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Witness: Stefan A. Bird

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

PACIFICORP

Exhibit Accompanying Rebuttal Testimony of Stefan A. Bird
Public Utility Commission of Oregon's Natural Gas Procurement Study
Relevant Portions

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Public Utility Commission of Oregon Natural Gas Procurement Study

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Executive Summary

This study on natural gas utility (LDC, or local distribution company) natural gas procurement was conducted under the Public Utility Commission of Oregon (OPUC or the Commission) 2004 Objective of establishing regulatory incentives and policies to promote least-cost energy resource development, specifically the examination of whether utility strategies for purchasing natural gas are reasonably designed to achieve rate stability at the lowest possible cost.

The study had four purposes, which are listed below with OPUC staff (staff) observations and findings:

1) Provide background information on natural gas markets, prices, and hedging instruments and techniques, including studies performed by and for other jurisdictions.

Staff's findings are:

- Hedging, defined broadly, is entering in to a transaction that reduces financial risk.
- Liberty Consulting, in their study for the Kentucky Public Service Commission, found that:
 - LDC staff responsible for the implementation of hedging plans should be knowledgeable about the futures market to know when the plan should be changed;
 - Hedging positions should be managed by a qualified LDC employee or an agent working in the interest of the LDC, not a commodities broker;
 - All parties should acknowledge that hedging programs will incur legitimate costs; and
 - The objective for any hedging program should be clearly defined.
- The Illinois Commerce Commission (ICC), in their study of hedging, found that:
 - The ICC is not opposed to hedging or liable to second guess legitimate risk management activities when hedged natural gas costs turn out to be higher than spot market prices;

- Hedging does not guarantee lower costs, but does reduce exposure to price volatility; and
- The use of hedging may distort price signals to customers.
- The Arizona Corporation Commission, in their study of natural gas procurement, found that:
 - LDCs should pursue longer term, fixed price supply options;
 - The Arizona Commission should adopt language that if a contract is prudent and reasonable at the time it is entered into, the utility should be permitted an opportunity to recover those gas costs; and
 - The Arizona Commission should recognize price stability as one of the goals of the natural gas procurement process.

2) *Analyze the results of Oregon LDC natural gas purchasing strategies over the past five years.*

Staff conducted a study of the three Oregon LDCs natural gas purchasing strategies for the five Purchased Gas Adjustment (PGA) Years 1999/2000 through 2003/2004. The three LDCs reported the following breakdowns of purchasing strategies:

Table E.1. Avista Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	99/00	00/01	01/02	02/03	03/04
Hedged Volumes	37	34	36	36	36
Jackson Prairie Volumes	1	1	1	1	1
First-of-the-Month (FOM) Volumes	62	65	63	63	63
Total	100	100	100	100	100

Table E.2. Cascade Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	99/00	00/01	01/02	02/03	03/04
Physical with Fixed Price from Supplier	96.1	95.6	97.7	98.7	99.1
Storage	3.9	4.4	2.3	1.3	0.9
Total	100.0	100.0	100.0	100.0	100.0

Table E.3. NW Natural Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	99/00	00/01	01/02	02/03	03/04
Without Hedge	7.0	9.3	7.2	4.5	1.7
With Hedge ¹	41.9	66.1	49.5	54.7	82.2
Fixed Price ²	31.1	8.2	30.2	27.0	3.3
Storage	20.0	16.4	13.1	13.9	12.8
Total	100.0	100.0	100.0	100.0	100.0

The PGA mechanisms of Cascade and NW Natural use forecast base commodity gas costs as a baseline by which their actual commodity costs are compared. If the actual commodity costs differ from the base commodity costs, 67 percent of the difference, either positive or negative, are debited or credited, respectively, to the PGA. The remaining costs or credits are charged to shareholders.

Avista has been on the Gas Benchmark Mechanism (GBM) tariff since 1999.³ The GBM fixes the price paid by all Oregon customers for the commodity portion of the natural gas costs to five cents per dekatherm (0.5 cents/therm) above the weighted average index price of natural gas sold. Avista weights their gas purchases by supply basin, and the weights are 50 percent AECO, 25 percent Sumas, and 25 percent Rockies. The GBM sunsets on March 31, 2005.

Staff analyzed the total cost of gas, which is the filed total gas cost rate embedded in customer rates plus deferrals, demand costs, and storage costs.

Table E.4. Oregon LDC Total Cost of Gas, PGA Years 1999/2000 through 2003/2004 (\$/therm).

PGA Year	Avista (\$)	% Change	Cascade (\$)	% Change	NW Natural (\$)	% Change
1999/2000	0.39990	-	0.34515	-	0.33899	-
2000/2001	0.57217	43.1	0.52270	51.4	0.46370	36.8
2001/2002	0.55802	(2.5)	0.61940	18.5	0.58638	26.5
2002/2003	0.56175	0.7	0.58834	(5.0)	0.49716	(15.2)
2003/2004	0.71292	26.9	0.59731	1.5	0.55959	12.6
5-Year Increase	0.31302	78.3	0.25216	73.1	0.22060	65.1

¹ Price with a supplier is tied to an index, but a financial transaction (swap or option) with a separate counterparty fixes the price.

² Price was fixed with a supplier for some period of time.

³ See Public Utility Commission of Oregon Order No. 99-521 and Avista Utilities Oregon Tariff Schedule 464.

Staff conducted an analysis of LDC purchasing strategies versus the market for the three Oregon LDCs. Staff analyzed the opportunity cost of choosing the overall procurement strategy over simply purchasing identical quantities from the LDC's respective hubs at the market index price, represented as the percent of market spent on natural gas as a result of the purchasing strategies for each PGA year studied.

In order to balance analytical rigor with the practicality of the data provision burden placed on the three LDCs, staff chose a monthly market framework for the cost of hedging analysis. The monthly market framework was also useful because a large portion of LDC purchases during the period were made under contracts in which the price of natural gas was fixed for the entire month or tied to a monthly market index, such as the FOM index.

This analysis was not intended to be a down-to-the-dollar precise accounting of the effects of each strategy. Some amount of precision is lost when using monthly data instead of daily data. For example, monthly data does not have the detail of daily spot transactions. In addition, using the FOM price may not be entirely representative of daily price movements within a month, and may not be as accurate as reported historical average hub prices. Because only a small percentage of LDC purchases took place at a daily level of granularity, staff concluded that, overall, the lack of daily data is not an issue in reporting generalized results, but that any interpretation of the results should be mindful of the nature of the data.

Staff's findings are:

- The analysis of each LDC's total cost of gas showed that NW Natural had the lowest total cost of gas in four of the five years studied and also had the lowest five year increase.
- The PGA mechanisms currently in place for Cascade and NW Natural encourage hedging to fix prices and as a result both LDCs have hedged nearly all of their natural gas supply.
- For the time period studied, Avista Energy purchased gas for Avista, and Avista was unable to verify Avista Energy's actual costs of natural gas.
- Even though NW Natural and Cascade have employed different purchasing strategies, the companies experienced similar results in their respective markets. However, NW Natural's purchasing strategies resulted in a lower percent of market spent on natural gas and lower purchase price volatility as compared to Cascade.
- For the five PGA years studied, Cascade and NW Natural have, on average, produced results that come very close to the natural gas market.

Cascade, for the years studied, spent 2.6 percent over the market, on average, but the majority of that figure is accounted for by the 2001/2002 PGA year. NW Natural, for the years studied, spent 4.5 percent *under* the market, on average. NW Natural's results were also affected by the 2001/2002 PGA year, and overall for the study period, their purchasing strategies performed better than the market.

- For Cascade and NW Natural, their purchasing strategies resulted in 30 and 35 percent overall reductions in price volatility, respectively, when compared to market price. However, when broken down by hub, both LDCs saw results in which a reduction in volatility was achieved with a large increase in price or both price and volatility increased.
- The LDC purchasing strategies softened the impact on customers of the price spike that began in April 2000 and ended in August 2001. Though NW Natural experienced a doubling of their weighted average settlement price between September and November 2000, and Cascade's weighted average settlement price tripled during the same period, the two LDCs combined to spend over \$160 million less than if they had purchased at the weighted average market index. Including storage costs, Cascade's purchases for the PGA year were at 70.1 percent of the market, and NW Natural's were at 57.1 percent of the market.
- With hedging, the deviation between market prices and purchasing strategy costs can represent a significant portion of annual revenue. For example, in the 2001/2002 PGA year, the difference between market prices and purchase costs was 21.7 percent of annual revenue for Cascade and 30.8 percent for NW Natural. However, over the five year study period, the representation of the deviation as a percentage of annual revenues for all three LDCs was very small, ranging from 1.1 percent to 1.8 percent.
- Using a monthly analysis of the purchasing strategies, the LDCs were unable to take advantage of the price trough that occurred directly after the price spike. The inability to take advantage of the price trough is because both LDCs used long-term contracts with locked-in prices during this period of time.
- The use of hedging may not necessarily result in the lowest possible price, but does reduce price volatility and can mitigate harm to customers from extreme price spikes.
- The natural gas purchasing strategies of Oregon's electric utilities and large industrial natural gas consumers differ from those of Oregon's LDCs. This is due to both the nature of their businesses (natural gas for peaking

generators vs. serving load, industrial production) and their peak demand times (e.g. summer vs. winter).

- For the five Oregon LDC PGA years studied, PacifiCorp has, on average, produced results better than the natural gas market. Over the study period, the company spent 14.7 percent less than the market, even with the inclusion of their performance in 2001/2002. PacifiCorp was also able to reduce both purchase price and price volatility for their total purchases.
- For the five Oregon LDC PGA years studied, PGE has, on average, produced results better than the natural gas market. Over the study period, the company spent 32.6 percent less than the market, even with the inclusion of their performance in 2001/2002. PGE was also able to reduce both purchase price and price volatility at the three hubs at which they purchased natural gas.

3) Compare the regulatory treatment of Oregon LDC natural gas purchasing strategies to treatments used by other commissions in the United States.

Staff designed and distributed a survey to gauge the regulatory treatment of natural gas purchasing strategies in other jurisdictions. The natural gas procurement survey was sent to the 50 state commissions, including Oregon, and the District of Columbia commission, who are responsible for the regulation of natural gas. In addition to Oregon, twenty-nine commissions responded to the survey. The 30 commissions are responsible for regulating 248 LDCs. Staff's findings are:

- There is no consensus among state regulatory agencies about which regulatory treatments are best for LDC natural gas purchasing practices. Treatments currently in place range from hands-off policies to prescribed purchasing strategies.
- Several commissions, including those in Missouri, Indiana, Illinois, and Michigan, have disallowed natural gas purchases for a variety of reasons. These reasons include failure to document natural gas purchasing practices, failure to evaluate alternative suppliers, failure to implement a planning process that considered the volatile nature of natural gas prices and the impact of price spikes, failure to enter into the lowest cost contract, and failure to renegotiate long-term contracts upon changes in market conditions.

4) Evaluate the potential to use performance-based ratemaking (PBR) techniques in the regulation of Oregon LDC natural gas purchasing strategies.

Oregon's LDCs do not currently employ any performance-based ratemaking mechanisms other than the incentive features of current PGA mechanisms. Staff

found that, nationwide, there is not much performance-based ratemaking that focuses solely on natural gas purchasing strategies, but two companies, Louisville Gas and Electric, and San Diego Gas and Electric, both utilize a PBR mechanism. Their PBR mechanisms benchmark LDC purchasing performance to the LDC's relevant natural gas markets. Staff modeled a hypothetical natural gas LDC called 'Bizgas,' which operated in markets similar to the Oregon LDCs and faced the same peaks and valleys in PGA Years 1999/2000 through 2003/2004, in order to evaluate a simplified version of the San Diego Gas and Electric mechanism.

Staff's findings are:

- When the LDC performs better than the market-based benchmark, the San Diego Gas and Electric PBR mechanism provides potential benefits to both customers and LDCs through its sharing mechanism. The mechanism also provides a strong performance incentive, because there are sharing mechanisms if natural gas costs exceed the benchmark as well as if the costs are below the benchmark.
- In the scenario modeled by staff, customers saw a net benefit and Bizgas experienced a net loss when the five PGA years 1999/2000 through 2003/2004 were summed together. This result is tempered by what may ultimately be two unusual years in the price spike of 2000/2001 and the overpayment for natural gas during the price trough in 2001/2002. It is beneficial to have those two years in the analysis, as they illustrate the need for PBR mechanisms to properly compensate customers and still provide participation incentive to shareholders, especially during unusual years.
- The implementation of the SDG&E PBR model, though simplified, demonstrates the need to balance the interests of both customers and shareholders with the provision of effective performance incentives.

As a result of the natural gas procurement study, staff offers the following recommendations:

- When evaluating LDC purchasing strategies, the Commission should consider total costs, including storage, transportation, etc.
- The Commission should take a results-based approach to purchasing strategy evaluation as opposed to evaluating each transaction or instrument. Individual transactions should still be reviewed if they raise affiliated interest issues or it is unclear that the LDC acted prudently.
- The results of this study do not indicate that there is a need for Commission *pre-approval* of transactions, instruments, or hedging plans. However, LDCs should appropriately document hedging transactions for the purposes of *ex post* Commission review.
- The Commission should require the Oregon LDCs to maintain and annually review a purchasing strategies document and revise as necessary. The document should describe the respective LDC's natural gas purchasing strategies and policies and track changes made over time.
- On a going-forward basis, the Commission should require the Oregon LDCs to maintain and abide by a comprehensive respective risk management policy.
- Additional time may be needed to draw more definitive conclusions. As of April 1, 2005, Avista will be changing their PGA mechanism away from the Gas Benchmark Mechanism, which will affect their purchasing strategies. Cascade has also indicated that it recently changed its purchasing strategies.
- Staff recommends beginning informal discussions with interested parties to consider changes to the current PGA and explore the use of other mechanisms or PBR for one or more LDCs. If the Commission wishes to explore PBRs, the San Diego Gas and Electric PBR, modeled in Section 6 of this report, is a reasonable starting point for designing a PBR mechanism. The market price-based San Diego Gas and Electric mechanism appears to have the potential to benefit both customers and LDCs while providing a strong incentive to meet the goals of the mechanism. Such incentive is provided by the excess costs beyond a preset deadband being shared equally by customers and the LDC, and a sharing mechanism is also applied to costs under the benchmark. The benchmark of any PBR is of utmost importance and should receive careful consideration. The ability to game a PBR mechanism should also be considered during PBR mechanism construction.

5. Oregon Electric Utilities and Industrial Users of Natural Gas

OPUC staff met with representatives of PacifiCorp, Portland General Electric (PGE), and Oregon industrial users of natural gas to discuss their natural gas procurement strategies.

PacifiCorp

PacifiCorp purchases natural gas for four power generation plants: Hermiston in Oregon and West Valley, Gadsby, and Little Mountain in Utah. PacifiCorp differs from the LDCs in that its peak natural gas purchasing season is the summer to meet cooling loads as opposed to the winter heating season. PacifiCorp purchases its natural gas supplies on the forward market based on forecasted requirements. The company also has natural gas storage rights available.

PacifiCorp cited reliability and risk management as the primary goals of their purchasing strategies. The company communicated to staff that it uses at least a three year horizon for supply and acts as a market participant in their purchasing practices. The company represents it transacts at prevailing market prices. PacifiCorp can, and sometimes does, use financial instruments as a part of their natural gas purchasing strategies. The company's natural gas costs for 2006 have been, at least partially, hedged by fixed price purchases executed as far back as 1994 for the Hermiston plant and 2003 for the Utah plants. The result of the hedging is that PacifiCorp's hedged cost of natural gas for 2006 is below current market prices.

In order to analyze PacifiCorp's natural gas purchasing strategies compared to the market, staff conducted an analysis similar to those for Oregon's LDCs in chapter three of this report.⁹⁹

In three of the five years studied, PacifiCorp natural gas purchasing strategies performed better than if the company only bought natural gas at market prices (Table 5.1). Overall, however, PacifiCorp's strategies resulted in a lower long-term percent of market than all three Oregon LDCs, though this result is aided by the flexibility afforded to PacifiCorp because it does not serve natural gas load directly and can sell natural gas based on the economics of its system.

PacifiCorp purchases natural gas at two hubs and at several points on Questar's pipeline transmission and distribution systems. For staff's analysis of PacifiCorp's results on a hub basis (Table 5.2), all delivery points on the Questar system were aggregated. As well, the market price for Stanfield was estimated for eight months of the analysis in which no data was available. The estimated values were simply the averages of the prior and subsequent months in which data existed.

⁹⁹ See page 30.

Table 5.1. PacifiCorp Natural Gas Purchasing Strategies (Including storage) vs. Market, Oregon LDC PGA Years 1999/2000 through 2003/2004.

PGA Year	Percent of Market (%)	Difference From Market (\$000,000)	Number of Therms (000)	Cents Per Therm (¢/therm)
1999/2000	103.0	2.7	304,129	0.9
2000/2001	66.5	(80.6)	440,598	(18.3)
2001/2002	162.6	42.7	324,548	13.1
2002/2003	81.4	(33.0)	408,849	(8.1)
2003/2004	76.0	(41.5)	353,888	(11.7)
Total		(109.7)	1,832,012	
5-Year Average	85.3	(21.9)	366,402	(6.0)

Table 5.2. PacifiCorp's Purchases vs. Market Index (Excluding Storage), Oregon LDC PGA Years 1999/2000 through 2003/2004 (\$/therm).

Hub/Pricing Point	PacifiCorp		Market Index		Increase (Decrease) in Price (%)	Reduction (Increase) in Volatility (%)
	Weighted Average (\$)	Coefficient of Variation	Weighted Average (\$)	Coefficient of Variation		
Questar ¹⁰⁰	0.386	0.25	0.324	0.47	19	9
Rockies	0.454	0.53	0.427	0.51	6	(3)
Stanfield	0.327	0.98	0.401	0.55	(26)	(78)
Overall	0.349	0.10	0.409	0.52	(15)	82

Source: Laura Beane's May 19, 2005, e-mail to Steve Chriss

For the Questar delivery points, PacifiCorp's average price was nineteen percent higher than the market index average, but the volatility of their prices was nine percent lower than if they were to purchase at index. From a price perspective, the company's result was similar for the Rockies hub, where their average price was six percent higher than the market index average, plus the volatility of their prices increased three percent. PacifiCorp's price result for Stanfield, where the company purchases a majority of their natural gas, was a 26 percent decrease in the price of natural gas. The volatility result for Stanfield may be misleading, as the result is thrown off by one month in the analysis in which the average purchase price for the month is seven to eight times higher than other months in that year. If the month in question more closely resembled adjoining months, the overall result would have shown a marked decrease in volatility.

¹⁰⁰ All delivery points.

Overall, when the entire portfolio is considered, PacifiCorp achieved an 82 percent reduction in volatility and a fifteen percent decrease on average in the per therm price of natural gas over the time period analyzed. This result is largely due to PacifiCorp's purchases at the Stanfield hub.

PGE

PGE, like PacifiCorp, cites reliability as a main goal of their natural gas purchasing strategies. PGE also cites low cost and a flat financial profile as goals of their strategies. The company locks-in their natural gas prices up to two years in advance through fixed-for-floating swaps and may buy physical index priced gas between two to three months in advance, or may purchase fixed priced gas in the cash market, depending on plant needs. PGE can use options, but has not executed many options contracts, and has also used basis trades. PGE employs Value-At-Risk (VAR), which specifies risk limits for each portfolio as well as company-wide for natural gas and power purchases. PGE's finance department executes currency hedges in support of the company's natural gas purchases.

The company also has a storage contract with NW Natural which gives PGE the rights to 600,000 MMBtu of capacity in the Mist storage system.

In order to analyze PGE's natural gas purchasing strategies compared to the market, staff conducted an analysis similar to those for Oregon's LDCs.

Because PGE purchases natural gas to supply power plants, not to directly serve load, the company proposed that the analysis look at the whole of their natural gas purchasing operations, including storage, resale of natural gas, and the use of financial instruments. Staff agreed to account for these activities in the analysis, so in each month of the model, the $WAST_t$ variable¹⁰¹ represents the net of natural gas purchases and resale, financial instrument results, and storage costs.

The nature of the $WAST_t$ variable meant that in some months, PGE had negative net purchases (i.e. they sold more than they bought). In calculating the market variable, $WAMI_t$, negative net purchase months were counted as zero therms. The inference was that the company would only purchase natural gas from the market in months that the company actually needed natural gas, and would only purchase as many therms as were necessary for operation.

In four of the five years studied, PGE's natural gas purchasing strategies performed better than if the company only bought natural gas at FOM market prices for as many therms as were necessary for operation (Table 5.3). PGE's strategies resulted in a lower long-term percent of market than all three Oregon LDCs and PacifiCorp, though, like PacifiCorp, this result is aided by the

¹⁰¹ See page 30.

Table 5.3. PGE Natural Gas Purchasing Strategies (Including Storage, Resale, and Financial Instruments) vs. Market, Oregon LDC PGA Years 1999/2000 through 2003/2004.

PGA Year	Percent of Market (%)	Difference From Market (\$000,000)	Number of "Necessary" Therms ¹⁰² (000)	Cents Per Therm (¢/therm)
1999/2000	72.1	(26.5)	311,417	(8.5)
2000/2001	51.5	(136.6)	536,008	(25.5)
2001/2002	229.6	39.8	179,600	22.1
2002/2003	61.0	(15.3)	117,559	(13.4)
2003/2004	61.9	(44.6)	259,665	(17.4)
Total		(184.4)	1,404,250	
5-Year Average	67.4	(36.9)	280,850	(14.6)

flexibility afforded to PGE because it does not serve natural gas load directly and can sell natural gas based on the economics of its system. If PGE's purchases were considered without resale and financial instruments, the company's five-year average percent of market would be 92 percent, which is closer, relatively, to NW Natural's value of 95.5 percent.

To compare PGE's results on a hub basis (Table 5.4), staff used purchases only to facilitate the most direct comparison to the market as possible.

For the Sumas hub, PGE's average price was four percent lower than the market index average, and the volatility of their prices was 51 percent lower than if they were to purchase at index. The company's result was similar for the Rockies hub, where their average price was two percent lower than the market index average, and the volatility of their prices decreased 42 percent. PGE's results for Alberta/NIT were a fourteen percent decrease in the price of natural gas coupled with a 28 percent reduction in price volatility.

Overall, when the entire portfolio is considered, represented by the weighted average numbers of purchases only, PGE achieved a 47 percent reduction in volatility with an eight percent decrease on average in the per therm price of natural gas over the time period analyzed.

¹⁰² Does not include resold therms.

Table 5.4. PGE's Purchases vs. Market Index (Excluding Storage, Resale, and Financial Instruments), Oregon LDC PGA Years 1999/2000 through 2003/2004 (\$/therm).

Hub	PGE		Market Index		Increase (Decrease) in Price (%)	Reduction in Volatility (%)
	Weighted Average (\$)	Coefficient of Variation	Weighted Average (\$)	Coefficient of Variation		
Sumas	0.399	0.27	0.417	0.55	(4)	51
Rockies	0.338	0.26	0.346	0.44	(2)	42
Alberta/NIT	0.329	0.28	0.384	0.39	(14)	28
Overall	0.356	0.24	0.387	0.45	(8)	47

Source: PGE's April 14, 2005, response to OPUC staff's March 23, 2005 data request

Table 5.5. Electric Utility Natural Gas Purchasing Strategies (Including Storage) vs. Market as a Percent of Annual Revenue.

Year	PacifiCorp (%)	PGE (%)
2000	2.4	7.6
2001	2.8 ¹⁰³	5.9
2002	3.3	1.6
2003	4.2	1.2
4-Year Average	1.6	2.8

Staff calculated the difference between the results of each company's natural gas purchasing strategies and its respective market for the years 2000 through 2003 for both electric utilities (Table 5.5). The discrepancy between the annual values and the four-year averages was due to the use of the absolute value of the sum of OUM and STO¹⁰⁴ to calculate the percentages. If the annual values were calculated without using the absolute value, years 2000, 2001, and 2003 would be negative for both PacifiCorp and PGE. The four-year average value takes the negative years into account through the summation of the four years of OUM data.

As was the case with the LDCs, the time frame of the analysis is very important. The results for PacifiCorp and PGE are the product of the specific market, company-specific operational conditions, and market prices from December, 1999, through September, 2004. Just as the performance of both companies varied in the past, the future performance of PacifiCorp and PGE should be expected to vary from the results of this study.

¹⁰³ Estimated, due to the company's change from calendar year to fiscal year for regulatory reporting.

¹⁰⁴ See pages 30 and 31.

Oregon Industrial Gas Users

In their meeting with staff, representatives of Oregon industrial gas users stated that the most successful companies use dollar cost averaging techniques in their natural gas purchasing strategies. The representatives cited the use of overlapping two year strips as a means to dollar cost average.

The use of participation swaps was also cited as a technique used by the industrials. A participation swap is similar to a regular fixed-for-floating swap in that one party pays a fixed price stream in exchange for the other counterparty's payment of a floating price stream. The participation swap is different in that the party that pays the fixed price receives a portion of the savings if the floating price drops below the fixed price.¹⁰⁵ For example, if an industrial agreed to a \$6/MMBtu price for natural gas with 50 percent participation, the industrial would receive 50 percent of any savings generated by the price of natural gas dropping below \$6.

The industrial representatives reported that the cost of hedging was probably in the range of one to three cents per dekatherm.

Staff's findings are:

- The natural gas purchasing strategies of Oregon's electric utilities and large industrial natural gas consumers differ from those of Oregon's LDCs. This is due to both the nature of their businesses (natural gas for peaking generators vs. serving load, industrial production) and their peak demand times (e.g. summer vs. winter).
- For the five Oregon LDC PGA years studied, PacifiCorp has, on average, produced results better than the natural gas market. Over the study period, the company spent 14.7 percent less than the market, even with the inclusion of their performance in 2001/2002. PacifiCorp was also able to reduce both purchase price and price volatility for their total purchases.
- For the five Oregon LDC PGA years studied, PGE has, on average, produced results better than the natural gas market. Over the study period, the company spent 32.6 percent less than the market, even with the inclusion of their performance in 2001/2002. PGE was also able to reduce both purchase price and price volatility at the three hubs at which they purchased natural gas.

¹⁰⁵ See Platt's Derivatives Glossary.
<http://www.platts.com/Oil/Resources/Glossaries/derivativesglossary.html>.