state commissions, including Oregon, and the District of Columbia commission, who are responsible for the regulation of natural gas. In addition to Oregon, twenty-nine commissions responded to the survey. The 30 commissions are responsible for regulating 248 LDCs. Staff's findings are:

- There is no consensus among state regulatory agencies about which regulatory treatments are best for LDC natural gas purchasing practices. Treatments currently in place range from hands-off policies to prescribed purchasing strategies.

- Several commissions, including those in Missouri, Indiana, Illinois, and Michigan, have disallowed natural gas purchases for a variety of reasons. These reasons include failure to document natural gas purchasing practices, failure to evaluate alternative suppliers, failure to implement a planning process that considered the volatile nature of natural gas prices and the impact of price spikes, failure to enter into the lowest cost contract, and failure to renegotiate long-term contracts upon changes in market conditions.

4) *Evaluate the potential to use performance-based ratemaking (PBR) techniques in the regulation of Oregon LDC natural gas purchasing strategies.*

Oregon's LDCs do not currently employ any performance-based ratemaking mechanisms other than the incentive features of current PGA mechanisms. Staff found that, nationwide, there is not much performance-based ratemaking that focuses solely on natural gas purchasing strategies, but two companies, Louisville Gas and Electric, and San Diego Gas and Electric, both utilize a PBR mechanism. Their PBR mechanisms benchmark LDC purchasing performance to the LDC's relevant natural gas markets. Staff modeled a hypothetical natural gas LDC called 'Bizgas,' which operated in markets similar to the Oregon LDCs and faced the same peaks and valleys in PGA Years 1999/2000 through 2003/2004, in order to evaluate a simplified version of the San Diego Gas and Electric mechanism.

Staff's findings are:

- When the LDC performs better than the market-based benchmark, the San Diego Gas and Electric PBR mechanism provides potential benefits to both customers and LDCs through its sharing mechanism. The mechanism also provides a strong performance incentive, because there are sharing mechanisms if natural gas costs exceed the benchmark as well as if the costs are below the benchmark.

- In the scenario modeled by staff, customers saw a net benefit and Bizgas experienced a net loss when the five PGA years 1999/2000 through 2003/2004 were summed together. This result is tempered by what may ultimately be two unusual years in the price spike of 2000/2001 and the overpayment for natural gas during the price trough in 2001/2002. It is beneficial to have those two years in the analysis, as they illustrate the need for PBR mechanisms to properly compensate customers and still provide participation incentive to shareholders, especially during unusual years.

- The implementation of the SDG&E PBR model, though simplified, demonstrates the need to balance the interests of both customers and shareholders with the provision of effective performance incentives.

As a result of the natural gas procurement study, staff offers the following recommendations:

- When evaluating LDC purchasing strategies, the Commission should consider total costs, including storage, transportation, etc.

- The Commission should take a results-based approach to purchasing strategy evaluation as opposed to evaluating each transaction or instrument. Individual transactions should still be reviewed if they raise affiliated interest issues or it is unclear that the LDC acted prudently.

- The results of this study do not indicate that there is a need for Commission *pre-approval* of transactions, instruments, or hedging plans. However, LDCs should appropriately document hedging transactions for the purposes of *ex post* Commission review.

- The Commission should require the Oregon LDCs to maintain and annually review a purchasing strategies document and revise as necessary. The document should describe the respective LDC's natural gas purchasing strategies and policies and track changes made over time.

- On a going-forward basis, the Commission should require the Oregon LDCs to maintain and abide by a comprehensive respective risk management policy.

- Additional time may be needed to draw more definitive conclusions. As of April 1, 2005, Avista will be changing their PGA mechanism away from the Gas Benchmark Mechanism, which will affect their purchasing strategies. Cascade has also indicated that it recently changed its purchasing strategies.

- Staff recommends beginning informal discussions with interested parties to consider changes to the current PGA and explore the use of other mechanisms or PBR for one or more LDCs. If the Commission wishes to explore PBRs, the San Diego Gas and Electric PBR, modeled in Section 6 of this report, is a reasonable starting point for designing a PBR mechanism. The market price-based San Diego Gas and Electric mechanism appears to have the potential to benefit both customers and LDCs while providing a strong incentive to meet the goals of the mechanism. Such incentive is provided by the excess costs beyond a preset deadband being shared equally by customers and the LDC, and a sharing mechanism is also applied to costs under the benchmark. The benchmark of any PBR is of utmost importance and should receive careful consideration. The ability to game a PBR mechanism should also be considered during PBR mechanism construction.

5. Oregon Electric Utilities and Industrial Users of Natural Gas

OPUC staff met with representatives of PacifiCorp, Portland General Electric (PGE), and Oregon industrial users of natural gas to discuss their natural gas procurement strategies.

PacifiCorp

PacifiCorp purchases natural gas for four power generation plants: Hermiston in Oregon and West Valley, Gadsby, and Little Mountain in Utah. PacifiCorp differs from the LDCs in that its peak natural gas purchasing season is the summer to meet cooling loads as opposed to the winter heating season. PacifiCorp purchases its natural gas supplies on the forward market based on forecasted requirements. The company also has natural gas storage rights available.

PacifiCorp cited reliability and risk management as the primary goals of their purchasing strategies. The company communicated to staff that it uses at least a three year horizon for supply and acts as a market participant in their purchasing practices. The company represents it transacts at prevailing market prices. PacifiCorp can, and sometimes does, use financial instruments as a part of their natural gas purchasing strategies. The company's natural gas costs for 2006 have been, at least partially, hedged by fixed price purchases executed as far back as 1994 for the Hermiston plant and 2003 for the Utah plants. The result of the hedging is that PacifiCorp's hedged cost of natural gas for 2006 is below current market prices.

In order to analyze PacifiCorp's natural gas purchasing strategies compared to the market, staff conducted an analysis similar to those for Oregon's LDCs in chapter three of this report. [99]

In three of the five years studied, PacifiCorp natural gas purchasing strategies performed better than if the company only bought natural gas at market prices (Table 5.1). Overall, however, PacifiCorp's strategies resulted in a lower long-term percent of market than all three Oregon LDCs, though this result is aided by the flexibility afforded to PacifiCorp because it does not serve natural gas load directly and can sell natural gas based on the economics of its system.

PacifiCorp purchases natural gas at two hubs and at several points on Questar's pipeline transmission and distribution systems. For staff's analysis of PacifiCorp's results on a hub basis (Table 5.2), all delivery points on the Questar system were aggregated. As well, the market price for Stanfield was estimated for eight months of the analysis in which no data was available. The estimated values were simply the averages of the prior and subsequent months in which data existed.

[99] See page 30.

Table 5.1. PacifiCorp Natural Gas Purchasing Strategies (Including storage) vs. Market, Oregon LDC PGA Years 1999/2000 through 2003/2004.

PGA Year	Percent of Market (%)	Difference From Market ($000,000)	Number of Therms (000)	Cents Per Therm (¢/therm)
1999/2000	103.0	2.7	304,129	0.9
2000/2001	66.5	(80.6)	440,598	(18.3)
2001/2002	162.6	42.7	324,548	13.1
2002/2003	81.4	(33.0)	408,849	(8.1)
2003/2004	76.0	(41.5)	353,888	(11.7)
Total		(109.7)	1,832,012	
5-Year Average	**85.3**	**(21.9)**	**366,402**	**(6.0)**

Table 5.2. PacifiCorp's Purchases vs. Market Index (Excluding Storage), Oregon LDC PGA Years 1999/2000 through 2003/2004 ($/therm).

	PacifiCorp		Market Index			
Hub/Pricing Point	**Weighted Average ($)**	**Coefficient of Variation**	**Weighted Average ($)**	**Coefficient of Variation**	**Increase (Decrease) in Price (%)**	**Reduction (Increase) in Volatility (%)**
Questar[100]	0.386	0.25	0.324	0.47	19	9
Rockies	0.454	0.53	0.427	0.51	6	(3)
Stanfield	0.327	0.98	0.401	0.55	(26)	(78)
Overall	0.349	0.10	0.409	0.52	(15)	82

Source: Laura Beane's May 19, 2005, e-mail to Steve Chriss

For the Questar delivery points, PacifiCorp's average price was nineteen percent higher than the market index average, but the volatility of their prices was nine percent lower than if they were to purchase at index. From a price perspective, the company's result was similar for the Rockies hub, where their average price was six percent higher than the market index average, plus the volatility of their prices increased three percent. PacifiCorp's price result for Stanfield, where the company purchases a majority of their natural gas, was a 26 percent decrease in the price of natural gas. The volatility result for Stanfield may be misleading, as the result is thrown off by one month in the analysis in which the average purchase price for the month is seven to eight times higher than other months in that year. If the month in question more closely resembled adjoining months, the overall result would have shown a marked decrease in volatility.

[100] All delivery points.

Overall, when the entire portfolio is considered, PacifiCorp achieved an 82 percent reduction in volatility and a fifteen percent decrease on average in the per therm price of natural gas over the time period analyzed. This result is largely due to PacifiCorp's purchases at the Stanfield hub.

PGE

PGE, like PacifiCorp, cites reliability as a main goal of their natural gas purchasing strategies. PGE also cites low cost and a flat financial profile as goals of their strategies. The company locks-in their natural gas prices up to two years in advance through fixed-for-floating swaps and may buy physical index priced gas between two to three months in advance, or may purchase fixed priced gas in the cash market, depending on plant needs. PGE can use options, but has not executed many options contracts, and has also used basis trades. PGE employs Value-At-Risk (VAR), which specifies risk limits for each portfolio as well as company-wide for natural gas and power purchases. PGE's finance department executes currency hedges in support of the company's natural gas purchases.

The company also has a storage contract with NW Natural which gives PGE the rights to 600,000 MMBtu of capacity in the Mist storage system.

In order to analyze PGE's natural gas purchasing strategies compared to the market, staff conducted an analysis similar to those for Oregon's LDCs.

Because PGE purchases natural gas to supply power plants, not to directly serve load, the company proposed that the analysis look at the whole of their natural gas purchasing operations, including storage, resale of natural gas, and the use of financial instruments. Staff agreed to account for these activities in the analysis, so in each month of the model, the $WAST_t$ variable[101] represents the net of natural gas purchases and resale, financial instrument results, and storage costs.

The nature of the $WAST_t$ variable meant that in some months, PGE had negative net purchases (i.e. they sold more than they bought). In calculating the market variable, $WAMI_t$, negative net purchase months were counted as zero therms. The inference was that the company would only purchase natural gas from the market in months that the company actually needed natural gas, and would only purchase as many therms as were necessary for operation.

In four of the five years studied, PGE's natural gas purchasing strategies performed better than if the company only bought natural gas at FOM market prices for as many therms as were necessary for operation (Table 5.3). PGE's strategies resulted in a lower long-term percent of market than all three Oregon LDCs and PacifiCorp, though, like PacifiCorp, this result is aided by the

[101] See page 30.

Table 5.3. PGE Natural Gas Purchasing Strategies (Including Storage, Resale, and Financial Instruments) vs. Market, Oregon LDC PGA Years 1999/2000 through 2003/2004.

PGA Year	Percent of Market (%)	Difference From Market ($000,000)	Number of "Necessary" Therms[102] (000)	Cents Per Therm (¢/therm)
1999/2000	72.1	(26.5)	311,417	(8.5)
2000/2001	51.5	(136.6)	536,008	(25.5)
2001/2002	229.6	39.8	179,600	22.1
2002/2003	61.0	(15.3)	117,559	(13.4)
2003/2004	61.9	(44.6)	259,665	(17.4)
Total		(184.4)	1,404,250	
5-Year Average	**67.4**	**(36.9)**	**280,850**	**(14.6)**

flexibility afforded to PGE because it does not serve natural gas load directly and can sell natural gas based on the economics of its system. If PGE's purchases were considered without resale and financial instruments, the company's five-year average percent of market would be 92 percent, which is closer, relatively, to NW Natural's value of 95.5 percent.

To compare PGE's results on a hub basis (Table 5.4), staff used purchases only to facilitate the most direct comparison to the market as possible.

For the Sumas hub, PGE's average price was four percent lower than the market index average, and the volatility of their prices was 51 percent lower than if they were to purchase at index. The company's result was similar for the Rockies hub, where their average price was two percent lower than the market index average, and the volatility of their prices decreased 42 percent. PGE's results for Alberta/NIT were a fourteen percent decrease in the price of natural gas coupled with a 28 percent reduction in price volatility.

Overall, when the entire portfolio is considered, represented by the weighted average numbers of purchases only, PGE achieved a 47 percent reduction in volatility with an eight percent decrease on average in the per therm price of natural gas over the time period analyzed.

[102] Does not include resold therms.

Table 5.4. PGE's Purchases vs. Market Index (Excluding Storage, Resale, and Financial Instruments), Oregon LDC PGA Years 1999/2000 through 2003/2004 ($/therm).

	PGE		Market Index			
Hub	Weighted Average ($)	Coefficient of Variation	Weighted Average ($)	Coefficient of Variation	Increase (Decrease) in Price (%)	Reduction in Volatility (%)
Sumas	0.399	0.27	0.417	0.55	(4)	51
Rockies	0.338	0.26	0.346	0.44	(2)	42
Alberta/NIT	0.329	0.28	0.384	0.39	(14)	28
Overall	0.356	0.24	0.387	0.45	(8)	47

Source: PGE's April 14, 2005, response to OPUC staff's March 23, 2005 data request

Table 5.5. Electric Utility Natural Gas Purchasing Strategies (Including Storage) vs. Market as a Percent of Annual Revenue.

Year	PacifiCorp (%)	PGE (%)
2000	2.4	7.6
2001	2.8[103]	5.9
2002	3.3	1.6
2003	4.2	1.2
4-Year Average	**1.6**	**2.8**

Staff calculated the difference between the results of each company's natural gas purchasing strategies and its respective market for the years 2000 through 2003 for both electric utilities (Table 5.5). The discrepancy between the annual values and the four-year averages was due to the use of the absolute value of the sum of OUM and STO[104] to calculate the percentages. If the annual values were calculated without using the absolute value, years 2000, 2001, and 2003 would be negative for both PacifiCorp and PGE. The four-year average value takes the negative years into account through the summation of the four years of OUM data.

As was the case with the LDCs, the time frame of the analysis is very important. The results for PacifiCorp and PGE are the product of the specific market, company-specific operational conditions, and market prices from December, 1999, through September, 2004. Just as the performance of both companies varied in the past, the future performance of PacifiCorp and PGE should be expected to vary from the results of this study.

[103] Estimated, due to the company's change from calendar year to fiscal year for regulatory reporting.
[104] See pages 30 and 31.

Oregon Industrial Gas Users
In their meeting with staff, representatives of Oregon industrial gas users stated that the most successful companies use dollar cost averaging techniques in their natural gas purchasing strategies. The representatives cited the use of overlapping two year strips as a means to dollar cost average.

The use of participation swaps was also cited as a technique used by the industrials. A participation swap is similar to a regular fixed-for-floating swap in that one party pays a fixed price stream in exchange for the other counterparty's payment of a floating price stream. The participation swap is different in that the party that pays the fixed price receives a portion of the savings if the floating price drops below the fixed price.[105] For example, if an industrial agreed to a $6/MMBtu price for natural gas with 50 percent participation, the industrial would receive 50 percent of any savings generated by the price of natural gas dropping below $6.

The industrial representatives reported that the cost of hedging was probably in the range of one to three cents per dekatherm.

Staff's findings are:

- The natural gas purchasing strategies of Oregon's electric utilities and large industrial natural gas consumers differ from those of Oregon's LDCs. This is due to both the nature of their businesses (natural gas for peaking generators vs. serving load, industrial production) and their peak demand times (e.g. summer vs. winter).

- For the five Oregon LDC PGA years studied, PacifiCorp has, on average, produced results better than the natural gas market. Over the study period, the company spent 14.7 percent less than the market, even with the inclusion of their performance in 2001/2002. PacifiCorp was also able to reduce both purchase price and price volatility for their total purchases.

- For the five Oregon LDC PGA years studied, PGE has, on average, produced results better than the natural gas market. Over the study period, the company spent 32.6 percent less than the market, even with the inclusion of their performance in 2001/2002. PGE was also able to reduce both purchase price and price volatility at the three hubs at which they purchased natural gas.

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[105] See Platt's Derivatives Glossary.
http://www.platts.com/Oil/Resources/Glossaries/derivativesglossary.html.

Exhibit PPL/404
Stefan A. Bird

CONFIDENTIAL
Docket No. UE-227
Exhibit PPL/404
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Confidential Exhibit Accompanying Rebuttal Testimony of Stefan A. Bird

Division of Public Utilities Blue Ridge Report
October 7, 2009

July 2011

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Exhibit PPL/405
Stefan A. Bird

REDACTED
Docket No. UE-227
Exhibit PPL/405
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Exhibit Accompanying Rebuttal Testimony of Stefan A. Bird

Rebuttal Testimony of Frank C. Graves
Submitted by Rocky Mountain Power in Utah Docket No. 10-035-124

July 2011

REDACTED
Rocky Mountain Power
Docket No. 10-035-124
Witness: Frank C. Graves

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Redacted Rebuttal Testimony of Frank C. Graves

Hedging

June 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 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 C.V. is attached as Appendix A.

Q. Have you previously testified for Rocky Mountain Power in regard to risk management or service pricing?

A. Yes, I was a witness for Rocky Mountain Power ("RMP") in 2009 in regard to its request for an ECAM mechanism in Utah to recover the costs of fuel and purchased power.

Q. What is the purpose of your testimony?

A. I have been asked to respond to criticisms in the following testimonies regarding views that RMP has misdesigned, or failed to update and modify, its hedging practices over the past few years: Messrs. Douglas D. Wheelwright and Mark W. Crisp on behalf of the Utah Division of Public Utilities ("DPU"); Dr. Lori Smith Schell and Mr. Paul Wielgus on behalf of the Office of Consumer Services ("OCS"); and Dr. J. Robert Malko and Mr. Mark Widmer on behalf of Utah Industrial Energy Consumers ("UIEC"). As a general rule, the DPU witnesses are concerned that RMP's risk management policy and hedge program provide for varying degrees of hedging of the price risk associated with its expected fuel and wholesale purchased power requirements and wholesale power sales up to four years forward, and that it does so primarily with forward contracts and swaps rather than options or collars. It is alleged that this mix of horizons and hedging instruments is inappropriate. Similar concerns are raised in the testimony of Dr. Schell and Dr. Malko.[1] More specifically, the concern is that this practice has exposed RMP customers to some out of the market hedges entered several years ago that are now expensive compared to spot or other short term supplies, and that this strategy leaves little or no opportunity for customers to enjoy cost reductions if short term natural gas prices should fall or if short tem electricity prices should generally rise. This approach is also criticized as being inconsistent with other utilities' common practices (especially hedging by natural gas distribution

[1] Mr. Wheelwright's Testimony, Dr. Malko's Testimony and Dr. Schell's Testimony all discuss both (i) the length of the hedges (magnitude of hedging) and (ii) the method used to hedge. The accuracy of Mr. Wheelwright's description of the Company's hedging program is addressed in the rebuttal testimony of Mr. Bird.

companies). Some also allege that RMP should have foreseen the reduction in natural gas and electric prices that ensued from the recent rapid development of shale gas resources, implying they were imprudent to have entered long-dated natural gas hedge commitments in the past.

Q. What are your general conclusions?

A. The accuracy of the intervener witnesses' description of RMP's hedging practices is discussed in Mr. Stefan A. Bird's and Mr. John A. Apperson's rebuttal testimony. Leaving this issue aside, it is true that in the very recent time frame, RMP's hedging strategy to hedge as far forward as 48 months has resulted in out of the money forward hedges for natural gas. However, I disagree that this indicates the company has been imprudent, or that its customers have even been harmed by this approach.

- The purpose of hedging is not to find the lowest after-the-fact approach to procurement. To the contrary, hedging is designed only to limit the *a priori* <u>range</u> of potential future costs. It is inevitable that non-speculative hedges will sometimes (about half the time) end up out of the money. Recent market conditions have turned dramatically downward, in the economy as a whole and in natural gas and electricity prices in particular, so it is not surprising with *ex pos*t hindsight that older, longer hedges are now above replacement costs.
- It is not appropriate to compare electric company hedging to natural gas companies. Even the comparisons that have been made are in some ways inaccurate in describing natural gas company practices. When storage is

recognized as a physical hedge, natural gas companies tend to hedge almost 100% of their requirements. Moreover, the volatility, price-load correlations and the skewness of electric prices are greater than natural gas, and these can justify being hedged for more than 100 percent of expected volumes.

- There is no intrinsically "best" horizon for hedging, nor any "best" mix of hedging instruments to use. Long term forward contracts or financial hedges will dampen exposure to correspondingly long shifts in energy costs, but that benefit comes with the inevitable possibility of hedges ending up out of the money (more expensive than having been unhedged). It is perfectly reasonable to re-evaluate desired tradeoffs between *ex ante* risk reduction and *ex post* regret exposure (i.e., potential disappointment over outcomes), but this is not a prudence issue. Call options could help reduce regret for the tradeoff of increased risk, but could also increase regret if the option expires unexercised, thus their prudence assessment and cost recovery rules must be thoughtfully articulated in advance.
- The shale gas revolution is an exciting and important one for US natural gas and power markets, but it is not fair to say to that this was a foreseen and foreseeable event that RMP should have anticipated by shortening its hedges. To the contrary, there was a great deal of skepticism about the promise of shale gas, and it has been developed rapidly for reasons that have little to do with its intrinsic value as a natural gas supply resource. Moreover, it would have been speculative for RMP to assume that the

forward prices of natural gas and power did not already reflect the consensus understanding of shale gas impacts.

- It is not appropriate to use recent *ex post* outcomes to test whether hedging has been prudent or not. The high volatility and (likely) instability of market conditions (and hedging requirements) make such hindsight snapshots uninformative and misleading about the merits of a hedging policy. *Even if a hedging policy has performed very well (saved money) from this hindsight perspective, that does not prove the company has a good risk management policy*. Instead, the Utah PSC, its utilities, and key customer representatives should agree on an *ex ante* approach that reflects agreed goals for risk reductions, and on transparent reporting for monitoring a procurement approach that is expected to achieve those risk management goals. For example, on a going-forward basis it would be appropriate to agree on the risk limits and risk tolerance bands expressed in RMP's risk management policy and hedging program, as well as the metrics and frequency of desired reporting.[2]

Q. How is your report organized?

A. The balance of my report addresses the question of whether too much was hedged, for too long forward, and whether options would have been more appropriate. I also explain what was known about shale gas over the past few

[2] I note that RMP in the past has presented its hedging policies to the Commission. See, for example, PacifiCorp Energy, "Commodity Price Risk Management Presentation," Utah Public Service Commission: Technical Conference May 18, 2009. On May 25, 2010, PacifiCorp provided a confidential update on its hedge program to the Commission (Confidential Hedge Program Update Presentation, Technical Conference May 25, 2010).

years, and I outline an approach to prudence review that should help RMP and its stakeholders have greater confidence in what is being done to manage risks.

Hedging 100 percent of Expected Needs

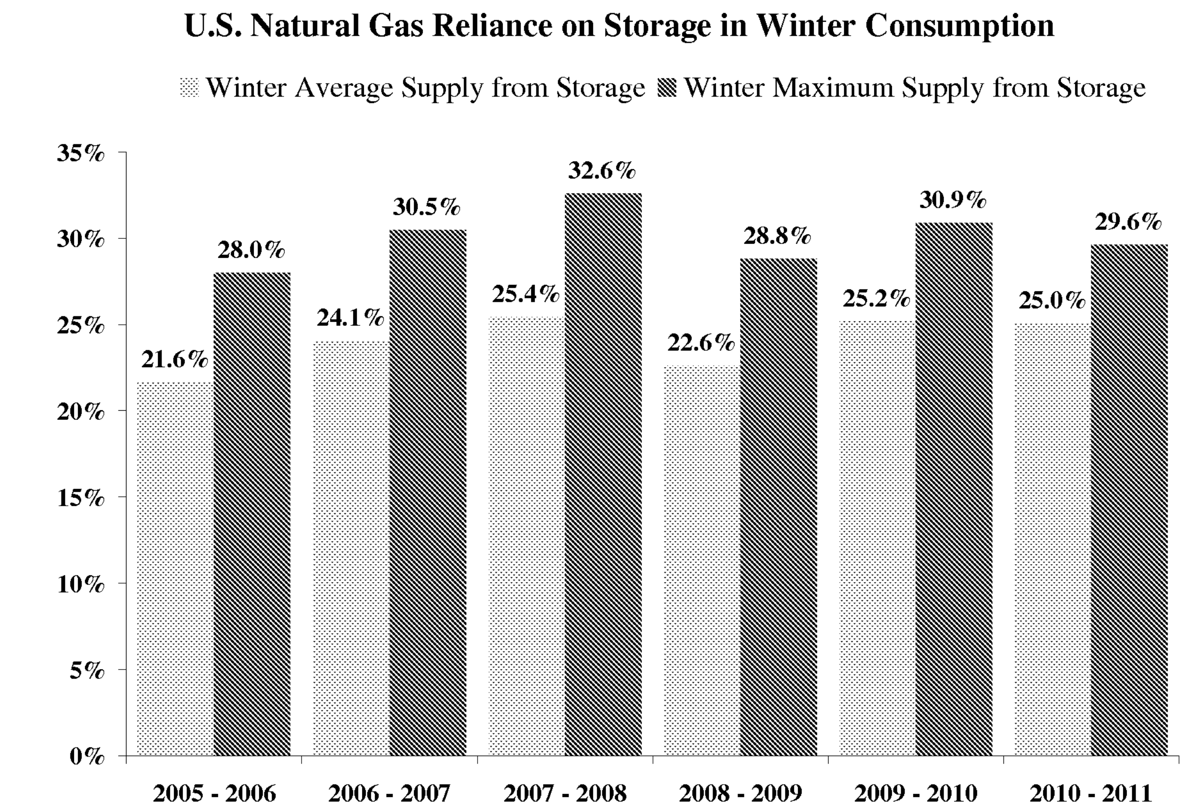
Q. Some intervenors[3] have alleged that natural gas distribution companies hedge only about 50-75 percent of their requirements, much less than the [redacted] hedged by RMP in the one to 12 month period, and that this indicates RMP is being too aggressive. How do you respond?

A. I have worked on hedging with a few gas companies, interviewed others, and I am aware of the trade literature on practices in this sector. My perception of natural gas industry practices is consistent with what intervenors have asserted: a typical gas distribution company will hedge most or all of its "baseload" gas needs for the coming winter or two by buying futures or forwards for gas (and perhaps its transportation costs, i.e. basis risk). This baseload is typically up to the distribution company's minimum load (such as the quantity that might be required in a warm winter), but not the LDC's expected total or maximum. In that sense, LDCs seem to be partially hedged. However, they usually are actually hedged more than it would appear, because nearly all have substantial amounts of physical storage, which effectively hedges winter gas at summer costs plus storage carrying fees. This is often enough to serve their entire peak load, above the amounts already hedged with forward contracts and swaps. Figure FCG - 1 below summarizes this degree of reliance on storage for the US gas industry as a whole. It depicts gross storage withdrawals per month as a percentage of overall

[3] See, for example, J. Robert Malko, "Prefiled Direct Testimony on Revenue Requirement," May 31, 2011 ("Malko Testimony"), pp. 24-26.

delivered gas in winter months for the past five years. On average in winter months (defined as December through March, due to only calendar month data being available), storage is used to serve from 20-25 percent of the total demand, with around 30 percent being supplied from storage in the peak (coldest) month (typically January, but not always). These percentages probably understate the extent to which local gas distribution companies (LDCs) rely on storage, because the denominator is for all gas consumption in the US, not just consumption by distribution companies. About 1/3 of gas demand is from electric utilities,[4] who often do not have much access to storage (or even firm gas, in the case of many electric generators) compared to LDCs. When this 20-30 percent from storage is combined with the tendency to cover most or all of their winter baseload needs with forward gas contracts, most LDCs will be close to 100 percent hedged.

[4] Energy Information Agency, "2010 Annual Energy Outlook: Energy Consumption by Sector and Source, United States, Reference Case."



Sources:
The Brattle Group.
US Energy Information Administration.

Figure FCG - 1

Q. Are natural gas distribution companies good proxies for electric companies, in regard to hedging needs or common practices?

A. They both face some of the same regulatory challenges in getting approvals for hedging strategies, but their physical and financial problems are different. Notably, gas companies are only concerned with the gas commodity (and its transportation); they do not have to worry about the value of that gas once converted to electricity, or how purchased power might substitute for (or increase) gas usage. That is, electric companies like RMP are more concerned about the "spark spread" between gas and electricity than the price of gas itself (for which they may be sellers, as well as buyers). Spark spread is the spot price of electricity, less the spot price of gas multiplied by the heat rate of a gas-fired generation plant, giving the net value per MWh of burning the gas to produce power. Both the electric and gas price components are uncertain and volatile, though partially correlated, so the spark spread can be positive or negative, and it varies by power plant as well as location of the transaction.

The volume of gas that electric companies need also tends to be more of a peaking or top-of-load requirement that can be quite variable throughout the year, depending on the cost of other fuels. Finally, electric companies also hedge much more than just their fuel costs, because they must buy and sell spot significant quantities of power to balance their system supply against load. (RMP in particular tends to sell more electric energy than it buys.) Thus, the hedging requirements of electric companies are generally more complex than for gas distribution companies.

Q. Do these differences affect the extent to which electric companies may want to hedge their expected fuel and purchased power requirements, in terms of quantities or how far in advance to hedge?

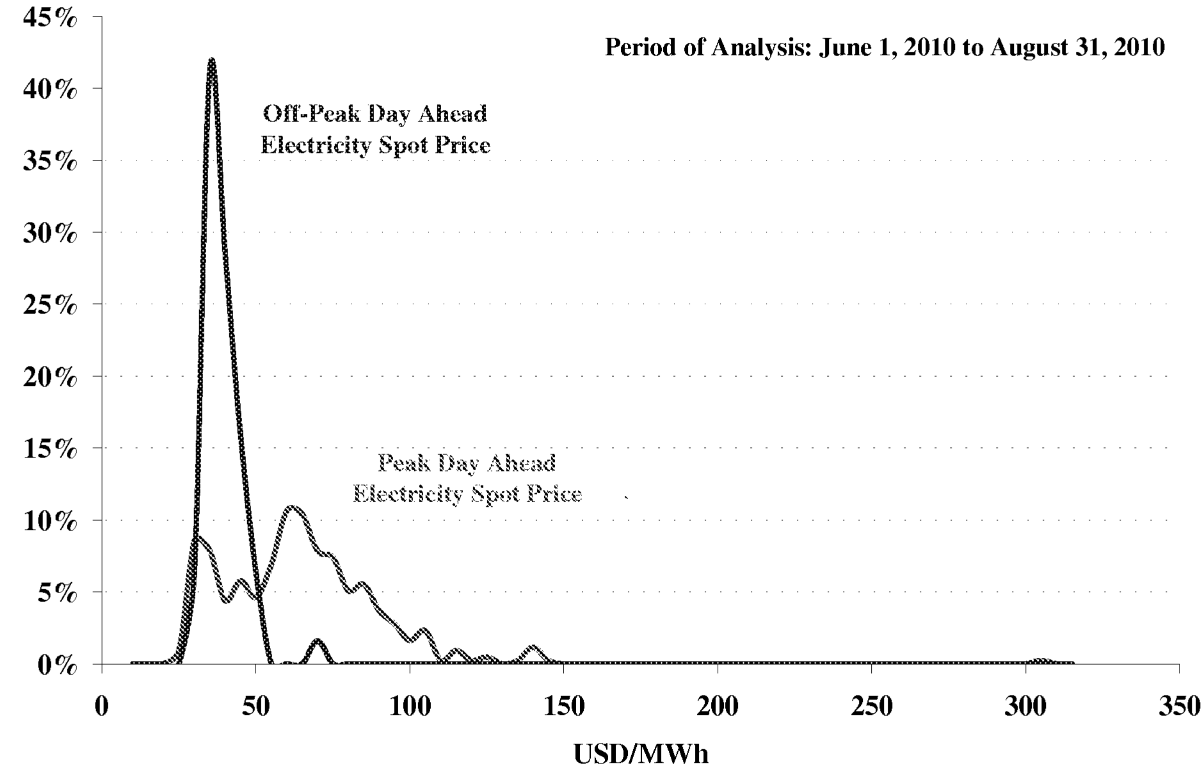
A. Yes, some of the risk characteristics of electric markets can justify hedging all or even more than all of the expected volume of fuel or purchased power, which gas companies are less likely to do.

Q. To what electric market risk characteristics are you referring?

A. Electricity prices tend to be skewed, and they also tend to have a fairly high positive correlation between prices and loads, especially during peak periods.

This is not unique to electricity, but the extreme volatility of spot electric prices may make it of greater concern. By skewness, I am referring to the asymmetry of price distributions, whereby spot prices are mostly centered around “ordinary” levels but there is a possibility of occasional, very high prices. The distribution of observed spot prices tends to have a long, positive “tail” because on-peak prices can spike to several times ordinary levels. Moreover, such extreme prices are more likely when demand is also unexpectedly high; demand and price uncertainty tend to be positively correlated. As illustrated in Figure FCG - 2, the difference between standard off peak day ahead power prices and the range of potential peak day-ahead power prices can be huge. In the example shown for Palo Verde in the summer of 2010 (a trading hub in Arizona that is relevant to RMP transactions), the maximum peak day-ahead electricity price reached $300 / MWh while the average off-peak price was less than $50 / MWh and is more concentrated around a central value.

Palo Verde Day Ahead Peak and Off Peak Prices Behavior



Sources: *The Brattle Group* . Bloomberg.

Figure FCG - 2

Q. How do electricity price skewness, high on-peak volatility, and positive price-demand correlations affect desirable hedging practices?

A. These characteristics of power markets cause open (unhedged) positions in on-peak hours to be exposed to potentially very high-priced, extreme events. Off-peak hours often have less volatility and less skewness, so they are less exposed to this problem. As a result, it will tend to be variance-minimizing to hedge for peak load (or peak capacity, if selling) rather than for average or minimum load. This is true regardless of whether a utility is a net buyer or a seller; the risk will be lower, given higher and more skewed volatility on peak, if more than the expected quantity is hedged.

Q. In your experience, do electric utilities tend to hedge 100% or more of their expected future fuel and purchased power requirements?

A. There is not much public information on how electric companies hedge, probably because many have unregulated generation and marketing subsidiaries for which their hedging practices would be commercially sensitive information. Also, because they are more heterogeneous in their needs and asset mixes, they are harder to compare to each other and find general patterns. However, I have advised several electric utilities on hedging alternatives, particularly in states that implemented retail choice and left their distribution companies with a Provider of Last Resort obligation. Those companies were trying to provide a fixed price product, and virtually all of them used forward procurement (mostly of forwards and swaps) that hedged essentially all (or more than all) of their expected load-serving requirements.

Hedging Horizons Up to Four Years Forward

Q. Some intervenors have complained that RMP's purchasing of gas hedges four years in advance is imprudent, or at least ought to be abandoned as a practice going forward. They are concerned that long-dated forwards are illiquid (hence allegedly too costly or too risky) and/or that they represent too big a bet on what the distant future will be like. What is your response?

A. I disagree that there is any per se flaw or problem with hedging four years forward, however it is reasonable to open the discussion for future hedging as to how much forward period risk reduction is desired.

I would first note, however, that RMP does not have volumetric targets for how much it should hedge gas or power four years ahead. Instead of such hedge volume targets, it applies a TeVaR metric to its total cost risk foreseen in future years, up to four years ahead, and hedges as needed to keep that measure of potential costs within acceptable limits. The extent of hedging four years hence can go up or down, according to shifting market conditions (such as changes in expected volatilities or correlations across sources of supply). Nonetheless, RMP has hedged with volume targets in the past, and combined with position and VaR limits in the risk management policy has generally led RMP to be partially hedged with forward contracts and swaps for the fourth year in the future.

Q. Why is there no *per se* reason to hedge four years forward, or to not do so?

A. 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 choice, not of economic value. 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. This 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 more later, 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. How do long-dated hedges help manage risks?

A. Power and gas market conditions over the last decade involved several major adjustments lasting a few years at a time, and long-lived hedges could help smooth out exposure to such large swings. Simplifying history to a few key events, and focusing on natural gas as an example, there were high gas prices in 2000 - 2001 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. Then the financial crisis and resulting recession, combined with the shale gas revolution, pushed prices back down to much lower, more comfortable 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 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. Even using one-sided hedges, such as call options, has this same tension, because in a low-cost market, options will end up expiring without being used (so the premium cost is incurred without producing savings, in hindsight).

Q. Are you aware of any examples of gas or electric companies that hedge four or more years forward?

A. Yes. RMP's (15-year) Hermiston power plant has a very long term natural gas hedge for 100 percent of its requirements. While this gas supply contract was slightly out of the money for a brief period in the early years, as Mr. Apperson testifies, it has produced enormous savings for customers for the past decade. Similarly, the Direct Testimony of Mr. Jeff L. Fishman reports that Portland General engages in physical hedges for up to five years.[5] In addition, Portland General appears to hedge 100 percent of its expected requirements.[6] Further, Public Service Company of Colorado recently entered into a ten year fixed price gas supply with an annual adjustment or escalation.[7] Thus, RMP's hedging horizon is not unique.

I would also note that the natural gas contracts available at Henry Hub and elsewhere are now available for well beyond a four year horizon into the future. This shows that both buyers and sellers do value longer term price certainty. This is especially true of bilateral or customized contracts, because they may be able to

[5] Prefiled Direct Testimony of Jeff L. Fishman on behalf of UAE Intervention Group, May 26, 2011, p. 15.
[6] Portland General's 2009 Integrated Resource Plan states that "as [Portland General] get(s) closer to our fueling needs, purchases are increased to ensure we that we have acquired contracts to meet our expected requirements roughly one year in advance." See PGE 2009 IRP p. 144.
[7] See Public Utilities Commission of the State of Colorado, Decision No. C10-1328, Page 75, Item 219.

avoid the heavy collateralization or mark to market re-valuations that are required on standard exchanges.

Foreseeability of the Drop in Recent Natural Gas Prices

Q. Some intervenors[8] have argued that the recent drop in power prices is substantially driven by natural gas price reductions arising from the development of shale gas, and that this should have caused RMP to hedge less far forward over the past few years. Do you agree?

A. I do not. I have followed the innovations in horizontal drilling, fracking, and shale gas development fairly closely over the past few years, as it is a key factor in forecasting and planning future needs and preferred resources of the industry. My experience has been that this development occurred much faster and had more impact than was generally expected. Moreover, it was by no means an isolated or singularly overwhelming factor in the recent reductions in power and fuel costs. The financial crisis has been a very big driver of those changes as well, and it too was not anticipated to be as deep or as long lasting as it has proven to be so far.

Q. Please describe your understanding of the evolution of shale gas economics.

A. In the middle of the past decade, e.g. around 2005, there was widespread belief that the US was running out of gas and that imported, liquefied natural gas LNG was going to be essential and costly as our long term solution. Partly for this reason, when Hurricanes Katrina and Rita hit the southeast in late summer of 2005, the forward prices of natural gas shot up to unprecedented levels, not just over the time frame it would take to repair the damaged infrastructure, but for a

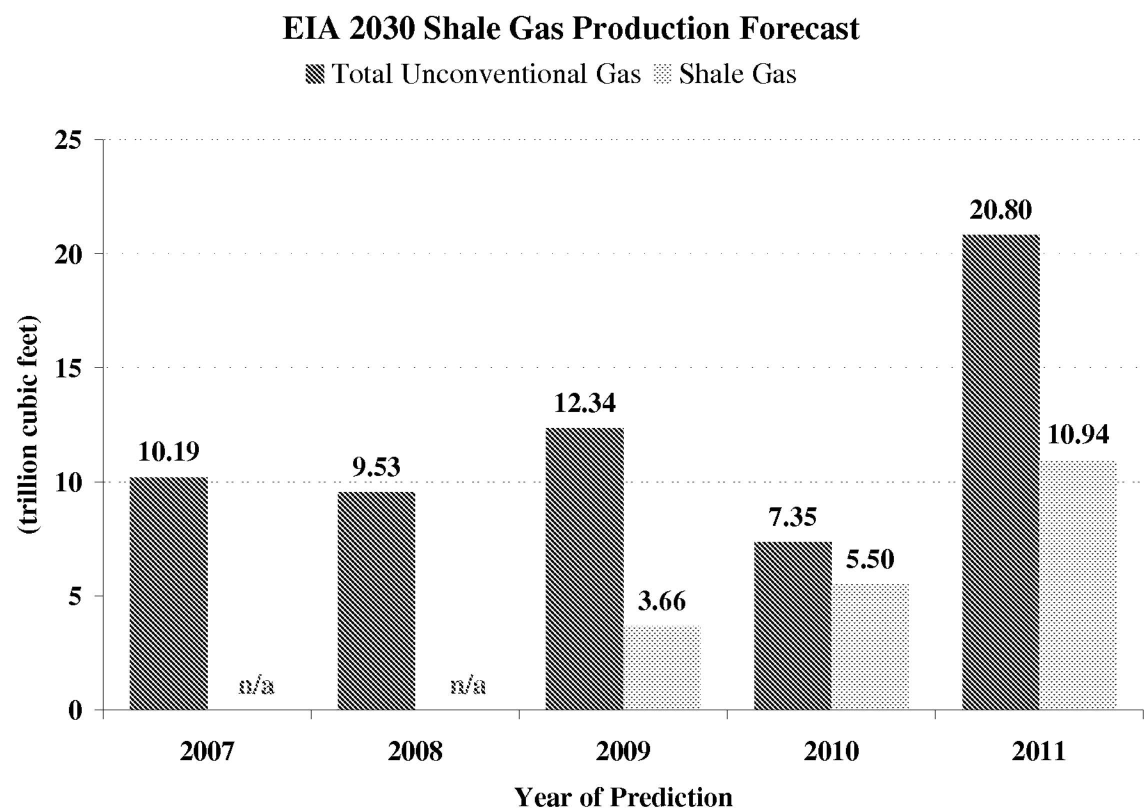
[8] Prefiled Direct Testimony of Mark W. Crisp on behalf of Utah Division of Public Utilities, May 26, 2011 (“Crisp Testimony”) pp. 11-14 and Malko Testimony p. 17 and pp. 20-21 .

few years going forward. Gas prices fell somewhat but still stayed well above previously normal levels throughout late 2006 and early 2007 and shortly thereafter they were rising again to very high levels, in conjunction with very high oil prices (eventually reaching almost $140/bbl).

These high prices of gas drove a wave of technology development and exploration for shale gas with horizontal fracturing, which proved to be extremely successful -- to the point where we now appear to have many decades of likely reserves from shale and other nonconventional gas supplies, possibly at $5-6/MMBtu in real terms for several years ahead. However, there was considerable debate (and some persists to the present) over what the true cost of shale gas development was, as some developers were reporting success at $4/MMBtu or so while some engineering studies were showing costs in the $9-10/MMBtu range or higher. Many analysts felt that the rapid pace of development was uneconomical, at current gas prices. This could well have been the case, because a lot of the development occurred in order to retain leasehold rights to shale gas properties, not for the intrinsic value of the gas. This was not widely foreseen, and it has depressed spot prices to date. It is also likely that some of the current development of shale gas is above the levels that are justifiable by gas prices alone, because some shale gas has associated liquids that are very valuable while oil prices are high. This is also somewhat unusual and was not generally foreseen by industry analysts.

While the testimony by Mr. Crisp for the Utah Division of Public Utilities uses data from the Energy Information Agency's (EIA) 2011 Annual Energy

Outlook, a review of the data from EIA beginning a few years back shows that the forecasted shale gas production only very recently reached significant levels. Figure FCG - 3 below shows EIA's forecast in recent years for shale gas production as well as for all unconventional gas in 2010. EIA has increased its forecast in each year.



Source: *The Brattle Group* . EIA Energy Outlook.

Figure FCG - 3

It is also instructive to review the amazing growth rates for shale gas as major source of US gas supply. Shale gas production in 2009 was 2.23 Tcf but that more than doubled to 4.8 Tcf in 2010.[9] The EIA in its 2011 Annual Energy Outlook

[9] EIA, "Annual Energy Outlook for 2011: Oil and Gas Supply – Reference Case."

notes that the production accelerated dramatically after 2006 with an annual growth of 48 percent from 2006 to 2010. This is virtually unprecedented and would have been very hard to foresee. I also note that I found no production volumes for shale gas in EIA's Annual Energy Outlook for 2007 or 2008.[10] This lag in EIA recognition of shale gas shows that it is not reasonable to have expected RMP to have foreseen more of the shale gas success than the market or than the industry data analysis specialists.

Q. Are these debates over the future promise of shale relatively settled today?

A. No. There are ongoing debates about what the environmental costs and limitations will be from water pollution that may be associated with shale gas, and several states are still reviewing their policies for allowing shale gas development. The NY Times recently had an article indicating that there is continuing skepticism about the prospects for the shale gas industry.[11]

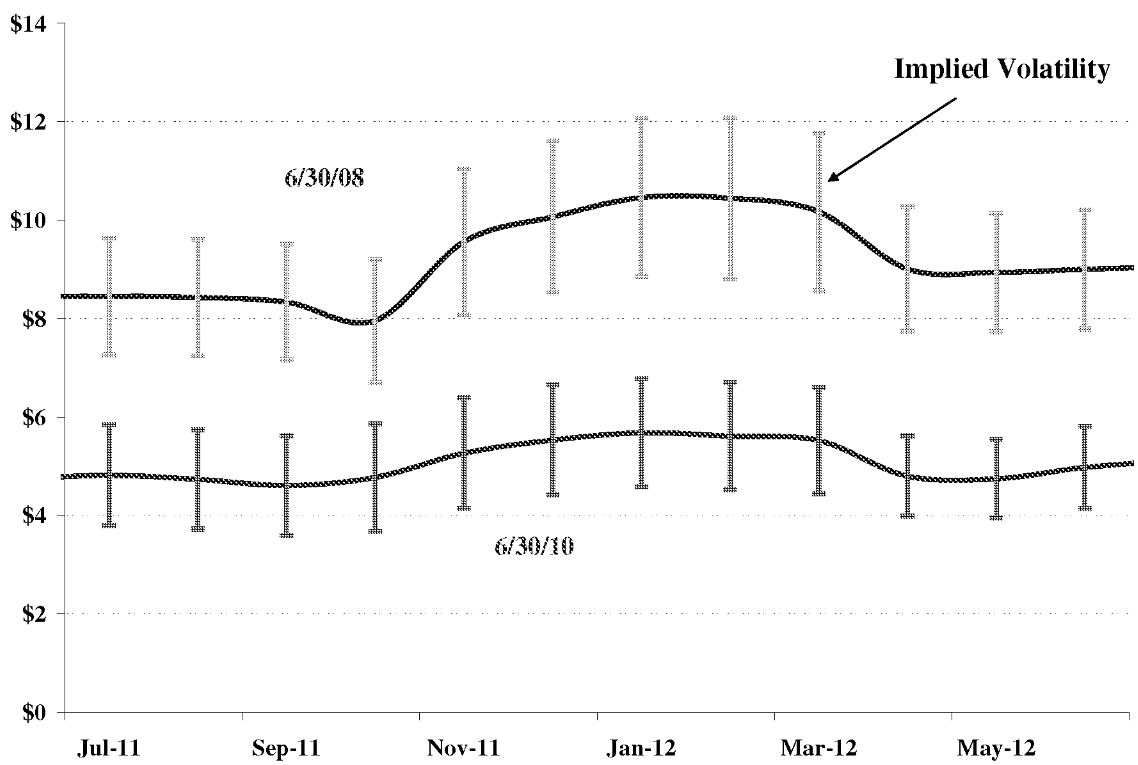
Q. What was the apparent market expectation for shale gas around 2008 compared to more recently?

A. There is no evidence that the market was expecting a shale gas revolution. Figure FCG – 4 below depicts the forward price of gas trading at OPAL near RMP as of early 2008 vs. early 2011. The curve has shifted dramatically downward, but there is little slope to the forward curve in 2008. This means that the dramatic drop in gas supply prices was not expected. This figure also shows vertical bars around the prevailing forward prices in 2008 and 2011, which reflect the expected annualized volatility (plus or minus one standard deviation) in monthly delivered

[10] EIA, "Annual Energy Outlook" for 2007, 2008, 2009, 2010 and 2010.
[11] New York Times, "Insiders Sound an Alarm Amid a Natural Gas Rush," June 25, 2011.

gas prices at the time these forward prices were in effect. One can see here that there is little overlap of the uncertainty bands around the 2008 prices with the realized spot prices for gas in 2011. Thus, the market was not anticipating even a range of risk for what has turned out to happen.

Forward RockOpal Price Curves and Volatilities



Source: Rocky Mountain Power.

Figure FCG - 4

Q. What are the implications of this history for the foreseeability of gas and electric prices falling so much in the past couple of years?

A. There was a lot of discussion and debate in the trade press about the above issues, so the market likely already incorporated as good a guess about where the prices of gas were headed as was reasonably knowable. Intervenors arguing that RMP managers should or could have had a better forecast of future gas and electric prices than the market was revealing in its forwards are basically insisting that RMP should have speculated in the past few years – a practice that RMP appropriately avoids and that the Commission should strongly discourage.

Greater Use of Options and Collars

Q. Please explain the distinction between risk and regret.

A. Hedging reduces risk, meaning exposure to future uncertain costs (or revenues). The more tightly and the farther forward in time that future range of costs is controlled, the greater the possibility that realized market circumstances will turn out to have a different cost than the hedges. Now, this is precisely what hedging was supposed to accomplish, but when the realized costs are lower than the hedges, we tend to feel frustration or regret over having hedged. However, one cannot minimize both risk and regret, as they are complementary to each other. Instead, you must choose which one you want to control, and let the other one be open. For this reason, it is not useful to evaluate the success of a hedging program in relation to its "winnings" or "losses". Rather, it should be evaluated based on whether it kept the expected range of potential costs within the target boundaries. If there is a desire to reduce the chance of regret with the tradeoff of increased risk, then the appropriate strategy is to hedge less or to rely more on one-sided hedges like options.

Q. Should RMP use, or have used, more call options or collars?

A. There can be no answer to this question apart from evaluating and responding to the preferences of customers for the types of costs and risks that would be involved. The expected cost will be the same, and there is no advantage to RMP from using more or fewer options in its hedging. However, options are a bit more complex to understand than forwards and swaps, and they have a history of being somewhat contentious in regulatory proceedings. Thus, it is not a common practice for electric companies to use significant quantities of call options or collars to manage their fuel and purchased power risk, for several reasons:

- They tend to be less liquid than swaps and standard forwards;
- They have up-front cash payments for the premiums;
- And most importantly, they are often not well understood or consistently evaluated by regulatory commissions and intervenors – Specifically, it is quite common for utilities to face complaints that unused call options (not exercised because they expired out of the money) were unnecessary or imprudent.

This latter problem of objecting to the costs of un-exercised options is somewhat like complaining that your fire insurance was a bad idea because your house did not burn down. However, it is not an uncommon complaint. I understand that RMP has faced some of this kind of inconsistent reactions to its own use of options in the past as well as in the instant case.[12]

It is also important to remember that like any fairly priced hedges, options do not reduce expected costs (nor do they raise them, despite the premium). Instead, they just trim the upside, with the buyer paying a fair price for the

[12] For a discussion of this issue, see the rebuttal testimony of Stefan A. Bird.

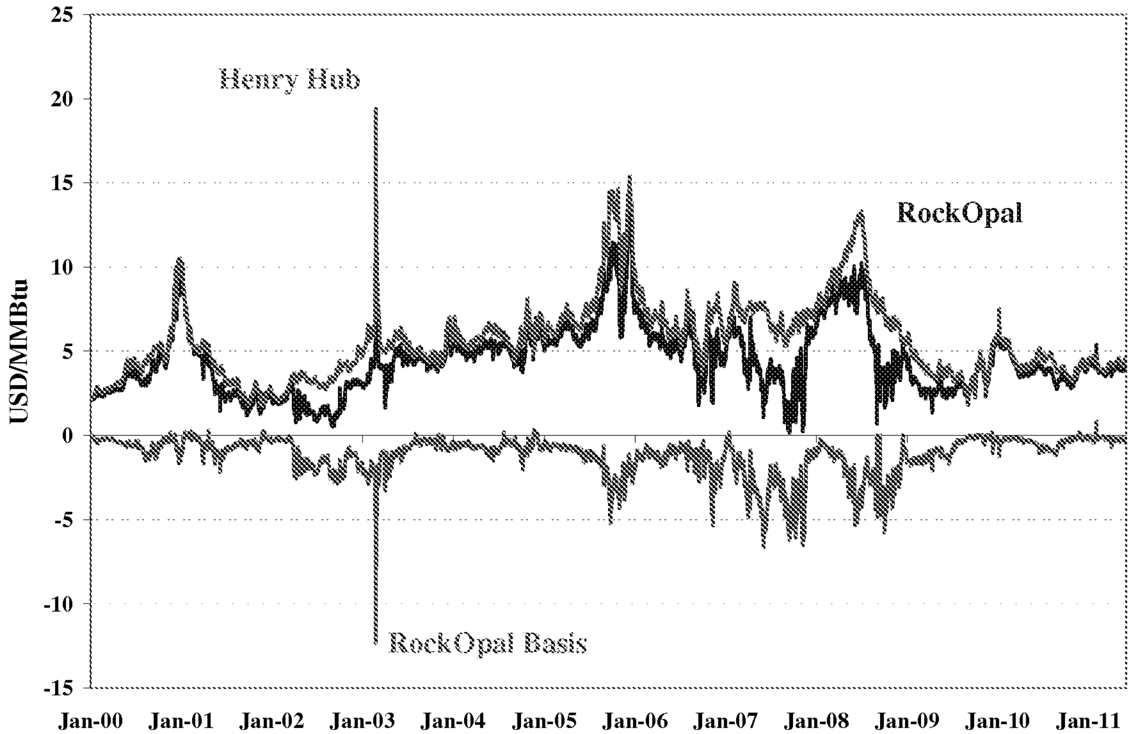
truncated high end exposure. It is reasonable to consider using them, but that should be an *ex ante* decision going forward, not an *ex post*, hindsight criticism.

Q. Witness Dr. Schell for the Office of Consumer Service suggests that it would have been better for RMP to rely almost entirely on call options over the past few years, thereby allowing for lots of cost reductions since prices have fallen. She suggests that Henry Hub options would have sufficed.[13] Do you agree?

A. No, I disagree. The gas contracts available at Henry Hub are for deliveries that are roughly 1500 miles away from RMP's Utah service territory. While natural gas is a somewhat correlated product around the nation, the prices at different locations can and do diverge materially from each other, especially over large distances with occasionally constrained pipeline delivery infrastructure. My Figure FCG - 5 below shows the price at Henry Hub versus the price at Opal over the past few years, and the size of the difference (generally called the "basis" risk). Generally, western gas prices have been below those at Henry Hub, so this basis has been negative. It has been as large as $6.66/MMBtu[14] and the average basis constitute about 20 percent of the Henry Hub commodity price itself. RMP would actually have wanted options for delivery to several different locations. This large basis risk means that options tied to prices at Henry Hub could have ended up in or out of the money for reasons that had nothing to do with market conditions at RMP's locations. Moreover, it might not even have been feasible to obtain the full range of needed options to accomplish what swaps and forwards can do, as the latter are traded much more heavily over longer horizons.

[13] Direct Testimony of Lori Smith Schell on behalf of the Office of Consumer Services, May 26, 2011 ("Schell Testimony"), pp. 13-17.
[14] Using daily data.

Henry Hub / RockOpal Spot Natural Gas Prices



Source: *The Brattle Group* . Bloomberg.

Figure FCG - 5

Prudence Standards

Q. You have mentioned a few times that it is inappropriate to use look-back tests to evaluate a hedging program. Please elaborate on why this is the case.

A. *Ex post* look-backs to see if hedges turned out to be cheaper than unhedged (or differently hedged) positions would have been can be very misleading for prudence review, and they are not very informative for redesigning a hedging policy going forward. The problem is that a single period reviewed in hindsight will rarely have encompassed much of the range of outcomes that the hedging strategy was designed to protect against. Instead, just a small range of conditions will have occurred, which will reveal little about the overall efficacy of the hedging strategy.[15]

For instance, if one is trying to decide if 7 is a good bet for the sum of two thrown dice, a single throw or two will not be very conclusive. It is the expected value, hence the best single bet, but one could easily observe a 2, 5, 12 or other (non-7) outcomes in just a few rolls and gain no insight about the merits of betting on 7. Hindsight review only works if 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 power 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.

Q. Does this concern apply to comparisons of alternative hedging strategies?

A. Yes, that is just a variation on the same kind of misleading comparison. Intervenors who are suggesting a new strategy based on just the most recent period are not demonstrating that they have a strategy which will perform better in general, just one that would have had better ex post results (less regret) in the most recent period. At the very least, any such proposal needs to be backcast under a wide range of circumstances to see if it has attractive properties in general, not just recently. RMP have done this kind of simulation of the suggestions to

[15] For an exposition of this concept, see also, Jeff. D. Makholm, Eugene T. Meehan, and Julie E. Sullivan, "*Ex Ante* or *Ex Post*? Risk Hedging and Prudence in the Restructured Power Business," *The Electricity Journal* 19, April 2006.

hedge a smaller percentage of needs in its 2009 presentation to the Commission, where it found that depending on the load shape, reducing RMP's hedging to 71 percent electric and 78 percent gas could result in a loss of up to $245 million or a gain of up to $141 million.[16] This does not mean that the intervenor suggestions are bad ones, just that those approaches have different risk reduction benefits and there is no reason to prefer them just because of alleged recent advantages.

Q. What would a better approach look like?

A. A better approach would be to focus on whether the risk-limiting goals appropriate for ratepayers are being monitored and controlled in a non-speculative, transparent fashion by RMP. That is, keep the focus of risk-management prudence on the range of risks and how those were managed, rather than getting distracted by how the costs turned out. Mechanically, this might involve the following steps:

1. Through workshops or other public processes, agree *a priori* with regulators and customer groups on risk-limiting goals for the future.
2. Agree on a risk simulation model for regulatory discussion that can test and demonstrate alternative hedging strategies to achieve the desired risk limitation goals.
3. Formalize a plan for type, timing, and triggers for implementing hedges.
4. Schedule periodic reporting of success in adherence to the agreed plan, and on continuing expectations of being able to achieve the risk goals (perhaps quarterly or semi-annually).

[16] PacifiCorp Energy, "Commodity Price Risk Management Presentation," Utah Public Service Commission, May 18, 2009, p. 23-24.

5. Use unanticipated major changes in market conditions to trigger reviews of whether hedging goals or strategy should be revised.

6. Evaluate prudence based on faithfulness in executing the plan and using good practices for risk management controls.

7. Apply no *ex post* look backs, except to open discussion of revised future goals.

This approach will keep the focus of hedging prudence reviews on whether risks are being reduced, rather than on whether the hedges happened to pay off. It will also increase intervenor and regulatory understanding of market conditions, as well as what can and cannot be accomplished with hedging. Ultimately, it should lead to an improved set of goals for risk reduction that more closely match consumer needs.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit PPL/500
Rick T. Link

REDACTED
Docket No. UE-227
Exhibit PPL/500
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Redacted Rebuttal Testimony of Rick T. Link

July 2011

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

A. My name is Rick T. Link. My business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232. My present position is Director, Structuring & Pricing.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a B.S. in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999. I have been employed in the commercial & trading area of PacifiCorp since 2003 where I have held positions in market fundamentals, structuring, and planning. Currently, I direct the work of the market assessment group, the structuring & pricing group, and the integrated resource planning group. Prior to joining the Company, I was an energy and environmental economics consultant for ICF Consulting (now ICF International) from 1999 to 2003.

Purpose and Overview of Testimony

Q. Please explain the purpose of your testimony and provide an overview of your conclusions.

A. My rebuttal testimony will show that the concerns raised by the Industrial Customers of Northwest Utilities (ICNU) in Mr. Donald W. Schoenbeck's June 24, 2011 testimony and July 5, 2011 supplemental testimony pertaining to the Company's forward price curve (FPC) and hourly price scalars (Scalars) are unfounded. Specifically, my rebuttal testimony shows:

- ICNU's claim that the Company treats the official FPC used to determine net power costs (NPC) as highly confidential is false, and as such, this claim does not support its recommendation to use a third party source for the FPC.
- Relying upon a third party source for the FPC would not give parties the ability to more precisely track how forward market movements would impact NPC, and as evidenced by ICNU's own analysis, parties can reasonably approximate such impacts without the Company developing a FPC off of third party data.
- The Company's method for developing its official FPC is reasonable and requires no modification.
- Removing hour-to-hour price variability from the Company's Scalar calculation ignores actual market trends and is not valid.
- Reducing the period over which historical price data are used to derive Scalars could introduce volatility to NPC when updated.
- The Company's method for calculating Scalars is reasonable and requires no modification.

Forward Price Curve

Q. Please summarize ICNU's concerns related to the source of the Company's FPC.

A. ICNU claims that the Company relies on internally generated highly confidential monthly electricity and natural gas prices to establish NPC. It is primarily concerned with the perceived highly confidential designation for the FPC as used to establish NPC.

Q. Does the Company designate the FPC it uses for determining NPC as highly confidential?

A. No. The official FPC used in this docket to determine NPC was provided to Staff and interveners in supporting workpapers, as required by the Transition Adjustment Mechanism Guidelines (TAM Guidelines).[1] The Company designates the official FPC as confidential and does not designate it highly confidential.

Q. Please describe how the Company produces the official FPC that is used to establish NPC.

A. The official FPC is developed by the Company's front office at market close for a given quote date consistent with where the forward market was trading on that day. In the Company's initial filing, the quote date for the official FPC is December 31, 2010. For the rebuttal update filing, the quote date for the official FPC is June 30, 2011. When producing the FPC, the front office takes into consideration market price quotations from energy brokers, exchanges, direct communication with market participants, and actual transactions executed by the Company. [redacted] When this criterion is met, the front office FPC is "locked down" and becomes the official FPC for that quote

[1] *See* Order No. 09-274, Appendix A at p. 17 (Section A(2)(c)).

date. The official FPC is established on the last trading day of each quarter and for any FPC used to determine NPC.

Q. Does the Company make available to parties the risk management validation of the front office FPC?

A. Yes. Under TAM Guidelines, the Company is required to provide the risk management validation for the final update that shows how the official FPC compares to broker quotes.[2]

Q. What specific recommendations does ICNU offer as it relates to the FPC used to determine NPC?

A. ICNU recommends that:

> [A]n independent (or third party) source be used to eliminate any concerns regarding the possibility of gaming, lessen disputes over the highly confidential treatment of the associated prices, and to allow for a more precise tracking of how forward market movements would impact the Company's NPC.[3]

Specifically, ICNU recommends using transactional data from the IntercontinentalExchange (ICE) as the source of the FPC.

Q. Has ICNU found any evidence of gaming?

A. No. ICNU conducted an analysis in which it compared a sample of Company FPCs with forward prices from ICE on the same quote dates. The results of this analysis showed only minor differences between the Company's FPC and those reported by ICE. Further, in response to Data Request 3.1, attached as Exhibit PPL/501, ICNU states:

[2] *See* Order No. 09-274, Appendix A at p. 5 (Section D(2)).
[3] *See* ICNU/100, Schoenbeck/3, lines 8-12.

> For the fifteen days examined by Mr. Schoenbeck, he did not believe he observed any gaming for the Company's forward hubs where third party data was available.

Q. Do you agree that ICNU's recommendation would lessen disputes over the highly confidential treatment of the Company's official FPC?

A. No. As I have described above, the Company does not treat the official FPC used to determine NPC as highly confidential, and thus ICNU's statement is not valid.

Q. What FPC materials does the Company treat as highly confidential?

A. The Company updates its FPC at the end of each trading day. Official FPCs are designated confidential. However, the Company treats the FPC for all other quote dates as highly confidential to protect information that could indicate prices the Company would pay or accept in its commercial activities. The Company has adopted this approach, which strikes a balance between protecting commercially sensitive information while at the same time facilitating discovery when the FPC is used to calculate NPC.

The dispute with ICNU over the highly confidential treatment of the FPC stemmed from its Data Request 2.11, which requested that the Company provide FPCs for all quote dates beginning January 1, 2011 through the latest date available at the time, which was March 31, 2011. In response to this request, the Company made available to ICNU the March 31, 2011 official FPC as a confidential attachment and ultimately provided to ICNU through a supplemental response to Data Request 2.11 redacted daily FPCs through March 31, 2011, designated as confidential. In the supplemental response, the Company agreed to classify these daily forward prices for points of delivery with substantial liquidity as confidential. The Company also provided the highly confidential daily FPCs for the illiquid points of delivery under the terms of a Modified Protective Order adopted by the Commission in Order No. 11-265. The Company continues to consider the most current daily forward prices as well as the prices for the illiquid points of delivery as highly confidential. ICNU has not alleged that the protections in the Modified Protective Order limited its ability to review the highly confidential FPC data, which were not used to determine NPC, undermining the argument that a lower level of protection is appropriate.

Q. If ICE were used as the source of the FPC, would this allow for a more precise tracking of how forward market movements would impact the Company's FPC?

A. No. When asked to provide the analysis showing that a third party forecast would serve this purpose, ICNU responded to Data Request 3.2 by stating that no analysis was done to support this statement. ICNU adds in its response:

> [H]aving the exact forward price curve series from an independent third party source would allow a party to precisely know the impact on the Company's net power cost.[4]

Q. How do you respond?

A. There is no third party source that provides forward price curves for each of the electricity and natural gas market hubs that are critical to determining NPC, and as such, use of a third party provider will not provide any party with a precise indication of how market movements impact NPC. For instance, no third party source provides burner tip gas prices for each of the Company's natural gas-fired resources. Similarly, ICE does not publish forward electricity prices for the

[4] *See* Exhibit PPL/501.

California Oregon Border, Four Corners, Mead and Mona market hubs.

Q. Does ICNU claim to resolve this problem by using a second source of data?

A. Yes. ICNU suggests that the Company could simply rely on a source such as Platts Megawatt Daily to derive historical basis spreads for the California Oregon Border, Four Corners, Mead, and Mona electricity market hubs that would then be applied to forward prices.

Q. Is this a reasonable alternative?

A. No. Historical price spreads are not a suitable replacement for forward price spreads informed by market price quotations on a specific trading day from energy brokers, exchanges, direct communication with market participants, and actual transactions executed by the Company. Moreover, data for these market hubs are not always available. For instance, ICNU provided a sample of the July 8, 2010 Platts Megawatt Daily with the workpapers that accompanied its testimony, attached as Confidential Exhibit PPL/502. This document shows that there were no on-peak transactions for the Mona market, and no off-peak transactions for the Mona, Mead, and Four Corners market hubs.

Q. Does ICNU identify in its recommendation any solutions for deriving burner tip natural gas prices for the Company's natural gas-fired resources that are not reported by any third party provider?

A. No.

Q. Considering it is not possible for a party to *precisely* know how forward market movements impact NPC even if a third party source were used for the FPC, can parties reasonably approximate the impacts without requiring the Company to utilize a third party provider?

A. Yes. [redacted], it would be reasonable to expect that a third party source would publish forward prices that are similar to those produced by the Company. In fact, this is precisely what ICNU found when its consultant compared a sample of the Company's FPC with ICE data, which showed that in most cases, the difference between the two price curves was less than 0.5%. As such and if so desired, parties could reasonably approximate the impact of forward market movements on NPC by using in their own analysis a third party provider such as ICE.

Q. What other problems are there with using a third party provider as the source for the Company's FPC when determining NPC?

A. The Company relies on the same forward price curve to establish NPC as is used in daily operations and in financial reporting. It is not reasonable for the Company to have one FPC derived from a third party provider to determine NPC in Oregon and another FPC that it uses in daily operations and financial reporting. In fact, a Stipulation in Docket UE 116 on direct access implementation among Commission Staff, ICNU, and the Company expressly provides that the Company will use the same FPC for Company operations and for determination of transition adjustments:

> The Company represents that the forward price curves it will base the transition credit and buyback calculations on are the Mid-C forward price curves generally used by the Company in all aspects of its business.[5]

Q. Does ICNU's proposal raise additional concerns with respect to NPC-related dockets in other states?

A. Yes. The Company relies upon its official FPC to set NPC in all states. The use of different FPCs in Oregon from that used in the Company's other five states could cause inconsistent results and would introduce a new layer of complexity to NPC-related proceedings.

Q. What do you recommend?

A. I recommend that the Commission reject the recommendations made by ICNU to use a third party provider as the source for the Company's FPC.

Hourly Scalars

Q. Please briefly describe Scalars and how they are applied to the FPC.

A. Scalars are multipliers that get applied to forward monthly prices to arrive at an hourly price profile. These multipliers are unique for every hour for a given day type (*i.e.,* weekdays excluding holidays, Saturdays excluding holidays, and Sundays/holidays), and therefore yield hour-to-hour price variability that is consistent with historical price data. Scalars greater than one would result in an hourly price for a given day type that is higher than the monthly forward price, and price multipliers that are less than one would result in an hourly price for a given day type that is lower than the monthly forward price. The hourly price profile that is a result of applying Scalars to forward monthly prices yields hourly

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[5] *See* Stipulation on Standard Offer and Transition Credit Among OPUC Staff, PacifiCorp and ICNU, Docket UE 116 at p. 3 (June 19, 2001).

prices that, when averaged across a given month, precisely equal the forward monthly prices in the FPC.

Q. Please summarize ICNU's position related to Scalars.

A. ICNU asserts that the Company's highly confidential treatment of Scalar data is not required. ICNU also recommends two alternatives for calculating Scalars. ICNU prefers that the Commission require the Company to remove hour-to-hour price variability from its Scalar methodology. In the alternative, ICNU recommends that the Commission require the Company to [redacted]

Q. How do you respond?

A. I emphatically disagree with each of ICNU's recommendations pertaining to the Company's Scalars. First, the Company considers its derivation of Scalars to be commercially sensitive and the highly confidential treatment of the Scalar methodology is applied to ensure the Company is not disadvantaged in its commercial activities. Second, ICNU's preferred alternative for calculating Scalars would remove entirely the hour-to-hour price variability that the Company knows with absolute certainty is a defining characteristic of the hourly electricity market. Third, ICNU's second alternative to [redacted] and introduce volatility to Scalar updates.

Q. Please explain why the Company believes its methodology for developing Scalars is commercially sensitive.

A. The forward markets routinely transact on standard products, which include trades for 25 MW blocks of power delivered either on-peak, off-peak, or on a flat pattern. On-peak products are delivered for hours ending 7 through 22 excluding Sundays and holidays. Off-peak products are delivered for hours ending 23 through 6 for Monday through Friday, and all hours on Sundays and holidays. Flat products are delivered for hours ending 1 through 24 including all Sundays and holidays. For these types of standard products, there is a high level of market transparency and trading volumes among nearly all points of delivery in western wholesale power markets, and consequently there is less risk that the Company would be disadvantaged in prospective commercial transactions for these types of standard products. In fact, the Company's official FPC represents forward prices for these types of products and is treated as confidential as I described earlier in my testimony.

In contrast, there is less forward market transparency and smaller trading volumes for non-standard products, which often include structured transactions for products that have delivery patterns outside of the standard definitions for on-peak, off-peak, and flat products. As an illustrative example, the Company might consider a structured transaction in which power is delivered from hours ending 14 through 18 with a counterparty. If this counterparty were aware of the methodology the Company uses to derive Scalars, they could duplicate the Company's calculations and use that information to their advantage in negotiating the price for such a non-standard transaction. In turn, the Company would be disadvantaged in this negotiation, which by extension, could introduce cost risk to customers. For this reason, the Company considers the methodology used to develop its Scalars to be commercially sensitive and has traditionally ascribed highly confidential treatment for this information.

Q. Does ICNU have full access to the highly confidential information related to Scalars under the Modified Protective Order adopted by the Commission in Order No. 11-265?

A. Yes.

Q. Why does ICNU recommend that the Company modify its Scalar methodology to remove hour-to-hour price variability?

A. ICNU offers two basic arguments to support its preferred recommendation. First, ICNU goes into great length to describe its analysis that shows [redacted] Second, ICNU states that the Company transacts more often in the forward market than in the real time or "spot" market, which is inappropriately used to justify removing the hour-to-hour price variability that results from the Company's calculations.

Q. Is ICNU's discussion of low or missing trade volumes in historical pricing data inconsistent with its testimony related to the Company's FPC?

A. Yes. As I noted earlier in my testimony, ICNU recommended using Platts Megawatt Daily price information for purposes of deriving forward price spreads for those markets hubs not published by ICE. Interestingly, the sample of the Platts Megawatt Daily document that ICNU chose to submit as work papers showed no trades for on-peak prices at Mona, and no trades for off-peak prices at

Mona, Mead, and Four Corners. Apparently, ICNU believes it is reasonable to use pricing data with no recorded trade volumes to support its recommendations related to the official FPC while at the same time arguing that pricing data with limited or no recorded trade volumes is a reason to alter the Company's Scalar methodology.

Q. Is the [redacted] used by the Company valid?

A. Yes. [redacted] Without question, the Company would ideally prefer to have a price index with enough breadth to capture all trade volumes; however, no such source exists. As such, the Company relies on [redacted]

[redacted]

Q. Is ICNU's preferred approach for deriving Scalars valid?

A. No. ICNU's preferred approach would entirely remove hourly price shapes from the derivation of Scalars. As a result, the price for all on-peak hours for a given day-type (*i.e.*, all Mondays) in a given month would be the same. Likewise, the price for all off-peak hours for a given day-type in a given month would be the same. Such an approach completely ignores the fact that there is, with absolute certainty, hour-to-hour price variability in the hourly market. Consequently, ICNU's approach would produce hourly price profiles that would deviate from known market trends, and any resulting NPC implications would, by extension, be suspect.

Q. How do you respond to ICNU's claim that it is more reasonable to remove hour-to-hour price variability in the Scalar calculation because the Company trades in the forward market more so than in the spot market?

A. This argument is misguided. [redacted] In truth, the Company uses an hourly shaped *forward* price curve for the test period, and this hourly price profile is precisely consistent with the hourly price profile used by the Company to evaluate non-standard structured commercial opportunities.

Q. Why do you disagree with ICNU's alternate recommendation to [redacted]

A. ICNU's alternate recommendation is certainly an improvement to its preferred method in that it yields a price profile that maintains hour-to-hour variability consistent with actual market trends. However, this alternate approach remains inferior to the Company's Scalar calculation.

Q. Please explain.

A. The Company has chosen to [redacted] As a result, changes to NPC resulting from quarterly updates to Scalars would likely become more volatile – at times higher and at times lower than the NPC established with prices derived from the Company's Scalar methodology.

Second, when the Company calculates Scalars, [redacted]

[redacted]

Q. What do you recommend?

A. I recommend that the Commission reject ICNU's recommendation that would alter the Company's designation of Scalar data as highly confidential. I further recommend that the Commission reject both of ICNU's recommendations to impose alternate Scalar calculation methodologies.

Q. Does this conclude your testimony?

A. Yes.

Docket No. UE-227
Exhibit PPL/501
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Rick T. Link

ICNU's Responses to Data Requests

July 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 227

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 3.1

July 14, 2011

Data Request No. 3.1:

See ICNU 100/Schoenbeck/3, lines 7-9. Please explain how using a third-party source of monthly and electricity forward price curves would eliminate any concerns regarding the possibility of gaming. Please explain the term "gaming" as used in this context. Please clarify whether Mr. Schoenbeck has found evidence of gaming as used in this context.

Response to Data Request No. 3.1:

Mr. Schoenbeck's testimony should be read or interpreted as referring to a reputable independent third party service provider such as ICE, Dow Jones or Platts. In that context, the concern over the possibility that the reported forward prices not reflecting the forward market at that time – gaming--would not exist. Any party having access to the data could readily verify that the reported prices were in fact the prices employed by the Company. For the fifteen days examined by Mr. Schoenbeck, he did not believe he observed any gaming for the Company's forward hubs where third party data was available.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 227

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 3.2

July 14, 2011

Data Request No. 3.2:

See ICNU 100/Schoenbeck/3, lines 10-12. Please provide the analysis that shows a third-party source of monthly electricity and natural gas forward price curves that would allow for a more precise tracking of how forward market movements would impact the Company's NPC. Please explain the term "more precise" as used in this context.

Response to Data Request No. 3.2:

No specific analysis was done to support this statement. It is based on the fact that having the exact forward price series from an independent third party source would allow a party to precisely know the impact on the Company's net power cost. This is in contrast to the current circumstance whereby by a party would have to estimate the Company's internally generated forward prices in order to estimate the impact on the Company's net power cost from a market movement.

CONFIDENTIAL
Docket No. UE-227
Exhibit PPL/502
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Confidential Exhibit Accompanying Rebuttal Testimony of Rick T. Link

Platt's Megawatt Daily – July 8, 2010

July 2011

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

Exhibit PPL/600
William R. Griffith

Docket No. UE-227
Exhibit PPL/600
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Rebuttal Testimony of William R. Griffith

July 2011

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

A. My name is William R. Griffith. My business address is 825 NE Multnomah St., Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing, Cost of Service, and Regulatory Operations, in the Regulation Department.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree with High Honors and distinction in Political Science and Economics from San Diego State University and a Master of Arts degree in Political Science from that same institution; I was subsequently employed on the faculty for one year. I also attended the University of Oregon and completed all course work towards a Ph.D. in Political Science. I joined the Company in the Pricing & Regulatory Affairs Department in December 1983. In June 1989, I became Manager, Pricing in the Regulation Department. In February 2001, I assumed my present responsibilities.

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

A. Yes. I have testified on behalf of the Company in regulatory proceedings in the states of Oregon, Washington, California, Utah, Wyoming, and Idaho.

Purpose of Testimony

Q. What are your responsibilities in this proceeding?

A. I respond to the $42.6 million "additional margin" adjustment for non-NPC revenues proposed by Industrial Customers of Northwest Utilities (ICNU) witness Mr. Donald W. Schoenbeck. I also present the Company's proposed change to

Schedule 220 which, as discussed by Company witness Mr. Gregory N. Duvall, addresses Noble Americas Energy Solutions' (NAES) witness Mr. Kevin Higgins' concern relating to line losses.

ICNU's Proposed Adjustment for Non-NPC Revenues

Q. Please describe ICNU's proposed adjustment.

A. ICNU proposes to reduce the Company's NPC increase in this TAM proceeding by $42.6 million. ICNU's witness, Mr. Schoenbeck, calculates this amount as the difference between non-NPC revenue at present rates on the 2012 test period as filed in this docket and the non-NPC revenue at present rates on the 2011 test period from the UE 216/217 proceedings. ICNU labels the non-NPC revenue as "margin revenue" and thereby labels the $42.6 million as "additional margin revenue [which] should be used to offset the NPC increase in this proceeding."[1]

Q. What rationale does ICNU offer for its proposed adjustment?

A. ICNU proposes this adjustment to "recognize the additional fixed cost revenue recovery from the additional sales…" in the 2012 forecast test period. ICNU's witness states that his "preference would be to use the same load levels as the prior docket" but indicates that the proposed adjustment would be a reasonable alternative.[2]

Q. Is ICNU's proposal reasonable?

A. No, it is not reasonable. ICNU's proposed adjustment is outside the scope of the TAM and violates the TAM Guidelines agreed to by ICNU and approved by the Commission for TAM proceedings. It is also a one-sided adjustment which

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[1] ICNU/100, Schoenbeck/10, lines 3-9.
[2] ICNU/100, Schoenbeck/9, lines 19-22.

proposes to update revenues without updating costs and violates the matching principle.

Q. How were the TAM Guidelines developed?

A. In Docket UE 199, ICNU, CUB, Staff, and Sempra Energy (the precursor to NAES) reached an all party settlement which included an agreement on TAM Guidelines governing future TAM proceedings. ICNU and the other parties signed the all-party TAM settlement stipulation, and it was ultimately approved by the Commission in Order No. 09-274.

Q. What are the objectives of the TAM and what is the scope of a stand-alone TAM according to the TAM Guidelines?

A. The objective of the TAM is set forth in the first sentence of the Guidelines:

> 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…"[3] [emphasis added]

Also the stand-alone TAM process is, according to the Guidelines, "intended to be narrower and more streamlined than when the TAM is filed in…a general rate case."[4]

Q. Is ICNU's proposal in line with these objectives?

A. No. ICNU's proposed non-NPC revenue adjustment is not related to the update of forecast net power costs and is outside the scope of the TAM. This proposal attempts to broaden the stand-alone TAM by updating it for non-NPC revenues while violating the TAM Guidelines to which ICNU agreed and which were adopted by the Commission.

[3] *See* Order No. 09-274, Appendix A at 9.
[4] *Id.*

Q. Do the TAM Guidelines specifically state the revenue accounts which can be updated in the TAM?

A. Yes. Attachment A to the TAM Guidelines provides a complete list of the FERC NPC accounts which can be updated through the TAM. Additionally, in the stipulation adopted by Order No. 10-363, parties agreed to a revision to the TAM Guidelines to allow updates for specific items in Other Electric Revenue in stand-alone TAM filings. Other Electric Revenue is tracked in non-NPC FERC Account 456. This update is for revenues which are not NPC but are NPC related. This is the only exception allowed by the Guidelines.

Q. Does ICNU's adjustment update revenues related to the listed FERC accounts?

A. No. In fact, ICNU's adjustment is an attempt to do just the opposite – to update revenues for every FERC account <u>except</u> the NPC accounts listed in Attachment A to the TAM Guidelines. In a data response, ICNU agrees that its $42.6 million adjustment is composed entirely of non-NPC revenues. This data response is provided as Exhibit PPL/601.

Q. Is ICNU's proposed adjustment to update non-NPC revenues balanced?

A. No. In addition to violating the TAM guidelines, ICNU's adjustment is entirely one-sided. It updates non-NPC revenues for changes in load, but it makes no corresponding update to costs for non-NPC items. It violates the matching principle which requires that costs must be matched with revenues. ICNU's adjustment is also punitive to the Company and would discourage PacifiCorp from taking steps in the future to avoid filing annual general rate cases.

Q. How are costs for non-NPC items updated in regulatory proceedings?

A. They are updated through a general rate case rather than through this proceeding. TAM proceedings are specifically designed to update NPC revenues and costs.

Q. Will the Company's non-NPC rates change as a direct result of the rate change in this TAM docket?

A. No. The Company's non-NPC rates will not change as a result of this docket.

Q. If non-NPC rates and revenues are not updated in the TAM, what is the reason for including an updated calculation of total revenues for the test period provided in Exhibit PPL/304, Ridenour/1?

A. Total Oregon revenues shown in Exhibit PPL/304 have been provided in order to offer additional information concerning the overall total bill impacts to customers of this NPC change based on the stand-alone TAM forecast test period.

Q. As you stated earlier, ICNU indicates that its proposed adjustment is not its preference. Instead, ICNU's preference would be to use the same load levels as were used in the prior docket for this stand-alone TAM. Please respond.

A. ICNU's preferred method also violates the TAM Guidelines. Section D of the Guidelines on Rate Design clearly states in paragraph 2, "In a stand-alone TAM, the TAM rate design test year will be the forecast test year during which the Schedule 201 rates will be effective."[5] Given that the Schedule 201 rates will be in effect for Calendar Year 2012, the rate design test year must also be the Calendar Year 2012. ICNU's preferred methodology would use the test year from UE 216/217, which was Calendar Year 2011, and which would also violate the TAM Guidelines. This TAM Guideline was specifically designed to address

[5] *Id.* at 4.

matching principle concerns raised by ICNU and Staff in UE 199.

Q. Please summarize your response to ICNU's proposed "additional margin" adjustment in this proceeding.

A. ICNU's "additional margin" adjustment is outside the scope of the TAM and violates the TAM guidelines ordered by the Commission in UE 199. These guidelines were originally developed and agreed to by ICNU and other parties in that docket. Additionally, ICNU's proposed adjustment is one-sided and violates the matching principle. ICNU's "additional margin" adjustment should be rejected.

Schedule 220

Q. What revisions does the Company propose to Schedule 220?

A. As indicated in the rebuttal testimony of Company witness Mr. Duvall to issues raised by NAES' witness Mr. Higgins, the Company proposes to change Schedule 220 to refer to the line losses in the Company's OATT. The specific language is set forth in the proposed tariff provided here as Exhibit PPL/602.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Docket No. UE-227
Exhibit PPL/601
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of William R. Griffith

ICNU's Response to Data Request 2.4

July 2011

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

DOCKET NO. UE 227

ICNU'S RESPONSE TO PACIFICORP'S DATA REQUEST NO. 2.4

July 13, 2011

Data Request No. 2.4:

See ICNU/100, Schoenbeck/10, lines 5-8. Would Mr. Schoenbeck agree that neither the $802.8 million for the 2011 test period in UE 216/217 nor the $845.4 million for the 2012 test period in this proceeding that he has calculated and labeled "fixed margin revenues" contains net power cost revenue? Would Mr. Schoenbeck agree that his value of $42.6 million in "additional margin revenue" contains no net power cost revenue? If the answer to either of these questions is no, please explain.

Response to Data Request No. 2.4:

Yes, the two values exclude net power cost revenue.

Docket No. UE-227
Exhibit PPL/602
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of William R. Griffith

Proposed Revisions to Schedule 220

July 2011

PACIFIC POWER
A DIVISION OF PACIFICORP

Return to Cost-Based Supply Service

The Consumer's return to Cost-Based Supply Service is restricted under the provisions of Schedule 201, Cost-Based Supply Service.

Loss Adjustment Factor

The loss adjustment shall be included by multiplying the above applicable Energy Charge ~~Option~~ by the following adjustment factors where the Real Power Losses Factors are as set forth for service in the PacifiCorp Zone in Schedule 10 of the Company's currently effective FERC Open Access Transmission Tariff (OATT):

~~Transmission Delivery Voltage 1.0361~~
~~Primary Delivery Voltage 1.0577~~
~~Secondary Delivery Voltage 1.0918~~

Delivery Voltage >= 46 kV	1 + Transmission System Real Power Losses Factor
Delivery Voltage < 46 kV	1 + Combination of the Transmission System and Distribution System Real Power Losses Factor

The Company's currently effective OATT can be found at www.oasis.pacificorp.com.

In addition to this energy charge, all customers purchasing this service are required to pay for ancillary services at the rates determined by the appropriate pro forma transmission tariffs.