

EXHIBIT NO. ____ (DEM-1CT)
DOCKET NO. UE-07 ____
2007 PSE PCORC
WITNESS: DAVID E. MILLS

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY, INC.,

Respondent.

Docket No. UE-07 ____

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS
ON BEHALF OF PUGET SOUND ENERGY, INC.**

**REDACTED
VERSION**

MARCH 20, 2007

PUGET SOUND ENERGY, INC.

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS**

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PUGET SOUND ENERGY, INC.

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS**

I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is David E. Mills. My business address is 10885 NE Fourth Street Bellevue, WA 98004. I am the Director, Power & Gas Supply Operations for Puget Sound Energy, Inc. ("PSE" or "the Company").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ____ (DEM-2).

Q. What are your duties as Director, Power & Gas Supply Operations for PSE?

A. My responsibilities include oversight of the Company's Power Supply Operations and Gas Supply Operations Departments, including the following: (i) managing all PSE short-term (intra-month) and medium-term (up to three years) wholesale power and natural gas portfolios; and (ii) working with the Company's Energy Resources Department to plan for long-term hedging requirements. My responsibilities also include developing strategies to address risks related to PSE's electric and gas

1 portfolios. Specifically, my focus tends to be more the operational and
2 implementation side of portfolio risk management. In other words, I focus on the
3 wholesale energy market transactions that the Company enters into to implement its
4 hedging strategies and policies.

5 **Q. What is the nature of your testimony in this proceeding?**

6 A. My testimony focuses on the risks facing the Company as a result of the electric
7 portfolio.¹ I also address the structures and policies the Company has in place to
8 manage these risks and the manner in which these policies are implemented.
9 Among other things, I describe the robust hedging program that the Company has in
10 place for its electric portfolio that is based on sound analyses and is reexamined and
11 adjusted, as needed, in response to updated information. In short, the Company
12 strives to further reduce the volatility of energy costs associated with its wholesale
13 market purchases of power and natural gas for generation.

14 I describe PSE's progress towards revising the existing hedging strategies. The
15 prefiled direct testimony of Mr. Donald E. Gaines, Exhibit No. ____ (DEG-1CT),
16 describes the Company's efforts to establish a separate line of credit to support the
17 Company's hedging activities.

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¹ The electric portfolio includes generation facilities, purchased power and transmission capacity. For a further discussion, please see the prefiled direct testimony of Mr. Eric M. Markell, Exhibit No. ____ (EMM-1HCT).

1 My testimony then describes and presents the Company's projection of rate year
2 power costs for this proceeding, noting changes to PSE's power supply portfolio
3 since Company's 2006 general rate case, Docket No. UE-060266 and UG-060267
4 (the "2006 GRC"). I explain how key assumptions used in projecting those costs
5 are consistent with the methodologies approved by the Commission, and
6 implemented by the Company, in the 2006 GRC, in the Company's 2004 general
7 rate case, Docket No. UG-040640, *et al.* (the "2004 GRC"), and in the Company's
8 last Power Cost Only Rate Case, Docket No. UE-050870 (the "2005 PCORC").

9 I also compare the projected rate year power costs in this proceeding to the
10 projected rate year power costs approved in the 2006 GRC. Altogether, PSE's
11 projected rate year net power costs for this case are \$1.047 billion, which is
12 approximately \$112.7 million higher than the power costs used in establishing
13 PSE's Power Cost Adjustment Mechanism ("PCA") Baseline Rate for the
14 2006 GRC.

15 **II. PSE'S MANAGEMENT OF POWER** 16 **AND GAS COST RISKS**

17 **Q. Is energy risk management a concern to the Company?**

18 A. Yes, absolutely. PSE's resource portfolio is subject to significant volatility and risk
19 that ultimately have a substantial impact on energy costs, which is one of the
20 reasons the Company has dedicated an entire department to energy risk
21 management.

1 **Q. What drives volatility and risk in the power portfolio?**

2 A. PSE's power supply portfolio contains a diverse mix of resources with widely
3 differing operating and cost characteristics. Mr. Eric Markell describes PSE's
4 power supply portfolio in his direct testimony. Although there are many complex
5 variables embedded in the portfolio, the major drivers of power cost volatility are:
6 (1) streamflow variation affecting the supply of hydroelectric generation;
7 (2) weather uncertainty affecting power usage; (3) variations in market conditions
8 such as wholesale gas and electric prices; (4) risk of forced outages; and (5)
9 transmission and transportation constraints. All of these have an impact on load
10 and resource volatility, which PSE balances with wholesale market purchases and
11 sales.

12 **Q. Please describe the volatility related to variations in hydroelectric supply.**

13 A. During an average streamflow year, approximately one-third of PSE's electric
14 energy production comes from hydroelectric resources. During poor streamflow
15 conditions, PSE may need to acquire replacement power to serve its customer load.
16 During favorable streamflow conditions, PSE may need to sell surplus power to
17 balance its supply portfolio. These balancing transactions are conducted in the
18 wholesale power markets. Because the market price of power is quite volatile,
19 hydroelectric shortfalls or surpluses can greatly affect PSE's power costs.

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1 **Q. Please describe the volatility that is related to load and temperature**
2 **uncertainty.**

3 A. The Pacific Northwest region has a high saturation of electric heating relative to
4 other areas of the country. As a result, the level of PSE's retail electric load is
5 closely related to temperature – meaning that during the winter heating season
6 PSE's load increases as the weather gets colder. In light of the significant electric
7 heating load in PSE's service territory, PSE's cost of load/temperature uncertainty
8 can be significant. While still a winter peaking region, the Pacific Northwest is also
9 experiencing a summer peaking load, such as was experienced on July 24, 2006.
10 This is evidence of a higher saturation of electric air conditioning and presents
11 another example of electric load volatility attributable to temperature.

12 **Q. Please describe the risks related to market price volatility.**

13 A. The foregoing volume-related risks affect the amount of PSE's exposure to market
14 prices. PSE also has significant price-related risk associated with the expected
15 volume of its purchases and sales of power in the wholesale markets and its need to
16 purchase or dispose of natural gas in connection with the operation of its gas-fueled
17 generating units.

18 **Q. Please describe the volatility related to forced outages.**

19 A. As shown below, PSE relies on nearly 2,400 MW (nameplate) of thermal
20 generating units to help meet its customer loads. These units include approximately

680 MW of large base load coal generators with low variable fuel costs; approximately 1,100 MW of gas combined-cycle combustion turbine co-generators with moderate heat rate conversions; and approximately 600 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generators.

Thermal Generation Units	
	Capacity (MW)
Coal	681
Goldendale	277
Fredrickson	134
Encogen	170
NUGS	523
Simple Cycle CTs	596
	2,381

Forced outages at any of these units can expose PSE to significant price volatility in its power supply portfolio. Material or equipment failure, fire, electrical disturbances, or other force majeure events typically cause forced outages.

Q. What risks are related to transmission and transportation constraints?

A. Pipeline outages, curtailment of transmission rights due to deratings,² and forced outages are examples of transmission and/or transportation risk. For example, if power cannot be wheeled³ from the Mid-Columbia trading hub ("Mid-C"), the Company may dispatch resources that are less economic in order to meet load.

² Derating refers to a decrease in the rated electric capability of an electric transmission line.

³ Wheeling means using the transmission facilities of one power system to transmit power of and for another system. This term is often used colloquially to mean transmission.

1 **Q. Are PSE's power and gas costs subject to other risks?**

2 A. Yes, examples of other risks include:

- 3 • counterparty risk, which is the risk of default by PSE's counterparties on
- 4 contractual obligations; and
- 5 • execution risk, which refers to the ability to execute wholesale market
- 6 transactions. Market liquidity, counterparty credit requirements and
- 7 contractual requirements are examples of execution risk.

8 **Q. How does the Company manage the volatility of power and gas costs?**

9 A. The Company has in place organizational structures, policies and overarching
10 strategies to provide oversight and control of energy portfolio management
11 activities, many of which must be undertaken on an hourly and daily basis by the
12 experienced energy traders employed by PSE. The Company also uses modeling
13 tools that assist in projecting whether its power and gas portfolios will be surplus or
14 deficit in future months. The Company uses these tools to develop and implement
15 hedging strategies to reduce the cost risks associated with portfolio volatility. A
16 detailed description of PSE's current and previous power hedging strategies is
17 attached as Exhibit No. __ (DEM-3C).

18 **Q. Please summarize the Company's efforts with respect to developing and**
19 **implementing hedging strategies for its electric portfolio.**

20 A. In order to manage its electric portfolio within a dynamic and complex
21 environment, as described above, the Company has put in place the following
22 measures:

- Internal organizations and staff dedicated to managing portfolio risks;
- Executive and Board level oversight of staff's portfolio management activities;
- Specific procedures, policies and limits governing energy portfolio management activities;
- Production cost modeling techniques that develop a one hundred scenario probabilistic view of PSE's wholesale electric portfolio and its underlying risks;
- Use of programmatic hedging strategies that specify a range of monthly volumes to be hedged, depending upon market fundamentals;
- Selection of specific commodities to be hedged as informed by Margin at Risk analyses;
- Revision of strategies to incorporate up-to-date fundamental views of energy commodity markets; and
- A counterparty credit risk system to evaluate potential transactions with respect to credit issues.

Q. Does the Company plan to revise its current power hedging strategies?

A. Yes. The Company is planning to extend the term of the power hedging strategy from ■■■ to ■■■ months as well as augment the active position management period from the first ■■■ months to the first ■■■ months. This revised strategy will retain many of the same features as our existing hedging strategy:

- (1) A required ratable reduction of monthly commodity exposure is removed each month;
- (2) The volume of monthly hedging and intra-month timing for hedging is informed by market fundamentals; and
- (3) Hedging targets are established on the basis of the minimum or

1 maximum amount of commodity exposure allowed under the
2 Company's Energy Hedging and Optimization Procedures.

3 The revised plan requires that on or before ■ months ahead of delivery, the bulk of
4 the hedging strategies and transactions have been made per this programmatic plan.
5 Beyond the ■ months prior to delivery, the revised strategy then employs a
6 "Rolling ■ Month Hedging Plan", making the cumulative term a total of ■
7 months.

8 **Q. Why is the Company planning to make revisions to its existing hedging**
9 **strategy?**

10 A. These revisions will enable the Company to monitor and more actively address the
11 exposure associated with PSE's power portfolio position ■ months ahead of the
12 time the power would be needed to meet load, thus enabling staff to more actively
13 manage the next rolling ■ months. We are able to expand our hedging strategy
14 with the flexibility allowed by our new line of credit facility discussed in he
15 prefled direct testimony of Mr. Donald E. Gaines, Exhibit No. ____ (DEG-1CT).

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1 **III. PROJECTED RATE YEAR POWER COSTS**

2 **A. OVERVIEW OF PROJECTED POWER COSTS FOR THIS PROCEEDING**

3 **Q. Please describe how PSE projected its pro forma net power costs in this filing.**

4 A. Consistent with prior rate cases, PSE developed projected power costs for the rate
5 year, which for this filing is September 1, 2007 through August 31, 2008. These
6 projections are based on the information available to the Company while preparing
7 this case for filing. As discussed by Mr. John Story in his testimony,
8 Exhibit No. ____ (JHS-1T), the resulting rate year forecast power costs were then
9 adjusted to test year levels by multiplying by an adjustment factor. This adjustment
10 factor represents the ratio of weather normalized delivered energy loads for the test
11 year to the rate year. Mr. Story then used that and other data to develop the revenue
12 deficiency for the rate year.

13 **Q. How did the Company project its power costs for the rate year?**

14 A. As in prior cases, PSE used the AURORA hourly dispatch model to project a
15 portion of its net power costs for the rate year. The AURORA model is a
16 fundamentals-based production cost model that simulates hourly economic dispatch
17 of the Company's generation resource portfolio within the Western Electricity
18 Coordinating Council ("WECC") region. AURORA thereby produces a forecast of
19 the variable operating costs for the Company's generating resources. As described
20 below, the Company's inputs to AURORA for projecting rate year power costs for

1 this case are consistent with the Commission's power cost determinations in the
2 Company's 2004 and 2006 general rate cases and 2005 PCORC.

3 Consistent with prior cases, the Company's projected power costs also include costs
4 not calculated within the AURORA model. Costs projected outside of the
5 AURORA model include items such as contract costs for the Mid-C hydroelectric
6 projects, transmission expenses, fixed pipeline charges, amortization of regulatory
7 assets, mark-to-market for fixed-price contracts, fixed coal supply costs, peaking
8 capacity and exchange costs, fixed capacity charges, wind integration and other
9 power supply costs.

10 **Q. Were there any changes in the AURORA model?**

11 A. Yes, EPIS, Inc., the AURORA model's developer, provides periodic software and
12 database updates. The version of AURORA used in this filing includes the most
13 recent updates from EPIS.

14 **Q. Has the Company used forward market electric prices in determining the rate**
15 **year power costs?**

16 A. No. For this proceeding, the Company used the forward electric market prices
17 determined by AURORA. Consistent with the Commission's order in the 2006
18 GRC, the Company will investigate the possibility of using forward electric market
19 prices to determine power costs and will advise the Commission of its findings on
20 or before the Company's next general rate case.

1 **Q. Is PSE's rate year power supply portfolio for this proceeding different from**
2 **the pro forma power cost portfolio approved in the 2006 GRC?**

3 A. Yes. A number of changes to the Company's portfolio have already occurred or
4 will occur by or during the rate year for this case, in that the Company:

- 5 • Added the Goldendale Generating Station to the power portfolio in
6 February 2007 (as discussed in the testimony of Mr. Roger Garratt);
- 7 • Added the 20-year purchased power agreement between PSE and
8 OrSumas, LLC for the output of the Northwest Pipeline recovered
9 heat generation resource at Sumas developed by ORMAT beginning
10 November 1, 2007. This resource acquisition was deemed prudent
11 in the Company's 2006 GRC;
- 12 • Reflected the expiration of the contract between PSE and Occidental
13 Energy Marketing, Inc. for gas transportation between Rockies and
14 Sumas effective March 31, 2008;
- 15 • Reflected the expiration of several long-term gas contracts effective
16 June 30, 2008;
- 17 • Projected that the contract with Powerex to serve the Point Roberts,
18 Washington load, would be extended past the September 2007
19 expiration date;
- 20 • Reduced the benefit from the Priest Rapids hydroelectric project due
21 to Grant County PUD's forecast load growth; and
- 22 • Reduced the forecast rate year generation from the Snoqualmie
23 hydroelectric facility as a result of construction required under the
24 FERC license.

25 **Q. Please quantify PSE's net power cost projection for this case.**

26 A. PSE's projected rate year net power costs, including production operation and
27 maintenance expenses and power cost ratemaking adjustments, are \$1.047 billion.

28 *See Exhibit No. ____ (DEM-4). Mr. John Story addresses adjustment of this cost to a*

test year level in his Exhibit No. ____ (JHS-1T).

B. POWER COST ASSUMPTIONS

1. Hydro

Q. What historical streamflow record has PSE used in its net power cost projection for this case?

A. Consistent with the past several rate cases, including the 2006 GRC, PSE used the average of the 50-year Mid-C streamflow history from 1928 through 1977 to project power costs for the rate year. Projections related to PSE's owned hydropower on the west side of the Cascades were based on historical west side streamflow records for the same period of time, consistent with the 2004 GRC, the 2006 GRC and the 2005 PCORC.

Q. What assumptions did the Company make for shaping hydro within the AURORA model?

A. The Company assumed the same hydro shaping factors within the AURORA model as it used in the 2006 GRC power cost analysis. Approximately 65.1% of hydro is included in the on-peak hours, consistent with 64.5% in the 2006 GRC.

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1 **2. Natural Gas Prices**

2 **Q. What natural gas prices did the Company use for the rate year in running its**
3 **AURORA model?**

4 A. As the Commission noted in the 2006 GRC order, the update for gas costs is “well-
5 established” and should be “straightforward, mechanical and non-controversial.”
6 *See WUTC v. PSE*, Docket No. UE-060266 and UG-060267, Order No. 08, ¶104
7 (Jan. 5, 2007). Consistent with this order, the Company used a three-month average
8 of daily forward market prices for the rate year for each trading day in the three-
9 month period ending February 27, 2007. These data were input into the AURORA
10 model for each of the months in the rate year. To the extent the Company has
11 fixed-priced contracts in place for power or natural gas for its power portfolio for
12 the rate year, the Company adjusted for those fixed-priced contracts outside of the
13 AURORA model.

14 **Q. Please explain the fixed-priced contracts adjustment.**

15 A. The gas price input to AURORA represents a three-month average of the forecast
16 *market* rate year gas prices at a certain point in time, e.g., February 27, 2007.
17 Given the Company’s extensive hedging protocol, which includes a programmatic
18 component that requires a specified amount of hedging be done each month, it is
19 required to reflect the actual fixed priced gas and power rate year contracts the
20 Company has transacted as of that date. This is the correct methodology for
21 reflecting these hedges because forecast rate year power costs consist of two

1 components: first, costs related to *actual* commitments, and second, *forecast*
2 *market costs* that are dependent upon the AURORA modeled operational and
3 market fluctuations. This methodology is consistent with the 2005 PCORC
4 (including the second compliance filing to the 2005 PCORC, Docket No. UE-
5 060783) and the 2006 GRC.

6 **Q. How do projected gas prices for this proceeding compare with the projected**
7 **gas prices for the 2006 GRC?**

8 A. Use of a single price can be misleading in that there are different projected gas
9 prices for each month of the rate year and for the different trading hubs from which
10 PSE purchases gas. However, for purposes of comparison, the average price at
11 Sumas (for the three months ended February 27, 2007) for this proceeding's rate
12 year is \$7.57/MMBtu compared to the average rate year price at Sumas of
13 \$7.41/MMBtu (for the three months ended November 30, 2006) for the 2006 GRC.

14 **Q. Please explain the Company's source of these inputs.**

15 A. For this proceeding, consistent with the 2006 GRC, the Company made use of
16 forward price data supplied by a third party service for energy and commodity
17 market data known as the Kiodex Global Market Data ("Kiodex"). The Company
18 has contracted with Kiodex for forward market price data for specific gas and
19 power trading points. The Company was able to use the Kiodex forward prices for
20 the rate year at each of the trading hubs that are input into AURORA.

1 **Q. Does PSE intend to update its projected power costs with updated gas price**
2 **projections?**

3 A. Yes. Because the factors that impact natural gas prices are constantly changing,
4 forward market prices quickly become “stale” and their predictive power with
5 respect to actual future prices decreases. Establishing rate year gas prices based on
6 the average of the forward prices for the rate year for a three-month period of time
7 closer to the beginning of the rate year will provide a more accurate projection of
8 rate year gas prices. Therefore, while PSE used the three-month average of the
9 forward marks ending February 27, 2007, for its direct testimony, it would be
10 appropriate for the Company to adjust its requested rate relief with updated forward
11 market data prior to rates becoming effective.

12 **3. Production Operation and Maintenance**

13 **Q. How has PSE developed its forecast of production operation and maintenance**
14 **costs in this filing?**

15 A. In estimating rate year power costs, PSE has made the following adjustments to its
16 test year (calendar year 2006) production operation and maintenance costs:

- 17 i) Projected the operation and maintenance costs of the Goldendale
18 Generating Station (as discussed in the testimony of Mr. Roger
19 Garratt);
- 20 ii) Projected the operation and maintenance costs of the Wild Horse and
21 Hopkins Ridge wind projects;

- 1 ii) Projected the operation and maintenance costs of the Frederickson 1
2 resource based on Epcor's forecasted operation and maintenance
3 costs and the rate year expected generation;
- 4 iii) Normalized the arbitration settlement awarded to the Muckleshoot
5 Indian Tribe for fish hatchery costs related to the White River
6 Project over a four-year period, as approved by the Commission in
7 the 2006 GRC;
- 8 iv) Normalized operation and maintenance for major maintenance for
9 PSE's owned simple-cycle gas and oil-fired combustion turbines and
10 PSE's owned Encogen and Fredrickson 1 plants based on operating
11 cost studies and expected rate year generation;
- 12 v) Projected the Whitehorn 2 & 3 and Fredonia 3 & 4 lease costs to
13 reflect the lease costs expected in the rate year;
- 14 vi) Projected the operation and maintenance costs associated with the
15 Snoqualmie Hydroelectric Project and with the FERC relicensing of
16 the Baker River Project;
- 17 vii) Projected the Colstrip operation and maintenance costs based upon
18 forecasted operation and maintenance costs; and
- 19 viii) Removed test year clean up costs for the Crystal Mountain oil spill.

20 **IV. COMPARISON OF PROJECTED POWER COSTS TO THE**
21 **COMPANY'S 2006 GENERAL RATE CASE**

22 **Q. What are the principal differences between the power cost projections in this**
23 **case and the power cost projections that were approved as part of the**
24 **Company's 2006 GRC filing?**

25 A. Exhibit No. ____ (DEM-5) shows a comparison of the projected power costs for the
26 2006 GRC rate year (calendar year 2007) and the projected power costs for the rate
27 year in this case (September 2007 through August 2008).

1 Altogether, the projection of power costs for this case, including production
2 operations and maintenance and ratemaking adjustments, are approximately \$112.7
3 million higher than the power costs included in PSE's Power Cost Baseline Rate as
4 established in the 2006 GRC.

5 The majority of the increase to the rate year power costs is due to Goldendale
6 generation costs, specifically costs that must be incurred for fuel to meet PSE's
7 increased load. In addition, the Snoqualmie hydro facility's powerhouse 2,
8 representing approximately 75% of the plant's 46 megawatt capacity, will be out of
9 service for over two years, beginning [REDACTED], as the Company carries out
10 refurbishment activities required under the FERC license issued for the project in
11 2004 and per the current FERC-approved construction schedule. This results in the
12 loss of approximately 12 average megawatts of nearly zero cost power during the
13 rate year. Last, the rate year includes increased amortization costs and Mid-C
14 contract costs as well as less below market priced power under the WNP-
15 3 Settlement Exchange Agreement power contract, due to the annual contract
16 update.

17 Other factors affecting power costs include increased transmission costs and
18 escalations in PSE's existing purchased power contract rates.

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1 **Q. How does the inclusion of the Goldendale Generating Station as a resource**
2 **affect projected power costs for the rate year?**

3 A. PSE ran the AURORA model with the same assumptions as for the rate year power
4 costs presented in this case, removing the Goldendale Generating Station. The
5 model showed that, with the forecast generation from Goldendale Generating
6 Station, PSE would need to purchase less market power, or would sell more excess
7 power in the market, than would have been the case without Goldendale. Even so,
8 for the rate year, the inclusion of Goldendale increases power costs by \$10.8
9 million, with \$9.3 million of this increase due to incremental production operations
10 and maintenance costs. *See* Exhibit No. ____ (DEM-6). However, over the life of
11 this generating asset, the savings related to the acquisition of Goldendale is in
12 excess of \$100 million, as discussed by Mr. Elsea in his prefiled direct testimony,
13 Exhibit No. ____ (WJE-1HCT).

14 **V. CONCLUSION**

15 **Q. Please summarize your testimony.**

16 A. PSE is actively managing the power and gas cost risks faced by its customers. The
17 updated hedging strategies, coupled with the new hedging line of credit, will allow
18 the Company to further reduce exposure to power cost risks. Finally, the
19 Company's projection of rate year power costs for this proceeding – although
20 higher than the power costs incorporated in the 2006 GRC Power Cost Baseline
21 Rate – are consistent with and based on sound assumptions using methodologies

1 approved by the Commission in the Company's 2006 GRC.

2 **Q. Does that conclude your testimony?**

3 A. Yes, it does.