Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • Facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

April 1, 2009

Via Electronic Filing and U.S. Mail
Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY'S 2010 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

Enclosed for filing in the above-captioned docket please find the following:

Original and five copies of testimony of:

- **Mike Niman and Jay Tinker (PGE/100); and**
- **Marc Cody (PGE/200)**

Two copies on CD and three paper copies of:

- **Work Papers (non-confidential portions only)**

Original and one copy of:

- **Portland General Electric Company's Motion for Protective Order**

PGE will submit the confidential exhibits and work papers after entry of a Protective Order.

PGE's initial forecast of 2010 NVPC is $830.7 million. At this level of NVPC, PGE projects a base rate reduction effective January 1, 2010 of 2.6%.

These documents are being filed electronically. Hard copies will be sent via postal mail. An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:cbm
Enclosures
cc: UE 197 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **DIRECT TESTIMONY AND WORK PAPERS (non-confidential portions only)** and **MOTION FOR PROTECTIVE ORDER OF PORTLAND GENERAL ELECTRIC COMPANY** to be served by electronic mail to those parties whose email addresses appear on the attached service list and by method specified, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No. UE 197.

Dated at Portland, Oregon, this 1st day of April, 2009.

DOUGLAS C. TINGEY, OSB # 044366
Assistant General Counsel
Portland General Electric Company
121 SW Salmon St., 1WTC1301
Portland, OR 97204
(503) 464-8926 (telephone)
(503) 464-2200 (fax)
doug.tingey@pgn.com

SERVICE LIST - OPUC DOCKET # UE 197

Jim Deason, Attorney at Law 1 SW Columbia Street Suite 1600 Portland, OR 97258-2014 jimdeason@comcast.net	Kurt J. Boehm, Attorney BOEHM KURTZ & LOWRY 36 E Seventh Street, #1510 Cincinatti, OH 45202 kboehm@bklawfirm.com
Michael L. Kurtz BOEHM KURTZ & LOWRY 36 E Seventh Street, #1510 Cincinatti, OH 45202 mkurtz@bklawfirm.com	G. Catriona McCracken CITIZEN'S UTILITY BOARD OF OREGON 610 SW Broadway – Suite 308 Portland, OR 97205 catriona@oregoncub.org
Robert Jenks CITIZEN'S UTILITY BOARD OF OREGON bob@oregoncub.org (*Waived Paper Service)	OPUC Dockets CITIZEN'S UTILITY BOARD OF OREGON dockets@oregoncub.org (*Waived Paper Service)
Jim Abrahamson COMMUNITY ACTION DIRECTORS OF OREGON jim@cado.org (*Waived Paper Service)	S. Bradley Van Cleve DAVISON VAN CLEVE 333 SW Taylor, Suite 400 Portland, OR 97204 mail@dvclaw.com
Jason W. Jones, Assistant AG Department of Justice 1162 Court Street, NE Salem, OR 97301-4096 Jason.w.jones@state.or.us	Janet L. Prewitt, Assistant AG Department of Justice 1162 Court Street NE Salem, OR 97301-4096 Janet.prewitt@doj.state.or.us
Michael T. Weirich, Assistant AG Regulated Utility and Business Section 1162 Court Street, NE Salem, OR 97301-4096 Michael.weirich@doj.state.or.us	Roger D. Colton FISHER SHEEHAN & COLTON roger@fsonline.com (*Waived Paper Service)
Scott Winkels LEAGUE OF OREGON CITIES PO BOX 928 Salem, OR 97308 swinkels@orcities.org	Kip Pheil OREGON DEPARTMENT OF ENERGY kip.pheil@state.or.us (*Waived Paper Service)
Vijay A. Satyal, Senior Policy Analyst OREGON DEPARTMENT OF ENERGY Vijay.a.satyal@state.or.us (*Waived Paper Service)	Joan Cote OREGON ENERGY COORDINATORS ASSOCIATION cotej@mwvcaa.org (*Waived Paper Service)
Judy Johnson Oregon Public Utility Commission 550 Capitol Street NE, #215 Salem, OR 97308-2148 judy.johnson@state.or.us	

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

MOTION FOR APPROVAL OF PROTECTIVE ORDER

PORTLAND GENERAL ELECTRIC COMPANY

April 1, 2009

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE _____

In the Matter of Portland General Electric Company's 2010 Annual Power Cost Update Tariff (Schedule 125)	**MOTION FOR APPROVAL OF PROTECTIVE ORDER [EXPEDITED CONSIDERATION REQUESTED]**

Pursuant to ORCP 36(C)(7) and OAR 860-12-0035(1)(k), Portland General Electric Company ("PGE") requests the issuance of a Protective Order in this proceeding. PGE believes good cause exists for the issuance of such an order to protect confidential market information and confidential business information, plans and strategies. In support of this Motion, PGE states:

1. Concurrent with the filing of this Motion, PGE has filed its annual power cost update pursuant to its tariff Schedule 125.

2. Some of the exhibits and work papers supporting the power cost filing contain confidential information regarding PGE's natural gas, electric and coal market activities as well as other confidential business matters. This information will include proprietary modeling code, PGE's timing of and expected prices for electricity purchases, PGE's timing of and expected prices for natural gas purchases, PGE's forward position for electricity, PGE's forward position for natural gas, and whether and the amount by which PGE is long or short for electricity and natural gas during various periods in 2010 and 2011. This information is confidential commercial information and/or trade secrets under ORCP 36(C)(7).

3. PGE would like to file with the Commission, and provide to other parties, a complete set of work papers as soon as possible, and requests expedited consideration of this motion.

4. PGE also anticipates that parties participating in this docket will make further requests for confidential information. PGE further anticipates it will be required to file periodic updates containing confidential information in this proceeding.

5. While PGE desires to provide parties with requested information, the information is of significant commercial value, and its public disclosure could be detrimental to PGE and its customers. The information discloses PGE's position, strategy and future needs to purchase and sell electricity, natural gas and coal. If other parties involved in the wholesale electricity, natural gas and coal markets obtained this information, they could use it to the financial harm of PGE and its customers.

6. The Commission should therefore issue a Protective Order to protect the confidentiality of that material. The requested order, identical to the one that the Commission customarily issues, is attached.

For the reasons stated above, PGE requests that a protective order be issued in this proceeding.

DATED this 1st day of April, 2009.

Respectfully submitted,

Douglas C. Tingey, OSB No. 044366
Assistant General Counsel
Portland General Electric Company
121 SW Salmon Street, 1WTC1301
Portland, Oregon 97204
(503) 464-8351 phone
(503) 464-2200 fax
doug.tingey@pgn.com

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE____

In the Matter of Portland General Electric Company's 2010 Annual Power Cost Update Tariff (Schedule 125)	**ORDER**

DISPOSITION: MOTION FOR PROTECTIVE ORDER GRANTED

On April 1, 2009, Portland General Electric Company ("PGE") filed a Motion for a Protective Order with the Public Utility Commission of Oregon ("Commission"). PGE states that the exhibits and work papers accompanying its initial testimony in this docket will contain confidential information regarding PGE's natural gas, electric and coal market activities as well as other confidential business matters PGE anticipates that there may be requests for further confidential information in this docket. PGE states that good cause exists for the issuance of a protective order to protect confidential business information, plans and strategies. PGE adds that the public release of such information could prejudice PGE and its customers.

Pursuant to OAR 860-012-0035(1)(k), I find that good cause exists to issue a Protective Order, attached as Appendix A. Under the terms of the order, a party may designate as confidential any information that falls within the scope of ORCP 36(C)(7).

Confidential Information shall be disclosed only to a "qualified person" as defined in paragraph 3 of the Protective Order. Authors of the confidential material, the Commission or its Staff, and counsel of record for a party or persons directly employed by counsel are "qualified persons" who may review confidential information. Other persons desiring confidential information must become qualified pursuant to paragraph 10.

To receive confidential information, however, all parties—with the general exception of Staff—must sign the Consent to be Bound Form attached as Appendix B. This includes the party seeking the issuance of the protective order, because any party may designate information as confidential under this order.

The confidentiality of confidential information shall be preserved for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality.

All persons who are given access to confidential information have the duty to monitor their own conduct to ensure their compliance with the Protective Order. Such persons shall not use or disclose the information for any purpose other than the preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the confidential information secure. If any questions exist as to the status of any person to receive confidential information, the parties may contact the Administrative Hearings Division at (503) 378-6678.

ORDER

IT IS ORDERED that the Protective Order, attached as Appendix A, shall govern the disclosure of confidential information in this case.

Made, entered, and effective on ____________________________.

____
[Judge]
Administrative Law Judge

A party may appeal this order to the Commission pursuant to OAR 860-014-0091.

PROTECTIVE ORDER

DOCKET NO. UE _______

Scope of this Order-

1. This order governs the acquisition and use of "Confidential Information" in this proceeding.

Definitions-

2. "Confidential Information" is information that falls within the scope of ORCP 36(C)(7) ("a trade secret or other confidential research, development, or commercial information").

3. A "qualified person" is an individual who is:

a. An author(s), addressee(s), or originator(s) of the Confidential Information;

b. A Commissioner or Commission staff;

c. Counsel of record for a party;

d. A person employed directly by counsel of record; or

e. A person qualified pursuant to paragraph 10. This includes parties and their employees.

Designation of Confidential Information-

4. A party providing Confidential Information shall inform other parties that the material has been designated confidential by placing the following legend on the information:

CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER

To the extent practicable, the party shall designate as confidential only those portions of the document that fall within ORCP 36(C)(7).

5. A party may designate as confidential any information previously provided by giving written notice to the other parties. Parties in possession of newly designated Confidential

Information shall, when feasible, ensure that all copies of the information bear the above legend to the extent requested by the party desiring confidentiality.

Information Given to the Commission-

6. Confidential Information that is: (a) filed with the Commission or its staff; (b) made an exhibit; (c) incorporated into a transcript; or (d) incorporated into a pleading, brief, or other document, shall be printed on yellow paper, separately bound and placed in a sealed envelope or other appropriate container. An original and five copies each separately sealed shall be provided to the Commission. **Only the portions of a document that fall within ORCP 36(C)(7) shall be placed in the envelope/container**. The envelope/container shall bear the legend:

> THIS ENVELOPE IS SEALED PURSUANT TO ORDER NO. ________ AND CONTAINS CONFIDENTIAL INFORMATION. THE INFORMATION MAY BE SHOWN ONLY TO QUALIFIED PERSONS AS DEFINED IN THE ORDER.

7. The Commission's Administrative Hearings Division shall store the Confidential Information in a locked cabinet dedicated to the storage of Confidential Information.

Disclosure of Confidential Information-

8. Parties desiring receipt of Confidential Information shall sign the Consent to be Bound Form attached as Appendix B. This requirement does not apply to the Commission staff. Confidential Information shall not be disclosed to any person other than a "qualified person," as defined in paragraph 3. When feasible, Confidential Information shall be delivered to counsel. In the alternative, Confidential Information may be made available for inspection and review by qualified persons in a place and time agreeable to the parties or as directed by the Administrative Law Judge.

9. Qualified persons may disclose confidential information to any other qualified person, unless the party desiring confidentiality protests as provided in Section 11.

10. To become a qualified person under paragraph 3(e), a person must:

a. Read a copy of this Protective Order;

b. Execute a statement acknowledging that the order has been read and agreeing to be bound by the terms of the order;

c. Date the statement;

d. Provide a name, address, employer, and job title; and

e. If the person is a consultant or advisor for a party, provide a description of the nature of the person's consulting or advising practice, including the identity of his/her current, past, and expected clients.

Counsel shall deliver a copy of the signed statement including the information in (d) and (e) above to the party desiring confidentiality and to all parties of record. Such notification may be made via e-mail or facsimile. A person qualified under paragraph 3(e) shall not have access to Confidential Information sooner than five (5) business days after receipt of a copy of the signed statement including the information in (d) and (e) above by the party desiring confidentiality.

11. All qualified persons shall have access to Confidential Information, unless the party desiring confidentiality protests as provided in this paragraph. The party desiring to restrict the qualified person(s) from accessing specific Confidential Information must provide written notice to the qualified person(s) and counsel for the party associated with the qualified person(s) as soon as the party becomes aware of reasons to restrict access. The parties must promptly confer and attempt to resolve any dispute over access to Confidential Information on an informal basis before filing a motion with the Administrative Law Judge. If the dispute cannot be resolved informally, either party may file a motion with the Administrative Law Judge for resolution. Either party may also file a motion if the other party does not respond within five days to a request to resolve the dispute. A motion must describe in detail the intermediate measures, including selected redaction, explored by the parties and explain why such measures do not resolve the dispute. After receipt of the written notice as required in this paragraph, the specific Confidential Information shall not be disclosed to the qualified person(s) until the issue is resolved.

Preservation of Confidentiality-

12. All persons who are given access to any Confidential Information by reason of this order shall not use or disclose the Confidential Information for any purpose other than the purposes of preparation for and conduct of this proceeding, and shall take all reasonable precautions to keep the Confidential Information secure. Disclosure of Confidential Information for purposes of business competition is strictly prohibited.

Qualified persons may copy, microfilm, microfiche, or otherwise reproduce Confidential Information to the extent necessary for the preparation and conduct of this proceeding. Qualified persons may disclose Confidential Information only to other qualified persons associated with the same party.

Duration of Protection-

13. The Commission shall preserve the confidentiality of Confidential Information for a period of five years from the date of the final order in this docket, unless extended by the Commission at the request of the party desiring confidentiality. The Commission shall notify the party desiring confidentiality at least two weeks prior to the release of confidential information.

Destruction After Proceeding-

14. Counsel of record may retain memoranda, pleadings, testimony, discovery, or other documents containing Confidential Information to the extent reasonably necessary to maintain a file of this proceeding or to comply with requirements imposed by another governmental agency or court order. The information retained may not be disclosed to any person. Any other person retaining Confidential Information or documents containing such Confidential Information must destroy or return it to the party desiring confidentiality within 90 days after final resolution of this proceeding unless the party desiring confidentiality consents, in writing, to retention of the Confidential Information or documents containing such Confidential Information. This paragraph does not apply to the Commission or its Staff.

Appeal to the Presiding Officer-

15. If a party disagrees with the designation of information as confidential, the party shall contact the designating party and attempt to resolve the dispute on an informal basis. If the parties are unable to resolve the dispute, the party desiring to use the information may move for exclusion of the information from the protection conferred by this order. The motion shall:

a. Specifically identify the contested information, and

b. Assert that the information does not fall within ORCP 36(C)(7) and state the reasons therefore.

The party resisting disclosure has the burden of showing that the challenged information falls within ORCP 36(C)(7). If the party resisting disclosure does not respond to the motion within ten (10) calendar days, the challenged information shall be removed from the protection of this order.

The information shall not be disclosed pending a ruling by the Administrative Law Judge on the motion.

Additional Protection-

16. The party desiring additional protection may move for any of the remedies set forth in ORCP 36(C). The motion shall state:

a. The parties and persons involved;

b. The exact nature of the information involved;

c. The exact nature of the relief requested;

d. The specific reasons the requested relief is necessary; and

e. A detailed description of the intermediate measures, including selected redaction, explored by the parties and why such measures do not resolve the dispute.

The information need not be released and, if released, shall not be disclosed pending the Commission's ruling on the motion.

SIGNATORY PAGE

DOCKET NO. UE _____

I. Consent to be Bound-

This Protective Order governs the use of "Confidential Information" in this proceeding.

_________________________PGE agrees to be bound by its terms of this Protective Order.

By: ______________________________ ______________________________

Signature & Printed Date

____

II. Persons Qualified pursuant to Paragraphs 3(a) through 3 (d)

______________________________PGE identifies the following person(s) automatically qualified under paragraph 3(a) through (d).

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

______________________________ ______________________________

Printed Date

III. Persons Qualified pursuant to Paragraph 3(e) and Paragraph 10.

I have read the Protective Order, agree to be bound by the terms of the order, and will provide the information identified in paragraph 10.

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

By: ______________________________ ______________________________
Signature & Printed Date

____

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___

Annual Update Tariff Filing
For Prices Effective January 1, 2010

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

Portland General Electric

April 1, 2009

UE ___ / PGE / 100
Niman - Tinker

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Jay Tinker

April 1, 2009

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

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

Our qualifications are included 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 2010 net variable power costs (NVPC), adjusted for the inclusion of Biglow Canyon Phase 2. We then compare this estimate with the 2009 General Rate Case (GRC) NVPC as approved by the Commission in Order No. 08-505 (UE 198) and 08-601 (UE 197). We also discuss updates to 2010 AUT parameters and explain why per unit NVPC have decreased by $2.26 per MWh from 2009 to 2010.

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

A. Our 2010 AUT forecast is $830.7 million, based on contracts and forward curves on February 26, 2009.

Q. What schedule in this docket do you propose for NVPC updates?

A. We propose the following schedule for the power cost updates:

- July – update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;
- September – update power, fuel, and transportation/transmission contracts; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads; and

- November – final updates of power, fuel, and transportation/transmission contracts, and gas and electric forward curves.

Q. Will the final AUT forecast update serve as the basis for the 2010 Power Cost Adjustment Mechanism established by Order No. 07-015?

A. Yes, with one modification. In the UE 201 (2007 PCAM) Stipulation, parties supported a change in the language of Schedule 126 to clarify that adjustments to forecasted NVPC are made to reflect the impact of customer direct access enrollments under Schedules 515 through 594 that take place after the final Monet[1] power cost run is filed in mid-November. If there is a change in the enrollments, then a new Monet run that reflects these changes will form the baseline unit net variable power cost for the PCAM calculations.

Q. Are there Minimum Filing Requirements (MFRs) associated with AUT NVPC?

A. Yes. In PGE's most recent general rate case, Docket No. UE 197/198, parties agreed to MFRs for NVPC. The MFRs define the documents PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings.

Q. Will PGE take reasonable steps to ensure MFRs are available to Citizens' Utility Board (CUB) and Industrial Customers of Northwest Utilities (ICNU) quickly?

A. Yes. PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at or close to the time of the filing[2].

Q. What information and timeframe did Parties agree to for the MFRs?

A. Parties agreed that in either an AUT or a GRC, at a minimum, Monet's summary documents and a few additional documents, if applicable, will be delivered with the initial filing. The

[1] Per the UE 198 Stipulation, most of the MFRs will be filed on or before April 15, 2009. The summary MFRs are filed with the testimony.
[2] Monet is PGE's power cost forecasting model described in more detail in Section II.

remainder of the MFRs will be delivered with the initial filing, if practical, or no later than fifteen days after the filing (e.g., April 15 for an AUT filing). The remainder of the MFRs consists of the supporting documents and work papers for the various sections of Monet and historical operating data. The AUT Update Filing MFRs will be delivered with the update filings.

Q. Are you delivering Monet's summary documents with the initial filing?

A. Yes. We will provide the summary MFRs to the PUC with the April 1 filing. Then, we will deliver the summary MFRs to ICNU and CUB as soon as a protective order is issued and parties have signed it. We have applied for a protective order and expect the Commission to issue it shortly. We expect this process to take 2-3 business days, at most. Finally, we expect to deliver the remainder of the MFRs to all parties on or before April 15, 2008.

Q. How do you organize the remainder of your testimony?

A. After this introduction, we have five sections:

- Section II: Monet Model;
- Section III: Monet Updates and Model Changes;
- Section IV: Load Forecast;
- Section V: Comparison with 2009 UE 197/198 NVPC Forecast; and
- Section VI: Qualifications.

II. Monet Model

Q. How did PGE forecast its NVPC for 2010?

A. As in previous dockets, we used our power cost forecasting model, called "MONET" (or Monet).

Q. Please briefly describe Monet.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, Monet models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales.

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. Given thermal output, expected hydro and wind 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) priced at the forward market price curve.

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 that generally change as power output changes. PGE records its net variable power costs to FERC accounts 501, 547, 555, 565, and 447. 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 (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The "net" refers to net of forecasted wholesale sales.

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

A. Yes. PGE Exhibit 100 in our 2008 Annual Update Tariff filing (UE 192), PGE Exhibit 100 in our 2006 Resource Valuation Mechanism filing (UE 172), and PGE Exhibit 400 in our 2007 test year general rate case (UE 180) describe Monet in greater detail. We have also held informal workshops for parties to understand several aspects of Monet.

Q. Do the MFRs provide even more detailed information regarding the inputs to Monet?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop this initial forecast of 2010 NVPC.

III. Monet Updates and Model Changes

Q. What updates are allowed under PGE's Schedule 125, Annual Power Cost Update (AUT) Tariff?

A. Schedule 125 states that the following updates are allowed in AUT 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; and
- Transportation contracts and other fixed transportation costs.

Q. Which of these updates do you include in this initial filing?

A. We include all of the adjustments listed and address significant items below.

Q. Did you include any Biglow Canyon Phase 2 costs in the 2010 AUT NVPC?

A. Yes. We include costs for BPA tariff integration, royalty payments, an imbalance premium, and day-ahead forecast error estimate, which total $7.1 million in the 2010 forecast. We also include Biglow Canyon Phase 2 in operating reserve calculations.

Q. Are the NVPC for Biglow Canyon Phase 2 comparable to the costs approved for Phase 1?

A. Yes. The BPA tariff integration, royalty payments, imbalance premium, and day-ahead forecast estimate for Phase 1 are approximately $6 million.

Q. What is the basis for your forecast of royalty payments related to Phase 2 of Biglow Canyon?

A. PGE has contracts with the Biglow Canyon land owners and original site developer, Orion Energy, LLC. These contracts specify royalty payments based on a contractual value of energy multiplied by the developer/landowner royalty percentage. The annual royalty payment is the product of four factors: the contractual base power price ($34.3/MWh), an inflation index escalator, the annual plant generation in MWh, and the developer/landowner royalty percentage.

Q. Did you use this same approach in UE 197 related to Biglow Canyon Phase 1?

A. Yes, it is the same approach, but the royalty percentage is different for Biglow Canyon Phase 2.

Q. What impact does Biglow Canyon Phase 2 have on 2010 power costs?

A. Biglow Canyon Phase 2 reduces 2010 NVPC by approximately $15.4 million. This is the result of lower net market purchases and sales ($19.8 million), lower wheeling cost ($2.3 million), and lower WECC incremental reserves cost ($0.4 million). As we noted above, new variable costs for Biglow Canyon Phase 2 are approximately $7.1 million. Confidential PGE Exhibits 101C and 102C are the Monet output files with and without Biglow Canyon Phase 2.

Q. Do any of the stipulated items from UE 197/198 impact the 2010 NVPC?

A. Yes, five items impact the 2010 NVPC. First, the Boardman Simulator forced outage rate benefit has been included and was modeled in a manner consistent with the UE 198 Stipulation. Second, PGE included two-thirds of the 2009 annual Super Peak extrinsic value because the contract is only in effect for 2 months rather than 3 months. Third, in the

UE 198 Stipulation, parties agreed that the projection for non-running station service (NRSS) costs for Colstrip Units 3 and 4 should be removed from Monet for 2009. However, NRSS for all other thermal generating plants remained as in the UE 198 final filing. The parties further agreed that PGE can propose a modification for Colstrip NRSS in the 2010 AUT proceeding; however, we did not include Colstrip NRSS in this filing. For 2010, we extended the NRSS modeling for our other thermal plants, excluding Colstrip. We did not update the parameters, such as the NRSS power draw in megawatts when the plant is down. Finally, the wind day-ahead forecast error estimate and the Boardman heat rate remain at the values agreed to in UE 197/198.

Q. Has PGE incorporated changes to the inputs to Monet in the 2010 NVPC estimates?

A. Yes. Changes made to the inputs to Monet model are as follows:

- Mercury Sorbent chemical costs have been added to Colstrip coal costs. The chemicals cost approximately $1.20 per ton, or $0.74/MWh of generation.
- PGE’s BPA IR contracts will expire on December 31, 2009. We assume that in 2010 these contracts are converted to Point-to-Point (PTP) contracts. However, PGE was recently contacted by BPA and there is a possibility that these contracts may be renegotiated. If a renegotiation is successful, PGE will include them in our Monet update.
- PGE has also included a 1-year amortization of the 2007 GRC gas transportation deferral (UM 1290, Order No. 07-452), returning approximately $3.25 million to customers in 2010.
- For net ancillary services sales revenues, we base our 2010 forecast of $0.6 million on actual 2008 sales of reserves to the California Independent System Operator (Cal-

ISO), net of grid management charges imposed by the Cal-ISO on those sales. According to Schedule 126, NVPC shall be adjusted as needed to comply with Commission Order No. 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should be taken into account in the mechanism.

Q. Are any of PGE's capacity contracts expiring?

A. Yes. PGE has one contract with PacifiCorp Power Marketing (PPM) that expires in 2010. The PPM Winter Super-peak contract, which was in effect for the months of December through February, will expire at the end of February 2010. This capacity shortfall will be analyzed in PGE's Integrated Resource Plan.

Q. Overall, have the 2010 four-year rolling average forced outage rates maintained or improved compared to those for 2009?

A. Yes. The majority of PGE's thermal units have maintained, or improved their four-year averages for 2010. Table 1 below compares the 2009 and 2010 four-year averages used in our Monet modeling. The 2010 rate for Boardman and Colstrip Units 3 and 4 have decreased by about 1-1.5% from 2009. The outage rates for Coyote Springs, Port Westward, and Beaver Unit 8 have remained constant. The forced outage rate for Beaver Units 1-7 increased 6.7 percentage points due to additional forced maintenance hours on Unit 6 in 2008. We updated forced outage rates based on actual 2005-2008 operating data for Boardman, Colstrip, Coyote Springs, and Beaver Units 1-7. We used the same 5.0% forced outage rate for Port Westward from UE 197, because this plant has only a year and a half of operating history.

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

Unit	2009	2010
Boardman	10.7%	9.9%
Colstrip Unit 3	7.9%	6.3%
Colstrip Unit 4	7.9%	6.3%
Coyote Springs	1.3%	1.3%
Beaver Units 1-7	17.9%	24.6%
Beaver Unit 8	36.4%	36.4%
Port Westward	5.0%	5.0%

IV. Load Forecast

Q. Please summarize PGE's forecast for its 2010 retail load.

A. Table 2 below summarizes actual and forecast deliveries to various customer groups from 2007 through 2010 in million kWh at average weather conditions.

Table 2
Retail Deliveries: 2007 – 2010
(Million kWh, average weather)

	2007 Actual	2008 Actual	(UE 197/198) 2009 Forecast	Current 2009 Forecast	(UE__)2010 Forecast
Residential	7,619	7,692	7,655	7,586	7,570
General Service	7,683	7,649	7,785	7,566	7,568
Industrial	4,137	4,259	4,663	4,309	4,393
Lighting	108	110	111	111	113
Total Retail	19,547	19,710	20,214	19,572	19,644

* The 2007 and 2008 Actual loads are weather adjusted.

Q. Does the 2010 forecast include all loads?

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

Q. Does the 2010 cost-of-service load forecast assume that certain long-term, opt-out customers return to a cost-of-service rate?

A. Yes. Under Schedules 483/489, large commercial and industrial customers have an option to receive electric service from an Energy Service Supplier for a period of 3 years. Those who choose this option are referred to as "opt-out" customers. Since some of those terms are ending in 2009, the 2010 cost-of-service load forecast assumes that approximately 140 MWa of opt-out load returns to a cost-of-service rate.

Q. What happens if these customers (or other eligible customers) select a long-term, opt-out program in September?

A. PGE will reduce the 2010 cost-of-service load forecast accordingly, as specified in Schedule 125.

Q. How does the 2010 forecast differ from the UE 197/198 forecast?

A. Table 2 shows PGE's historical weather-adjusted retail deliveries for 2007 and 2008, the UE 197/198 forecast for 2009, and our current forecast for 2009 and 2010. The total deliveries for all retail customers were 19,547 million kWh in 2007 and 19,710 million kWh in 2008. In UE 197/198, we projected total deliveries of 20,214 million kWh for 2009 and we currently project 19,572 million kWh for 2009 and 19,644 million kWh for 2010 under average weather conditions. Our forecast for 2010 loads is 2.8% lower than the forecast used to set rates in UE 197/198 for 2009 but is essentially flat from our current forecast of 2009 loads.

We applied the same model and input assumptions that drive the UE 197/198 delivery forecast to develop our 2010 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 2010 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), as shown below in Table 3.

Table 3
Total Retail Deliveries by Cost of Service Rates & Schedule 483/494: 2010
(Cycle Month Energy in million kWh)

Cost of Service Load	19,235.8
Schedules 483/489	401.8
Market Price Options	6.7
Total System Load	19,644.3

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 2,362 MWa, or 20,689,300 MWh (or 20,689.3 million kWh). This load is the basis for the hourly Monet load input data.

V. Comparison with 2009 UE 197/198 NVPC Forecast

Q. Please restate your initial 2010 NVPC forecast.

A. The initial forecast is $830.7 million including Biglow Canyon Phase 2. Without Biglow Canyon Phase 2 the forecast is $846.1 million.

Q. How does the 2010 forecast (including Biglow Canyon Phase 2) compare with the UE 197/198, 2009 forecast approved in Commission Order Nos. 08-601 and 08-505?

A. Based on PGE's final updated Monet run for the 2009 test year, the 2009 forecast was $848.4 million, or $42.41 per MWh. The 2010 forecast is $830.7 million, or $40.15 per MWh[3], approximately $2.26/MWh lower.

Q. What are the primary factors that explain the decrease in the 2010 forecast of $830.7 million versus the UE 197/198 forecast of $848.4 million?

A. As Table 1 demonstrates, the approximate $18 million decrease is due to several factors:

Table 1
Factors in Power Cost Differences ($Million)

Element	**Effect**
Hydro Cost and Performance	$8
Coal Cost and Performance	-4
Gas Cost and Performance	-26
Wind Cost and Performance	-10
Contract and Market Purchases	16
Market Purchases for Cost of Service Load Increase	28
Lower Market Purchase Price	-29
Other (Net)	-1
Total	**-$18**

PGE expects less hydro production primarily due to the renewal of the Wanapum agreement being effective for the entire year of 2010. The old Wanapum contract is in place for ten months of 2009 (January through October), while in 2010 the renewed contract, with its lower PGE share, is in place for the entire year. This lower hydro production necessitates additional market purchases. Coal-generated output increases in 2010 because of two

[3] These calculations are based on bus-bar cost-of-service load and include the fact that the 2010 cost-of-service load forecast is 78 MWa (2,362 MWa – 2,284 MWa) higher than the 2009 cost-of-service load forecast.

factors: shorter planned maintenance outages at both Boardman and Colstrip, and reduced thermal plant forced outage rates. In addition to increased output leading to higher coal costs, coal costs at Colstrip are higher due in large part to increased mining costs and costs for the addition of mercury control chemicals. The cost of gas-generated production decreases is due to reduced output, lower gas forward price curves, and the effect of mark-to-market gas financial hedge contracts. Contract costs for 2010 are higher on a per MWh basis, and more market purchases are needed to offset a lesser quantity of contract MWh. Market purchases in 2010 are expected to be significantly less costly than in 2009 on a per MWh basis due to lower forward electric price curves. Market purchases are also necessary to serve the approximate 78 MWa increase in cost-of-service loads from 2009 to 2010.

Q. Does PGE rely more on financial markets, rather than the physical market, to hedge its open electric position?

A. Yes. During the last year, the market has witnessed a profound change in the trading of term power products, increasing PGE's volume of financial transactions for 2010 and beyond. Previously, the majority of traded power products were physical in nature (i.e., an agreement to deliver a specified amount of power over a specified time period). More recently, the market has emerged as an all-financial term power market and has shifted PGE's power purchases from fixed-price physical transactions to fixed/index-price financial swaps coupled with physical index-price purchases.

Q. What benefits transpired with the development of the financial markets?

A. A robust financial market has allowed non-traditional entities to participate in the market. The entrance of these participants initially provided more liquidity and better price discovery. Credit issues also became simplified as Intercontinental Exchange (ICE) or an over-the-counter broker can clear transactions. The alleviation of counter-party credit concerns led to better capitalized participants. However, the improvement in market liquidity was temporary.

Q. As the U.S. economy rapidly entered into a deep and prolonged recession, how have the credit markets been affected by the current recession?

A. The bankruptcy of Lehman Brothers in mid-September 2008 with the subsequent collapse of short-term credit markets removed substantial liquidity from the term power market. Counterparties refused to deal directly because of credit concerns. Transactions that normally would have been done on a bi-lateral basis were now cleared through exchanges such as ICE.

Q. What impact has this had on the volume of transactions in the market?

A. The volume of market transactions fell dramatically and even ICE reported significantly reduced earnings for the fourth quarter, 2008 as the volume of cleared transactions fell.

VI. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

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 1996.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101C	April 1 Initial Filing Monet Output Files and Assumptions Summary
102C	Monet Output Files and Assumptions Summary without Biglow Canyon Phase 2

UE ___ / PGE / 200
Cody

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody

April 1, 2009

Table of Contents

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 listed in Section V.

Q. What is the purpose of your testimony?

A. This testimony describes the following:

- The estimated price impacts from this filing as well as other price changes anticipated to occur on January 1, 2010.
- The calculation of the Schedule 125 prices.
- The calculation of the changes in the system usage charges for Schedules 83 and 89 (as well as their direct access equivalents) based on estimates of load returning to Cost of Service (COS) pricing from multi-year direct access.

PGE will file the final Schedule 125 rates incorporating the final updates to Net Variable Power Costs on November 16. PGE will also file the new system usage charges for Schedules 83 and 89 on November 16.

II. Estimated Rate Impacts

Q. What base rate changes do you anticipate to occur on January 1, and what are their cumulative impacts?

A. Table 1 below summarizes the COS base rate impacts for 2010 for selected Schedules. These estimates contain not only the projected $46.8 million reduction in Schedule 125 prices, but also the $41.3 million revenue requirement associated with Schedule 122 Renewable Resources Automatic Adjustment Clause and changes in System Usage Charges resulting from projected load returning to COS pricing from Schedules 483 and 489. These estimates are preliminary and subject to change due to among other items, market electric and gas prices, and the potential for large changes in projected COS loads resulting from the multi-year direct access window in September. The 2010 load forecast used to develop these estimated impacts includes the loads of those customers on the three-year optout option contained in Schedules 483 and 489 who are eligible to return to COS in 2010.

Table 1
Estimated Base Rate Impacts

Schedule	Rate Impact
Sch 7 Residential	-0.3%
Sch 32 Small Non-residential	-0.3%
Sch 83 Secondary	-4.2%
Sch 83 Primary	-4.4%
Sch 89 Secondary	-4.4%
Sch 89 Primary	-4.8%
Sch 89 Subtransmission	-5.1%
Overall	**-2.1%**

Q. What other price changes do you expect to occur on January 1, 2010?

A. In addition to the changes in Schedule 122, I anticipate changes in Schedule 126 Annual Power Cost Variance Mechanism, and Schedule 105 Regulatory Adjustments. I expect that Schedule 126 will be set to zero from the current level of a credit of 1.10 mills/kWh and

Schedule 105 will capture the amortization of miscellaneous deferrals. Updated estimates of these price changes will be provided later in this proceeding.

III. Calculation of Schedule 125 Prices

Q. Please describe how you calculated the Schedule 125 amount.

A. I determined the Schedule 125 amount by comparing the projection of 2010 Net Variable Power Costs (NVPC) to the amount of NVPC that is recovered through the combination of our current energy prices adjusted to exclude fixed generation cost recovery, multiplied by the 2010 load forecast by schedule (the resulting revenues I reference as NVPC revenues). The difference between NVPC and NVPC revenues constitutes the Change in NVPC. This amount, either positive or negative is multiplied by 1.0337 to account for revenue sensitive costs such as uncollectibles and franchise fees. Page 1 of PGE Exhibit 202 provides a summary of the Schedule 125 amount of ($46.8) million and how it is spread to the respective schedules. Also included on page 1 are the proposed Schedule 125 prices.

Q. Please provide a more detailed description of how you calculate the NVPC revenues.

A. Page 2 of PGE Exhibit 202 demonstrates the calculation. I start with the tariff energy prices for each schedule and remove the portion of these energy prices that recovers the UE 197 fixed generation costs. I then multiply these prices by the respective energy billing determinants to calculate the amount of NVPC projected to be recovered for the 2010 test period. For 2010 I project NVPC revenues of $875.9 million. This amount is carried over to Page 1 of PGE Exhibit 202 in order to calculate the Schedule 125 amount.

Q. Please describe how you allocate the Schedule 125 amount to each rate schedule and how you calculate the Schedule 125 price.

A. I allocate and price the Schedule 125 amount consistent with Special Condition 1 of Schedule 125 which states the following:

> Costs recovered through this schedule will be allocated to each schedule using the applicable schedule’s forecasted energy based on the basis of an equal

percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

Q. Where can I find the calculation of the basis of the Schedule 125 allocations, the 2010 Base Generation Revenues?

A. I present this calculation, which is simply the 2010 projected energy billing determinants times the tariff energy price on page 2 of PGE Exhibit 202.

IV. Changes in Schedule 83 and 89 System Usage Charges

Q. Why are you proposing to change the System Usage Charges for Schedules 83/483/583 and 89/489/589?

A. I propose to change the System Usage Charges for these schedules in accordance with Special Conditions 1-3 of Schedule 129 Long-Term Transition Adjustment. These Special Conditions specify the manner in which PGE trues-up year-to-year changes in both Schedule 129 transition adjustments and fixed generation contributions from changes in Schedules 483 and 489 levels of participation. These trued-up amounts are recovered or refunded by adjusting the appropriate System Usage charges for Schedules 83/483/583 and 89/489/589.

Q. What is the purpose of the Special Conditions contained in Schedule 129?

A. As mentioned above, the Special Conditions true-up the differences in fixed generation cost allocations from our most recent general ratecase (UE 197) and Schedule 129 transition adjustment transfer payments that occur due to multi-year COS optout Schedules 483 and 489. Because PGE's rate making is generally done on a single calendar year test-period basis, the multi-year COS optout and the accompanying Schedule 129 Long-Term Transition Cost Adjustment creates unique ratemaking issues.

Q. What is the amount of Schedule 129 Long-Term Transition Adjustment you project for 2010 and what are the ramifications for customers?

A. Presuming that all eligible load returns to COS pricing, I project that the Schedule 129 amount paid to multi-year direct access customers will be approximately $3.6 million. This translates to a volumetric recovery rate of 0.35 mills/kWh for applicable customers. The current Schedule 129 recovery rate embedded in the system usage charges of applicable customers is 1.78 mills/kWh; therefore, customers should see a decrease in their system usage charges should all eligible multi-year direct access load return to COS pricing. The converse may also apply should a number of large customers choose to receive service under Schedules 483 and 489 for 2010 and should the Schedule 129 transition adjustment be a credit. This could cause the Schedule 129 amount paid to customers in 2010 to exceed that which is embedded in current rates.

Q. What is the amount of fixed generation true-up you project for 2010?

A. Should all eligible load return to COS pricing, I estimate a $19.4 million increase in fixed generation revenues. Of this amount I propose to pass through to customers $18.0 million as a reduction to applicable customers' System Usage Charges. Below, I discuss why I do not propose to pass through the full amount of the true-up.

Q. Have you prepared an exhibit that summarizes the potential changes to the system usage charges based on the true-ups?

A. Yes. Page 1 of PGE Exhibit 203 presents the current System Usage Charge, the portion of the current charge unrelated to Schedule 129, the 2010 proposed true-ups, and the resulting 2010 System Usage Charge. Given the presumption of eligible load returning to COS pricing, the 2010 system usage charge would be greatly reduced for eligible customers. The final determination of the changes in the System Usage Charge will depend on customer elections during the September 2009 enrollment window.

Q. Have you prepared exhibits that demonstrate how you calculate the true-up amounts?

A. Yes. Page 2 of PGE Exhibit 203 details the calculation of the 2010 Schedule 129 transition amount recovery and the resulting price of 0.35 mills/kWh. This amount is considerably lower than the current UE 197 Schedule 129 recovery amount of 1.78 mills/kWh.

Q. Please explain how you calculate both the increase in fixed generation revenues and the amount of the reduction in eligible customers' System Usage Charges.

A. In order to calculate the increase in fixed generation revenues, I simply multiply the estimated returning load by the factors contained in Special Condition 3 of Schedule 129. I note that these factors will need to be updated for the prices resulting from a Commission Order in PGE's UE 204 docket. I pass less than the full amount of fixed generation revenues through to the System Usage Charges because Special Condition 2 of Schedule 129 requires that "the adjustment to the System Usage Charge resulting from changes in fixed generation revenues shall not result in a rate increase or decrease to Schedules 83 or 89 of more than 2 percent." This 2% limit was stipulated in UE 197 and incorporated into Order No. 09-020.

Q. Can you please demonstrate how you calculated the appropriate amount of fixed generation revenues to be passed through to eligible customers?

A. I first calculated the current base rate revenues for Schedule 83 and 89 customers and then calculated the overall mills/kWh for both schedules. I then calculated the proposed Schedule 125 prices as well as the Schedule 125 prices that would prevail if the returning load remains on Schedules 483 and 489. The latter calculation is consistent with Special condition 2 of Schedule 129 that states: "For purpose of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased Schedules 483 and 489 participating load will be determined." From the calculated mills/kWh of the case of customers remaining on Schedules 483 and 489, I simply calculated an amount of allowable decrease. Any amount of fixed generation adjustment that causes the overall mills/kWh to exceed the 2% limitation is not passed through to eligible customers through their System

Usage Charges. PGE Exhibit 203 contains the detailed calculations of the 2% limitation and the estimated NVPC and NVPC revenues that would occur should the projected Schedule 483 and 489 returning load remain on multi-year direct access.

V. Qualifications of Witness

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.

List of Exhibits

PGE Exhibit	Description
201	Schedule 125-1
202	Calculation of Schedule 125 Prices
203	System Usage Charge Prices

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 (the Annual Power Cost Update). 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 and other fixed transportation costs.
- No other changes or updates will be made in the annual filings under this schedule.

CHANGES IN NET VARIABLE POWER COSTS

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0337.

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 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 based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh
7		-0.247
15		-0.229
32		-0.247
38	Large Nonresidential	-0.246
47		-0.229
49		-0.230
75	Secondary	-0.246 (1)
	Primary	-0.235 (1)
	Subtransmission	-0.227 (1)
83	Secondary	-0.245
	Primary	-0.237
87	Secondary	-0.246
	Primary	-0.235
	Subtransmission	-0.227

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

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh
89	Secondary	-0.246
	Primary	-0.235
	Subtransmission	-0.227
91		-0.229
92		-0.240
93		-0.245
94		-0.240

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Prices

Schedules	2010 Calendar COS Energy MWH	2010 Base Generation Revenues	Generation Allocation	2010 Base NVPC Revenues	Sch 125 Allocation	2010 NVPC Revenues	2010 Sch 125 Rate mills/kWh	2010 Sch 125 Revenues
Schedule 7	7,561,317	$484,601	39.90%	$349,480	($18,663)	$330,818	(2.47)	($18,676)
Schedule 15	23,933	$1,426	0.12%	$1,029	($55)	$974	(2.29)	($55)
Schedule 32	1,495,562	$95,776	7.89%	$69,095	($3,688)	$65,407	(2.47)	($3,694)
Schedule 38	70,389	$4,504	0.37%	$3,247	($173)	$3,074	(2.46)	($173)
Schedule 47	22,076	$1,312	0.11%	$947	($51)	$896	(2.29)	($51)
Schedule 49	68,335	$4,078	0.34%	$2,942	($157)	$2,785	(2.30)	($157)
Schedule 83-S	5,176,754	$329,397	27.12%	$237,665	($12,686)	$224,979	(2.45)	($12,683)
Schedule 89-S	669,778	$42,698	3.52%	$30,789	($1,644)	$29,145	(2.46)	($1,648)
Schedule 83-P	282,533	$17,384	1.43%	$12,542	($669)	$11,872	(2.37)	($670)
Schedule 89-P	2,516,174	$153,317	12.62%	$110,491	($5,904)	$104,587	(2.35)	($5,913)
Schedule 89-T	1,243,302	$73,189	6.03%	$52,848	($2,819)	$50,030	(2.27)	($2,822)
Schedule 91	107,337	$6,396	0.53%	$4,614	($246)	$4,368	(2.29)	($246)
Schedule 92/94	5,016	$313	0.03%	$226	($12)	$214	(2.40)	($12)
Schedule 93	573	$36	0.00%	$26	($1)	$25	(2.45)	($1)
TOTAL	19,243,078	$1,214,426	100%	$875,941	($46,769)	$829,172		($46,801)
			Sch 125 TARGET ===>		($46,769)			
2010 NVPC	$830,697							
2010 NVPC Revenues	$875,941	(page 2 of Exhibit 202)						
Change in NVPC	($45,244)							
Revenue Senstitive Adj. 3.37%	($1,525)							
Sch 125 Revenue Requirement	($46,769)							

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues

Schedule	2010 Calendar MWh	Energy Price	2010 Base Generation Revenues	UE 197 Fixed. Gen. Price	NVPC Price	2010 NVPC Revenues	2010 Cycle MWh
Sch 7							
Block 1	2,087,557	51.24	$106,966	17.87	33.37	$69,662	2,088,184
Block 2	5,473,760	68.99	$377,635	17.87	51.12	$279,819	5,475,405
Sch 15	23,933	59.59	$1,426	16.60	42.99	$1,029	23,933
Sch 32	1,495,562	64.04	$95,776	17.84	46.20	$69,095	1,494,294
Sch 38							
On-peak	32,745	70.73	$2,316	17.85	52.88	$1,732	32,821
Off-peak	37,644	58.11	$2,187	17.85	40.26	$1,516	37,730
Sch 47	22,076	59.44	$1,312	16.56	42.88	$947	21,900
Sch 49	68,335	59.67	$4,078	16.62	43.05	$2,942	68,505
Sch 83-S	5,176,754	63.63	$329,397	17.72	45.91	$237,665	5,167,663
Sch 83-P	282,533	61.53	$17,384	17.14	44.39	$12,542	276,888
Sch 89-S							
On-peak	428,490	68.98	$29,557	17.78	51.20	$21,939	432,725
Off-peak	241,288	54.46	$13,141	17.78	36.68	$8,850	243,673
Sch 89-P							
On-peak	1,487,268	66.60	$99,052	17.02	49.58	$73,739	1,487,960
Off-peak	1,028,906	52.74	$54,265	17.02	35.72	$36,753	1,029,385
Sch 89-T							
On-peak	683,136	64.80	$44,267	16.36	48.44	$33,091	682,317
Off-peak	560,166	51.63	$28,921	16.36	35.27	$19,757	559,494
Sch 91	107,337	59.59	$6,396	16.60	42.99	$4,614	107,337
Sch 92	5,016	62.42	$313	17.39	45.03	$226	5,016
Sch 93	573	63.53	$36	17.70	45.83	$26	573
Totals	19,243,078		$1,214,426			$875,941	19,235,804

Note: See Attachment B page 48 of PGE UE 197 compliance work papers for source of fixed generation prices.

PORTLAND GENERAL ELECTRIC
Calculation of 2010 System Usage Charge

Schedules	UE 197 System Usage Charge mills/kWh	UE 197 Sch 129 Component mills/kWh	Net UE 197 System Usage Charge mills/kWh	2010 Sch 129 Transition Adj mills/kWh	2010 Sch 129 Fixed Gen. Adj. mills/kWh	2010 System Usage Charge mills/kWh
Schedule 83S/583S/483S	4.06	1.78	2.28	0.35	(1.75)	**0.88**
Schedule 89S/589S/489S	3.94	1.78	2.16	0.35	(1.75)	**0.76**
Schedule 83P/583P/483P	3.91	1.78	2.13	0.35	(1.75)	**0.73**
Schedule 89P/589P/489P	3.73	1.78	1.95	0.35	(1.75)	**0.55**
Schedule 89T/589T/489T	3.60	1.78	1.82	0.35	(1.75)	**0.42**

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2010

Grouping	Calendar Energy	Percent	Transition Adjustment Allocations ($000)	Transition Adjustment Recovery mills/kWh	Transition Adjustment Recovery ($000)	Fixed Generation Allocation ($000)	Fixed Generation True Up mills/kWh	Fixed Generation Revenue ($000)
Schedule 83-S	5,211,287	50.6%	$1,829	0.35	$1,824	($9,120)	(1.75)	($9,120)
Schedule 89-S	687,032	6.7%	$241	0.35	$240	($1,202)	(1.75)	($1,202)
Schedule 83-P	282,533	2.7%	$99	0.35	$99	($494)	(1.75)	($494)
Schedule 89-P	2,723,407	26.4%	$956	0.35	$953	($4,766)	(1.75)	($4,766)
Schedule 89-T	1,394,032	13.5%	$489	0.35	$488	($2,440)	(1.75)	($2,440)
TOTAL	10,298,291	100.00%	$3,615	0.35	$3,604	($18,022)		($18,022)
		TARGET	**$3,615**		**TARGET**	**($18,022)**		

Note: energy includes direct access customers

2010 Projection of Schedule 483/489 Loads & Schedule 129 Revenues

Delivery Voltage	Enrollment Period	Calendar MWH	Schedule 129 mills/kWh	Schedule 129 Revenues ($000)
Secondary (vintage 2003)	A	12,609	0.00	$0
Secondary (vintage 2008)	F	39,178	(12.48)	($489)
Primary (vintage 2004)	B	71,776	0.00	$0
Primary (vintage 2008)	F	135,457	(12.48)	($1,691)
Subtransmission (vintage 2007)	E	143,995	(9.97)	($1,436)
Total		403,015		($3,615)
2010 Sch 129 transition adjustment payments				$3,615

2010 Projection of Fixed Generation Revenues from Schedule 483/489 returning to COS

Schedule	Enrollment Period	Calendar MWH	Fixed Revenue Recovery factor mills/kWh	Fixed Gen. Revenues ($000)
Schedule 83S	E	3,715	17.72	$66
Schedule 89S	E	16,286	17.78	$290
Schedule 83P	E	0	17.14	$0
Schedule 89P	E	744,248	17.02	$12,667
Schedule 89T	E	390,989	16.36	$6,397
Total		1,155,238		$19,419

Increase in Fixed Generation Revenue	$19,419	
Decrease in System Usage Charges	($19,419)	
Eligible MWh	10,298,291	
Unadjusted Change to System Usage Charge	(1.89)	(mills/kWh)
Adjust for 2% limitation:		
Reduction in System Usage Charges	(1.89)	(mills/kWh)
Mills/kWh limitation	0.14	(mills/kWh)
Adjusted Reduction in System Usage Charges	(1.75)	(mills/kWh)
Adjusted Decrease in system usage revenue	($18,022)	
Amount exceeding 2% limitation	$1,397	

PORTLAND GENERAL ELECTRIC
Calculation of 2% limitation of Schedule 129 Fixed Generation True-up

1. Load Returns to COS Pricing

Schedules	COS Cycle MWH	Current Base Revenues	Base Rate mills/kWh	Sch 125 mills/kWh	Fixed Gen. Adjustment mills/kWh	Subtotal mills/kWh	2% Test Adjustment mills/kWh	Proposed mills/kWh
83-S	5,167,663	$430,329,834	83.27	(2.45)	(1.89)	78.93	0.14	79.07
83-P	276,888	$21,533,628	77.77	(2.37)	(1.89)	73.51	0.14	73.65
89-S	676,398	$53,769,916	79.49	(2.46)	(1.89)	75.14	0.14	75.28
89-P	2,517,345	$180,649,879	71.76	(2.35)	(1.89)	67.52	0.14	67.66
89-T	1,241,812	$83,230,110	67.02	(2.27)	(1.89)	62.86	0.14	63.00
Totals	9,880,106	$769,513,367	77.89			73.59		73.73
				Two percent limiter ===>		73.73		

2. Load Remains on Multi-year Direct Access

Schedules	Base Rate mills/kWh	Sch 125 mills/kWh	Subtotal mills/kWh	Percent Change[1]
83-S	83.27	(2.70)	80.57	-1.9%
83-P	77.77	(2.61)	75.16	-2.0%
89-S	79.49	(2.71)	76.78	-2.0%
89-P	71.76	(2.59)	69.17	-2.2%
89-T	67.02	(2.51)	64.51	-2.3%
Totals	77.89	(2.65)	75.24	-2.0%

Source of Schedule 125 estimate is on page 5 of Exhibit 203
1. Percent change is with 2% limiter.

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Price: Eligible Load Remains on Schedules 483/489

Schedules	2010 Calendar COS Energy MWH	2010 Base Generation Revenues	Generation Allocation	2010 Base NVPC Revenues	Sch 125 Allocation	2010 NVPC Revenues	2010 Sch 125 Rate mills/kWh	2010 Sch 125 Revenues
Schedule 7	7,561,317	$484,601	42.32%	$349,480	($20,585)	$328,896	(2.72)	($20,567)
Schedule 15	23,933	$1,426	0.12%	$1,029	($61)	$968	(2.53)	($61)
Schedule 32	1,495,562	$95,776	8.36%	$69,095	($4,068)	$65,027	(2.72)	($4,068)
Schedule 38	70,389	$4,504	0.39%	$3,247	($191)	$3,056	(2.72)	($191)
Schedule 47	22,076	$1,312	0.11%	$947	($56)	$891	(2.52)	($56)
Schedule 49	68,335	$4,078	0.36%	$2,942	($173)	$2,769	(2.53)	($173)
Schedule 83-S	5,173,039	$329,160	28.74%	$237,494	($13,982)	$223,512	(2.70)	($13,967)
Schedule 89-S	653,492	$41,667	3.64%	$30,048	($1,770)	$28,278	(2.71)	($1,771)
Schedule 83-P	282,533	$17,384	1.52%	$12,542	($738)	$11,803	(2.61)	($737)
Schedule 89-P	1,771,926	$108,146	9.44%	$77,988	($4,594)	$73,394	(2.59)	($4,589)
Schedule 89-T	852,313	$50,317	4.39%	$36,373	($2,137)	$34,236	(2.51)	($2,139)
Schedule 91	107,337	$6,396	0.56%	$4,614	($272)	$4,343	(2.53)	($272)
Schedule 92/94	5,016	$313	0.03%	$226	($13)	$213	(2.65)	($13)
Schedule 93	573	$36	0.00%	$26	($2)	$25	(2.70)	($2)
TOTAL	18,087,841	$1,145,117	100%	$826,051	($48,642)	$777,410		($48,606)
			Sch 125 TARGET ===>		($48,642)			

2010 NVPC	$830,697	
Adjustment for Returning Load	($51,701)	(page 8)
Adjusted NVPC	$778,995	
2010 NVPC Revenues	$826,051	(page 6)
Change in NVPC	($47,056)	
Revenue Senstitive Adj. 3.37%	($1,586)	
Sch 125 Revenue Requirement	($48,642)	

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues: Eligible Load Remains on Direct Access

Schedule	2010 Calendar MWh	Energy Price	2010 Base Generation Revenues	UE 197 Fixed. Gen. Price	NVPC Price	2010 NVPC Revenues
Sch 7						
Block 1	2,087,557	51.24	$106,966	17.87	33.37	$69,662
Block 2	5,473,760	68.99	$377,635	17.87	51.12	$279,819
Sch 15	23,933	59.59	$1,426	16.60	42.99	$1,029
Sch 32	1,495,562	64.04	$95,776	17.84	46.20	$69,095
Sch 38						
On-peak	32,745	70.73	$2,316	17.85	52.88	$1,732
Off-peak	37,644	58.11	$2,187	17.85	40.26	$1,516
Sch 47	22,076	59.44	$1,312	16.56	42.88	$947
Sch 49	68,335	59.67	$4,078	16.62	43.05	$2,942
Sch 83-S	5,173,039	63.63	$329,160	17.72	45.91	$237,494
Sch 83-P	282,533	61.53	$17,384	17.14	44.39	$12,542
Sch 89-S						
On-peak	418,600	68.98	$28,875	17.78	51.20	$21,432
Off-peak	234,893	54.46	$12,792	17.78	36.68	$8,616
Sch 89-P						
On-peak	1,060,222	66.60	$70,611	17.02	49.58	$52,566
Off-peak	711,704	52.74	$37,535	17.02	35.72	$25,422
Sch 89-T						
On-peak	479,275	64.80	$31,057	16.36	48.44	$23,216
Off-peak	373,038	51.63	$19,260	16.36	35.27	$13,157
Sch 91	107,337	59.59	$6,396	16.60	42.99	$4,614
Sch 92	5,016	62.42	$313	17.39	45.03	$226
Sch 93	573	63.53	$36	17.70	45.83	$26
Totals	18,087,841		$1,145,117			$826,051

PORTLAND GENERAL ELECTRIC
Calculation of NVPC Decrement due to Current Schedule 483/489 Customers Remaining on Direct Access

Current Schedule	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	12 Month Avg/Total
Schedule 483-S													
Total Energy (MWh)													
On-Peak	173	176	170	197	189	162	185	144	176	186	233	199	2,190
Off-Peak	118	121	115	131	144	110	128	100	116	139	162	141	1,524
Total	290	297	285	328	333	273	313	244	293	325	395	340	3,715
Schedule 489-S													
Total Energy (MWh)													
On-Peak	835	776	863	849	814	832	850	883	843	795	813	737	9,890
Off-Peak	560	505	574	548	570	499	532	581	498	541	511	478	6,395
Total	1,395	1,281	1,437	1,397	1,384	1,331	1,381	1,464	1,341	1,337	1,324	1,215	16,286
Schedule 489-P													
Total Energy (MWh)													
On-Peak	33,536	35,427	35,000	33,330	36,097	35,555	36,442	38,031	35,042	36,624	36,221	35,741	427,046
Off-Peak	26,205	25,344	25,751	25,919	26,237	25,232	28,510	26,784	26,731	26,366	25,840	28,284	317,202
Total	59,741	60,771	60,750	59,248	62,334	60,787	64,952	64,814	61,774	62,990	62,062	64,026	744,248
Schedule 489-T													
Total Energy (MWh)													
On-Peak	15,593	15,171	17,773	16,702	17,602	19,047	17,986	18,581	16,867	16,967	16,014	15,558	203,862
Off-Peak	14,618	13,503	15,122	14,593	14,933	15,910	18,365	17,499	17,189	16,437	15,744	13,213	187,128
Total	30,211	28,674	32,896	31,295	32,535	34,957	36,352	36,080	34,056	33,405	31,758	28,771	390,989
Secondary Energy Totals													
On-Peak	1,008	953	1,033	1,047	1,002	995	1,034	1,027	1,019	981	1,046	936	12,081
Off-Peak	678	626	688	678	714	609	660	681	615	680	673	619	7,920
Total	1,685	1,578	1,722	1,725	1,717	1,603	1,694	1,707	1,634	1,661	1,719	1,554	20,001
Primary Energy Totals													
On-Peak	33,536	35,427	35,000	33,330	36,097	35,555	36,442	38,031	35,042	36,624	36,221	35,741	427,046
Off-Peak	26,205	25,344	25,751	25,919	26,237	25,232	28,510	26,784	26,731	26,366	25,840	28,284	317,202
Total	59,741	60,771	60,750	59,248	62,334	60,787	64,952	64,814	61,774	62,990	62,062	64,026	744,248
Subtransmission Energy Totals													
On-Peak	15,593	15,171	17,773	16,702	17,602	19,047	17,986	18,581	16,867	16,967	16,014	15,558	203,862
Off-Peak	14,618	13,503	15,122	14,593	14,933	15,910	18,365	17,499	17,189	16,437	15,744	13,213	187,128
Total	30,211	28,674	32,896	31,295	32,535	34,957	36,352	36,080	34,056	33,405	31,758	28,771	390,989

PORTLAND GENERAL ELECTRIC
Calculation of NVPC Decrement due to Current Schedule 483/489 Customers Remaining on Direct Access

Current Schedule	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	12 Month Avg/Total
Busbar Loads													
Secondary Energy Totals													
On-Peak	1,092	1,032	1,120	1,134	1,086	1,078	1,121	1,112	1,104	1,063	1,134	1,014	13,088
Off-Peak	734	678	746	735	774	660	715	738	666	737	729	670	8,580
Total	1,826	1,710	1,865	1,869	1,860	1,737	1,836	1,850	1,770	1,800	1,862	1,684	21,669
Primary Energy Totals													
On-Peak	35,172	37,156	36,707	34,956	37,858	37,290	38,221	39,887	36,752	38,411	37,989	37,486	447,886
Off-Peak	27,484	26,580	27,007	27,183	27,518	26,463	29,901	28,091	28,036	27,653	27,101	29,664	332,682
Total	62,656	63,736	63,715	62,140	65,376	63,753	68,122	67,977	64,788	66,064	65,090	67,150	780,567
Subtransmission Energy Totals													
On-Peak	16,119	15,682	18,372	17,265	18,196	19,689	18,592	19,207	17,436	17,539	16,553	16,082	210,732
Off-Peak	15,111	13,958	15,632	15,085	15,436	16,446	18,984	18,089	17,768	16,991	16,275	13,658	193,434
Total	31,229	29,641	34,004	32,350	33,632	36,135	37,577	37,296	35,204	34,530	32,828	29,740	404,165
Total Busbar Loads													
On-Peak	52,383	53,870	56,199	53,355	57,139	58,056	57,934	60,206	55,292	57,013	55,676	54,581	671,706
Off-Peak	43,328	41,216	43,385	43,003	43,728	43,569	49,601	46,917	46,470	45,381	44,105	43,993	534,696
Total	95,711	95,087	99,584	96,358	100,867	101,625	107,534	107,123	101,762	102,394	99,781	98,574	1,206,401

Note: Losses are 8.34%, 4.88%, and 3.37% for secondary, primary and subtransmission delivery voltages.

Current Schedule	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	12 Month Avg/Total
Mid-Columbia Projected Prices													
On-peak	52.75	46.75	40.50	38.75	34.25	31.50	52.75	58.00	53.00	50.00	54.25	56.50	47.42
Off-peak	45.25	40.00	34.00	32.50	21.50	20.25	37.00	41.50	40.00	40.00	44.75	48.25	37.08
Net Variable Power Cost Decrement													
On-Peak	$2,763	$2,518	$2,276	$2,067	$1,957	$1,829	$3,056	$3,492	$2,930	$2,851	$3,020	$3,084	$31,844
Off-Peak	$1,961	$1,649	$1,475	$1,398	$940	$882	$1,835	$1,947	$1,859	$1,815	$1,974	$2,123	$19,857
Total	$4,724	$4,167	$3,751	$3,465	$2,897	$2,711	$4,891	$5,439	$4,789	$4,666	$4,994	$5,206	$51,701

PORTLAND GENERAL ELECTRIC
ALLOCATION OF SCHEDULE 129 TRANSITION ADJUSTMENT
2009

Grouping	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 83-S	5,368,304	50.0%	9,531	1.78
Schedule 89-S 1-4 MW	683,443	6.4%	1,213	1.78
Schedule 89-S GT 4 MW	26,194	0.2%	47	1.78
Schedule 83-P	289,156	2.7%	513	1.78
Schedule 89-P 1-4 MW	683,792	6.4%	1,214	1.78
Schedule 89-P GT 4 MW	2,014,310	18.8%	3,576	1.78
Schedule 89-T	1,664,965	15.5%	2,956	1.78
TOTAL	10,730,165	100.00%	19,050	
		TARGET	19,050	

Note: cycle energy includes direct access customers