BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

L. Alex Tooman- Jay Tinker – Stephen Schue

April 2, 2007

Power Costs

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I. Introduction

Q. What are your names and positions with Portland General Electric?

A. My name is L. Alex Tooman. I am a project manager for PGE. I am responsible, along with Mr. Tinker, for the development of PGE's revenue requirement forecast. In addition, my areas of responsibility include affiliated interest filings, results of operations reporting, and other regulatory analyses.

My name is Jay Tinker. I am also a project manager for PGE. My areas of responsibility include revenue requirement analyses and other regulatory analyses.

My name is Stephen Schue. I am a senior analyst for PGE. My areas of responsibility include power supply analysis and other regulatory analyses.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial Annual Update Tariff (AUT) forecast of PGE's 2008 net variable power costs (NVPC) and compare this estimate with the 2007 general rate case (GRC) NVPC approved in Order No. 07-105. We also explain why per unit NVPC have decreased slightly from 2007 to 2008, which translates into the rate reduction described in PGE Exhibit 200.

Q. What is your AUT net variable power cost estimate?

A. Our 2008 AUT forecast is $777 million, based on contracts through and forward curves on January 25, 2007.

Q. How is the remainder of your testimony organized?

A. Our testimony includes the following sections:

- Section II: Monet model

- Section III: Load forecast
- Section IV: Comparison with 2007 GRC NVPC estimate
- Section V: Update schedule and relationship with other dockets
- Section VI: Qualifications

II. Monet Model

Q. How did PGE model net variable power costs (NVPC) for the 2008 test year?

A. We used our power cost forecasting model, called "MONET," (or Monet)

Q. Please describe Monet.

A. We built this model in the mid-1990s and have since incorporated several refinements. Monet models the hourly dispatch of our generating units. Each thermal unit has an individual profile that includes its capacity, heat rate, fuel costs, variable operation and maintenance costs, and other characteristics. Monet models hydroelectric units with peak capabilities and annual, monthly, and hourly usage factors, except the Mid-Columbia facilities, for which Monet uses hourly dispatch logic. For the Biglow Canyon wind project, Monet assumes an hourly output profile based on a numerical weather prediction model simulation which was then calibrated against actual historical data. Since the emergence of forward markets, PGE has input the forward market curves for purchased power and gas, and then run its dispatchable resources, including its gas-fired plants, in Monet under a "dispatch to forward market curve" mode.

Q. How does Monet then forecast NVPC?

A. Monet minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial fuel contract prices and quantities, and related transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, and any variable operating and

maintenance costs (although not part of net variable power costs for ratemaking purposes);

- Hydroelectric plants, with output reflecting current non-power operating constraints (such as for fish passage) and peak, annual, seasonal, and hourly maximum usage capabilities, except in the case of the Mid-Columbia facilities, for which Monet includes hourly dispatch logic;
- Wind turbines, with hourly output reflecting historical data if no related integration products have been purchased;
- Transmission (wheeling) contract costs;
- Physical and financial electric contract purchases and sales; and
- Forward market curves for gas and electric market purchases and sales.

Using these data inputs, Monet dispatches PGE resources to meet customer loads based on the principle of economic dispatch. Generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price, subject to operational constraints, such as minimum unit commitment times. Specifically, plants can be operated in various stages – maximum availability, starting up, ramping up to maximum availability, shutting down, or off-line. Given thermal output, expected hydro generation, and contract purchases and sales, Monet fills any resulting gap between total resource output and PGE's retail load with market purchases (or sales) based on the forward market price curve.

Q. Has PGE provided additional information on Monet in other dockets?

A. Yes. PGE Exhibit 100 in our 2006 RVM filing (Docket UE 172) and PGE Exhibit 400 in our most recent general rate case (Docket UE 180) describe Monet in detail.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs of power that generally change as power output changes, such as transmission payments to third parties. PGE records its variable power costs to FERC accounts 501, 547, 555, 565, and 447. Based on historical decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. We "amortize" these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (FERC 151). We also exclude some variable power costs, such as variable operation and maintenance costs, because they are already included elsewhere in PGE's accounting. The "net" refers to net of forecasted wholesale sales.

Q. Has PGE incorporated major changes to Monet in the 2008 test year NVPC estimates?

A. No. For the AUT forecast, we limited changes to the five updates specified in Order No. 07-015. These are:

- Hourly loads for the forecast year.
- New physical and financial contracts and changes to existing contracts for power, fuel, fuel transportation, or transmission/wheeling.
- Forced outage rates, using the traditional four-year weighted, rolling-average methodology.[1]
- Planned maintenance outage days for the forecast year.
- Forward curves for long or short open power, natural gas, oil, or U.S./Canadian foreign exchange rate positions.[2]

[1] This is consistent with the Order's direction to retain the current four-year rolling average methodology.
[2] The forward curves also impact MONET's modeling of plant dispatch.

Q. You mention how you have incorporated an Order 07-015 provision for the forced outage rates. What did Order No. 07-015 require concerning the forecasted forced outage rates for PGE's plants?

A. The Order calls for continuation of the current method – using the four-year rolling average forced outage rate (four-year average). This method bases the forecasted forced outage rate on historical data.

Q. What did Order No. 07-015 require concerning Boardman's forced outage rate?

A. The Order calls for removing the period November 18, 2005, through December 31, 2005, when calculating Boardman's four-year average for 2007. This four-year period is part of PGE's deferral request in UM 1234, and thus Order No. 07-015's forced outage rate provisions should apply. For the 2008 test year, we removed the period January 1 through February 5, 2006, also part of UM 1234, when calculating the four-year forced outage rate.

Q. PGE committed to exclude the cost of a second outage beginning February 6, 2006. How did you make this adjustment?

A. The UM 1234 deferral request concerned replacement power costs related to a forced outage caused by damage to Boardman's steam turbine rotor. On February 6, 2006, while returning the plant to service, the generator rotor was damaged, resulting in another extended forced outage. PGE, however, determined that it would not seek recovery of excess costs resulting from this second outage. In reference to this outage, from the UM 1234 Oral Arguments held October 3, 2006:

> We didn't then and we don't now want to ask our customers to bear any responsibility for that. We're not seeking to defer those costs, and we won't seek to include those outage days in any future forecast, should we still use historical operations in creating that forecast.

This was reiterated in several of PGE's SEC filings. For example, PGE's September 30, 2006, 10-Q stated:

> PGE did not file an application to defer incremental power costs related to the generator rotor outage (February 6, 2006 through late May 2006), and will not propose the inclusion of this outage in the 4-year rolling average of forced outages in its annual power cost update filings starting in 2008.

PGE eliminated the period February 6 through May 22, 2006, from Boardman's forced outage calculation in a manner consistent with the OPUC Staff calculation approved by OPUC Order No. 07-015.

Q. Were there other outages related to the UM 1234 outage in 2006?

A. Yes, after the second outage, Boardman operated generally at less than full power until May 25, 2006, when it was taken off-line because it was not economic to dispatch – PGE could purchase power at a cost lower than Boardman's incremental cost. PGE next dispatched Boardman on June 1, 2006. However, it was taken off-line to investigate excess bearing vibrations in the low-pressure rotor 1 (LP1). PGE attempted to correct the vibration over the next two days, but was unsuccessful. Boardman was removed from service on June 2 for repairs to a loose coupling at LP1. This issue is directly related to the UM 1234 deferral outage (October 2005 through February 5, 2006) because it concerns LP1, the failure of which was the subject of UM 1234. Repairs were relatively simple, taking about 16 labor hours. The work, however, had to wait for the turbine to cool down. Coupling repairs were completed on June 6 and the plant would then have returned to service had the plant operators not discovered another problem, a loose balance weight at the low pressure rotor 2 (LP2) end connected to the generator.

Q. Was this LP2 loose balance weight issue related to either of the two previous outages?

A. No. This LP2 issue, and the resulting outage, were independent of both of the preceding outages. The damaged balance weight was only discovered because the plant was off-line to repair the loose coupling. In fact, had the plant not been off-line, it is possible that the damage from the loose balance weight could have been much worse. Repairs to LP2 took approximately three weeks, with the plant returning to service on June 28, and released for dispatch on July 1, 2006.

Q. How did PGE treat this third outage for purposes of this filing?

A. As the third outage is partially due to UM 1234, we removed those hours related to UM 1234 from our forced outage calculations. PGE Exhibit 101 is a work order documenting repairs to the loose coupling which were completed on June 6, 2006. For forced outage rate calculations we assumed that the unrelated portion of the outage began on June 7, 2006.

Q. What is the result of the above assumptions?

A. We removed all hours from January 1 through June 6, 2006, for Boardman forced outage rate calculations in a manner consistent with the OPUC Staff calculation approved by OPUC Order No. 07-015. Boardman's four-year average is 10.3%, up somewhat from the 9.01% approved in UE 180.

Q. Overall, how do the four-year averages for 2008 compare to those for 2007?

A. The majority of PGE's thermal units have maintained, or improved their four-year averages for 2008. Table 1 below compares the 2007 and 2008 four-year averages used in our Monet modeling. Besides Boardman, as discussed above, Coyote Springs is the only plant with a higher average for 2008 than for 2007, and the increase is small, less than one half of one percentage point. However, the Colstrip units and Beaver Units 1-7 show a large decrease, approximately four percentage points.

Table 1
Four-Year Rolling Forced Outage Rate – Thermal Units

Unit	2007	2008
Boardman	*9.01%	10.30%
Colstrip Unit 3	12.40%	8.60%
Colstrip Unit 4	12.40%	8.60%
Coyote Springs - All States	7.20%	7.60%
Beaver Units 1-7	20.80%	16.60%
Beaver Unit 8	36.40%	36.40%
Port Westward	5.00%	5.00%

* Per Order No. 07-015

III. Load Forecast

Q. Please summarize PGE's forecast for its 2008 retail load.

A. Table 2 below summarizes actual and forecast deliveries to various customer groups from 2005 through 2008 in million kWh at average weather conditions.

Table 2
Retail Deliveries: 2005 – 2008
(Million kWh, average weather)

	(Actual) 2005	(Actual) 2006	(UE 180/181) 2007	(UE 188) 2008
Residential	7,388	7,568	7,584	7,706
General Service	7,387	7,609	7,762	7,981
Industrial	3,983	4,085	4,144	4,208
Lighting	104	105	108	110
Total Retail	18,862	19,367	19,598	20,004

Q. Does the forecast include all loads?

A. Yes. The forecast includes both PGE cost-of-service loads and deliveries of energy to customers under Schedule 483/489. We sometimes refer to these deliveries as "non cost-of-service" loads.

Q. How does this forecast differ from the UE 180/UE 181 forecast?

A. Table 2 shows PGE's actual weather-adjusted retail deliveries for 2005 and 2006, the UE 180/UE 181 (November 2006) forecast for 2007, and our current (UE 188) forecast by customer group for 2008. In UE 180/181 we projected total deliveries to all retail customers of 19,598 million kWh for 2007 and now forecast total deliveries of 20,004 million kWh for 2008 under average weather conditions. This translates into a 1.2% annual increase in kWh delivery in 2007 from the actual weather-adjusted 2006 base and a 2.1% increase in 2008 from the 2007 forecast base.

Our 2008 forecast is essentially an extension of the UE 180/181 delivery forecast filed with the Oregon Public Utility Commission on November 2, 2006. We applied the same model and input assumptions that drive the UE 180/181 delivery forecast to develop our 2008 delivery forecast. PGE Exhibit 1200 in Docket UE 180 (particularly pages 7 and 9) explains the estimation procedures in detail.

Q. What load do you use in your 2008 test year power cost forecast?

A. The load listed in Table 2 represents total system load at the customer meter and is used to calculate rates. The load used to generate power costs with Monet is based on cost-of-service load (i.e., total system load less Schedule 483/489 and less market price option load). This decomposition is listed below in Table 3.

Table 3
Total Retail Deliveries by Cost of Service Rates & Schedule 483/494: 2008
(Cycle Month Energy in million kWh)

Cost of Service Load	18,526
Schedules 483/489	1,465
Market Price Options	13
Total System Load	20,004

Q. The Cost-of-Service load in Table 3 is at the customer meter. What is the corresponding busbar load?

A. The busbar load is 2,275 MWa, or 19,984,340 MWh (or 19,984 million kWh). This load is the basis for the hourly Monet load input data.

IV. Comparison with 2007 General Rate Case NVPC Forecast

Q. Please restate your 2008 AUT NVPC forecast.

A. The AUT forecast is $777 million.

Q. What is this forecast on a per busbar MWh basis?

A. Given forecasted loads of 19,984,340 MWh, the AUT forecast is $38.88 per MWh.

Q. How does the 2008 AUT forecast compare with the 2007 general rate case (GRC) forecast approved in Order No. 07-015?

A. Based on PGE's final updated GRC Monet run for the 2007 test year and the requirements of Order No. 07-015, the 2007 forecast is $767.1 million, or $39.19 per MWh. The 2008 cost-of-service load forecast is higher than the 2007 forecast by approximately 40 MWa (2,275 MWa in 2008 versus 2,235 in 2007). The higher load more than off-sets the approximately $10 million increase in the power cost forecast, resulting in a small decrease in per MWh costs of approximately $0.31.[3]

Q. Which Order No. 07-015 requirements are included in the 2007 forecast?

A. Order No. 07-015 required three reductions in net variable power costs. These are related to:

- Possible dispatch margins related to PGE's Super Peak capacity contract
- Lower forced outage rate assumption for PGE's Boardman plant
- 10-month versus 12-month differential in Port Westward dispatch benefits

Q. Do you also include these elements in your 2008 NVPC forecast?

A. Yes. We explicitly include the Super Peak contract margin estimate. The 2008 forced outage rate assumption for Boardman includes the adjustment that resulted in the specific

[3] This calculation includes the fact that 2008 is a leap year.

Order No. 07-015 dollar reduction. Finally, the Monet run for 2008 assumes that Port Westward is available for dispatch for the entire 2008 period (except for planned and forced outages).

Q. Does this filing change the treatment of expected net revenues for the sale of ancillary services to the California Independent System Operator?

A. No. Order No. 07-015 directed that "This adjustment is made to Other Revenues in revenue requirement." (Order 07-015 at 16) Because this is not a general rate case filing, we do not propose changes to Other Revenues. Therefore, in 2008 customers will continue to benefit from approximately $1.4 million of expected net ancillary service revenues through their inclusion in Other Revenues in UE 180.

Q. What are the primary factors that explain the difference between the 2007 and 2008 GRC (without Biglow) forecasts?

A. As Table 4 shows, the $10 million increase in overall power costs is due to numerous factors:

Table 4
Factors in Power Cost Differences

Element	Effect
Hydro Cost and Performance	12
Coal Cost and Performance	(7)
Gas Cost and Performance	4
Gas Financials	(12)
Contract Costs	(21)
Market Purchases to Fill Contract Deficit	14
Market Purchases for Load Increase	25
Other	(5)
Total	**10**

With decommissioning of Bull Run and planned replacement of two turbines at Sullivan, we expect slightly less hydro production in 2008 and our purchased hydro contract costs increase, primarily due to payments under the Grant County Settlement Agreement related to Priest Rapids. With lower forecasted forced outage rates at Colstrip Units 3 and 4, we expect slightly more coal output in 2008, although at a somewhat higher unit cost. With Port Westward available during the entire year, we expect greater output from our gas plants in 2008. However, there is also slight increase in per MWh costs for these plants. Gas financial exposure is less in 2008. Contract costs for 2008 are lower on a per MWh basis, but market purchases are needed to make up for a lesser quantity. Market purchases are also necessary to serve the approximately 40 MWa increase in cost-of-service loads from 2007 to 2008.

Q. Is this result, that per-unit NVPC change very little between 2007 and 2008, consistent with differences between the forward curves used in the forecasting process?

A. Yes. Both the electric and gas forward curves used in the 2008 forecast are slightly higher than those used in the 2007 forecast. Therefore, the dispatch value of PGE's gas-fired plants changes very little. Coal plants continue to run whenever forecasted to be available and the value of our hydro resources does not change greatly. These factors combine to result in very little change in dispatch benefits for customers from PGE's overall resource portfolio.

Other factors, which are largely related to contract and market quantities and prices, generally off-set each other, resulting in only a small increase in overall forecasted NVPC from 2007 to 2008, and a small decrease on a per MWh basis.

Q. Did you prepare a comparison of the 2008 AUT forecast with those of recent years?

A. Yes. Table 5 below provides the comparison.

Table 5
Power Cost Forecast Summary

	2005 RVM	2006 RVM	2007 GRC	2008 AUT
Costs ($000)	$486,266	$628,512	$767,113	$776,990
Busbar Cost of Service Loads (000 MWh)	18,551	19,556	19,575	19,984
Unit Cost ($/MWh)	$26.21	$32.14	$39.19	$38.88

Table 5 includes the 2007 GRC to 2008 AUT comparison discussed above. It also includes data from the final Monet runs used in PGE's 2005 and 2006 RVM filings. Unit power costs rose in both 2006 and 2007. However, as we discussed above, in 2008 there is a small decrease in forecasted unit power costs.

V. Update Schedule and Relationship with Other Dockets

Q. When will PGE update its AUT forecast?

A. We will update this forecast according to the schedule established by the parties to this docket. We expect the final update to be in November 2007.

Q. Does this forecast include the expected net dispatch benefits from Phase 1 of the Biglow Canyon (Biglow) wind project?

A. No. Biglow's 2008 costs and associated dispatch benefits are the primary subject of Docket UE 188. However, we expect to estimate the dispatch benefits of Biglow for use in UE 188, assuming our proposal in that docket is adopted.

Q. Will the final AUT forecast update serve as the basis for the 2008 Power Cost Adjustment Mechanism established by Order No. 07-015?

A. Yes.

VI. Witness Qualifications

Q. Mr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from The Ohio State University, a Master of Arts degree in Economics from the University of Tennessee, and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs Department since 1996.

Q. Mr. Tinker, please state your educational background and experience.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since joining PGE in 1996.

Q. Mr. Schue, please state your educational background and experience.

A. I received a Bachelor of Science degree in Economics from the University of Oregon, a Master of Arts degree in Economics from the University of Minnesota, and a Master of Business Administration degree from the University of Louvain (Belgium). I have taught beginning and intermediate level economics courses at the University of Minnesota, particularly in the area of public finance.

I have been employed at PGE in a variety of positions beginning in 1984, primarily in the Rates and Regulatory Affairs Department. I have worked on Bonneville Power Administration rate cases, particularly in transmission rate design. I was the Project

Manager for PGE's 2000 Integrated Resource Plan (IRP) and I worked on PGE's 2002 IRP and related 2003 Request for Proposals. In addition, I worked at the Oregon Public Utility Commission during 1986 and 1987, where my primary assignment was the economic analysis of conservation programs.

Q. Does this complete your testimony?

A. Yes.

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CODY

BEFORE THE PUBLIC UTILITY COMMISSION

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Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody

April 2, 2007

Pricing

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I. Introduction and Summary

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are described in Section IV.

Q. What is the purpose of your testimony?

A. This testimony demonstrates how the prices contained in proposed Tariff Schedule 125 are calculated and provides an estimate of the 2008 base rate impacts from proposed Schedule 125 for selected rate schedules. PGE will file the final rates incorporating the final updates to Net Variable Power Costs on November 15.

II. Estimated Prices and Rate Impacts

Q. Please list the projected prices and accompanying rate impacts for 2008 resulting from this filing.

A. Table 1 below summarizes the preliminary price estimates and the base rate impacts for 2008 for selected Schedules. The preliminary price estimates for all rate schedules are calculated per the provisions of Schedule 125 as the unit change in Net Variable Power Costs (NVPC) times a revenue sensitive cost factor of 1.0287 to account for franchise fees and uncollectables. A draft copy of Schedule 125 is included as Exhibit 201. Table 2 contains the calculation of the Schedule 125 prices applicable to all customers except those on Schedules 76R, 483, and 489. The level of NVPC and the projected loads are discussed in PGE Exhibit 100.

Q. What other price changes do you expect to occur on January 1, 2008?

A. In addition to the Biglow Canyon filing (UE 188) and this AUT filing, I anticipate changes to Schedule 102 Regional Power Act Exchange Credit, Schedule 105 Regulatory Adjustments, Schedule 111 Advanced Metering Infrastructure (removal of the part B credits), and potential recovery of an increase in OPUC regulatory fees. These price changes were discussed in greater detail in PGE's Biglow Canyon filing.

Table 1
Estimated Prices and Rate Impacts

Schedule	Price (mills/kWh)	Rate Impact
Sch 7 Residential	-0.34	-0.3%
Sch 32 Small Non-residential	-0.34	-0.4%
Sch 83 Secondary	-0.34	-0.4%
Sch 83 Primary	-0.34	-0.5%
Sch 89 Secondary	-0.34	-0.5%
Sch 89 Primary	-0.34	-0.5%
Sch 89 Subtransmission	-0.34	-0.6%
Overall		-0.4%

Table 2
Calculation of Schedule 125 Price

2007 NVPC ($000)	767,112
2007 Calendar Loads (MWH)	18,165,207
2007 Unit NVPC	$42.23
2008 NVPC ($000)	776,990
2008 Calendar Loads	18,543,981
2008 Unit NVPC	$41.90
Change in NVPC (dollars per MWh)	-$0.33
Adjust for Revenue Sensitive Costs	-$0.34
Schedule 125 Price (mills per kWh)	-0.34

III. Qualifications of Witnesses

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Does this complete your testimony?

A. Yes.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs. This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

APPLICABLE

To all bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 87, 89, 91, 92, 93 and 94.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts.
- No other changes or updates will be made in the annual filings under this schedule.

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC are defined as the projected per unit change in NVPC from the per unit NVPC used to develop the Energy Charge for the applicable rate schedules. Unit NVPC are defined as the total NVPC divided by the projected retail calendar loads. Projected retail calendar loads include the projected loads of all the Company's Customers except those served under Schedule 483 or Schedule 489.

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final unit change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be the final unit change in NVPC times a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectables applied to each of the above Schedules on an equal cents per kWh basis.

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh
7		-0.034
15		-0.034
32		-0.034
38	Large Nonresidential	-0.034
47		-0.034
49		-0.034
75	Secondary	-0.034 (1)
	Primary	-0.034 (1)
	Subtransmission	-0.034 (1)
83	Secondary	-0.034
	Primary	-0.034
87	Secondary	-0.034
	Primary	-0.034
	Subtransmission	-0.034

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh
89	Secondary	-0.034
	Primary	-0.034
	Subtransmission	-0.034
91		-0.034
92		-0.034
93		-0.034
94		-0.034