

REDACTED

Docket No. UE-227

Exhibit PPL/400

Witness: Stefan A. Bird

**BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON**

PACIFICORP

Redacted Rebuttal Testimony of Stefan A. Bird

July 2011

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp (the Company).**

3 A. My name is Stefan A. Bird. My business address is 825 NE Multnomah, Suite
4 600, Portland, Oregon 97232. I am Senior Vice President, Commercial and
5 Trading, for PacifiCorp Energy, a division of PacifiCorp.

6 **Q. Please describe your educational and business background.**

7 A. I hold a B.S. in mechanical engineering from Kansas State University. I joined
8 PacifiCorp Energy and assumed my current position in January 2007. From 2003
9 to 2006, I served as president of CalEnergy Generation U.S., an owner and
10 operator of Qualifying Facility and merchant generation assets, including
11 geothermal and natural gas-fired cogeneration projects across the United States.
12 From 1999 to 2003, I was vice president of acquisitions and development for
13 MidAmerican Energy Holdings Company (MEHC). From 1989 to 1997, I held
14 various positions at Koch Industries, Inc., including energy marketing, financial
15 services, corporate acquisitions, project engineering and maintenance planning in
16 the Americas and Europe.

17 In my current position I oversee the Company's Commercial and Trading
18 organization which is responsible for dispatch of the Company's owned and
19 contracted generation resources, procurement of new generation resources, and
20 wholesale purchases and sales of natural gas and electricity to balance the
21 Company's load and resources. I am also responsible for PacifiCorp's load and
22 revenue forecast, integrated resource plan (IRP) and net power costs modeling.

1 **Q. Please specifically describe your experience in electric utility risk**
2 **management, hedging and natural gas procurement.**

3 A. I have over 20 years of experience in the energy field with a concentration in
4 managing the commercial and financial aspects of large scale electricity and
5 natural gas commodity risk. I began analyzing and developing strategies to
6 manage natural gas risk in 1992 in the Gulf Coast following the acquisition of an
7 interstate pipeline company and the deregulation of the natural gas market. The
8 start-up electricity services company I helped develop in 1994 traded the first
9 NYMEX electricity futures contract and was at the time one of the three largest
10 electricity trading companies in the United States. As a developer for
11 MidAmerican Energy Holdings Company and as president of CalEnergy, I
12 negotiated short-term and long-term contracts and developed and executed risk
13 management strategies to manage natural gas procurement and electricity sales for
14 generation assets distributed across the United States. For the past four and a half
15 years at PacifiCorp, I have been a member of the Risk Oversight Committee and I
16 oversee all of the Company's wholesale electricity purchases and sales, natural
17 gas procurement and risk management activity to comply with the risk
18 management policy and manage risk on behalf of our customers.

19 **Q. Do the witnesses for CUB and ICNU have any direct experience in electric**
20 **utility risk management, hedging and natural gas procurement?**

21 A. Not based upon the experience referenced in the qualifications filed with their
22 testimony in this docket.

1 **Q. What is the purpose of your testimony?**

2 A. My rebuttal testimony responds to the opening testimony of the Citizens' Utility
3 Board of Oregon (CUB) presented by Messrs. Robert Jenks and Gordon Feighner
4 and the Industrial Customers of Northwest Utilities (ICNU) presented by Mr.
5 Donald Schoenbeck with respect to the Company's hedging activities. My
6 rebuttal testimony addresses the Company's hedging strategy and practices and
7 demonstrates that these practices are prudent and reasonable. Specifically, my
8 rebuttal testimony:

- 9 • Provides an overview of the Company's risk management policy and
10 hedging program;
- 11 • Demonstrates that the Company's hedging activities associated with the
12 test period in this case were consistent with the risk management policy
13 and hedging program;
- 14 • Discusses prior regulatory and third-party review of the Company's risk
15 management policy and hedging program; and
- 16 • Demonstrates that there is no basis for a prudence disallowance based on
17 contentions that the Company hedged too much or hedged too far forward.

18 In support of these conclusions, the rebuttal testimony of Company witness Mr.
19 Gregory N. Duvall quantifies the impact of the Company's risk management
20 policy and hedging program on net power costs in Oregon rates and demonstrates
21 that the risk management policy and hedging program have reduced the volatility
22 and overall level of the Company's net power costs.

1 **Overview of Company's Risk Management Policy and Hedging Program**

2 **Q. What is the purpose of the Company's risk management policy and hedging**
3 **program?**

4 A. The goals of the Company's risk management policy and hedging program are to:
5 (1) ensure that reliable power is available to serve customers; (2) reduce net
6 power cost volatility; and (3) protect customers from significant risks. The
7 Company's risk management policy and hedging program were designed to
8 follow electric industry best practices and are periodically reviewed and updated
9 as necessary.

10 **Q. What are the main components of the Company's risk management policy?**

11 A. As outlined in the Company's risk policy, the main components of the Company's
12 risk management of fuel and power price volatility are value-at-risk (VaR)
13 measurements and VaR limits, position limits, and stop-loss limits. These limits
14 force the Company to monitor the open positions it holds in power and natural gas
15 on behalf of its customers on a daily basis and limit the size of these open
16 positions by prescribed time frames in order to reduce customer exposure to price
17 concentration and price volatility.

18 **Q. What is the purpose of the Company's hedging program?**

19 A. The hedging program supplements and is subordinate to the Company's risk
20 management policy by specifying separate to-expiry VaR calculation and targets.
21 As stated in the Company's most recent IRP: "Hedging is done solely for the
22 purpose of limiting financial losses due to unfavorable wholesale market
23 changes....Hedging modifies the potential losses and gains in net power costs

1 associated with wholesale market price changes.”¹

2 The Company has a large short position in natural gas because of its
3 ownership of gas-fired electric generation, requiring it to purchase large quantities
4 of natural gas to generate power for its customers. The hedge program has targets
5 for the Company to purchase natural gas well in advance of when it is required to
6 reduce the size of this short position. Likewise, on the power side, the Company
7 either purchases or sells power in advance of anticipated open short or long
8 positions to manage price volatility on behalf of customers.

9 **Q. Please identify the documents that govern the Company’s hedging activities.**

10 A. The primary governance of the Company’s hedging activities is in the Company’s
11 Confidential Risk Management Policy, and Highly Confidential Appendices,
12 which are attached as Confidential/Highly Confidential Exhibit PPL/401. The
13 hedging program is also governed by the Company’s Confidential Front Office
14 Procedures and Practices, Exhibit 10, also included in Confidential Exhibit
15 PPL/401. The documents expressly state that the risk management policy governs
16 in the event of a conflict between it and the front office procedures and practices.

17 **Q. Does the Company hedge its separate power or natural gas positions or its
18 net energy position?**

19 A. The Company hedges its net energy (combined natural gas and power) position on
20 a portfolio basis to take full advantage of any natural offsets between its long
21 power and short natural gas positions.² The Company’s 2011 IRP analysis shows
22 that a “hedge only power” or “hedge only natural gas” approach results in higher

¹ PacifiCorp 2011 IRP, Docket LC 52, Appendix G at 161-162 (Mar. 31, 2011).

² *Id.* at 170.

1 risk (*i.e.*, a wider distribution of outcomes).³ There is a natural need for an electric
2 company with natural gas fired electricity generation assets to have a hedge
3 program that simultaneously manages natural gas and power open positions with
4 appropriate coordinated metrics.

5 **Q. Can you explain why this is such a critical factor for electric utilities?**

6 A. Yes. Assume the Company has a 500 MW natural gas-fired generation plant with
7 a heat rate of 8 MMBtu/MWh (*i.e.*, requires 8 MMBtu of natural gas to create 1
8 MWh of electricity). In the first example, assume natural gas prices for a forward
9 period are \$4.00/MMBtu and electricity prices are \$40/MWh. Under these
10 conditions, it would be economic to dispatch the natural gas plant, as the cost to
11 produce the electricity is \$32/MWh (\$4.00/MMBtu multiplied by 8
12 MMBtu/MWh) which is less than the electricity market price. Therefore, the
13 Company would hedge the fuel requirements by purchasing 4,000 MMBtu of
14 natural gas (500 MW multiplied by 8 MMBtu/MWh) and sell 500 MW of
15 electricity. In the second example assume natural gas prices fell to \$3.50/MMBtu
16 and electricity prices fell to \$26/MWh. Under these conditions it would not be
17 economic to dispatch the natural gas plant, as the cost to produce the electricity is
18 \$28/MWh (\$3.50/MMBtu multiplied by 8 MMBtu/MWh) which is greater than
19 the available electricity market price. Therefore, the Company would not hedge
20 the fuel requirements.

21 **Q. What is your conclusion from these examples?**

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

³ *Id.* at 170.

1 generation such as the Company. Neither CUB nor ICNU considered this
2 important factor in their testimony and recommendations in this case.

3 **Q. How is the Company's hedging program structured?**

4 A. Since 2003, the Company's hedge program has employed a portfolio approach of
5 dollar cost averaging to progressively reduce net power cost risk exposure over a
6 defined time horizon while adhering to best practice risk management governance
7 and guidelines. Highly Confidential Exhibit PPL/402 provides a tabular
8 representation of the Company's current progressive portfolio hedging approach
9 as a percentage of net power costs. In May 2010, the Company moved from
10 hedging targets based on volume percentages to targets based on the "to expiry
11 value-at-risk" or TEVaR metric. The primary goal of this change was to increase
12 the transparency to the Company's combined natural gas and power exposure by
13 period. It enhances the progressive approach to hedging that the Company has
14 employed for many years and provides the benefit of a more sophisticated
15 measure of risk that responds to changes in the market and changes in open
16 natural gas and power positions. Importantly, the TEVaR metric automatically
17 results in reducing hedge requirements as commodity price volatility decreases
18 and increasing hedge requirements as correlations among commodities diverge,
19 all the while maintaining the same risk exposure.

20 **Q. Have the Company's risk management policy and hedging program changed**
21 **in response to the development of shale gas and the decreasing price of**
22 **natural gas?**

23 A. Yes. The Company's risk management policy has been actively reviewed by its

1 internal risk oversight committee and updated every year for several years
2 running to reflect best practices and respond to changing market conditions. In
3 addition, as mentioned above, the hedging program was modified in May 2010
4 with the institution of the TEVaR metric. The result of these program changes in
5 combination with changes in the market (such as reduced volatility to which the
6 Company's program automatically responds), has been a significant decrease in
7 the Company's longer-dated hedge activity, *i.e.*, four years forward on a rolling
8 basis. These hedges have decreased from a peak forward hedge percentage of
9 approximately ■ percent in 2008 (a period reflecting high volatility) to
10 approximately ■ percent in 2011 (a period reflecting lower volatility).

11 **Q. ICNU contends that many of the gas hedges in this proceeding fell outside the**
12 **guidelines for pre-approved transactions because the hedge horizon was**
13 **longer than 36 months. Is this contention correct?**

14 A. No. As noted above, the Company's risk management policy ultimately governs
15 the Company's hedging program. The Company amended its risk management
16 policy in October 2006 to move to a 48-month transaction tenor. The risk
17 management policy was further amended in November 2006 and this version,
18 which maintained the 48-month tenor, was operative during the time of the
19 transactions ICNU now challenges.

20 The confusion on this point is likely a result of the Company producing
21 various versions of its risk management policy in response to one data request
22 (ICNU 7.3) and its front office procedures and practices in response to another
23 data request (ICNU 2.18). The Company's supplemental response to ICNU Data

1 Request 2.18 clarifies that the two documents must be reviewed together, with the
2 risk management policy expressly governing in the event of any conflict between
3 the two.

4 **Q. Do the hedges in this case include some transactions that extend beyond 48**
5 **months?**

6 A. Yes. The Company purchased certain natural gas swaps in late 2007 and 2008
7 which extended beyond 48 months forward. The Company made an exception to
8 its normal policy for these transactions, which reduced hedging costs through the
9 use of standard market products. In forward markets at that time, there was
10 greater liquidity in standard tenor products such as November-March or April-
11 October than for individual months. As such, rather than incur a higher cost due
12 to low liquidity, the Company opted to transact the more standard winter strip.
13 By doing so, the Company avoided the illiquidity cost of an individual month and
14 the continued illiquidity and higher costs by hedging with individual months as
15 they rolled into the policy defined hedging horizon.

16 **Q. Why did the Company purchase a relatively high volume of long-dated**
17 **natural gas swaps in 2007 and 2008?**

18 A. The Company entered into the 2007 and 2008 longer dated hedges to mitigate the
19 risk of unfavorable prices and maintain compliance with its risk management
20 policy as large open positions rolled into the period within 48 months of delivery.
21 The Company's risk management policy at the time set absolute limits on short
22 positions measured in MMBtu per day, for each forward month or quarter through
23 48 months. In addition, the Company's risk management policy also contained

1 value-at-risk limits, calculated based on power and natural gas open positions,
2 power and natural gas market prices and volatilities which were elevated in the
3 2007-2008 period, and commodity correlations.

4 At the time these hedges were transacted, there was an elevated risk of
5 future price escalation reflected by then current high market volatility. Third party
6 expert forecasters at the time also projected the risk of even higher prices
7 consistent with then current views of continued economic growth, likely carbon
8 legislation and the need for more expensive LNG to replace declining
9 conventional natural gas supply to satisfy growing demand. The global economic
10 crisis and shale gas revolution that subsequently developed was not anticipated by
11 the market and most third party experts. Since that time the Company has
12 continued to update its risk management policy and hedge program to reflect
13 larger position limits consistent with its natural gas generation resource expansion
14 and incorporate a more dynamic hedge program with the replacement of volume
15 percentage based targets with TEVaR-based targets.

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

17 **Q. Has the Oregon Commission previously reviewed the Company's risk**
18 **management policy and hedging program?**

19 A. Yes. As part of the Commission's 2005 Natural Gas Procurement Study, the
20 Commission Staff met with representatives of the Company to discuss natural gas
21 procurement strategies. The report notes:

22 PacifiCorp cited reliability and risk management as the primary goals of
23 their purchasing strategies. The company communicated to staff that it
24 uses at least a three year horizon for supply and acts as a market
25 participant in their purchasing practices. The company represents it

1 transacts at prevailing market prices. PacifiCorp can, and sometimes does,
2 use financial instruments as a part of their natural gas purchasing
3 strategies. The company's natural gas costs for 2006 have been, at least
4 partially, hedged by fixed price purchases executed as far back as 1994 for
5 the Hermiston plant and 2003 for the Utah plants. The result of the
6 hedging is that PacifiCorp's hedged cost of natural gas for 2006 is below
7 current market prices.⁴

8 Staff also conducted an "opportunity cost" analysis for the years 1999 through
9 2004 that compared the Company's overall procurement strategies over simply
10 purchasing identical quantities from the identical hubs at prevailing market index
11 prices. Based on this analysis, the report concluded:

12 Overall, when the entire portfolio is considered, PacifiCorp achieved an 82
13 percent reduction in volatility and a fifteen percent decrease on average in
14 the per therm price of natural gas over the time period analyzed.⁵

15 The pages of the report pertinent to PacifiCorp are reflected in Exhibit PPL/403.

16 **Q. Has the Company updated the analysis contained in the Oregon Staff's**
17 **natural gas procurement report?**

18 A. Yes. Mr. Duvall's rebuttal testimony presents the results of a similar analysis
19 conducted for the years from 2005 through 2010. This analysis demonstrates that,
20 during the most recent six-year period, the Company's power and natural gas
21 hedging activity decreased net power costs volatility by 50 percent and 52
22 percent, respectively.

23 **Q. Has any party to a PacifiCorp general rate case or TAM filing previously**
24 **proposed to disallow the Company's hedging costs?**

25 A. No. I understand that in the Company's net power costs deferral arising from the
26 Western energy crisis, Docket UM 995, ICNU challenged certain power costs on

⁴ See Exhibit PPL/403 at p. 56.

⁵ *Id.* at p. 58.

1 the basis that the Company should have hedged more of its market exposure.⁶

2 The Commission rejected this argument, but in the concurring opinion of the
3 Commission chair, directed electric utilities to more comprehensively examine
4 and plan for risk in the future.⁷ PacifiCorp's current risk management policy is
5 informed by these events.

6 **Q. Was the Company's risk management policy and hedging policy recently**
7 **evaluated comprehensively by an independent third party?**

8 A. Yes. In October 2009, the Division of Public Utilities (DPU) in Utah completed a
9 comprehensive, third-party evaluation of the Company's risk management policy
10 and hedging program. The DPU's Blue Ridge Report affirmatively concluded
11 that the Company's risk management policy and hedging program adhered to
12 generally accepted industry standards:

13 Overall, Blue Ridge found that the Company's commercial trading
14 and risk management programs (and the related hedging programs)
15 are well-documented and controlled and adhere to generally
16 accepted standards found elsewhere in the industry. The Company
17 has well-stated goals and strategy that is aimed at mitigating price
18 volatility. In addition, our review of the Company's internal
19 documents showed that the Company is self-monitoring
20 compliance with accepted commercial trading and risk
21 management procedures through its own internal audit function.

22 While the Company's risk management policy and hedging program have
23 continued to be refined and improved, the fundamentals of the risk management
24 policy and the hedging program have not changed since the time of the DPU's
25 Blue Ridge Report. The report is provided as Exhibit PPL/404.

⁶ See Order No. 02-469 at 16.

⁷ *Id.* at 76.

1 **Q. Did the Blue Ridge Report address policy issues related to hedging?**

2 A. Yes. The Blue Ridge Report noted:

3 The question has been asked, “Why hedge?” The answer lies in
4 one fundamental statement: prices and supplies for energy
5 commodities (crude oil, natural gas, electricity, etc.) can and have
6 been extremely volatile. The benefit of hedging is that when prices
7 are rising (either rapidly in the short term or gradually in the long
8 term), a hedged portfolio of supply should mitigate the effect of
9 those increases. However, the opposite is also true. When prices
10 fall suddenly, a hedged portion of the supply can cost the utility
11 and its customers the difference between the prices that were
12 available at the current time versus the hedged prices for that
13 supply. This cost (when netted against any gains) along with the
14 administrative costs associated to operate and manage the trading
15 operations is considered the insurance premium associated with a
16 hedged portfolio.

* * * * *

17 [H]aving a “no hedge” policy clearly exposes consumers to
18 significant (and likely) price swings. Assuming that an upward
19 price trend continues (despite recent price levels and short-term
20 price forecasts), consumers are very likely to pay higher prices for
21 energy absent some level of hedging and price volatility
22 mitigation.

23 **Q. Has the National Regulatory Research Institute (NRRI) provided guidance**
24 **related to natural gas hedging by utilities?**

25 A. Yes. The DPU also sponsored a presentation by NRRI to the Utah Commission in
26 June 2009. The NRRI Report⁸ indicates that, for many years, state commissions
27 have conveyed that the failure to engage in hedging (*i.e.*, buying natural gas in the
28 day-ahead market or spot price) may be imprudent.

⁸ Docket No. 09-035-21, Gas Hedging Presentation to The Public Service Commission of Utah Technical Conference, Ken Costello, The National Regulatory Research Institute (June 3, 2009), available at: [http://www.psc.utah.gov/utilities/electric/09docs/0903521/TechConf%206-3-09/Gas%20Hedging.ppt%20\(UT%20PSC\).pdf](http://www.psc.utah.gov/utilities/electric/09docs/0903521/TechConf%206-3-09/Gas%20Hedging.ppt%20(UT%20PSC).pdf)

1 **Q. Does the NRRI Report provide guidance on standards for determining the**
2 **prudence of a utility’s hedging costs?**

3 A. Yes. The NRRI Report states that “Second-guessing and micromanaging should
4 be avoided.” It explains that “Second-guessing is contrary to the traditional
5 prudence standard, and in addition, creates distorted incentives for utility
6 hedging.” Instead, it recommends that, “[a]ccording to the prudence standard, a
7 commission should maintain authority to evaluate the reasonableness of (1) a
8 hedging strategy *ex ante*, and (2) the execution of the strategy.” The NRRI
9 Report suggests that a Commission could set an *ex ante* standard by, for example,
10 defining an acceptable level of risk tolerance to price volatility.

11 **Q. Does the Company agree with the NRRI Report’s recommended approach to**
12 **Commission review of the prudence of the Company’s risk management**
13 **policy and hedging program?**

14 A. Yes. The Company welcomes *ex ante* direction from the Commission on the
15 Company’s risk management policy and hedging program. However, the
16 Company agrees that second-guessing the Company’s risk management policy
17 and hedging program is contrary to the prudence standard. This is especially true
18 given the fact that CUB and ICNU second-guess the risk management policy and
19 hedging program based upon a single year of net losses and a subset of the
20 Company’s hedges—and fail to consider the *ex ante* risk reduction benefits to
21 customers and net savings to customers of hedging on a multi-year, all-in basis.

1 **Overall Response to Hedging Adjustments**

2 **Q. Please summarize CUB's and ICNU's hedging adjustments.**

3 A. While CUB and ICNU propose different approaches, they each seek to disallow a
4 large amount of the Company's net power costs related to the Company's hedging
5 activities in the test period. However, a set of incorrect assumptions and facts
6 provide the foundation for these proposed adjustments, including:

7 (1) The Company did not follow its risk management policy;

8 (2) The Company hedged too much of its open position, compared to other
9 utilities; and

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

12 I addressed and corrected the first issue above, and correct the record on the
13 remaining two issues below.

14 **Q. Is there another threshold flaw in the approach of CUB and ICNU?**

15 A. Yes. While CUB and ICNU purport to support a portfolio approach to the
16 Company's hedging, they attempt to isolate the Company's natural gas swaps
17 from other aspects of the Company's portfolio. It is inappropriate and unfair to
18 propose to disallow natural gas swaps in isolation from other hedges when the
19 Company has an integrated hedging program designed to take full advantage of
20 the natural offsets between its long power and short natural gas positions.

21 As discussed above, power and natural gas prices are correlated and the
22 positions for each commodity are inextricably linked to spark spreads. Spark
23 spreads represent the difference in the market price of power and the market price

1 of natural gas converted to power through a gas-fueled power plant. Further, the
2 price of power in on-peak hours is often established by a gas-fired plant on the
3 margin. Because power and natural gas commodity prices are highly-interrelated,
4 it is appropriate and necessary to report and manage the risk exposures from these
5 commodities in a combined fashion. Separate management of these commodities
6 increases the risk of over or under hedging or increases the overall risk profile of
7 the Company by hedging in a manner that ignores or reduces natural offsetting
8 positions. A hedging program that ignores this correlation and relationship will
9 naturally be less effective than the current program. This is further demonstrated
10 in the Company's recent 2011 IRP discussion on appropriate hedging strategies.

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

12 A. Yes. As set forth in PPL/108, Duvall/1, net power costs in the Company's initial
13 filing reflect approximately \$100.6 million of forecast hedging losses.

14 **Q. Why did the Company incur these forecast losses?**

15 A. The forecast hedging losses in the test period are a function of unforeseen
16 declining forward prices, not the volume of the hedges, the time horizon of the
17 hedges or the hedging instruments used. Hedging protects customers from the
18 risk that net power costs in rates could be significantly higher if prices moved
19 unfavorably in the test period that is used to set rates. To get this protection,
20 customers must forego potentially lower net power costs that could result if prices
21 moved favorably in the test period. As ICNU acknowledges, it is unlikely that a
22 company can "beat the market" through its hedging program.

1 **Effectiveness of the Company's Hedging Program**

2 **Q. Should the Commission judge the effectiveness of the hedging program on**
3 **the basis of whether it has made or lost money for customers?**

4 A. No. The goal of the hedging program is to reduce volatility in the Company's net
5 power costs primarily due to changes in market prices. Consistent with the
6 findings in the Commission's 2005 Natural Gas Procurement Study, Mr. Duvall
7 demonstrates that the Company's hedging program has significantly reduced net
8 power cost volatility. In addition, the Company's risk management policy and
9 hedging program has been thoroughly reviewed and validated by an independent
10 third party expert retained by the Utah DPU, on the basis that it was well-
11 documented and controlled, and adhered to generally accepted industry standards.

12 **Q. Nevertheless, can you demonstrate that the Company's hedging program has**
13 **reduced net powers costs for Oregon customers over the last several years?**

14 A. Yes. Mr. Duvall sponsors an exhibit that demonstrates that the Company's
15 hedging activity since Oregon Docket UE 191 has reduced net power costs by
16 approximately \$118.4 million.

17 **Hedging Volumes**

18 **Q. Please respond to the claims of intervenors that the Company is hedged at**
19 **too high a percentage compared to other utilities.**

20 A. The Company's hedging program progresses at gradually increasing levels
21 approaching the time of delivery. This graduated approach provides diversity and
22 flexibility to the hedging program. At the time of delivery, the Company is
23 generally [REDACTED] percent hedged. This limits the Company's exposure to the

1 volatility of the spot market. By the end of the fourth year on a rolling basis the
2 Company is [REDACTED] (following the expiration of the 15-year
3 Hermiston natural gas supply hedge in July 2011). The Company's portfolio
4 approach to progressive hedging from [REDACTED] percent at the time of delivery to [REDACTED]
5 by the end of the fourth year provides the risk diversification benefits of dollar
6 cost averaging during this rolling four year period and avoids concentrated
7 exposure to short periods of price changes. In fact, the Company's TEVaR-based
8 hedge program is consistent with the spirit of the progressive approach advocated
9 by CUB in its opening testimony, but the Company's TEVaR-based program is
10 more effective in delivering the progressive risk mitigation approach desired by
11 CUB than can be accomplished by using CUB's simple volume percentage
12 targets.

13 **Q. At what percentage is the Company's open position for natural gas hedged**
14 **for the test period in the 2012 GRID NPC Rebuttal Update study?**

15 A. Mr. Duvall's testimony shows that the Company's natural gas position is
16 approximately [REDACTED] percent hedged in the 2012 GRID NPC study in the rebuttal
17 filing in this case. The GRID study reflects all of the Company's actual hedges
18 for the forecast test period, which also comply with the TEVaR targets. The
19 volume percentage of hedging is lower in the Company's normalized GRID net
20 power costs than is reflected in its daily risk management operations model that is
21 used to measure and report daily compliance with the risk management policy.
22 The difference is due to different assumptions and modeling methodology. With
23 normalized inputs and a static point forecast for all assumptions, GRID optimizes

1 the Company's natural gas plants and runs them at a higher capacity factor, thus
2 increasing the forecast natural gas requirements. In contrast, the Company's risk
3 management operations model is updated daily with numerous inputs and does
4 not rely on a static forecast but rather incorporates volatility to forecast power and
5 natural gas requirements, which results in a lower forecast natural gas supply
6 requirement than forecast in GRID. Since the forecast natural gas requirement is
7 higher in GRID, the hedge percentage of forecast natural gas requirements is
8 smaller.

9 **Q. Please respond to the claims of intervenors that the Company hedged its**
10 **natural gas exposure at too high a percentage compared to other utilities.**

11 A. On a normalized basis—which is the basis for forecasting net power costs—the
12 Company's hedged position is less than the percentage limits proposed by
13 intervenors. This demonstrates that there is no basis for the adjustments in this
14 case that claim that the Company is overhedged.

15 **Q. Please respond more specifically to ICNU's recommended hedging**
16 **parameters.**

17 A. ICNU's recommended hedging parameters would decrease the sophistication and
18 effectiveness of the Company's hedging strategy.

19 ICNU recommends that PacifiCorp hedge at 80 percent in year one,
20 reducing the volume by 20 percent each year through year four. ICNU does not
21 provide any evidence in support of these particular targets. ICNU recommends
22 hard, volumetric targets, which would reduce the flexibility, responsiveness and
23 transparency of PacifiCorp's current TEVaR targets.

1 In addition, ICNU argues that PacifiCorp should be hedged at a
2 substantially lower level during the second quarter of each year “when abundant
3 hydro is available to displace the vast majority if not all the gas-fired generation
4 in the Pacific Northwest region.”⁹ PacifiCorp’s hedge program currently takes
5 into account market conditions such as abundant Pacific Northwest hydro.
6 Modifying the hedge program further would be double counting this impact.

7 **Q. CUB cites the testimony of Dr. Lori Schell on behalf of the Utah Office of**
8 **Consumer Services (OCS) in the Company’s most recent Utah general rate**
9 **case in support of CUB’s position that the Company was over-hedged for the**
10 **Utah test period. Similarly, ICNU notes that several parties in Utah have**
11 **challenged the Company’s hedging costs. Please respond.**

12 A. The Utah general rate case refers to a different test period than in this case. Even
13 if the test periods did align, the hedging issues in the Utah general rate case,
14 among other items, were recently settled. As a part of that settlement, the parties
15 agreed on a process to review the Company’s hedging practices on a *prospective*
16 basis to determine whether the risk management policy and hedging program
17 should be revised in some manner. PacifiCorp is agreeable to a similar process in
18 Oregon to address CUB’s and ICNU’s concerns.

19 In addition, I understand that the pre-filed testimony of a witness of
20 another party in another state cannot provide the foundation for CUB’s proposed
21 adjustment, especially when the testimony has been made moot by a settlement.
22 Moreover, Dr. Schell’s testimony cannot fairly be evaluated without also

⁹ ICNU/100, Schoenbeck/16.

1 considering the testimony filed in that case by the Company's expert, Mr. Frank
2 Graves, of The Brattle Group, attached as Confidential Exhibit PPL/405.

3 Based on The Brattle Group's work with electric utilities for many years,
4 it has access to information about electric industry standards on the scope of
5 hedging programs, which is otherwise difficult to obtain given the confidential
6 nature of the underlying data. Mr. Graves' expert opinion is that electric
7 companies with combined natural gas/power hedging programs often hedge at
8 higher volume levels than natural gas-only companies (which rely heavily upon
9 gas storage) and that the Company's program, including its hedging volumes and
10 hedging horizon (discussed in more detail below), fully comports with industry
11 standards. As such, the degree of hedging boils down to a subjective preference
12 level of risk tolerance, and there is certainly nothing objectively imprudent about
13 the extent of the Company's hedging program.

14 **Q. How do natural gas distribution companies differ from electric utilities with
15 respect to their hedging needs and practices?**

16 A. There are significant physical and financial differences in the hedging issues
17 faced by natural gas companies and electric utilities. First, natural gas companies
18 are only concerned with the natural gas commodity (and its transportation); they
19 do not have to worry about the value of that natural gas once converted to
20 electricity, or how purchased power might substitute for (or increase) gas usage.
21 In contrast, electric utilities are more concerned about the spark spread between
22 gas and electricity than the price of gas itself (for which they may be sellers, as
23 well as buyers). Second, the volume of gas that electric utilities need also tends to

1 be more of a peaking requirement that can be variable throughout the year,
2 depending on the cost of other fuels. Third, electric utilities also hedge much
3 more than just their fuel costs, because they must buy and sell significant
4 quantities of power to balance their system supply against load. Fourth, spot
5 electric prices are both extremely volatile and asymmetrical in terms of price
6 distribution, resulting in price spikes often at times of high demand. For all of
7 these reasons, the hedging requirements of electric companies are generally more
8 complex than for gas distribution companies and may result in an electric utility
9 hedging more volume for a longer time horizon.

10 **Q. CUB also points to a previous Commission order, Order No. 07-200, lowering**
11 **Avista’s hedging volume as support for its adjustment. Please comment.**

12 A. For several reasons, this case provides no support for CUB’s adjustment
13 disallowing hedging costs in this case for transactions beyond a 36 month
14 horizon.

15 First, in Oregon Avista is a natural gas local distribution company, not an
16 electric utility. Consistent with my observations above, the Commission’s gas
17 procurement study specifically distinguished natural gas and electric utilities,
18 noting at pp 5-6 that:

19 The natural gas purchasing strategies of Oregon’s electric utilities and
20 large industrial natural gas consumers differ from those of Oregon’s
21 LDCs. This is due to both the nature of their businesses (natural gas for
22 peaking generators versus serving load, industrial production) and their
23 peak demand times (e.g. summer vs. winter).

24 Second, Staff commenced its investigation into Avista’s gas procurement
25 and hedging practices primarily because of concerns that are not implicated by
26 PacifiCorp’s risk management policy and hedging program, including “lax

1 internal monitoring and controls,” “inadequate research and analysis of market
2 intelligence,” and “lack of management attention and control.”¹⁰ Additionally,
3 Avista was pursuing a different hedging strategy in Oregon than in its other state
4 jurisdictions, because its purchase gas adjustment mechanism in Oregon allowed
5 for only 90 percent recovery of its purchase gas costs.¹¹ The governance and
6 operation of PacifiCorp’s risk management policy has never been challenged, and
7 this policy does not vary based on state-specific cost recovery mechanisms.

8 Third, under the Stipulation in that case, Avista agreed to hedge at the 70
9 percent level for one year only, in return for an agreement that permitted it 100
10 percent recovery of its purchase gas costs.

11 Finally, CUB claims that in adopting the Stipulation in Order No. 07-200,
12 the Commission indicated that Avista “was engaging in a natural gas strategy that
13 was imprudent because it was too reliant on hedging.” There is no such statement
14 or finding anywhere in the Order.

15 **Hedge Horizon**

16 **Q. Do you agree with CUB’s recommendation that the Company should restrict**
17 **hedging to up to 36 months?**

18 A. No. The hedge program is based on the premise of hedging forward as long as
19 there is sufficient liquidity. Although CUB asserts that “[t]here are real questions
20 about the liquidity of the market in a timeframe greater than 36 months”,¹² CUB
21 presents no data or evidence to support this assertion. Ironically, CUB supports

¹⁰ See Order No. 06-610, Appendix A at pp. 13-14.

¹¹ *Id.* at 9.

¹² See CUB/100, Jenks – Feighner/10, lines 21-22.

1 this position by citing to information developed in NW Natural's Encana
2 transaction—a thirty-year gas supply hedge which CUB supported as being in the
3 best interests of customers.

4 **Q. ICNU also alleges that PacifiCorp hedged too much, too far out in time. Does
5 it provide any specific evidence to support these contentions?**

6 A. No. While ICNU alleges that PacifiCorp's hedges are more extensive than NW
7 Natural's, at the same time it acknowledges that NW Natural hedges for up to five
8 years (longer than PacifiCorp), and entered the 2010-2011 prompt year 77 percent
9 hedged, which is higher than the ■ percent natural gas hedged percentage
10 reflected in the net power cost study in this case (further, if NW Natural's
11 percentage excludes its gas storage, the 77 percent number would be understated).

12 In any event, as explained above, comparisons to gas distribution
13 companies are of limited value in determining the reasonableness of PacifiCorp's
14 hedging. Notably, ICNU makes no comparison to Portland General Electric
15 Company's hedging practices, which according to its most recent Integrated
16 Resource Plan, appear to be similar to PacifiCorp's in the context of progressively
17 hedging over its hedging horizon, however its hedging horizon is slightly longer
18 at five years compared to PacifiCorp's four-year horizon.

19 **Q. Is there adequate liquidity in the market in the period 36 to 48 months from
20 delivery?**

21 A. Yes.

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

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

Confidential Figure 1



10 **Q. Why is the year 4 bar partially shaded in Confidential Figure 1?**

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

14 **Q. Is there a more direct measure of liquidity?**

15 A. Yes. The price spread between the ask price to sell and the bid price to buy is a

1 more direct indicator of liquidity. This spread can be viewed as a surrogate for
2 the transaction costs of hedging, with wider bid ask spreads indicating reduced
3 market liquidity and higher transaction costs to hedge and narrow bid ask spreads
4 indicating enhanced market liquidity and reduced transaction costs to hedge.

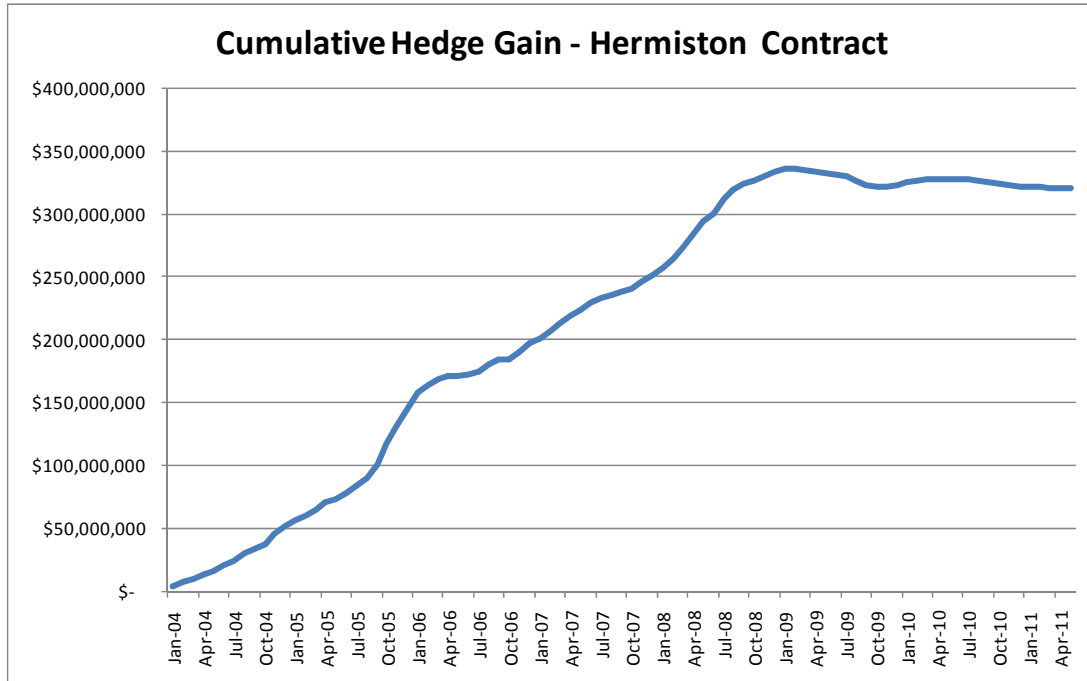
5 **Q. What are the bid ask spreads for the Company's hedging periods?**

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

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

13 A. Yes. The Company hedged 100 percent of the fuel for the Hermiston natural gas
14 fired plant with a 15-year supply agreement. At times the hedge was favorable
15 and at times unfavorable compared to spot prices. Overall, the long term supply
16 agreement was very favorable. As shown in Figure 2 the Hermiston gas hedge
17 yields a cumulative benefit to customers of \$320 million from January 2004
18 through May 2011.

Figure 2



1 **Q. How is this long-term transaction consistent with PacifiCorp's risk**
 2 **management policy?**

3 A. The risk management policy sets the parameters for pre-approved hedging
 4 transactions. The policy retains the flexibility for the Company's management to
 5 specially approve transactions outside of these pre-approval limits, such as the
 6 Hermiston gas supply contract.

7 **Q. Has the Company reduced the amount of its hedges in year four in response**
 8 **to current conditions in the natural gas markets?**

9 A. Yes, as noted above, the Company's longer-dated hedge activity, *i.e.*, four years
 10 forward on a rolling basis, has decreased by approximately █ percent between
 11 2008 and 2011. Hedging flexibly in this manner over a 36- to 48-month period is
 12 a reasonable and prudent practice, especially for an electric utility such as the
 13 Company.

1 **Foresight of Falling Natural Gas Prices**

2 **Q. During the period when the Company was executing hedges 36 to 48 months**
3 **in advance for the test period, should the Company have foreseen the**
4 **decrease in natural gas prices for the test period in this case?**

5 A. No. Spot natural gas prices were very high during this time period. Neither the
6 forward price curves at the time the hedges were transacted, nor third party spot
7 price forecasts indicated a significant expected future drop in natural gas prices. If
8 natural gas prices had remained high as then reflected in forward market prices or
9 even higher as then forecast by PIRA, the Company's hedges in the test period,
10 especially those in the 36- to 48-month category, would have been deep in the
11 money.

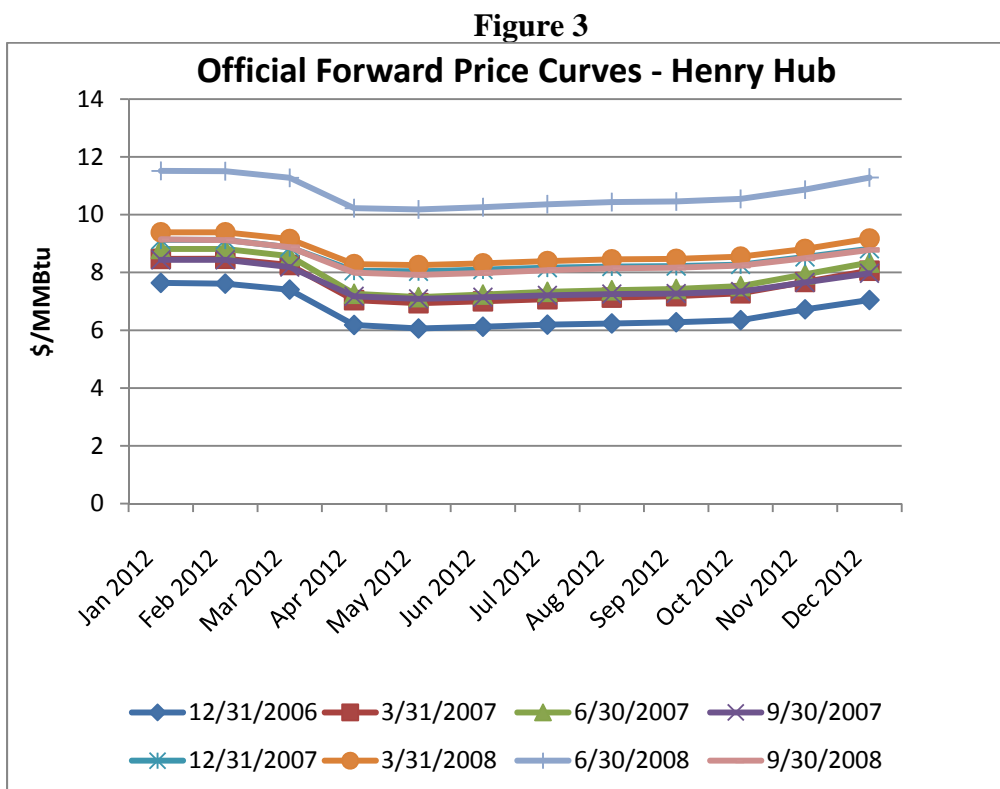
12 **Q. Please explain the distinction between a forward price curve and a spot price**
13 **forecast.**

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

1 in today for that future date whereas the spot price forecast represents the price an
 2 energy expert believes will be the prevailing market price in August 2012 for
 3 natural gas deliveries or settlements in August 2012.

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

7 A. Figure 3 shows the Company's official forward price curve as of each quarter in
 8 2007 and 2008 for natural gas delivered in the test period. These prices are
 9 consistent with the prices paid by the Company for the natural gas hedges in this
 10 case.



1 **Q. Is it apparent that the market in general, as reflected in the forward price**
2 **curves shown in Figure 3, anticipated the precipitous drop in natural gas**
3 **prices?**

4 A. No. The forward price curves shown in Figure 3 did not indicate the drop in
5 natural gas prices that occurred in the subsequent months and years. If the market
6 in general had known or anticipated such a drop in prices, the forward price
7 curves would have reflected that knowledge or anticipation in the form of
8 declining prices in the future. In contrast, as Figure 3 shows, the market
9 consistently reflected rising natural gas prices through mid-2008.

10 **Q. If the test period market instead reflected 2008 forward market price levels,**
11 **what would be the value of the Company's test period hedges?**

12 A. In that scenario, the Company's swap transactions in the current proceeding
13 would have significantly decreased net power costs. Figure 4 below duplicates
14 ICNU's adjustment for gas financial hedging strategy at ICNU/103,
15 Schoenbeck/15, replacing the market prices used in the Company's direct case
16 with market prices from the Company's June 2008 Official Forward Price Curve
17 (which was used in the July Update filing of the Company's 2009 TAM filing in
18 UE 199). This analysis shows significant benefits associated with the Company's
19 hedges under then-projected market prices. In this scenario, ICNU's adjustment
20 would increase the Company's net power costs by \$43.7 million, and only allow
21 into rates \$76.9 million out of the total \$120.5 million in hedging benefits.

Figure 4

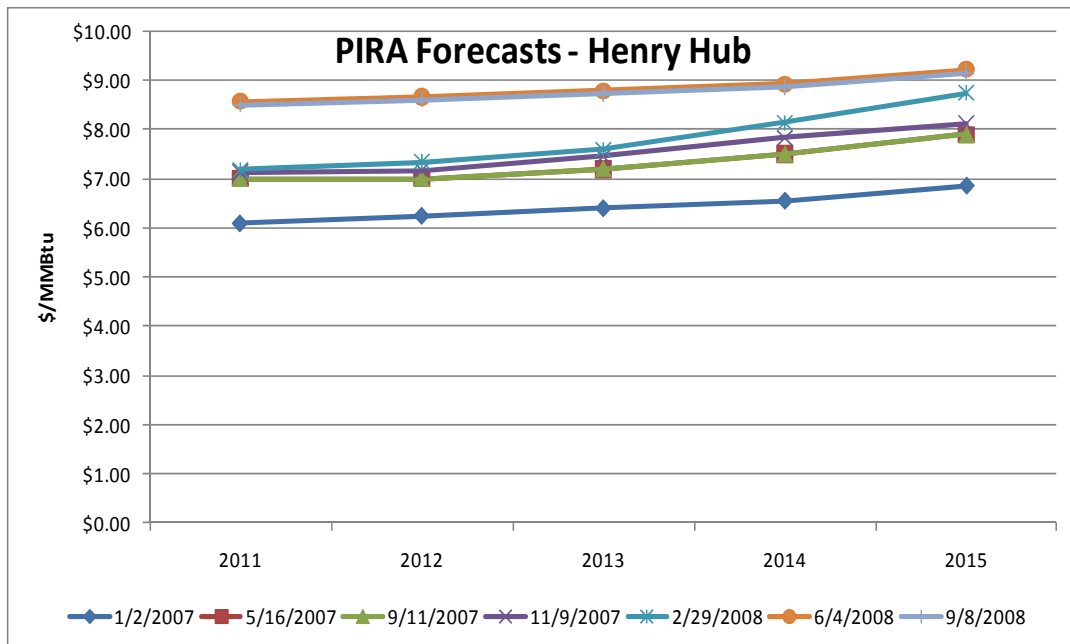
Transaction Year	Pacificorp MTM Adj	ICNU Adjustment	Recommended MTM Amount
2007	-\$20.4	\$20.4	\$0.0
2008	-\$49.8	\$23.3	-\$26.5
2009	-\$36.3	\$0.0	-\$36.3
2010	-\$14.0	\$0.0	-\$14.0
Total:	-\$120.5	\$43.7	-\$76.9

- 1 **Q. At the time the hedges in this case were transacted, what did spot price**
2 **forecasts show with respect to natural gas prices in the test period?**
- 3 A. The Company subscribes to a forecasting service provided by PIRA, a well-
4 known and respected company that provides forecasts of many commodities,
5 including natural gas. PIRA's 2007 and 2008 forecasts of 2011 and 2012 Henry
6 Hub natural gas spot prices, shown in Figure 5, increased from approximately \$6
7 per MMBtu in early 2007 to approximately \$9 per MMBtu in mid-2008 before
8 decreasing to approximately \$8 per MMBtu in late 2008. These spot price
9 forecasts were slightly but not significantly lower than the forward market price
10 curves for each of the contemporaneous time periods. However, spot price
11 forecasts only represent a speculative view of expected prices; there is no legal
12 recourse if forecasted prices fail to materialize. Spot price forecasts only serve as
13 price indicators and carry a high degree of price uncertainty that often has more
14 upward than downward price risk due to the asymmetrical nature of commodity
15 prices. Contracts, however, are based on forward prices that bind counterparties
16 to stipulated prices and delivery schedules with payments made at time of
17 delivery.

1 **Q. Is it apparent that PIRA, as reflected in its spot price forecast shown in**
 2 **Figure 5, anticipated the precipitous drop in natural gas prices?**

3 A. No. Notably, PIRA's spot price forecast continued to climb for the delivery
 4 period 2011 through 2015.

Figure 5



5 **Conclusion**

6 **Q. Please summarize your rebuttal testimony on the intervenors' hedging**
 7 **adjustments.**

8 A. The Company respectfully requests that the Commission allow full recovery of
 9 the Company's forecast hedging costs in this case. These costs were incurred in
 10 compliance within a well-defined risk management policy and hedging program
 11 that has been independently verified. When measured on a multi-year, all-in
 12 basis, the Company's hedge program has reduced the volatility of net power costs
 13 in rates and provided significant benefits to customers. There is no basis for a

1 prudence disallowance simply because hedges increase net power costs in this
2 case. Nor is there any basis for a prudence disallowance because some parties use
3 hindsight to allege that the Company hedged too much or hedged too far forward.
4 The premise of each of these arguments is that the Company should have
5 predicted in 2007-2009 that gas prices would decrease for the test period. This
6 premise is undermined by the evidence of actual market forward price curves and
7 third party spot price forecasts during the time that the Company transacted the
8 hedges in this case. Although the Company believes its current risk management
9 policy and hedge program reflect industry best practices and reasonable risk
10 tolerances, the Company welcomes Commission feedback particularly in regard
11 to going forward risk tolerances, any other aspect of the Company's risk
12 management policy and hedge program, and any type of reporting that the
13 Commission may desire.

14 **Q. Does this conclude your rebuttal testimony?**

15 **A. Yes.**