Q. Are you the same Stefan A. Bird who submitted direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. My rebuttal testimony addresses three separate issues in this case.

Section I of my testimony addresses the reasonableness of the Company's Renewable Energy Credit (REC) revenue forecast. In Section I, I update the REC revenues in this case and respond to the adjustments on REC revenues presented by Ms. Brenda Salter on behalf of the Utah Division of Public Utilities ("DPU"), Ms. Donna Ramas on behalf of the Utah Office of Consumer Services ("OCS"), Mr. Kevin Higgins on behalf of UAE Intervention Group ("UAE"), and Mr. Roger Swenson on behalf of US Magnesium LLC.

Section II of my testimony addresses the Company's hedging strategy and practices and demonstrates why the associated costs are prudent and reasonable. In Section II, I respond to the adjustments for hedging costs proposed by Messrs. Douglas D. Wheelwright and Mark W. Crisp on behalf of the DPU;[1] Ms. Michele Beck and Dr. Lori Smith Schell and Mr. Paul J. Wielgus on behalf of the OCS; Messrs. Kevin Higgins and Jeff L. Fishman on behalf of UAE; and Messrs. J. Robert Malko and Mark T. Widmer on behalf of Utah Industrial Energy Consumers (UIEC). Company witnesses Messrs. John A. Apperson and Gregory N. Duvall and Mr. Frank C. Graves from The Brattle Group join me in responding

[1] Mr. George W. Evans, the net power cost witness for the DPU, reflects Mr. Wheelwright's hedging adjustment in his overall net power costs calculation, but does not independently address the hedging issue. In reflecting Mr. Wheelwright's adjustment in his testimony, Mr. Evans misstates (and doubles) the adjustment.

to particular aspects of the hedging adjustments proposed by intervenors.

Section III of my testimony briefly addresses the Company's decision to terminate negotiations to acquire the Apex project in the All Source RFP. DPU witness Mr. Charles E. Petersen incorporates my testimony from Docket No. 10-035-126 in this case. Company witness Mr. Duvall provides the primary testimony responding to various issues raised by Mr. Petersen.

Section I REC Revenues

Q. Please summarize your rebuttal testimony on REC revenue.

A. I cover the following issues in this section of my rebuttal testimony:

- I update the test period REC revenue forecast to $86.1 million, an increase of $30.4 million from my direct testimony.
- I provide background on recent developments in the REC markets in the Western Electric Coordinating Council (WECC) and explain how they validate the Company's REC revenue forecast in this case.
- I support the general proposal from the DPU and OCS for a mechanism to track actual REC revenues for inclusion in rates.
- I respond to the adjustments sponsored by the DPU, OCS and UAE to increase forecasted REC revenues. I demonstrate that these adjustments are unrealistic because their proposed prices are well above market and their proposed volumes do not take into account the volatility in the output of the Company's wind resources.
- I respond to the adjustment sponsored by US Magnesium, based upon its proposal that the Company sell all of the output of its renewable energy

facilities into the market for terms of 5 or 10 years. I explain that such a proposal is both inconsistent with the Company's responsibility to use its resources to serve customers and incorrectly assumes the existence of a long-term market for REC sales.

Update to REC Revenue from Direct Testimony

Q. What is the Company's updated forecast for revenue from the sale of RECs in the test period?

A. The Company forecasts REC revenues of $86.1 million on a total Company basis or $50.9 million on a Utah-allocated basis. Company witness Mr. Steven R. McDougal provides the details of the allocation of total Company REC revenue to Utah.

Q. How does the updated forecast compare to the REC revenue forecast in your direct testimony?

A. My direct testimony included $55.7 million of REC revenue on a total Company basis, or $32.9 million on a Utah-allocated basis.

Q. Please explain the increase in REC revenues from $55.7 million to $86.1 million.

A. My direct testimony included two known transactions forecasted at 982,800 MWh of RECs or $41.9 million; 1,677,463 MWh of forecasted excess net marketable wind at $7.00MWh or $11.7 million; and 509,796 MWh forecasted vintage wind at $4.00 per MWh or $2.0 million for a total REC revenue of $55.7 million. My direct testimony discussed the possibility of a third major transaction resulting from the NV Energy Short-Term RFP, and promised to update the REC revenue forecast if the Company was successful in this RFP.

On February 9, 2011, the Company executed this third transaction. This increased the forecast of known transactions from $41.9 million to $78.0 million. It also reduced the forecasted excess net marketable wind to 875,348 MWh at $7.00/MWh or $6.1 million. The forecasted vintage wind remained the same at 509,796 MWh at $4.00/MWh or $2.0 million. This results in total REC revenues of $86.1 million for the test period.

Q. Your direct testimony explained the Company's calculation of forecast REC revenues. Does your rebuttal update reflect any changes to this calculation?

A. No. The update simply reflects an increase in known transactions and a corresponding decrease in incremental sales.

Q. Your updated forecast retains the $7.00/MWh price for incremental sales. What evidence did the Company rely upon in determining that this price remains appropriate?

A. For the voluntary market, the Company estimated $7.00/MWh price using recent broker quotes on standalone RECs. Because the market is so illiquid, the bid ask spread is $4.00/MWh to $7.00/MWh. Exhibit RMP___(SAB-1R) is a recent broker quote demonstrating the continuing validity of this forecast price.

For the compliance market, the estimated $7.00/MWh [redacted]

Q. Please describe the RFP the Company issued for RECs on May 25, 2011.

On May 25, 2011, the Company issued a request for proposals (RFP) for RECs needed for compliance purposes for a term of 2012 through 2015 with a maximum quantity of 30,000 MWh. The Company received a robust response to this RFP with a range of pricing and terms. The evaluation of the RFP is now complete and the Company is poised to execute several transactions all at REC prices [redacted]

The WECC and California Renewable Markets

Q. Your direct testimony explained why developments in the California REC market made additional negotiated contracts for the test period uncertain. Please summarize the current status of WECC REC markets.

A. Since I filed my direct testimony, there have been a number of developments in California which impact the WECC REC markets. In summary, these developments have restricted the Company's ability to make additional negotiated REC sales and have reduced prices for any such potential sales during the test period.

Q. Please explain what has transpired since January 14, 2011, when the California Public Utility Commission issued Decision 11-01-025, described in your direct testimony.

A. On February 1, 2011, Senate Bill No. 2 of the California Legislature 2011-2012 First Extraordinary Session ("SB 2x") was introduced. It was eventually passed by the California Legislature and was signed by Governor Brown on April 12, 2011. A copy of the law is attached as Exhibit RMP___(SAB-3R).

Q. Has SB 2x become effective?

A. No. SB 2x will become effective on the 91st day following close of the First Extraordinary Session, which remains in session. I understand that, by default, a special session cannot extend beyond the regular legislative session, and the latest that SB 2x could become effective is February 28, 2013. However, it is expected that the current special session will be adjourned sometime this summer. Even if the budget is addressed by mid-July, and the Extraordinary Session closed promptly thereafter, SB 2x would not become effective until mid-October. Because of the ongoing delay, there is uncertainty in the renewables market as to 2011 procurement targets and other changes enacted by SB 2x.

Q. What were the major changes to the California Renewable Portfolio Standard (RPS) made by SB 2x?

A. Major changes included an expanded RPS procurement goal of 33 percent by 2020; expansion of the compliance obligation to publicly owned utilities; use of multi-year compliance period with incremental procurement targets; enactment of statutory excuses for procurement shortfalls; designation of procurement "product" types; and the specification of a minimum and maximum product type content for retail sellers' RPS portfolios, which change with each compliance period. The latter two changes both impose a preference for in-state resources and modify delivery and other requirements for use of out-of-state resources. Additionally, retail sellers' ability to bank RPS procurement surpluses is restricted by the inability to carry forward short-term transactions or Tradable RECs ("TRECs").

Q. What is required to implement SB 2x and what are the associated timelines?

A. The legislation requires implementation by the California Energy Commission (CEC), which certifies resources program eligibility and verifies annual production levels, and the California Public Utilities Commission (CPUC), which oversees RPS program compliance by jurisdictional entities such as the Investor-Owned Utilities (IOU), Energy Service Providers (ESP), and Community Choice Aggregators (CCA). The California Air Resources Board will also conduct rulemakings in its new capacity as a regulator with respect to publicly owned utilities. It is also likely that additional implementation action may be required by the Western Renewable Energy Generation Information System (WREGIS).[2] The full implementation process is anticipated to take approximately 18 months to 2 years, although further delays are possible given the number of agencies involved.

Q. Please explain the new RPS targets and compliance requirements.

A. There are three compliance periods, each of which has different compliance requirements and specific caps for the three types of RPS Products (Products) eligible to meet RPS compliance requirements. The three compliance periods are: (1) 20 percent average procurement target from January 1, 2011 through December 31, 2013; (2) 25 percent procurement required by the end of 2016; and (3) 33 percent from January 1, 2017 through December 31, 2020.

Q. Did SB 2x change California's approach to RPS noncompliance?

A. Yes. SB 2x's approach to noncompliance is more flexible and less punitive than

[2] SB 2x creates different types of RPS products that have corresponding procurement requirements or limitation. Since some of these product definitions are associated with the manner that out of state resources are imported into California, it is foreseeable that tracking of WREGIS Certificates by delivery process may be necessary.

was previously the case. California's RPS previously required payment of a penalty for noncompliance, and required noncompliant utilities to make up any deficit in the next compliance period. SB 2x provides new statutory excuses for noncompliance (such as inadequate transmission capacity and delays in interconnection and permitting) and does not require the deficit to be made up in the next compliance period.

Q. How will SB 2x impact the REC market during the test period in this case?

A. SB 2x and most particularly its pending effective date and the three separate state agency rulemakings with respect to its implementation, have continued the period of deep uncertainty in the California REC market. Even though the rulemakings at the three state agencies are now underway, they are proceeding under a cloud of uncertainty given SB 2x's not-yet-effective status.

Q. Will the Company respond to the three California IOUs' RFPs for renewable resources?

A. Yes, however, due to the uncertainty around the effective date of SB 2x and the pending rulemakings, there is some reason to believe that the RFPs will be more informational for the California IOUs than real at least for the near future. The Company is not optimistic that any transactions will occur under the RFPs until the later part of 2012, which is after the test period in this case. While the Company hopes to transact with one of the California IOUs through the RFPs and achieve a better price for its RECs than now otherwise available, this possibility is too uncertain to serve as a basis for adjusting the Company's forecast upward. It is this uncertainty that informs the Company's support of a tracking mechanism, as I discuss below.

Q. If the Company cannot participate in the California market, in which markets will it participate?

A. The voluntary market for REC sales in the Northwest is likely to be the only other market.

Q. What about the potential for future sales to Nevada Power?

A. The prior opportunistic sale to Nevada Power was done under Nevada Power's request for proposals. In addition, Nevada Power has not indicated that they will be issuing a request for proposals or have additional requirements post the expiration of the existing transaction. Any additional opportunistic sales would be outside of the test period.

REC Tracker Mechanism

Q. Given the uncertainty in the WECC REC markets highlighted above, does the Company support the tracking of actual REC revenues for ratemaking as proposed by the DPU and OCS?

A. Yes. The Company has consistently taken the position that the Commission should track both actual REC revenues and actual net power costs for purposes of reflecting these items in rates. The Company recently implemented a separate REC tracker mechanism in Wyoming, and another is pending before the Washington Commission.

Q. The Commission excluded REC revenues from the Company's Energy Balancing Account (EBA). Has this impacted the Company's view of the appropriateness of separately tracking actual REC revenues for inclusion in rates?

A. Yes. Given the Commission's decision excluding RECs from the EBA, the Company is not opposed to adoption of a separate tracking mechanism. The Company agrees with the DPU that the EBA and the REC tracking mechanism should operate in a coordinated manner. Mr. McDougal addresses additional details on the mechanics of the tracking mechanism.

Responses to Intervenor Adjustments on REC Revenues

Q. The DPU, OCS and UAE each propose adjustments to increase the REC revenue forecast. Why is the Company's current REC revenue forecast, including the $6.1 million in incremental REC sales in the test period, more realistic than the alternatives proposed by the DPU, OCS and UAE?

A. There is no disagreement among the parties for the portion of the REC forecast based upon known transactions. With respect to incremental sales, the Company's REC revenue forecast is based upon sales of 75 percent of the net marketable production from the renewable resource at a price of $7.00/MWh for current RECs and $4.00/MWh for vintage RECs. The DPU, OCS and UAE all substitute a higher price for incremental sales. The Company's price forecast, however, was based upon actual market data for the broker markets and was recently validated by the Company's REC RFP.

The OCS also challenges the Company's estimated sales volume, arguing that it should forecast sales of 90 percent of net marketable product. The Company sells only 75 percent of the forecast wind RECs on a forward basis to ensure that it can perform under any contracts, bundled or unbundled, that it may enter into. Based on the Company's experience and the wind data we have received, selling 75 percent of the forecast output ensures the Company can perform under its contracts and avoids the risk of liquated damages or other nonperformance penalties.

Q. Why is the DPU proposal to substitute the Company's forecast sales price of $7.00/MWh and $4.00/MWh to the actual average sales price in 2010 unreasonable?

A. The DPU's proposal uses a price drawn predominantly from three large executed transactions in 2010 and applies it to the forecast for incremental sales in the test period. The executed transactions are very different in kind than the incremental sales the Company may make in the test period. The three executed transactions in 2010 are very highly structured, limited opportunities. Two of the three executed transactions were originally executed in 2009. The third was a limited opportunity through an RFP which the counterparty only issued to fill a temporary resource gap to meet its RPS requirement. The Company's broker quotes and REC RFP are much more accurate predictors of REC sales prices for the incremental sales in the test period than prices drawn from the unique executed transactions in 2010.

Q. Why is the OCS adjustment substituting a $36.00/MWh price and increasing the forecast sale from 75 percent to 90 percent unreasonable?

A. The OCS has produced no support for its proposed price other than evidence drawn from past, noncomparable REC sales. Nor has OCS provided any basis for disregarding the Company's 75 percent sales threshold, which is required to protect against overselling RECs in light of variable wind performance. The Company's REC sales transactions require the delivery of firm RECs. To receive full value for its REC sales, the Company is subject under its sales contracts to liquidated damages of up to $50/MWh for nonperformance of delivery of firm RECs. In light of these factors, it is inappropriate to forecast sales revenues at volume levels higher than those that are realistically and prudently achievable.

Q. Please respond to UAE's proposal to reprice 50 percent of incremental sales at 90 percent of known transactions in test period.

A. UAE assumes that the price that the Company has obtained for the executed transactions in the test period can be replicated for one-half of remaining incremental sales. This ignores the developments in California and their impact on the REC market, the Company's broker quotes and the proposals the Company is evaluating as a result of the Company's REC RFP.

Q. Please respond to the adjustment proposed by US Magnesium based upon the assumed sale of all of the Company's renewable resources for terms of 5 to 10 years.

A. As stated in my direct testimony, the Company acquires wind resources primarily to serve its growing need for new resources on a diversified basis consistent with its integrated resource plan. This is consistent with the Company's duty to serve customers with reliable, reasonably priced utility service. The adjustment proposed by US Magnesium effectively seeks to convert the Company from an electric utility service provider into a REC broker on behalf of its customers.

Q. Did the Utah Commission acknowledge the Company's most recent IRP, which included its renewable resources as a power supply source (not just a REC sales supply source) for its customers?

A. Yes. See Report and Order, Docket No. 09-2035-01 (April 1, 2010).

Q. Did US Magnesium participate in the Company's IRP and make its proposal for sale of all renewable resources in that context?

A. No.

Q. US Magnesium's adjustment assumes sales of renewable resources for 5 to 10 years. Is there a market for REC sales of this length?

A. The Company's REC sales are supported by its full portfolio of renewable resources to optimize existing surplus resources and RECs and are not earmarked to a single resource. The Company's experience is these sales are limited in duration. The longest REC sales transaction the Company has ever executed is less than five years in duration. More commonly thus far, the transactions are one to two years in duration. US Magnesium has not provided evidence of the existence of the market in which they urge the Company to transact.

Section II Hedging Issues

Q. Please summarize your testimony and the testimony of the Company's other hedging witnesses.

A. My testimony provides the Company's overall response to the intervenors' criticism of the Company's hedging program. I first provide a general description of the Company's risk management policy and hedging program, explaining what they are and how they work. Next, I provide the context for the hedging adjustments in this case, including the previous regulatory review of these issues in Utah and the prudence standard applicable to their review. Then, I correct the record on the major misstatements of fact underlying intervenors' adjustments, explain the serious policy flaws inherent in their adjustments and demonstrate the overall prudence of the Company's hedging program.

Mr. Graves from The Brattle Group provides independent expert testimony corroborating the prudence of the Company's hedging program, in light of electric utility industry norms and standards. Additionally, Mr. Graves also provides perspectives on the changes in the natural gas markets and unforeseeable nature of the current low prices. Finally, Mr. Graves provides his opinion on the most effective and fair way for the Utah Commission to review and monitor the Company's hedging program.

Mr. Apperson responds to the adjustments presented by the intervenors, based upon his expertise as the Company's Director of Trading. Mr. Apperson sponsors the quantitative analysis the Company relies upon to rebut intervenors' adjustments and provides additional evidence on the reasonableness of the

Company's hedge horizon. He also explains that the Company could not have reasonably foreseen the drop in natural gas prices which caused the hedging losses in this case, responds to the OCS's proposal to substitute the use of natural gas options for natural gas and power swaps, addresses issues raised about other costs of hedging, including cash collateral and explains how the hedge program responds to fluctuations in loads.

Finally, Mr. Duvall quantifies the impact of the Company's hedging program on net power costs in Utah rates and demonstrates that the hedging program has 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?

A. The goals of the Company's risk management 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 was designed to follow electric industry best practices and is 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.

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 risk policy requires 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. What is the purpose of the Company's hedging program?

A. The hedging program supplements and is subordinate to the Company's risk policy by specifying separate to-expiry VaR calculation and targets. As stated in the Company's most recent Integrated Resource Plan ("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."[3]

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 to take full advantage of any natural offsets between its long power and short natural gas positions.[4] The Company's 2011 IRP analysis shows that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.*, a wider

[3] Docket No. 11-2035-01, PacifiCorp 2011 IRP, Appendix F at 161-162 (March 31, 2011).
[4] *Id*. at 170.

distribution of outcomes).[5] Mr. Apperson's testimony further explains the 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. How is the Company's hedging program structured?

A. Since 2003, the Company's hedge program has employed dollar cost averaging to progressively reduce net power cost risk exposure closer to delivery over a defined time horizon. In May 2010, the Company moved from hedging targets based on volume 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. Importantly, the TEVaR metric automatically results in reducing hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same risk exposure.

Q. Please describe the Company's hedging targets.

A. These targets are set forth in Highly Confidential Exhibit RMP__(SAB-4R) both on a percentage and July 2011 to June 2012 net power cost basis.

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

A. Yes. The Company's risk management program has been actively reviewed by its internal risk oversight committee and updated every year for several years

[5] *Id*. at 170.

running to reflect best practices and respond to changing market conditions. In addition, as mentioned above, the hedge program was modified in May 2010 with the institution of the TEVaR metric. The result of these changes has been a decrease in the Company's longer-dated hedge activity, i.e., four years forward on a rolling basis, has 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).

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

Q. Has the Utah Commission reviewed the Company's risk management policy and hedging program in previous dockets?

A. Yes. The Company's risk management policy and hedging program have been a focus of a number of previous Commission dockets.

First, in May 2009, the Commission opened a docket on hedging, Docket No. 09-035-21, as a result of the parties' stipulation in the Company's 2008 general rate case, Docket No. 08-035-38. The Commission held a technical conference in May 2009 to hear Rocky Mountain Power's initial presentation regarding its risk management policy and hedging program. On June 3, 2009, the Commission held a second technical conference to hear a DPU-sponsored presentation by a representative from the National Regulatory Research Institute (NRRI) regarding different types of hedging mechanisms on and advantages and disadvantages of natural gas pricing policies used by utility companies across the country. In May 2010, the Company made another presentation in the docket to update parties on the implementation of the TEVaR metric.

Second, the Company's hedging program was the subject of extensive testimony in Docket No. 09-035-15, the Company's request for an energy cost adjustment mechanism ("ECAM") docket. The Company filed four rounds of testimony in that case addressing hedging issues,[6] and responded to dozens of data requests on the issue. Because the inclusion of natural gas and power swaps in the Energy Balancing Account is currently the subject of rehearing, the Company will file additional testimony on these issues in July 2011.

Third, in the Company's last rate case, Docket No. 09-035-23, the DPU filed the results of its independent, third-party evaluation of the Company's risk management policy and hedging program. This evaluation, dated October 7, 2009, was conducted by Blue Ridge Consulting Service (Blue Ridge Report).

Fourth, in Docket No. 09-2035-01, the Commission's April 1, 2010 order acknowledging the Company's IRP directed the Company to include hedging costs in future IRP analysis, and perform sensitivity analysis to determine a hedging strategy which minimizes costs and risks for customers. The Company included this analysis in its 2011 IRP, filed on March 31, 2011 in Docket No. 11-2035-01.

In summary, the Company's risk management policy and hedging program have been the subject of ongoing regulatory review, extensive discovery and testimony in several dockets since at least 2009.

[6] Messrs. Duvall and Graves addressed hedging in their direct and rebuttal testimony on the first phase of the ECAM docket, filed in August 2009 and December 2009, respectively. In July 2010, Mr. Duvall again addressed these issues in the Company's opening testimony in Phase 2 of the docket. Finally, I filed rebuttal testimony on hedging issues, along with Messrs. Duvall and Graves, in September 2010.

Q. Some parties to this case have complained about the complexity and lack of transparency in the Company's hedging program. Please respond.

A. The Company has taken all reasonable steps to ensure that its hedging program is transparent and auditable. First, the Company's hedging program is structured using the most straightforward hedging instruments available: financial swaps and forward contracts (*i.e.*, fixed price physical electricity and natural gas transactions). Second, the Company has provided significant discovery on its hedging program, responding to approximately 250 data requests on the subject in the dockets cited above, and another 125 in this case.

Q. At any time during these regulatory proceedings, has any party taken the position that the Company failed to develop, implement and carry out a prudent risk management policy?

A. No. On the contrary, the most 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 related 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 policy and the hedging program have not changed since the time of the DPU's Blue Ridge Report.

Q. At any time during these regulatory proceedings, has any party taken the position that the Company was imprudent to engage in hedging?

A. No. While the parties in this case propose *ex post* disallowances questioning the volume, length and type of hedging, no party here or elsewhere has questioned the prudence of the Company engaging in hedging. Again, the DPU's Blue Ridge Report is instructive:

> 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. Is the DPU-sponsored presentation from NRRI in the Company's hedging docket ("NRRI Report")[7] also relevant to this question?

A. Yes. The NRRI Report 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.

Q. Is it your understanding that the Utah Commission has previously allowed the Company to recover its prudent hedging costs?

A. Yes. In *Re PacifiCorp, dba Utah Power and Light Company*, Docket No. 01-035-01 (September 10, 2001), the Commission allowed the Company to recover "prudent hedging and arbitrage transactions."

Q. Does the NRRI Report provide guidance to the Commission on 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 price volatility.

[7] 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).

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

A. Yes. First, throughout the ECAM docket, the Company welcomed guidance from the Commission on the Company's approach to hedging (but disagreed that the ECAM approval should be contingent on the issuance of such guidance). The Company continues to welcome *ex ante* direction from the Commission on the Company's hedging program. The Company is supportive of many of the processes suggested by the intervenors for additional Commission review and oversight.

Second, the Company agrees that adjustments second-guessing the Company's hedging program are contrary to the prudence standard. This is especially true given the fact that the intervenors in this case second-guess the hedging program based upon a single year of net losses and/or a subset of the Company's hedges—and fail to consider the net benefits to customers of the hedging program on a multi-year, all-in basis.

Q. Using the NRRI Report's approach, how should the Commission review the hedging issues in this case?

A. The Company recommends that the Commission first review whether the Company was in compliance with its established risk management policy and hedging program.

Second, the Commission should review the Company's current hedging policy to determine whether the Company should change its policy <u>prospectively</u>.

Q. Do any of the intervenor adjustments challenge the Company's execution of its hedging program?

A. No. All of the adjustments challenge the Company's underlying policy guidelines, not the Company's adherence to these guidelines. The evidence is undisputed that the Company transacted its hedges in accordance with its policies. For this reason, the Company recommends that the Commission reject all proposals for disallowance of hedging costs. To the extent that the Commission agrees with intervenors that the Company's hedging program should be revised in some manner, the Commission should order these changes to take effect on a forward-looking basis only.

Overall Response to Hedging Adjustments

Q. Please summarize the intervenors' hedging adjustments.

A. While the intervenors calculate their adjustments differently, they each seek to disallow a large amount of the Company's hedging losses in the test period. A common set of incorrect assumptions and facts provide the foundation for these adjustments, including:

(1) that the Company's hedging program has increased net power costs during its duration;

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

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

(4) that the Company failed to adjust its hedging program to respond to

foreseeable changes in the natural gas markets; and

(5) that the Company should have used options on swap contracts, in addition to or instead of natural gas swaps as a hedging instrument.

I correct the record on each of these issues below.

Q. Is there another threshold issue raised by the intervenor adjustments?

A. Yes. To some extent, each of the intervenors attempts to isolate the Company's natural gas swaps from other aspects of the Company's hedging program. It is inappropriate and unfair to propose to disallow gas swaps in isolation 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.

Power and natural gas are correlated and the positions for each commodity are inextricably linked to spark spreads. As the 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 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. Are the intervenors' attempts to isolate natural gas hedges from other parts of the Company's integrated hedging program problematic from a policy prospective?

A. Yes, In the ECAM docket, the DPU and OCS supported rehearing on the inclusion of swaps in the EBA. The DPU argued that including some net power costs and not others in the EBA could create perverse incentives—including leading "the Company to abandon, or lessen, its interest in swaps as a method to control net power costs."[8] The hedging adjustments proposed in this case by DPU and others—which allow recovery of some hedges and not others—will raise the same set of issues.

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

A. Yes. As Mr. Apperson discusses in his testimony, the updated net power costs in the Company's rebuttal filing reflect approximately $83 million of hedging forecast 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 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 give up potentially lower net power costs that could result if prices moved favorably in the test period.

---

[8] *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No, 09-035-15, Response of the Division of Public Utilities to Rocky Mountain Power's Request for Clarification and Reconsideration or Rehearing at 3 (May 2, 2011).

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. Mr. Duvall demonstrates that the Company's hedging program has significantly reduced net power cost volatility and net power costs.

Q. Please respond to the claim from OCS that the Company's hedging program did not reduce volatility.

A. Mr. Duvall addresses this issue. His analysis confirms that the Company's hedges reduce net power cost volatility associated with natural gas and power market price changes.

Q. The DPU, OCS and UIEC all claim that the Company's hedging program has significantly increased the Company's net power costs. Is this accurate?

A. No, Messrs. Apperson and Duvall provide more complete evidence on the overall results of the hedging program, which are favorable to customers. As Mr. Duvall testifies, from March 2005, when rates from Docket 04-035-42 went into effect through the end of September 2011 when rates from this case become effective, customers will have received $149 million in lower net power costs as a result of the Company's hedging program. The customer savings from the hedges now in rates through September 2011 are $192 million, more than twice the hedging losses reflected in this case.

Q. Why are the Company's results so different than the DPU's?

A. As Mr. Apperson explains, the DPU looks only at natural gas and power swaps, and excludes forward contracts (*i.e.*, fixed price physical power and natural gas transactions). In addition, in comparing the Company's hedged natural gas costs to market, the DPU looks only at natural gas prices, not net energy prices after considering the Company's power swaps and other hedges. The DPU's analysis is incomplete and misleading.

Q. Does UIEC's analysis have the same flaw?

A. Yes. As Mr. Apperson demonstrates, UIEC's assessment of the hedging program is focused only on natural gas swaps and fails to consider the power swaps and other hedging instruments which offset the losses on the natural gas swaps.

Q. What is the problem with OCS's analysis?

A. OCS looks at one year of the Company's hedging results, simplistically showing net power costs and rates, with and without the Company's financial swaps transactions. As Mr. Apperson and Mr. Duvall demonstrate, a multiple-year review of the Company's complete hedging program shows that its results are favorable to the Company and its customers. It is clear that the Company's hedge program has achieved the goal of mitigating net power cost volatility and protecting customers from the risk of adverse price movement.

Q. Is there another problem with the DPU's analysis?

A. Yes. In Mr. Wheelwright's testimony in the 2009 GRC, he was clear that: "It should be understood that there will be periods when the cost exceeds the benefit and periods when benefits exceed costs. Any review or cost benefit analysis should be conducted over an extended period of time."[9]

Mr. Wheelwright omits this statement from his testimony in this docket, and alleges that the Company was imprudent for failing to respond to emerging developments, including "the recent increase in shale gas production, changes in the availability of electric sales and a projected low price for natural gas." While Mr. Wheelwright previously advocated a long-term view, his adjustment in this case is expressly based upon only "recent" developments.

Q. Mr. Wheelwright claims that the Company's hedging program is designed for an environment of increasing natural gas prices and is no longer appropriate because of the decrease in gas prices. Please comment.

A. Mr. Wheelwright relies upon Chart 1 in his testimony to support this point. This chart does not show decreasing natural gas prices. It shows continued increases in natural gas prices, albeit on a more gradual slope. The continued changes in the natural gas price forward markets and third party forecasts over the past several years demonstrate that natural gas markets continue to be volatile.

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

[9] Docket No. 09-035-23, DPU Exhibit 12.0 at 2, Mr. Wheelwright (Oct 8, 2009).

Company is [redacted], (following the expiration of the 15-year Hermiston natural gas supply hedge in July 2011). The 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.

Q. Do parties such as the DPU overlook the graduated nature of the Company's hedging program and overstate the hedged volumes?

A. Yes. Mr. Wheelwright testifies that: "Under the current program the Company will begin to purchase natural gas swap transactions up to [redacted] months in advance with the goal of having up to [redacted] percent of the forecast gas requirement in place [redacted] months in advance." This testimony is inaccurate as shown in the TEVaR table in Highly Confidential Exhibit RMP___(SAB-4R). The Company's hedge program only provides the potential to be [redacted] percent hedged in the first rolling 12 months.

Q. If the Company had restricted its hedging volumes as proposed by UAE and UIEC, would customers have been better off in the past?

A. No. As Mr. Duvall's analysis demonstrates, had the Company imposed the upper limits UAE and UIEC now recommend (75 percent and 66 percent, respectively), customers would have been exposed to higher net power costs and market volatility over the past six years.

Q. Do UAE and UIEC provide sufficient evidence to demonstrate that the Company is hedging at imprudent levels?

A. No. To support their claims that the Company is hedged at a higher level than is prudent, both UAE and UIEC provide evidence that a handful of other utilities, including natural gas local distribution companies, hedge at a lower percentage level. UAE points to five other companies, only two of which are in the West, and UIEC reports data from eight companies. Neither UAE nor UIEC make any attempt to determine whether these companies are similarly situated to the Company or have similar risk management policies or hedging programs. Given the fact that several are natural gas distribution companies, it is clear that at least some of the companies are very dissimilar to the Company. None of these companies appear to operate in as large or geographically diverse an area as the Company, where the Company is exposed to the fluctuations of multiple market hubs.

Q. Does UAE's consultant Mr. Fishman warn against looking at industry averages to determine appropriate target levels for hedging?

A. Yes. Mr. Fishman acknowledges that "(e)ach hedging strategy is specific and an average may not necessarily reflect an appropriate target." Despite this statement, UAE consultant Mr. Higgins relies upon Mr. Fishman's analysis to recommend an upper boundary for hedging of 75 percent of the Company's natural gas supply.

Q. Does Mr. Fishman's survey show that 75 percent is an upper boundary in the electric utility industry?

A. No. Mr. Fishman's survey includes only a small number of natural gas and electric utilities and does not purport to show what the upper boundary of hedging levels is for combined natural gas/power hedging. One of the utilities he reports on, Arizona Public Service Company, reported hedging levels of 85 percent in the year of delivery. Mr. Fishman omitted this data in his survey summary because it was a combined natural gas/power number. Mr. Fishman also reported on Portland General Electric, but failed to note that according to their IRP (excerpted in Mr. Graves' testimony), they hedge their full requirements one year forward. In other words, Mr. Fishman excluded the hedging programs most comparable to the Company's in his results.

Q. Does Mr. Graves provide a broader perspective on these issues?

A. Yes. Mr. Graves has worked with electric utilities for many years and is an expert on electric utility hedging programs. He has access to information about electric industry standards on this issue, which is otherwise difficult to obtain given the confidential nature of the underlying data. Mr. Graves' expert testimony is that electric companies with combined natural gas/power hedging programs 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, comports with industry standards. As Mr. Graves testifies, the degree of hedging boils down to a subjective judgment of risk tolerance, and there is certainly nothing objectively imprudent about the extent of the Company's hedging program.

Hedge Horizon

Q. Do you agree with Dr. Lori Schell's testimony 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. Mr. Apperson demonstrates the liquidity of the market in the period 36 to 48 months from delivery.

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.

Q. Does Mr. Graves provide expert testimony on this issue?

A. Yes. Mr. Graves testifies that hedging over a 36 to 48 month period is a reasonable and prudent practice, especially for an electric utility such as the Company.

Q. Do the results of the Mr. Fishman's survey, limited as it is, show that other utilities hedge past 36 months?

A. Yes. Mr. Fishman reported that both Northwest Natural and Portland General Electric hedge over a 5-year horizon.

Q. Did UIEC witness Mr. Mark Widmer claim in a recent Wyoming rate case that the Company was imprudent for not having hedged more of its gas supply on a long-term basis?

A Yes. In the summer of 2008, on behalf of Wyoming Industrial Energy Consumers ("WIEC"), UIEC witness Mr. Widmer proposed a large adjustment challenging the Company's failure to execute a long-term natural gas supply agreement for its Lake Side plant.[10] In that case, Mr. Widmer argued that the Company should

[10] *In re Application of Rocky Mountain Power to Change Deferred Net Power Costs*, Docket No, 0000-315-EP-08, Deposition of Mark Widmer at 64-66, 87-89(July 15, 2008).

diversify market price risk by “hedging on a near term and intermediate and a long-term basis as opposed to doing everything on a near term basis.” Mr. Widmer advocated long-term hedging as a means of prudently protecting customers from inevitable price increases farther out the curve.

He also commented that: (1) while he understood that the Company had moved to a longer hedge horizon, “it was still nowhere near where it needs to be;” (2) a review of other utilities’ hedges (like that conducted by fellow UIEC witness Mr. Malko) “was not really relevant;” (3) the Company “has had great experience in terms of controlling costs relative to longer-term hedging;” and (4) “given everything that’s going on in the environment surrounding the price of oil and gas, it just doesn’t make any sense to continue with an approach of hedging costs on a near term, rolling forward basis.”

Q. Did Mr. Widmer propose this adjustment during the time period in which the Company acquired some of the hedges in the test period in the case?

A. Yes. This adjustment was proposed in 2008, when natural gas spot prices were high forecast to remain so. Under the Company’s official price curve for June 2008, average natural gas prices through June 2012 were $10.73/MMBtu at Henry Hub and $9.23/MMBtu at RockOpal. Under these market circumstances, the Company was being criticized by Mr. Widmer for not hedging more, in contrast to this case, where Mr. Widmer supports UIEC’s opposite, hindsight-informed conclusion.

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. As just illustrated, spot natural gas prices were very high during this time period. Mr. Apperson shows that neither the forward price <u>curves</u> at the time the hedges were transacted, nor third party spot price <u>forecasts</u> indicated a significant expected future drop in natural gas prices. Mr. Apperson also shows that 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.

Use of Options

Q. As an alternative to the Company's traditional practice of using swaps for its hedging program, the OCS proposes that the Company use Henry Hub natural gas options. Is this appropriate?

A. No. Mr. Apperson analyzes this proposal in detail and demonstrates its many problems, including the fact that it uses a single hedge instrument for the Company's natural gas and power exposures derived from a market (Louisiana) that is remote from the Company's operations. This approach is clearly out of step with current electric industry best practices for hedging, which generally employ more locationally appropriate, liquid and transparent gas and electric swaps to comprehensively and flexibly cover market exposures.

Q. Should the Company include options in its hedging program?

A. There may well be instances when options should be a viable and economic part of the Company's portfolio. Indeed, the Company has used options on a limited basis previously, such as the Morgan Stanley electricity call option contracts reflected in the net power costs in the test period in this case. Before relying upon options on a larger scale as a part of the Company's hedging program, however, an analysis must be made regarding liquidity, basis risk and economics compared to alternatives. In the ECAM docket, the Company proposed a "carefully staged approach" to the broader use of options. This contemplated hedging a small portion of the hedging portfolio initially with options, while working with the Commission and other parties to review the results and address associated issues, including cost recovery of premiums from options that were never exercised.

Q. Have parties questioned the Company's past use of options by challenging the recovery of option premiums in rates?

A. Yes. The most immediate example is in this case, where UIEC witness Mr. Widmer recommends that the Commission disallow the option premiums associated with the Morgan Stanley call option contracts. The DPU makes the same proposal in the testimony of Mr. Evans.

In the Company's 2007 general rate case, Docket No. 07-035-93, OCS's witness Mr Falkenberg proposed similar adjustments. In the Company's 2010 Wyoming general rate case, Docket No. 20000-384-ER-10, both Messrs. Falkenberg and Widmer also proposed the same adjustment for WIEC. The Company disagrees with these adjustments. Nevertheless, in the face of such adjustments, the Company cannot reasonably be expected to have implemented a hedging strategy based solely upon option contracts, as OCS now advocates.

Conclusion on Hedging

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. There is no dispute that these costs were incurred in compliance within a well-defined risk management and hedging program. 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 the Company hedged too much, hedged too far forward, or used the wrong hedging instruments. 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.

Section III Apex Termination

Q. Do you have anything to add to Mr. Duvall's rebuttal testimony in response Mr. Petersen's proposal to penalize the Company for terminating negotiations to acquire Apex?

A. Yes. As explained more fully in my rebuttal testimony in Docket No. 10-035-126, also incorporated herein by the DPU, the Company made the decision to terminate negotiations for the Apex facility after a comprehensive and thorough due diligence process and economic evaluation. The Company has demonstrated that the termination of negotiations with LS Power was a prudent decision that was in customers' best interest and was not premature as argued by Mr. Peterson. In Docket No. 10-035-126, the Company admitted that modeling errors were made in the course of updating models with the results of due diligence, but also demonstrated that the errors were quickly recognized and corrected. Once the models were updated and the economics considered with all accompanying risks reflecting complete due diligence, it was clear that the decision to terminate was in the best interest of customers.

Mr. Duvall's rebuttal testimony in this case resummarizes the many reasons why the decision to terminate was prudent and why the DPU's proposal is unfounded, inconsistent with the approved evaluation process and violates appropriate ratemaking. Nonetheless, the Company recognizes lessons learned from the RFP and proposes to address the process concerns raised by the DPU and the IE by holding a stakeholder workshop in advance of the issuance of the next RFP to consider process improvements and revisit the approved evaluation process to assess and implement improvements to address more unique opportunities like Apex.

Q. Does this conclude your rebuttal testimony?

A. Yes.