Introduction

Q. Please state your name and position.

A. My name is Frank C. Graves. I am a Principal at the economics consulting firm *The Brattle Group*, where I am also the leader of the utility practice group.

Q. Briefly describe your qualifications and professional background.

A. I specialize in regulatory and financial economics, especially for electric and gas utilities. I have assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. I have testified before the Federal Energy Regulatory Commission ("FERC") and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning ("IRP"s), the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions. I am the author of several publications in risk management. I received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975. A detailed resume is included in the Appendix.

Q. Have you previously testified for Rocky Mountain Power (RMP or the Company) in regard to risk management and hedging?

A. Yes. I filed testimony on behalf of the Company before the Public Service Commission of Utah in Docket No. 10-035-124. I also filed testimony in the Company's request for a power cost adjustment mechanism in Utah, Docket No. 09-035-15, some of which addressed risk management and hedging. I participated in the 2011 Utah workshops on risk management goals and approaches between RMP, the Division of Public Utilities, the Office of Consumer Services, various customer group representatives, and other interested parties. Most recently, I filed rebuttal testimony on behalf of the Company in Utah, Dockets No. 11-035-200 and No. 12-035-67, and in Wyoming, Docket No. 20000-405-ER-11. The recent testimonies also related to risk management issues.

Q. What is the purpose of your testimony?

A. I have been asked to review the Company's hedge positions for 2012 and to discuss

1. What the purpose of hedging is and especially whether hedging aims at minimizing costs.

2. Whether the Company's hedging policies are consistent with good industry practices, including whether the Company's hedging instruments were appropriately diversified;

3. The trends, uncertainties, and outlook for natural gas markets during late 2007 through 2011, when the hedges in question were entered into.[1]

4. Whether it would have been useful (or normal, in relation to industry risk management practices) for RMP to have engaged in early liquidation of its prior hedging positions, as it became more evident that they were moving "out of the money" in 2009 and beyond, and;

5. Whether power companies with generation tend to or should hedge natural gas and power separately or focus on the net exposure.

Company witness Mr. Stefan A. Bird is addressing the Company's hedging program and Company witness Mr. Brian S. Dickman is providing the accounting data that pertains to the EBA costs.

Q. Please summarize your general findings and conclusions.

A. I will provide my summary conclusions in the same order as the purposes for my testimony described above:

First, risk management is about controlling the potential width (and shape) of the distribution of future costs and not about minimizing costs. Even though it is possible to trim or avoid extreme prices with hedging, that trimming cannot reduce expected costs, because the risk protections come at a fair price. What you gain from hedging as avoided "downside" (bad) outcomes, you must lose as avoided "upside" (good) outcomes as well, and vice versa for your hedging counterparty. The two, corresponding positions must balance for no expected net

[1] Data provided by the Company. The hedges were entered into from October 2007 through September 2011.

gain. Thus, the minimization of energy costs has nothing to do with good risk management practices.

Second, the Company's hedging policies and practices, i.e. its analytic methods, risk metrics and controls, and hedging instruments, are fully in line with good industry practices. Like most electric utilities, the Company relies primarily on swaps purchased in regular installments over time. This avoids attempts to second-guess or "time" the market, while also assuring that hedges are steadily accrued, subject to risk-based guidelines for the needed quantity of total hedges. Consistent adherence to these methods, along with evidence of careful monitoring and control of the resulting risk metrics (keeping them within appropriate bounds), are the relevant standards for prudence review of the EBA costs the Company has incurred.

Third, U.S. natural gas markets in the late 2007 through 2011 period (when PacifiCorp entered the hedges) were dominated by the unexpectedly rapid and inexpensive development of shale gas, compounded by the credit crisis and deep recession. During the first two years of this period there were few indications that shale gas would become a major component of U.S. gas supply. Only towards the end of the period did it become evident that shale gas would become a prominent and quite inexpensive part of the natural gas supply in the U.S. Even natural gas exploration and production firms aggressively leading the development of the hydraulic fracturing technology that caused this price drop have been badly surprised by the rapid price reductions.[2] Therefore, the outlook for natural gas supply and prices were very different throughout the period during which the hedges were entered than it is today. It is imperative that the merits of a hedging program be evaluated based on the market conditions and information availability as of the time of the transaction.

Fourth, it would not have been useful or normal for the Company to have liquidated any of its prior hedges in the middle of this price decline. It might appear so in hindsight, but the spot prices we ultimately observed are not similar to the way risks or expected costs appeared at any time in the hedge procurement period. Utility companies should not and do not generally liquidate hedges if/when the forward price curve shifts and causes prior hedges to become "out of the money" (i.e. to have a higher cost than replacement hedges). Because hedge positions are liquidated at prevailing prices, early liquidation cannot be expected to benefit the Company or its customers; the expected alternative cost (whether re-hedged or not) would have been the then prevailing forward prices – with no net savings likely. (As it turns out, liquidation and not re-hedging, i.e. dramatically increasing the Company's risk exposure, would have been cheaper. But this can only be known in hindsight, and pursuing this strategy would have been very speculative, possibly in violation of company risk-control guidelines and prior regulatory agreements about hedging activity.

Fifth, natural gas and power hedges should be considered together, which

[2] For example, an August 2009 article in the New York Times cites senior management at exploration and production companies that the continual drop puts the viability of smaller companies at risk. See Clifford Krauss, "Natural Gas Price Plummet to a Seven-Year Low," New York Times, August 21, 2009.

is what the Company does. The literature and common practice in hedging is solidly on the side of taking advantage of positions that predictably tend to offset each other, in order to reduce the cost and scope of hedging transactions that are needed. Electric and gas operations fit this model very nicely, in that they naturally tend to be correlated. Separating them for review would create perverse and untenable incentives for both regulation and operations.

1. THE PURPOSE OF HEDGING

Q. What is the overarching goal of risk management and hedging?

A. A hedge is a trade designed to reduce risk, where risk is understood to mean the potential width (and shape) of the distribution of <u>future</u> costs (or revenues). Risk management is NOT about improving (reducing) the mean of this distribution of future costs (nor about increasing expected revenues). Risk also should not be confused with after-the-fact regret about whether a hedge proved to be necessary or attractive relative to remaining unhedged. In fact, risk and regret are mostly conflicting or competing goals, in that the more you lock down future prices (reduce *ex ante* risk) the greater the chance of eventually departing materially from the *ex post* cost of going unhedged. Conversely, if you wanted to have no regret about realized spot prices being lower than your hedges, than you should not hedge in the first place – but this would be risky! Some of the debate in regulatory review about risk management prudence involves confusion between these two concepts. However, the appropriate reference point is not the realized outcomes, which can only be known in hindsight (and which will only be better or worse than the hedges by luck), but the market information and outlook available at the time the hedges and risk reduction targets were committed.

Q. Why do you say that it will only be luck, in hindsight, if hedges turn out to be better or worse than spot prices?

A. Fairly and competitively priced hedges will only trade if both sides regard the amount paid for the risk transfer to be worth the value gained (or cost incurred). This means there can be no improvement in the expected cost for one side of the deal, or else the other side is facing an expected degradation. If so, they would be better off not trading. For the same reason, you cannot expect to reduce your future costs by not hedging. The hedges you forego have a fair price that reflects what you would be likely to pay on an unhedged basis (i.e. expected spot prices) - albeit with a different, more certain pattern over time.

Q. How are prices for hedging instruments such as swaps determined?

A. Hedges are basically agreements to pay a future price, or to put a limit on future prices paid, for forward commitments to transact. The agreed future price should be a good estimate of the expected (unhedged) spot prices over the delivery period, so that it is agreeable to both sides and so no money needs to exchange hands up front. Of course the beliefs about what the future spot price will be change every day, so the forward prices of traded hedging instruments also change every day on exchanges and in bilateral, over the counter markets. As the forward prices for a given delivery period change, the prices of hedges previously entered into (at other forward prices) become in or out of the money and so they can then only be sold for the present value of the change in forward prices.

Swaps are the most commonly used instrument for hedging in wholesale electricity and gas markets. They are an agreement to pay the delivery-period difference between a stated fixed price and the realized spot price for a fixed volume of the commodity. Since they are widely and competitively traded, it is reasonable to conclude they are fairly priced in a manner that individual market participants (such as RMP) cannot control. The price on the fixed side of a swap is derived (literally, as they are derivatives) from expected future spot fuel and power prices. Thus, holding (or writing) a swap is neither a better nor worse deal (in expectation) than being unhedged. When expected future spot prices change (e.g. with new information about macroeconomic conditions, supply developments, etc.), the swap prices react immediately and re-center on the new expectations.

Swaps are also priced the same way that physical forward contracts are, because both are alternative (and virtually equivalent) ways of setting a fixed price for a future fixed quantity of energy service. The main difference is that swaps are standardized and so are more liquid.

Q. What does that mean for the prices paid by RMP for the hedges at issue in this proceeding?

A. Because swap and other hedge prices are determined competitively, they represent the market participants' consensus about future likely power costs and cannot be readily manipulated by any one party (absent fraudulent or manipulative behavior). Instead, they move in response to the same types of external influences as physical markets for gas and electricity. The forward curve as observed in the market place is the price paid by RMP and the price at which RMP could unload a position it holds. Some will end up "in the money" (cheaper than realized spot, so RMP is paid by the counterparty) while others will end up out of the money (with losses, as is the case here for many gas hedges, due to the unexpected drops in natural gas spot prices).

Q. Does hedging with other kinds of instruments besides swaps and physical forwards change expected costs?

A. No, there is no kind of hedging that changes the <u>expected</u> costs of the commodity being hedged. Even a one-sided hedge, like a call option (that protects the buyer from upside increases in costs while leaving the downside open should prices fall) does not reduce expected costs. The reason is that the upside protection comes at a cost equal to the insurance benefit (present value of the expected cost trimming). There are no expected savings, just a change in the shape of the total cost distribution that could eventually be faced. For instance, buying call options instead of swaps or forwards will involve an open possibility of being at market if spot prices end up below the option strike prices, but this possibility of less regret comes at the price of having to pay the option prices (or premiums) as insurance against spot prices rising. The combined effect will have the same mean as not hedging, or as hedging with swaps.

The only costs that are eligible for minimization under hedging are transaction costs and potential costs of non-performance of the other side. Both of these are generally small in relation to the traded price at delivery – and that is especially true for highly liquid swaps. I am not aware of any theory or practice of energy risk management that includes a dimension for “cost minimization”, beyond the *de minimus* consideration of transaction costs.

2. PACIFICORP’S PRACTICES IN RELATION TO INDUSTRY NORMS

Q. Are you familiar with the Company’s hedging policy?

A. Yes. On several occasions over the past few years, I have reviewed the Company’s risk policy and various monitoring reports that have been provided to me by the Company. I have also spoken to employees responsible for managing, measuring and monitoring the Company’s risks. I am also familiar with risk management practices commonly used in the utility industry, as well as the mathematical tools and financial instruments available for energy market hedging.

Q. What are the main components of the Company’s hedging program?

A. The main components of the Company’s current risk activities that serve to reduce customer exposure to fuel and power price volatility are To-Expiry Value at Risk (TEVaR) and Value at Risk (VaR) measurements. The VaR and TEVaR are widely used risk measures that quantify the financial risk within the Company’s supply portfolio. Both the VaR and the TEVaR measures are statistical measures of potential losses. While the VaR measures the amount the Company could lose on its gas portfolio over a short period, the TEVaR measures the statistical exposure of net combined natural gas and power open positions over long periods within the time to expiry (such as whole future delivery years). These risks are simulated using sophisticated financial and operational models that are updated and re-evaluated daily for the entire supply portfolio. The

Company also has set upper and lower VaR and TEVaR limits to keep future costs from being uncontrolled outside of reasonable bounds, as outlined in the Company's risk policy and procedures.

These limits and targets force the Company to closely monitor the open positions it holds in power and natural gas on behalf of its customers (which it does on a daily basis) and to limit the risk exposure resulting from these open positions for prescribed time frames in order to dampen customer exposure to price volatility. Specifically, the TEVaR metric automatically results in a reduced hedge requirement as commodity price volatility decreases, and it requires an increase in hedged volumes as volatility increases or as correlations among commodities diverge. Prior to May 2010, the Company had volume-based hedging targets. These can also be effective, but they are less responsive to shifting market conditions than using TEVaR. As a result of the Utah hedging collaborative workshops in 2011, the Company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy in May 2012. Company witness Mr. Dickman discusses the actual positions held by the Company.

Q. Did the Company's hedging portfolio use appropriate instruments and was it adequately diversified?

A. Yes. The Company relies predominantly on swaps for delivery over a few months to a few years ahead. Compared to options or fixed price physicals, swaps are often more heavily traded (more liquid) and are available over longer horizons (tenor), making them the most useful means of insuring against price fluctuations.

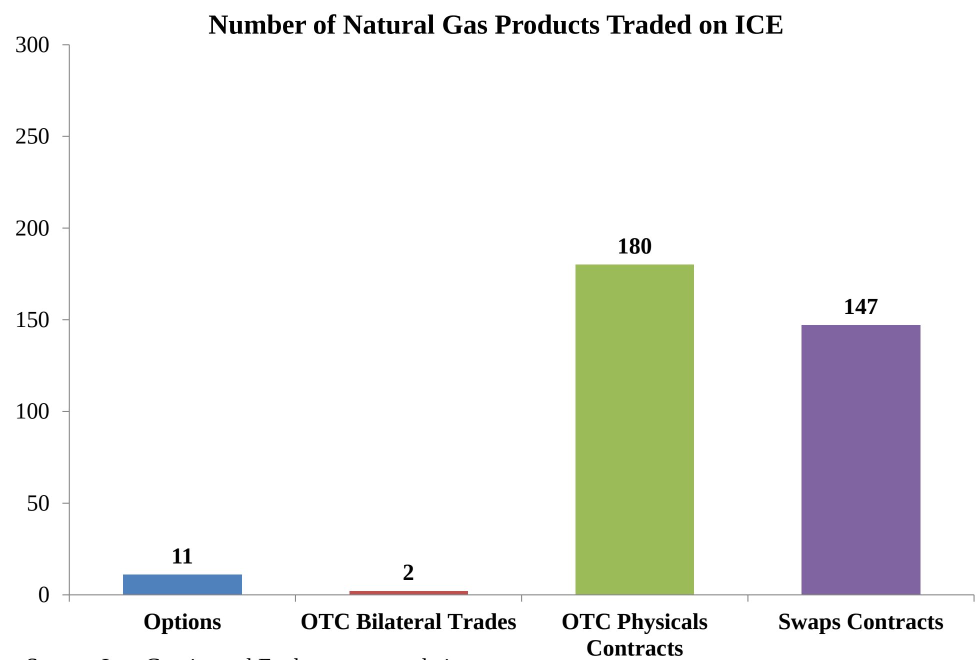
In other words, swaps are often the least-cost and most powerful method (in the sense of minimizing transaction costs, not delivered energy costs) that can reduce customers' exposure to price volatility. At least as important is the fact that swaps are available at more locations and for a longer time horizon than most other instruments.

In terms of diversity, the Company uses many different counterparties for these swaps, thereby diversifying credit risk, and it has entered swaps with prices tied to a few different delivery point indices, consistent with the physical span of their system. It also holds hedges of different contract lengths ("tenors"), in part as a result of its customary practice (widely used throughout the electric and gas utility industries) of generally purchasing hedges in installments on a regular basis (often referred to as "dollar cost averaging", in reference to the similar practice recommended for making personal investments over time). This practice and its benefits are described in the testimony of Mr. Bird. Beyond this kind of temporal, geographic, and counterparty diversity, there is little need and no basis for diversifying into a broader range of hedging instruments. Many (e.g. options) will be less liquid than the swap products predominantly used and would be useful only if there was *a priori* agreement to pursue a different shape of potential cost distributions.

Q. Do you have any evidence for the magnitude of utilities' use of swaps vs. other types of hedges?

A. Yes. ICE (InterContinental Exchange) provides data on the number of types of swaps, options, as well as physical trade products available on the exchange.

Figure FCG - 1 below shows the number of swaps, options, physicals, and bilateral contracts that are traded on ICE. There were 147 different types of gas swaps and only 11 gas options, which indicates that swaps are much more common than options. These differentiated products are mostly for gas delivered at different locations ("basis" swaps).



Source: InterContinental Exchange, www.theice.com.

Figure FCG - 1

Another indication of the predominance of swaps over other instruments is that volumes are publicly reported on the difference in price between natural gas at different locations (basis, e.g., from Henry Hub to Rock Opal) only for swap contracts. There are no volumes reported for traded options or other financial instruments (other than swaps) for gas basis prices.[3]

[3] Bloomberg and Ventyx Energy Velocity.

Q. Have you reviewed evidence that the Company's risk management policies were followed and were successful in constraining risk to desired levels up to and throughout the EBA cost period?

A. Yes, and witness Mr. Bird presents a discussion and summary of actual risk metrics in 2008-2012 for the Company in his testimony demonstrating this success. He shows that the hedged percentage of gas needs has been steadily in the range of 50 to 80 percent, as agreed to in the Collaborative, and his Figure SAB-2 shows that the Company's procurement practices kept the VaR and TEVaR over time within the target bands for the entire period. Moreover, the volume of hedging (by tenor) also shown on that graphic indicate that the procured hedges declined over time as prices and risks fell (while still keeping VaR and TEVaR within limits) because less and less forward commitment was needed to keep the portfolio risk range within target zones. This is exactly the kind of risk control results and practices that should be desired by the Commission, and it is also the right kind of information to be reviewing to decide if the Company's hedged positions were prudent.

Q. Please summarize why *ex post* comparisons of costs from hedging vs. not hedging are not useful for prudency evaluations.

A. Since the purpose of hedging cannot be to reduce expected costs, it is not reasonable to review or criticize hedges for whether they ended up being attractive compared to the cost unhedged supplies would have had. This is a fallacy which basically involves criticizing the Company for not beating the market – a behavior it should not have even attempted to do. It is also not plausible that had the next best alternative to what the Company actually hedged would have been to do no hedging whatsoever. But this is the comparison that is often made by hindsight analysts.

It is also inequitable and inconsistent to make such hindsight criticisms and to suggest cost disallowances based on unfortunate outcomes, unless the advocates of such an approach would also be prepared to symmetrically praise the Company for making favorable hedges and would encourage allowing it to keep a significant portion of the in-the-money savings – i.e. *to raise rates up towards what they would have been without the successful hedges.* I am very doubtful that this will be the position of any opposing parties in this proceeding, but that is the logical corollary of any proposed disallowances of out-of-the money hedges.

Q. In summary, what are your opinions about the Company's hedging practices and policies compared to industry norms?

A. The Company's risk policies, analytic methods, and controls are sophisticated, well-developed, and aptly suited to monitoring and managing natural gas and power cost risks over time. The Company has in place an advanced platform for estimating and reporting the mark-to-market value of, and risk metrics pertaining to, its electric and natural gas portfolios. These metrics are reported and reviewed on a routine, timely basis, and the Company is required to resolve movements in its portfolio beyond established risk limits. The hedging policies have been carefully and repeatedly explained to interveners and the Division, the Office, Commission Staff, and there are substantial documents reporting on hedging activities and results that are informative and consistent. In my judgment, the Company's policies stand up well under such comparisons.

3. THE NATURAL GAS MARKET IN 2007-2011

Q. What are the basic causes of the large drop in gas and power prices over the past 3-4 years?

A. These dramatic reductions are mostly due to two dramatic changes that were both larger and more sudden than expected: the development of shale gas and the credit crisis/recession. I have followed the innovations in horizontal drilling, fracking, and shale gas development fairly closely over the past few years, as it is a key factor in forecasting and planning future needs and preferred resources of the energy industry. This development occurred much faster and had more impact than was generally foreseen. For instance, it was fostered and deepened by some contracting practices (foreign joint ventures) and leasehold development obligations that were not immediately apparent to market observers and industry analysts. Because gas is often the fuel on the margin in power markets, it has also caused wholesale power prices to fall relative to the levels expected in the mid-2000s. In parallel, demand for power and gas both declined due to the financial crisis and resulting Great Recession – in some cases taking a year or two of demand growth out of the energy market. The crisis and resulting recession was not anticipated to be as deep or as long lasting as it has proven to be so far.

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

A. In the middle of the past decade, e.g. around 2005, there was widespread belief that the U.S. was running out of gas and that imported, liquefied natural gas

(LNG) was going to be essential and costly as our long term solution.[4] In that context, when Hurricanes Katrina and Rita hit the southeast in late summer of 2005, the forward prices of natural gas shot up to unprecedented levels, not just over the time frame it would take to repair the damaged infrastructure, but for a few years going forward. Gas prices fell somewhat throughout late 2006 and early 2007, but shortly thereafter they were rising again to very high levels, in conjunction with very high oil prices.[5]

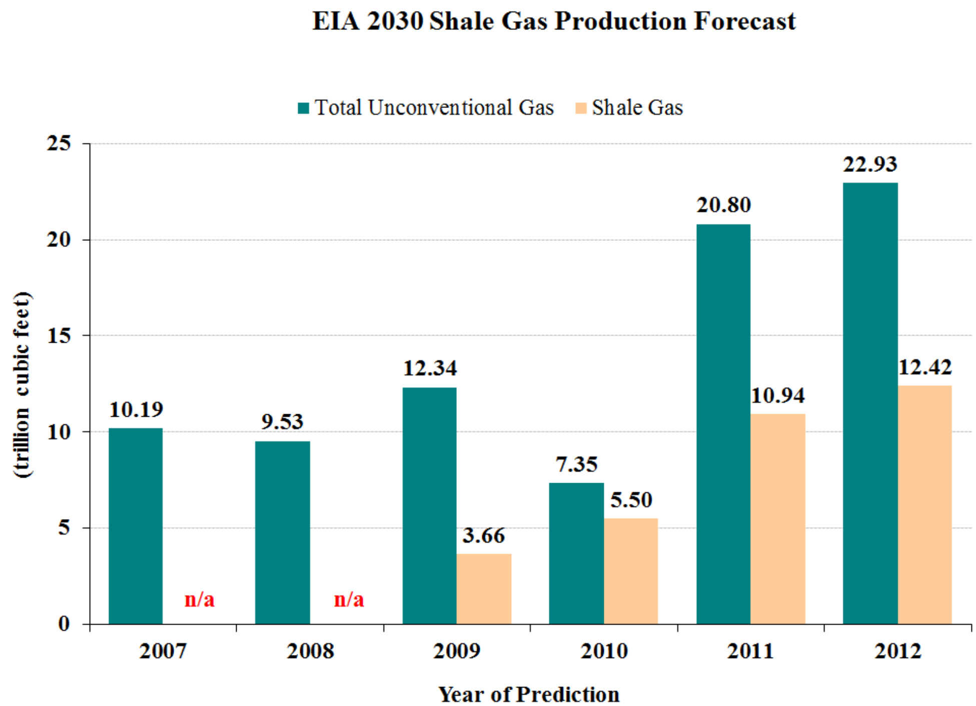
These high prices of gas drove a wave of technology development and exploration for shale gas with horizontal drilling and fracturing (or “fracking”), which proved to be extremely successful -- to the point where we now appear to have many decades of likely reserves from shale and other nonconventional gas supplies, possibly at $4-6/MMBtu in real or even nominal terms for many years ahead. (The current futures prices at Henry Hub are below $5/MMBtu through 2017.) However, there was considerable debate (and some persists to the present) over what the true cost of shale gas development was, as some developers were reporting success at $3-4/MMBtu while some engineering studies were asserting costs in the $9-10/MMBtu range or higher. Many analysts also felt that the rapid pace of development was uneconomical at prevailing gas prices. This could well have been the case, because a lot of the development occurred in order to retain leasehold rights to shale gas properties, or to satisfy joint venture financial commitments with foreign development partners, rather than for the intrinsic

[4] See, for example, the Energy Information Administration’s *Annual Energy Outlook 2008* (issued June 2008) p. 10.
[5] The Annual Energy Outlook 2008 uses a base natural gas price of $6.90 / MMBtu for 2010 (p. 158).

value of the gas. Also, by around 2011, natural gas became essentially a free byproduct of fracking in regions that had “wet gas” or hydrocarbon liquids in conjunction with the methane. Almost all of these downward pressures on prices were not widely foreseen nor understood for a while (e.g. until around 2010 or so).

One indication of this delayed appreciation for the shale revolution can be seen in the history of forecasted shale gas production. Figure FCG - 2 below shows the U.S. Department of Energy Information Administration’s (EIA’s) forecast in recent years for shale gas production, as well as for all unconventional gas. In the 2007 - 2008 period, when the Company entered most of its hedges, EIA had no forecast reflecting shale gas as a distinct component of unconventional gas. Amazingly, the actual U.S. shale gas production in 2011 was about 8.5 trillion cubic feet (Tcf),[6] more than 50 percent above the EIA forecast of 5.5 Tcf in 2010 for 2030! The EIA 2011 Annual Energy Outlook notes that the shale gas production accelerated dramatically after 2006 with an annual growth of 48 percent from 2006 to 2010. This is virtually unprecedented and was obviously very difficult to foresee.

[6] Energy Information Agency, “US Natural Gross Withdrawals from Shale Gas,” February 28, 2013.



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

Figure FCG - 2

As shale gas emerged, the EIA price forecasts for gas were also much higher than the realized spot prices in 2012. For instance, in 2007, the EIA's Reference Case forecasted a 2012 Henry Hub spot gas price of approximately $5.66 / MMBtu (in 2005 dollars), while actual spot prices turned out to be in the $2.00-$3.00 range from most of that year. In 2008 EIA's forecasted price per MMBtu had increased to $6.13, despite starting to recognize the presence of shale gas in the supply mix.[7]

[7] Energy Information Agency, "Annual Energy Outlook 2007," Table 14 and "Annual Energy Outlook 2008," Table 14.

Q. How did the commodity markets reflect the increasing impacts of shale gas on forward prices?

A. There is no evidence that the market was at any time over the past several years expecting a shale gas revolution that would continue to drive down prices. Figure FCG – 3 below depicts the forward prices of gas trading at Henry Hub over the period RMP entered into the 2012 hedges at several illustrative dates from October 2007 to September 2011. The figure also shows the realized spot prices (for delivery month) for the period 2005 through today (as the bold black curve, while forward strips are in color). Every forward curve starts at the then-current spot price <u>and rises thereafter</u>. In effect, after every spot price decline, market traders believed that the decline was over and that the future would have higher prices. The forward curves shift dramatically downward, but despite being repositioned in this manner, the forward curve has been at all times increasing. This means that the dramatic drop in gas supply prices was not expected.

Forward Curves at Henry Hub and Realized Natural Gas Prices

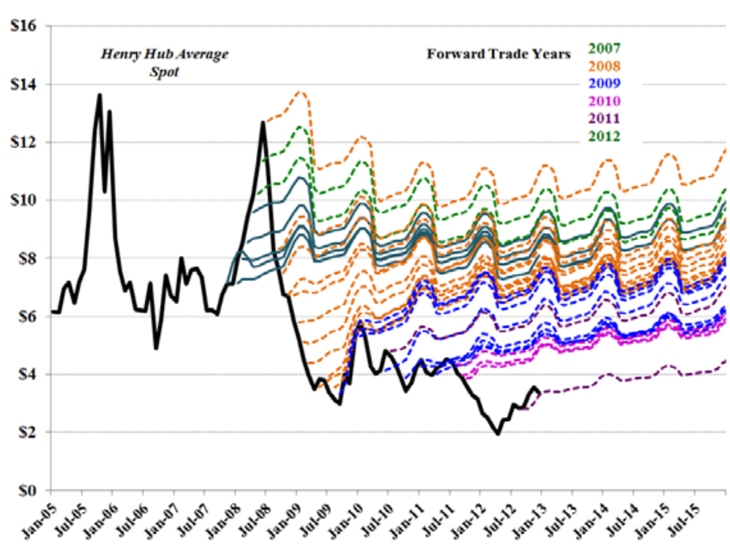
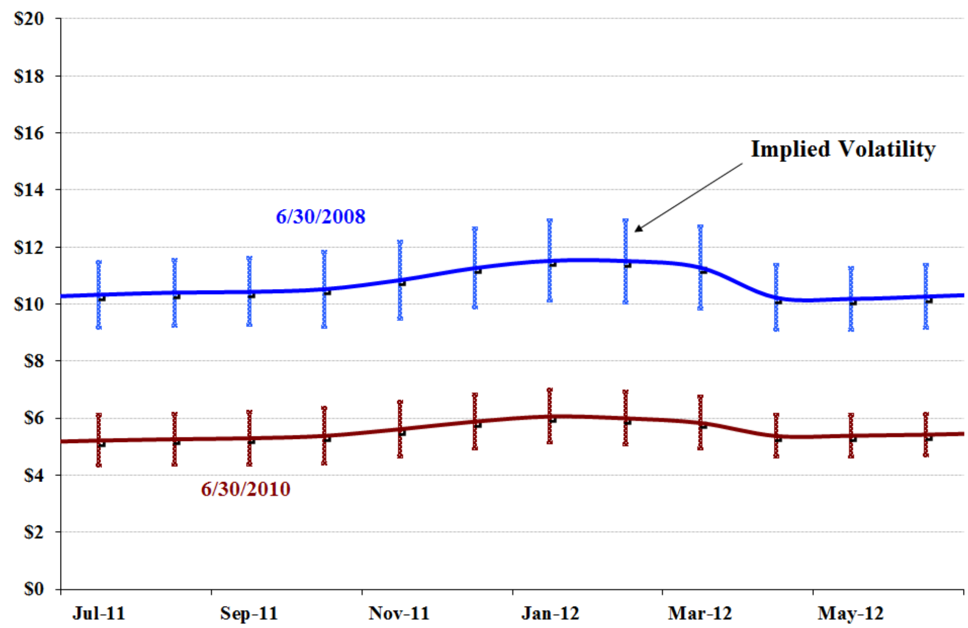


Figure FCG - 3

To further illustrate the disparity in perceived market conditions at the beginning and end of RMP’s hedge procurement period, I looked to the forward curves for mid-2008 and mid-2010 and compared the level of those curves to their implied volatilities, i.e., to the range of uncertainty that was associated with their future possible changes in prices for the 2011/2012 delivery period. Looking at data from Henry Hub, Figure FCG - 4 below shows the absolute value of the forward price as well as vertical bars around the prevailing forward prices in 2008 and 2011, which reflect the expected annualized volatility (plus or minus one standard deviation) in monthly delivered gas prices at the time these forward prices were in effect. What this shows is that there is no overlap of these one-deviation uncertainty bands around the 2008 prices with the corresponding levels or uncertainty bands for gas in mid-2010. In fact, several standard deviations below the 2008 forwards would have been needed to reach the range of spot prices that actually have prevailed in this 2011/12 delivery period. Thus, the market was not anticipating even a range of risk for what has turned out to happen.

Forward Henry Hub Price Curves and Volatilities



Source: Bloomberg.

Figure FCG - 4

Q. Did natural gas prices and volatility move in the same direction, i.e., generally downward, throughout the 2007-2009 time frame, when many of the more expensive gas hedges were procured?

A. No. Even as spot and forward prices continued to fall throughout the 2008-09 period, the expected future volatility in gas prices was high and even continued to rise through late 2009. This is evident from looking at the volatility quotes of the natural gas prices at Henry Hub during the period. The derived volatilities are derived from (or implied by) a standard financial model, usually based on the Black-Scholes option model for pricing options on gas futures. [8] The implied

[8] The Black-Scholes formula is a widely used mathematical (and equilibrium economic) relationship between the forward price of a security or commodity like natural gas, the current spot price, time to delivery, and the volatility of the price.

volatility is expressed as the annualized standard deviation of prices and it is a measure of how far from its expected, forward value the gas prices could become by the time the option to purchase natural gas at a predetermined price has to be exercised (i.e. by the forward delivery date). The larger the volatility, the higher the option prices will be and vice versa. Thus, if we know the forward price of natural gas and the prices of the options for the same time and place of delivery, we can infer the expected volatility.

Q. Can you provide a chart of the volatilities at Henry Hub during the period?

A. Yes. Each month, volatilities are quoted as a percentage price uncertainty for each future month thereafter (typically looking ahead out about one - two years), where each value represents the standard deviation of how much that month's forward price currently tends to change per day in percentage (scaled up to an annualized equivalent value). There is a different percentage for each forward month, and the overall pattern of these monthly percentages is called the volatility term structure. The typical volatility term structure declines as the time to delivery increases, so that the short-term volatility is larger than the long-term (far out) volatility. This pattern is observed because short term risk factors (such as weather) often do not have much influence on long term expectations or risks. In addition, the term structure of volatility typically exhibits seasonal effects. Figure FCG - 5 below shows the implied volatilities for natural gas prices at Henry Hub at a few dates several months apart in the period October 2007 through September 2011.[9]

[9] Data from Bloomberg.

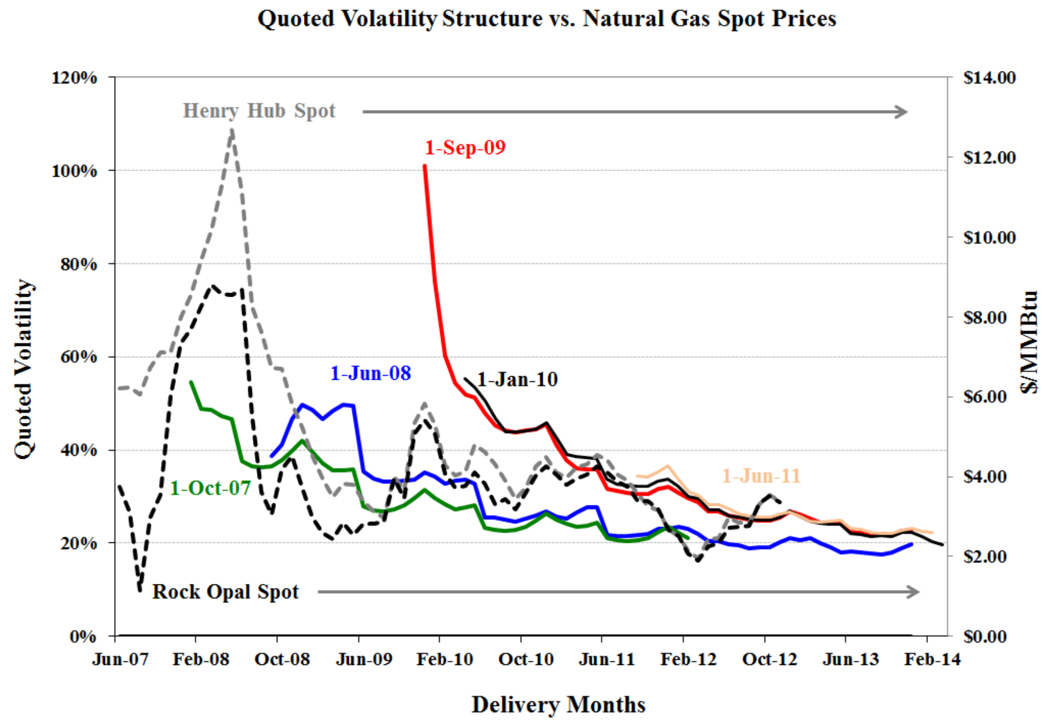


Figure FCG - 5

It is clear from the figure above that both the near term and longer-term volatility rose through late 2009. The near-term volatility is represented by the height of the curves at the time of the quote while the longer-term volatility is indicated by the height of the curves out in time. The fact that these curves are rising through most of 2009 (and even by mid-2011 had not dropped back to 2007 and 2008 levels for corresponding delivery months) indicates that the risk indicators were still strong, despite falling spot prices for gas. This pattern would have influenced the Company's VaR and TEVaR measures in the same general manner, suggesting that a high volume of hedging was necessary.

Q. What are the implications of the above for the Company's hedging policy?

A. Not only could the Company not have foreseen the sharp decline in natural gas prices in 2007-2010 (and beyond), the Company (and other participating in the market) would have been seeing risk signals for the first two years of this time frame indicating that volatility remained high, so that hedging was essential in order to maintain VaR and TEVaR within target ranges. (See Figure SAB-2 of Company witness Mr. Bird's testimony and the surrounding text for specific metrics during this time period.)

4. EARLY LIQUIDATION OF PART OF THE PORTFOLIO IS NOT INDUSTRY STANDARD

Q. Please explain what it means for a hedge to be "in the money" versus "out of the money".

A. In finance, a hedge position to buy natural gas is "in the money" if the prevailing forward price today is higher than the price underlying the hedge position (i.e., the price the hedge will guarantee). Such a hedge saves the buyer money compared to buying at spot. On the other hand, a hedge is out of the money if today's forward natural gas price is lower than the price guaranteed by the hedge. The present value of the difference in price between the current forwards and the hedge price, in each future month, times the corresponding hedged volume(s), is the dollar value of the in or out of the money position. In the delivery month itself, this calculation is performed against the spot price and becomes the gain or loss on that month's hedges.

Q. Even if the above market trends in gas supply and pricing were not foreseen, they were of course observed by the Company as they happened. If a utility realizes that its hedges no longer are in the money, couldn't it simply liquidate these hedges?

A. It could, but utilities rarely do so, because only in hindsight could the Company know what the eventual spot prices will be and whether it thereafter should go unhedged. Once a utility has set its hedging goals based on risk metrics and begins covering those needs, it rarely if ever reverses prior positions. This is because there is no expected economic benefit from liquidating (short of learning that the needed volumes have also declined, e.g. if other fuels or technologies should unexpectedly reduce the attractiveness of using gas plants as much as originally hedged). The only way to get out of a contract is to sell it at prevailing market forward prices - which are the same set of prices the utility then expects to face for replacing that supply of fuel or power going forward. Assuming there is still a future need for just as much fuel or power, there is no expected savings from marking to market and then buying at market thereafter. In fact, for the Company (and many utilities with gas-fired generation in their supply mix), a reduction in forward gas prices tends to cause its future demand for gas supply to increase, because gas-fired generation then becomes more likely to be attractive to dispatch. Thus there is no reason for a utility to unwind gas hedges as prices fall. Replacing them would simply involve incurring the bid-ask spread needlessly.

Q. What if the Company had simply liquidated and decided to go without hedges from some point onward?

A. Even if the Company had considered going without hedges at some point in the past, it would and should have then expected that this strategy would thereafter cost what the forward curve was saying the future gas commodity was worth. There is no difference in the expected future supply costs regardless of how the liquidated contracts are replaced. Moreover, if the Company had chosen to abandon hedging because it believed prices would be below the forward curve, this would have been speculation – betting against the market. This would have violated the Company's strict and appropriate risk policies in two ways which would have been genuinely imprudent: First, it would have involved decisions against its own risk metrics, likely driving the probability of significant losses to levels that were much higher than what the Company's policy and prudence would dictate as a maximum.[10] Second, it would have been speculation, which is appropriately barred in every utility hedging policy in the country, and which in general can only pay off by luck.

5. NATURAL GAS AND ELECTRIC HEDGE POSITIONS SHOULD NOT BE EVALUATED SEPARATELY

Q. Is there a natural connection between gas and electricity hedging?

A. Yes, the two activities are intrinsically and predictably related to each other, and the market prices of wholesale gas and electricity are reliably positively correlated. This makes it far more efficient to evaluate them (and manage their risks) jointly,

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[10] Technically, the Company's Value at Risk (VaR) or To-Expiration Value at Risk (TEVaR) metrics likely would have been too high to be acceptable.

focusing on the net power cost rather than the components separately. Power and gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch for the Company's generation system and throughout much of the WECC. As a result, wholesale power and gas prices are fairly highly correlated. This co-movement relationship between electric and natural gas prices is shown in Figure FCG - 6 below, which depicts the monthly average electricity spot price for Palo Verde (on and off-peak ($/MWh), and the Rock Opal natural gas price.

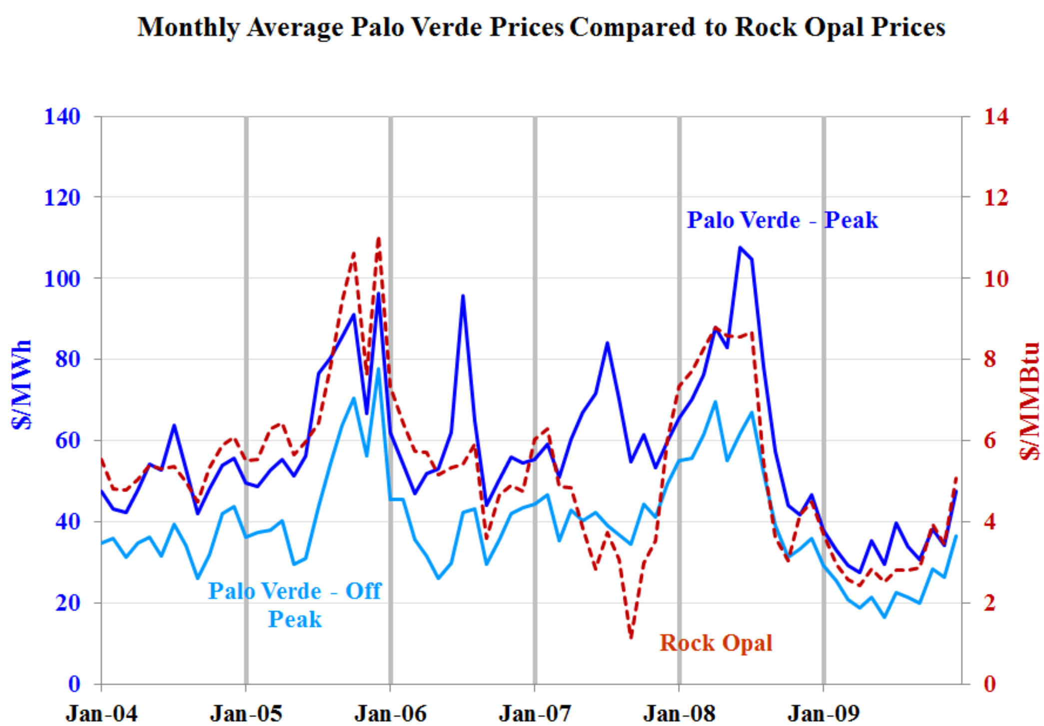

Figure FCG - 6

Q. Even if these two are correlated, is there anything wrong with separating two related cash flows and hedging or managing them separately?

A. The simplest answer is that it would involve needless and costly administration for no net benefit. Imagine that you were managing a company with risky revenues e.g., sales denominated in a foreign currency that you would have to repatriate, but that your costs were also denominated in that same currency and were highly correlated with the sales. Hypothetically, assume that the net margin between them is fixed. Each flow could be hedged separately, e.g., selling your expected revenues forward at the foreign exchange (FX) future prices, and buying your expected costs forward at the same FX rates (though this might be difficult if the size of each was highly uncertain). Then each would be fixed and the difference between them would be a fixed amount as well, but that is already the situation before the hedging begins, due to the assumed perfect correlation between the two. Under the philosophy of managing the two risks separately, you would have hedged many times the needed volume, with associated accounting and credit risks, when only the net amount (already quite safe and much easier to predict) needed repatriation hedging.

While not perfectly analogous, this situation is quite similar to the spark spread relationship between PacifiCorp's fuel cost (gas) and electric revenues, as a result of which it typically enjoys an offset to any gas purchase losses from gains in its electric sales' position (or vice versa). This is not a coincidental result. Rather, it intrinsically occurs in power markets for companies with a mix of generation assets like PacifiCorp's. PacifiCorp tends to be "long" on electricity and "short" on gas, as well as somewhat long on energy and short on capacity. That is, it has low cost, base load capacity that is more than it needs in off-peak periods, so it can sell some slack output profitably into the wholesale market. If gas prices fall after it has already sold electricity forward and covered the needed supply with forward gas, it tends to lose money on the gas supply but make money on the power sale.

The potential gains versus losses on power and gas are not one for one, because they depend on whether forward prices for power fall more or less than the corresponding gas prices (as well as on how similarly the positions were hedged in timing and duration, what other types of power plants are supporting the offsystem sales, and other factors). However, this effect is still quite predictable, so it can be (and is) incorporated explicitly into the risk management practices of the Company. If market conditions change (e.g., the net long electric vs. net short gas needs, or the correlations or volatilities of the two commodities), the Company changes its incremental hedging practices. Thus, these are more like two sides of the same coin for utility operations. It is not meaningful to criticize gas performance by itself, as the electric performance would not be feasible (or the same) without the gas situation, and vice versa.

Q. Would there be any disincentives associated with separating natural gas and electric hedging performance for regulatory reviews?

A. Yes. There is a very serious regulatory economics problem which would arise if natural gas and electric hedges were considered separately: Because the gas and electric positions of PacifiCorp intrinsically move opposite to each other, it is inevitable that one or the other will be yielding savings while the other is incurring a cost. This means that it will always be possible for someone to come into <u>any and every</u> RMP rate case and say that regulatory review should just focus on disallowing some of the “badly performing” side of the business and ignore the savings or offsets from the other side. This opportunity would present itself all the time, regardless of whether PacifiCorp hedged either side of its gas or electric operation! Thus, an approach that separates natural gas and electric hedges would put PacifiCorp in an untenable situation of having no possible strategy that would not have purportedly unreasonable costs. This is clearly untenable, inefficient and unfair.

Q. Does the Company jointly manage its gas and electric risks?

A. Yes, it keeps track of the net effect of gas and electricity in its TEVaR metric that it has been using since May 2010.[11] Prior to that, it had separate hedging targets and limits for each, but those were jointly developed based on power simulation models that predicted both related needs simultaneously.

Because of this practice, as well as the intrinsic linkage between the two components and the adverse implications of separating them in regulatory review, the prudence review of the Company’s EBA costs should be based on its success in managing their joint risk, and on the Company’s consistency in adherence to its risk control protocols. It should not be based on a review of the hindsight extent to which either gas or electric hedges by themselves turned out to be out of the money.

Q. Does this conclude your direct testimony?

A. Yes.

[11] Since May 2012 the Company has also maintained its hedging percentage in the 50-80 percentage range.