BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power To Increase Rates by $29.3 million or 1.7 percent through the Energy Balancing Account.	)))))))))	**DOCKET NO. 12-035-67** **Exhibit DPU 2.0 Dir** **Testimony and Exhibits** **Richard S. Hahn**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

REDACTED VERSION

Testimony of

Richard S. Hahn

November 13, 2012

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<u>ATTACHMENTS</u>

DPU Exhibit 2.1 Dir, Resume of Richard S. Hahn

I. Introduction

Q: Please state your name, business address and title.

A: My name is Richard S. Hahn. I am employed by La Capra Associates, Inc. ("La Capra Associates") as a Principal Consultant. My business address is One Washington Mall, Boston, Massachusetts, 02108.

Q: On whose behalf are you testifying?

A: The Division of Public Utilities of the State of Utah (the "Division").

Q: Please summarize your educational and professional experience.

A: I received my Bachelor's in Science, Electrical Engineering, in 1973, and my Masters in Science, Electrical Engineering, in 1974, both from Northeastern University. I received my Masters in Business Administration from Boston College in 1982. Since joining La Capra in 2004, I have worked on many projects related to energy markets, utility resource planning projects, forecasts of wholesale market prices, and asset valuations. Prior to joining La Capra, I was employed by NSTAR Electric & Gas (formerly Boston Edison Company) from 1973 to 2003, where I was responsible for, among other activities, rates, integrated resource planning and procurement of fuel supplies and power supplies via Requests For Proposals ("RFPs") and bilateral contract negotiations. Throughout my career, I have gained and demonstrated considerable experience and expertise in utility planning and operating activities and electric rates. I am a registered professional electrical engineer in the Commonwealth of Massachusetts. My resume is provided in DPU Exhibit 2.1 Dir.

Q: What is the purpose of your testimony?

A: La Capra Associates was retained by the Division to assist in reviewing the Application of Rocky Mountain Power ("RMP" or the "Company") seeking approval from the Public Service Commission of Utah ("Commission") to increase electric rates. The scope of our assignment was to ascertain whether the actual costs included in the Energy Balancing Account ("EBA") filing were incurred pursuant to an in-place policy or plan, were prudent, and were in the public interest. This direct testimony presents the results of and the conclusions from that review. It should be noted that this proceeding and my assignment to review the Q4 2011 EBA deferral is being implemented on an expedited basis and on a very tight schedule. In the time allowed to prepare and file this direct testimony, I have addressed as many issues as possible. However, at the time of this filing, there were some discovery requests outstanding or still under review. Therefore, I will supplement this direct testimony if additional information becomes available.

Q: Have you previously testified before the Public Service Commission of Utah?

A: Yes. I testified in Docket 11-035-200 regarding the Application of RMP to increase its electric rates. The purpose of my testimony in that docket was to review the Company's proposed capital additions. I also testified in Docket No. 10-035-126 regarding the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals. And I testified in Docket No. 10-035-124 regarding the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

II. Executive Summary of Testimony

Q: Can you summarize the results and conclusions of your review of the Application in this proceeding?

A: The results and conclusions of my review can be summarized as follows.

- **Based upon the concerns identified below and later in this testimony, I cannot yet recommend that the Commission allow the requested recovery of the EBA deferral amount. The Company should be afforded the opportunity to address the issues identified in this testimony. My recommendation regarding the appropriate amount to be included in rates will be developed after review of the Company's response.**
- The explanation provided in the Company's direct testimony regarding the variance between actual and forecasted net power costs does not adequately explain the reasons for actual net power costs being higher than forecast.
- Based upon the status of my review to date, I cannot agree that these costs underlying the variance were prudently incurred. The Company should provide greater in-depth analysis of this variance that addresses the issues raised in this testimony.
- The Company should also provide more information regarding certain plant outages that were in effect during Q4 2011. Additional review and analysis should be performed to determine whether these outages were the result of prudent actions.
- I reviewed a sample of the four types of transactions for which data were provided in the filing requirements: physical purchases/sales and financial swaps for both power and gas. The review was limited because the Company did not provide the specific reasons for entering into these transactions. Later in this testimony, I identify certain

additional information or justification that should be provided for some of these transactions.

- Based upon my review thus far of wheeling revenues or costs, I have not identified any concerns that would cause me at this time to propose any changes in the EBA deferral amount due to lower than expected wheeling revenues or costs.
- Lastly, I identify additional information that should be provided in future EBA filings. Having this additional information at the time of filing will greatly facilitate future reviews and assessments.

III. Overview of the Application

Q: Can you briefly summarize the Company's application in this proceeding?

A: In its Corrected Report and Order in Docket No. 09-035-15 issued March 3, 2011 ("EBA Order"), the Commission approved the implementation of the EBA to recover the differences between actual net power costs ("NPC") and approved forecasted NPC established in a general rate case. The Commission found in its Order that an EBA mechanism as modified by the Commission was in the public interest and would result in rates that were just and reasonable.

On March 15, 2012, RMP filed a request to increase its rates by $29.3 million to reflect EBA activity through December 31, 2011. Of this total, $20 million was previously approved as part of a settlement stipulation that covered activities through September 30, 2011. The remaining $9.3 million of this request is for activities during the fourth quarter of 2011, plus interest. This amount represents 70% of Utah's share of the EBA deferral. Since the filing of this application, RMP made two corrections to its calculations and reduced the EBA balance proposed for recovery in this proceeding to $8.9 million (see Figure 1 below).

Figure 1

Incremental EBA Deferral		
Actual EBA Rate ($/MWh)		23.41
Base EBA Rate ($/MWh)		21.39
$/MWh Differential	$	2.02
Utah Load (MWh)		6,103,728
Total Deferrable	$	12,317,535
EBA Deferral at 70% Sharing	**$**	**8,622,274**
EBA Deferral Account Balance		
Beginning EBA Deferral Balance: Oct 1, 2011		**-**
Incremental EBA Deferral		8,622,274
Interest		50,827
EBA Revenues		-
Ending EBA Deferral Balance: Dec. 31, 2011	**$**	**8,673,101**
Accrued Interest through June 1, 2012		219,007
Stipulated Deferred Net Power Costs Amortization		20,000,000
Requested EBA Recovery	**$**	**28,892,108**

On June 12, 2012, the Commission issued an order approving the recovery of $20 million portion of the requested $28.9 million increase in rates, effective June 1, 2012. Thus, the remaining issue to be addressed is whether the requested $8.9 million increase that resulted from EBA activity in the fourth quarter of 2011 is appropriate.

IV. Settlement Stipulation

Q: Please describe the Settlement Stipulation.

A: On July 28, 2011, the parties in Docket 10-035-124 reached agreement on major issues in that proceeding and several others and entered into a settlement stipulation. This settlement stipulation resulted in several changes, including the lowering of the Company's requested rate increase to $117 million from $188 million. It also established certain agreements that have a direct bearing on this current proceeding. The Parties to the stipulation agreed the Company should be allowed to recover $60.0 million of the $157.0 million projected by the Company to be in the Deferred NPC Account as of September 30, 2011 from Utah customers. The Parties agreed that this $60.0 million amount should be recovered through an annual $20.0 million surcharge without a carrying charge over three years, and should be applied as a line item in the EBA surcharge commencing June 1, 2012. The Parties agreed that a base net power cost amount of $1,475 million, or $629.1 million on a Utah-allocated basis, should be established for the rate year as the basis for the in-rates level of net power costs beginning October 1, 2011, for purposes of the EBA. The agreed-upon level of annual Utah net power costs was $15 million lower than what was contained in the Company's rebuttal forecast. The Parties agreed that annual wheeling revenues in the amount of $70,500,682 for PacifiCorp, or $30,461,769 on a Utah-allocated basis, should be established as the basis for the in-rates level of wheeling revenues for purposes of the EBA. The settlement stipulation established the monthly Base EBA amounts for the July 2011 to June 2012 rate year, as shown in Figure 2. The average Base EBA for Q4 2011 was $21.391 per MWh.

Figure 2

	Utah EBA $/MWh
Jul-2011	$ 23.533
Aug-2011	26.103
Sep-2011	24.430
Oct-2011	21.518
Nov-2011	21.167
Dec-2011	21.488
Jan-2012	22.166
Feb-2012	22.076
Mar-2012	21.884
Apr-2012	23.109
May-2012	23.407
Jun-2012	22.444
Total	$ 22.824

The Company committed to work collaboratively with the Parties to develop new and improved hedging policies and practices. The Parties agreed to place limits on the review of pre-July 28, 2011 hedging transactions. Paragraph 54 of the settlement stipulation states that "[T]he Parties agree, based on such representation and in consideration of the Company's compromises reached in this Stipulation, that hedging transactions entered into before July 28, 2011 will not be challenged for prudence on the grounds that they:

- Do not comply with the policy changes implemented through the Collaborative Process, Commission order or as a result of this Stipulation;
- Result in over-hedging of natural gas or power positions;
- Were entered into for a period of time beyond a reasonable horizon for hedging transactions; or
- Were comprised of too great a portion of financial products relative to fixed price physical transactions."

Paragraph 56 states that "[T]he Parties agree not to challenge the prudence of the existing financial hedge transactions, including swaps, entered into before July 28, 2011 for the reasons identified in Paragraph 54 above, but Parties reserve the right to challenge such transactions for reasons other than those identified in Paragraph 54 above."

Lastly, the settlement stipulation stated that additional wheeling revenues that may result from the Company's transmission rate case, Docket No. ER11-3643, before the Federal Energy Regulatory Commission ("FERC") are not reflected in the agreed upon revenue requirement. Any such additional revenues resulting from increased price or utilization that accrue from the time the new FERC transmission rates go into effect through the end of the test period in the General Rate Case (i.e. June 30, 2012) shall be deferred and credited to customers in the 2013 EBA annual filing without application of the 70-30 percent sharing mechanism. It is my understanding that this settlement agreement was approved by the Commission on September 13, 2011.

Q: What are the implications of the settlement stipulation for your assignment in this proceeding?

A: The settlement stipulation has important implications that govern my review of the $8.9 million requested increase in rates being adjudicated in this proceeding. First, it established the approved Base EBA costs, including wheeling revenues. Second, it established parameters that would govern the review of transactions that were settled in Q4 2011 but were consummated or entered into prior to July 28, 2011. Specifically, the settlement stipulation establishes four criteria under which pre-July 28, 2011 hedging transactions cannot be challenged for prudence. The settlement stipulation does not place any restrictions on non-hedging transactions, and Pre-July 28, 2011 transactions settled in the deferral period can be challenged for reasons other than the four listed in Paragraph 54.

V. EBA Deferral

Q: Can you briefly describe the EBA deferral?

A: The determination of the EBA deferral is governed by P.S.C.U. No. 94. This tariff describes how the EBA deferral is to be calculated. It also contains a provision that allows the Company to collect or refund 70% of the difference between actual EBA costs and the base EBA costs that are included in the Company's rates. The remaining 30% of the variance between actual and base EBA costs is borne by the Company. EBA costs are defined as Net Power Cost ("NPC") less wheeling revenue. Figure 3 below summarizes the Q4 2011 EBA actual costs, stipulated costs, and cost forecasted per the Company's rebuttal analysis for the PacifiCorp system and the Utah share from Docket 10-035-124. It is important to note that the stipulated Base EBA costs reflect the Q4 2011 portion of the $15 million reduction. When the Company forecasts its net power costs and establishes the Base EBA costs, it normally performs a simulation of the dispatch and operation of its generation resources using the GRID model to estimate fuel consumption and costs and purchases and sales. In establishing the stipulated Base EBA costs, the Company did not run a GRID simulation. Instead, the Company used the GRID simulation from its rebuttal analysis, and deducted $15 million from the annual costs, prorated monthly.

Figure 3 - CONFIDENTIAL
[REDACTED}

Source: Hahn Workpaper 2 (CONF).xlsx

Q: What was your overall approach to the review of the EBA deferral?

A: I attempted to review and understand the Company's procedures and practices for hedging and for non-hedging activities. I also examined the underlying basis for the requested $8.9 million increase in rates due to the EBA deferral. The main focus of my efforts was on the latter, namely trying to understand the root causes of the EBA deferral and the specific transactions that lead to the requested rate increase. I placed the main focus on the costs and transactions for a couple of reasons. The collaborative effort resulted in revisions to the Company's hedging policies and practices that were agreed to by the Parties. The settlement stipulation established conditions that limited prudence challenges to hedging activities that were implemented according to pre-collaborative practices and policies. In addition, in 2009 the DPU had retained a consulting firm to perform a review of the Company's hedging policies and practices. This 2009 review looked at policies and procedures but did not examine any actual transactions. So, in this proceeding, I deemed that the best course of action was to focus on specific cost variances and the underlying transactions.

Q: How did you begin your review of the approximately $12.3 million under-collection of EBA costs that the Company proposes be shared 70% customers and 30% Company?

A; The first step was to perform an analysis of the total variance between base EBA costs and Actual EBA costs by major cost category. Figure 4 below provides a summary of this variance analysis. I have separated the individual items into two major categories. The first category is items that are generally forecast outside of the GRID simulation model. These items include the variance in Utah jurisdictional sales, wheeling revenue and cost and differences, and differences between the forecasted and actual gains or losses from financial swaps. The Utah jurisdictional sales forecast is developed independently of, but is a key input to, the GRID model. It is my understanding the wheeling revenues are forecast outside of the GRID model, based upon a recent twelve month average. It also is my understanding that wheeling costs are based upon one year of actual costs and available transmission capacity is based on four years of PacifiCorp usage. Capacity and wheeling costs are then input into the GRID model.[1] For ease of comparison, I will include wheeling costs in this first category. The assignment of costs into these two categories is purely for presentation purposes, and it does not affect the overall variance between actual and forecast.

[1] See Direct Testimony of Greg Duvall in Docket 10-035-124, pages 17-19.

The second category includes items for which the forecasts are generally developed by the GRID dispatch simulation model. These items include consumption of coal and gas at Company-owned generating plants and physical purchase and sale transactions. Because the Company did not develop a detailed stipulated forecast of these items, the variances shown in Figure 4 for this category are compared to the Company's rebuttal forecast. The lump-sum adjustment between the rebuttal net power costs and the stipulated net power costs is included in the first category of variances.

Figure 4 CONFIDENTIAL
{REDACTED}

Source: Hahn Workpaper 2 (CONF).xlsx

As shown in Figure 4 above, each of the two variance categories accounted for slightly over $[redacted], or roughly half of the total variance. In category one, the Utah jurisdictional sales forecast variance accounts for about $[redacted] of the total $12.3 million under-collection.[2] The variance in wheeling revenues and costs contributed about a net variance of about $[redacted]. Financial swaps produced [redacted]. In category two, coal and natural gas consumption and costs were [redacted]. These reductions were more than offset by [redacted] Each of these items is discussed in greater detail in later sections of this testimony. In the next section of this testimony, I discuss category 2 variances (i.e., variances in parameters determined by the GRID model) before turning to category 1 variances such as financial swaps and wheeling costs and revenues.

VI. Review of Category 2 Variances

{Note: This section contains a significant amount of CONFIDENTIAL information and all answers and figures will be redacted in their entirety.}

Q: Does the Company's filing attempt to explain the variance in net power costs between the rebuttal forecast and actual results?

2 In this testimony, I do not analyze the sales forecast used in the rebuttal analysis, as it was accepted by the settlement stipulation.

A:

Q: Did you attempt to verify these explanations?

A:

.

Figure 5 CONFIDENTIAL
[REDACTED}

Source: Hahn Workpaper 2 (CONF).xlsx

Q: What elements of the total variance did you examine?

A:

Q: What did your review of the variance in net power costs due to coal plant performance reveal?

A:

Figure 6 CONFIDENTIAL
{REDACTED}

Source: Hahn Workpaper 2 (CONF).xlsx

Figure 7 CONFIDENTIAL
[REDACTED}

Hahn Workpaper 1 (CONF).xlsx

Q: Can you provide a rough estimate of the impact of the coal plant variance on the net power costs and the EBA deferral?

A:

Q: What did your review of the variance in net power costs due to natural gas plant performance reveal?

A:

Figure 8 CONFIDENTIAL
[REDACTED}

Source: Hahn Workpaper 2 (CONF).xlsx

Q: Could unplanned outages be the cause of the variance?

A:

Q: Could you explain why you believe that these coal and gas outages have not been adequately explained thus far?

A:

Q: Did you attempt to analyze variance in purchases and wholesale sales that are included in the EBA deferral?

A:

.

Q: What do you conclude regarding the category 2 variances between the forecasted net power costs and actual net power costs?

A:

VII. Review of Financial & Physical Transactions

{Note: This section contains a significant amount of CONFIDENTIAL information and all answers and figures will be redacted in their entirety.}

Q: What information was available regarding financial and physical transactions?

A:

.

Figure 9 CONFIDENTIAL
{REDACTED}

Source: Hahn Workpaper 1 (CONF).xlsx

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Q: Are all of these the transactions summarized in Figure 9 above considered by the Company to be hedging transactions?

A:

Q: Please explain.

A:

Q: What is the effect of applying this definition to the filing requirements databases?

A:

Figure 10 CONFIDENTIAL
[REDACTED}

Hahn Workpaper 1 (CONF).xlsx

Q: Do you agree with the application of the Company's definition to the filing requirements databases?

A:

Q; How will you deal with such a large number of potential transactions to review?

A:

Figure 11 CONFIDENTIAL
{REDACTED}

Source: Hahn Workpaper 1 (CONF).xlsx

Q: Please describe the materials that were available for review.

A:

Q: Do transaction confirms represent adequate documentation regarding the request, analysis or approval for the transaction?

A:

Q: What were the results of your review?

A:

.

A. Power Physical Transactions

Q: What data regarding power physical transactions did you review?

A:

Q: What did your review of these power physical transactions reveal?

A:

Q: Did you find other similar transactions?

A:

Figure 12 CONFIDENTIAL
{REDACTED}

Source: Hahn Workpaper 4 (CONF).xlsx

B. Gas Physical Transactions

Q: What data regarding power physical transactions did you review?

A:

Q: What did your review of these transactions reveal?

A:

C. Power and Gas Swap Transactions

Q: What data regarding power swap transactions did you review?

A:

Q: What data regarding gas swap transactions did you review?

A:

Q: What do these gas and power swap data signify?

A:

Q: What analysis did you perform to analyze these power and gas swap transactions?

A:

Q: What did your review of power swaps reveal?

A:

Q: What did your review of gas swaps reveal?

A:

.

Figure 13 CONFIDENTIAL
[REDACTED}

Source: Hahn Workpaper 5 (CONF).xlsx

VIII. Wheeling Revenues and Costs

Q: Please describe the forecasted and actual wheeling revenues.

A: As noted previously, the settlement stipulation approved a forecast of wheeling revenues for PacifiCorp of $70,500,682 for the 12 months ending June 2012. This consisted of a flat $5,875,057 per month for each of the 12 months. The forecasted wheeling revenues for Q4 2011 were $17,625,171. It is my understanding that this forecast was developed by examining actual historical data for 12 months ending June 2010 with adjustments for certain out-of-period and one-time transactions. Utah's share of these forecasted wheeling revenues was $30,461,769 for the 12-month period or $2,538,481 per month. Utah's share of Q4 2011 forecasted wheeling revenues was $7,615,442. [redacted]

Q: How did you evaluate the reasonableness of this variance?

A: Figure 14 below provides PacifiCorp wheeling revenues for calendar years 2006 to 2011.[3] The data in this figure indicate that the $70,500,682 wheeling revenues in the settlement stipulation are consistent with recent historical data. However, the stipulated wheeling revenues were developed as a fixed dollar amount for each month and not as the result of a forecast of a volume of power wheeled multiplied by a wheeling rate. Thus, it is difficult to compare the forecasted wheeling revenues to actual wheeling revenues.

Figure 14

PacifiCorp Wheeling Revenues 2006-2011

	2006	2007	2008	2009	2010	2011
Wheeling Revenue	54,335,509	56,223,453	75,553,244	63,697,983	67,812,115	73,666,512
MWH Rec'd	39,484,656	16,933,144	17,170,080	14,464,153	13,164,045	14,698,484
$/MWH	1.38	3.32	4.40	4.40	5.15	5.01

Source: Hahn Workpaper 3.xlsx

I do note that PacifiCorp made [redacted]

[3] This data was taken from publicly available FERC Form 1 data.

Figure 15 CONFIDENTIAL

Source: Hahn Workpaper 2 (CONF).xlsx

Q: What do you conclude regarding the EBA deferral variance attributable to wheeling revenues?

A: Based upon my review thus far, I have not identified any concerns that would cause me at this time to propose any changes in the recovery of the under-collection of lower than expected wheeling revenues. I do note that there are outstanding discovery responses relevant to this issue. Upon review of those responses, I will supplement this testimony as appropriate.

Q: Please describe the forecasted and actual wheeling costs.

A: In its rebuttal forecast of net power costs, the Company included an estimate of wheeling costs for the 12 months ending June 2012 of [redacted]

Q: How did you evaluate the reasonableness of this variance?

A: I compared the forecasted amount to historical levels of wheeling costs. Figure 16 below provided PacifiCorp's wheeling expenses for the calendar years 2006 to 2011.[4] The

[4] This data was taken from publicly available FERC Form 1 data.

rebuttal forecast of $138,720,895 for the rate year which was stipulated to be included in Base EBA costs is very consistent with 2010 and 2011 actual values. The actual wheeling costs for Q4 2011 are extremely close to the forecast, [redacted]

Figure 16

PacifiCorp Wheeling Expenses 2006-2011

	2006	2007	2008	2009	2010	2011
Wheeling Costs	94,110,633	106,592,111	121,167,183	117,161,210	136,854,649	138,234,854
MWH Del'd	14,484,760	15,548,183	15,643,840	16,355,485	17,871,426	15,878,375
$/MWH	6.50	6.86	7.75	7.16	7.66	8.71

Source: Hahn Workpaper 3.xlsx

Q: What do you conclude regarding the EBA deferral variance attributable to wheeling costs?

A: Based upon my review thus far, I have not identified any concerns that would cause me at this time to propose any changes in the EBA deferral due to slightly lower than expected wheeling costs. If necessary, I will supplement this testimony as appropriate.

Q: What is the status of FERC Docket No. ER11-3643?

A: On May 26, 2011, PacifiCorp filed with FERC for revisions to its Open Access Transmission Tariff ("OATT"). On August 8, 2011, FERC issued an order accepting the Company's filing and suspending the effective date of the new rates for five months until December 25, 2011, subject to refund. FERC directed that a settlement judge be appointed and that the parties work during settlement discussions to attempt to reach agreement on outstanding issues. On September 10, 2012, the FERC settlement judge issued a statement to FERC that settlement discussions were making progress and that they should be continued. At this point, the final resolution of the new rates that were effective on December 25, 2011 is unknown. This issue should be addressed in the 2013 audit of 2012 EBA deferral, including any new incremental revenues that occurred in December 2011.

IX. Recommendations for Future EBA Filings

Q: Do you have any recommendations for improving the ability to review future EBA filings?

A: I think that there are several issues for the parties in this proceeding to consider.

- The Company does not provide information that explains why specific transactions were made. It is difficult to fully evaluate individual transactions without knowing their intended purpose. In future EBA filings, such information should be provided. For example, in reviewing transactions within the EBA deferral, it would be helpful to know if a transaction was done to (a) correct a situation where the Company was temporarily not in compliance with its hedging policies and limits, or (b) adjust the Company’s supply portfolio in response to a market or system event (i.e., unexpected loss of a major generator).
- The Company has not provided very much detail on its trading strategies, objectives, and instructions given to its traders. Such guidance and direction would be necessary for the traders to enter into transactions that produce the desired results. In future EBA filings, such information should be provided.

- The Company should discuss the interaction between its trading strategies and policies and operational (in terms of plant dispatch) strategies and policies. Moreover, the Company should describe how this interaction influenced the actual NPC and EBA costs that were filed compared to the base numbers.
- The Company has stated in its response to DPU 20.1 that a more detailed breakdown of actual purchases and sales that comport with the detailed forecast of these items is not available. Without such information, it is difficult to explain the variance between actual and forecasted costs for these transactions. The Company should modify the manner in which it forecasts and records actual costs so that such comparable data can be provided. For example, if the Company's GRID model forecasts purchases and sales by pricing hubs (i.e., Mid-C), then the Company should track actual sales at these hubs.
- The filing requirements do not include details on long-term purchases, and yet these costs are included in the EBA deferral. In Q4 2011, the actual cost of long-term purchases exceeded the forecasted level by about $10.8 million. The parties should consider whether to include these in future EBA filings.

X. Conclusion

Q: Does this conclude your testimony?

A: At this time, yes, it does. Should additional or new information become available, I will supplement this testimony as appropriate.