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BEFORE THE UTAH PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN UTAH AND FOR APPROVAL OF ITS PROPOSED ELECTRIC SERVICE SCHEDULES AND ELECTRIC SERVICE REGULATIONS	))))))	DPU EXHIBIT 11.0 D-RR DOCKET NO. 10-035-124 NET POWER COST - HEDGING

Pre-filed Direct Testimony

of

Douglas D. Wheelwright

on Behalf of

Utah Division of Public Utilities

May 26, 2011

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

A: My name is Douglas D. Wheelwright. I am a Utility Analyst in the Division of Public Utilities ("Division"). My business address is 160 East 300 South, Salt Lake City, Utah 84114.

Q: On whose behalf are you testifying?

A: I am testifying on the Division's behalf.

Q: Please describe your position and duties with the Division.

A: I research, analyze, document, and establish regulatory positions on a variety of regulatory matters. I review operations reports and evaluate compliance with the laws and regulations. I provide testimony in hearings before the Utah Public Service Commission ("Commission"); and assist in the analysis of testimony and case preparation.

Q: What is the purpose of your testimony?

A: The Division believes that PacifiCorp's (" Company") current hedging practices have created significant additional expense to the projected total net power cost. The current hedging program does not provide enough flexibility and the Company has not recognized the internal and external changes in market conditions. My testimony will be in support of the Division's consultant, Mark Crisp who has looked specifically at what other utilities and commissions throughout the country are doing with their hedging programs.

Q: Can you summarize the Division's position on the current hedging practices and provide recommendations to the Commission?

A: The Division has reviewed the information provided by the Company and by the Division consultant and has determined that the Company should assume a portion of the additional costs associated with the swap contracts and should not be allowed to recover the full amount requested. The Company has not been able to demonstrate that the current hedging policies and practices provide the appropriate balance of risk to both the Company and ratepayers. The existing hedging strategy has been designed for price stability and does not adequately consider the potential cost impact. The current program creates additional cost to ratepayers and does not provide a mechanism to allow for possible cost reductions that could potentially benefit both the Company and ratepayers. Using financial swap transactions to hedge up to [redacted] of the price volatility does not provide enough flexibility to allow for changing load requirements or changes in market conditions. The program creates price stability for rate making purposes but reduces the incentive for the Company to look for possible cost savings opportunities. It is the position of the Division that the Company has not been prudent and should not be allowed to recover the full amount identified as swap costs. The Division is proposing a disallowance on swaps included in net power costs of $57,948,207 in a system-wide basis with $25,051,494 allocated to Utah.

Q: Will you identify the Division's concerns?

A: Several issues related to hedging have been addressed by various parties in previous rate cases,[1] in the EBA docket,[2] and in a separate docket created to address natural gas price risk and hedging practices.[3] In previous testimony, the Division and other parties have provided evidence and made recommendations to modify the Company's current program and have asked the Commission to establish standards or guidelines and create a review process.

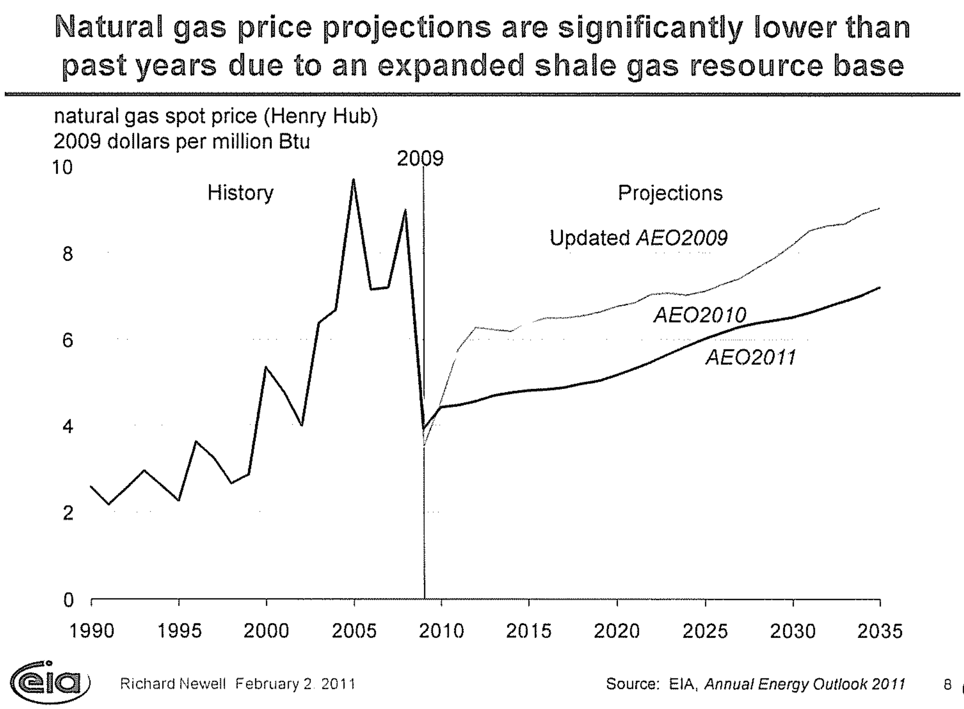
In the recent EBA order, the Commission indicated it would not establish standards or targets, or set limits on the components of net power cost. The order further states that an appropriate venue to look at the inclusion or disallowance of costs associated with financial hedges is in a general rate case.[4]

The current practice of using financial swaps to hedge the future natural gas price is designed for an environment of increasing natural gas prices. With the increase in the availability of natural gas due to increased shale gas production, the price of natural gas

[1] Docket No. 09-035-23.
[2] Docket No. 09-035-15.
[3] Docket No. 09-035-21.
[4] Docket No. 09-035-15 ECAM Order p.72.

has come down and is projected to remain near the current levels for some time.[5] Chart 1 below is from the 2011 EIA Annual Energy Outlook and provides a forecast for natural gas through 2035. This chart compares the natural gas forecast for the last three years and indicates that the 2011 projections have come down from 2010 and 2009 forecasts.

Chart 1



[6]

This assessment of the current market forecast is in agreement with the forward price curve provided by the Company in this docket.[7] While the external market conditions have changed there has been no change to the current hedging strategy.

In addition to the external changes, there have been significant internal changes in the amount of the Company's excess power available for wholesale sales. In previous testimony and in the 2011 IRP document,[8] the Company has indicated that the value of the natural gas and electric swaps historically moved in opposite directions. In the two

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[5] EIA Annual Energy Outlook 2011.
[6] EIA - The Long Term Energy Outlook for Natural Gas, Richard G. Newell, February 2, 2011.
[7] UIEC Data Request 6.23.
[8] PacifiCorp 2011 IRP Appendix G Docket No. 11-2035-01 p 170.

previous years, gains in long term wholesale electric sales have offset some or all of the loss in the gas swap contracts. With the increase in the domestic load requirements and expiring long term purchase contracts, the Company has identified a reduction in the amount of electric sales available. The current hedging program assumes that the Company will continue the same level of electric sales and that the internal price hedge between gas and electric will continue. In Mr. Gregory Duvall's direct testimony he identifies the three primary drivers for the increase in net power cost as increases in load growth and coal costs, and decreases in sales revenue.[9] These internal changes, along with the external market changes should have prompted a review of the current hedging strategy.

Q: Has the Company indicated that it intends to maintain the current hedging strategy?

A: In DPU data request 20.19, the Division asked if the abundance of shale natural gas and the projected price would have an impact on the current hedging strategy. The Company responded as follows:

> The Company does not anticipate any change in hedge strategy based on current price projections. While the current forward price curve indicates projections of stable price in future years, history has proven that this can change radically. The Company anticipates maintaining a hedging strategy that manages the impact of changing natural gas prices on net power costs within acceptable tolerances as defined by current risk management policy and practices in the current front office procedures and practices.[10]

In DPU data request 20.20, the Division asked if the projected reduction in the amount of electric sales would have an impact on the current hedging strategy. The Company responded as follows:

> The Company does not anticipate any changes to its hedge strategy as a result of a shorter open electricity position, (i.e., the Company anticipates no change to the hedge targets measured as a percentage of the weighted net power costs nor to the to-expiry value-at-risk methodology).[11]

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[9] Direct Testimony of Gregory N. Duvall, p. 3, Line 54.
[10] DPU Data Request 20.19.
[11] DPU Data Request 20.20.

Q. Has the Company demonstrated that hedging in future years provides the best protection from volatility?

A. There has been no information presented to indicate that the current level of hedging has been determined to provide the best protection for the Company or for ratepayers. Securing up to [redacted] of the future gas price has been established to reduce the fluctuation in net power cost for the test period that will likely be used in the next rate case.

Q. Has the Company demonstrated that the current hedging program will result in the least cost to the Company and to ratepayers?

A. The Company has stated in testimony and in response to data requests that the current strategy will not result in the lowest cost and that the program should be cost effective with the net result expected to have no cost impact. Appendix G of the 2011 IRP identifies the current hedging strategy and states the following:

> Hedging does not modify the expected outcome of net power costs associated with wholesale market price and natural gas price changes. Consequently, the long-term gains and losses from hedging are expected to net to zero. As shown in Figure G.1 above, the Company's hedging costs are not material enough to warrant adjustment to resource costs or influence portfolio selection.
>
> In regard to assessment of hedging strategies, a hedging strategy should be tailored to fall within a designated risk tolerance and conform to Company financial and administrative capabilities. A rationale must be created taking into account risk tolerance for adverse impacts to net power costs, and effects including market liquidity and hedge product availability, credit risk, and costs such as collateral funding for margining.
>
> Finally, PacifiCorp shows that there is no objective measurement to indicate the optimum amount of hedging, as demonstrated by a sensitivity analysis that compares a reference portfolio, a less hedged portfolio, and a more hedged portfolio. Nevertheless, the analysis shows that hedging should take full advantage of any natural offsets between long power and short natural gas positions. Not taking advantage results in high risk (a wider distribution of outcomes) as indicated in the "hedge only power" and "hedge only natural gas" portfolios. [12]

[12] 2011 PacifiCorp IRP – Volume 2, Appendix G – Hedging Strategy p.169.

While this may be the Company's goal, the projected cost of the hedging program is adding to the total Net Power Cost (NPC). Cost minimization does not appear to be a consideration in the current program.

Q: What does the Company identify that should be included in the total hedging program?

A: This is where the confusion begins. As a broad definition of hedging, the Company includes financial swaps for electric and gas along with the physical transactions for both gas and electric. For the test year the Company has identified the value of the natural gas and electric swap transactions in the UT GRC June 2012 (GOLD) report. The gas and electric swap transactions are the primary focus of my analysis.

Q: How does the price volatility of natural gas affect the Company?

A: PacifiCorp natural gas-fired generating facilities account for 21% of the total net owned generating capacity but only 12% of the total energy. In determining whether to dispatch its natural gas-fired facilities, PacifiCorp considers, among other factors, its operating requirements to balance electricity supply and demand and the current spark spread. Spark spread is the difference between the wholesale market price of electricity at any given hour and the cost to convert natural gas to electricity.[13] The decision to dispatch the natural gas facilities is affected by the volatility of the price of natural gas. A change in the forward price curve will change the spark spread and the decision to dispatch a natural gas facility or purchase electricity.

Q: What is the impact of swap transactions that are included in NPC?

A: In the UT GRC June 2012 (Gold) report, natural gas swaps add $160.7 million to NPC while the electric swaps reduce NPC by $61.7 for a net increase of $99.0 million. The majority of the increase occurs in the last six months of the test year and, thus, the impact of the swap transactions increases significantly in the last six months of the test period. As of December 31, 2011, the net of electric and gas swaps is $8,231,437.

Q: How does the forecast compare with the historical values for swaps?

[13] PacifiCorp, 2009 10-K Report, p. 10.

A: Table 1 below is a summary of the settled value of the natural gas and electric swaps transactions for 12 months ending June 2007 through June 2010.[14] The positive values identified as gas and electric swaps are expenses which add to the total fuel cost included in NPC. The negative value identified as electric swaps is revenue from the increased value of electric swaps which reduces NPC.

Table 1

[redacted]

The combination of gas and electric swap transactions system wide have added an average of [redacted] to NPC for the previous four years.

The cost of the natural gas swaps increased in 2009 due to the rapid decline in the price of natural gas. The difference between the spot market price and the existing long term contracts created the large mark-to-market adjustment in the value of the existing contracts. Due to the advanced purchase and the long term nature of the current natural gas hedging program, the Company and ratepayers have not been able to take advantage of the reductions in price of natural gas.

A large portion of the increase in NPC is due to the loss of the offset in electric sales. The Company has been aware for some time that a number of the electric sales contracts were expiring but did not consider the impact and modify the hedging program. Chart 2 below shows the historical and the forecast impact of swap transactions on NPC. Due to the long term nature of the natural gas hedging program, the gas cost included in rates has not come down with the changing market conditions.

[14] DPU Data Request 20.14.

Chart 2

[redacted]

Q. Have you been able to determine anything else about the current hedging program?

A. Yes. Based on the way the program is designed and the wide tolerance, there is only a remote possibility that the Company will ever be in an over-hedged position. The Company has indicated that if they were to become over-hedged they would not try to get out or unwind any of the transactions. The most likely outcome would be to wait and see if market conditions changed to return the program to the predetermined tolerance levels.

Appendix H of the PacifiCorp Energy Commercial and Trading Risk Management Policy specifies a stop loss limit; however the specific dollar amount of the loss limit is classified as highly confidential. Even with the volatile gas prices experienced in previous years, the Company since 2006 has not exceeded the dollar amount of the stop loss limit.[15] This would suggest that the limits are set too high to be effective in reducing potential

[15] DPU Data Request 20.9.

losses. The highly confidential nature of the hedging policies has been discussed by the Division's consultants and limits the ability of the Division and the Commission to review the hedging practices.

Q. Are there other factors that can have an impact on the hedging program?

A. Yes. The projected load forecasts can have an impact on the effectiveness of the hedging program. The supplemental testimony in the Energy Balancing Account (EBA) Docket, Company witness Frank C. Graves identified the following:

> When deciding how much to hedge, a utility relies heavily on forecasting (esp. of untraded factors that influence its total costs) to estimate how much fuel and power it will need to procure in future months and years. Forward gas prices are observable and can be locked in, but forward demands for retail power can only be estimated. Errors in forecasting and estimation can reduce the value of hedging and impose additional costs to a utility which might otherwise be fully hedged absent the load uncertainty.[16]

The importance of having accuracy in the projected load forecast was further emphasized by the Company in response to OCS Data Request 2.143 in the ECAM Docket.[17]

> Having the "right hedges" for the wrong load will impose costs and reduce the net value of hedging. Likewise, having the wrong hedges for the right load will also be costly. For instance, even if the load forecast is accurate, if correlations between different factors driving prices are estimated with error, the hedges may cover more or less risk than perceived.

Under the current program the Company will begin to purchase natural gas swap transactions up to [redacted] in advance with the goal of having [redacted] of the forecast gas requirement in place [redacted] in advance. This will secure a specific price but also commits the Company to a volume associated with the agreement. If the actual load is lower than anticipated or if the spark spread indicates that purchases are more economical than generation, the Company will have financial commitments that will need to be completed which could further increase the total cost of natural gas. Since

[16] 09-035-15 Frank C. Graves Supplemental ECAM Testimony, p. 39, Line 797.
[17] Docket No. 09-035-15 OCS Data Request 2.143.

the actual gas requirement will vary based on the actual load and current spark spread it would be more economical to leave a portion of the need open to spot market purchases. This would reduce the possibiltiy of excess purchases of both swap and physical transactions. The exact amount that should be left open will need to be reviewed in relationship to the historical fluctuation in the spark spread and actual volumes compared to forecast. The Company should provide this type of analysis to the Commission on a regular basis.

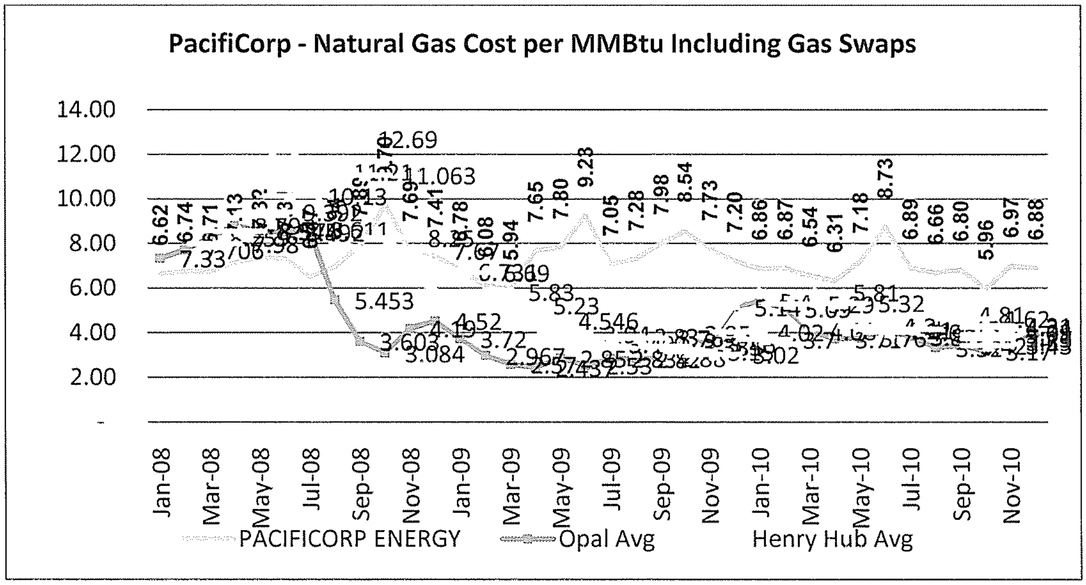
Another factor that has not been addressed by the Company is the additional cash collateral requirements that are generated as a result of a decline in the price of natural gas. When there is a significant difference between the contract price and the current market price, the Company may be required to make a cash collateral payment to the counterparty. While this does not increase the total cost, it does tie up cash that could be used for other purposes and could impact other management decisions. Additional collateral requirements on derivative contracts totaled $82 million in 2008, $25 million in 2009 and $127 million in 2010.[18]

Q: How does the price of natural gas consumed by PacifiCorp compare to the spot price?

A: While it is not a direct comparison to look at the unhedged spot price with the hedged position, it does provide a way to look at the discount or premium of the hedged portfolio. Chart 3 below is a summary of the actual cost per MMBtu including swap costs from January 2008 through December 2010. As identifed below, the Company was paying below market rates prior to September 2008 but has paid a premium since then.

[18] PacifiCorp 10K Report, December 31, 2010.

Chart 3



Q: Have you been able to calculate the total price for natural gas that is included in the test year?

A: In order to look at the impact of swaps on the total cost of natural gas I have calculated the total price of the gas including both the commodity and the swap costs. Table 2 below identifies the natural gas commodity portion at $4.85. This is consistent with the forward price projections of EIA and the forward price curve provide by the Company. In addition to the commodity cost, the swap cost adds $2.38 or an additional 31.2% for a total cost of $7.23 per MMBtu. Based on the long term price projection the price of natural gas, the spot price of natural gas will not be in the $7 range until 2035. The question for the Commission is should ratepayers be asked to pay 31.2% premium for rate stability or is that price too high?

Table 2

	Test Year Cost	Cost Per MMBtu	Percent of Total
Gas Fuel Burn	$ 328,543,939	$ 4.85	63.7%
Gas Physical	$ 69,552	$ 0.00	0.0%
Gas Swaps	$ 160,723,241	$ 2.38	31.2%
Gas Fuel Burn Expense	$ 489,336,732	**$ 7.23**	94.9%

Pipeline Reservation Fees	$ 26,451,016	$ 0.39	5.1%
TOTAL GAS FUEL BURN EXP	$ 515,787,748	$ 7.62	100.0%
Volume	67,672,662	MMBtu	

Chart 4 below is a breakdown of the the monthly forecast cost per MMBtu included in the rate case compared to the EIA and PacifiCorp forward price curve. This is similar to Chart 3 above and compares the forecast hedged price to the forecast spot market price. As stated above, while it is not a direct comparison to look at the unhedged spot price with the hedged position, it does provide a way to look at the discount or premium of the hedged portfolio. While commodity prices have come down the total cost to ratepayers remains well above the market with significant premiums in the last portion of the test year.

Chart 4

[redacted]

Q: How does the projected cost compare to the forward price curve and the probable price ranges?

A: DPU Exhibit 11.1 D-RR is an EIA projected Henry Hub price for natural gas through December 2012 along with the calculated lower and upper price range for the commodity. The months included in the test year have been highlighted with the averages calculations to the right of the test year months. Using this template I have calculated the anticipated upper and lower price band forecasts at various confidence levels. Page 2 of DPU Exhibit 11.1 D-RR identifies the forecast upper and lower natural gas price range for confidence intervals from 50% to 99%.

To review the projected price included in the test year I have compared the projected price provided by the Company to the EIA forecast price range. Using a 95% confidence estimate, the EIA forecast produces a forecast price range from a low of $2.95 to a high of $7.61. This places the test year forecast price of $7.23 on the high end of the range and significantly above the average settled price of $4.73. Thus, it appears that the actions of the Company and the current hedging policy have shifted nearly all of the price risk to ratepayers.

Q: How does the hedging strategy at PacifiCorp compare to the strategy used by Questar Gas Company?

A: Questar Gas Company ("Questar")prepares an annual hedging plan and makes a presentation to the Commission prior to implementation. Over the last 5 years, Questar has entered into fixed price agreements for approximately 63% of the forecast winter heating season need and has purchased the remaining quantity on the spot market. This has allowed Questar to take advantage of the recent drop in the market price which has been a benefit to both Questar and to rate payers. In the Questar Gas pass-through docket the Commission indicated that Questar should consider cost, reliability and price stability as the three factors that should influence a gas purchase strategy.[19]

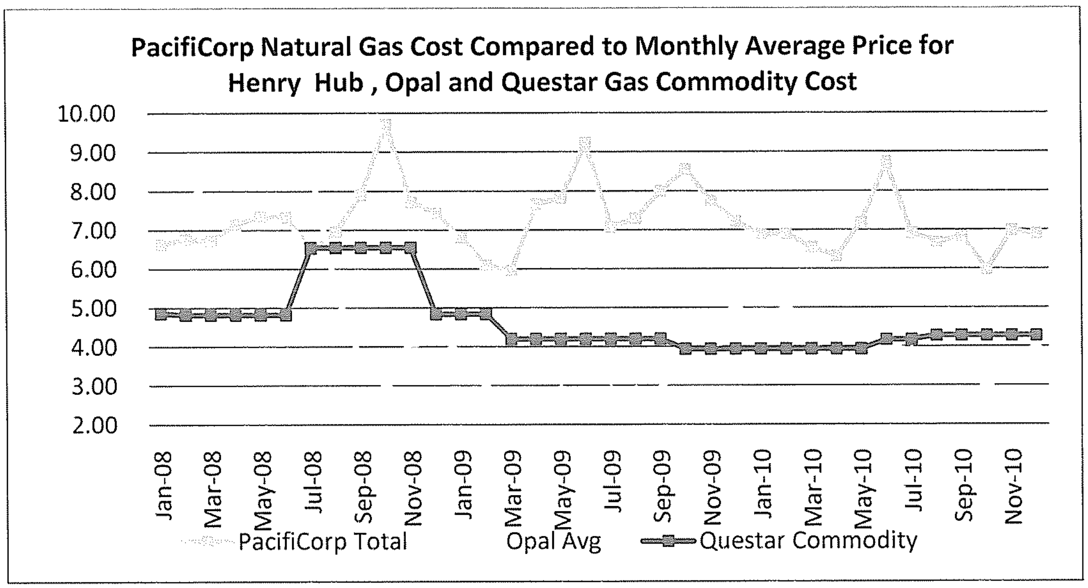
Q: How does the price for the natural gas commodity consumed by PacifiCorp ratepayers compare to the price of natural gas consumed by Questar's ratepayers?

A: Chart 5 below is summary of the cost for natural gas paid by ratepayers of PacifiCorp and ratepayers of Questar compared to the Opal spot market price. The actual values used for the Questar information has been taken from information provided in the 191

[19] Questar Gas Order in Docket Nos. 00-057-08 and 00-057-10 p. 7.

account. By using a shorter time horizon and allowing for some market purchases, Questar has been able to stabilize prices and still take advantage of the reduction in gas prices in recent years. Questar includes the WEXPRO production as part of their fixed price contracts. This has helped to keep the price down, but the remaining 37% has been purchased at market price.

Chart 5



Q: What is the Company currently paying for natural gas contracts in future years?

A: In response to DPU data request 32.3, the Company identified a few of the contracts that have been completed in the last 6 months. [redacted] which confirms the flat nature of the forward markets. While these new contract prices are lower than the historical information provided, due to the long term nature of the program it will take several years to realize a reduction in the price per MMBtu.

Q: Are you suggesting that the Company completely abandon its hedging program?

A: Not at all. The Division believes there is a benefit to hedging in order to stabilize price and minimize dramatic price spikes that would affect both the Company and ratepayers.

While the current projections are for stable gas prices, there is a possibility that natural disasters or economic conditions could change causing prices to increase rapidly. For example, environmental concerns related to the "fracking" process used in shale gas recovery could affect the future price along with other environmental or natural resource issues. Therefore, the Division is supportive of a certain level of hedging and recognizes that there will be costs associated with any hedging program.

Nevertheless, the Division is concerned that the current hedging strategy has been conducted without the scrutiny or approval of regulators and has not been explicitly determined to be in the best interest of the Company or ratepayers. Additionally, the Division is concerned that the Company's current hedging program and practices do not provide an appropriate degree of flexibility to adapt to changing conditions and are weighted too heavily toward price stability at the expense of cost minimization. With that said, the Division recognizes that there are likely as many different hedging programs as there are electric utility companies and probably no perfect hedging program exists.

Q: How does the Division interpret the current EBA order that allows swaps to be included in base rates but excluded from the EBA calcluation?

A: This is a bit confusing. The Commission has been asked to review its decision to include or exclude swap transactions from the EBA, but has not yet acted.. The EBA order states;

> ...swap transactions should be excluded from the calculation of both base and actual net power costs. We agree swap transactions do not track well with the statutory definition of energy cost. Swap transactions currently approved will remain in basic customer rates. We also conclude these transactions must be reviewed and approved in each general rate case, which is an appropriate proceeding for determining the prudence of Company decisions. [20]

The order indicates that swap transactions are excluded from the base and the balancing calculation but swaps already approved and included can remain in rates. The inclusion of any future swap transactions must be reviewed and approved in a general rate cases.

[20] Docket No. 09-035-15, ECAM Order p 75.

This would imply that the Commission could recognize and approve some level of hedging and could allow the Company to receive cost recovery for a specific dollar amount. The order does not allow the change in the market value of the contracts or the mark-to-market price adjustment to be included. The Division has interpreted this order to mean that a general rate case is the proper place to determine a dollar amount that could be allowed for hedging. The order also implies that a portion of the costs could potentially be disallowed if it was determined that certain costs were not appropriate. With large volume of gas and electric swap contracts with various maturities, new contracts being added and market price fluctuation for a [redacted] program, it is very difficult to determine what amount has been approved in previous rate cases. While the Company has locked in the price of natural gas in future periods, the change in the market price of these contracts between the date that rates were approved in a general rate case and the settlement date should not be included in the EBA calculation. Excluding these sorts of market price changes would be similar to the treatment of the Questar 191 account since Questar's accounting does not allow for mark-to-market entries.[21]

Since the value of these contracts is changing and the volume of gas can change based on load and market conditions, the amount to be included or excluded should be valued based on the price per MMBtu. This would allow for changes in both volume and price based on changes in market conditions and would allow customers to participate in possible cost savings. This is a difficult issue that will be discussed in future hearings and must be clearly resolved prior to the implementation of the EBA.

Q. Can you summarize the Division's finding and recommendations?

A. The primary goal of the Company's current hedging program is to reduce the price volatility of commodities in order to stabilize prices [redacted] in advance. The Company has not provided evidence that the current amount or the duration of the hedging program reduces the appropriate amount of risk to the Company or to ratepayers. With the recent increase in availability of shale gas production, changes in the availability of electric sales and a projected low price for natural gas, the Company has not responded

[21] Questar Gas, Docket Nos. 00-057-08 and 00-057-10, p 7.

to changing market conditions. While both internal and extra conditions have changed, the Company has indicated that they do not intend to change their strategy in the future.

A key part of the Company's hedging strategy is the relationship of the gas swaps with electric swaps. With the reduction in the availability of electric sales, the Division feels that the Company and Commission should explore whether the Company should structure its overall swaps policy not as an electricity and natural gas combination, but rather as two separate strategies.

Since the Commission has stated that it will not provide guidelines or standards,[22] the responsibility to analyze and provide alternatives rests with the Company to present and seek approval of an appropriate hedging strategy. The Commission should direct the Company to complete an analysis and review of specific investment vehicles currently available such as options, caps, collars and their associated cost. This analysis should also include an examination of other mixes of contract types and durations. As part of this analysis the Company should prepare a hedging decision protocol and a method to determine when the use of other products would be appropriate to incorporate into the current program.

The Division would like to see the Company file a comprehensive hedging plan with the Commission every two years. The plan should include the current hedging goals and strategies for both natural gas and electricity along with estimates for market purchases. A broad energy policy for the Company reviewed by the Commission would provide guidance and direction to the trading department and would include predetermined policies and procedures to deal with potential and significant changes in the market conditions. The absence of any guidance or direction from the Commission creates uncertainty for the Company and possible unintended consequences.

Q: Does the Division believe that the Company should be allowed to recover the full amount identified as swap costs?

[22] Docket No. 09-035-15 ECAM Order, p. 72.

A: No. The Division's consultant, Mr. Mark Crisp, has presented evidence that could justify a disallowance of all of the swap transactions in this case $99,039,393. While the Division believes the Company has not effectively managed its hedging program, the Commission has not provided guidance or required the Company to receive prior approval of its hedging program. For this and the other reasons stated herein, the Division is proposing a partial disallowance of $57,948,207 on a total system basis with $25,081,494 allocated to Utah.

In determining an amount for swap transactions that could be allowed, the primary focus was on the forecast natural gas cost provided by the Company and the EIA forecast. With the EIA forecast model, a range of confidence levels was used to calculate the upper and lower price estimates for the test period. The Division also looked at the historical average of the settled swap transactions for the past four years. DPU Exhibit 11.2 D-RR identifies the total cost and the calculated cost per MMBtu provided in this case along with the Division's calculations used to determine the amount for disallowance. This calculation is not intended to be the permanent calculation going forward but is used to determine a starting point for the EBA and could be used to review the prudence of a hedging program in the future.

Instead of using a percentage of the total cost for disallowance, the Division attempted to estimate a range of prices calculated per MMBtu that could be allowed. Using the EIA Short-term energy outlook model, the 75% confidence interval calculates the range of natural gas prices between $3.59 and $6.25. The Division proposal disallows the natural gas cost in excess of the larger amount. By multiplying the $6.25 by the estimated volume, the total amount of the allowed gas fuel expense including swaps can be calculated. This would allow $94.4 million in natural gas swap costs to be included in rates which is $66.3 million less than the Company has requested. The adjusted amount represents 86.4% of the proposed commodity and gas swap costs.

This same 86.4% is then applied to the electric swap transactions for a disallowance of $8.4 million. The adjustment to the electric swaps represents an increase in total NPC, although the net of gas and electric swaps taken together results in a total adjustment of $57.9 million on a total Company basis, or $25.1 million for Utah. This adjustment reduces the impact of the combined swap transactions from $99.0 million to $41.1

million on a system-wide basis. This adjustment compares favorably to the [redacted] four-year average impact of swaps on NPC calculated above.

Q: Why do you believe an adjustment for swaps and a disallowance is appropriate?

A: Based on the information presented above, the Company has not responded to the changing conditions both inside and outside of their control. The Company should not be allowed to recover all of these costs when they have not taken the appropriate steps to review or modify the current hedging program. With the implementation of the EBA scheduled to begin at the conclusion of this rate case, determining the appropriate costs to be include in base rates becomes even more important.

Q: Does this conclude your testimony?

A: Yes.