Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("the Company").

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

Qualifications

Q. Briefly describe your education and professional background.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003 including positions in revenue requirement and regulatory affairs, and I assumed my current role managing the Company's net power cost group in March 2012.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in California, Idaho, Oregon, Utah, and Wyoming.

Purpose of Testimony

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents the Company's calculation of the Energy Balancing Account ("EBA") deferral amount for the 12-month period from January 1, 2012, through December 31, 2012 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover

$17.4 million for the Deferral Period; and,

- A discussion of the main drivers of the difference between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC").

Throughout my testimony I describe how the Company has complied with settlement stipulations and Commission orders from previous cases, including the outcome of Docket No. 12-035-67 ("2012 EBA").

EBA Deferral Calculation

Q. Please describe the Company's calculation of the EBA deferral for the Deferral Period.

A. The Company's application requests recovery of $17.4 million for the Deferral Period, comprised of $17.0 million deferral of excess EBA-related costs plus $0.4 million of interest accrued during the Deferral Period. Exhibit RMP___(BSD-1) presents the detailed calculation of the EBA deferral on a monthly basis during the Deferral Period. Table 1 below provides a breakdown of the total requested EBA recovery.

Table 1
Summary of EBA Deferral Account Balance

Calendar Year 2012 EBA Deferral	
Actual EBAC ($/MWh)	$ 24.39
Base EBAC ($/MWh)	$ 23.40
$/MWh Differential	**$ 0.99**
Utah Load (MWh)	25,157,542
Total Deferrable*	$ 24,300,033
EBA Deferral at 70% Sharing	$ 17,010,023
Interest Accrued through December 31, 2012	384,940
Requested EBA Recovery	**$ 17,394,963**

** Calculated monthly*

Q. What revenue requirement components are included in the EBA deferral calculation?

A. The EBA deferral calculation consists of two revenue requirement components: NPC and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue. Wheeling revenue includes amounts booked to the Federal Energy Regulatory Commission ("FERC") account 456.1, revenues from transmission of electricity of others. Collectively these two components are known in the Company's EBA tariff as Energy Balancing Account Costs ("EBAC").

During 2012 several new SAP accounts were used in the Company's accounting system to track components of net power costs and wheeling revenue. These new accounts fall within the main FERC accounts that make up EBAC, but the specific SAP accounts are not identified in the current Schedule 94.

Exhibit RMP___(BSD-2) identifies the new accounts used in 2012. The new accounts are also included in the revised tariff sheets provided in the testimony of Ms. Joelle R. Steward.

Q. What methodology did the Company use to calculate the EBA Deferral Account Balance?

A. The EBA calculation is a comparison of actual NPC and wheeling revenue to the levels in rates as established in a general rate case, with 70 percent of the difference being deferred for later recovery or refund to customers. The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

$$EBA\ Deferral_{Utah,month} = \left[\left(Actual\ EBAC_{\frac{month}{MWh}} - Base\ EBAC_{\frac{month}{MWh}}\right) \times Actual\ MWh_{Utah,month}\right] \text{x } 70\%$$

The calculation of the Actual EBAC, Base EBAC, and the resulting EBA Deferral in this application is according to the stipulated Scalar Method. The Scalar Method was originally developed as part of the settlement agreement reached in Docket No. 10-035-124 ("2011 GRC") and the same approach was again adopted in the settlement resolving Docket No. 11-035-200 ("2012 GRC"). In the 2012 GRC settlement the Scalar Method was detailed in Exhibit A1: "Utah Allocation Based on Scalar Method from Docket 10-035-124".

Q. Have you included carrying charges in the calculation of the EBA Deferral?

A. Yes. Consistent with the Commission's March 2, 2011, Order in

Docket No. 09-035-15, carrying charges accrue on the monthly EBA deferral at an annual rate of six percent. Pursuant to the 2012 GRC stipulation the 2012 EBA Deferral includes carrying charges only through December 31, 2012.

Q. Please describe the Base EBAC the Company used to calculate the amount to be deferred during the Deferral Period.

A. For the 2012 Deferral Period, the Base EBAC consists of EBAC determined in two separate general rate cases: Base EBAC from the 2011 GRC were effective in rates from January 1, 2012, through October 11, 2012, and Base EBAC from the 2012 GRC were effective in rates from October 12, 2012, through December 31, 2012. In the 2011 GRC, total Company Base NPC were set at $1.475 billion, which included an unspecified reduction of $33.4 million for purposes of settlement. Consistent with the Commission's 2012 EBA order, the $33.4 million adjustment is split between the system generation ("SG") and system energy ("SE") factors for purposes of allocation to Utah. In the 2012 GRC, total Company Base NPC were set at $1.479 billion, which was the level included in the Company's updated NPC filed in May 11, 2012. The combined Base NPC for the Deferral Period is $1.479 billion on a total Company basis.

Q. What was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total Company basis, Actual NPC for the Deferral Period was approximately $1.497 billion, or approximately $18.1 million higher than the $1.479 billion Base NPC. Table 2 below summarizes the differences between Actual NPC and Base NPC.

Table 2
Total Company Net Power Cost Reconciliation ($millions)

		EBA Deferral Period
1	**Base NPC**	1,479
2	**Reverse Settlement Adjustment**	27
3	Increase/(Decrease) to NPC:	
4	Wholesale Sales Revenue	214
5	Purchased Power Expense	(147)
6	Coal Fuel Expense	(19)
7	Natural Gas Expense	(55)
8	Wheeling, Hydro and Other Expenses	(1)
9	**Total Increase/(Decrease)**	(8)
10	**Adjusted Actual NPC 2012**	**1,497**
11	Total Increase / (Decrease)	18

Q. Please describe Table 2 and the line items making up the difference between Actual NPC and Base NPC.

A. Line one of Table 2 displays the settled level of NPC, or the combined approved Base NPC, for the 12 month Deferral Period. Line two of Table 2 displays the settlement adjustment of approximately $26.5 million that was in effect during the Deferral Period - the portion of the 2011 GRC settlement adjustment from January through October 11, 2012. The remainder of Table 2 is a breakout of the difference between Actual NPC and Base NPC, by cost category, on a total Company basis. Because the settlement adjustment in the 2011 Stipulation was not identified by category, an item by item comparison of Actual NPC to Base NPC is not possible. The differences by category in Table 2 result from comparing Actual NPC to the combined Base NPC which was effective during the Deferral Period.

Q. How did the settlement adjustment impact the difference between Base NPC and Actual NPC?

A. As can be seen in Table 2, if the settlement adjustment from the 2011 GRC is excluded, the difference between Actual NPC and Base NPC would be $8.4 million on a total Company basis.

Q. Why is the EBA deferral $24.3 million if the difference in total Company NPC is only $18.1 million?

A. In addition to the difference between Actual NPC and Base NPC, the EBA deferral calculation is impacted by other items such as wheeling revenue, inter-jurisdictional allocation factors, and changes in retail sales volumes which impact the collection of Base NPC in rates. Table 3 provides an accounting of the EBA deferral with the various components separated.

Table 3
Summary of EBA Deferral by Category

Utah Allocated Actual NPC		646,618,468
Utah Allocated Base NPC		631,887,909
NPC Variance	**$**	**14,730,560**
Utah Allocated Actual Wheeling Revenue		(32,995,864)
Utah Allocated Base Wheeling Revenue		(30,848,870)
Wheeling Revenue Variance	**$**	**(2,146,994)**
Actual Utah Load/Sales		25,157,542
Base Utah Load/Sales		25,688,602
Load Variance		(531,060)
Base EBAC Collection Variance	**$**	**11,716,468**
Combined Impact on Total Deferrable EBAC	**$**	**24,300,033**
EBA Deferral at 70% Sharing		17,010,023
Interest Accrued through December 31, 2012		384,940
Requested EBA Recovery	**$**	**17,394,963**

Q. Please explain the $11.7 million collection variance shown in Table 3 above.

A. The EBA calculation is designed to compare Base EBAC collected to the Actual EBAC incurred over a period of time. The level of Base EBAC collected through customer rates depends on the retail sales volumes that are realized over the Deferral Period. During 2012, Utah load[1] was approximately 531 GWh lower than the level used to determine the Base EBAC causing a lower amount of Base EBAC to be included in customers' bills. The accrual in the deferred account is determined by comparing the realized Base EBAC to Actual EBAC for the period. When realized sales volumes are lower than those used in the test period used to establish Base EBAC the deferral for the period will be larger than a simple comparison of projected Base EBAC to Actual EBAC. If realized sales volumes were greater than those used in the test period just the opposite would occur and the deferral would be smaller.

Drivers of NPC Variance

Q. What is the difference between Actual NPC and Base NPC?

A. As shown in Table 2 above, when the settlement adjustment in effect during the base period is excluded from the total, the overall difference between Actual NPC and Base NPC is reduced to $8.4 million on a total Company basis. The various categories making up NPC have larger individual variances but are mostly offsetting. The largest variances were a reduction in wholesale sales revenue (which has the effect of increasing NPC) and a reduction in purchased power expense.

[1] A combination of load and sales was used to compute the EBA deferral, consistent with the Commission's Order in the 2011 GRC.

Q. Were there other factors that complicate the comparison of Base NPC and Actual NPC?

A. Yes. To compare Base NPC to Actual NPC, and to calculate the monthly EBA deferral, the projected costs in a given calendar month are matched up to actual costs for the same month. However, the test periods in the 2011 GRC and 2012 GRC were not aligned with the periods when rates from each case were in effect, nor were they aligned with the Deferral Period. As a result, the test period from the 2011 GRC – July 2011 through June 2012 – was out of synch for approximately 3 ½ months during the Deferral Period. Since Base NPC from the 2012 GRC did not become effective until October 12, 2012, there are 3 months and 11 days where Base NPC from months in 2011 are compared against 2012 Actual NPC. For example, July 2012 Actual NPC is compared against July 2011 Base NPC to calculate the deferrable amount for July.

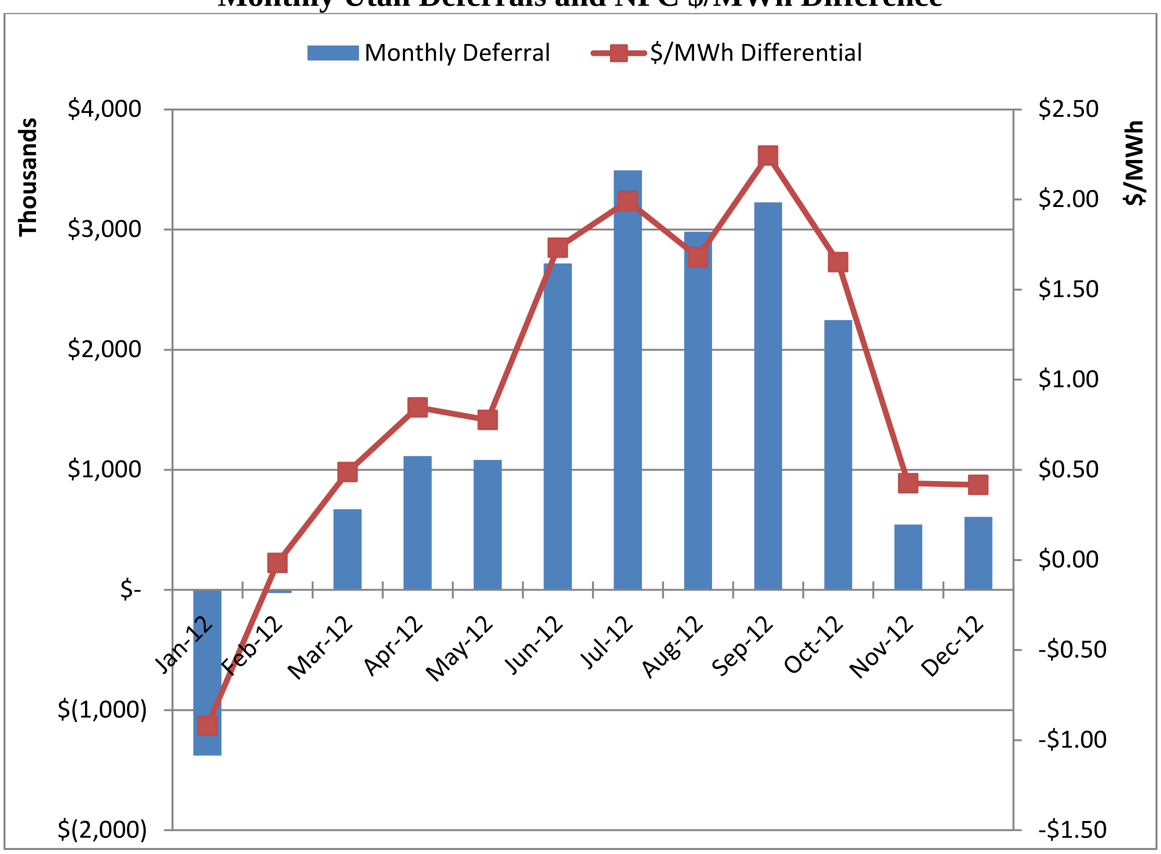
The mismatch between Base NPC test periods and the Deferral Period creates three distinct divisions during 2012: 1) January 2012 through June 2012, when Base NPC from the 2011 GRC aligns with the corresponding months in the Actual NPC, 2) July 2012 through October 11, 2012, when Base NPC from the 2011 GRC is still effective but the monthly comparison is one year out of synch, and 3) October 12, 2012, through December 31, 2012, when Base NPC from the 2012 GRC was in effect and aligned with the corresponding months in Actual NPC.

Q. What is the impact of the mismatched periods?

A. First, comparing actual costs during months in 2012 to a stale forecast of costs for the same months in 2011 is difficult at best and is not an ‘apples-to-apples’ comparison. Second, the out-of-date forecast of NPC during the summer months understated the Base NPC and caused a large variance with Actual NPC from July through October 2012.

Figure 1, below, illustrates the difference between Actual NPC and Base NPC on a dollar-per-megawatt-hour basis and the dollars deferred each month during the Deferral Period. The chart demonstrates that the majority of the deferral occurred during the July through October time period when the mismatch in test year occurred. During those four months, over $12.0 million (or 71 percent) accrued to the EBA deferral, out of the total $17.0 million total deferral for 2012.

Figure 1
Monthly Utah Deferrals and NPC $/MWh Difference



Q. Not withstanding the mismatched months, what factors caused the variance in the various NPC components?

A. Two main issues impacted the operation of the Company's system compared to the Base NPC: 1) a decrease in net system load, and 2) a drop in wholesale market prices for electricity and natural gas.

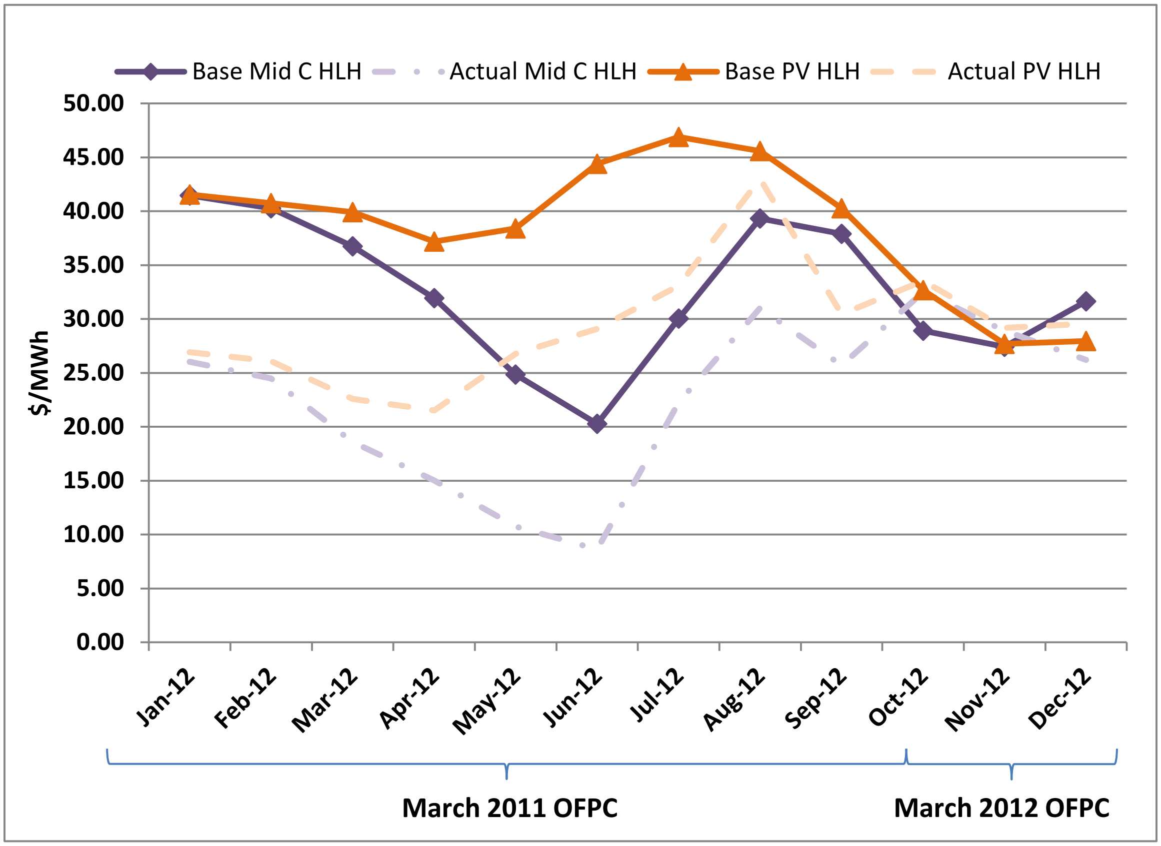
Q. How did actual net system load compare to the load forecasts included in Base NPC for the Deferral Period?

A. Compared to the load used to determine the combined Base NPC from the 2011 GRC and the 2012 GRC, actual net system load was 1,737 GWh (3 percent) lower than forecast. Generally speaking, lower system load enables the Company to increase the net sales made to the wholesale market. Lower Utah loads also results in lower retail revenues as I addressed earlier in my testimony.

Q. Given the reduction in load, why did revenue from wholesale sales decrease?

A. Revenue from wholesale market sales was impacted by a reduction in market prices compared to the Official Forward Price Curve ("OFPC") reflected in Base NPC. On average, prices at the Mid-Columbia ("Mid-C") and Palo Verde ("PV") market hubs were lower by 35 percent and 22 percent, respectively. Figure 2, below, demonstrates the magnitude of the change in the average heavy load hour price at Mid-C and PV for the Deferral Period.

Figure 2
Wholesale Electricity Market Prices
Forecast vs Actual



For the Deferral Period, actual wholesale sales revenue declined approximately $213.6 million when compared to wholesale sales revenues included in Base NPC as shown in Table 2. The reduction in wholesale sales revenue was largely offset by a reduction in purchased power expense, also attributable to the reduction in market prices.

Q. Did the volume of net short term market sales change?

A. Yes. As expected with a decrease in system load, the actual volume of net short term market sales (total short term sales less total short term purchases) was higher than the level included in Base NPC. However, the reduction in market prices overwhelmed the impact of additional net sales.

Q. Do lower wholesale electricity market prices also impact generation from the Company's owned resources?

A. Yes. All else held equal, lower wholesale electricity market prices impact the economics of the Company's generating units, such that if market prices are less than the cost of generating electricity at Company facilities, the Company will not operate those facilities during those hours. In this circumstance, the Company will purchase lower cost power to serve customers, or if customer load has already been served, the Company will back down the uneconomic facility as it cannot make an economic sale of excess generation. During the Deferral Period, lower wholesale market prices contributed to a decrease of 1,152 GWh (3 percent) in coal fired generation compared to Base NPC.

Q. Please further describe the changes in coal fuel expense and the decrease in volume compared to Base NPC.

A. As shown in Table 2, coal fuel expense fell approximately $19 million compared to Base NPC, due to the 1,152 GWh overall decrease in generation volume. Figure 3, below, compares the average cost of coal during the Deferral Period to the forecasted and actual Mid-C market prices during light load hours. Figure 4 makes the same comparison using the PV market.

Figure 3
Average Monthly Coal Generation Costs to Mid-C LLH Market

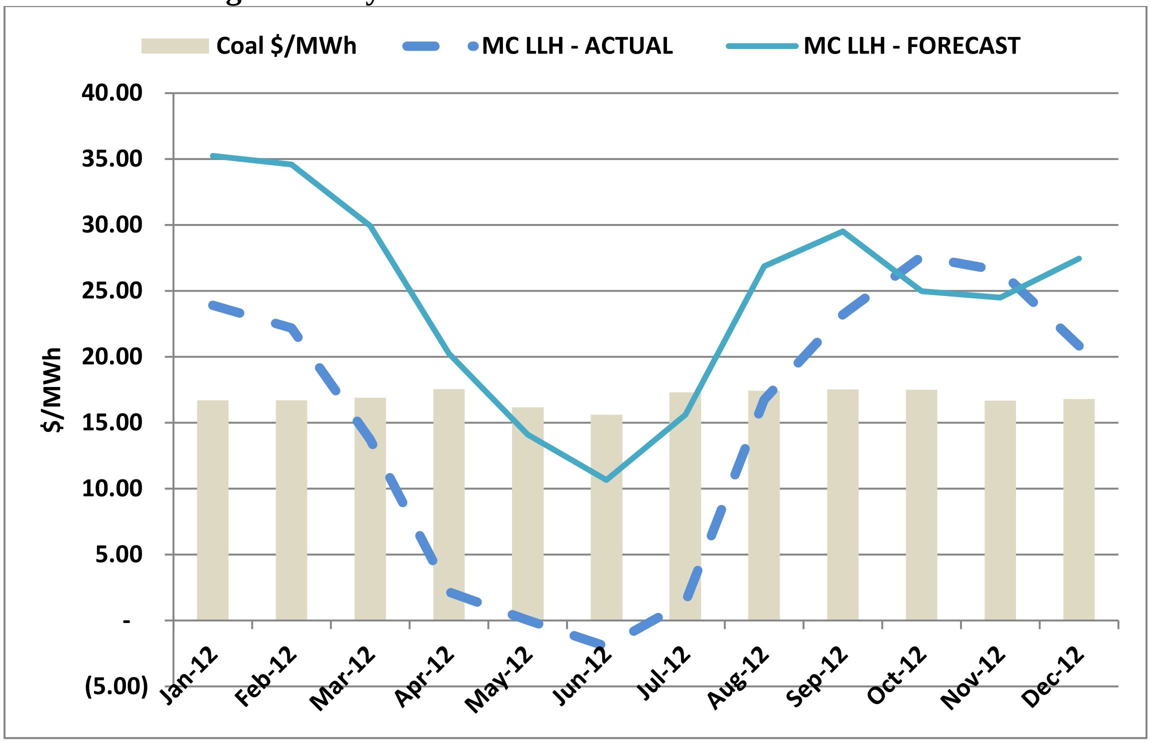
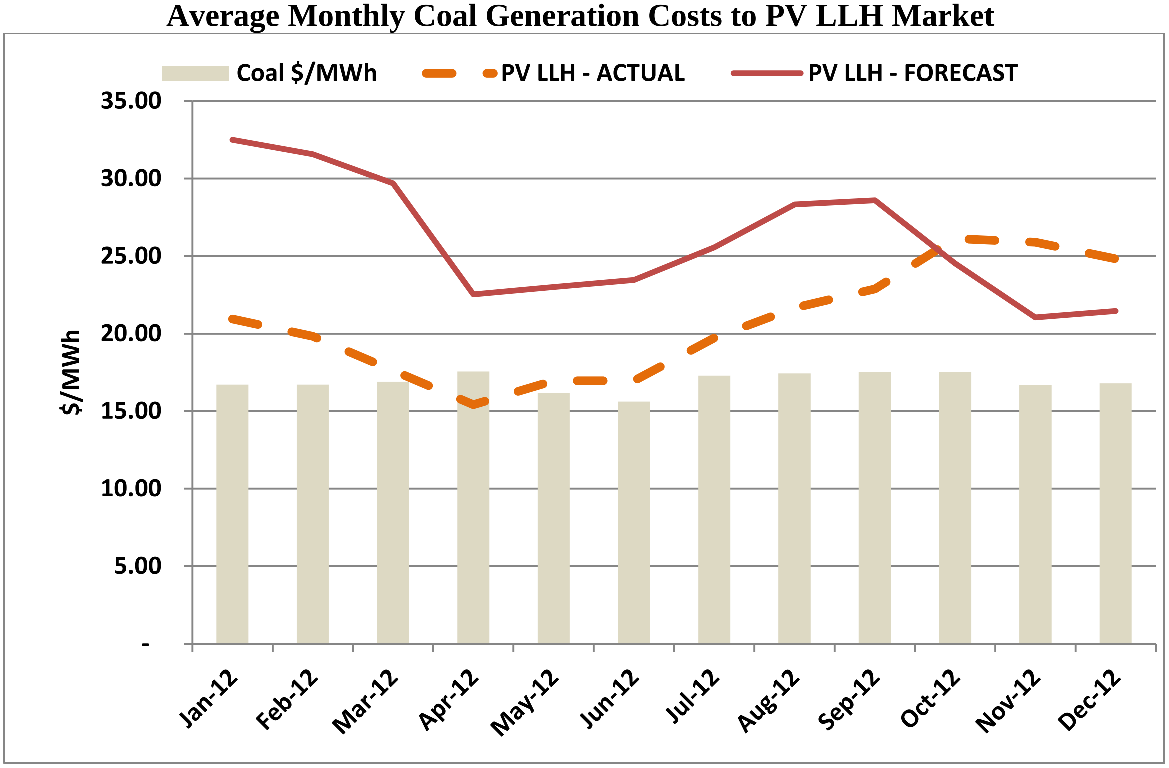


Figure 4
Average Monthly Coal Generation Costs to PV LLH Market

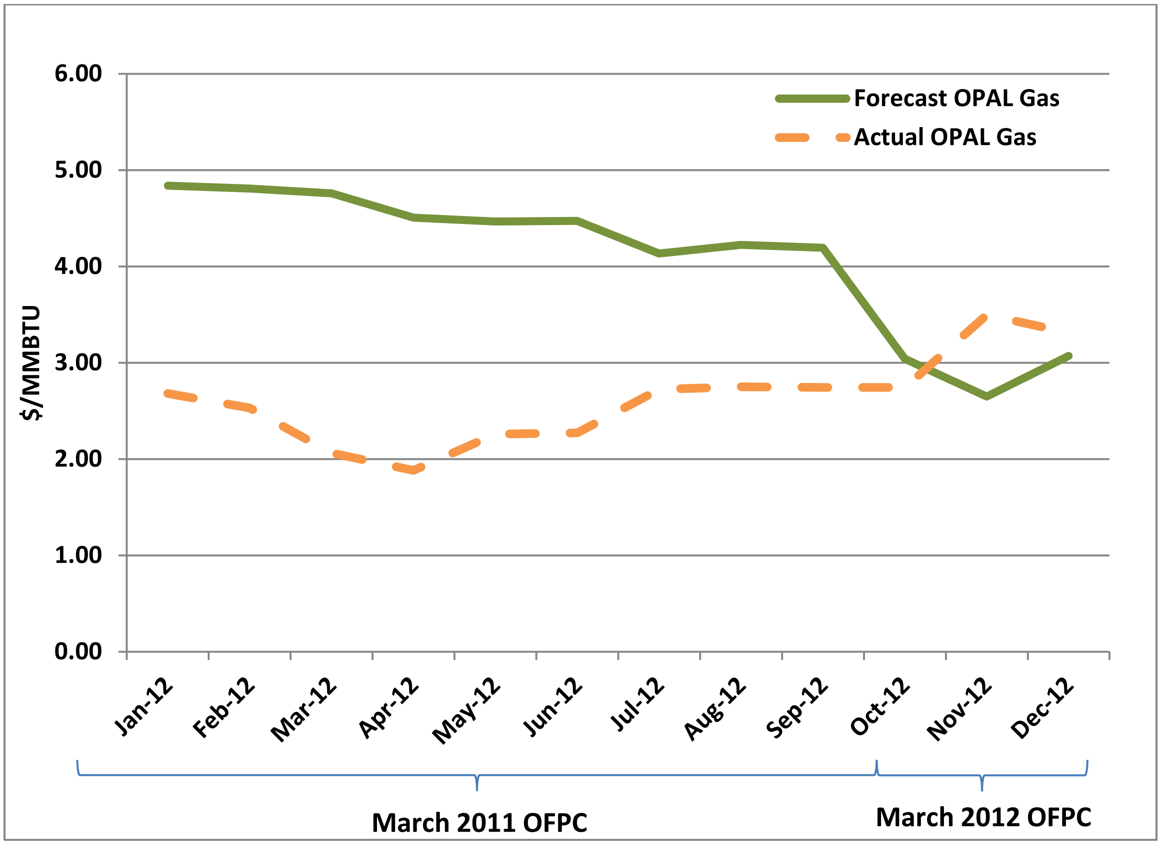


Figures 3 and 4 demonstrate that there were more hours during the Deferral Period than previously forecasted, where market prices were lower than the average cost of coal generation, contributing to the overall reduction in output from coal facilities.

Q. Please describe the changes in natural gas fuel expense.

A. The total natural gas fuel expense in Actual NPC decreased by $54.9 million compared to Base NPC. The decrease in natural gas fuel expense was due to a net decrease in generation from the Company’s natural gas facilities of 540 GWh, compounded by the decrease in actual natural gas market price forecast. On average, the market price of natural gas fell approximately 36 percent when compared to the forecast in Base NPC. Figure 5 illustrates the change in the price of natural gas at the Opal market.

Figure 5
Natural Gas Market Prices
Forecast vs. Actual



Q. Does the reduction in natural gas expense include the impact of hedging?

A. Yes. Consistent with the Commission order approving the 2011 Stipulation, the Company has included all settled gains and losses of its natural gas hedges (i.e. swaps) in the EBA deferral calculation. Company witnesses Mr. Stefan A. Bird and Mr. Frank C. Graves provide testimony supporting the Company's hedging program and the impact of swaps during the Deferral Period.

Compliance with Previous Orders

Q. Has the Company prepared this EBA filing in conformance with Commission orders in Docket No. 09-035-15 as well as the outcome of the 2012 EBA?

A. Yes. In particular, the settlement in the 2012 EBA adopted a list of filing requirements augmenting the filing requirements approved by the Commission in Docket No. 09-035-15. The Company has also provided illustrative calculations of the EBA Deferral under the various methods called for in the 2012 EBA stipulation and the Commission's orders in Docket Nos. 12-035-67 and 09-035-15. Details of the illustrative EBA calculations are provided in the testimony of Mr. Steven R. McDougal.

Q. Has the information provided in the filing requirements improved as a result of the 2012 EBA proceeding?

A. Yes. In particular, the Company improved the 'Trade Data' provided under the original filing requirement 6b. In the 2012 EBA, significant effort was expended to reconcile the detailed transactional information to the summary level NPC accounting. The augmented filing requirements call for such a reconciliation to be performed in advance. That reconciliation, and the additional information provided with the other filing requirements, will enhance parties' ability to review the 2012 EBA data.

Q. Have you provided a detailed breakdown of all hedging and system balancing transactions that settled during the Deferral Period?

A. Yes. Exhibit RMP___(BSD-3) includes a summary of the hedging and balancing transactions included in the Deferral Period, along with the supporting transactional details. The transactional data is also provided as part of the filing requirements in this case. Company witness Mr. Stefan A. Bird provides testimony demonstrating the prudence of the natural gas and electricity hedging transactions and balancing transactions that settled in 2012.

Q. Does this conclude your direct testimony?

A. Yes.