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

A. My name is John A. Apperson, my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232, and my present position is Director, Trading.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in electrical engineering from Oregon State University. I have worked for PacifiCorp since 1982 and have held various positions in transmission planning and commercial and trading areas. I have worked in the wholesale marketing area of the company beginning in 1995 and was promoted to my current position in April 2000.

Q. What are your responsibilities as Director of Trading?

A. I am responsible for financial and physical hedging and balancing the Company's energy position in the wholesale market to economically meet the company's load obligations. This includes transmission purchases and associated activities performed by the cash and forward trading, real-time trading, prescheduling and production planning groups.

Purpose and Summary of Testimony

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony addresses the Company's hedging strategy and practices and demonstrates why the associated costs are prudent and reasonable. Specifically, I respond to the adjustments for hedging costs proposed by Messrs. Douglas D. Wheelwright and Mark W. Crisp on behalf of the Division of Public Utilities ("DPU"); Ms. Michele Beck, Dr. Lori Smith Schell and Mr. Paul

Wielgus on behalf of the Office of Consumer Services ("OCS"); Messrs. Kevin Higgins and Jeff J. Fishman on behalf of UAE Intervention Group ("UAE"); and Messrs. J. Robert Malko and Mark T. Widmer on behalf of Utah Industrial Energy Consumers ("UIEC"). Company witnesses Messrs. Stefan A. Bird, Gregory N. Duvall and Frank Graves also respond to particular aspects of the hedging adjustments proposed by intervenors.

Q. Please summarize your testimony.

A. I sponsor the quantitative analysis the Company relies upon to rebut intervenors' adjustments and show the benefits customers have received as a result of the Company's hedge program. I provide evidence on the reasonableness of the Company's hedge horizon, explain that the Company could not have reasonably foreseen the drop in natural gas prices which caused the hedging losses in this case, respond to the OCS's proposal to substitute the use of natural gas options for natural gas and power swaps, address issues raised about other costs of hedging, including cash collateral, and explain how the hedge program responds to fluctuations in loads.

Effectiveness of Hedging Program - Quantitative Analysis

Q. Mr. Wheelwright of the DPU testifies on the historic and projected costs of the Company's hedging program. Have you reviewed his analysis to determine whether it is accurate and complete?

A. Yes. I have determined that the analysis is inaccurate and incomplete because it omits certain hedging costs.

Q. What portion of hedging costs does Mr. Wheelwright exclude from his analysis?

A. At page 7, line 144-145 of his testimony, Mr. Wheelwright notes that financial swaps for electricity and natural gas are the "primary focus of his analysis." These are in fact the exclusive focus of Mr. Wheelwright's analysis, as he excludes forward contracts (*i.e.*, fixed price physical electricity and natural gas transactions) from his analyses of historical gains and losses of the Company's hedging program, as well as forward test year results. Further, while Mr. Wheelwright correctly notes at lines 150-153 that the Company's natural gas fired units' spark spreads and natural gas price volatility are considerations necessary for hedging, Mr. Wheelwright omits the fact that electricity price volatility is the other core component of spark spreads and therefore also fundamental to the Company's natural gas hedging program.

Q. Can you provide examples demonstrating the importance of electricity price volatility as a consideration?

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

Q. What is your conclusion from these examples?

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

Q. Is it appropriate to exclude forward contracts from an analysis of the costs of the Company's hedge program?

A. No. The Company uses forward contracts and financial swaps interchangeably, subject to market liquidity, to hedge price exposure.

Q. What is the effect of excluding forward contracts from Mr. Wheelwright's testimony on <u>forward</u> test year hedge program results?

A. Mr. Wheelwright notes that natural gas swaps add $160.7 million to net power costs while the electric swaps reduce net power costs by $61.7 million for a net increase to net power costs of $99.0 million total Company. However, when forward contracts are added, total natural gas hedge transactions add $160.5 million to net power costs while total electricity hedge transactions reduce net power costs by $69.8 million for a net power cost increase of $90.7 million. Thus, including forward contracts in the analysis reduces the net power cost impact by approximately $8 million. As Mr. Duvall testifies, the hedging losses in net power costs have been further reduced by the Company's rebuttal update, which now shows a total forecast loss of $82 million total Company.

Q. What is the effect of excluding forward contracts from Mr. Wheelwright's testimony on <u>historical</u> hedge program results?

A. Figure 1 replicates Wheelwright Table 1, which shows settled value of natural gas and electric swap transactions for each 12 month period ending June 2007 through June 2010. Additionally, Figure 1 includes a partial period of 10 months ending April 2011. Following the summarization of net swap transactions, Figure 1 includes forward contracts settled under the same applicable periods, as well as the combined total hedge program results.

Figure 1

Wheelright Testimony Table 1 Plus Updates	Jun-07	Jun-08	Jun-09	Jun-10	Apr-11
Gas Swaps	2,144,035	43,175,607	187,829,118	177,495,820	123,550,716
Electric Swaps	1,133,068	21,759,293	(66,455,329)	(195,862,775)	(213,737,651)
Net Swap Transactions	3,277,103	64,934,900	121,373,789	(18,366,955)	(90,186,936)

Forward Contracts	Jun-07	Jun-08	Jun-09	Jun-10	Apr-11
Gas Forward Contracts	(7,787,768)	32,587,801	200,599	(282,073)	15,322
Electric Forward Contracts	(70,220,454)	(87,991,225)	(211,379,285)	(114,681,373)	(31,002,476)
Net Forward Contracts	(78,008,222)	(55,403,424)	(211,178,687)	(114,963,447)	(30,987,154)

All Hedges	Jun-07	Jun-08	Jun-09	Jun-10	Apr-11
Gas Hedges	(5,643,733)	75,763,408	188,029,717	177,213,747	123,566,038
Electric Hedges	(69,087,386)	(66,231,932)	(277,834,614)	(310,544,148)	(244,740,127)
Net Hedge Transactions	(74,731,119)	9,531,476	(89,804,898)	(133,330,402)	(121,174,090)

When all hedging program instruments--swaps and forward contracts--are incorporated into the analysis of the Company's hedging program, the results of Mr. Wheelwright's analysis change dramatically. Rather than an increase in net power costs of $3.3 million for 12 months ending June 2007, the hedge program resulted in a $74.7 million *decrease* in net power costs. Rather than an increase in net power costs of $64.9 million for 12 months ending June 2008, the hedge program resulted in only a $9.5 million increase in net power costs. Rather than an increase in net power costs of $121.4 million for 12 months ending June 2009, the hedge program resulted in an $89.8 million *decrease* in net power costs. Finally, rather than a decrease in net power costs of $18.4 million for 12 months ended June 2010, the hedge program resulted in a decrease of $133.3 million.

In summary, the total hedge program has *decreased* net power costs an average of $72.1 million per year rather than increased net power costs by $42.8 million as erroneously alleged in Mr. Wheelwright's testimony. With the addition of the 10 month period ending April 2011, the hedge program has decreased net power costs an average of $80.5 million per year.

Q. Did you review the total price for natural gas calculation in Mr. Wheelwright's testimony?

A. Yes

Q. Is Mr. Wheelwright's analysis here similarly incomplete?

A. Yes. Mr. Wheelwright notes on Table 2 that natural gas swaps add an additional 31.2 percent to the price of natural gas that is included in the test year. He excludes all power hedges as well as the rest of the costs which make up the total net power costs of $1.5 billion. Taking into account all of these components, the power and natural gas hedges for the test period add 6 percent, or $90.7 million to the net power costs in the test period.

Q. Have you reviewed Mr. Widmer's exhibit UIEC (MTW-5), which Mr. Malko uses to conclude that PacifiCorp's gas hedging program has been unsuccessful beginning in 2006?

A. Yes. The analysis of Messrs. Widmer and Malko is even more inaccurate and incomplete than Mr. Wheelwright's. Messrs. Widmer and Malko look only at the Company's natural gas swaps and conclude that the Company has lost approximately $707 million[1] since 2006. Looking at the Company's hedge program in its entirety and correcting data errors in Mr. Widmer's exhibit, the losses UIEC alleges reverse to a gain of approximately $349 million.

Q. Please explain the data error corrections and inclusion of all hedges.

A. First, the electricity swap values in exhibit (MTW-5), albeit not included in the $707 million figure, have their signs erroneously reversed for the period July 2011 through June 2012. Second, the electricity swaps with a (corrected) gain of approximately $527 million have been added. Third, natural gas forward contracts with a loss of approximately $6 million have been added. Fourth, electricity forward contracts with a gain of approximately $535 million have been added.

Q. Have you reviewed Mr. Wielgus' Exhibit OCS 6.1, which he relies upon to claim that customers have not benefited from Company hedging?

A. Yes. Mr. Wielgus' Exhibit OCS 6.1 is a graph depicting net power costs and rates with and without the hedging for the test year. Mr. Duvall addresses Mr. Wielgus's claim that the chart shows that the Company's hedge program has not reduced net power cost volatility. My criticism of OCS 6.1 is that it focuses on

[1] Mr. Widmer's testimony originally stated $715 million and was subsequently revised to $707 million. Mr. Malko's testimony still refers to $715 million and was not revised.

one year only. By its very nature, hedging results will fluctuate year-to-year as my analysis in Figure 1 demonstrates. Therefore, a meaningful review of hedging results must look to multiple years.

Hedge Horizon

Q. Please respond to Dr. Schell's testimony that the Company should restrict hedging to up to 36 months.

A. The Company's hedge program is based on the premise of hedging forward in progressively smaller amounts to achieve the benefit of dollar cost averaging over time as long as there is sufficient liquidity. Dr. Schell assumes in her testimony that the dramatic decline in natural gas volume traded on NYMEX from year 1 to year 4 indicates insufficient liquidity in year 4. Dr. Schell demonstrates this with figures at lines 153 and 177 in her direct testimony.

Q. Is the natural gas volume traded on NYMEX an accurate indication of liquidity for the Company's hedging program?

A. No. NYMEX is a cleared, or fully collateralized, market which discourages longer term transactions because of the significant collateral posting requirements. Parties with strong credit ratings, such as PacifiCorp, often choose to transact in over-the-counter markets that require much less collateralization.

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

A. Yes. Confidential Figure 2 shows the number of credit-worthy counterparties with whom the Company currently transacts natural gas hedges. While the market liquidity does diminish somewhat further from the time of delivery as indicated by the number of available counterparties, there is sufficient liquidity in the 36 to 48 month period (i.e., year 4) for the Company to hedge its natural gas exposure. The Company recognizes the market constraints in this period through its hedging target levels, which are much lower in year 4 than in year 1.

Confidential Figure 2

[redacted]

Q. Why is the year 4 bar partially shaded in Confidential Figure 2?

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

Q, Is there a more direct measure of liquidity?

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

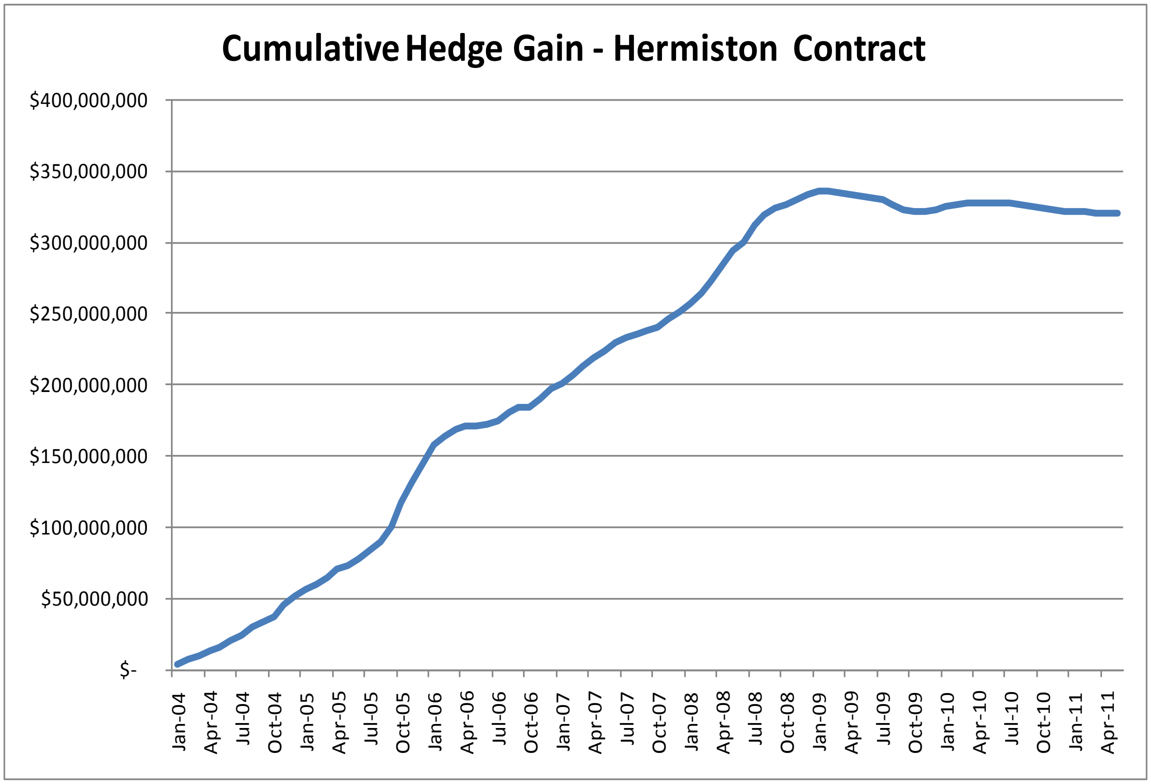
Q. What are the bid ask spreads for the Company's hedging periods?

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

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

A. Yes. The Company hedged 100 percent of the fuel for the Hermiston natural gas fired plant with a 15-year supply agreement. At times the hedge was favorable and at times unfavorable compared to spot prices. Overall, the long term supply agreement was very favorable. The Company's presentation at May 2009 technical conference in Docket No, 09-035-21 included a chart reflecting the benefits of the Hermiston gas hedge. As shown in Figure 3 the Hermiston gas hedge yields a January cumulative benefit to customers of $320 million January 2004 through May 2011.

Figure 3



Foresight of Falling Natural Gas Prices

Q. In 2007-2008 when the 36 to 48 month hedges in this case were transacted, could the Company have reasonably foreseen the decrease in natural gas prices for the test period in this case?

A. No. Neither the forward price curves representing the forward market at the time the hedges were transacted, nor third-party expert spot price <u>forecasts</u> indicated a significant drop in natural gas prices.

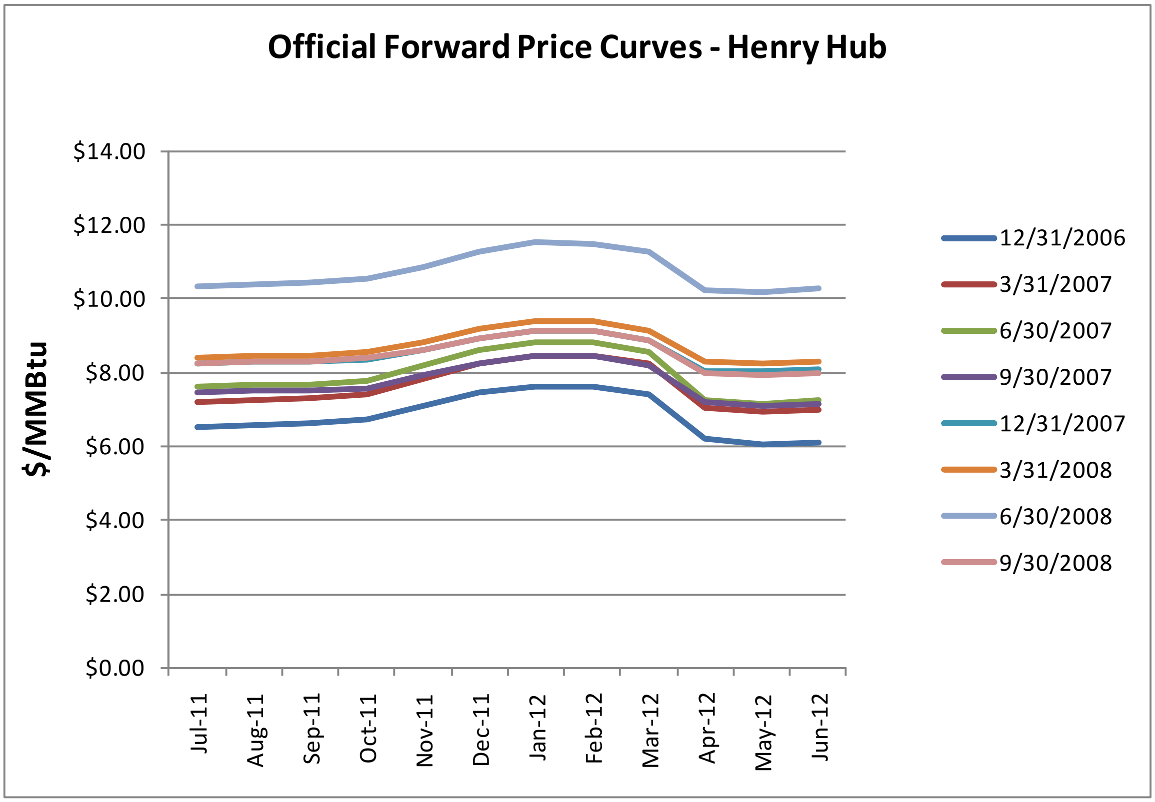
Q. Please explain the distinction between a forward price curve and a spot price forecast.

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

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

A. Figure 4 shows the Company's official forward price curve as of each quarter in 2007 and 2008 for natural gas delivered in the test period. These prices are consistent with the prices paid by the Company for the natural gas hedges in this case.

Figure 4



Q. Is it apparent that the market in general, as reflected in the forward price curves shown in Figure 4, anticipated the precipitous drop in natural gas prices?

A. No. The forward price curves shown in Figure 4 did not indicate the drop in natural gas prices that occurred in the subsequent months and years. If the market in general had known or anticipated such a drop in prices, the forward price curves would have reflected that knowledge or anticipation in the form of declining prices in the future. In contrast, as Figure 4 shows, the market consistently reflected rising natural gas prices through mid-2008.

Q. If the market had stabilized as evidenced by forward market prices in 2007 and 2008, what would be the value of the Company's test period hedges?

A. If market prices had remained high, the Company's swap transactions in the current proceeding would produce entirely different results. Figure 5 below duplicates Dr. Schell's analysis, replacing the market prices used in the Company's direct case with market prices from the Company's 2008 general rate case (using the Company's June 2008 Official Forward Price Curve). This analysis shows significant benefit associated with the same hedges, with the greatest benefit being in the hedges 36 to 48 month forward. In this example, natural gas hedge benefits dramatically offset losses in power hedges.

Figure 5

	Natural Gas	**Power**	**Net by Time Period**
1-12 months	(11,201,957)	2,945,260	(8,256,697)
13-24 months	(12,540,487)	61,457,784	48,917,296
25-36 months	(30,262,320)	19,374,793	(10,887,527)
37-48 months	(95,932,404)	7,295,296	(88,637,108)
Total	**(149,937,168)**	**91,073,132**	**(58,864,036)**

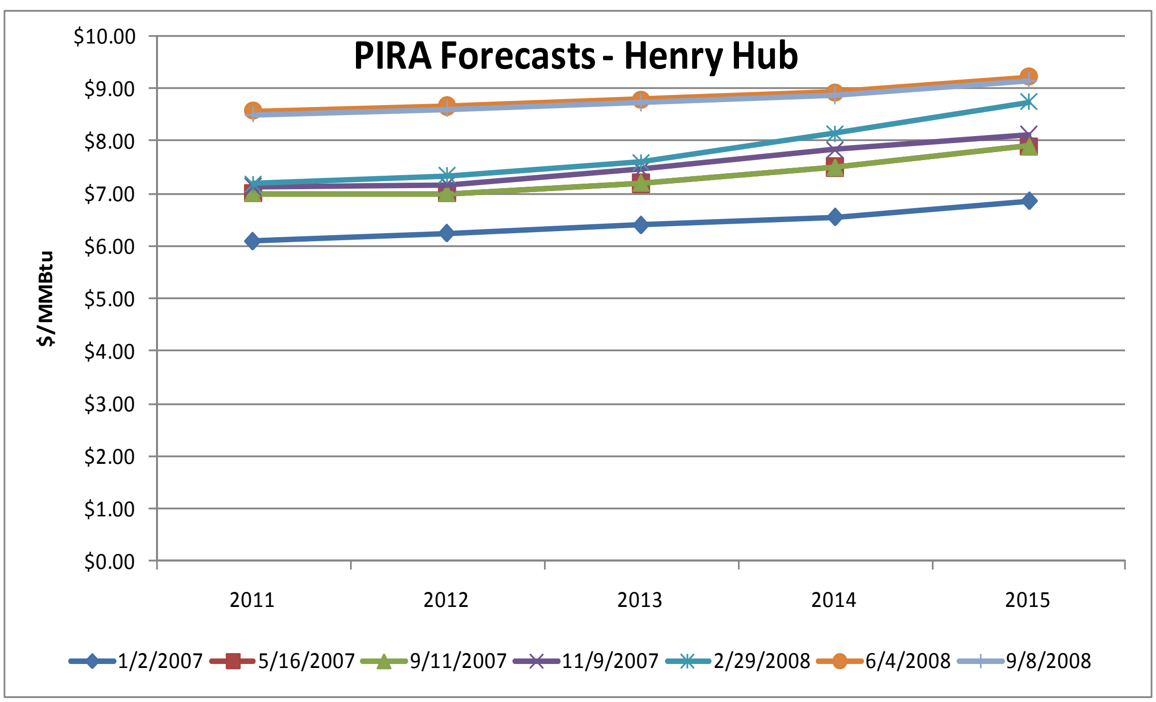
Q. At the time the hedges in this case were transacted, what did spot price forecasts show with respect to natural gas prices in the test period?

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

Q. Is it apparent that PIRA, as reflected in its spot price forecast shown in Figure 6, anticipated the precipitous drop in natural gas prices?

A. No. In addition, the spot price forecast continued to climb for the delivery period 2011 through 2015.

Figure 6

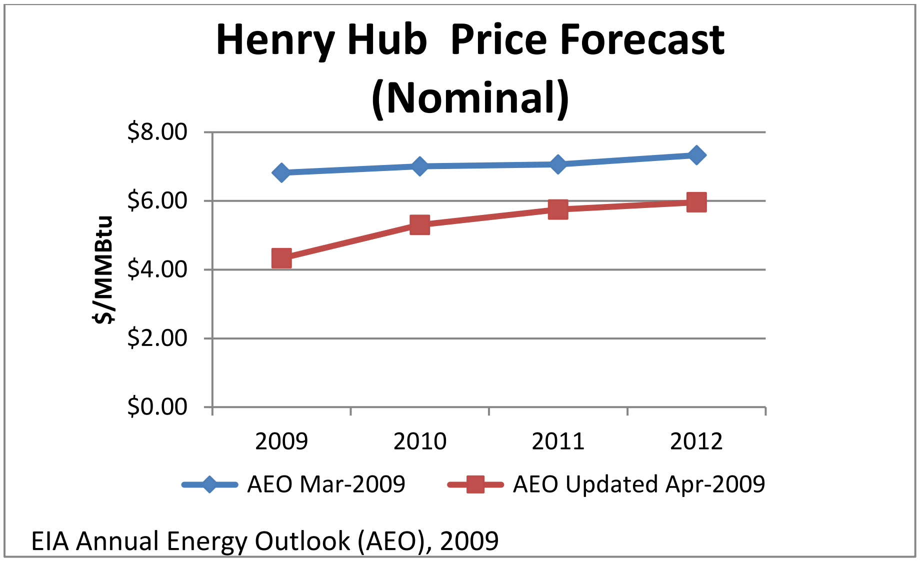


Q. Does Mr. Wheelwright's Chart 1 provide information that was available to the Company at the time the Company purchased the 36 to 48 month natural gas hedges in this case?

A. No. The U.S. Energy Information Administration (EIA) Annual Energy Outlook forecasts shown in Mr. Wheelwright's Chart 1 are spot price forecasts made after the Company purchased the 36 to 48 month natural gas hedges. As seen in Figure 7, as late as March 2009 the EIA was forecasting high and climbing Henry Hub prices for 2011 and 2012. One month later, the EIA significantly revised its nominal Henry Hub price forecast downward albeit still climbing.[2] The significance of this is that within the course of a month in 2009, the EIA issued a major revision to its long-term natural gas price forecast, illustrating how quickly expectations had changed. The Company executed the majority of its natural gas hedges for the test period prior to 2009; thus, its hedges were prudent given expectations at the time of execution.

[2] U.S. Energy Information Administration, Annual Energy Outlook, 2009.

Figure 7



Use of Options

Q. As an alternative to the Company's traditional practice of using swaps for its hedging program, Dr. Schell and Mr. Wielgus propose that the Company use Henry Hub natural gas options. Is this appropriate?

A. No, for many reasons. Most fundamentally, the Company has commodity exposure to electricity and natural gas across the Western United States and a portion of Canada. The Company's traditional approach using swaps provides a flexible and comprehensive approach to covering this exposure. In contrast, the OCS proposal would limit and restrain this hedge exposure with a single product-Henry Hub natural gas options. Henry Hub is located in Louisiana, some 1500 miles away from the Company's Utah operations.

Q. Please describe the obstacles in using Henry Hub options in lieu of swaps as described by Dr. Schell.

A. Dr. Schell's analysis ignores the *basis* risk associated with purchasing options through NYMEX, and the lack of liquidity associated with purchasing options over the counter at locations near the Company's requirements**.**

Q. What is basis risk and what is the impact?

A. Basis risk is the risk that prices at two separate markets will not move in tandem. For example, the price of a NYMEX hedge can be significantly different than the price at the location the Company requires the natural gas, resulting in location basis. Continuing the example, if the Henry Hub price on NYMEX goes up $0.50 per MMBtu, and the price at Opal goes up $0.30 per MMBtu, then the basis difference and resultant hedge ineffectiveness in this example is $0.20 per MMBtu. Hedging at NYMEX would present a location basis risk and be an incomplete or inaccurate hedge of natural gas requirements which could result in significant losses**.**

Q. What are the liquidity considerations?

A. To avoid basis risk, the Company may be able to transact options near the location of its natural gas requirements. However, unlike NYMEX, there is limited liquidity for options at those locations. Attempting to purchase a very large volume would adversely impact the premiums paid by the Company by driving the price of the premium up. In contrast, swaps are very liquid at these same more proximate trading locations to the Company's actual requirements and use of swaps thereby mitigates the cost and liquidity concerns associated with options as well as basis risk.

Q. How does Dr. Schell propose to hedge power?

A. Dr. Schell makes no distinction between power and natural gas in her options analysis. She proposes an “equivalent” number of Henry Hub natural gas options to hedge power at an assumed heat rate of 10,000 MMBtu/kWh.

Q. Would Henry Hub natural gas options be an effective hedge against the Company’s power exposures?

A. No, for several reasons. First, as described above, Henry Hub is located in an entirely different market than the West, where the Company operates. The difference between markets is not negligible. Second, Dr. Schell asserts that an “equivalent” number of options can be calculated by converting electricity (MWh) into natural gas (MMBtu) using a 10,000 MMBtu/kWh heat rate. In order for such an assumption to be valid, a perfect correlation would need to exist between on-peak and off-peak electricity to natural gas. Absent near-perfect correlations, the effectiveness of the proposed hedge program is significantly reduced.

Q. Do the premiums shown in Dr. Schell’s analysis reflect the cost of options the Company would have paid if it had followed this strategy?

A. No. Dr. Schell’s supporting work papers indicate she obtained at-the-money option premium quotes for the prompt month through the second forward year on April 9, 2010 and presented a “what-if” analysis of the Company’s hedging strategy for the July 2011 to June 2012 test year. The premium quotes she collected for April 9, 2010 for two forward years seem to establish her use of $0.50, $0.75, and $1.00/MMBtu as representative of the cost of hedging using options.

Q. What premiums would the Company have paid if it hedged using options in 2008 when a majority of the natural gas swap transactions in the test period were executed?

A. The option premium is estimated to be $1.67 per MMBtu for call options settled July 2011, which is the beginning of the test period, as of April 23, 2008, which is approximately three years prior to settlement, similar to the time when the Company purchased many of the natural gas swaps.

Q. Does OCS witness Mr. Wielgus testify that customers would be unwilling to pay an option premium at or in excess of $1.00/MMBtu?

A. Yes, at lines 246-248 of his testimony. This is further evidence of the unreasonableness of the OCS's option proposal.

Q. What is the source of the data used to calculate the premium?

A. The premium was calculated using a publicly available source that is not confidential and can be readily verified at www.ivolatility.com. The strike price is $9.20 per MMBtu, the volatility is 23.5 percent and the interest rate is 1.118 percent.

Q. Why is the premium calculated by the Company greater than the premium suggested by Dr. Schell?

A. The option premiums calculated by Dr. Schell assumed the options would be purchased on or around April 9, 2010 and are therefore understating the premiums due to the lower volatility and prices. Furthermore, the cost of an option increases significantly the greater the period from the transaction date to the expiration of the option. Using option premiums from only the first two years to establish a range of costs the Company purportedly could have paid for options covering all four years of its position management horizon is flawed.

Additional Hedging Costs

Q. Do you agree with Mr. Wheelwright's testimony stating that cash collateral requirements have not been addressed by the Company?

A. No. The Company addresses cash collateral requirements as part of its hedging program.

Q. Mr. Wheelwright expressed a concern that collateral requirements related to the Company's hedging program could impact management decisions. Is this a valid concern?

A. No. While management is certainly aware of collateral requirements and amounts posted, the Company has not changed its capital, operating or maintenance budgets due to collateral requirements. In fact, the Company continues to invest significant amounts of capital into the business for the benefit of customers.

Q. Has the cost of maintaining cash collateral hindered the Company's ability to execute its hedge program?

A. No. The Company has practices in place to mitigate large cash collateral requirements without incurring unacceptable credit risk.

Q. What has the Company done to mitigate large cash collateral requirements?

A. The contracts that the Company has used to hedge natural gas and power price exposures have helped to reduce the collateral requirements. These contracts require the parties to post collateral only for the exposures in excess of negotiated threshold levels (which are typically ratings dependent). The Company to date has avoided transacting on the NYMEX or utilizing other cleared transactions which would have resulted in greater collateral requirements (or inflows depending on the net position) as the Company would no longer have any threshold levels and would be required to collateralize all related credit exposures.

Q. Have the collateral amounts impacted the Company's credit ratings?

A. No. The current collateral amounts are within a range that the credit rating agencies have historically ignored when doing their credit rating analysis. As such, the current collateral levels would not be expected to have a negative impact on Funds from Operations or resulting cash flow coverage metrics used by the rating agencies.

Q. Is the Company always in a net position of paying cash collateral to counterparties?

A. No. There are times when the Company has been a net recipient of cash collateral from counterparties. This has occurred when, for example, the Company has made sales and the market price has subsequently decreased.

Q. Does the Company periodically review its cash collateral requirement?

A. Yes. The Company monitors and updates its cash collateral requirements daily based on prior day credit exposure calculations. In addition, the Company does a monthly analysis of actual and future collateral requirements for a rolling 48 month period. Further the Company undertakes a quarterly analysis of collateral requirements for scenarios including forward price curve changes and credit ratings reductions to project what collateral requirements may be.

Q. Mr. Wielgus' testimony infers that customers would save administrative costs if hedging was eliminated. Please comment.

A. Administrative costs, which include staff and systems, are required for physical balancing of the Company's power and natural gas requirements. The same trade capture systems are required whether transacting hedges a year forward or buying one day prior to delivery. Credit position reporting, invoicing and checkout would continue to be required absent hedging.

Load Levels and Power Sales

Q. Please respond to Mr. Wheelwright's testimony that the Company's forecast load, forecast power sales, and temperature forecasts impact its level of natural gas hedging.

A. I disagree with this testimony. Retail load does not impact natural gas hedging. Neither do forecast wholesale power sales, open power positions, or temperature forecasts. Mr. Wheelwright is correct that growth in retail loads is offsetting the Company's excess generation. But he is incorrect in the inference that the Company continues to hedge assuming the same level of electricity sales and that the internal price hedge between natural gas and electricity will continue. The Company updates its forward electricity positions daily to reflect expected retail loads, expected generation and all wholesale electricity transaction commitments. The Company also updates its forward natural gas positions daily to reflect fuel requirements from expected natural gas fired generation and all wholesale natural gas transaction commitments. As retail load increases, the Company naturally enters into fewer electricity hedge sales (as the "short" retail load position offsets the “long” generation position). The Company’s natural gas exposure, however, is unaffected by this increase in retail loads (since retail load is an *electricity* position), so there is no “natural” reduction in the Company’s exposure to natural gas price movements. The volume of natural gas hedging in relation to electricity hedging will naturally be greater. Further, one should expect in such circumstances that the net power cost impacts of the Company’s natural gas hedges will exceed the net power cost impacts of the Company’s electricity hedges.

Q. Does this conclude your rebuttal testimony?

A. Yes.