Portland General Electric Company
Trojan Nuclear Plant
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Rainier OR 97048
(503) 556-3713

July 12, 2005

VPN-029-2005

Trojan ISFSI
Docket No. 72-17
License No. SNM-2509

10 C.F.R. § 72.50

ATTN: Document Control Desk
Director, Spent Fuel Project Office
Office of Nuclear Material Safety and Safeguards
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Application for Consent to Indirect Transfer of Materials License

Pursuant to Section 184 of the Atomic Energy Act of 1954, as amended ("AEA"), 42 U.S.C. § 2234, and 10 C.F.R. § 72.50, Portland General Electric Company ("PGE"), acting on its own behalf and that of its parent company, Enron Corp. ("Enron"), and of Stephen Forbes Cooper, LLC ("SFC"), as Disbursing Agent on behalf of the Reserve for Disputed Claims ("Reserve"),[1] requests Nuclear Regulatory Commission ("NRC" or "Commission") consent to an indirect transfer of control over Trojan Independent Spent Fuel Storage Installation ("Trojan ISFSI") License No. SNM-2509 issued under the specific license provisions of 10 C.F.R. Part 72, to the extent such license is held by PGE.[2] As detailed further in the enclosed Application for Consent to Indirect Transfer of Control of Materials License ("Application"), the proposed transfer is necessary to implement the Plan's directive to transfer 100 percent of PGE's common equity from Enron to the creditors of Enron by canceling the existing PGE common stock held by Enron and by authorizing and issuing to Enron's creditors new PGE common stock ("New

[1] On December 2, 2001, Enron filed to initiate bankruptcy proceedings under Chapter 11 of the United States Bankruptcy Code. The Reserve was created by the Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated July 2, 2004, including the Plan Supplement and all schedules and exhibits thereto ("Plan"). (*In re: Enron Corp., et al.*, Bankr. S.D.N.Y., Case No. 01-16034). The Plan was confirmed by the United States Bankruptcy Court for the Southern District of New York ("Bankruptcy Court") on July 15, 2004. The Disbursing Agent is defined in Plan section 1.83. SFC was appointed as Disbursing Agent by the Bankruptcy Court in the Confirmation Order.

[2] The Trojan ISFSI is jointly owned by PGE (67.5 percent), Eugene Water and Electric Board ("EWEB", 30 percent) and PacifiCorp (2.5 percent). As such, PGE, EWEB, and PacifiCorp are collectively specified as the "Licensee" in Trojan ISFSI License No. SNM-2509. EWEB and PacifiCorp are not involved in the indirect transfer of control requested herein.

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PGE Common Stock"). Upon issuance of the New PGE Common Stock, PGE will be separated from Enron, and will become a "stand-alone" publicly traded Oregon corporation.

It is noted that unlike a prior recent PGE application[3] requesting approval of indirect transfer of both the Trojan Nuclear Plant Facility Operating (Possession Only) License No. NPF-1 maintained under the requirements of 10 C.F.R. Part 50 and the Trojan ISFSI license maintained under those of 10 C.F.R. Part 72, the enclosed Application requests NRC approval only of the indirect transfer of control over the Trojan ISFSI license. This reflects the recent termination of the Trojan Nuclear Plant license,[4] as a result of which the Trojan ISFSI 10 C.F.R. Part 72 license is now the only NRC license in effect at the Trojan site. With the Trojan Nuclear Plant license now terminated, the requirements governing transfers of Part 50 licenses (including, but not limited, to those in 10 C.F.R. § 50.80) no longer apply to the Trojan site and, for that reason, the enclosed Application addresses only those NRC criteria for license transfers that are contained in 10 C.F.R. Part 72.

As detailed in the enclosed Application, issuance of the New PGE Common Stock and the associated separation of PGE from Enron will not impact PGE's status as a licensee for the Trojan ISFSI with authority to operate and maintain and to store specified spent nuclear fuel and fuel-related materials at that facility. The information included in the Application demonstrates that PGE will retain the requisite technical and financial qualifications under its license for the Trojan ISFSI, and its ability to continue funding its share of the costs of operating, maintaining, and ultimately decommissioning the Trojan ISFSI.

In summary, the proposed indirect license transfer will be consistent with the requirements set forth in the AEA, NRC regulations and orders, and Trojan ISFSI License No. SNM-2509. No physical changes will be made to the Trojan ISFSI. The proposed indirect license transfer will not involve any changes to the current Trojan ISFSI licensing basis, and will not have any adverse impact on the public health and safety or be inimical to the common defense and security. No license amendment is required to implement the proposed indirect license transfer.

PGE and SFC, as Disbursing Agent, have filed an application with the Oregon Public Utility Commission ("OPUC") dated June 17, 2005, (attached as Enclosure (1) to the Application). Other applications, as are necessary, will be filed with (among others), the Federal Communications Commission ("FCC"), the Securities and Exchange Commission ("SEC"), and the Federal Energy Regulatory Commission ("FERC"). PGE has requested an October 2005 date for the OPUC approval. PGE is prepared to work closely with the NRC Staff to help

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3 By PGE letter VPN-020-2005 dated June 14, 2004, as subsequently supplemented, PGE requested NRC approval of the indirect transfer of its Trojan Nuclear Plant license and Trojan ISFSI license to Oregon Electric Utility Company ("OEUC"). The NRC granted approval of this indirect transfer application by letter dated December 30, 2004. By PGE letter VPN-016-2005 dated April 20, 2005, PGE formally notified the NRC that the proposed transfer to OEUC was terminated.

4 This termination was documented in NRC letter "Termination of Trojan Nuclear Plant Facility Operating License No. NPF-1," dated May 23, 2005.

expedite the Application's review, but respectfully requests that the NRC complete its review on a schedule to permit the issuance of its approval of the indirect transfer of control as promptly as possible, with a target date of October 1, 2005, or as soon thereafter as reasonably practicable. PGE further requests that the NRC's consent be made effective immediately upon issuance. PGE will inform the NRC of any other developments that may have an impact on the schedule.

For purposes of answering questions concerning this application, please contact Douglas R. Nichols, General Counsel, Portland General Electric Company, Suite 1700, 121 SW Salmon St., Portland, OR 97204 (phone number 503-464-8402). Service of any comments, hearing requests, intervention petitions, or other filings should be made to Mr. Nichols at the above address, and also to: Samuel Behrends IV, LeBoeuf, Lamb, Greene & McRae, 1875 Connecticut Ave., N.W., Suite 1200, Washington, DC 20009 (sbehrend@llgm.com).

Sincerely,

Stephen M. Quennoz
Vice President, Generation

Enclosure: Application for Consent to Indirect Transfer of Control of Materials License

c: C. M. Regan, NRC, NMSS, SFPO
Director, DNMS, NRC Region IV
Ken Niles, ODOE
Mitchell S. Taylor, Enron Corp.
David Koogler, Enron Corp.
Sam Behrends, LeBoeuf, Lamb, Greene & McRae
Trojan Owners Committee representatives of BPA, PacifiCorp, and EWEB
Douglas R. Nichols, PGE

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
Portland General Electric Company	)	Docket No. 72-17
Trojan Independent Fuel Storage Installation	)	

AFFIRMATION

I, Stephen M. Quennoz, being duly sworn, hereby depose and state that I am Vice President, Generation of Portland General Electric Company ("PGE"); that I am duly authorized to file with the Nuclear Regulatory Commission the attached Application for Consent to Indirect Transfer of Control of Materials License; that I am familiar with the content thereof; and that the matters set forth therein with regard to PGE are true and correct to the best of my knowledge and belief.

Stephen M. Quennoz

Stephen M. Quennoz

STATE OF OREGON	)
	)
MULTNOMAH COUNTY	)

Subscribed and sworn to before me, a Notary Public in and for the State of Oregon, this 12th day of July, 2005.

Karen J. Lewis

NOTARY PUBLIC, State of Oregon
Commission Expires: Oct. 20, 2006

OFFICIAL SEAL
KAREN J LEWIS
NOTARY PUBLIC-OREGON
COMMISSION NO. 361532
MY COMMISSION EXPIRES OCT 20, 2006

APPLICATION FOR CONSENT TO INDIRECT TRANSFER OF CONTROL OF MATERIALS LICENSE

I. INTRODUCTION

Pursuant to Section 184 of the Atomic Energy Act of 1954, as amended ("AEA"), 42 U.S.C. § 2234, and 10 C.F.R. § 72.50, Portland General Electric Company ("PGE"), acting on its own behalf and that of its parent company, Enron Corp. ("Enron"), and of Stephen Forbes Cooper, LLC ("SFC"), as Disbursing Agent on behalf of the Reserve for Disputed Claims ("Reserve" or "DCR"),[1] requests Nuclear Regulatory Commission ("NRC" or "Commission") consent to an indirect transfer of control over Trojan Independent Spent Fuel Storage Installation ("Trojan ISFSI") License No. SNM-2509, to the extent such license is held by PGE. As detailed further in this Application, the proposed transfer is necessary to implement the Plan's directive to transfer 100 percent of PGE's common equity from Enron to the creditors of Enron by canceling the existing PGE common stock held by Enron and by authorizing and issuing to Enron's creditors new PGE common stock ("New PGE Common Stock"). Upon issuance of the New PGE Common Stock, PGE will be separated from Enron, and will become a "stand-alone" publicly traded Oregon corporation.

The issuance of the New PGE Common Stock as described in this Application will not change PGE's status as NRC licensee of the Trojan ISFSI, and there will be no direct transfer of

1 On December 2, 2001, Enron filed to initiate bankruptcy proceedings under Chapter 11 of the United States Bankruptcy Code. The Reserve was created by the Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated July 2, 2004, including the Plan Supplement and all schedules and exhibits thereto ("Plan"). (*In re: Enron Corp., et al.*, Bankr. S.D.N.Y., Case No. 01-16034). The Plan was confirmed by the United States Bankruptcy Court for the Southern District of New York ("Bankruptcy Court") on July 15, 2004. The Disbursing Agent is defined in Plan section 1.83. SFC was appointed as Disbursing Agent by the Bankruptcy Court in the

the Trojan ISFSI license. Control of the 10 C.F.R. Part 72 license for the Trojan ISFSI now held by PGE and its co-owners will remain with PGE and the same co-owners, and will not be affected by the issuance of the New PGE Common Stock. PGE will remain a regulated public electric utility in the State of Oregon. PGE's name will not change, PGE's headquarters will remain in Portland, Oregon, and PGE's current management team will continue to operate the utility on a day-to-day basis. PGE will continue to be regulated by the NRC, OPUC, and FERC in the same manner as it is today. Finally, as described in more detail below, issuance of the New PGE Common Stock will not affect PGE's technical and financial qualifications and its ability to continue funding its share of the costs of operating, maintaining, and ultimately decommissioning the Trojan ISFSI.

II. PURPOSES FOR WHICH THE INDIRECT TRANSFER OF CONTROL OVER THE LICENSE IS REQUESTED AND NATURE OF THE TRANSACTION MAKING SUCH TRANSFER DESIRABLE

A. BACKGROUND

PGE is a subsidiary of Enron, which owns 100 percent of the common stock of PGE and is a registered public utility holding company under the Public Utility Holding Company Act of 1935 ("PUHCA"). As further detailed below, Enron emerged from bankruptcy on November 17, 2004. The common stock of PGE held by Enron is part of the bankruptcy estate.

PGE is an Oregon corporation engaged principally in the generation, transmission, distribution, and sale of electric energy in Oregon. PGE serves approximately 765,000 retail customers in Oregon and is an "electric utility" as defined in the Commission's regulations at

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Confirmation Order. The Plan and Plan-related documents are available at the website maintained at the direction of the United States Bankruptcy Court at www.elaw4enron.com.

10 C.F.R. § 2.4. PGE also sells electric energy at wholesale to, and transmits electric energy in interstate commerce for, other electric utilities under rate schedules approved by the Federal Energy Regulatory Commission ("FERC").

PGE's utility operations are subject to regulation by the Oregon Public Utility Commission ("OPUC") under Oregon law. Among other things, the OPUC regulates PGE's retail rates and charges, issuances of securities (other than short-term debt securities), services, facilities, classification of accounts, and transactions with affiliated interests.

PGE presently holds a 67.5 percent interest in, and is the sole operator of, the Trojan ISFSI, which is located in Columbia County, Oregon.[2] PGE is licensed to operate, maintain, and store specified spent nuclear fuel and fuel-related materials[3] at the Trojan ISFSI in accordance with a specific license issued by the Commission pursuant to 10 C.F.R. Part 72 on March 31, 1999.

B. DESCRIPTION OF THE TRANSACTION RESULTING IN THE INDIRECT TRANSFER OF CONTROL

This section provides details of the proposed issuance of New PGE Common Stock and associated separation of PGE from Enron that would result in the indirect transfer of control over the Trojan ISFSI license requested in this Application. Additional details and supporting documents regarding the proposed stock issuance were incorporated into an application filed

2 The Trojan ISFSI is jointly owned by PGE (67.5 percent), Eugene Water and Electric Board ("EWEB", 30 percent) and PacifiCorp (2.5 percent). As such, PGE, EWEB, and PacifiCorp are collectively specified as the "Licensee" in Trojan ISFSI License No. SNM-2509. EWEB and PacifiCorp are not involved in the transfer requested herein.

3 The contents of the Trojan ISFSI are limited to the spent nuclear fuel and fuel-related materials that exist at the site as a result of the operation of the former Trojan Nuclear Plant, the license for which was terminated on May 23, 2005, in accordance with 10 C.F.R. § 50.82.

with the OPUC jointly by PGE and SFC. A copy of the OPUC application, filed on June 17, 2005, is provided as Enclosure (1) to this Application.

1. Development, Confirmation, and Effect of the Plan

The issuance of New PGE Common Stock that is the subject of this Application implements the Plan that was confirmed by the Bankruptcy Court in its order dated July 15, 2004 ("Confirmation Order"), and became effective on November 17, 2004 ("Effective Date"). As detailed further below, the confirmed Plan determines the rights of creditors, the method of calculating their interests in the assets of Enron and the other debtors (collectively referred to herein as the "Debtors"),[4] and the manner in which distributions will be made to the various classes of creditors.

(a) Confirmation Order

As stated above, the Bankruptcy Court confirmed the Plan in its Confirmation Order dated July 15, 2004.[5] Confirmation means that, upon the Effective Date, the Plan is subject to no further objections, and is binding on the Debtors, the creditors and all other parties subject to the Plan.[6] The Confirmation Order includes several decisions by the Bankruptcy Court that apply to PGE and this Application. These decisions are:

4 The Debtors are Enron and the other entities identified in Plan section 1.77, all of whose bankruptcy filings were consolidated with Enron.

5 The SEC separately approved the Plan on March 9, 2004, pursuant to a Plan Order, which is attached as Exhibit 6 to the OPUC filing provided as Enclosure (1) to this Application.

6 Two Creditors have pursued appeals of the Confirmation Order. Neither sought a stay to prevent the occurrence of the Effective Date and substantial consummation of the Plan. Enron and the other reorganized debtors have moved to dismiss both the appeals as moot. On June 24, 2005, the United States District Court for the Southern District of New York entered an order dismissing one of the appeals as moot. The motion to dismiss the other appeal is pending.

- Appointment of SFC as the Plan Administrator and Disbursing Agent, and approval of the Plan Administration Agreement.[7] The duties and operations of the Plan Administrator and the Disbursing Agent are described in more detail in Section III.D of this Application.
- Approval of the DCR Guidelines and the Overseer Guidelines.[8]
- Approval of four new members of Enron's board of directors. The Bankruptcy Court also approved these same four individuals as DCR Overseers. A fifth board member and a fifth Overseer, who is the same person, was appointed after the Confirmation Order. The five DCR Overseers and the Enron board members are U.S. citizens.
- Approval of forms of new Articles of Incorporation and Bylaws for PGE, which drafts are included in the Plan Supplement as Schedules N and M, respectively. Prior to the issuance of the New PGE Common Stock, PGE intends to adopt the Articles of Incorporation[9] and Bylaws.[10] These Articles of Incorporation and Bylaws are substantially similar to the form approved by the Bankruptcy Court and are a common form of articles of incorporation and bylaws for publicly traded companies incorporated and headquartered in Oregon.

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7 Attached as Exhibit 7 to the OPUC filing provided as Enclosure (1) to this Application.

8 Attached as Exhibits 3 and 4, respectively, to the OPUC filing provided as Enclosure (1) to this Application.

9 Draft attached as Exhibit 9 to the OPUC filing provided as Enclosure (1) to this Application.

10 Draft attached as Exhibit 10 to the OPUC filing provided as Enclosure (1) to this Application.

(b) Effective Date

As stated previously, the Plan became effective on November 17, 2004. The Effective Date resulted in the following actions and effects that apply to PGE and this Application:

- The Debtors whose plans were confirmed by the Confirmation Order became "Reorganized Debtors," which means that they emerged from bankruptcy and are no longer debtors in possession under Chapter 11 of the Bankruptcy Code. For convenience, this Application continues to use the term "Debtors" to refer to the "Reorganized Debtors."
- Enron's new board of directors replaced the prior board of directors, and the same individuals who are the new directors of Enron became the DCR Overseers.
- The Unsecured Creditors' Committee was disbanded, except to handle certain litigation matters.
- All of the assets of the Debtors were vested in the Debtors free of all liens and encumbrances.
- The Bankruptcy Court retained exclusive jurisdiction over any matter arising under the Bankruptcy Code and arising in or relating to the Chapter 11 Cases or the Plan in certain circumstances, including the entry of all orders as may be necessary or appropriate to implement or consummate the provisions of the Plan and all contracts, instruments, releases and other agreements or documents created in connection with the Plan.[11]

[11] See Plan section 36, attached as Exhibit 11 to the OPUC filing provided as Enclosure (1) to this Application.

(c) Effect of the Plan on Creditors and Former Equity Holders

The Plan determines the interests of the various classes of creditors in the assets of the Debtors and the method for calculating such interests. The Plan also determines the manner in which the creditors will receive the assets of the Debtors. Distributions will only be made to creditors who become Holders of Allowed Claims.[12]

Under the Plan, 373 different classes of unsecured creditors will receive distributions. Approximately 200 classes of unsecured creditors are eligible to receive common stock, including the New PGE Common Stock. The anticipated recovery to the various creditors of the Debtors vary from a low of approximately 6 percent of Allowed Claims to approximately 75 percent of Allowed Claims, with the majority of creditors anticipated to recover between 15 percent and 30 percent of Allowed Claims. These are expected recovery percentages only. The final distributions under the Plan will not be known until all claims against the Debtors, and all claims by the Debtors for the recovery of assets, are resolved.

The Plan creates a common Plan Currency[13] consisting primarily of cash and common stock, including the New PGE Common Stock.[14] The Plan provides that each Holder of an Allowed Claim will receive a pro rata share of the Plan Currency allocated to other Holders

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12 An Allowed Claim is one scheduled by a Debtor as liquidated and not contingent or disputed or, if not so scheduled, filed against a Debtor and allowed by a Final Order of the Bankruptcy Court. The Bankruptcy Court fixed November 29, 2004 as the record date for determining which holders of Allowed Claims are entitled to receive distributions under the Plan, including distributions of New PGE Common Stock. As used herein, "Holder of an Allowed Claim" means the holder, as of the record date, of an Allowed Claim.

13 See Plan section 1.198, attached as Exhibit 12 to the OPUC filing provided as Enclosure (1) to this Application.

14 See Plan section 1.191, attached as Exhibit 13 to the OPUC filing provided as Enclosure (1) to this Application.

similarly classified under the Plan.[15] In general, each Holder of an Allowed Claim will receive a percentage of each of the assets available for distribution based on the ratio of that Holder's Allowed Claims to the Allowed Claims of all other Holders of the same class. This means that each Holder will receive cash and common stock held by the Debtors, including the New PGE Common Stock, in a percentage equal to its percentage claim, regardless of how the stock is valued. For example, if a Holder of an Allowed Claim is entitled to 2 percent of the assets available for distribution, that Holder will receive 2 percent of each asset, including 2 percent of cash and 2 percent of New PGE Common Stock. It will receive this percentage of New PGE Common Stock regardless of whether that stock is distributed early or late in the claim settlement process and regardless of whether the value of the New PGE Common Stock has gone up or down over time.

The Plan Administrator will calculate the recovery percentages for Holders of Allowed Claims each April and October. Each calculation will require about two months to perform: during January and February for April percentages and during July and August for October percentages. Holders of Allowed Claims will receive distributions based on those calculations in April and October. Claims that are first allowed other than in April or October may receive first distributions in June, August, December or February, based upon the most recent April or October calculation of recovery percentages.

Distribution of all assets from the Debtors, including the issuance of the New PGE Common Stock, and the continuing release of New PGE Common Stock from the Reserve over time as described below, will be made to Holders of Allowed Claims as their claims are allowed.

15 See Plan section 7.1, attached as Exhibit 14 to the OPUC filing provided as Enclosure (1) to this

Creditors may sell their claims against the bankruptcy estates of the Debtors. Enron does not keep a registry of such sales. The Holders of Allowed Claims are responsible for any subsequent transfer of assets to a purchaser of a claim.

2. Issuance, Listing, and Trading of New PGE Common Stock

As detailed in the OPUC filing provided as Enclosure (1) to this Application, PGE will create 80,000,000 shares of New PGE Common Stock that will replace in full the existing PGE common stock. 62,500,000 shares of New PGE Common Stock will be issued when sufficient claims have been allowed to permit the issuance of not less than 30 percent of the New PGE Common Stock to Holders of Allowed Claims.[16] The intent of the 30 percent condition is to assure that a liquid market can exist for shares of New PGE Common Stock and to permit the listing of the New PGE Common Stock on a national securities exchange. A trading market in the New PGE Common Stock at the date of issuance will allow Holders of Allowed Claims to retain the New PGE Common Stock distributed to them or sell such shares in the market.

The Disbursing Agent on behalf of the Reserve will receive any New PGE Common Stock not initially distributed to Holders of Allowed Claims. This amount will not exceed 70 percent and will decline with each subsequent release of New PGE Common Stock from the Reserve, as claims are resolved. The result of this will be a continuous release of New PGE

Application.

16 See Plan section 32.1(c), attached as Exhibit 16 to the OPUC filing provided as Enclosure (1) to this Application.

Common Stock from the Reserve to Holders of Allowed Claims and accordingly a continuous reduction in the percentage of New PGE Common Stock held in the Reserve.[17]

The current expectation is that the Reserve will hold less than 50 percent of the New PGE Common Stock within one year after the issuance and may hold less than 30 percent of the New PGE Common Stock within two years after the issuance. The speed at which the Reserve releases stock to Holders of Allowed Claims, and thus reduces the amount of New PGE Common Stock held, will depend upon the speed and timing of the resolution of further claims. Ultimately, the Reserve will release all of the New PGE Common Stock when all claims are resolved; however, the Reserve must hold not less than one (1) percent of the New PGE Common Stock until then.[18]

The New PGE Common Stock will be publicly traded. This means that PGE, its officers, directors, and shareholders must comply with the U.S. Securities Exchange Commission ("SEC"), stock exchange, and state securities laws and regulations that apply to public companies. Thus, PGE will file public annual reports and proxy statements for the election of directors and other shareholder actions, and will continue to file forms 10-K, 10-Q and 8-K with

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17 This means that, in the future, the Reserve will transfer amounts of the New PGE Common Stock to a large number of Holders of Allowed Claims, each of whom will receive only a small fraction of the total shares. In terms of their impact on the licensee, these subsequent distributions are much like the ordinary sale of stock on the open market, which has never required Commission approval unless such sale reaches the relatively high threshold that creates control. Under applicable precedent, no single Holder of Allowed Claims will ever gain control of PGE unless that holder acquires at least 10 percent of the voting stock of PGE. *See, e.g.*, 15 U.S.C § 79b (a)(7) (when a party owns less than 10 percent of an entity's stock, burden shifts to the SEC to prove that there is a controlling influence). For that reason, as long as no party holds 10 percent or more of the voting stock of PGE, the future doling out of a small portion of stock to an individual Holder of Allowed Claims should not constitute a transfer of control. PGE is not aware of any Holder of Allowed Claims that will own or control 10 percent or more of the New PGE Common Stock as a result of the initial issuance of New PGE Common Stock or the release of New PGE Common Stock from the Reserve.

the SEC, among other requirements. PGE's shareholders will be subject to the laws and regulations applicable to investors in publicly traded securities. For example, the Williams Act requires that any purchaser acquiring 5 percent or more of the common stock of a publicly traded company must file a Form 13-D with the SEC informing the SEC of that fact and of the investment intentions of the purchaser.

3. Governance of PGE Following Issuance of New PGE Common Stock

As a result of the issuance of the New PGE Common Stock, PGE will separate from Enron. PGE will be governed by its board of directors, who the PGE shareholders will elect annually. The board of directors of PGE will owe its fiduciary duties to all shareholders, not a single shareholder.

In preparation for initial issuance of New PGE Common Stock, PGE has begun a search for additional members for PGE's board of directors that satisfy the requirements of the selected stock exchange, the SEC, and Sarbanes/Oxley. Among other things, these requirements include that a majority of the PGE board of directors be independent[19] of PGE and its management and that at least one board member possesses the qualifications of a "financial expert" as defined in Item 401(h) of Regulations S-K. Although the new members that will be added to the PGE board of directors have not yet been selected, a substantial majority of the PGE board members will at all times be U.S. citizens.

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18 See Plan section 32.1(c), attached as Exhibit 16 to the OPUC filing provided as Enclosure (1) to this Application.

19 Independence means, in part, that a Board member has a sufficiently small economic stake in PGE so that the member's independent judgment is not affected by personal considerations.

The PGE board of directors will set the policies and direction for PGE, just like any other board of directors of other publicly traded companies. The PGE board of directors will be responsible for selecting and evaluating PGE's management. There are no expected changes in management at PGE as a result of the issuance of New PGE Common Stock and associated separation of PGE from Enron. The PGE board of directors will act on matters such as PGE's operating and capital budgets, PGE's major investments and risk management policies, and PGE's dividends.

PGE's board of directors will owe a fiduciary duty to all shareholders, including those who have purchased their shares in the open market, Holders of Allowed Claims who have received shares upon the issuance of New PGE Common Stock or by the release of New PGE Common Stock from the Reserve, and the Reserve. The fiduciary duties of PGE's board of directors are the same for all shareholders, including the Reserve, regardless of the percentage of New PGE Common Stock owned by any shareholder.

4. Roles and Operation of the Plan Administrator, the Disbursing Agent, and the DCR Overseers

(a) Plan Administrator

The Plan Administration Agreement[20] describes the rights and duties of SFC as the Plan Administrator. Those rights and duties are, essentially, to carry out the Plan, resolve all claims made against the Debtors, resolve all claims that the Debtors have against any third party, make regular reports to the Enron board of directors and to the Bankruptcy Court on the status of claims resolution, liquidate assets remaining in the estates of the Debtors, and consult with and

20 Attached as Exhibit 7 to the OPUC filing provided as Enclosure (1) to this Application.

provide the DCR Overseers with information in connection with the voting or sale of the Plan securities, including New PGE Common Stock once it is issued, held in the Reserve. There is no legal or economic incentive for the Plan Administrator to do anything other than resolve claims and close the bankruptcy estates as rapidly and as prudently possible.

The authority of the Plan Administrator is limited, as set forth in section 5 of the Plan Administration Agreement, by the dollar amounts and types of claims it can settle without the approval of the board of directors of Enron and, if requested by Enron's board of directors, the approval of the Bankruptcy Court.

Among other responsibilities, the Plan Administrator must hold sufficient assets of the Debtors in reserve to provide for the distribution to the Holders of Disputed Claims[21] as they become Holders of Allowed Claims and to the Holders of previously Allowed Claims as Disputed Claims are disallowed. The Plan Administrator also must calculate the expected recovery percentages that form the basis for the distributions to Holders of Allowed Claims prior to the final settlement of all claims under the Plan.

The compensation of SFC as the Plan Administrator is set forth in the Plan Administration Agreement, and is the sole compensation for any and all services rendered by SFC or any of its employees or affiliates to the Debtors for acting as the Plan Administrator, the Disbursing Agent, or the trustee of any trust formed pursuant to the Plan.

SFC is owned 50 percent by Stephen Forbes Cooper and 25 percent each by Leonard LoBiondo and Michael E. France. SFC is providing management services to the Debtors. SFC

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21 Defined in Plan section 1.86 as a claim made against a Debtor that is disputed by the Debtor and has not been withdrawn, dismissed with prejudice, or determined by Final Order.

operates under a formal Operating Agreement.[22] SFC's sole business is providing services to the Debtors. An agreement is maintained between SFC and Kroll Zolfo Cooper, LLC, which provides that all amounts received by SFC for providing services to the Debtors will be the property of, and shall be paid to, Kroll Zolfo Cooper, LLC.[23] Kroll Zolfo Cooper, LLC, is owned 100 percent by Kroll, Inc., which is owned 100 percent by Marsh, Inc., which is owned 100 percent by the Marsh and McLennan Companies ("MMC"), a publicly traded corporation.

(b) Disbursing Agent and the Disputed Claims Reserve

The DCR Guidelines and the Plan control the operation of the Reserve and the Disbursing Agent. The New PGE Common Stock issued to the Reserve will be held in trust/escrow for the benefit of Holders of Disputed Claims and Holders of Allowed Claims, along with all other assets in the Reserve.[24] The Disbursing Agent has no economic or beneficial interest in the New PGE Common Stock or other assets in the Reserve.

The DCR Guidelines limit investment of assets held in the Reserve. All cash is held in interest-bearing depositary accounts at financial institutions with a reported capital surplus of $100 million, or invested in interest-bearing obligations issued by the U.S. Government or by an agency of the U.S. Government and guaranteed by the U.S. Government, having maturity of not more than 30 days in either case, unless modified by the Bankruptcy Court. The DCR Guidelines do not give the Disbursing Agent any discretion to invest in other assets, and do not allow the Disbursing Agent to sell the New PGE Common Stock or vote it, except as instructed

22 Attached as Exhibit 18 to the OPUC filing provided as Enclosure (1) to this Application.

23 Attached as Exhibit 19 to the OPUC filing provided as Enclosure (1) to this Application.

24 See Plan sections 21.3(a) and 32.3, attached as Exhibit 2 and Exhibit 20, respectively, to the OPUC filing provided as Enclosure (1) to this Application.

by the DCR Overseers. The Disbursing Agent is in the process of requesting from the Bankruptcy Court a change in the investment guidelines to allow it to invest cash and cash equivalents in Treasury Bills with maturities up to 6 months and in money market funds that invest in U.S. Government securities.

In short, the Disbursing Agent will take directions from the Plan Administrator as to the assets the Reserve holds or releases from time to time to Holders of Allowed Claims. The Disbursing Agent has no economic interest in, and no authority over, the operation or valuation of the Reserve. The Disbursing Agent has no authority to invest assets held in the Reserve in anything other than cash or cash equivalents and is prohibited from determining how to vote Plan securities, including the New PGE Common Stock.

(c) DCR Overseers

The Disbursing Agent will vote the New PGE Common Stock held in the Reserve at the direction of the DCR Overseers. The registered owners on the books of PGE's transfer agent will vote the remainder of the New PGE Common Stock held by them.

The DCR Overseers will have the limited functions of determining (1) how to vote the New PGE Common Stock held by the Reserve on all matters for which a shareholder vote is required under Oregon law or PGE's Articles of Incorporation and Bylaws and (2) whether to sell the New PGE Common Stock held by the Reserve. The Plan Administrator will be required to bring to the DCR Overseers matters that require the vote of shareholders and any offers to buy New PGE Common Stock.

As a matter of Oregon law and the proposed draft Articles of Incorporation and Bylaws of PGE, the DCR Overseers will have the right to vote annually on the election of PGE's board of directors. Under Oregon law, shareholders are also entitled to vote on major transactions, such as mergers and sale or mortgage of all or substantially all of the assets of a corporation such as PGE. As long as the Reserve holds more than 10 percent of the New PGE Common Stock, the DCR Overseers also will have the ability to call a special meeting of the shareholders.

The DCR Overseers are required to exercise their business judgment to vote Plan securities, including the New PGE Common Stock, in a manner they believe will maximize the value of assets to be distributed to creditors. The DCR Guidelines require that the DCR Overseers take all actions that a board of directors of a public corporation chartered in the State of Delaware would be required to take to satisfy its fiduciary duties in making a decision requiring the voting by such corporation of a comparable proportion of securities it holds in another entity. The DCR Overseers may not vote in matters in which they have a conflict of interest. Like the Disbursing Agent, the DCR Overseers have no economic or beneficial interest in the assets held in the Reserve. Their sole compensation is the compensation they receive for acting as directors of Enron. Enclosure (2) to this Application lists the names, addresses, and citizenship of the DCR Overseers.

C. PURPOSE OF THE LICENSE TRANSFER AND NATURE OF THE TRANSACTION THAT MAKES THE TRANSFER DESIRABLE

The primary purpose of the indirect transfer of control over the Trojan ISFSI license is to allow for implementation of the Plan's directive to transfer 100 percent of PGE's common equity from Enron to the creditors of Enron by canceling the existing PGE common stock held by Enron and by authorizing and issuing to Enron's creditors New PGE Common Stock. NRC approval of the indirect transfer of control over the Trojan ISFSI license that would result from the issuance of New PGE Common Stock as requested herein is desirable for several reasons. Approval of this Application will allow Enron, PGE, and SFC to carry out fully the Plan approved by the Bankruptcy Court pursuant to federal law for the issuance of the New PGE Common Stock. This action is expected to enhance the financial stability of PGE by effectively removing PGE's stock from Enron's bankruptcy estate and restoring PGE to its former status as a publicly traded stand-alone electric utility headquartered in Portland, Oregon. PGE will be governed by a new board of directors, elected annually by the PGE shareholders, and owing fiduciary duties to all shareholders as opposed to a single shareholder – Enron – as is currently the case.

III. GENERAL AND FINANCIAL INFORMATION REGARDING INDIRECT TRANSFEREE

The general and financial information about the indirect license transferee, as required by 10 C.F.R. § 72.22(a) through (e), is set forth below.

A. Full Name, Address, and Business of Indirect Transferee

The name and registered office of the indirect license transferee are:

Portland General Electric Company
121 SW Salmon St.
Portland, Oregon 97204

PGE is and will remain engaged principally in the generation, transmission, distribution, and sale of electric energy in Oregon. PGE serves approximately 765,000 retail customers in Oregon and is an "electric utility" as defined in the Commission's regulations at 10 C.F.R. § 2.4. PGE also sells electric energy at wholesale to, and transmits electric energy in interstate commerce for, other electric utilities under rate schedules approved by the FERC.

B. State of Incorporation and Identity of Directors and Principal Officers of Indirect Transferee

1. State of Incorporation

Upon issuance of the New PGE Common Stock, PGE will be a publicly traded company incorporated in the State of Oregon.

2. Board of Directors and Principal Officers

Enclosure (3) to this Application lists the names, addresses, and citizenship of the current members of the PGE board of directors and its principal officers. All of the current members of the PGE board of directors and its principal officers are U.S. citizens.

In preparation for initial issuance of New PGE Common Stock, PGE has begun a search for additional members for PGE's board of directors that satisfy the requirements of the selected stock exchange, the SEC, and the Sarbanes/Oxley Act. Although the new members that will be added to the PGE board of directors have not yet been selected, a substantial majority of the PGE board members will at all times be U.S. citizens. (The owners of the Disbursing Agent and each member of the DCR Overseers are also U.S. citizens.)

3. Shareholders

Enron and PGE plan to enter into a Separation Agreement that will take effect upon the issuance of the New PGE Common Stock.[25] At that time, PGE will become a publicly traded stand-alone electric utility headquartered in Portland, Oregon. As discussed above, a majority of the New PGE Common Stock (but not more than 70 percent) is anticipated to be issued initially to the Disbursing Agent on behalf of the Reserve. The Reserve will release all of the New PGE Common Stock when all claims are resolved, and the New PGE Common Stock will be publicly traded on a national stock exchange.

C. Financial Qualifications

Pursuant to 10 C.F.R. § 72.22(e), the following information demonstrates that PGE, the indirect transferee of the Trojan ISFSI license, will possess the financial qualifications to carry out the required activities under the license in accordance with the Commission regulations.

The issuance of New PGE Common Stock and associated separation of PGE from Enron as detailed in this Application will not materially impact PGE's ability to provide funds to cover estimated operating costs over the planned life of the Trojan ISFSI and estimated decommissioning costs. Specifically, the existing resources in and continuing contributions to the Trojan decommissioning fund to cover costs associated with Trojan ISFSI operation and decommissioning, combined with OPUC ratemaking actions that allow PGE to recover such costs through electric rates, ensure PGE ample ability to continue to safely operate, maintain, and ultimately decommission the ISFSI.

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25 A draft of the Separation Agreement is attached as Exhibit 17 to the OPUC filing provided as Enclosure (1) to this Application.

Each Trojan ISFSI co-owner separately collects and assures the availability of funds for its ownership share of costs associated with the operation and subsequent decommissioning of the Trojan ISFSI. PGE's share of funds required for Trojan ISFSI operation and decommissioning is collected through rates and deposited to an external trust fund. The portion of this external sinking fund and the associated contributions that are intended to cover PGE's ownership share of Trojan ISFSI decommissioning costs meet the decommissioning financial assurance requirements of 10 C.F.R. §§ 72.30(c)(5) and 50.75(e)(1)(ii).[26]

As indicated above, the OPUC currently allows PGE to collect Trojan ISFSI operation and decommissioning costs from electric rates charged to customers. Specifically, in its Order No. 95-322, entered March 29, 1995, on Docket UE-88, a copy of which is included as Enclosure (4) to this Application, the OPUC approved PGE's funding plans[27] for inclusion in the rates. The OPUC stated:

> In this order, we also approve funds to decommission Trojan and to pay for the transition to shutdown. Decommissioning costs are the costs of physically dismantling the plant and packaging and storing the radioactive components and spent fuel. Transition costs are the operations and maintenance (O&M) and administrative and general (A&G) costs associated with plant closure.[28]

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26 By letter dated March 17, 2005, the NRC approved a partial exemption from the requirements of 10 C.F.R. § 72.30(c)(5) that allows PGE to continue (following the recent termination of the Trojan Nuclear Plant 10 C.F.R. Part 50 license) to use the decommissioning financial assurance provisions of 10 CFR § 50.75(e).

27 These plans specifically addressed funding for decommissioning of the former Trojan Nuclear Plant, which included operation and decommissioning of the Trojan ISFSI.

28 OPUC Order No. 95-322, entered March 29, 1995, Docket No. UE 88, Page 3. Challenges and litigation are still pending before the OPUC and in state courts, on the OPUC's authority to grant a return on PGE's investment in Trojan under Oregon law. None of the challenges or litigation contests the inclusion of Trojan decommissioning in rates.

The OPUC approved new PGE rate schedules via Order No. 01-777, entered August 31, 2001. The new rate schedules do not impact the OPUC approval of PGE's decommissioning and funding plans for inclusion in the rate base as specified in Order No. 95-322. A copy of OPUC Order No. 01-777 is included as Enclosure (5) to this Application.

The issuance of New PGE Common Stock and associated separation of PGE from Enron as detailed herein will not alter the recovery by PGE of costs for Trojan ISFSI operation and decommissioning through rates established by the OPUC as detailed above.

Trojan ISFSI decommissioning funding was addressed by the NRC Staff in the Safety Evaluation Report ("SER") in connection with the NRC's issuance of the Trojan ISFSI license in March 1999. The NRC's SER states in Section 13, "Decommissioning Evaluation,"

> The staff has determined that the financial assurance mechanisms submitted by the applicant are sufficient to provide reasonable assurance that adequate funds will be available to decommission the facility so that the site will ultimately be available for unrestricted use for any private or public purpose. The staff, therefore, concluded that the financial assurance mechanisms in the decommissioning funding plan comply with 10 CFR Part 72.[29]

PGE's implementation of its financial assurance mechanisms as described in the Trojan ISFSI Safety Analysis Report, on which this finding was based, has not changed since the NRC issued its SER in March 1999.

For these reasons, approval of this Application will not adversely affect the availability of funds to cover operating costs over the planned life of the Trojan ISFSI and estimated decommissioning costs for the Trojan ISFSI.

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29 NRC SER accompanying Materials License No. SNM-2509 dated March 31, 1999, Finding F13.3 at Page 13-2.

IV. TECHNICAL QUALIFICATIONS

The technical information required to be included in an application for the transfer of a license pursuant to 10 C.F.R. § 72.50 and 10 C.F.R. § 72.28 is set forth below.

There will be no changes to the management or operation of the Trojan ISFSI as a result of the issuance of New PGE Common Stock and associated separation of PGE from Enron as detailed in this Application. PGE will remain the licensee with exclusive authority to take appropriate actions regarding the Trojan ISFSI in accordance with the Trojan ISFSI license issued under 10 C.F.R. Part 72 and applicable laws and regulatory requirements. PGE will continue to have sole authority to make all decisions to protect public health and safety, as required by the license and applicable laws and regulations.

Specifically, the Trojan ISFSI Safety Analysis Report ("SAR"), as approved by the Commission and revised in accordance with 10 C.F.R. § 72.48 from time to time, describes the Trojan ISFSI organization in place to operate and ultimately decommission the Trojan ISFSI, including key Trojan ISFSI management positions and other personnel utilized to perform technical and administrative tasks required during Trojan ISFSI operations and decommissioning.[30] The issuance of New PGE Common Stock and associated separation of PGE from Enron as detailed herein will not result in any changes to the Trojan ISFSI SAR, nor will it involve any change of the individuals assigned to the key management or technical and administrative positions at the Trojan ISFSI.

PGE's executive officer team will continue to include Peggy Fowler, who has been PGE's President and Chief Executive Officer since April 2000. She joined PGE in 1974 and has held various management positions at the company including Vice President of Hydroelectric and Substation Operations, and Vice President of Power Production. She will continue to be responsible for PGE's generating plants, as well as the Trojan ISFSI. Additionally, Stephen Quennoz, currently PGE's Vice President, Generation, has been the PGE executive directly responsible for NRC licensed activities at Trojan since 1994. He will continue to be the PGE officer directly responsible for NRC licensed activities, including the management of the Trojan ISFSI.Thus, the indirect transfer of control over the Trojan ISFSI license will not adversely affect the management of PGE's activities licensed by the NRC. PGE will continue to be the operator of the Trojan ISFSI. Individuals assigned to the key management or technical and administrative positions at the Trojan ISFSI will not change.

V. Environmental Considerations

The issuance of the New PGE Common Stock as described in this Application meets the categorical exclusion set forth in 10 C.F.R. § 51.22(c)(21). Therefore, pursuant to 10 C.F.R. § 51.22(b), no environmental impact statement or environmental assessment is required.

VI. OTHER REGULATORY APPROVALS

PGE and SFC have filed an application with the OPUC dated June 17, 2005, requesting an October 2005 date for the OPUC approval. PGE, the Disbursing Agent and Enron will file such applications as are necessary with other regulatory agencies, such as (among others) the Federal Communications Commission ("FCC"), SEC and FERC.

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30 The information contained in the Trojan ISFSI SAR includes that specified in 10 C.F.R. § 72.28 (a) through (c).

VII. SCHEDULE

PGE is prepared to work closely with the NRC Staff to help expedite the Application's review, but respectfully requests that the NRC complete its review on a schedule to permit the issuance of its approval of the indirect transfer of control as promptly as possible, with a target date of October 1, 2005, or as soon thereafter as reasonably practicable. PGE will inform the NRC of any other developments that may have an impact on the schedule.

VIII. CONCLUSIONS

For the foregoing reasons, the proposed indirect license transfer will not have any material adverse impact on the operation and/or decommissioning of the Trojan ISFSI, and will not affect the managerial, technical, or financial qualifications of PGE to perform the activities required by the Trojan ISFSI license. Thus, the Commission should find pursuant to 10 C.F.R. § 72.50 (c) (1) and (2) that PGE, the proposed indirect transferee, is qualified to be the holder of the license, and that the indirect transfer of control of the Trojan ISFSI license is consistent with applicable provisions of the law, and the regulations and orders issued by the Commission.

Accordingly, and based on the foregoing information, PGE, acting on its own behalf and that of its parent company, Enron, and of SFC as Disbursing Agent on behalf of the Reserve, respectfully requests that the NRC issue an Order approving the indirect transfer of Trojan ISFSI License No. SNM-2509, to the extent held by PGE, as described in this Application.

ENCLOSURES:

(1) Application For Approval By The Oregon Public Utility Commission Dated June 17, 2005, OPUC Docket Nos. UF 4218/UM 1206

(2) Names, Addresses, and Citizenship of the Overseers of the Reserve for Disputed Claims

(3) Names, Addresses, and Citizenship of the Current Members of the PGE Board of Directors and Principal Officers

(4) OPUC Order No. 95-322, entered March 29, 1995 in Docket UE 88

(5) OPUC Order No. 01-777, entered August 31, 2001 in Docket UE 115

ENCLOSURE (1)

APPLICATION FOR APPROVAL BY THE OREGON PUBLIC UTILITY COMMISSION DATED JUNE 17, 2005, OPUC DOCKET NOS. UF 4218/UM 1206

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UF 4218 /UM 1206

In the Matter of the Application of PORTLAND GENERAL ELECTRIC COMPANY for an Order Authorizing the Issuance of 62,500,000 Shares of New Common Stock Pursuant to ORS 757.410 et seq. and In the Matter of the Application of STEPHEN FORBES COOPER, LLC, as Disbursing Agent, on behalf of the RESERVE FOR DISPUTED CLAIMS, for an Order Allowing the Reserve for Disputed Claims to Acquire the Power to Exercise Substantial Influence over the Affairs and Policies of Portland General Electric Company Pursuant to ORS 757.511	**APPLICATION**

June 17, 2005

TABLE OF CONTENTS

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of the Application of PORTLAND GENERAL ELECTRIC COMPANY for an Order Authorizing the Issuance of 62,500,000 Shares of New Common Stock Pursuant to ORS 757.410 et seq. and In the Matter of the Application of STEPHEN FORBES COOPER, LLC, as Disbursing Agent, on behalf of the RESERVE FOR DISPUTED CLAIMS, for an Order Allowing the Reserve for Disputed Claims to Acquire the Power to Exercise Substantial Influence over the Affairs and Policies of Portland General Electric Company Pursuant to ORS 757.511	**APPLICATION**

I. INTRODUCTION AND SUMMARY

This is a joint application by Portland General Electric Company ("PGE") and Stephen Forbes Cooper, LLC ("SFC"), as Disbursing Agent ("Disbursing Agent")[1], on behalf of the Reserve for Disputed Claims ("Reserve").[2] This Application seeks to implement the Plan's directive to transfer 100% of PGE's common equity from Enron Corp. ("Enron") to the creditors

[1] Defined in Plan section 1.83. SFC was appointed as Disbursing Agent by the Bankruptcy Court in the Confirmation Order. A copy of the Confirmation Order is attached as Exhibit 1.

[2] The Reserve was created by the Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated July 2, 2004, including the Plan Supplement and all schedules and exhibits thereto ("Plan") (*In re: Enron Corp., et al.*, Bankr. S.D.N.Y., Case No. 01-16034). The Plan was confirmed by the United States Bankruptcy Court for the Southern District of New York ("Bankruptcy Court") on July 15, 2004. See Plan section 21.3(a) attached as Exhibit 2. To view or print the Plan and the Plan Supplements, see http://www.enron.com/corp/por.

of Enron and other Debtors[3] by canceling the existing PGE common stock held by Enron and by authorizing and issuing to Enron's creditors new PGE common stock ("New PGE Common Stock"). PGE will create 80,000,000 shares of New PGE Common Stock.

PGE requests an order pursuant to ORS 757.410 et seq. authorizing PGE to issue 62,500,000 shares of New PGE Common Stock, with Holders of Allowed Claims[4] receiving not less than 30% or 18,750,000 of such shares and the Disbursing Agent as registered holder for the Reserve receiving not more than 70% or 43,750,000 of such shares. The issuance of the New PGE Common Stock will replace in full the existing PGE common stock, which will be canceled. The New PGE Common Stock meets the requirements of ORS 757.415(1) because it replaces common stock lawfully issued.[5]

The Disbursing Agent, on behalf of the Reserve, requests an order pursuant to ORS 757.511 for the Reserve to hold more than 5% of the New PGE Common Stock and to vote not more than 70% of the New PGE Common Stock. The Disbursing Agent will be the registered holder of the New PGE Common Stock and, in accordance with procedures implemented in connection with the Plan, the DCR Overseers[6] will determine how the Disbursing Agent votes the New PGE Common Stock held in the Reserve. The DCR Overseers

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[3] The Debtors are Enron and the other entities identified in Plan section 1.77, all of whose bankruptcy filings were consolidated with Enron. In this Application, the term "Debtors" excludes Portland General Holdings, Inc. and Portland Transition Company, Inc., whose bankruptcy plans were not confirmed by the Bankruptcy Court.

[4] Defined in Plan section 1.8. An Allowed Claim is one made against a Debtor and approved in a Final Order of the Bankruptcy Court (as defined in Plan section 1.154). A Holder of an Allowed Claim is a claimant whose claim against a Debtor was registered with Enron on November 29, 2004.

[5] Alternatively, the Oregon Public Utility Commission ("Commission") could find that the issuance is exempt from the requirements of ORS 757.410 to 757.480 under ORS 757.412 if the Commission finds that the application of those statutes is not required by the public interest.

[6] Defined in Plan section 1.76. The DCR Overseers were appointed by the Bankruptcy Court in the Confirmation Order. The role and operation of the DCR Overseers are described in more detail in Section V.C of this Application. "DCR" is another term for the Reserve for Disputed Claims.

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will also determine whether and on what terms the Reserve would sell the New PGE Common Stock held in the Reserve should a credible purchase offer be made.

This Application is unique and substantially different from any other application under ORS 757.511 previously considered by the Commission. First, this Application implements a confirmed bankruptcy plan. Second, the purpose of the Reserve as an Applicant is not to acquire PGE for investment or strategic purposes. The purpose of the Reserve is to preserve the value of PGE and the other assets of Enron and the other Debtors, and to hold all of those assets only so long as necessary to transfer them to Holders of Allowed Claims. Third, this Application does not seek to change the beneficial ownership in PGE. Beneficial ownership is and, as far as the Reserve is concerned, remains with the creditors. Fourth, this Application does not propose to create a holding company or other investment vehicle that can use dividends from PGE to diversify investments. Last, there is no comparator or "but for" world for the Commission to consider because the status quo with respect to the ownership of PGE's common stock must and will change. We review each of these differences below.

The first difference is that, here, the Plan requires the issuance of New PGE Common Stock as proposed in this Application. The only circumstance in which the Plan does not require issuance of New PGE Common Stock is if Enron has sold the existing PGE common stock. Because Enron has a fiduciary duty to its creditors, it has stated publicly that it will consider any credible offer to purchase the existing PGE common stock. A credible offer includes one that meets Enron's economic and commercial terms, is for the purchase of PGE common stock only, can be financed and, in Enron's judgment, can be closed in a reasonable period of time. At present, there is no agreement pending to sell the existing PGE common stock to anyone, although granting the approvals requested under this Application does not preclude such a sale from occurring.

Second, although the Reserve will initially hold the majority of the New PGE Common Stock, its purpose is not to invest in any other assets or seek actively to control PGE. The Plan and the Guidelines adopted by the Bankruptcy Court[7] confirm that the Reserve is a trust/escrow acting as the nominal shareholder for the benefit of Holders of Allowed and Disputed Claims.[8] The objective of the Plan, the Disbursing Agent, and the Reserve is to resolve all claims against Enron and the other Debtors as rapidly as possible consistent with prudent business practices and to distribute the assets of Enron and the other Debtors, including the New PGE Common Stock, to the Holders of Allowed Claims. Therefore, unlike other prospective owners that have appeared before this Commission, the fundamental purpose of the Reserve is to reduce its interest in PGE, not to hold onto its interest in PGE.

The Reserve is not requesting that the Commission grant it permission to hold a majority of the New PGE Common Stock because it has made a strategic decision to invest in PGE. The Reserve did not exist until the Plan became effective and its only function is to carry out the role assigned to it in the Plan. That role is not to control or operate PGE. The Reserve's role is to release all available assets to the Holders of Allowed Claims in the proper percentages when the Plan Administrator resolves the claims. When that function is fulfilled, the Reserve will cease to exist.

Third, this Application does not seek to change the beneficial ownership of PGE. Other applications previously considered by the Commission were for the purchase or acquisition by

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7 For the Reserve, these are called the "DCR Guidelines" and for the DCR Overseers they are called the "Overseer Guidelines." Copies of these Guidelines are attached as Exhibit 3 and Exhibit 4, respectively. See Plan section 21.3(a) (attached as Exhibit 2), which created the Reserve.

8 Defined in Plan section 1.86 as a claim made against a Debtor that is disputed by the Debtor and has not been withdrawn, dismissed with prejudice or determined by Final Order.

merger of PGE common stock. Those transactions proposed to change the beneficial ownership of PGE's common stock. Here, the creditors of Enron and the other Debtors currently hold all of the beneficial interests in the assets of Enron and the Debtors, including the PGE common stock.[9] The issuance of New PGE Common Stock to Holders of Allowed Claims will vest in them legal as well as beneficial ownership of the New PGE Common Stock and will permit them to hold or sell the stock as they determine. The Disbursing Agent will hold the New PGE Common Stock in the Reserve, in trust/escrow for the benefit of Holders of Disputed Claims and Allowed Claims. Neither the Disbursing Agent nor the DCR Overseers have any economic interest in the assets in the Reserve, including the New PGE Common Stock.

Fourth, granting this Application will not create a holding company such as the Commission considered in the case of Portland General Corporation and PacifiCorp Holdings, Inc. While the Reserve will initially hold a majority of the New PGE Common Stock, it will act as a shareholder and will have no rights other than those provided to shareholders by Oregon law and PGE's Articles of Incorporation and Bylaws. It will not use dividends from PGE to invest in diversified businesses or service acquisition debt. Instead, pending distribution to Holders of Allowed Claims, it will hold any dividends received from PGE in low-risk cash-equivalent investments, as described below. PGE will cease to be consolidated with Enron and will not be consolidated with the Reserve or any other person or entity (other than PGE's own subsidiaries) for income tax purposes and will not acquire any new debt in the course of implementing the Plan.

Finally, there is no comparator or "but for" world or alternative to consider when reviewing this Application, unlike other applications reviewed by the Commission. Here, as a

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9 As discussed below, it is highly unlikely that there will be sufficient assets for any distribution to the former shareholders of Enron.

matter of federal law and the Confirmation Order, all of the assets of Enron and the other Debtors, including 100% of PGE's common equity, must be distributed to Holders of Allowed Claims. The Plan provides the method by which that distribution will occur. The status quo cannot continue. Enron must cease to own PGE's common stock, and the Holders of Allowed Claims must receive all of PGE's common stock, or its equivalent value if such stock is sold.

Section II of this Application describes the development of the Plan and its effect on creditors, former shareholders and the existing PGE common stock. Section III describes the Plan's directives for the issuance and trading of the New PGE Common Stock. Section IV describes the governance and operation of PGE after the issuance. Section V describes the roles and operation of the Plan Administrator, the Disbursing Agent and the DCR Overseers. Section VI addresses the Enron merger conditions and explains why they are no longer needed after the issuance of the New PGE Common Stock and will not apply except as to PGE. Finally, Section VII describes the lack of risk to PGE and its customers from implementing the Plan as requested in this Application and how granting this Application serves the public generally and benefits PGE's customers.

Appendix A to this Application sets forth the information required with respect to PGE's request for authorization to issue New PGE Common Stock under ORS 757.410 et seq. and OAR 860-027-0030. Appendix B to this Application sets forth the information required by ORS 757.511 and OAR 860-027-0200 with respect to the request by the Disbursing Agent on behalf of the Reserve for an order authorizing it to acquire a majority of the New PGE Common Stock.

Applicants request a prehearing conference in this matter during the week of July 4, 2005. At the prehearing conference, Applicants will request that this proceeding use written

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comment (and oral comments if granted by the Commission) for purposes of a record, rather than written testimony. Applicants suggest that the other parties file written comments during the week of August 15, 2005 and that Applicants and the other parties file responsive comments during the week of September 12, 2005. Applicants are willing to schedule settlement conferences shortly before initial comments or responsive comments are due. Applicants request an order of the Commission in this matter by September 30, 2005 and waive the requirements of ORS 757.511(3) with respect to 19 business days and the 30-day requirement in ORS 757.420 until the close of business September 30, 2005.

II. DEVELOPMENT, CONFIRMATION AND EFFECT OF THE PLAN[10]

This section describes the development of the Plan, the provisions of which have necessitated this Application. The Plan is the result of extensive negotiations and compromises to reach a consensus among Debtors, the Unsecured Creditors' Committee,[11] the individual creditors and the ENA Examiner.[12] Most of the creditors approved the Plan after an extensive process of disclosure, including the distribution of a final disclosure statement. The Bankruptcy

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[10] An expanded discussion of the negotiations and multiple iterations of the Plan that resulted in a confirmed Plan is attached to this Application as Exhibit 5. Source: Finding of Fact and Conclusions of Law Confirming Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, and Related Relief entered July 15, 2004 (docket number 19758).

[11] This was a statutory committee defined in section 1.65 of the Plan.

[12] The ENA Examiner was originally appointed by the Bankruptcy Court to investigate and report on transactions between Enron North America Corp. ("ENA") and Enron. The ENA Examiner's duties were subsequently expanded by the Bankruptcy Court to facilitate the negotiations concerning the Plan on behalf of the creditors of ENA. The evolution of the Plan's terms and the extensive negotiations and discussions between the ENA Examiner, the Unsecured Creditors' Committee and the Debtors are evidenced by the periodic reports filed by the ENA Examiner regarding the status of the Chapter 11 plan developments and recommendations related to exclusivity. In particular, the report filed on or about January 5, 2004 contains the ENA Examiner's recitation of the circumstances and events related to withdrawal of his support for the First Amended Plan. In addition, changes and modifications to the Plan as a result of the discussion and negotiations between the Debtors, the Unsecured Creditors' Committee, the ENA Examiner and other parties in interest are evidenced by the prior filings of the Plan on July 11, 2003, September 18, 2003, November 13, 2003, December 17, 2003 and January 4, 2004 and the disclosure statements related thereto.

Court confirmed the Plan on July 15, 2004; it became effective on November 17, 2004 ("Effective Date"). As a result, Enron and the other Debtors are reorganized debtors and are no longer debtors in a bankruptcy case. They now own all of their assets free and clear of all liens and encumbrances, and may distribute their assets or the proceeds thereof to creditors as provided in the Plan. The Plan determines the rights of creditors, the method of calculating each creditor's interest in the assets of Enron and the other Debtors, and the manner in which distributions will be made to the various classes of creditors.

A. Confirmation Order

The Bankruptcy Court confirmed the Plan on July 15, 2004.[13] Confirmation means that, upon the Effective Date, the Plan is subject to no further objections, and is binding on the Debtors, the creditors and all other parties subject to the Plan.[14] The Confirmation Order includes several decisions by the Bankruptcy Court that apply to PGE and this Application. These decisions are:

- Appointment of SFC as the Plan Administrator and Disbursing Agent, and approval of the Plan Administration Agreement.[15] The duties and operations of the Plan Administrator and the Disbursing Agent are described in more detail in Section V of this Application.
- Approval of the DCR Guidelines and the Overseer Guidelines.

[13] The SEC separately approved the Plan on March 9, 2004, pursuant to a Plan Order, attached as Exhibit 6.
[14] Two Creditors are pursuing appeals of the Confirmation Order. Neither sought a stay to prevent the occurrence of the Effective Date and substantial consummation of the Plan. Enron and the other reorganized debtors have moved to dismiss the appeals as moot. One of two appellant creditors has conceded that substantial consummation has occurred and requests only a modification not relevant to the plan provisions relating to distributions.
[15] Attached as Exhibit 7.

- Approval of four new members of Enron's board of directors. The Bankruptcy Court also approved these same four persons as DCR Overseers. A fifth board member and a fifth Overseer, who is the same person, was appointed after the Confirmation Order. Four of the board members of Enron were proposed by Enron in consultation with the Unsecured Creditors' Committee, and one member was proposed by Enron in consultation with the ENA Examiner. Biographies of the five DCR Overseers and the Enron board members are attached.[16]
- Approval of forms of new Articles of Incorporation and Bylaws for PGE, which are included in the Plan Supplement as Schedules N and M, respectively. Prior to the issuance of the New PGE Common Stock, PGE intends to adopt new Articles of Incorporation[17] and Bylaws[18] substantially similar to those attached as exhibits to this Application. These Articles of Incorporation and Bylaws are substantially similar to the form approved by the Bankruptcy Court and are a common form of articles of incorporation and bylaws for publicly traded companies incorporated and headquartered in Oregon.

B. Effective Date

The Plan became effective on November 17, 2004. The Effective Date resulted in the following actions and effects that apply to PGE and this Application:

- Enron and the other Debtors whose plans were confirmed by the Confirmation Order became "Reorganized Debtors," which means that they emerged from bankruptcy and are no longer debtors in possession under Chapter 11 of the

[16] Attached as Exhibit 8.
[17] A draft is attached as Exhibit 9.
[18] A draft is attached as Exhibit 10.

United States Bankruptcy Code. For convenience, this Application continues to use the term "Debtors" to refer to the "Reorganized Debtors."

- Enron's new board of directors replaced the prior board of directors, and the same individuals who are the new directors of Enron became the DCR Overseers.
- The Unsecured Creditors' Committee was disbanded, except to handle certain litigation matters.
- All of the assets of Enron and the other Debtors were vested in Enron and the other Debtors free of all liens and encumbrances.
- The Bankruptcy Court retained exclusive jurisdiction over any matter arising under the Bankruptcy Code and arising in or relating to the Chapter 11 Cases or the Plan in certain circumstances, including the entry of all orders as may be necessary or appropriate to implement or consummate the provisions of the Plan and all contracts, instruments, releases and other agreements or documents created in connection with the Plan.[19]

C. Effect of the Plan on Creditors and Former Equity Holders

The Plan determines the interests of the various classes of creditors in the assets of the Debtors and the method for calculating such interests. The Plan also determines the manner in which the creditors will receive the assets of the Debtors. Distributions will only be made to creditors who become Holders of Allowed Claims.

Under the Plan, 373 different classes of unsecured creditors will receive distributions. Approximately 200 classes of unsecured creditors are eligible to receive common stock, including the New PGE Common Stock. The anticipated recovery to the creditors of the

[19] See Plan section 36, attached as Exhibit 11.

various Debtors varies from a low of approximately 6% of Allowed Claims to approximately 75% of Allowed Claims, with the majority of creditors anticipated to recover between 15% and 30% of their Allowed Claims. These are expected recovery percentages only. The final distributions under the Plan will not be known until all claims against Enron and the other Debtors, and all claims by Enron and the other Debtors for the recovery of assets, are resolved.

The Plan creates a common Plan Currency,[20] which consists primarily of cash and common stock, including the New PGE Common Stock.[21] The Plan provides that each Holder of an Allowed Claim will receive a pro rata share of the Plan Currency allocated to other Holders similarly classified under the Plan.[22] In general, each Holder of an Allowed Claim will receive a percentage of each of the assets available for distribution based on the ratio of that Holder's Allowed Claims to the Allowed Claims of all other Holders of the same class. This means that each Holder will receive cash and common stock held by Enron and the other Debtors, including the New PGE Common Stock, in a percentage equal to its percentage claim, regardless of how the stock is valued. For example, if a Holder of an Allowed Claim is entitled to 2% of the assets available for distribution, that Holder will receive 2% of each asset, including 2% of cash and 2% of New PGE Common Stock. It will receive this percentage of New PGE Common Stock regardless whether that stock is distributed early or late in the claim settlement process and whether the value of the New PGE Common Stock has gone up or down over time.

The Plan Administrator will calculate the recovery percentages for Holders of Allowed Claims each April and October. Each calculation will require about two months to perform: during January and February for April percentages and during July and August for

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[20] See Plan section 1.198, attached as Exhibit 12.
[21] See Plan section 1.191, attached as Exhibit 13.
[22] See Plan section 7.1, attached as Exhibit 14.

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October percentages. Holders of Allowed Claims will receive distributions based on those calculations in April and October. Claims that are first allowed other than in April or October may receive first distributions in June, August, December or February, based upon the most recent April or October calculation of recovery percentages.

Distribution of all assets from Enron and the other Debtors, including the issuance of the New PGE Common Stock, and the continuing release of New PGE Common Stock from the Reserve over time as described below, will be made to the holders of record of claims as of November 29, 2004 ("Record Holders"), as their claims are allowed. Creditors may sell their claims against the bankruptcy estates of Enron and the other Debtors. Enron does not keep a registry of such sales. The Record Holders of Allowed Claims are responsible for any subsequent transfer of assets to a purchaser of a claim.

There are insufficient assets for any distribution to former shareholders of Enron. The Plan canceled all of Enron's common and preferred stock, created new Enron common and preferred stock, and issued that stock to a Common Equity Trust and a Preferred Equity Trust ("Trust"), respectively, with SFC as Trustee. The Trust holds that stock for the benefit of Enron's former shareholders, for distribution to them in the highly unlikely event that any residual assets remain after full recovery for all creditors.[23]

III. ISSUANCE, LISTING AND TRADING OF NEW PGE COMMON STOCK

A. Issuance

The issuance of the 62,500,000 shares of New PGE Common Stock that is the subject of this Application will occur when: (i) sufficient claims have been allowed to permit the

[23] See Plan sections 1.115, 1.120, 1.149, 1.150, 18.1-18.3, and 19.1-19.3, attached as Exhibit 15.

issuance of not less than 30% of the New PGE Common Stock to Holders of Allowed Claims and (ii) any required consents have been obtained.[24] The 30% condition is likely to occur in time to permit the issuance of the New PGE Common Stock in April 2006. PGE, the Disbursing Agent and Enron will file such applications as are necessary with the U.S. Securities and Exchange Commission ("SEC"), the Federal Energy Regulatory Commission ("FERC"), the Nuclear Regulatory Commission ("NRC"), the Federal Communications Commission ("FCC") and the Oregon Energy Facilities Siting Council ("EFSC").

The amount of New PGE Common Stock initially issued to the Holders of Allowed Claims will not be less than 30%. The intent of the 30% condition is to assure that a liquid market can exist for shares of New PGE Common Stock and to permit the listing of the New PGE Common Stock on a national securities exchange. A trading market in the New PGE Common Stock at the date of issuance will allow Holders of Allowed Claims to retain the New PGE Common Stock distributed to them or sell such shares in the market.

The Disbursing Agent on behalf of the Reserve will receive any New PGE Common Stock not initially distributed to Holders of Allowed Claims. This amount will not exceed 70% and will decline with each subsequent release of New PGE Common Stock from the Reserve, as claims are resolved. The result of this will be a continuous release of New PGE Common Stock from the Reserve to Holders of Allowed Claims and, accordingly, a continuous reduction in the percentage of New PGE Common Stock held in the Reserve. Enron's current expectation is that the Reserve will hold less than 50% of the New PGE Common Stock within one year after the issuance and may hold less than 30% of the New PGE Common Stock within two years after the issuance. The speed at which the Reserve releases stock to Holders of

[24] See Plan section 32.1(c), attached as Exhibit 16.

Allowed Claims, and thus reduces its ownership interest in New PGE Common Stock, will depend upon the speed and timing of the resolution of further claims.

Ultimately, the Reserve will release all of the New PGE Common Stock when all claims are resolved, and it must hold not less than 1% of the New PGE Common Stock until then.[25]

B. Preparation for Issuance

To prepare for the issuance, PGE will register the New PGE Common Stock with the SEC[26] and apply to list it on a national stock exchange. PGE will conduct a search for additional members for PGE's board of directors that satisfy the requirements of the selected stock exchange, the SEC and Sarbanes/Oxley. Among other things, these requirements include that a majority of the PGE board of directors be independent of PGE[27] and its management and that at least one board member possesses the qualifications of a "financial expert" as defined in Item 401(h) of Regulation S-K. A search for new board members has already begun, with criteria including utility, business (customer service, information technology, etc.), and financial expertise, and a preference for Northwest residents.

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[25] See Plan section 32.1(c), attached as Exhibit 16.

[26] PGE will register the New PGE Common Stock under the Securities Exchange Act of 1934. The Plan provides for the issuance of the New PGE Common Stock on account of claims held by creditors of Enron and the other Debtors. Pursuant to section 1145 of the Bankruptcy Code, securities of a Debtor or its affiliate, such as PGE, issued pursuant to a plan of reorganization are exempt from registration pursuant to section 5 of the Securities Act of 1933 and any other applicable state or local law. This provision of the Bankruptcy Code was expressly incorporated into the Plan and Confirmation Order of the Debtors. The Plan contains language that exempts PGE securities from registration as permitted by the provisions of the Bankruptcy Code. Specifically, section 42.19 of the Plan entitled "Exemption from Registration," provides that, "[p]ursuant to section 1145 of the Bankruptcy Code, and except as provided in subsection (b) thereof, the issuance of the Plan Securities, the Litigation Trust Interests and the Special Litigation Trust Interests on account of, and in exchange for, the Claims against the Debtors shall be exempt from registration pursuant to section 5 of the Securities Act of 1933 and any other applicable non-bankruptcy law or regulation."

[27] Independence means, in part, that a Board member has a sufficiently small economic stake in PGE so that his or her independent judgment is not affected by personal considerations.

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Prior to the issuance of the New PGE Common Stock, PGE will select a transfer agent. PGE will also establish relationships with common stock analysts, some of whom may cover PGE for potential investors, providing those analysts with the information necessary to promote coverage of New PGE Common Stock in the analysts' publications. Among other things, PGE will need to establish a dividend policy, in part so that analysts and the market can assess PGE and its prospects, both as an operating business and as an investment. PGE plans to begin this process sufficiently prior to the issuance of the New PGE Common Stock so that analysts are prepared once the stock begins to trade.

Finally, PGE will have an investor relations function for the first time since it was acquired by Enron. PGE estimates that the additional activities associated with being a publicly traded company will cost approximately $2 million per year.

C. Trading in New PGE Common Stock

The New PGE Common Stock will be publicly traded. This means that PGE, its officers, directors, and shareholders must comply with the SEC, stock exchange and state securities laws and regulations that apply to public companies. These laws and regulations are designed in part to promote fair public disclosure of all information an investor would deem relevant in making an investment decision and to prevent insiders from taking unfair advantage of non-public information.

For PGE, this means that it will file public annual reports and proxy statements for the election of directors and other shareholder actions, and will continue to file forms 10-K, 10-Q and 8-K with the SEC, among other requirements. It also means that PGE will have to adopt an insider trading policy that prohibits PGE directors, officers or employees from trading in New PGE Common Stock based on non-public information.

PGE's shareholders will be subject to the laws and regulations applicable to investors in publicly traded securities. For example, the Williams Act requires that any purchaser acquiring 5% or more of the common stock of a publicly traded company must file a Form 13-D with the SEC informing the SEC of that fact and of the investment intentions of the purchaser. Enron and the Plan Administrator do not expect that any person or entity (other than the Reserve) will own or control 5% or more of the New PGE Common Stock as a result of the issuance of New PGE Common Stock. Such ownership could also trigger the Commission's jurisdiction under ORS 757.511.

IV. GOVERNANCE AND OPERATION OF PGE AFTER ISSUANCE OF NEW PGE COMMON STOCK

As a result of the issuance of the New PGE Common Stock, PGE will separate from Enron. PGE will be governed by its board of directors, who the PGE shareholders will elect annually. The board of directors of PGE will owe its fiduciary duties to all shareholders, not a single shareholder.

A. Separation from Enron

Enron and PGE plan to enter into a Separation Agreement that will take effect upon the issuance of the New PGE Common Stock.[28] Among other things, the Separation Agreement will:

- Provide for Enron to indemnify PGE and its subsidiaries against any federal taxes that PGE or its subsidiaries may incur as a result of inclusion in the Enron Control Group for federal tax purposes.

[28] A draft of the Separation Agreement is attached as Exhibit 17.

- Provide for Enron to indemnify PGE and its subsidiaries against any liabilities they may incur arising out of any employee benefit plans sponsored by Enron or its ERISA Affiliates (other than PGE) as described in the Separation Agreement.
- Terminate the tax allocation agreement between Enron and PGE, except as to tax years open to audit.
- Terminate the Master Services Agreement between Enron and PGE.[29]

To the extent that, prior to the issuance of the New PGE Common Stock, Enron settles the claims for which it was indemnifying PGE, Enron and PGE will modify the Separation Agreement to eliminate the indemnity.

PGE will, both prior to and after the issuance of the New PGE Common Stock, maintain its separate books and records and accounting system. After the issuance of the New PGE Common Stock, PGE will be deconsolidated from Enron for income tax purposes and will file and pay its taxes to the respective taxing authorities with jurisdiction over it. After the issuance of the New PGE Common Stock, neither PGE nor Enron will supply any services to the other.[30]

B. <u>Governance and Operation</u>

The PGE board of directors will set the policies and direction for PGE, just like any board of directors of other publicly traded companies. The PGE board of directors will be responsible for selecting and evaluating PGE's management. There are no expected changes in management at PGE at the present time. The PGE board of directors will act on matters such as

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29 PGE will continue to share some services with its subsidiaries. PGE will prepare and file with the Commission a new Master Services Agreement to cover these services.

30 PGE will work with Enron on any tax filings or audits related to the period of consolidation, but no charges for services will flow in either direction in connection with this cooperation.

PGE's operating and capital budgets, PGE's major investments and risk management policies, and PGE's dividends.

PGE's board of directors will interact with management on PGE's strategy and longer-term plans, including PGE's plans for operating as a public company and providing timely public information about PGE's financial and operational matters. For the near term, PGE's strategy will remain as expressed in its 2004-2006 Statement of Direction and its most recently acknowledged Integrated Resource Plan.

PGE's board of directors will owe a fiduciary duty to all shareholders, including those who have purchased their shares in the open market, Holders of Allowed Claims who have received shares upon the issuance of New PGE Common Stock or by the release of New PGE Common Stock from the Reserve, and the Reserve. PGE's board of directors will no longer owe its fiduciary duties to a single shareholder, such as Enron. The fiduciary duties of PGE's board of directors are the same for all shareholders, including the Reserve, regardless of the percentage of New PGE Common Stock owned by any shareholder.

PGE will continue to be regulated by the Commission and by FERC in the same manner as it is today. Nothing about the issuance of the New PGE Common Stock changes the regulatory authority or jurisdiction of the Commission or FERC. [31]

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[31] Enron has applied to the SEC under the Public Utility Holding Company Act of 1935 ("PUHCA") for authorization to dispose of its interest in PGE. In addition, SFC and the Reserve will seek an exemption from holding company status under PUHCA related to their roles as temporary custodians of the New PGE Common Stock, pending its full distribution to Holders of Allowed Claims. Because Enron will no longer own PGE common stock or control PGE after the issuance of the New PGE Common Stock to the Reserve and the Holders of Allowed Claims, Enron's SEC application also may request a determination that it is no longer a holding company under PUHCA and authorization to deregister as such. If the application to the SEC is granted, PGE would cease to be a subsidiary of a registered holding company and would no longer be subject to regulation under PUHCA.

V. ROLES AND OPERATION OF THE PLAN ADMINISTRATOR, THE DISBURSING AGENT AND THE DCR OVERSEERS

The primary objective of the Plan Administrator is to take all actions necessary to distribute the assets of the Debtors to the Holders of Allowed Claims as rapidly as prudently possible. There is no legal or economic incentive for the Plan Administrator to do anything other than resolve claims and close the bankruptcy cases. Likewise, the Plan's role for the Reserve is as a trust/escrow that reduces its interest in all assets, including the New PGE Common Stock, as rapidly as the Plan Administrator can resolve claims.

A. Plan Administrator

The Plan Administration Agreement describes the rights and duties of SFC as the Plan Administrator. Those rights and duties are, essentially, to carry out the Plan, resolve all claims made against the Debtors, resolve all claims that the Debtors have against any third party, make regular reports to the Enron board of directors and to the Bankruptcy Court on the status of claims resolution, liquidate assets remaining in the estates of the Debtors, and consult with and provide the DCR Overseers with information in connection with the voting or sale of the Plan securities, including New PGE Common Stock once it is issued, held in the Reserve.

The authority of the Plan Administrator is limited, as set forth in section 5 of the Plan Administration Agreement, by the dollar amounts and types of claims it can settle without the approval of the board of directors of Enron and, if requested by Enron's board of directors, the approval of the Bankruptcy Court.

Among other responsibilities, the Plan Administrator must hold sufficient assets of the Debtors in reserve to provide for distributions to the Holders of Disputed Claims as they become Holders of Allowed Claims and to the Holders of previously Allowed Claims as Disputed Claims are disallowed. The Plan Administrator also must calculate the expected recovery percentages that form the basis for the distributions to Holders of Allowed Claims prior to the final settlement of all claims under the Plan.

The compensation of SFC as the Plan Administrator is set forth in the Plan Administration Agreement, and is the sole compensation for any and all services rendered by SFC or any of its employees or affiliates to the Debtors for acting as the Plan Administrator, the Disbursing Agent or the trustee of any trust formed pursuant to the Plan.

SFC is owned 50% by Stephen Forbes Cooper and 25% each by Leonard LoBiondo and Michael E. France. SFC is providing management services to Enron and the other Debtors. A copy of the Operating Agreement of SFC is attached.[32] SFC's sole business is providing services to Enron and other Enron related Debtors. It has no other business. Also attached to this Application is a copy of an agreement between SFC and Kroll Zolfo Cooper, LLC, which provides that all amounts received by SFC for providing services to Enron and the other Debtors acting in any capacity pursuant to the Plan will be the property of, and shall be paid to, Kroll Zolfo Cooper, LLC.[33] Kroll Zolfo Cooper, LLC is owned 100% by Kroll, Inc., which is owned 100% by Marsh, Inc., which is owned 100% by MMC, a publicly traded corporation.

B. Disbursing Agent and the Disputed Claims Reserve

The DCR Guidelines and the Plan control the operation of the Reserve and the Disbursing Agent. The New PGE Common Stock issued to the Reserve will be held in trust/escrow for the benefit of Holders of Disputed Claims and Holders of Allowed Claims,

[32] Attached as Exhibit 18.
[33] Attached as Exhibit 19.

along with all other assets in the Reserve.[34] The Disbursing Agent has no economic or beneficial interest in the New PGE Common Stock or other assets in the Reserve.

The DCR Guidelines limit investment of assets held in the Reserve. All cash is held in interest-bearing accounts at financial institutions with a reported capital surplus of $100 million, or invested in interest-bearing obligations issued by the U.S. Government or by an agency of the U.S. Government and guaranteed by the U.S. Government, having maturity of not more than 30 days in either case, unless modified by the Bankruptcy Court. The DCR Guidelines do not give the Disbursing Agent any discretion to invest in other assets.[35] The Disbursing Agent is in the process of requesting from the Bankruptcy Court a change in the investment guidelines to allow it to invest cash and cash equivalents in Treasury Bills with maturities up to 6 months and in money market funds that invest in U.S. Government securities.

In short, the Disbursing Agent will take directions from the Plan Administrator as to the assets the Reserve holds or releases from time to time to Holders of Allowed Claims. The Disbursing Agent has no economic interest in, and no authority over, the operation or valuation of the Reserve. The Disbursing Agent has no authority to invest assets held in the Reserve in anything other than cash or cash equivalents and is prohibited from determining how to vote Plan securities, including the New PGE Common Stock.

C. DCR Overseers

The Disbursing Agent will vote the New PGE Common Stock held in the Reserve at the direction of the DCR Overseers. The other registered owners on the books of PGE's transfer agent will vote the New PGE Common Stock held by them.

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[34] See Plan sections 21.3(a) and 32.3, attached as Exhibit 2 and Exhibit 20, respectively.

[35] In addition, the DCR Guidelines do not allow the Disbursing Agent to sell the New PGE Common Stock or vote it, except as instructed by the DCR Overseers.

The DCR Overseers will have the limited functions of determining (1) how to vote the New PGE Common Stock held by the Reserve on all matters for which a shareholder vote is required under Oregon law or PGE's Articles of Incorporation and Bylaws and (2) whether to sell the New PGE Common Stock held by the Reserve. The Plan Administrator will be required to bring to the DCR Overseers matters that require the vote of shareholders and any offers to buy New PGE Common Stock.

As a matter of Oregon law and the proposed Articles of Incorporation and Bylaws of PGE, the DCR Overseers will have the right to vote annually on the election of PGE's board of directors. Under Oregon law, shareholders are also entitled to vote on major transactions, such as mergers and sale or mortgage of all or substantially all of the assets of a corporation such as PGE. As long as the Reserve holds more than 10% of the New PGE Common Stock, the DCR Overseers will also have the ability to call a special meeting of the shareholders.

The DCR Overseers will exercise their business judgment to vote Plan securities, including the New PGE Common Stock, in a manner they believe will maximize the value of assets to be distributed to creditors. The Guidelines require that the DCR Overseers take all actions that a board of directors of a public corporation chartered in the State of Delaware would be required to take to satisfy its fiduciary duties in making a decision requiring the voting by such corporation of a comparable proportion of securities it holds in another entity. The DCR Overseers may not vote in matters in which they have a conflict of interest.

Like the Disbursing Agent, the DCR Overseers have no economic or beneficial interest in the assets held in the Reserve. Their sole compensation is the compensation they receive for acting as directors of Enron.

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The DCR Overseers must require that any potential buyer of the New PGE Common Stock offer all other shareholders of New PGE Common Stock the same terms and conditions as are offered to the Reserve. This prevents the Reserve from receiving a premium from the sale of the New PGE Common Stock not available to other shareholders of PGE.

VI. ENRON MERGER CONDITIONS

The Enron merger conditions adopted by the Commission in Order 97-196 will cease to apply by their terms with respect to Enron at the time, likely April 2006, when the issuance of New PGE Common Stock occurs. Some have already expired by their terms, including numbers 4, 13, 16 and 19. Other conditions included commitments by PGE, such as Condition 7, and by the parties to the Stipulation, such as Condition 20, and these commitments will continue for circumstances arising out of the merger with Enron.

Enron merger conditions were justified based upon the specific facts and circumstances of Enron's acquisition of PGE. The issuance of New PGE Common Stock has no similar facts and circumstances. Below we discuss the Enron conditions and explain why, with one exception, the circumstances here do not warrant similar conditions.

As a general matter, the following circumstances were significant in supporting the conditions adopted in Order No. 97-196:

- A single entity, Enron, owned 100% of PGE's common stock.
- Enron could control PGE's dividend policy.
- As a result of the acquisition, PGE became affiliated with a myriad of Enron subsidiaries and affiliates, many of which conducted business in the energy sector.

- Enron planned to provide services to PGE and allocate expenses to PGE.
- The acquisition was expected to produce costs savings and synergies.

The Commission specifically identified these concerns in adopting the conditions, explaining that Enron "might weaken PGE's financial condition," the increase in affiliates could lead to "cross-subsidization," the acquisition would result in "direct charges" and "cost allocation" and the merger was expected to lower administrative expenses. Order 97-196 at 7.

Implementing the Plan's arrangements for transferring the New PGE Common Stock and other assets to creditors does not raise any of these concerns because:

- PGE will be held widely by public shareholders.
- PGE's board of directors will establish a dividend policy suitable to its financial circumstances and investors' needs.
- PGE will have only subsidiaries, not a corporate parent and affiliated sister companies.
- The Reserve's only purpose is to facilitate carrying out the terms of the Plan.
- The Reserve will not provide services to PGE and will not allocate costs to PGE.
- PGE will experience no cost savings or synergies because of the issuance of New PGE Common Stock.

With respect to specific conditions, Conditions 1-3 concerned affiliate transactions and required PGE to keep its books and records separate from its corporate parent Enron. As stated in the Commission Order adopting the parties' stipulation, these conditions focused on "inter-corporate transactions that result in direct charges or cost allocations." Neither the Reserve nor the Disbursing Agent will allocate costs to or engage in transactions with PGE. The only entities that will remain affiliated with PGE are its current and any future subsidiaries. The Commission affiliate statutes and rules are more than sufficient to address any affiliate issues between PGE and its subsidiaries. As noted above PGE will keep separate books and records for PGE.

Condition 4 required PGE to exclude all merger related costs from utility accounts. PGE will offer a condition similar to Condition 4 to assure the Commission and customers that the one-time costs of issuing the New PGE Common Stock and listing the stock on a national stock exchange will be borne by PGE and its shareholders and not its customers. PGE currently estimates that these costs will be less than $650,000.

Condition 5 required PGE to maintain separate debt and preferred stock ratings. This condition has no purpose with respect to the issuance of New PGE Common Stock because PGE will no longer have a corporate parent.

Conditions 6 and 9 were financial conditions, regulating the declaration and payment of dividends and the transfer of PGE's retained earnings to Enron. These conditions reflected concerns that Enron, as the sole owner of PGE, could have an incentive to weaken PGE's financial condition to benefit Enron or its other subsidiaries or affiliates. The Plan Administrator, the DCR Overseers, and the Reserve have no such incentive. Moreover, such conditions are unnecessary when a utility has public shareholders. In fact, limitations on PGE's ability to declare and pay dividends could harm customers by impairing PGE's access to capital markets. PGE will establish its own dividend policy to meet the expectations of the equity and debt markets and its financial circumstances.

Conditions 7 and 10 protected customers against a higher cost of capital or a higher revenue requirement as a result of the transaction. These conditions are not necessary for the issuance of New PGE Common Stock. The issuance of New PGE Common Stock will not change PGE's regulatory capital structure. PGE is incurring no new debt. Most important, PGE will have no parent company, which might affect PGE's credit ratings.

Condition 8 provided the Commission with access to written information concerning PGE given by Enron to stock or bond analysts. The Commission already has access to information PGE provides to stock or bond analysts.

Condition 11 sets forth a service quality program that will run until mid-2007. PGE plans to raise in its next general rate case whether another service quality program should follow this one and, if so, of what design.

Conditions 12-14 provide protections against cross-subsidization between PGE and affiliates. These concerns are not applicable because PGE will not have additional affiliates (other than the Reserve, which will be an affiliate) as a result of the issuance of New PGE Common Stock. The Reserve will not allocate any costs to PGE, and there will be no affiliate transactions between the Reserve and PGE.

Conditions 15-17 were put in place to restrict Enron's access to PGE's power, natural gas assets, or excess pipeline capacity because of the competitive nature of Enron's energy business at the time. The Reserve will not be involved in any business other than carrying out the terms of the Plan. In addition, the Commission subsequently adopted OAR 860-038-500 through 620, which deals with the subject matter of Condition 17. The Commission rules and statutes are more than sufficient to address PGE's relationships with its subsidiaries.

The circumstances that gave rise to and supported Conditions 18 through 21 do not exist now. The Reserve has not entered into an MOU with environmental groups, which formed the basis of Condition 18. The issuance of New PGE Common Stock creates no administrative costs savings or synergies, which were the basis of the merger credits in Condition 19. The Reserve has no plans to market and sell energy in other retail markets, which was the basis for the merger credit in Condition 20.[36] There is no need for enforcement provisions (Condition 21). Condition 22, which required the filing of a customer choice (UE 102), has long since been superseded by Oregon's direct access program.

VII. THIS APPLICATION SERVES PUBLIC INTEREST AND BENEFITS CUSTOMERS

There are several reasons why this Application serves the public interest and benefits customers. First, there are no risks to PGE or its customers as a result of the Plan for the New PGE Common Stock. PGE will not be subject to any new debt or liability. Any one-time costs associated with this Plan will not pass through to customers. There is no holding company created and no acquisition debt that must be serviced by PGE dividends.

Second, PGE will become a publicly traded stand-alone electric utility headquartered in Portland. The policy, direction and management decisions for PGE will be made by PGE's board of directors and management with full knowledge that PGE has no other business or purpose but to operate as a regulated public utility within the State of Oregon. As a publicly traded company, PGE will have access to the public equity market, something it does not have now.

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[36] The merger credit in condition 20 was also "full payment for any entitlement PGE's customers may have to value that relates to: 1) use of PGE's name, reputation, business relationships, expertise, goodwill or other intangibles; 2) wholesale and non-franchise retail activities that PGE has undertaken that will not take place within PGE after the merger (this includes but is not limited to PGE's discontinued term wholesale trading and risk management activities), and wholesale and non-franchise retail activities that PGE might have undertaken had the merger with Enron not occurred; and 3) added value of the merged entity that is achievable because of the combination or because of the association with PGE. This payment obligation also shall constitute full payment to PGE's customers for any entitlement to the revenues, value or other benefits arising from the business activities of the merged entity, other than the regulated business activities conducted by PGE. The term 'regulated business activities' shall mean the assets and services of PGE which are subject to economic regulation under Oregon or federal law." The Commission should continue to recognize this full payment in any applicable circumstances.

Third, PGE will not be consolidated for tax purposes with any other entity (other than with its wholly-owned subsidiaries) and will file and pay its taxes with and directly to all taxing authorities.

The Reserve and the Plan Administrator are charged with resolving disputed claims and distributing New PGE Common Stock to Holders of Allowed Claims as rapidly as possible. The expected outcome of the Plan is that ultimately the New PGE Common Stock will be publicly and widely held. Approval of this Application will allow Enron, PGE and the Commission to carry out fully the Plan approved by the Bankruptcy Court pursuant to federal law for the issuance of the New PGE Common Stock. Approval of this Application is the fastest way to return PGE to its previous status as a publicly traded company, headquartered in Portland, Oregon.

The Applicants respectfully request that the Commission grant the orders described in this Application.

DATED this 17th day of June, 2005.

Portland General Electric Company

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SCHEDULE OF EXHIBITS

Exhibit	Description
1	Bankruptcy Court Confirmation Order
2	Plan section 21.3(a)
3	Guidelines for the Disputed Claims Reserve
4	Guidelines for the DCR Overseers
5	History of the Plan
6	SEC Plan Order
7	Plan Administration Agreement
8	Biographies of the five DCR Overseers/Enron Board
9	Draft PGE Articles of Incorporation
10	Draft PGE Bylaws
11	Plan section 36
12	Plan section 1.198
13	Plan section 1.191
14	Plan section 7.1
15	Plan sections 1.115, 1.120, 1.149, 1.150, 18.1-18.3, and 19.1-19.3
16	Plan section 32.1(c)
17	Draft Separation Agreement
18	SFC Operating Agreement
19	Agreement between SFC, LLC and Kroll Zolfo Cooper, LLC
20	Plan section 32.3

Appendix A

REQUIRED INFORMATION FOR APPLICATION TO ISSUE NEW PGE COMMON STOCK

A. The following information is required by OAR 860-027-0030(1):

1. Applicant's Name and Address (OAR 860-027-0030(1)(a))

Portland General Electric Company, 121 SW Salmon Street, Portland, Oregon 97204.

2. Applicant's Incorporation and Authorizations to Transact Utility Business (OAR 860-027-0030(1)(b))

PGE is a corporation organized and existing under and by the laws of the State of Oregon, and the date of its incorporation is July 25, 1930. PGE is authorized to transact business in the states of Oregon, Washington, California, Arizona, Idaho, Utah and Montana, but conducts retail utility business only in the State of Oregon. As of February 21, 1995, PGE is also registered as an extra provincial corporation in Alberta, Canada.

3. Notices (OAR 860-027-0030(1)(c))

The names and addresses of the persons authorized to receive notices and communications in respect of this Application:

PGE-OPUC Filings
Rates & Regulatory Affairs
Portland General Electric Company
121 SW Salmon Street, 1WTC0702
Portland, OR 97204
(503) 464-7857 (telephone)
(503) 464-7651 (telecopier)
pge.opuc.filings@pgn.com

The names and addresses to receive notices and communications via the e-mail service list are:

Patrick G. Hager, Manager Regulatory Affairs
E-Mail: patrick.hager@pgn.com, and

J. Jeffrey Dudley, Associate General Counsel
E-Mail: jay.dudley@pgn.com

4. Principal Officers (OAR 860-027-0030(1)(d))

As of June 1, 2005, the names, titles and addresses of PGE's principal officers are as follows:

NAME	TITLE
Peggy Y. Fowler	Chief Executive Officer & President
James J. Piro	Executive Vice President, Finance, Chief Financial Officer & Treasurer
Arleen Barnett	Vice President, Administration
Carol A. Dillin	Vice President, Public Policy
Stephen R. Hawke	Vice President, Customer Service & Delivery
Ronald W. Johnson	Vice President, Business & Government Customers; Economic Development
Pamela G. Lesh	Vice President, Regulatory Affairs & Strategic Planning
James F. Lobdell	Vice President, Power Operations & Resource Planning
Joe A. McArthur	Vice President, Distribution
Douglas R. Nichols	Vice President, General Counsel & Secretary
Stephen M. Quennoz	Vice President, Nuclear & Power Supply / Generation
Kirk M. Stevens	Controller and Assistant Treasurer
William J. Valach	Assistant Treasurer
Steven F. McCarrel	Assistant Secretary
J. Mack Shively	Assistant Secretary

5. **Applicant's Business (OAR 860-027-0030(1)(e))**

PGE is engaged in the generation, purchase, transmission, distribution, and sale of electric energy for public use in Clackamas, Columbia, Hood River, Jefferson, Marion, Morrow, Multnomah, Polk, Washington, and Yamhill counties, Oregon.

6. **Authorized and Outstanding Stock (OAR 860-027-0030(1)(f))**

(f) A statement, as of the date of the balance sheet submitted with the

application, showing for each class and series of capital stock: brief description; the amount authorized(face value and number of shares); the amount outstanding(exclusive of any amount held in the treasury), held amount as reacquired securities; amount pledged by applicant; amount owned by affiliated interests, and amount held in any fund

PGE's capital stock as of March 31, 2005.

	Outstanding	
	Shares	Amount ($000s)
Cumulative Preferred Stock *:		
7.75% Series No Par Value (30,000,000 shares authorized):	204,727	$20,473
$1 Par Value Limited voting Jr.	1	-
Total Preferred Stock	204,728	$20,473
Common Stock:		
$3.75 Par Value (100,000,000 shares authorized):	42,758,877	$160,346

*As required by SFAS No. 150, PGE's 7.75% Series preferred stock has been reclassified Long-Term Debt, effective July 1, 2003, and the Company began recording the related dividends as interest expense.

None of the capital stock is held as reacquired securities, pledged, held by affiliated corporations (other than Enron), or held in any sinking or other fund.

7. Authorized and Outstanding Long-Term Debt or Notes (OAR 860-027-0030(1)(g))

(g) A statement, as of the date of the balance sheet submitted with the application, showing for each class and series of long-term debt or notes: brief description(amount, interest rate and maturity); amount authorized; amount outstanding(exclusive of any amount held in the treasury); amount held as reacquired securities; amount pledged by applicant; amount held by affiliated interests; and amount in sinking and other funds

PGE's long-term debt as of March 31, 2005.

Description	Authorized ($000s)	Outstanding ($000s)
First Mortgage Bonds:		
MTN Series due August 15, 2005 9.07%	18,000	18,000
MTN Series due June 15, 2007 7.15%	50,000	50,000
MTN Series due August 11, 2021 9.31%	20,000	20,000
8-1/8% Series due February 1, 2010	150,000	150,000
5.6675% Series due October 25, 2012	100,000	100,000
5.279% Series due April 1, 2013	50,000	50,000
5.625% Series due August 1, 2013	50,000	50,000
6.75% Series due August 1, 2023	50,000	50,000
6.875% Series due August 1, 2033	50,000	50,000
Total First Mortgage Bonds	538,000	538,000
Pollution Control Bonds:		
City of Forsythe, Montana		
5.45% Series due May 1, 2033	21,000	21,000
5.20% Series due May 1, 2033	97,800	97,800
Port of Morrow		
5.20 % Series May 1, 2033	23,600	23,600
Port of St. Helens, Oregon		
4.80% Series due April 1, 2010	20,200	20,200
4.80% Series due June 1, 2010	16,700	16,700
5.25% Series due August 1, 2014	9,600	9,600
7.125% Series due December 15, 2014	5,100	5,100
Total Pollution Control Bonds	194,000	194,000
Other Long-Term Debt:		
6.91% Conservation Bonds	80,730	16,757
7-7/8% Notes due March 15, 2010	150,000	149,250
Other Long-Term Obligation		462
Unamortized Debt Discount and Other	(1,500)	(1,353)
Total Other Long-Term Debt	229,230	165,116
Less Maturities and Sinking Funds Included in Current Liabilities	28,370	28,370
Total Long-Term Debt	932,860	868,746

None of the long-term debt is pledged or held as reacquired securities, by affiliated corporations, or in any fund.

8. Proposed Issuance of Securities (OAR 860-027-0030(1)(h))

(h) *A full description of the securities proposed to be issued, showing: kind and nature of securities or liabilities; amount(face value and number of shares); interest or dividend rate, if any; date of issue and date of maturity; and voting privileges, if any*

See Sections I and III of the Application.

9. Description of Proposed Transaction (OAR 860-027-0030(1)(i))

(i) A reasonably detailed and precise description of the proposed transaction, including a statement of the reasons why it is desired to consummate the transaction and the anticipated effect thereof. If the transaction is part of a general program, describe the program and its relation to the proposed transaction. Such description shall include, but is not limited to, the following:

(a) A description of the proposed method of issuing and selling the securities;

(b) A statement of whether such securities are to be issued pro rata to existing holders of the applicant's securities or issued pursuant to any preemptive right or in connection with any liquidation or reorganization;

(c) A statement showing why it is in applicant's interest to issue securities in the manner proposed and the reason(s) why it selected the proposed method of sale; and

(d) A statement that exemption from the competitive bidding requirements of any federal or other state regulatory body has or has not been requested or obtained, and a copy of the action taken thereon when available.

For information responsive to subparts (a)-(c), *see* Sections I, II, III, and VII of the Application. As to subpart (d), an exemption from federal or state competitive bidding requirements has not been obtained because no such requirements exist with the respect to the issuance of New PGE Common Stock.

10. Transaction Fees (OAR 860-027-0030(1)(j))

(j) The name and address of any person receiving or entitled to a fee for service(other than attorneys, accountants and similar technical services) in connection with the negotiation or consummation of the issuance or sale of securities, or for services in securing underwriters, sellers or purchasers of securities, other than fees included in any competitive bid; the amount of each such fee, and facts showing the necessity for the services and that the fee does not exceed the customary fee for such services in arm's-length transactions and is reasonable in the light of the cost of rendering the service and any other relevant factors

PGE will pay ordinary and customary fees for listing the New PGE Common Stock on a national stock exchange, for a transfer agent and registrar and for printing stock certificates and related activities.

11. Commissions and Net Proceeds (OAR 860-027-0030(1)(k))

(k) A statement showing both in total amount and per unit the price to the public, underwriting commissions and net proceeds to the applicant. Supply also the information(estimated if necessary) required in section(4) of this rule. If the securities are to be issued directly for property, then a full description of the property to be acquired, its location, its original cost(if known) by accounts, with the identification of the person from whom the property is to be acquired, must be furnished. If original cost is not known, an estimate of original cost based, to the extent possible, upon records or data of the seller and applicant or their predecessors must be furnished, with a full explanation of how such estimate has been made, and a description and statement of the present custody of all existing pertinent data and records. A statement showing the cost of all additions and betterments and retirements, from the date of the original cost, should also be furnished

None.

12. Purpose for Issuance (OAR 860-027-0030(1)(l))

(l) Purposes for which the securities are to be issued. Specific information will be submitted with each filing for the issuance of bonds, stocks or securities:

- *Construction, completion, extension or improvement of facilities. A description of such facilities and the cost thereof;*
- *Reimbursement of the applicant's treasury for expenditures against which securities have not been issued. A statement giving a general description of such expenditures, the amounts and accounts to which charged, the associated credits, if any, and the periods during which the expenditures were made;*
- *Refunding or discharging of obligations. A description of the obligations to be refunded or discharged, including the character, principal amounts discount or premium applicable thereto, date of issue and date of maturity, purposes to which the proceeds were applied and all other material facts concerning such obligations; and*
- *Improvement or maintenance of service. A description of the type of expenditure and the estimated cost in reasonable detail;*

See Section I of the Application.

13. Other Federal and State Applications (OAR 860-027-0030(1)(m))

(m) A statement as to whether or not any application, registration statement, etc., with respect to the transaction or any part thereof, is required to be filed with any federal or other state regulatory body

See Section III(A) of the Application.

14. Facts Showing that Issuance is Lawful, Appropriate, and in the Public Interest (OAR 860-027-0030(1)(n))

(n) The facts relied upon by the applicant to show that the issue:

- *Is for some lawful object within the corporate purposes of the applicant;*
- *Is compatible with the public interest;*
- *Is necessary or appropriate for or consistent with the proper performance by the applicant of service as a utility;*
- *Will not impair its ability to perform that service;*
- *Is reasonably necessary or appropriate for such purposes; and*
- *If filed under ORS 757.495, is fair and reasonable and not contrary to public interest;*

See Section VII of the Application.

15. Acquisition of Rights (OAR 860-027-0030(1)(o))

Not applicable.

16. Affiliated Interest Transactions (OAR 860-027-0030(1)(p))

Not applicable.

B. The following exhibits are required by OAR 860-027-0030(2):

1. EXHIBIT A (OAR 860-027-0030(2)(a))

PGE's current articles of incorporation with amendments to date (previously filed in Docket UP 79 and incorporated by reference hereto).

2. **EXHIBIT B (OAR 860-027-0030(2)(b))**

PGE's current bylaws with amendments to date (previously filed in Docket UP 4206 and incorporated by reference hereto).

3. **EXHIBIT C (OAR 860-027-0030(2)(c))**

Resolutions for the issuance of new PGE Common Stock are not currently available. They will be submitted when available.

4. **EXHIBIT D (OAR 860-027-0030(2)(d))**

None.

5. **EXHIBIT E (OAR 860-027-0030(2)(e)) (see attached)**

PGE's balance sheets as of March 31, 2005. Adjustments to record the proposed issuance of New PGE Common Stock and pro forma are not currently available. They will be submitted when available.

6. **EXHIBIT F (OAR 860-027-0030(2)(f)) (see attached)**

A statement of all known contingent liabilities as of March 31, 2005.

7. **EXHIBIT G (OAR 860-027-0030(2)(g)) (see attached)**

PGE's comparative income statements for the 3-month period ended March 31, 2005. Adjustments to record the proposed issuance of New PGE Common Stock and pro forma are not currently available. They will be submitted when available.

8. **EXHIBIT H (OAR 860-027-0030(2)(h)) (see attached)**

An analysis of PGE's surplus for the 3-month period ended March 31, 2005.

9. **EXHIBIT I (OAR 860-027-0030(2)(i))**

EXHIBIT I: A copy of registration statement proper, if any, and financial exhibits made a part thereof, filed with the Securities and Exchange Commission

PGE will file a Form 8A with the SEC prior to the issuance of New PGE Common Stock and will file a copy with the Commission.

10. **EXHIBIT J (OAR 860-027-0030(2)(j))**

EXHIBIT J: A copy of the proposed and of the published invitation of proposals for the purchase of underwriting of the securities to be issued; of each proposal received; and of each contract, underwriting, and other arrangement entered into for the sale or marketing of the securities. When a contract or underwriting is not *in final form so as to permit filing, a preliminary draft or a summary identifying parties thereto and setting forth the principal terms thereof, may be filed pending filing of conformed copy in the form executed by final amendment to the application*

Not Applicable.

11. EXHIBIT K (OAR 860-027-0030(2)(k))

Stock certificates for the New PGE Common Stock are not currently available. Copies will be provided when they are available.

12. (OAR 860-027-0030(2)(l))

Application for a utility to loan its funds to an affiliated interest, in addition to Exhibits A through K, shall also include the following:

Not applicable.

13. (OAR 860-027-0030(2)(m))

An application for a utility to give credit on its books or otherwise by:

Not applicable.

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Exhibit "E"

Portland General Electric Company and Subsidiaries
Consolidated Balance Sheet
(Unaudited)
For the Three Months Ended March 31, 2005
(Millions of Dollars)

	March 31, 2005	Adjustments (1)	Adjusted Total
Assets			
Electric Utility Plant - Original Cost			
Utility plant (includes construction work in progress of $142 and $114)	$4,043	$0	$4,043
Accumulated depreciation	($1,734)	$0	($1,734)
	2,309	$0	2,309
Other Property and Investments			
Nuclear decommissioning trust, at market value	21		21
Non-qualified benefit plan trust	62		62
Miscellaneous	31	$0	31
	114		114
Current Assets			
Cash and cash equivalents	316	$0	316
Accounts and notes receivable (less allowance for uncollectible accounts of $50 and $50)	187		187
Unbilled revenues	57		57
Assets from price risk management activities	213		213
Inventories, at average cost	46		46
Prepayments and other	116		116
	935	$0	935
Deferred Charges			
Regulatory assets	281		281
Miscellaneous	24	$0	24
	305	$0	305
	$3,663	$0	$3,663
Capitalization and Liabilities			
Capitalization			
Common stock, $3.75 par value per share, 100,000,000 shares authorized; 42,758,877 shares outstanding	160		160
Other paid-in capital - net	481		481
Retained earnings	675		675
Accumulated other comprehensive income (loss):			
Unrealized gain on derivatives classified as cash flow hedges	4		4
Minimum pension liability adjustment	-4		-4
Limited voting junior preferred stock	0		0
Long-term obligations	889	$0	889
	2205		2205
Commitments and Contingencies (see Notes)			
Current Liabilities			
Long-term debt due within one year	30		30
Accounts payable and other accruals	193		193
Liabilities from price risk management activities	83		83
Customer deposits	68		68
Accrued interest	15		15
Accrued taxes	67		67
Deferred income taxes	51	$0	51
	507	$0	507
Other			
Deferred income taxes	259		259
Deferred investment tax credits	12		12
Trojan asset retirement obligation	104		104
Accumulated asset retirement obligation	16		16
Regulatory liabilities:			
Accumulated asset retirement removal costs	309		309
Other: unamortized regulatory liabilities	139	$0	139
Non-qualified benefit plan liabilities	71		71
Miscellaneous	41		41
	951		951
	$3,663	$0	$3,663

(1) Adjusting entries are not currently available.

Exhibit "F"

Statement of Contingent Liabilities

Legal Matters

Trojan Investment Recovery

In 1993, following the closure of the Trojan Nuclear Plant, PGE sought full recovery of and a rate of return on its Trojan plant costs, including decommissioning, in a general rate case filing with the OPUC. The filing was a result of PGE's decision earlier in the year to cease commercial operation of Trojan as a part of its least cost planning process. In 1995, the OPUC issued a general rate order (1995 Order) which granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs, and full recovery of its estimated decommissioning costs through 2011.

Numerous challenges, appeals and requested reviews were subsequently filed in the Marion County, Oregon Circuit Court, the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of and a return on the Trojan investment. The primary plaintiffs in the litigation were the Citizens' Utility Board (CUB) and the Utility Reform Project (URP). The Court of Appeals issued an opinion in 1998, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE and the OPUC requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision on the return on investment issue. In addition, URP requested the Oregon Supreme Court to review the Court of Appeals decision on the return of investment issue. PGE requested the Oregon Supreme Court to suspend its review of the 1998 Court of Appeals opinion pending resolution of URP's complaint with the OPUC challenging the accounting and ratemaking elements of the settlement agreements approved by the OPUC in September 2000 (discussed below). On November 19, 2002, the Oregon Supreme Court dismissed PGE's and URP's petitions for review of the 1998 Oregon Court of Appeals decision. As a result, the 1998 Oregon Court of Appeals opinion stands and the case has been remanded to the OPUC.

While the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, in 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in the Trojan plant. URP did not participate in the settlement. The settlement, which was approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The largest of such amounts consisted of before-tax credits of approximately $79 million in customer benefits related to the previous settlement of power contracts with two other utilities and the approximately $80 million remaining credit due customers under terms of the 1997 merger of Portland General Corporation (PGC) with Enron. The settlement also allows PGE recovery of approximately $47 million in income tax benefits related to the Trojan investment which had been flowed through to customers in prior years; such amount is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five-year period, beginning in October 2000. After offsetting the investment in Trojan with these credits and prior tax benefits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan is no longer included in rates charged to customers, either through a return of or a return on that investment. Authorized collection of decommissioning costs of Trojan is unaffected by the settlement agreements or the OPUC orders.

The URP filed a complaint challenging the settlement agreements and the OPUC's September 2000 order. In March 2002, after a full contested case hearing, the OPUC issued an order (2002 Order) denying all of URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County, Oregon Circuit Court. On November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have filed appeals to the Oregon Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the other case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class). The suits seek damages of $190 million for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges its customers. On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of Plaintiff's claims. On December 14, 2004, the Judge granted the Plaintiff's motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered on February 1, 2005. On March 3, 2005, PGE filed a Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court, asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints or to show cause why they should not be dismissed. On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court, seeking to overturn the Class Certification. On May 3, 2005, the Oregon Supreme Court granted both Petitions. The parties will file briefs on both Petitions over the next few months. Oral argument before the Oregon Supreme Court is expected in the fall of 2005.

On March 3, 2004, the OPUC re-opened three dockets in which it had addressed the issue of a return on PGE's investment in Trojan, including the 1995 Order and 2002 Order related to the settlement of 2000, and issued a notice of a consolidated procedural conference before an administrative law judge to determine what proceedings are necessary to comply with the court orders remanding this matter to the OPUC. On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration. On April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order.

On February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs) stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, the Company's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of $100 million. Management cannot predict the ultimate outcome of the above matters. However, it believes these matters will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Multnomah County Business Income Taxes

In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MBIT) after 1996. The plaintiffs allege that during the period 1997 through the third quarter 2004, PGE collected in excess of $6 million from its customers for MBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs seek a judgment against PGE for restitution of MBIT collected from customers. Plaintiffs also seek interest, recoverable costs, and reasonable attorney fees. The Plaintiffs filed an amended complaint on February 25, 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages. On February 24, 2005, PGE requested a declaratory ruling from the OPUC on this matter. On March 24, 2005, PGE filed in the Circuit Court a motion to abate or in the alternative to dismiss. Management cannot predict the ultimate outcome of this matter.

Union Grievances

In November 2001, grievances were filed by several members of the International Brotherhood of Electrical Workers (IBEW) Local 125, the bargaining unit representing PGE's union workers, alleging that losses in their pension/savings plan were caused by Enron's manipulation of its stock. The grievances, which do not specify an amount of claim, seek binding arbitration. PGE filed for relief in Multnomah County Oregon Circuit Court seeking a ruling that the grievances are not subject to arbitration. On August 14, 2003, the Court granted PGE's motion for summary judgment, finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW appealed the decision. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Environmental Matters

Harborton

A 1997 investigation by the Environmental Protection Agency (EPA) of a 5.5 mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. Based upon analytical results of the investigation, the EPA included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund). In December 2000, PGE received a "Notice of Potential Liability" regarding its Harborton Substation facility and was included, along with sixty-eight other companies, on a list of Potentially Responsible Parties with respect to the Portland Harbor Superfund Site.

Also in 2000, PGE agreed with the Oregon Department of Environmental Quality (DEQ) to perform a voluntary remedial investigation of its Harborton Substation site to confirm whether any hazardous substances had been released from the substation property into the Portland Harbor sediments. In February 2002, PGE submitted its final investigative report to the DEQ, indicating that the voluntary investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the Harborton Substation site. Further, the voluntary investigation demonstrated that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the final investigative report to the EPA and in a May 18, 2004 letter, the EPA stated that "Based on the summary information provided by DEQ and the limited data EPA has at this stage in its process, EPA agrees at this time, that this site does not appear to be a current source of contamination to the river." Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis Potentially Responsible Party.

The EPA is coordinating activities of natural resource agencies and the DEQ and in early 2002 requested and received signed "administrative orders of consent" from several Potentially Responsible Parties, voluntarily committing themselves to further remedial investigations; PGE was not requested to sign, nor has it signed, such an order.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of Potentially Responsible Parties, including PGE. Management cannot predict the ultimate outcome of this matter or estimate any potential loss. However, it believes this matter will not have a material adverse impact on its financial statements.

Other
In October 2003, PGE agreed with the DEQ to provide cost recovery for oversight of a voluntary investigation and/or potential cleanup of petroleum products at another Company site that is upland from the Portland Harbor Superfund Site. Sufficient information is currently not available to determine the total costs related to this matter. However, PGE believes this matter will not have a material adverse impact on its financial statements.

Refunds on Wholesale Transactions

California
On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds for federally-mandated wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology have since been issued by the FERC. Appeals of the FERC orders were filed and in August 2002 the U.S. Ninth Circuit Court of Appeals issued an order requiring the FERC to reopen the record to allow the parties to present additional evidence of market manipulation.

Also in August 2002, the FERC Staff issued a report that included a recommendation that natural gas prices used in the methodology to calculate potential refunds be reduced significantly, which could result in a material increase in PGE's potential refund obligation.

In December 2002, a FERC administrative law judge issued a certification of facts to the FERC regarding the refunds, based on the methodology established in the 2001 FERC order rather than the August 2002 FERC Staff recommendation. On March 26, 2003, the FERC issued an order in the California refund case (Docket No. EL00-95) adopting in large part the certification of facts of the FERC administrative law judge but adopting the August 2002 FERC Staff recommendation on the methodology for the pricing of natural gas in calculating the amount of potential refunds. PGE estimates its potential liability under the modified methodology at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas. On October 16, 2003, the FERC issued an order reaffirming, in large part, the modified methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and on December 20, 2003, the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit Court has now begun to hear the numerous appeals.

It has bifurcated appeals of the existing cases into two phases. The first will consider arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. Briefing and oral argument have been completed on this first phase. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the continuing issues remaining before FERC become final and are appealed.

Also on May 12, 2004, the FERC issued a separate order that provided clarification regarding certain aspects of the methodology for California generators to recover fuel costs incurred to generate power that were in excess of the gas cost component used to establish the refund liability. On September 24, 2004, the FERC issued an order that denied requests for rehearing of its May 12, 2004 fuel cost order and also adopted a new methodology to allocate the excess amounts of fuel costs that California generators are permitted to recover. Additional clarifying orders continue to be issued periodically. Under the new allocation methodology of the September 24, 2004 order, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect that this order will materially increase the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs, PGE has opted to become a participant in several settlements filed jointly by large generators and California parties, and approved by the FERC during 2004 and 2005.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. In December 2004, the FERC requested comments regarding the manner in which such studies should be conducted and the principles that should control. PGE and numerous other parties filed comments and reply comments. Comments in support of aspects of PGE's position were filed by the Oregon and Washington public utility commissions and by the Oregon and Washington senate delegations. A decision by the FERC to adopt PGE's approach to these studies could reduce the Company's ultimate refund liability.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). Interest has not yet been recorded by the Company. In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the Federal Power Act (FPA), and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates during the period October 2, 2000 - June 4, 2002 should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. In the refund case and in related dockets, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. PGE cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Challenge of the California Attorney General to Market Based Rates
On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the Federal Power Act (FPA), and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates during the period October 2, 2000 - June 4, 2002 should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. In the refund case and in related dockets, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. PGE cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Pacific Northwest
In the July 25, 2001 order, the FERC also called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market

sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceedings and denying the claims for refunds. In July 2003, numerous parties filed requests for rehearing of the June 2003 FERC order. In November 2003 and February 2004, the FERC issued orders that denied all pending requests for rehearing. Parties have appealed various aspects of these FERC orders and briefing is ongoing.

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for future reporting periods.

<u>**Enron Bankruptcy**</u>

Liabilities and Impairments
Although PGE is not included in the Enron bankruptcy, it has been affected. Numerous shareholder and employee class action lawsuits have been initiated against Enron, its former independent accountants, legal advisors, executives, and board members. In addition, investigations of Enron have been commenced by several Congressional committees and state and federal regulators, including the FERC and the State of Oregon. PGE has been included in requests for documents related to Congressional and regulatory investigations, with which it is fully cooperating.

In addition to the general effects discussed above, PGE may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. These are:

1. **Amounts Due from Enron and Enron-Supported Affiliates in Bankruptcy** – On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts representing intercompany obligations between PGE and Enron and its bankrupt subsidiaries arising prior to the commencement of the bankruptcy case. In December 2004, PGE made a distribution to Enron of all pre-petition amounts owed by Enron and its affiliates, and related proofs of claim, except for those related to PGH. The distribution was made in an effort to eliminate all pre-petition intercompany balances from PGE's books in order to remove the uncertainties regarding the value of the proofs of claim. Following the distribution, PGE's balance sheet was cleared of all pre-petition intercompany balances with Enron and its affiliates, with the exception of PGH. As of March 31, 2005, PGE has outstanding accounts receivable of $5 million due from PGH. Based on management's assessment of the realizability of accounts receivable from PGH, a reserve of $1 million has been established.

2. **Controlled Group Liability** - Enron's bankruptcy has raised questions regarding potential PGE liability for certain employee benefit plans and tax obligations of Enron.

Pension Plans
Funding Status

The pension plan for the employees of PGE (the PGE Plan) is separate from the Enron Corp. Cash Balance Plan (the Enron Plan). At December 31, 2004, the total fair value of PGE Plan assets was $2 million higher than the projected benefit obligation on a SFAS No. 87 (Employers' Accounting for Pensions) basis. In addition, the PGE Plan was over-funded on an accumulated benefit obligation basis by approximately $58 million as of December 31, 2004.

Enron's management has informed PGE that, as of December 31, 2004, the assets of the Enron Plan were less than the present value of all accrued benefits by approximately $48 million on a SFAS No. 87 basis and approximately $166 million on a plan termination basis. The PBGC insures pension plans, including the PGE Plan and the Enron Plan and the pension plans of other Debtors. Enron's management has informed PGE that the PBGC has filed claims in the Enron bankruptcy cases with respect to the Enron Plan and the plans of the other Debtors (Pension Plans). The claims are duplicative in nature because certain liability under ERISA is joint and several. Five of the PBGC's claims represent unliquidated claims for PBGC insurance premiums (the Premium Claims), five are unliquidated claims for due but unpaid minimum funding contributions (the Contribution Claims) under the Internal Revenue Code of 1986, as amended, and ERISA, 26 U.S.C. Section 412, and 29 U.S.C. Section 1082, and the remaining five claims are for unfunded benefit liabilities (the UBL Claims). PBGC has informed the Debtors that it has reduced its aggregate estimate of the UBL Claims for the Pension Plans to $321.8 million, including $240.2 million for the Enron Plan and $64.6 million related to the PGE Plan, although it has not amended the UBL Claims to reflect those amounts. While the PBGC and Enron are in settlement discussions, Enron has created a reserve fund equal to the amount of the maximum PBGC exposure, as delineated in the PBGC UBL Claims, of $321.8 million. This reserve provides security to the PBGC and PGE and other affiliates of Enron against the possibility of PBGC seeking to assert its UBL Claims against Enron's affiliates as set forth below with respect to controlled group liability. Except for one PBGC premium which is not material, the Debtors are current on their PBGC premiums and their minimum funding contributions to the Pension Plans. Therefore, the Debtors' value the Premium Claims and the Contribution Claims at $0. Enron management has informed PGE that the PBGC has informally alleged in pleadings filed with the Bankruptcy Court that the UBL claim related to the Enron Plan could increase by as much as 100%. PBGC has not provided support (statutory or otherwise) for this assertion and Enron management disputes the validity of any such claim.

Because the Enron Plan is underfunded, in certain circumstances the Enron Plan may be terminated and taken control of by the PBGC upon approval of a Federal District Court.

In addition, with consent of the PBGC, Enron could seek to terminate the Enron Plan while it is underfunded. Moreover, if it satisfies certain statutory requirements, Enron can commence a voluntary termination by fully funding the Enron Plan, in accordance with the Enron Plan terms, and terminating it in a "standard" termination in accordance with ERISA.

Upon termination of an underfunded pension plan, all of the members of the ERISA controlled group of the plan sponsor become jointly and severally liable for the plan's underfunding. The PBGC can demand payment from one or more of the members of the controlled group. If payment is not made, a lien in favor of the PBGC automatically arises against all of the assets of that member of the controlled group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the controlled group members. In addition, if the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in favor of the plan in the amount of the missed funding automatically arises against the assets of every member of the controlled group. In either case, the PBGC may file to perfect the lien and attempt to enforce it against the assets of the plan sponsor and the members of its controlled group. PGE management believes that the lien would be subordinate to prior perfected liens on the assets of the members of the controlled group. Substantially all of PGE's assets are subject to a prior perfected lien in favor of the holders of its First Mortgage Bonds. PGE management believes that any lien asserted by the PBGC would be subordinate to that lien. In addition, the PBGC retains an interest in the proceeds of any sale by Enron of its ownership interest in PGE.

On January 30, 2004, the Bankruptcy Court entered an order authorizing Enron and certain of its affiliated Debtors to contribute $200 million to the Pension Plans and terminate them in a manner that should eliminate the PBGC's claims. However, there can be no assurance that Enron will have the ability to obtain funding for accrued benefits on acceptable terms, that certain funding contingencies will be met, or that the required government agencies that review pension plan terminations will approve the termination of the Pension Plans. If the proposal to fund and terminate the Enron Plan is approved and consummated, it should eliminate any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan.

On June 2, 2004, the PBGC issued notices to Enron and Enron Facility Services, Inc., an Enron affiliate, stating that the PBGC had determined that the Pension Plans should be terminated. On June 3, 2004, the PBGC filed a complaint (PBGC Complaint) in the District Court for the Southern District of Texas against Enron seeking an order (i) terminating the Pension Plans; (ii) appointing the PBGC the statutory trustee of the Pension Plans; (iii) requiring transfer to the PBGC of all records, assets or other property of the Pension Plans required to determine the benefits payable to the Pension Plans' participants; and (iv) establishing June 3, 2004 as the termination date of the Pension Plans.

The PGE Plan was not included in the above Complaint, nor was PGE issued a similar notice of determination regarding the PGE Plan. The PBGC has taken no action to terminate the PGE Plan.

Unless and until the District Court authorizes the PBGC to terminate the Pension Plans and the PBGC makes a demand on PGE to pay some or all of any unfunded benefit liabilities under the Pension Plans, which would not occur unless the Proposed Pension Settlement (as described below) is not approved by both the District and Bankruptcy Courts or the parties do not satisfy the terms of the Proposed Pension Settlement, PGE has no liability for the unfunded benefit liabilities and no termination liens arise against any PGE property.

Proposed Settlement
Enron management has informed PGE management that Enron has reached a settlement in principle (Proposed Pension Settlement) with the PBGC, the terms of which have not yet been disclosed. As a result, the PBGC and Enron have filed to stay the PBGC Complaint. The Proposed Pension Settlement must be filed and approved by the District Court and the Bankruptcy Court and all terms of the Proposed Pension Settlement must be satisfied for the contingent liability against PGE by the PBGC to be relinquished. If the Proposed Pension Settlement is not approved by both the District and Bankruptcy Courts or the parties do not satisfy all the terms of the Proposed Pension Settlement, and if the relief sought in the Enron Complaint is not obtained when the stay is lifted, Enron may be precluded from funding and terminating the Pension Plans as previously authorized by the Bankruptcy Court until, if at all, after resolution of the PBGC Complaint as the stay with respect to such litigation also would be lifted. In addition, in that case it may be possible, subject to applicable law, for the Enron Plan and PGE Plan to be merged while Enron and PGE are in the same controlled group, and any excess assets in the PGE Plan would reduce the deficiency in the Enron Plan. However, if the plans are not merged, the deficiency in the Enron Plan could become the responsibility of the PBGC and the PGE Plan assets would be undiminished.

If the Proposed Pension Settlement is approved, Enron would proceed with the standard termination of the Pension Plans as discussed above and any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan would be eliminated.

PGE management cannot predict the outcome of the above matters or estimate any potential loss. In addition, if the PBGC did look solely to PGE to pay any amount with respect to the Enron Plan, PGE would exercise all legal rights, if any, available to it to defend against such a demand and to recover any contributions from the other solvent members of the controlled group. No reserves have been established by PGE for any amounts related to this issue.

Minimum Funding Obligation
If the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in the amount of the missed funding automatically arises against the assets of every member of the controlled group. The lien is in favor of the plan, but may be enforced by the PBGC. The PBGC may perfect the lien by appropriate filings. PGE management believes that

the lien would not take priority over other previously perfected liens on the assets of a member of the controlled group. If Enron does not timely satisfy its minimum funding obligation in excess of $1 million, a lien will arise against the assets of PGE and all other members of the Enron controlled group. The PBGC would be entitled to perfect the lien and enforce it in favor of the Enron Plan against the assets of PGE and other members of the Enron controlled group. However, substantially all of PGE's assets are subject to a prior perfected lien in favor of the holders of its First Mortgage Bonds. PGE management believes that any lien asserted by the PBGC would be subordinate to that lien.

Based on discussions with Enron management, PGE's management understands that Enron has made all required contributions to date. PGE does not know if Enron will make contributions as they become due. PGE management is unable to predict if Enron will miss a payment and, if so, whether the PBGC would seek to have PGE make any or all of the payment. If the PBGC did look solely to PGE to pay the missed payment, PGE would exercise all legal rights, if any, available to it to defend against such a demand and to recover contributions from the other solvent members of the Enron controlled group. Until Enron misses contributions exceeding $1 million, PGE has no liability and no liens will arise against any PGE property. Other members of Enron's controlled group could, to the extent of any legal rights available to them, seek contribution from PGE for their payment of any missed payments demanded by the PBGC. No reserves have been established by PGE for any amounts related to this issue.

Retiree Health Benefits

PGE management understands, based on discussions with Enron management, that Enron maintains a group health plan for certain of its retirees. If retirees of Enron lose coverage under Enron's group health plan for retirees due to Enron's bankruptcy proceedings, the retirees must be provided the opportunity to purchase continuing coverage (known as COBRA Coverage) from an Enron group health plan, if any, or the appropriate group health plan of another member of the controlled group. The liability for benefits under the Enron group health plan for retirees (other than the potential liability to provide COBRA Coverage) is not a joint and several obligation of other members of the Enron controlled group, including PGE, so PGE would not be required to assume from Enron, or otherwise pay, any liabilities from the Enron group health plan. Neither PGE nor any other member of Enron's controlled group would be required to create new plans to provide COBRA Coverage for Enron's retirees, and the retirees would not be entitled to choose the plan from which to obtain coverage. Retirees electing to purchase COBRA Coverage would be provided the same coverage that is provided to similarly situated retirees under the most appropriate plan in the Enron controlled group. Retirees electing to purchase COBRA Coverage would be required to pay for the coverage, up to an amount not to exceed 102% of the cost of coverage for similarly situated beneficiaries. Retirees are not required to acquire COBRA Coverage. Retirees will be able to shop for coverage from third party sources and determine which is the least expensive coverage.

PGE management believes that in the event Enron terminates retiree coverage, any material liability to PGE associated with Enron retiree health benefits is unlikely for two reasons. First, based on discussions with Enron management, PGE management understands that most of the retirees that would be affected by termination of the Enron plan are from solvent members of the controlled group and few, if any, live in Oregon. PGE management believes that it is unlikely that any PGE plans would be found to be the most appropriate to provide COBRA coverage. Second, even if a PGE plan were selected, PGE management believes that retirees in good health should be able to find less expensive coverage from other providers, which will reduce the number of retirees electing COBRA Coverage. PGE management believes that the additional cost to PGE to provide COBRA Coverage to a limited number of retirees that are unable to acquire other coverage because they are difficult to insure or have preexisting conditions will not be material. No reserves have been established by PGE for any amounts related to this issue.

Income Taxes

Under regulations issued by the U.S. Treasury Department, each member of a consolidated group during any part of a consolidated federal income tax return year is severally liable for the tax liability of the consolidated group for that year. PGE became a member of Enron's consolidated group on July 2, 1997, the date of Enron's merger with PGC. Based on discussions with Enron's management, PGE management understands that Enron has treated PGE as having ceased to be a member of Enron's consolidated group on May 7, 2001 and becoming a member of Enron's consolidated group once again on December 24, 2002. On December 31, 2002, PGE and Enron entered into a tax allocation agreement pursuant to which PGE agreed to make payments to Enron that approximate the income taxes for which PGE would be liable if it were not a member of Enron's consolidated group. Due to the uncertainty with the reconsolidation during 2003, PGE held certain tax payments due Enron. Enron obtained an agreement from the IRS on February 2, 2004 stipulating that PGE did become a member of the Enron consolidated group on December 24, 2002. PGE resumed tax payments due Enron in early 2004.

Enron's management has provided the following information to PGE:

A. Enron's consolidated tax returns through 1995 have been audited and are closed.

B. The IRS has completed an audit of Enron's consolidated tax returns for 1996-2001. For years 1996 through 1999, Enron and its subsidiaries generated substantial net operating losses (NOLs). For 2000, Enron and its subsidiaries paid an alternative minimum tax. Enron's 2001 consolidated tax return showed a substantial net operating loss, which was carried back to the tax year 2000, for which Enron seeks a tax refund for taxes paid in 2000. The 2001 loss is also expected to provide Enron and its subsidiaries with substantial NOLs which may be used to offset additional income tax liabilities that may result from future IRS audits for the taxable periods PGE was a member of Enron's consolidated federal income tax returns.

C. Enron's 2003 tax return was filed on September 14, 2004. As noted in paragraph

B. above, Enron expects to have substantial NOLs from operations in years preceding 2003. Enron had 2003 NOLs sufficient to eliminate Enron's regular income tax and alternative minimum income tax liabilities for 2003. Enron expects to file its 2004 tax return on or before September 15, 2005 and expects to have sufficient NOLs to eliminate its regular income tax for 2004, but expects to pay alternative minimum tax with respect to that year. For calendar year 2005, Enron expects that it will have sufficient NOLs to eliminate regular income tax should it earn positive taxable income for the year. However, such taxable income, if realized, could be subject to the alternative minimum tax.

On March 28, 2003, the IRS filed various proofs of claim for taxes in the Enron bankruptcy, including a claim for approximately $111 million with respect to income tax, interest, and penalties for taxable years in which PGE was included in Enron's consolidated tax return. The IRS has amended the proof of claim to reduce it to $20 million. The IRS and Enron reached a settlement on Enron's 1996-2001 tax liability on January 5, 2005. The settlement, which indicates no net taxes due by Enron to the IRS, eliminates any further assessment of tax, interest or penalties for the years 1996-2001 against PGE and any other member of the consolidated group in those years in excess of the overpayment currently held by the IRS.

With respect to periods after 2001, PGE is potentially severally liable for post-petition interest, as well as any portion of the claim allowed in the bankruptcy that the IRS does not collect from the debtors.

To the extent, if any, that the IRS would look to PGE to pay any assessment not paid by Enron, PGE would exercise whatever legal rights, if any, that are available for recovery in Enron's bankruptcy proceeding, or to otherwise seek to obtain contributions from the other solvent members of the consolidated group. As a result, management believes the income tax, interest, and penalty exposure to PGE (related to any future liabilities from Enron's consolidated tax returns during the period PGE was a member of Enron's consolidated returns) would not be material. No reserves have been established by PGE for any amounts related to this issue.

PGE management cannot predict with certainty what impact the Chapter 11 Plan may have on PGE. However, the assets and liabilities of PGE will not become part of the Enron estate in bankruptcy.

Threatened Litigation - Non-Qualified Benefit Plans
In 1983, PGE adopted certain non-qualified deferred compensation arrangements and associated "rabbi" trusts for the benefit of key employees, officers, and directors. In 1989, sponsorship of these arrangements was transferred to PGC (which was subsequently merged into Enron in 1997) and in 1997 sponsorship was transferred to PGH. Although plan sponsorship was transferred, PGE continued to participate in these plans as a participating employer for the benefit of its own employees. PGC, PGH, and certain of their subsidiary companies also had employees who participated in these plans. The plan documents specifically provide that: (1) a participating employer's obligation under the

plans shall be that of an unfunded and unsecured promise to pay money in the future; and, (2) the payment of a participant's benefit pursuant to the plan shall be borne solely by the participating employer that employs the participant and reports the participant as being on its payroll during the accrual or increase of the plan benefit, and no liability for the payment of any plan benefit shall be incurred by reason of plan sponsorship or participation except for the plan benefits of a participating employer's own employees. Upon the bankruptcy filing by Enron and certain of its affiliates, and the subsequent bankruptcy filing of PGH, payment by those companies of participant benefits under these plans ceased. Since PGE is not in bankruptcy, benefit payments to participants due benefits from PGE have continued. Plan participants with benefits due from the bankrupt companies sought to have the companies or the trusts commence payments without success. Certain of these Plan participants indicated their intention to commence a lawsuit against PGE and other parties if they are unable to reach a resolution with respect to their benefit payments. Enron and representatives of the plan participants reached a settlement that was approved by the Bankruptcy Court on February 24, 2005. The settlement included a release of any claims against PGE by the plan participants. Under the settlement, PGE received approximately $8.4 million (net of tax) in compensation for assuming the administration and payment of non-qualified benefit plan obligations for certain PGH plan participants.

Complaint to OPUC - Income Taxes

On March 7, 2003, the URP and Linda K. Williams (Complainants) filed a petition to open an investigation and a complaint with the OPUC with respect to the amount of federal, state, and local income taxes paid by PGE since 1997. On March 31, 2003, the OPUC rejected the request for an investigation and on July 9, 2003 issued an order that dismissed the complaint. On September 22, 2003, the OPUC denied the Complainants' request for reconsideration. On December 23, 2003, the URP appealed to the Marion County Circuit Court the OPUC decision not to investigate PGE's tax payments, and on June 4, 2004 the Court reversed the OPUC decision and remanded the matter to the OPUC to proceed on Complainants' allegation that the estimates included in rates for taxes was based on fraud and deceit. On April 5, 2005, the Complainants voluntarily withdrew their complaint, and on April 26, 2005 the OPUC entered an order dismissing the complaint and closing the matter.

Class Action Lawsuit - Multnomah County Business Income Taxes

On January 18, 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MBIT) after 1996. The plaintiffs allege that during the period 1997 through the third quarter 2004, PGE collected in excess of $6 million from its customers for MBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs seek a judgment against PGE for restitution of MBIT collected from customers. Plaintiffs also seek interest, recoverable costs, and reasonable attorney fees. The Plaintiffs filed an amended complaint on February 25, 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages. On February 24, 2005, PGE requested a declaratory ruling from the OPUC on this matter. On March 24, 2005, PGE filed in the Circuit Court a motion to abate or in the alternative to dismiss. Management cannot predict the ultimate outcome of this matter.

<u>Legal Proceedings</u>
For further information regarding the following proceedings, see PGE's 2004 Annual Report on Form 10-K and other reports filed with the SEC since its 2004 Form 10-K was filed.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court Case No. 03C 10640.

On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court seeking to overturn the Class Certification. On May 3, 2005, the Oregon Supreme Court granted both Petitions. The parties will file briefs on both Petitions over the next few months. Oral argument before the Oregon Supreme Court is expected in the fall of 2005.

David Kafoury, an individual, and Kafoury Brothers, LLC, an Oregon Limited Liability Corporation, each as representative of class, etc. v. Portland General Electric Company, Multnomah County Circuit Court for the State of Oregon, Case No. 0501-00627

On March 24, 2005, PGE filed a motion to abate or in the alternative dismiss.

Wah Chang, a division of TDY Industries, Inc. v. Avista Corporation, Avista Energy, Inc., Avista Power, LLC, Dynegy Power Marketing, Inc., El Paso Electric Company, IDACORP, Inc., Idaho Power Company, IDACORP Energy L.P., Portland General Electric Company, Powerex Corporation, Puget Energy, Inc., Puget Sound Energy, Inc., Sempra Energy, Sempra Energy Resources, Sempra Energy Trading Corp., Williams Power Company, Inc., United States District Court for the District of Oregon, Case No. 04-CV-00619-AS.

On March 10, 2005, a notice of appeal was filed in the Ninth Circuit Court of Appeals.

City of Tacoma, Department of Public Utilities, Dreyer, Light division v. American Electric Power Service Corporation, Quila Holdings, LLC, Aquila Power Corporation, Arizona Public Service Company, Automated Power Exchange, Inc., Avista Corporation, et. al., United States District Court for the Western District of Washington, Case No. C07-5325 RBL.

On March 10, 2005, a notice of appeal was filed in the Ninth Circuit Court of Appeals.

Exhibit "G"

Portland General Electric Company and Subsidiaries
Consolidated Statement of Income
(Unaudited)
For the Three Months Ended March 31, 2005
(Millions of Dollars)

	March 31, 2005	Adjustments (1) (In Millions)	Adjusted Total
Operating Revenues	$371		$371
Operating Expenses			
Purchased power and fuel	142		142
Production and distribution	28		28
Administrative and other	38		38
Depreciation and amortization	60		60
Taxes other than income taxes	20		20
Income taxes	30		30
	318		318
Net Operating Income	$53		$53
Other Income (Deductions)			
Miscellaneous	2		2
Income taxes	1		1
	$3		$3
Interest Charges			
Interest on long-term debt and other	$18		$18
Net Income before cumulative effect of a change in accounting principle	$64		$64
Cumulative effect of a change in accounting principle, net of related taxes of $(1)	0		0
Net Income (Loss)	$64		$64
Preferred Dividend Requirement	0		0
Income (Loss) Available for Common Stock	$64		$64

(1) Adjusting entries are not currently available.

Exhibit "H"

Portland General Electric Company and Subsidiaries
Consolidated Statement of Retained Earnings
(Unaudited)
For the Three Months Ended March 31, 2005
(Millions of Dollars)

	March 31, 2005	Adjustments (1) (In Millions)	Adjusted Total
Balance at Beginning of Period	$637		$637
Net Income (Loss)	38		38
	675		675
Dividends Declared			
Preferred stock	0		0
Balance at End of Period	$675		$675

(1) Adjusting entries are not currently available.

Appendix B

REQUIRED INFORMATION FOR ORS 757.511 APPLICATION

A. The following information is required by ORS 757.511 and the governing Commission rule (OAR 860-027-0200):

1. **Identity and Financial Ability of Disputed Claims Reserve (ORS 757.511(2)(a))**

   (a) *The applicant's identity and financial ability*

   The Application is filed by SFC as Disbursing Agent on behalf of the Disputed Claims Reserve. The Reserve has no debt. It will hold assets in trust/escrow for the benefit of Holders of Allowed and Disputed Claims. The expenses of the Reserve are provided for by the Plan.

2. **Background of Key Personnel of Applicant (ORS 757.511(2)(b))**

   (b) *The background of the key personnel associated with the applicant*

   The key personnel of the Reserve are the Disbursing Agent, SFC, and the DCR Overseers. For background information regarding SFC and the DCR Overseers, see Sections II(A) and V(A), and Exhibit 8 of the Application.

3. **Source and Amount of Funds (ORS 757.511(2)(c))**

   (c) *The source and amounts of funds or other consideration to be used in the acquisition*

   The issuance of New PGE Common Stock is not an acquisition for which an acquisition price or acquisition funding is necessary. The payment of the Reserve's expenses associated with the issuance of New PGE Common Stock are provided for under the Plan.

4. **Compliance with Federal Law (ORS 757.511(2)(d))**

   (d) *The applicant's compliance with federal law in carrying out the acquisition*

   Any required applications will be filed with the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Nuclear Regulatory Commission, and the Federal Communications Commission.

5. **Violations of Statutes (ORS 757.511(2)(e))**

   (e) Whether the applicant or the key personnel associated with the applicant have violated any state or federal statutes regulating the activities of public utilities

   Neither the Reserve nor any of the key personnel associated with the Reserve has violated any state or federal statutes regulating the activities of public utilities.

6. **All Documents Relating to Transaction (ORS 757.511(2)(f))**

   (f) All documents relating to the transaction giving rise to the application

   The documents giving rise to this application are the Plan, Plan Supplement, and the Confirmation Order. The Plan and Plan Supplement are provided on diskette to the Commission as part of this Application. The Plan, Plan Supplement, and Confirmation are available on Enron's website at www.enron.com.

7. **Experience in Operation of a Public Utility (ORS 757.511(2)(g))**

   (g) The applicant's experience in operating public utilities providing heat, light or power

   The Reserve has no formal utility experience. The Reserve is formed for the purpose of holding assets (including New PGE Common Stock) for the benefit of Holders of Allowed and Disputed Claims as provided under the Plan.

8. **Plan for Operating PGE (ORS 757.511(2)(h))**

   (h) The applicant's plan for operating the public utility

   See Sections IV and V of the Application.

9. **Public Interest Considerations (ORS 757.511(2)(i))**

   (i) How the acquisition will serve the public utility's customers in the public interest

   See section VII of the Application.

B. The following information is required by OAR 860-027-0200(1), which incorporates certain sections of OAR 860-027-0030:

1. **Applicant Information (OAR 860-027-0030(1)(a))**

(a) *The applicant's exact name and the address of its principal business office*

Disputed Claims Reserve
c/o Stephen Forbes Cooper, LLC
101 Eisenhower Parkway
Roseland, New Jersey 077068

2. **Incorporation Information and where authorized to do business (OAR 860-027-0030(1)(b))**

(b) *The state in which incorporated, the date of incorporation, and the other states in which authorized to transact utility business*

The Reserve is an entity created by the Plan to carry out the terms of the Plan. It has no state of incorporation or origination.

3. **Notices (OAR 860-027-0030(1)(c))**

(c) *Name and address of person authorized, on behalf of applicant, to receive notices and communications in respect to application*

Mitchell S. Taylor
Enron Corp.
1221 Lamar Street
Suite 1600
Houston, Texas 77251
mitch.taylor@enron.com

Michael M. Morgan
Tonkon Torp LLP
1600 Pioneer Tower
888 SW 5th Avenue
Portland, Oregon 97204
mike@tonkon.com

4. **Principal Officers (OAR 860-027-0030(1)(d))**

(d) *The names, titles and addresses of the principal officers of the applicant*

The Reserve has no officers. For information regarding SFC and the DCR Overseers, see Sections II(A) and V(A), and Exhibit 8 of the Application. The address of the Reserve, SFC and the DCR Overseers are:

Disputed Claims Reserve
c/o Stephen Forbes Cooper, LLC
101 Eisenhower Parkway
Roseland, New Jersey 077068

The following information is required by OAR 860-027-0200(2)-(8):

5. Capital Structure of PGE (current and pro forma 12 months after issuance of New PGE Common Stock) (OAR 860-027-0200(2))

A schedule detailing the existing capital structure of the energy utility to be acquired, as well as a pro forma utility capital structure as of 12 months after the acquisition is to be completed

Capital Structure
$Million

	Actuals As of 12/31/2004		Pro Forma As of 4/30/2007	
Long Term Debt	881	40.42%	1,063	48.29%
Preferred Stock	20	0.94%	15	0.68%
Common Equity	1,278	58.64%	1,123	51.03%
Total	2,180	100.00%	2,201	100.00%

6. Impact, if any, on Bond Ratings and Capital Costs (OAR 860-027-0200(3))

An explanation of how the bond ratings and capital costs of the acquired utility will be affected by the acquisition

The issuance of New PGE Common Stock is not expected to affect PGE's bond ratings or PGE's capital costs.

7. Affiliated Interests and Organizational Structure (OAR 860-027-0200(4))

A description of existing and planned nonutility businesses which are or will become affiliated interest of the acquired utility under ORS 757.015, and a description of the organizational structure under which the applicant intends to operate its businesses

The issuance of the New PGE Common Stock will create no new PGE affiliated interest other than the Reserve. The Reserve is created by the Plan to carry out the terms of the Plan. It has no other business.

8. **Allocation of Applicant's resources between utility and non-utility operations (OAR 860-027-0200(5))**

A description of the method by which management, personnel, property, income, losses, costs, and expenses will be allocated by the applicant between its utility and nonutility operations (if applicable)

The Reserve will not allocate expenses to PGE.

9. **Planned Changes that may impact utility (OAR 860-027-0200(6))**

A description of any planned changes that may have a significant impact upon the policy, management, operations, or rates of the energy utility

For information regarding the governance and operation of PGE after the issuance of New PGE Common Stock, see section IV of the Application. The Reserve does not currently plan to make changes that would have a significant impact on the policy, management, operations, or rates of PGE.

10. **Disposition of Utility Assets (OAR 860-027-0200(7))**

A description of any plans to cause the energy utility to sell, exchange, pledge, or otherwise transfer its assets;

For information regarding the governance and operation of PGE after the issuance of New PGE Common Stock, see section IV of the Application. The Reserve has no plans to sell, exchange, pledge, or otherwise transfer any of PGE's assets.

11. **Agreements with Affiliated Interests (OAR 860-027-0200(8))**

A copy of any existing or proposed agreement between the energy utility and any businesses which will become affiliated interests of the acquired utility under ORS 757.015

There are no existing or proposed agreements between PGE and any business that will become a PGE affiliate as a result of the issuance of New PGE Common Stock.

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UNITED STATES BANKRUPTCY COURT
SOUTHERN DISTRICT OF NEW YORK

In re:	Chapter 11
ENRON CORP., *et al.*,	Case No. 01-16034 (AJG)
Debtors.	(Jointly Administered)

ORDER CONFIRMING SUPPLEMENTAL MODIFIED FIFTH AMENDED JOINT PLAN OF AFFILIATED DEBTORS PURSUANT TO CHAPTER 11 OF THE UNITED STATES BANKRUPTCY CODE, AND RELATED RELIEF

The Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 (the "Fifth Amended Plan"), as thereafter amended pursuant to that certain (1) Modification of Fifth Amended Plan of Reorganization for Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated June 1, 2004 (the "Initial Modification") (Docket No. 18793), and (2) Supplemental Modification of Fifth Amended Joint Plan of Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated July 2, 2004 (the "Supplemental Modification" and, together with the Fifth Amended Plan and the Initial Modification, the "Plan") [1] (Docket No. 19477), having been filed with the Court by ENE and certain of its direct and indirect subsidiaries and affiliates, as debtors and debtors in possession (collectively, the "Debtors") [2]; and the Court having entered, pursuant to, *inter alia*,

[1] A copy of the Plan is annexed hereto as Exhibit A. Unless otherwise defined, capitalized terms used herein shall have the meanings ascribed to such terms in the Plan.

[2] As set forth in Section 7.9 of the Initial Modification, pursuant to the Bankruptcy Court's order, dated April 8, 2004, and the notice, dated May 17, 2004, in connection therewith (Docket Nos. 17625 and 18434), (a) a majority of the equity interests of Enron Mauritius Company, Enron India Holdings Ltd. and Offshore Power Production C.V. (collectively, the "Dabhol Debtors") were sold, (b) such entities were, among other things, removed as Debtors and Proponents of the Plan, and (c) Classes 58, 59, 60, 246, 247 and 248 of the Plan have been rendered unnecessary and inoperative.

section 1125 of the Bankruptcy Code and Bankruptcy Rule 3017(b), after due notice and hearing, orders, dated January 9, 2004, approving the Disclosure Statement for Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 (the "Disclosure Statement"), and establishing procedures for voting on the Fifth Amended Plan, respectively (collectively, the "Disclosure Statement Approval Orders"), which established procedures for the solicitation, voting and tabulation of votes on the Fifth Amended Plan, approved the forms of ballots and master ballots used in connection therewith, and scheduled the Confirmation Hearing to consider confirmation of the Fifth Amended Plan pursuant to sections 1128 and 1129 of the Bankruptcy Code; and the affidavits of service of solicitation packages and notices of non-voting status (the "Affidavits of Service") having been filed with the Court; and the affidavits of publication of notice of the Confirmation Hearing (the "Affidavits of Publication") having been filed with the Court; and due notice of the Confirmation Hearing having been given to holders of Claims against and Equity Interests in the Debtors and to other parties in interest, all in accordance with the Bankruptcy Code, the Bankruptcy Rules and the Disclosure Statement Approval Orders, and it appearing that no other or further notice need be given; and the Confirmation Hearing having been held by the Court on June 3, 4, 8, 9, 10, 14, 16, 17 and 18, 2004; and the appearances of all interested parties having been noted in the record of the Confirmation Hearing; and after full consideration of: (a) each of the objections to confirmation of the Plan not otherwise withdrawn or resolved (collectively, the "Objections"), (b) the Debtors' response and memorandum of law in support of confirmation of the Plan, each

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In addition, as stated on the record at the Confirmation Hearing, the Debtors and the Creditors' Committee have reached a settlement in principal, subject to definitive documentation and Bankruptcy Court approval, with certain former employees of Portland General Holdings ("PGH"). Consequently, the Confirmation Hearing was adjourned with respect to the Portland Debtors, and the Debtors may move to dismiss one or both of the Portland Debtors' cases upon approval of the settlement by the Bankruptcy Court.

dated June 1, 2004 (Docket Nos. 18797 and 18798), (c) the Creditors' Committee's statement, dated June 1, 2004 (Docket No. 18795), (d) the Baupost Group and Racepoint Partners' comment, dated June 1, 2004 (Docket No. 18786), (e) the ENA Examiner's citations to the record, dated June 22, 2004 (Docket No. 19283), (f) the Debtors' proposed findings of fact and conclusions of law, dated June 23; 2004 (Docket No. 19307), (g) various counter-proposed findings of fact and conclusions of law filed by multiple parties in interest on June 29 – July 1, 2004 (Docket Nos. 19407, 19408, 19420, 19423, 19424, 19428, 19429, 19430, 19432, 19433, 19438, 19451 and 19453), and (h) the Debtors' reply to the various counter-proposed findings of fact and conclusions of law, dated July 7, 2004, and the Debtors' modified proposed findings of fact and conclusions of law, dated July 7, 2004 (Docket Nos. 19532 and 19533, respectively); and upon the arguments of counsel and all of the evidence adduced at the Confirmation Hearing and the record in these Chapter 11 Cases; and after due deliberation and good and sufficient cause appearing therefore; and the Court having rendered its decision to CONFIRM the Plan and entered its findings of fact and conclusions of law on July 15, 2004,

It hereby is DECREED AND ORDERED:

JURISDICTION

1. This Court has subject matter jurisdiction to confirm the Plan pursuant to 28 U.S.C. § 1334.

2. Venue is proper before this Court pursuant to 28 U.S.C. §§ 1408 and 1409.

3. Confirmation of the Plan is a core proceeding determined by this Court pursuant to 28 U.S.C. § 157(b)(2)(L).

MODIFICATIONS TO THE PLAN

4. The Plan complies with section 1127 of the Bankruptcy Code.

5. On June 1, 2004 and July 2, 2004, the Debtors filed the Initial Modification and the Supplemental Modification (Docket Nos. 18793 and 19477), respectively.

6. The Initial Modification and the Supplemental Modification (collectively, the "Modifications") do not adversely affect the treatment of any Class of Claims or Equity Interests in the Debtors under the Fifth Amended Plan.

7. In accordance with section 1127 of the Bankruptcy Code and Bankruptcy Rule 3019, all holders of Claims against the Debtors who voted to accept the Plan are hereby deemed to have accepted the Fifth Amended Plan, as amended consistent with the Modifications.

8. No holder of a Claim against the Debtors that has voted to accept the Fifth Amended Plan shall be permitted to change its acceptance to a rejection as a consequence of the Modifications.

9. The filing with the Court of the Modifications, the service of the same in accordance with the Court's Case Management Order, and the disclosure of the Modifications on the record at the Confirmation Hearing constitute due and sufficient notice thereof.

CONFIRMATION OF THE PLAN

10. The Plan complies fully with sections 1122 and 1123 of the Bankruptcy Code. The Debtors have complied with section 1125 with respect to the Disclosure Statement and the Plan.

11. The Findings of Fact and Conclusions of Law Supporting The Approval Of (A) Certain Settlements Under The Supplemental Modified Fifth Amended Joint Plan Of Affiliated Debtors Pursuant To Chapter 11 Of The United States Bankruptcy Code; (B) The

Debtors' Motion Pursuant To Bankruptcy Rule 9019 And Sections 105 And 363 Of The Bankruptcy Code Seeking Approval Of The Global Compromise Of Inter-Estate Issues; (C) The Motion Of Debtors Pursuant To Section 363 Of The Bankruptcy Code For Order Approving And Authorizing Post-Confirmation Allocation Formula For Overhead And Expenses; And (D) Confirmation Of The Plan, dated July 15, 2004, (the "Findings and Conclusions") are hereby incorporated by reference into, and are an integral part of, this Confirmation Order.

12. The Plan is CONFIRMED.

PLAN PROVISIONS

Implementation of the Plan

13. The compromise and settlement set forth in Section 2.1 of the Plan is approved in all respects. On the Effective Date, such compromise and settlement shall be binding upon the Debtors, all Creditors, all holders of Equity Interests and other Entities.

14. From and after the Effective Date, holders of Allowed Claims and Allowed Equity Interests shall receive a portion of their distributions based upon the assets and liabilities of all the Debtors, other than the Portland Debtors.[3] Any Claims against one or more of the Debtors based upon a guaranty, indemnity, co-signature, surety or otherwise, of Claims against another Debtor shall be treated as separate and distinct Claims against the estate of the respective Debtors and shall be entitled to distributions under the Plan in accordance with the provisions thereof.

[3] Although not excluded from the Plan, Enron Development Funding Limited ("EDF"), a Debtor, is also the subject of insolvency proceedings in the Cayman Islands. (Stipulation And Agreed Order Establishing Procedures For Compensation And Reimbursement Of Expenses For Professionals Of Enron Development Funding Limited And Its Joint Provisional Liquidators, dated June 26, 2003, Docket No. 11953). In light of the joint proceedings, until such time as the Cayman scheme of arrangement proceedings has concluded, currently anticipated to be in August 2004, no distributions of assets held by or attributed to EDF will be made to Creditors holding Allowed Claims pursuant to the Plan.

15. The record date for determining the holders of Allowed Claims and Allowed Equity Interests entitled to receive distributions under the Plan shall be the date of the entry of this Confirmation Order.

16. Within thirty (30) days following the second (2^{nd}) anniversary of the Effective Date, the Reorganized Debtors shall file a list with the Court setting forth the names of those Entities for which distributions have been made under the Plan and have been returned as undeliverable as of the date thereof. Any holder of an Allowed Claim or Allowed Equity Interest set forth on such list and that does not assert its rights pursuant to the Plan to receive a distribution within three (3) years from and after the Effective Date shall have its entitlement to such undeliverable distribution discharged and shall be forever barred from asserting any entitlement pursuant to the Plan against the Reorganized Debtors or their property. In such case, any consideration held for distribution on account of such Claim or Equity Interest shall revert to the Reorganized Debtors for redistribution to holders of Allowed Claims and Allowed Equity Interests in accordance with the provisions of Section 32.1 of the Plan.

17. Subject to the provisions of Bankruptcy Rule 9010 and the TOPRS Stipulation, and except as provided in Section 32.4 of the Plan, distributions and deliveries to holders of Allowed Claims shall be made at the address of each such holder as set forth on the Schedules filed with the Court unless superseded by the address set forth on proofs of claim filed by such holders, or at the last known address of such a holder if no proof of claim is filed or if the Debtors have been notified in writing of a change of address or at the address provided in any applicable notice of transfer filed with the Clerk of the Court pursuant to Bankruptcy Rule 3001(e) and served upon the Debtors or the Reorganized Debtors, as the case may be, in accordance with the notice provision set forth in Section 42.16 of Plan. Subject to the provisions

of Section 9.1 of the Plan and the TOPRS Stipulation, distributions for the benefit of holders of Enron Senior Notes shall be made to the appropriate Enron Senior Notes Indenture Trustee. Each such Enron Senior Notes Indenture Trustee shall in turn administer the distribution to the holders of Allowed Enron Senior Note Claims in accordance with the provisions of the Plan and the applicable Enron Senior Notes Indenture. The Enron Senior Notes Indenture Trustee shall not be required to give any bond or surety or other security for the performance of their duties unless otherwise ordered by the Court.

18. Pursuant to sections 1123(a) and 1142(a) of the Bankruptcy Code and the provisions of this Confirmation Order, the Plan, and all Plan-related documents (including, but not limited to, the Plan Supplement) shall apply and be enforceable notwithstanding any otherwise applicable nonbankruptcy law.

19. The respective forms of the Reorganized Debtors Certificate of Incorporation and the Reorganized Debtors By-laws set forth or referenced in Schedules P and Q of the Plan Supplement are approved. On the Effective Date, such applicable forms of Reorganized Debtors Certificate of Incorporation and Reorgariized Debtors By-laws, with any changes to conform to each Reorganized Debtor's respective entity type, capital structure, jurisdictional requirements, governance requirements, and economic requirements deemed necessary, appropriate or advisable by (a) the President, any Associate Director, any Vice President, any Managing Director, the General Counsel or any Associate General Counsel, of the applicable Reorganized Debtor, if such Reorganized Debtor has officers; (b) any general partner of such Reorganized Debtor, if such Reorganized Debtor is a general partnership or limited partnership; (c) any managing member of such Reorganized Debtor, if such Reorganized Debtor is a limited liability company; or (d) the board of directors of such Reorganized Debtor, if such

Reorganized Debtor has directors, shall be authorized and approved as (1) the certificate or articles of incorporation and bylaws, respectively, in the case of a Reorganized Debtor that is a corporation incorporated under the laws of one of the United States of America; (2) the certificate or articles of formation and limited liability company agreement, respectively, in the case of a Reorganized Debtor that is a limited liability company under the laws of one of the United States of America; (3) the certificate or articles of limited partnership and limited partnership agreement, respectively, in the case of a Reorganized Debtor that is a limited partnership under the laws of one of the United States of America; (4) the general partnership agreement (which, unless otherwise agreed to, in writing, by the Debtors and the Creditors' Committee, shall each be on the same terms as the form of limited partnership agreement set forth in Schedule P to the Plan Supplement), in the case of a Reorganized Debtor that is a general partnership under the laws of one of the United States of America; (5) memorandum of association and articles of association, respectively, in the case of a Reorganized Debtor that is a Cayman Islands limited company; and (6) charter, in the case of a Reorganized Debtor formed under the laws of the Netherlands, of each Reorganized Debtor, without further action under applicable law, regulation, order, rule or agreement, including, without limitation, any action by the shareholders, stockholders, officers, members, partners, board of directors or managers, as applicable, of such Reorganized Debtor. Without limiting the approval and authority granted in the foregoing sentence, each officer, director, managing director, general counsel, associate general counsel, partner, member and manager, as the case may be, of each Reorganized Debtor is hereby, authorized, empowered, and directed, for and on behalf and in the name of the Reorganized Debtor of which it is an officer, director, managing director, general counsel, associate general counsel, partner, member or manager, as the case may be, without further action or approval, of any shareholder, stockholder, officer, board of directors, manager, member or partner, as the case may be, to take any further action and to do all things it may deem necessary, appropriate or advisable to effect the amendment and/or restatement of the organizational documents of the respective Reorganized Debtors described in the foregoing sentence, (collectively, the "Organizational Documents"), including, without limitation, executing documents, agreements and certificates, filing, as applicable, the Organizational Documents of each Reorganized Debtor with the appropriate governmental authority and paying any filing fees in connection therewith, placing copies of the applicable filed Organizational Documents in the minute book of each such Reorganized Debtor, and giving any consent on behalf of a Reorganized Debtor as a shareholder, stockholder, member or partner of another Reorganized Debtor to approve the Organizational Documents of such other Reorganized Debtor. Notwithstanding the form in the Plan Supplement, the certificate of limited partnership of a Reorganized Debtor that is a limited partnership shall contain a prohibition on the issuance of nonvoting equity securities.

20. As of the Effective Date, the boards of directors or managers of each respective Debtor, as constituted immediately prior to the Effective Date that had a board of directors or managers, are hereby removed and (a) Stephen D. Bennett, Rick A. Harrington, James R. Latimer, III, and John J. Ray, III are hereby appointed as the board of directors of Reorganized ENE to serve until their resignation or removal pursuant to the Reorganized Debtor Certificate of Incorporation of Reorganized ENE; provided, however, that, pursuant to the notice, dated June 2, 2004 (the "Director Notice") (Docket No. 18841), in the event that the Debtors select a replacement person during the period from the date hereof up to, but not including the Effective Date, such selection shall be made in a manner consistent with Section 40.1 of the Plan

and be deemed to have been made as of the date hereof; (b) Raymond M. Bowen, Jr., Robert H. Walls, Jr. and K. Wade Cline are hereby appointed as the board of directors of the Debtors listed on Exhibit B1 hereto to serve until their resignation or removal pursuant to the Organizational Documents of such Reorganized Debtor; (c) Raymond M. Bowen, Jr., Robert H. Walls, Jr., K. Wade Cline and Robert J. Semple, are hereby appointed as the board of directors of the Debtors listed on Exhibit B2 hereto, to serve until their resignation or removal pursuant to the Organizational Documents of such Reorganized Debtor; (d) each Reorganized Debtor that is a limited liability company formed under the laws of one of the United States of America that was manager or director managed immediately prior to the Effective Date shall be converted to a member managed limited liability company with the member holding the largest membership interest therein being designated as the managing member thereof; and (e) each member holding the largest membership interest in a Reorganized Debtor that is a limited liability company formed under the laws of one of the United States of America that was member managed, but did not have a designated managing member immediately prior to the Effective Date is hereby designated as the managing member of such Reorganized Debtor. Each of the individuals named in Section V of Schedule U and V of the Plan Supplement as officers of the respective Reorganized Debtors are hereby appointed to the office of each such Reorganized Debtor set forth for such individual in such Schedule, and as an officer of the same title of each of the Reorganized Debtors listed on Exhibit B3 hereto, to serve until his or her resignation or removal.

21. The cancellation of all Equity Interests and other matters provided under the Plan involving the corporate structure of the Reorganized Debtors or corporate action by the Reorganized Debtors shall be deemed to have occurred, be authorized, and shall be in effect, all in accordance with the provisions of the Plan, without requiring further action under applicable

law, regulation, order, or rule, including, without limitation, any action by the shareholders, stockholders, officers, board of directors, partners, members and managers of the Debtors or the Reorganized Debtors. As a condition to receiving any distribution with respect to any Preferred Equity Trust Interest or Common Equity Trust Interest (which will not occur unless Plan Currency and Trust Interests are deemed redistributed to holders of Allowed Enron Preferred Equity Interests pursuant to Sections 7.5, 8.2, 9.2 and 17.2 of the Plan, in the case of Preferred Equity Trust Interests, and to holders of Allowed Enron Common Equity Interests pursuant to Sections 7.5, 8.2, 9.2, 17.2 and 18.2 of the Plan, in the case of Common Equity Trust Interest), each record holder of a certificate representing Enron Preferred Equity Interests or Enron Common Equity Interests, as the case may be, in exchange for which such Preferred Equity Trust Interest or Common Equity Trust Interest was allocated upon the cancellation of such Equity Interests pursuant to the Plan, shall (a) surrender such certificate to the Disbursing Agent or its designee, or (b) deliver to the Disbursing Agent or its designee an affidavit claiming such certificate to be lost, stolen or destroyed, and, if required by the Disbursing Agent, post a bond in such reasonable amount as the Disbursing Agent may direct as indemnity by such person against any claim that may be made against any Reorganized Debtor or the Disbursing Agent with respect to such certificate.

22. Notwithstanding any applicable law or contract, and except as otherwise provided in the Plan, no Debtor shall be deemed removed as a member or partner of a limited liability company or limited partnership, respectively, nor shall any limited liability company or limited partnership be deemed to have been dissolved, or be in dissolution, as a result of filing a voluntary petition for bankruptcy in the Chapter 11 Cases.

23. Without limiting the foregoing, from and after the Confirmation Date, the Debtors, the Reorganized Debtors and the Reorganized Debtor Plan Administrator may take any and all actions deemed appropriate in order to consummate the transactions contemplated herein, including, without limitation, selling or otherwise disposing of all of the Reorganized Debtors' assets and winding-up their respective affairs and not engaging in business (except to the extent reasonably necessary to, and consistent with, such purpose). Notwithstanding any provision contained in the Debtors' organizational or charter documents, or the Reorganized Debtors' Organizational Documents, as the case may be to the contrary, such Entities shall not require the affirmative vote of holders of Equity Interests to take any corporate action including to (a) consummate a Sale Transaction, (b) compromise and settle claims and causes of action of or against the Debtors and their chapter 11 estates, and (c) dissolve, merge or consolidate with any other Entity.

24. This Confirmation Order hereby incorporates, without modification, each provision of the Court's order, dated February 5, 2004 (the "PGE Sale Order"), pursuant to sections 105 and 363 of the Bankruptcy Code and Bankruptcy Rule 6004(a), authorizing and approving the terms and conditions of that certain Stock Purchase Agreement, dated as of November 18, 2003, by and between ENE and Oregon Electric Utility, LLC, for the sale by ENE of all the issued and outstanding shares of PGE (the "PGE Purchase Agreement"), and Reorganized ENE or the PGE Trust, to the extent created pursuant to the provisions of the Plan, shall be bound in accordance with the terms of the PGE Purchase Agreement and the PGE Sale Order as if it were deemed "Seller" thereunder.

25. Pursuant to section 1145 of the Bankruptcy Code, issuance of the Plan Securities, the Litigation Trust Interests and the Special Litigation Trust Interests on account of,

and in exchange for, the Claims against the Debtors are exempt from registration pursuant to section 5 of the Securities Act of 1933 and any other applicable nonbankruptcy law or regulation.

26. Pursuant to section 1146(c) of the Bankruptcy Code, the issuance, transfer or exchange of notes, Equity Interests, Plan Securities, Exchanged Enron Common Stock or Exchanged Enron Preferred Stock pursuant to the Plan, the creation of any mortgage, deed of trust, or other security interest, the making or assignment of any lease or sublease, or the making or delivery of any deed or other instrument of transfer under, in furtherance of, or in connection with the Plan, shall not be subject to any stamp, real estate transfer, mortgage recording or other similar tax. All filing or recording officers, wherever located and by whomever appointed, are hereby directed to accept for filing or recording, and to file or record immediately upon presentation thereof, all such deeds, bills of sale, mortgages, leasehold mortgages, deeds of trust, leasehold deeds of trust, memoranda of lease, notices of lease, assignments, leasehold assignments, security agreements, financing statements, and other instruments of absolute or collateral transfer without payment of any stamp tax, transfer tax, or similar tax imposed by federal, state or local law, and, to the extent necessary, the Court retains jurisdiction to enforce the foregoing direction, by contempt or otherwise.

27. The Litigation Trust Agreement is approved in all respects. If and only if the Litigation Trust is formed pursuant to Section 22.1 of the Plan, Stephen Forbes Cooper, LLC is approved as Litigation Trustee and, as of the date that the Litigation Trust Agreement becomes effective, is so appointed and vested with the powers necessary and appropriate to enable the Litigation Trustee to carry out its responsibilities as defined in the Plan and the Litigation Trust Agreement. Upon the joint determination of the Debtors or the Reorganized Debtors, as the case may be, and, provided that the Creditors' Committee has not been dissolved in accordance with

the provisions of Section 33.1 of the Plan, the Creditors' Committee, on or after the Effective Date, but in no event later than December 31st of the calendar year in which the Effective Date occurs, unless such date is otherwise extended by the Debtors or the Reorganized Debtors, as the case may be, and the Creditors' Committee, in their joint and absolute discretion and by notice filed with the Court, Reorganized ENE, on its own behalf, on behalf of the other Reorganized Debtors, and on behalf of holders of Allowed Claims in Classes 3 through 190, shall execute the Litigation Trust Agreement and shall take all other steps necessary to establish the Litigation Trust; provided, however, that in the event that the board of directors of Reorganized ENE and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee determines that the aggregate distributions of Plan Currency and Trust Interests would permit a distribution to be made pursuant to Section 17.2, 18.2 or 19.2 of the Plan, then the Debtors or the Reorganized Debtors, as the case may be, shall modify the Plan to provide for such distributions to be made. If the Litigation Trust is created, in accordance with and pursuant to the terms of Article XXII of the Plan, the Debtors or the Reorganized Debtors, as the case may be, shall transfer to the Litigation Trust, (a) all of their right, title, and interest in the Litigation Trust Claims, and (b) subject to the provisions of the Post-Confirmation Allocation Formula, such amounts of Cash as jointly determined by the Debtors or the Reorganized Debtors, as the case may be, and the Creditors' Committee as necessary to fund the operations of the Litigation Trust. Notwithstanding the foregoing, for purposes of section 553 of the Bankruptcy Code, in accordance with Section 22.13 of the Plan, the transfer of the Litigation Trust Claims to the Litigation Trust shall not affect the mutuality of obligations which may have otherwise existed prior to the effectuation of such transfer. In the event that the Litigation Trust is created, Stephen D. Bennett, Rick A. Harrington, James R.

Latimer, III, and John J. Ray, III are appointed as members of the Litigation Trust Board and vested with the powers necessary and appropriate to enable the Litigation Trust Board to carry out its responsibilities as defined in the Plan and the Litigation Trust Agreement; provided, however, that pursuant to the Director Notice and unless otherwise expressly set forth, in the event that a replacement director is selected for Reorganized ENE, such selection shall be deemed to be applicable to the Litigation Trust Board.

28. The Special Litigation Trust Agreement is approved in all respects. If and only if the Special Litigation Trust is formed pursuant to Section 23.1 of the Plan, ABN Amro Bank, Calyon, as successor to Credit Lyonnais, and Wells Fargo Bank Minnesota, N.A., are hereby appointed as members of the Special Litigation Trust Board and directed to take such action as is necessary to appoint the Special Litigation Trustee. Upon the joint determination of the Debtors or the Reorganized Debtors, as the case may be, and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, on or after the Effective Date, but in no event later than December 31st of the calendar year in which the Effective Date occurs, unless such date is otherwise extended by the Debtors or the Reorganized Debtors, as the case may be, and the Creditors' Committee, in their joint and absolute discretion and by notice filed with the Court, Reorganized ENE, on its own behalf, on behalf of the other Reorganized Debtors, and on behalf of holders of Allowed Claims in Classes 3 through 190, shall execute the Special Litigation Trust Agreement and shall take all other steps necessary to establish the Special Litigation Trust; provided, however, that in the event that the board of directors of Reorganized ENE and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee determines that the aggregate distributions of Plan Currency and Trust

Interests would permit a distribution to be made pursuant to Section 17.2, 18.2 or 19.2 of the Plan, then the Debtors or the Reorganized Debtors, as the case may be, shall modify the Plan to provide for such distributions to be made. If the Special Litigation Trust is created, and in accordance with and pursuant to the terms of Article XXIII of the Plan, the Debtors or the Reorganized Debtors, as the case may be, shall transfer to the Special Litigation Trust (a) all of their right, title, and interest in the Special Litigation Trust Claims, and (b) subject to the provisions of the Post-Confirmation Allocation Formula, as defined below, such amounts of Cash as jointly determined by the Debtors or the Reorganized Debtors, as the case may be, and the Creditors' Committee as necessary to fund the operations of the Special Litigation Trust. Notwithstanding the foregoing, for purposes of section 553 of the Bankruptcy Code, the transfer of the Special Litigation Trust Claims to the Special Litigation Trust shall not affect the mutuality of obligations, which may have otherwise existed prior to the effectuation of such transfer.

29. The Operating Trust Agreements are each approved in all respects. Stephen Forbes Cooper, LLC is approved as Operating Trustee and, if and only if one or more of the Operating Trusts are established pursuant to Section 24.1 of the Plan, as of the date that each applicable Operating Trust Agreement becomes effective, is so appointed and vested with the powers necessary and appropriate to enable the Operating Trustee of the Operating Trust so formed to carry out its responsibilities as defined in the Plan and the applicable Operating Trust Agreement. Upon the joint determination of the Debtors or the Reorganized Debtors, as the case may be, and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, on or after the Confirmation Date, the Debtors or the Reorganized Debtors, as the case may be, on their own

behalf and on behalf of holders of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382 shall execute the respective Operating Trust Agreements and shall take all other steps necessary to establish the respective Operating Trusts. On such date, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental, agency or other consents, and in accordance with and pursuant to the terms of Section 24.4 of the Plan, if such trust is formed, the Debtors or the Reorganized Debtors, as the case may be, shall transfer to the respective Operating Trusts so formed all of their right, title, and interest in the assets subject to the Operating Trust Agreements. In the event that the one or more Operating Trusts is created, Stephen D. Bennett, Rick A. Harrington, James R. Latimer, III and John J. Ray, III are appointed as members of the PGE Trust Board, CrossCountry Trust Board and Prisma Trust Board, as the case may be, and vested with the powers necessary and appropriate to enable each of the aforementioned trust boards to carry out each of their respective responsibilities as defined in the Plan and each of the Operating Trust Agreements; provided, however, that pursuant to the Director Notice and unless otherwise expressly set forth, in the event that a replacement director is selected for Reorganized ENE, such selection shall be deemed to be applicable to the aforementioned trust boards.

30. The Remaining Asset Trust Agreements are approved in all respects. Stephen Forbes Cooper, LLC is approved as Remaining Asset Trustee and, if and only if the Remaining Asset Trusts are established pursuant to Section 25.1 of the Plan, as of the date that each of the Remaining Asset Trust Agreements become effective, is so appointed and vested with the powers necessary and appropriate to enable the Remaining Asset Trustee to carry out its responsibilities as defined in the Plan and the Remaining Asset Trust Agreements. If the Remaining Asset Trusts are established, Stephen D. Bennett, Rick A. Harrington, James R.

Latimer, III and John J. Ray, III are hereby appointed as members of the Remaining Asset Trust Board for each respective Remaining Asset Trust and vested with the powers necessary and appropriate to enable each of the aforementioned trust boards to carry out each of their respective responsibilities as defined in the Plan and each of the Remaining Asset Trust Agreements; provided, however, that, pursuant to the Director Notice and unless otherwise expressly set forth, in the event that a replacement director is selected for Reorganized ENE, such selection shall be deemed to be applicable to the aforementioned trust boards. Upon the joint determination of the Debtors or the Reorganized Debtors, as the case may be, and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, on or after the Confirmation Date, the Debtors or the Reorganized Debtors, as the case may be, on their own behalf and on behalf of holders of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382 shall execute the respective Remaining Asset Trust Agreements and shall take all other steps necessary to establish the respective Remaining Asset Trusts. On such date, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental agency or other consents, and in accordance with and pursuant to the terms of Article XXV of the Plan, if such trust is formed, the Debtors shall transfer to the respective Remaining Asset Trusts all of their right, title and interest in the Remaining Assets.

31. The Preferred Equity Trust Agreement is approved in all respects. Stephen Forbes Cooper, LLC is approved as Preferred Equity Trustee and, as of the date that the Preferred Equity Trust Agreement becomes effective, is so appointed and vested with the powers necessary and appropriate to enable the Preferred Equity Trustee to carry out its responsibilities as defined in the Plan and the Preferred Equity Trust Agreement. On or after the Confirmation

Date, but prior to the Effective Date, the Debtors, on their own behalf and on behalf of holders of Allowed Equity Interests in Class 383 shall execute the Preferred Equity Trust Agreement and shall take all other steps necessary to establish the Preferred Equity Trust. On such date of execution, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental, agency or other consents, and in accordance with and pursuant to the terms of Article XXVI of the Plan, if such trust is formed, Reorganized ENE shall issue to the Preferred Equity Trust the Exchanged Enron Preferred Stock subject to the Preferred Equity Trust Agreement. Notwithstanding anything contained herein or in the Plan to the contrary, there shall be separate classes of Preferred Equity Trust Interests that (a) separately reflect the distributions and other economic entitlements, and (b) maintain the following order of priority with respect to the separate classes of Exchanged Preferred Equity Interests contributed: (1) Series 1 Exchanged Preferred Stock and Series 2 Exchanged Preferred Stock on a *pari passu* basis; (2) Series 3 Exchanged Preferred Stock; and (3) Series 4 Exchanged Preferred Stock.

32. The Common Equity Trust Agreement is approved in all respects. Stephen Forbes Cooper, LLC is approved as Common Equity Trustee and, as of the date that the Common Equity Trust Agreement becomes effective, is so appointed and vested with the powers necessary and appropriate to enable the Common Equity Trustee to carry out its responsibilities as defined in the Plan and the Common Equity Trust Agreement. On or after the Confirmation Date, but prior to the Effective Date, the Debtors, on their own behalf and on behalf of holders of Allowed Enron Common Equity Interests in Class 384, shall execute the Common Equity Trust Agreement and shall take all other steps necessary to establish the Common Equity Trust. On such date of execution, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental, agency or other consents, and in accordance with and

pursuant to the terms of Article XXVII of the Plan, if such trust is formed, Reorganized ENE shall issue to the Common Equity Trust the Exchanged Enron Common Stock subject to the Common Equity Trust Agreement.

33. The Reorganized Debtor Plan Administration Agreement is approved in all respects. Each officer, director, managing director, general counsel, associate general counsel, partner, member and manager, as applicable, of each Reorganized Debtor is hereby authorized to execute on behalf of such Reorganized Debtor, the Reorganized Debtor Plan Administration Agreement (and with respect to Reorganized ENE, countersign each accompanying Duty of Loyalty Agreement) without any further action or approval of any board of directors, managing member or partner. Stephen Forbes Cooper, LLC is approved as Reorganized Debtor Plan Administrator and, on the Effective Date, is so appointed and vested with the powers necessary and appropriate to enable the Reorganized Debtor Plan Administrator to carry out its responsibilities as defined in the Plan and the Reorganized Debtor Plan Administration Agreement. The Reorganized Debtor Plan Administrator shall take all necessary and appropriate actions to comply with the provisions of the Plan in the name of and on behalf of the Reorganized Debtors.

34. Stephen Forbes Cooper, LLC is approved as Disbursing Agent. Except to the extent that the responsibility for the same is vested in the Reorganized Debtor Plan Administrator pursuant to the Reorganized Debtor Plan Administration Agreement, the Disbursing Agent shall be empowered to (a) take all steps and execute all instruments and documents necessary to effectuate the Plan, (b) make distributions contemplated by the Plan, (c) comply with the Plan and the obligations thereunder, (d) file all tax returns and pay taxes in connection with the reserves created pursuant to Article XVIII of the Plan, and (e) exercise such

other powers as may be vested in the Disbursing Agent pursuant to order of the Court, pursuant to the Plan or as deemed by the Disbursing Agent to be necessary and proper to implement the provisions of the Plan.

35. The formation of the reserve for Disputed Claims provided for in Section 21.3 of the Plan (the "Disputed Claims Reserve"), the appointment of Stephen D. Bennett, Rick A. Harrington, James R. Latimer, III and John J. Ray, III as DCR Overseers and the use of the Guidelines for Disputed Claims Reserve and the Guidelines for the DCR Overseers, each as set forth in Schedule Y and Z, respectively, of the Plan Supplement, all in accordance with the applicable terms and conditions of the Plan, are each approved in their entirety; provided, however, that, pursuant to the Director Notice and unless otherwise expressly set forth, in the event that a replacement director is selected for Reorganized ENE, such selection shall be deemed to be applicable to the DCR Overseers. On the Effective Date, the DCR Overseers shall be vested with the powers necessary and appropriate to enable the DCR Overseers to carry out their responsibilities as defined in the Plan, the Guidelines for Disputed Claims Reserve and the Guidelines for the DCR Overseers, and to oversee the Disputed Claims Reserve in accordance therewith.

36. With respect to Allowed Priority Tax Claims, holders of such Allowed Priority Tax Claims shall be entitled to receive distributions as provided in Section 3.3 of the Plan. In accordance therewith and with the Notice of Election of Option with Respect to Payment of Priority Tax Claims (Docket. No. 18775) exercised in writing prior to the commencement of the Confirmation Hearing, and subject to Articles XXI and XXXII of the Plan, the Debtors have elected to exercise their option to make such distributions to each holder

of an Allowed Priority Tax Claim in full, in Cash, on the Effective Date or following such later date as any Priority Tax Claim shall become an Allowed Claim.

<u>Discharge, Injunctions, Limited Releases, and Exculpations</u>

37. Except as otherwise provided in the Plan, this Confirmation Order or such other applicable order of the Court, on the latest to occur of (a) the Effective Date, (b) the entry of a Final Order resolving all Claims in the Chapter 11 Cases, or (c) the final distribution made to holders of Allowed Claims and Allowed Equity Interests in accordance with Article XXXII of the Plan, all Claims against and Equity Interests in the Debtors and Debtors in Possession, shall be discharged and released in full; <u>provided</u>, <u>however</u>, that the Court may, upon request by the Reorganized Debtors, and notice and a hearing, enter an order setting forth that such Claims and Equity Interests shall be deemed discharged and released on such earlier date as determined by the Court; and, <u>provided</u>, <u>further</u>, that upon all distributions being made pursuant to the Plan, the Debtors and the Reorganized Debtors, as the case may be, shall be deemed dissolved for all purposes and the Reorganized Debtor Plan Administrator shall cause the Debtors and the Reorganized Debtors, as the case may be, to take such action to effect such dissolution in accordance with applicable state law. All Persons and Entities are hereby precluded from asserting against the Debtors, the Debtors in Possession, their successors or assigns, including, without limitation, the Reorganized Debtors, or their respective assets, properties or interests in property, any other or further Claims based upon any act or omission, transaction or other activity of any kind or nature that occurred prior to the Confirmation Date, whether or not the facts or legal bases therefor were known or existed prior to the Confirmation Date, regardless of whether a proof of Claim or Equity Interest was filed, whether the holder thereof voted to accept

or reject the Plan or whether the Claim or Equity Interest is an Allowed Claim or Allowed Equity Interest.

38. Except as otherwise expressly provided in the Plan, this Confirmation Order or such other applicable order of the Court, all Persons or Entities who have held, hold or may hold Claims or other debt or liability that is discharged or Equity Interests or other right of equity interest that is terminated or cancelled pursuant to the Plan are permanently enjoined, from and after the Effective Date, from (a) commencing or continuing in any manner any action or other proceeding of any kind on any such Claim or other debt or liability or Equity Interest or other right of equity interest that is terminated or cancelled pursuant to the Plan against the Debtors, the Debtors in Possession or the Reorganized Debtors, the Debtors' estates or properties or interests in properties of the Debtors or Reorganized Debtors; (b) the enforcement, attachment, collection or recovery by any manner or means of any judgment, award, decree or order against the Debtors, the Debtors in Possession or the Reorganized Debtors, the Debtors' estates or properties or interests in properties of the Debtors, the Debtors in Possession or the Reorganized Debtors; (c) creating, perfecting, or enforcing any encumbrance of any kind against the Debtors, the Debtors in Possession or the Reorganized Debtors or against the property or interests in property of the Debtors, the Debtors in Possession or the Reorganized Debtors; and (d) except to the extent provided, permitted or preserved by sections 553, 555, 556, 559 or 560 of the Bankruptcy Code or pursuant to the common law right of recoupment, asserting any right of setoff, subrogation or recoupment of any kind against any obligation due from the Debtors, the Debtors in Possession or the Reorganized Debtors or against the property or interests in property of the Debtors, the Debtors in Possession or the Reorganized Debtors, with respect to any such Claim or other debt or liability that is discharged or Equity Interest or other right of equity

interest that is terminated or cancelled pursuant to the Plan; provided, however, that such injunction shall not preclude the United States of America, any State or any of their respective police or regulatory agencies from enforcing their police or regulatory powers; and provided, further, that, except in connection with a properly filed proof of claim, the foregoing proviso does not permit the United States of America, any State or any of their respective police or regulatory agencies from obtaining any monetary recovery from the Debtors, the Debtors in Possession or the Reorganized Debtors or their respective property or interests in property with respect to any such Claim or other debt or liability that is discharged or Equity Interest or other right of equity interest that is terminated or cancelled pursuant to the Plan, including, without limitation, any monetary claim or penalty in furtherance of a police or regulatory power. Such injunction (y) shall extend to all successors of the Debtors and Debtors in Possession and the Creditors' Committee and its members, and their respective properties and interests in property; provided, however, that such injunction shall not extend to or protect members of the Creditors' Committee and their respective properties and interests in property for actions based upon acts outside the scope of service on the Creditors' Committee, and (z) is not intended, nor shall it be construed, to extend to the assertion, the commencement or the prosecution of any claim or cause of action against any present or former member of the Creditors' Committee and their respective properties and interests in property arising from or relating to such member's pre-Petition Date acts or omissions, including, without limitation, the Class Actions.

39. None of the Debtors, the Reorganized Debtors, the Creditors' Committee, the Employee Committee, the ENA Examiner (other than those functions defined by the Investigative Orders), the Indenture Trustees, and any of their respective directors, officers, employees, members, attorneys, consultants, advisors and agents (acting in such capacity), shall

have or incur any liability to any Entity for any act taken or omitted to be taken in connection with and subsequent to the commencement of the Chapter 11 Cases, the formulation, preparation, dissemination, implementation, confirmation or approval of the Plan or any compromises or settlements contained therein, the Disclosure Statement related thereto or any contract, instrument, release or other agreement or document provided for or contemplated in connection with the consummation of the transactions set forth in the Plan; provided, however, that the foregoing provisions of this paragraph shall not affect the liability of (a) any Entity that otherwise would result from any such act or omission to the extent that such act or omission is determined in a Final Order to have constituted gross negligence or willful misconduct, including, without limitation, fraud and criminal misconduct; (b) State Street Bank and Trust Company in its capacity as Independent Fiduciary appointed in accordance with the Court's order, dated April 19, 2002 or (c) the professionals of the Debtors, the Reorganized Debtors, the Creditors' Committee, the Employee Committee, the ENA Examiner or the Indenture Trustees to their respective clients pursuant to DR 6-102 of the New York Code of Professional Responsibility. Any of the foregoing parties in all respects shall be entitled to rely upon the advice of counsel with respect to their duties and responsibilities under the Plan.

40. Except as otherwise provided in the Plan, including, without limitation, Articles XXII and XXIII of the Plan, or in any contract, instrument, release or other agreement entered into in connection with the Plan, in accordance with section 1123(b) of the Bankruptcy Code, the Reorganized Debtors shall retain sole and exclusive authority to enforce any claims, rights or causes of action that the Debtors, the Debtors in Possession or their chapter 11 estates may hold against any Entity, including any claims, rights or causes of action arising under sections 541, 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code.

41. The Reorganized Debtors may, pursuant to applicable bankruptcy and nonbankruptcy law, set off against any Allowed Claim and the distributions to be made pursuant to the Plan on account thereof (before any distribution is made on account of such Claim), the claims, rights and causes of action of any nature the Debtors or the Reorganized Debtors may hold against the holder of such Allowed Claim; provided, however, that neither the failure to effect such a setoff nor the allowance of any Claim hereunder shall constitute a waiver or release by the Debtors, Debtors in Possession or the Reorganized Debtors of any such claims, rights and causes of action that the Debtors, Debtors in Possession or the Reorganized Debtors may possess against such holder; and provided, further, that nothing contained herein or in the Plan is intended to limit the ability of any Creditor to effectuate rights of setoff or recoupment preserved or permitted by the provisions of sections 553, 555, 556, 559 or 560 of the Bankruptcy Code or pursuant to the common law right of recoupment.

42. No claims of the Debtors' estates against their present and former officers, directors, employees, consultants and agents and arising from or relating to the period prior to the Initial Petition Date are released by the Plan. As of the Effective Date, the Debtors and Debtors in Possession shall be deemed to have waived and released their present and former directors, officers, employees, consultants and agents who were directors, officers, employees consultants or agents, respectively, at any time during the Chapter 11 Cases, from any and all claims of the Debtors' estates arising from or relating to the period from and after the Initial Petition Date; provided, however, that, except as otherwise provided by prior or subsequent Final Order of the Court, this provision shall not operate as a waiver or release of (a) any Person (i) named or subsequently named as a defendant in any of the Class Actions, (ii) named or subsequently named as a defendant in any action commenced by or on behalf of the Debtors in

Possession, including any actions prosecuted by the Creditors' Committee and the Employee Committee, (iii) identified or subsequently identified as a wrongful actor in the "Report of Investigation by the Special Investigative Committee of the Board of Directors of Enron Corp.," dated February 1, 2002, (iv) identified or subsequently identified in a report by the Enron Examiner or the ENA Examiner as having engaged in acts of dishonesty or willful misconduct detrimental to the interests of the Debtors, or (v) adjudicated or subsequently adjudicated by a court of competent jurisdiction to have engaged in acts of dishonesty or willful misconduct detrimental to the interests of the Debtors or (b) any claim (i) with respect to any loan, advance or similar payment by the Debtors to any such person, (ii) with respect to any contractual obligation owed by such person to the Debtors, (iii) relating to such person's knowing fraud, or (iv) to the extent based upon or attributable to such person gaining in fact a personal profit to which such person was not legally entitled, including, without limitation, profits made from the purchase or sale of equity securities of the Debtors which are recoverable by the Debtors pursuant to section 16(b) of the Securities Exchange Act of 1934, as amended; and, provided, further, that the foregoing is not intended, nor shall it be construed, to release any of the Debtors' claims that may exist against the Debtors' directors and officers liability insurance.

43. Unless otherwise provided, all injunctions or stays provided for in the Chapter 11 Cases pursuant to sections 105, 362 or 525 of the Bankruptcy Code, or otherwise, and in existence on the Confirmation Date, shall remain in full force and effect until entry of an order in accordance with Section 42.17 of the Plan or other Final Order of the Court.

44. Except as provided in the Plan, as of the Effective Date, all non-Debtor entities are permanently enjoined from commencing or continuing in any manner, any action or proceedings, whether directly, derivatively, on account of or respecting any claim, debt, right or

cause of action of the Debtors, the Debtors in Possession or the Reorganized Debtors which the Debtors, the Debtors in Possession or the Reorganized Debtors, as the case may be, retain sole and exclusive authority to pursue in accordance with Section 28.1 of the Plan or which has been released pursuant to the Plan, including, without limitation, pursuant to Sections 2.1, 28.3 and 42.6 of the Plan; provided, however, that such injunction is not intended, nor shall it be construed, (a) to the extent authorized or permitted by an order of the Court, to extend to the ongoing prosecution of the Class Actions or (b) to apply to any proceeding not involving property of any Debtor's estate that a non-Debtor Entity brings against another non-Debtor Entity.

Executory Contracts and Unexpired Leases

45. Pursuant to sections 365(a) and 1123 of the Bankruptcy Code, the rejection, on the Confirmation Date, of all executory contracts and unexpired leases that (a) have not been assumed pursuant to prior Court orders, (b) are not the subject of a pending motion to assume, or (c) are not included in the Assumption Schedule filed on March 19, 2004, (Docket No. 17054) as the same has been amended by notice from time to time (as amended, hereinafter referred to collectively as the "Assumption Schedule"), is approved in all respects.

46. Pursuant to sections 365(a) and 1123 of the Bankruptcy Code, the assumption, as of the Effective Date, of the executory contracts and unexpired leases listed on the Assumption Schedule, which are not the subject of a timely filed objection (including any objection that may be timely filed in accordance with the terms of a notice of an amendment of the Assumption Schedule), is approved in all respects in accordance with the noticed terms of the Assumption Schedule. The ability of the Debtors to assume, or assume and assign, any

executory contract or unexpired lease that is the subject of a timely-filed objection shall be addressed by the Court upon notice and a hearing.

47. In accordance with Section 34.2 of the Plan, the Debtors in Possession may at any time during the period from the Confirmation Date, up to and including the Effective Date, amend the Assumption Schedule to delete any executory contracts or unexpired leases therefrom.

48. The filing and service of the Plan and Assumption Schedule and the publication of notice of the entry of the Confirmation Order provide adequate notice of the assumption of executory contracts and unexpired leases that are assumed pursuant to Article XXXIV of the Plan.

49. All counterparties to all executory contracts and unexpired leases of the Debtors assumed pursuant to Article XXXIV of the Plan and the Assumption Schedule have been provided with adequate assurance of future performance pursuant to section 365(f) of the Bankruptcy Code.

50. Notwithstanding anything contained in the Plan to the contrary, all trading contracts between or among (a) two or more Debtors, or (b) a Debtor and any wholly-owned Affiliate shall be deemed for all purposes to have been rejected and otherwise terminated as of the Initial Petition Date, and the values and damages attributable thereto shall be calculated as of the Initial Petition Date.

51. Any monetary amounts required as cure payments on each executory contract and unexpired lease to be assumed pursuant to the Plan shall be satisfied, pursuant to section 365(b)(1) of the Bankruptcy Code, by payment of the cure amount in Cash on the Effective Date or upon such other terms and dates as the parties to such executory contracts or

unexpired leases otherwise may agree. If a dispute regarding (a) the amount of any cure payment, (b) the ability of the Debtors or any assignee to provide "adequate assurance of future performance" (within the meaning of section 365 of the Bankruptcy Code) under the contract or lease to be assumed, or (c) any other matter pertaining to assumption arises, the cure payments required by section 365(b)(1) of the Bankruptcy Code shall be subject to the jurisdiction of the Court and made following the existence of a Final Order, obtained upon notice and a hearing, resolving such dispute.

52. Except with regard to executory contracts governed in accordance with the provisions of Section 34.3 of the Plan, if the rejection of an executory contract or unexpired lease by the Debtors in Possession under the Plan results in damages to the other party or parties to such contract or lease, any claim for such damages, if not heretofore evidenced by a filed proof of claim, shall be forever barred and shall not be enforceable against the Debtors, or its properties or agents, successors, or assigns, unless a proof of claim is filed with the Court and served upon attorneys for the Debtors on or before thirty (30) days after the latest to occur of (a) the Confirmation Date, (b) the date of entry of an order by the Court authorizing rejection of a particular executory contract or unexpired lease, or (c) the date of the Rejection Notice with respect to a particular executory contract or unexpired lease.

53. For purposes of the Plan, the obligations of the Debtors to indemnify and reimburse its directors or officers that were directors or officers, respectively, on or prior to the Petition Date, shall be treated as Section 510 Subordinated Claims. Indemnification obligations of the Debtors arising from services as officers and directors during the period from and after the Initial Petition Date shall be Administrative Expense Claims to the extent previously authorized by Final Order.

54. On the Effective Date, (a) each of the (i) ECT I Trust Declarations, (ii) ECT II Trust Declarations, (iii) EPF I Partnership Agreement, and (iv) EPF II Partnership Agreement shall be deemed to be rejected, and (b) subject to the Debtors' obligations set forth in decretal paragraph 16 of the TOPRS Stipulation and in the Plan and this Confirmation Order, in full and final satisfaction of any rights, interests or Claims of ECT I, ECT II , EPF I, EPF II and holders of the TOPRS against any of the Debtors and their affiliates, ENE, as general partner of EPF I and EPF II, shall (i) waive any right of EPF I and EPF II to reinvest distributions made pursuant to the Plan, (ii) liquidate the Eligible Debt Securities, as defined in the EPF I Partnership Agreement and the EPF II Partnership Agreement, owned by EPF I and EPF II to Cash as soon as practicable following the Effective Date, and (iii) declare a distribution of all assets of EPF I and EPF II, including, without limitation, Cash, Plan Securities and Eligible Debt Securities, as defined in the EPF I Partnership Agreement and the EPF II Partnership Agreement, to ECT I and ECT II, respectively, which distribution shall be made to National City Bank, in its capacity as ECT I Property Trustee and ECT II Property Trustee. Upon the earlier to occur of (i) this Confirmation Order becoming a Final Order, or (ii) the Effective Date, (a) all claims, causes of action or other challenges of any kind or nature which could be asserted by the Debtors, the Creditors' Committee, any trustee appointed in the Debtors' bankruptcy cases, or any creditor or party in interest in the Debtors' bankruptcy cases, or any of them, against or with respect to National City Bank, as Indenture Trustee, ECT I Property Trustee and ECT II Property Trustee, ECT I, ECT II, the TOPRS issues by either of them, EPF I, EPF II, the limited partnership interests issued by either of them, the ETS Debentures, the ENA Debentures or the Enron TOPRS Debentures, including, without limitation, substantive consolidation, piercing of the corporate veil, re-characterization of the TOPRS or the limited partnership interests in EPF I or

EPF II as preferred stock or any other equity interest of ENE or any of its affiliates, preference, fraudulent conveyance and other avoidance actions shall be deemed forever waived and released, and (b) none of the Debtors, the Creditors' Committee, any trustee or any creditor or party in interest in the Debtors' bankruptcy cases, or any of them, shall without National City Bank's prior written consent, which consent shall not be unreasonably withheld, (i) seek to change, remove or substitute any of the Enron TOPRS Debentures, the ETS Debentures, the ENA Debentures, the Eligible Securities or any other interest of any of ECT I, ECT II, EPF I or EPF II. in any property, or (ii) otherwise seek to merge or consolidate any or all of ECT I, ECT II, EPF I, EPF II, ENE, ENA or ETS or in any manner change or otherwise affect the economic or other interests of National City Bank, as Indenture Trustee and Property Trustee, the holders of TOPRS, ECT I, ECT II, EPF I or EPF II, or any of them.

<u>Title to Assets</u>

55. Except as otherwise provided in the Plan, including, without limitation, Section 42.2 of the Plan, on the Effective Date, title to all assets and properties encompassed by the Plan shall vest in the Reorganized Debtors and, to the extent created, the Remaining Asset Trust(s), the Litigation Trust and the Special Litigation Trust, as the case may be, free and clear of all Liens and in accordance with section 1141 of the Bankruptcy Code. This Confirmation Order is a judicial determination of discharge of the liabilities of the Debtors and the Debtors in Possession except as provided in the Plan. Notwithstanding the foregoing, the Debtors and the Reorganized Debtors, in their sole and absolute discretion, may (a) encumber all of the Debtors' estates' assets for the benefit of Creditors, or (b) transfer such assets to another Entity to secure the payment and performance of all obligations provided for in the Plan.

56. Except to the extent subject to a valid and enforceable Lien, upon the Effective Date, all proceeds reserved pursuant to a Sale/Settlement Order and not subject to a dispute concerning the allocation thereof shall vest in the Reorganized Debtors, the Litigation Trust or the Special Litigation Trust, as the case may be, free and clear of all Liens and in accordance with section 1141 of the Bankruptcy Code and be subject to distribution in accordance with the provisions hereof; provided, however, that, notwithstanding the foregoing, the Debtors shall escrow Two Hundred Million Dollars ($200,000,000.00) to satisfy its obligations in accordance with the terms and provisions of the Standard Termination Order until the earlier to occur of (a) satisfaction of the obligations contained in the Standard Termination Order, and (b) entry of an order of the Court, upon notice to the PBGC, authorizing the release thereof.

57. Notwithstanding the terms and conditions of any of the Sale/Settlement Orders, to the extent necessary to allocate the proceeds reserved pursuant to a Sale/Settlement Order, on or prior to the three (3) month anniversary of the Confirmation Date, the Debtors shall file one or more motions with the Court to determine the allocation of proceeds reserved pursuant to a Sale/Settlement Order. Any such motion shall be deemed served upon the necessary parties if served in accordance with the Case Management Order. Upon entry of a Final Order of the Court with respect to the allocation of such proceeds, and to the extent allocated to the Debtors, the Litigation Trust, the Special Litigation Trust, or any Enron Affiliate, as the case may be, all such proceeds shall vest in the Reorganized Debtors or such Enron Affiliate free and clear of all Liens and in accordance with section 1141 of the Bankruptcy Code and be subject to distribution in accordance with the provisions of the Plan and this Confirmation Order.

58. Each of the transfers of property of the Debtors or Reorganized Debtors, as the case may be, pursuant to the Plan: (a) are or shall be deemed to be legal, valid and effective transfers of property; (b) shall not constitute, or be construed to be, avoidable transfers under the Bankruptcy Code or under applicable nonbankruptcy law; and (c) shall not subject the Debtors or the Reorganized Debtors, as the case may be, to any liability by reason of such transfer under the Bankruptcy Code or under applicable nonbankruptcy law, including, without limitation, any laws affecting successor or transferee liability.

Payment of Statutory Fees

59. All fees payable pursuant to section 1930 of title 28 of the United States Code, shall be paid as and when due or otherwise pursuant to an agreement between one or more of the Reorganized Debtors and the United States Department of Justice, Office of the United States Trustee, until such time as a Chapter 11 Case for a Debtor shall be closed in accordance with the provisions of Section 42.17 of the Plan.

Retention of Jurisdiction

60. In accordance with (and as limited by) Article XXXVIII of the Plan and section 1142 of the Bankruptcy Code, the Court shall retain and have exclusive jurisdiction over any matter arising under the Bankruptcy Code, arising in or related to the Chapter 11 Cases or the Plan, or that relates to the following:

(a) to resolve any matters related to the assumption, assumption and assignment or rejection of any executory contract or unexpired lease to which a Debtor is a party or with respect to which a Debtor may be liable, and to hear, determine and, if necessary, liquidate, any Claims arising therefrom, including those matters related to the amendment after the Effective Date of the Plan, and to add any executory contracts or unexpired leases to the list of executory contracts and unexpired leases to be rejected;

(b) to enter such orders as may be necessary or appropriate to implement or consummate the provisions of the Plan and all contracts, instruments, releases, and other agreements or documents created in connection with the Plan;

(c) to determine any and all motions, adversary proceedings, applications and contested or litigated matters that may be pending on the Effective Date or that, pursuant to the Plan, may be instituted by the Reorganized Debtors, the Litigation Trust or the Special Litigation Trust prior to or after the Effective Date;

(d) to ensure that distributions to holders of Allowed Claims and Allowed Equity Interests are accomplished as provided in the Plan;

(e) to hear and determine any timely objections to Administrative Expense Claims or to proofs of Claim and Equity Interests filed, both before and after the Confirmation Date, including any objections to the classification of any Claim or Equity Interest, and to allow, disallow, determine, liquidate, classify, estimate or establish the priority of or secured or unsecured status of any Claim, in whole or in part;

(f) to enter and implement such orders as may be appropriate in the event the Confirmation Order is for any reason stayed, revoked, modified, reversed or vacated;

(g) to issue such orders in aide of execution of the Plan, to the extent authorized by section 1142 of the Bankruptcy Code;

(h) to consider any modifications of the Plan, to cure any defect or omission, or to reconcile any inconsistency in any order of the Court, including the Confirmation Order;

(i) to hear and determine all applications for awards of compensation for services rendered and reimbursement of expenses incurred prior to the Effective Date;

(j) to hear and determine disputes arising in connection with or relating to the Plan or the interpretation, implementation, or enforcement of the Plan or the extent of any Entity's obligations incurred in connection with or released under the Plan;

(k) to issue injunctions, enter and implement other orders or take such other actions as may be necessary or appropriate to restrain interference by any Entity with consummation or enforcement of the Plan;

(l) to determine any other matters that may arise in connection with or that are related to the Plan, the Disclosure Statement, the Confirmation Order or any contract, instrument, release or other agreement or document created in connection with the Plan or the Disclosure Statement;

(m) to hear and determine matters concerning state, local and federal taxes in accordance with sections 346, 505, and 1146 of the Bankruptcy Code;

(n) to hear any other matter or for any purpose specified in the Confirmation Order that is not inconsistent with the Bankruptcy Code; and

(o) to enter a final decree closing the Chapter 11 Cases;

provided, however, that the foregoing does not (1) expand the Court's subject matter jurisdiction beyond that allowed by applicable law, (2) impair the rights of an Entity to (i) invoke the jurisdiction of a court, commission or tribunal, including, without limitation, the Federal Energy Regulatory Commission, with respect to matters relating to a governmental unit's police and regulatory powers and (ii) contest the invocation of any such jurisdiction; provided, however, that the invocation of such jurisdiction, if granted, shall not extend to the allowance or priority of Claims or the enforcement of any money judgment against a Debtor or Reorganized Debtor, as the case may be, entered by such court, commission or tribunal, and (3) impair the rights of an Entity to (i) seek the withdrawal of the reference in accordance with 29 U.S.C. § 157(d) and (ii) contest any request for the withdrawal of reference in accordance with 28 U.S.C. § 157(d).

GENERAL AUTHORIZATIONS

61. The Debtors, Debtors in Possession and the Reorganized Debtors, as the case may be, are hereby authorized and empowered pursuant to section 1142(b) of the Bankruptcy Code to:

(a) Execute and deliver, and take such action as is necessary to effectuate the terms of, all instruments, agreements and documents in substantially the form of such instruments, agreements or documents attached as exhibits to the Plan, the Plan Supplement or the Disclosure Statement, or to be filed with the Court on or before the Effective Date, including all annexes and exhibits attached to those exhibits to the Plan, the Plan Supplement or Disclosure Statement and any other documents delivered in connection with those exhibits; and

(b) Issue, execute, deliver, file and record any documents, Court papers or pleadings, and to take any and all actions that are necessary or desirable to implement, effect or consummate the transactions contemplated by the Plan whether or not specifically referred to in the Plan or related documents, and without further application to or order of the Court.

62. Without the need for further order or authorization of the Court, the Debtors and/or Reorganized Debtors are authorized and empowered to make any and all modifications to any and all documents included as part of the Plan Supplement that do not materially modify the terms of such documents and are consistent with the Plan.

GLOBAL COMPROMISE MOTION

63. Subject to the full paragraph on page six of the findings of fact and conclusions of law issued on July 15, 2004, the settlements and compromises embodied in the Plan and the Global Compromise Motion are approved for all Debtors. Notwithstanding the exclusion of a Debtor from the Plan pursuant to Sections 39.1 or 42.14 of the Plan, such Debtor and any successor trustee or representative of the Estate shall be bound by the terms of the global compromise pursuant to the Global Compromise Motion.

POST-CONFIRMATION ALLOCATION FORMULA

64. The Motion of Debtors Pursuant to Section 363 of the Bankruptcy Code for Order Approving and Authorizing Post-Confirmation Allocation Formula for Overhead and

Expenses, dated March 24, 2004 (Docket No. 17283) (the "Overhead Allocation Motion")[4] is granted in full as to all Debtors. The Post-Confirmation Allocation Formula, for allocation, from and after the Confirmation Date, of shared overhead and other expenses among the Enron Entities, including the procedures related thereto, is approved. The Debtors are authorized to take all action necessary to fully implement and carry out the Post-Confirmation Allocation Formula as described in the Overhead Allocation Motion and authorized by this Order. Except as provided herein, all other provisions of the Court's orders, dated February 25, 2002, November 21, 2002 and November 25, 2002, with respect to the allocation of overhead and expenses, shall remain in full force and effect.

65. If an Enron Entity is unable to fund its Entity Reserve Amount, either in whole or in part, the unfunded portion will be reallocated to the first equity owner in the ownership chain of such Enron Entity (the "Funding Entity") with the ability to pay. To the extent the Funding Entity is a Debtor, (a) the funding of an Entity Reserve Amount by such Funding Entity on behalf of another Debtor will result in a Junior Reimbursement Claim (as defined in the Amended Cash Management Order) held by such Funding Entity against such Debtor, and (b) the funding of an Entity Reserve Amount by such Funding Entity on behalf of a non-Debtor will result in an Intercompany Loan (as defined in the Amended Cash Management Order) payable by such non-Debtor to such Funding Entity. To the extent the Funding Entity is a non-Debtor, (x) the funding of an Entity Reserve Amount by such Funding Entity on behalf of a Debtor will result in an Allowed Administrative Expense Claim held by such Funding Entity against such Debtor, and (y) the funding of an Entity Reserve Amount by such Funding Entity on

[4] Capitalized terms used in this section, if not defined herein or in the Plan, shall have the meanings ascribed to such terms in the Overhead Allocation Motion.

behalf of a non-Debtor will result in an intercompany receivable held by such Funding Entity against such non-Debtor.

66. The Amended Cash Management Order is modified to the extent that the funding of an allocation obligation by a Funding Entity pursuant to this Order shall not be in violation or contravention of any provision of the Amended Cash Management Order, including, but not limited to the aggregate fair value tests, solvency tests and Intercompany Loan limits of paragraphs 5 and 6 of the Amended Cash Management Order.

67. The Debtors and the Reorganized Debtors, in the exercise of their business judgment, may enact modifications to the Post- Confirmation Allocation Formula, without further Court approval; provided, however, the Debtors or the Reorganized Debtors, as applicable, obtain the agreement of (a) the Creditors' Committee and the ENA Examiner; or (b) if, in accordance with the Plan, the Creditors' Committee has been dissolved and/or the ENA Examiner's role has concluded, the board of directors of Reorganized ENE along with the remaining Creditors' Committee or the ENA Examiner, to the extent they then exist.

68. During the post-Confirmation Date period, and solely to the extent the Creditors' Committee has not yet been dissolved and/or the ENA Examiner's role has not yet concluded in accordance with the Plan, the Creditors' Committee and the ENA Examiner will participate in a monitoring process of the application by the Debtors of the Post-Confirmation Allocation Formula. Such monitoring process will permit the Creditors' Committee, to the extent it has not yet been dissolved, and the ENA Examiner, to the extent his role has not yet concluded, to, *inter alia*, (a) verify the accuracy of certain data, including, but not limited to, data associated with the GEAR, EAOR and other data produced in connection with the Post-Confirmation Allocation Formula, (b) oversee and evaluate the allocation of overhead and other

expenses, and the application of the allocation methodologies, (c) consult with the Debtors regarding the Post-Confirmation Allocation Formula, and (d) review the reasonableness of any other aspect of the Post-Confirmation Allocation Formula or its application.

69. The Enron Entities may use funds held in restricted or escrow accounts by the Enron Entities (the "Escrowed Funds") solely to satisfy overhead allocation of such Enron Entity without further Court order, provided, that the following conditions apply:

(a) To the extent the Creditors' Committee has not yet been dissolved and/or the ENA Examiner's role has not yet concluded in accordance with the Plan, (i) the Debtors provide ten (10) days prior written notice to the Creditors' Committee and the ENA Examiner (1) setting forth (a) the name of the Enron Entity proposing to use the Escrowed Funds, (b) the amount of Escrowed Funds proposed to be released, and (c) an explanation of the need for the Escrowed Funds, and (2) attaching supporting documentation for the overhead or other expenses to be paid with the Escrowed Funds (a "Notice"), and (ii) the Creditors' Committee and the ENA Examiner do not object to the proposed use of such Escrowed Funds within ten (10) days of receipt of the Notice (an "Escrow Objection"). The Debtors shall schedule a hearing on the proposed use of the Escrowed Funds if an Escrow Objection is interposed and the Escrow Objection is not consensually resolved.

(b) To the extent the Creditors' Committee has been dissolved and/or the ENA Examiner's role has been concluded in accordance with the Plan: (i) the Debtors provide thirty (30) days prior written Notice to the board of directors of Reorganized ENE setting forth the information described in the immediately preceding paragraph, and (ii) the board of directors of Reorganized ENE does not raise and Escrow Objection to the proposed use of such Escrowed Funds within thirty (30) days of receipt of the Notice. In determining whether to raise an Escrow Objection or approve the proposed use of such Escrowed Funds, the Board of Directors of Reorganized ENE, in their sole discretion, may request a hearing on such matter.

MISCELLANEOUS

70. Each of the Objections not withdrawn prior to the entry of this Confirmation Order or resolved by written agreement or by oral agreement, stated and made a part of the record of the Confirmation Hearing, including, without limitation, those Objections interposed by parties whose standing was challenged as part of the confirmation process (which issue the Court need not have addressed due to the rulings set forth in the Findings and Conclusions and herein) is OVERRULED and DENIED. All withdrawn objections are deemed withdrawn with prejudice.

71. Each term and provision of the Plan, as it may have been altered or interpreted in accordance with Section 42.14 of the Plan, is valid and enforceable pursuant to its terms.

72. The Montgomery County Litigation, and all claims and causes of action comprising the Montgomery County Litigation, shall be deemed to be, for all and any purposes whatsoever, Special Litigation Trust Claims.

73. Pursuant to section 1123(b) of the Bankruptcy Code, the Litigation Trust and the Special Litigation Trust, to the extent created, shall be deemed to be successors to ENE for any and all purposes whatsoever, notwithstanding the transfer of the Litigation Trust Claims and the Special Litigation Trust Claims from ENE to the Litigation Trust and the Special Litigation Trust, respectively, which transfers shall (a) be deemed to have occurred and/or taken place for tax purposes only, and (b) shall not impair or result in the lapsing of such causes of action or claims, notwithstanding any applicable nonbankruptcy law prohibiting the assignment of pre-judgment tort claims, and shall not affect the validity or survival of such causes of actions or claims.

74. Exhibit L to the Plan and Schedule S to the Plan Supplement represent the Debtors' position as of the date hereof and are indicative only of the types of Claims that may benefit from subordination and therefore do not set forth, in any manner whatsoever, a definitive list or catalog of the Claims that may benefit from subordination; accordingly, the rights of holders of Claims to assert the benefits of subordination in connection with the Plan or any distributions made pursuant to the terms thereof are preserved in all respects and are in no manner limited or restricted by Exhibit L to the Plan and/or Schedule S to the Plan Supplement. Consistent therewith, pursuant to an agreement among the Debtors, the Creditors' Committee and the ENA Examiner, (a) Schedule S to the Plan Supplement may not be the "final schedule," (b) Schedule S to the Plan Supplement may be amended or modified prior to the initial distribution pursuant to Section 32.1(a) of the Plan to add or remove certain claims entitled to the benefits of subordination, provided, however, that the Debtors may not amend or modify Schedule S in a manner that would violate the provisions of the Baupost Stipulation, including without limitation, the provisions of decretal paragraph 4 thereof, and (c) the Debtors shall file a final Schedule S (which may be identical to the schedule contained in existing Schedule S to the Plan Supplement) with the Court prior to making the initial distribution pursuant to Section 32.1(a) of the Plan, giving all parties (including the ENA Examiner, to the extent such role has not been terminated in accordance with the provisions of Section 33.4 of the Plan) an opportunity to be heard with respect to the final Schedule S on the grounds that certain claims should be included in or removed from such Schedule.

75. Although not excluded from the Plan, EDF, a Debtor, is also the subject of insolvency proceedings in the Cayman Islands. (Stipulation And Agreed Order Establishing Procedures For Compensation And Reimbursement Of Expenses For Professionals Of Enron

Development Funding Limited And Its Joint Provisional Liquidators, dated June 26, 2003, Docket No. 11953). In light of the joint proceedings, until such time as the Cayman scheme of arrangement proceedings has been concluded, currently anticipated to be in August 2004, no distributions of assets held by or attributed to EDF will be made to Creditors holding Allowed Claims pursuant to the Plan.

76. The Reorganized Debtors shall file and serve (a) no later than twenty (20) days following the Confirmation Date, unless extended for cause upon motion by the Debtors upon notice to the Creditors' Committee and the Creditors affected thereby, objections to Claims with regard to the Yosemite and Credit Linked Notes financing transaction, as described in the Disclosure Statement, (b) no later than fifty (50) days following the Confirmation Date, unless extended for cause upon motion by the Debtors upon notice to the Creditors' Committee and the Creditors affected thereby, objections to the twenty (20) largest proofs of Claim filed against ENA, and identified by the ENA Examiner in a list provided no later than the Confirmation Date, and (c) all objections to other Claims as soon as practicable, but, in each instance, not later than two hundred forty (240) days following the Confirmation Date or such later date as may be approved by the Court.

77. All applications (collectively, the "Applications" and each an "Application") for final allowances of compensation and reimbursement of expenses pursuant to sections 328, 330, 331, 503(b) and/or 1103 of the Bankruptcy Code shall be filed with the Court and served upon the parties listed below no later than October 31, 2004:

Weil, Gotshal & Manges LLP
Attorneys for the Debtors
767 Fifth Avenue
New York, New York 10153
Attention: Martin J. Bienenstock, Esq. and Brian S. Rosen, Esq.

Milbank, Tweed, Hadley & McCloy LLP
One Chase Manhattan Plaza
New York, New York 10005
Attention: Luc A. Despins, Esq. and Susheel Kirpalani, Esq.

Reorganized Enron
1221 Lamar Street, Suite 1600
Houston, Texas 77010
Attention: General Counsel

The Office of the United States Trustee
33 Whitehall Street, 21st Floor
New York, New York 10004
Attention: Mary Elizabeth Tom, Esq.

78. A status conference will be held before the Court on December 16, 2004, at 10:00 a.m., in the United States Bankruptcy Court for the Southern District of New York, Alexander Hamilton Custom House, One Bowling Green, Courtroom 523, New York, New York 10004-1408, at which the Court will schedule a hearing (the "Final Fee Hearing") to consider the Applications for final allowance of compensation and reimbursement of expenses and related matters.

79. Each Application shall comply with the applicable provisions of the Bankruptcy Code and the Bankruptcy Rules and shall set forth, among other things, in reasonable detail, (a) the name and address of the applicant, (b) the nature of the professional or other services rendered and expenses for which reimbursement is requested for all periods from the date the particular applicant was retained through the Effective Date, (c) the amount of compensation and reimbursement of expenses requested, (d) whether any payments have been received on account and, if so, the amount or amounts thereof, and (e) the amounts of compensation and reimbursement of expenses previously allowed by the Court, if any.

80. No applications shall be filed for compensation and reimbursement by professional persons for services rendered or expenses incurred on or after the Confirmation Date. From and after the Confirmation Date, the Reorganized Debtors, the Reorganized Debtor Plan Administrator, the Litigation Trustee, the Special Litigation Trustee, the Remaining Asset Trustee, the Operating Trustees, the Preferred Equity Trustee, the Common Equity Trustee and the DCR Overseers shall, in the ordinary course of business and without the necessity for any approval by the Court, (a) retain such professionals, (including professionals previously retained by the Debtors and/or the Creditors' Committee) and (b) pay the reasonable professional fees and expenses incurred by the Debtors or the Reorganized Debtors, as the case may be, the Creditors' Committee and the ENA Examiner related to implementation and consummation of or consistent with the provisions of the Plan, including, without limitation, reasonable fees and expenses of the Indenture Trustees incurred in connection with the distributions to be made pursuant to the Plan. Disputes concerning such fees and expenses may be brought to the Court for resolution.

81. Pursuant to section 503(b) of the Bankruptcy Code and Bankruptcy Rule 3003(c), and except as otherwise provided in the following decretal paragraph of this Confirmation Order, each Person or Entity that asserts an Administrative Expense Claim against one or more of the Debtors, that arose after the commencement of such Debtor's Chapter 11 Case, shall file and serve on the parties listed in decretal paragraph 77 hereof a request for payment of such administrative expense no later than 5:00 p.m. New York City Time on the later to occur of (a) September 30, 2004, or (b) the first (1st) Business Day sixty (60) days following the Effective Date (the "Administrative Expense Bar Date").

82. The following Persons or Entities are not required to file Administrative Expense Claims by the Administrative Expense Bar Date: (a) any Person or Entity that has

already filed an Administrative Expense Claim; (b) holders of Administrative Expense Claims previously allowed by order(s) of the Court; (c) the Debtors or any affiliates of the Debtors, individually or collectively, holding Claims against any of the other Debtors or their affiliates, individually or collectively; (d) except as otherwise set forth herein, any Person or Entity seeking allowance of final compensation or reimbursement of expenses for professional services rendered to the Debtors or in relation to these Chapter 11 Cases pursuant to section 327, 328, 330, 331, 503(b) or 1103 of the Bankruptcy Code; and (e) any administrative expenses that arise and are due and payable in the ordinary course of the Debtors' businesses, except with respect to those expenses that remain outstanding and unpaid by the Debtors beyond ordinary business terms or prior course of business dealings.

83. Each Administrative Expense Claim, to be properly filed pursuant to this Confirmation Order, must (a) be written in the English language, (b) be denominated in lawful currency of the United States, (c) set forth the name of the specific Debtor against which such claim is asserted, and (d) otherwise comply with applicable provisions of the Bankruptcy Code and Bankruptcy Rules.

84. Pursuant to Bankruptcy Rule 3003(c), any Person or Entity that is required to file an Administrative Expense Claim against a Debtor, in the form and manner specified by this Confirmation Order, and that fails to do so on or before the Administrative Expense Bar Date shall be forever barred, estopped and enjoined from ever asserting such Administrative Expense Claim against any of the Debtors (or filing a claim with respect thereto) and the Debtors and their estates' properties shall be forever discharged of and from any and all indebtedness or liability with respect to such Administrative Expense Claim, and such holder shall not be permitted to participate in any distribution in the Debtors' Chapter 11 Cases under the Plan or

otherwise on account of such Administrative Expense Claim or to receive any further notice regarding such Administrative Expense Claim.

85. Notice of the Administrative Expense Bar Date, substantially in the form annexed to this Confirmation Order as Exhibit C (the "Effective Date Notice and Administrative Bar Date Notice"), which Effective Date Notice and Administrative Bar Date Notice is hereby approved in all respects, shall be deemed good, adequate and sufficient notice, if such Effective Date Notice and Administrative Bar Date Notice is (a) published as provided in the following decretal paragraph of this Confirmation Order, and (b) filed and served in accordance with the Case Management Order on or before the fifteenth (15^{th}) Business Day after the Effective Date.

86. The Debtors or the Reorganized Debtors shall cause the Effective Date Notice and Administrative Bar Date Notice to be published one time in each of the Houston Chronicle, the national editions of The Wall Street Journal and The New York Times, the Financial Times, and El Nuevo Dia no later than fifteen (15) Business Days after the Effective Date, which publication is hereby approved in all respects and which shall be deemed good, adequate and sufficient notice by publication.

87. The Debtors or Reorganized Debtors, as the case may be, shall file and serve any objections to Administrative Expense Claims no later than 120 days following the Administrative Expense Bar Date, unless further extended by the Court.

88. On or before the fifteenth (15^{th}) Business Day after entry of this Confirmation Order, the Debtors shall (a) serve, in accordance with the Case Management Order, all creditors and other parties in interest, including, without limitation, parties to executory contracts and unexpired leases rejected or deemed rejected in accordance with the terms and conditions of the Plan and this Confirmation Order and known to the Debtors, notice of the entry

of this Confirmation Order in substantially the form annexed hereto as Exhibit D, and (b) publish notice of the entry of this Confirmation Order on one occasion in each of the Houston Chronicle, the national editions of The Wall Street Journal and The New York Times, the Financial Times, and El Nuevo Dia.

89. In accordance with Local Bankruptcy Rule 3021-1, annexed hereto as Exhibit E is a proposed form of a Postconfirmation Order and Notice, to be filed and served by the Court upon entry of the Confirmation Order. The Debtors will comply with Local Bankruptcy Rule 3021-1 and the terms of the proposed Postconfirmation Order and Notice.

90. To the extent of any inconsistency between the provisions of the Plan and this Confirmation Order, the terms and conditions contained in the Confirmation Order shall govern.

91. The provisions of this Confirmation Order are integrated with each other and are nonseverable and mutually dependent.

92. The determinations, finding, judgments, decrees and orders set forth or incorporated herein constitute the Court's findings of fact and conclusions of law pursuant to Bankruptcy Rule 7052, made applicable to this proceeding pursuant to Bankruptcy Rule 9014. Each finding of fact set forth or incorporated herein, to the extent it is or may be deemed a conclusion of law, shall also constitute a conclusion of law. Each conclusion of law set forth or incorporated herein, to the extent it is or may be deemed a finding of fact, shall also constitute a finding of fact.

93. This Confirmation Order is a final order and the period in which an appeal

may be timely filed shall commence upon the entry thereof.

Dated: New York, New York
July 15, 2004

s/ Arthur J. Gonzalez
UNITED STATES BANKRUPTCY JUDGE

21.3 **Payments and Distributions on Disputed Claims**:

(a) Disputed Claims Reserve: From and after the Effective Date, and until such time as all Disputed Claims have been compromised and settled or determined by Final Order, the Disbursing Agent shall reserve and hold in escrow for the benefit of each holder of a Disputed Claim, Cash, Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests and any dividends, gains or income attributable thereto, in an amount equal to the Pro Rata Share of distributions which would have been made to the holder of such Disputed Claim if it were an Allowed Claim in an amount equal to the lesser of (i) the Disputed Claim Amount, (ii) the amount in which the Disputed Claim shall be estimated by the Bankruptcy Court pursuant to section 502 of the Bankruptcy Code for purposes of allowance, which amount, unless otherwise ordered by the Bankruptcy Court, shall constitute and represent the maximum amount in which such Claim may ultimately become an Allowed Claim or (iii) such other amount as may be agreed upon by the holder of such Disputed Claim and the Reorganized Debtors; provided, however, that, under no circumstances, shall a holder of an Allowed Convenience Claim be entitled to distributions of Litigation Trust Interests, Special Litigation Trusts Interests or the proceeds thereof. Any Cash, Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests reserved and held for the benefit of a holder of a Disputed Claim shall be treated as a payment and reduction on account of such Disputed Claim for purposes of computing any additional amounts to be paid in Cash or distributed in Plan Securities in the event the Disputed Claim ultimately becomes an Allowed Claim. Such Cash and any dividends, gains or income paid on account of Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests reserved for the benefit of holders of Disputed Claims shall be either (x) held by the Disbursing Agent, in an interest-bearing account or (y) invested in interest-bearing obligations issued by the United States Government, or by an agency of the United States Government and guaranteed by the United States Government, and having (in either case) a maturity of not more than thirty (30) days, for the benefit of such holders pending determination of their entitlement thereto under the terms of the Plan. No payments or distributions shall be made with respect to all or any portion of any Disputed Claim pending the entire resolution thereof by Final Order.

(b) Allowance of Disputed Claims: At such time as a Disputed Claim becomes, in whole or in part, an Allowed Claim, the Disbursing Agent shall distribute to the holder thereof the distributions, if any, to which such holder is then entitled under the Plan together with any interest which has accrued on the amount of Cash and any dividends or distributions attributable to the Plan Currency or Trust Interests so reserved (net of any expenses, including any taxes of the escrow, relating thereto), but only to the extent that such interest is attributable to the amount of the Allowed Claim. Such distribution, if any, shall be made as soon as practicable after the date that the order or judgment of the Bankruptcy Court allowing such Disputed Claim becomes a Final Order but in no event more than ninety (90) days thereafter. The balance of any Cash previously reserved shall be included in Creditor Cash and the balance of any Plan Currency and Trust Interests previously reserved shall be included in future calculations of Plan Currency and Trust Interests , respectively, to holders of Allowed Claims and, to the extent determined to be distributable to holders of Allowed Equity Interests in accordance with the terms and provisions of the Plan, holders of Allowed Equity Interests.

GUIDELINES
FOR THE
DISPUTED CLAIMS RESERVE

These Guidelines for the Disputed Claims Reserve (these "Guidelines") were adopted pursuant to the [Fifth] Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, *In re Enron Corp., et al.*, including, without limitation, the Plan Supplement and the exhibits and schedules thereto (the "Plan"), for the Disbursing Agent, the Reorganized Debtor Plan Administrator and the Reorganized Debtors to follow in connection with the reserve for Disputed Claims created pursuant to Section 21.3(a) of the Plan (the "Reserve"). All capitalized terms used herein and not otherwise defined herein have the meanings given to those terms in the Plan.

I. PURPOSE

The purpose for the Reserve is for the Disbursing Agent to hold Cash, Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests and any dividends, gains or income attributable thereto (collectively, the "Reserved Assets"), in escrow for the benefit of each holder of Disputed Claims.

II. RESERVED ASSETS IN GENERAL

The Disbursing Agent shall hold and release the Reserved Assets in accordance with the requirements of the Plan, these Guidelines and other applicable law. To the extent that there is a conflict among the provisions of these Guidelines, the provisions of the Plan, and/or the Confirmation Order, each such document shall have controlling effect in the following rank order: (1) the Confirmation Order; (2) the Plan; and (3) these Guidelines.

III. CASH

All Cash held in the Reserve, including, without limitation, any dividends, gains or income paid on account of Plan Securities, Operating Trust Interests, Remaining Asset Trust Interest, Litigation Trust Interests and Special Litigation Trust Interests, shall be, pending release pursuant to the Plan, (i) held in the name of the Disbursing Agent for the benefit of holders of Disputed Claims in an interest bearing account with a depositary institution or trust company organized under the laws of the United States of America or any state thereof, subject to supervision and examination by United States or state banking or depositary institution authorities and having, to the knowledge of the Disbursing Agent at the time such deposit is made, reported capital and surplus in excess of $100 million, or (ii) invested in interest-bearing obligations issued by the United States Government, or by an agency of the United States Government and guaranteed by the United States Government, and having (in either case) a maturity of not more than thirty (30) days.

IV. PLAN SECURITIES

1. The Disbursing Agent may only vote and sell Plan Securities as record holder of such securities pursuant to the instructions of, or upon the prior approval of, the DCR Overseers pursuant to the Guidelines for the DCR Overseers, subject to

applicable law. The Reorganized Debtor Plan Administrator or any member of the DCR Overseers shall promptly call a meeting of the DCR Overseers each time (i) a shareholder vote of Plan Securities is called for a matter, whether by solicitation of proxy or otherwise, or (ii) an offer is made by a third party to the Disbursing Agent or the Reorganized Debtor Plan Administrator to purchase Plan Securities. At such meeting, the Reorganized Debtor Plan Administrator shall provide (to the maximum extent allowed by applicable law) such information as an officer of a public corporation chartered under Delaware would be required to provide to its board of directors in a similar situation.

2. The Disbursing Agent shall comply with all applicable securities laws with regard to the possession of any material non-public information regarding Plan Securities, including, without limitation, requirements to maintain confidentiality and restrictions on selling.

3. The Disbursing Agent shall comply as a record holder of Plan Securities with all securities, corporate and other laws applicable to a holder of large amounts of Plan Securities, including, without limitation, filing any required Schedules 13D and forms required under Section 16 of the Securities Exchange Act of 1934.

4. Upon each release of Plan Securities to the holders of Allowed Claims, the Disbursing Agent shall give notice of such release to the applicable transfer agent identifying the recipients of such Plan Securities.

V. OPERATING TRUST INTERESTS AND REMAINING ASSET TRUST INTERESTS

1. The Disbursing Agent shall hold all Operating Trust Interests and Remaining Asset Trust Interests as a record holder of such interests subject to the requirements and restrictions of the Operating Trust Agreement and Remaining Asset Trust Agreement, respectively, including, without limitation, restrictions on transfer.

2. Upon each release of Operating Trust Interests and Remaining Asset Trust Interests to the holders of Allowed Claims, the Disbursing Agent shall give notice of such release to the applicable trustee identifying the recipients of such trust interests.

3. The Disbursing Agent shall not have the authority to sell or otherwise dispose of any Operating Trust Interests or Remaining Asset Trust Interests, except to release such interests to holders of Allowed Claims as permitted by the Plan.

VI. LITIGATION TRUST INTERESTS AND SPECIAL LITIGATION TRUST INTERESTS

1. The Disbursing Agent shall hold all Litigation Trust Interests and Special Litigation Trust Interests as a record holder of such interests subject to the

requirements and restrictions of the Litigation Trust Agreement and Special Litigation Trust Agreement.

2. Upon each release of Litigation Trust Interests and Special Litigation Trust Interests to the holders of Allowed Claims, the Disbursing Agent shall give notice of such release to the applicable trustee or transfer agent identifying the recipients of such trust interests.

3. The Disbursing Agent shall not have the authority to sell or otherwise dispose of any Litigation Trust Interests or Special Litigation Trust Interests, except to release such interests to holders of Allowed Claims as permitted by the Plan.

4. The Disbursing Agent shall comply with all applicable securities laws with regard to the possession of any material non-public information regarding Litigation Trust Interests and Special Litigation Trust Interests, including, without limitation, any requirements to maintain confidentiality.

5. The Disbursing Agent shall comply as a record holder of Litigation Trust Interests and Special Litigation Trust Interests with all securities, trust and other laws applicable to a holder of large amounts of Litigation Trust Interests and Special Litigation Trust Interests, including, without limitation, filing any required Schedules 13D and forms required under Section 16 of the Securities Exchange Act of 1934.

6. Any sale of Plan Securities from the Reserve may only be made after the holders of Plan Securities other than the Reserve have been given an opportunity to participate in such sale on a pro rata basis by (i) a tender offer to such holders as required by the Securities Exchange Act of 1934, and the rules thereunder (as amended), or (ii) merger of the issuer of such Plan Securities, in either event, in a manner that satisfies Section 1123(a)(4) of the Bankruptcy Code with respect to the holders of Allowed Claims that have received the securities of the same class of the Plan Securities to be sold and the holders of Disputed Claims that would be entitled to distribution of shares in such class of Plan Securities if such Disputed Claims were allowed pursuant to the Plan.

VII. SELECTION OF DCR OVERSEERS

1. The initial DCR Overseers shall be selected and appointed by the Debtors prior to the Effective Date, which shall consist of a group of five (5) Persons, with the consent of (a) the Creditors' Committee with respect to four (4) of the Debtors' selections (the "Committee Approved Overseers") and (b) the ENA Examiner with respect to one (1) of the Debtors' selections (the "ENA Examiner Approved Overseer").

2. A DCR Overseer may be removed by a unanimous vote of the other DCR Overseers; provided, however, such removal may only be made for Cause (hereinafter defined). In the event of a vacancy in a DCR Overseer's position (whether by removal, death or resignation), a new DCR Overseer may be

appointed to fill such position by a majority of the other DCR Overseers, with the consent of (i) in the case of a replacement of a Committee Approved Overseer, if the Creditors' Committee has not been dissolved, the Creditors' Committee, and (ii) in the case of a replacement of an ENA Examiner Approved Overseer, if the ENA Examiner has not been discharged, the ENA Examiner; provided, however, in the case of a replacement of an ENA Examiner Appointed Overseer, the remaining DCR Overseers shall select such new member from the list of potential ENA Examiner Appointed Overseers set forth on Exhibit A[1] to the extent that such individuals are available and willing to serve as a DCR Overseer and have not been previously removed as a DCR Overseer for Cause. In the event that there are no remaining DCR Overseers, appointments to fill such vacancies shall be made upon an order entered after an opportunity for a hearing by the Bankruptcy Court, upon motion of the Reorganized Debtor Plan Administrator.

For purposes of this Article VII, "Cause" with respect to any DCR Overseer shall be defined as: (i) such DCR Overseer's theft or embezzlement or attempted theft or embezzlement of money or tangible or intangible assets or property; (ii) such DCR Overseer's violation of any law (whether foreign or domestic), which results in a felony indictment or similar judicial proceeding; (iii) such DCR Overseer's recklessness, gross negligence, willful misconduct, breach of fiduciary duty or knowing violation of law, in the performance of its duties; (iv) such DCR Overseer's failure to perform any of its other material duties under these Guidelines or the Guidelines for the DCR Overseers; provided, however, the DCR Overseer shall have been given a reasonable period to cure any alleged Cause under clauses (iii) (other than willful misconduct) and (iv).

VIII. TAX TREATMENT

Subject to the receipt of contrary guidance from the IRS or a court of competent jurisdiction (including the receipt by the Disbursing Agent of a private letter ruling requested by the Disbursing Agent, or the receipt of an adverse determination by the IRS upon audit if not contested by the Disbursing Agent, or a condition imposed by the IRS in connection with a private letter ruling requested by the Debtors), the Disbursing Agent shall (i) treat the Reserve as one or more discrete trusts (which may be composed of separate and independent shares) for federal income tax purposes in accordance with the trust provisions of the IRC (Sections 641 et seq.) and (ii) to the extent permitted by applicable law, report consistent with the foregoing for state and local income tax purposes.

IX. FUNDING OF RESERVE EXPENSES

If the Reserve has insufficient funds to pay any expenses, including, without limitation, indemnification of DCR Overseers and applicable taxes imposed upon it or its assets, subject to the provisions contained in the Plan, the Reorganized Debtors shall advance to the Reserve the funds necessary to pay such expenses (an "Expense Advance"), with such Expense Advances

[1] A list of four (4) potential ENA Examiner Appointed Overseers to be selected by the Debtors after consultation with the ENA Examiner prior to the Effective Date.

repayable from future amounts otherwise receivable by the Reserve pursuant to Section 21.3 of the Plan or otherwise. If and when a distribution is to be made from the Reserve, the distributee will be charged its pro rata portion of any outstanding Expense Advance (including accrued interest). If a cash distribution is to be made to such distributee, the Disbursing Agent shall be entitled to withhold from such distributee's distribution the amount required to pay such portion of the Expense Advance (including accrued interest charged by the Reorganized Debtors as reasonably determined by the Reorganized Debtor Plan Administrator). If such cash is insufficient to satisfy the respective portion of the Expense Advance and there is also to be made to such distributee a distribution of other Plan Currency or interests in the trusts to be created pursuant to the Plan, the distributee shall, as a condition to receiving such other assets, pay in cash to the Disbursing Agent an amount equal to the unsatisfied portion of the Expense Advance (including accrued interest). Failure to make such payment shall entitle the Disbursing Agent to reduce and permanently adjust the amounts that would otherwise be distributed to such distributee to fairly compensate the Reserve for the unpaid portion of the Expense Advance (including accrued interest).

X. AMENDMENTS

Any provision of these Guidelines may be amended or waived by the Reorganized Debtor Plan Administrator with the approval of the Bankruptcy Court upon notice and an opportunity for a hearing, provided that such amendment is not in contradiction of the Plan; provided, however, technical amendments to these Guidelines may be made, as necessary to clarify these Guidelines or enable the Reorganized Debtor Plan Administrator, the DCR Overseers and the Disbursing Agent to effectuate the terms of these Guidelines, by the Reorganized Debtor Plan Administrator without the consent of the Creditors' Committee or the approval of the Bankruptcy Court so long as notice of such technical amendment is filed as soon as reasonably practicable with the Bankruptcy Court following its effectiveness.

XI. GOVERNING LAW

These Guidelines shall be governed by the internal laws of the State of Delaware, without giving effect to the principles of conflict of laws that would require the application of the law of another jurisdiction.

GUIDELINES FOR THE DCR OVERSEERS

These Guidelines for the DCR Overseers (these "Guidelines") were adopted pursuant to the [Fifth] Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, *In re Enron Corp., et al.*, including, without limitation, the Plan Supplement and the exhibits and schedules thereto (the "Plan"), for the DCR Overseers in connection with the reserve for Disputed Claims created pursuant to Section 21.3(a) of the Plan (the "Reserve"). All capitalized terms used herein and not otherwise defined herein have the meanings given to those terms in the Plan.

I. PURPOSE

The sole purpose of the DCR Overseers shall be to determine how the Disbursing Agent is to vote and whether, and under what terms, the Disbursing Agent is to sell, Plan Securities held in the Reserve.

In discharging their duties, the DCR Overseers are authorized: (i) to review any matter that the DCR Overseers deem appropriate with respect to the Plan Securities, with access to all books, records, facilities and personnel available to the Disbursing Agent and the Reorganized Debtor Plan Administrator, except to the extent prohibited by applicable securities laws, and (ii) to retain independent counsel or other experts, with adequate funding provided by the Reserve.

II. MEMBERSHIP

The DCR Overseers shall consist of a group selected and maintained pursuant to the "Guidelines for the Disputed Claims Reserve," as amended from time to time (the "Reserve Guidelines").

III. MEETINGS

A. The DCR Overseers shall meet on a regularly-scheduled basis four times per year and more frequently as circumstances dictate, including, without limitation, each time a shareholder vote is called with respect to any Plan Securities or an offer is made to purchase Plan Securities held by the Reserve.

B. The Reorganized Debtor Plan Administrator, or a representative thereof, shall attend all meetings called of the DCR Overseers, but the presence of such Person is not necessary for the DCR Overseers to conduct business at such meeting.

C. At all meetings of the DCR Overseers, a majority of the DCR Overseers shall constitute a quorum for the transaction of business. If at any meeting of the DCR Overseers there be less than a quorum present, a majority of those present or any DCR Overseer solely present may adjourn the meeting from time to time without further notice. The act of a majority of the DCR Overseers present at a meeting at which a quorum is in attendance shall be the act of the DCR Overseers.

D. No DCR Overseer shall be permitted to delegate his duties or grant a proxy of his vote.

E. At the first meeting of the DCR Overseers, the DCR Overseers shall appoint a Secretary of the DCR Overseers, which may be any Person selected by a vote of the DCR Overseers. The Secretary shall act as the secretary of each meeting of the DCR Overseers unless the DCR Overseers appoint another Person to act as secretary of the meeting. The DCR Overseers shall keep regular minutes of their proceedings which shall be placed in a minute book of the DCR Overseers, which shall be available for review by the Reorganized Debtor Plan Administrator.

F. The Reorganized Debtor Plan Administrator or any member of the DCR Overseers shall call each meeting of DCR Overseers. The Secretary shall give to each DCR Overseer and the Reorganized Debtor Plan Administrator at least two (2) business days' prior notice of each such meeting. Notice of any such meeting need not be given to any DCR Overseer who shall, either before or after the meeting, submit a signed waiver of notice or who shall attend such meeting without protesting, prior to or at its commencement, the lack of notice to him. Neither the business to be transacted at, nor the purpose of, any regular or special meeting of the DCR Overseers need be specified in the notice or waiver of notice of such meeting.

G. DCR Overseers may participate in meetings in person or by telephone.

IV. KEY RESPONSIBILITIES

The DCR Overseers' role is to determine how the Disbursing Agent should vote, and whether, and under what terms, the Disbursing Agent should sell, Plan Securities as the record holder thereof for the benefit of the holders of Disputed Claims. Such role may be satisfied by instructing the Disbursing Agent to take an action or by approving an action of the Disbursing Agent.

To fulfill their purpose, the DCR Overseers shall:

A. When determining how the Disbursing Agent should vote Plan Securities:

   1. Subject to the remainder of these Guidelines, exercise their business judgment to vote the Plan Securities in a manner that they believe will maximize the value of the Plan Securities, or the proceeds thereof (whether in the form of Cash, Cash Equivalents or securities issued in exchange of Plan Securities, whether by merger, reorganization or otherwise), upon their release from the Reserve to the holders of Allowed Claims as such Claims are allowed in accordance with the Plan.

   2. Review information available to the holders of Plan Securities in connection with such vote.

3. Consult with the Reorganized Debtor Plan Administrator prior to making a decision regarding such vote.

4. Take all actions that a board of directors of a public corporation chartered in the State of Delaware would be required to take to satisfy its fiduciary duties when making a decision regarding the voting by such corporation of a comparable proportion of securities it holds in another entity.

B. When determining whether the Disbursing Agent should sell Plan Securities:

1. Subject to the remainder of these Guidelines, exercise their business judgment to maximize the value of the Plan Securities, or the proceeds thereof (whether in the form of Cash, Cash Equivalents or securities issued in exchange of Plan Securities, whether by merger, reorganization or otherwise), upon their release from the Reserve to the holders of Allowed Claims as such Claims are allowed in accordance with the Plan.

2. Review information available to the holders of Plan Securities in connection with such sale.

3. Consult with the Reorganized Debtor Plan Administrator prior to making a decision regarding such sale.

4. Take all actions that a board of directors of a public corporation chartered in the State of Delaware would be required to take to satisfy its fiduciary duties when making a decision regarding the sale by such corporation of a comparable proportion of securities it holds in another entity.

V. DUTIES; LIABILITIES; STANDARD OF CARE; INDEMNIFICATION; INSURANCE; COMPLIANCE WITH LAW

A. In the fulfillment of their role set forth in Article IV above, each of the DCR Overseers shall have the same duties, liabilities, defenses and standards of care of a director of a corporation chartered under the Delaware General Corporation Law, as the same exists or may hereafter be amended (the "DGCL").

B. Any Person who was, is, or is threatened to be made a party to a proceeding (as hereinafter defined) by reason of the fact that he is or was a DCR Overseer shall be indemnified by the Reserve to the fullest extent that a corporation is permitted to indemnify its directors under the DGCL, with the determinations that would be made by the directors or stockholders of such corporation being made by the Reorganized Debtor Plan Administrator. Such right shall be a contract right and as such shall run to the benefit of any Person who is appointed and accepts the position of a DCR Overseer or elects to continue to serve as a DCR Overseer. Any repeal or amendment of this indemnification clause shall be prospective only and shall not limit the rights of any such Person or the obligations of the Reserve with respect to any claim arising from or related to the services of such Person prior to any such repeal or amendment to this clause. In the event of the death of any person having a right of indemnification under the foregoing provisions, such right shall inure to the benefit of his heirs, executors, administrators, and personal representatives to the extent applicable under the DGCL. The rights conferred above shall not be exclusive of any other right which any Person may have or hereafter acquire under any statute, agreement, or otherwise.

C. The Reorganized Debtor Plan Administrator shall be entitled to cause the Reserve to purchase and maintain insurance utilizing funds from the Reserve on behalf of any DCR Overseer against any liability asserted against such Person or incurred by such Person in such capacity or arising out such Person's status as such, whether or not such Person would be indemnified against such liability as a director of a corporation chartered under, and as provided by, the DGCL.

D. In fulfilling their duties as DCR Overseers, each DCR Overseer shall comply with all applicable law, including, without limitation, (i) filing any required Schedules 13D or required forms under Section 16 of the Securities Exchange Act of 1934, if any, and (ii) complying with all applicable securities laws regarding the possession of any material non-public information involving Plan Securities.

VI. CONFLICTS OF INTEREST

Prior to the taking of a vote on any matter or issue or the taking of any action with respect to any matter or issue, each member of the DCR Overseers shall report to the DCR Overseers any conflict of interest such member has or may reasonably be expected to have with respect to the matter or issue at hand and fully disclose the nature of such conflict or potential conflict (including without limitation disclosing any and all financial or other pecuniary interests that such member might have with respect to or in connection with such matter or issue). A member who has or who may reasonably be expected to have a conflict of interest shall be deemed to be a "conflicted member" who shall not be entitled to vote or take part in any action with respect to such matter or issue (however such member shall be counted for purposes of determining the existence of a quorum); the vote or action with respect to such matter or issue shall be undertaken only by members of the DCR Overseers who are not "conflicted members"; and a majority of the DCR Overseers with regard to such vote shall be the majority of DCR Overseers in attendance at such meeting entitled to vote on such issue.

VII. AMENDMENTS

Any provision of these Guidelines may be amended or waived by the Reorganized Debtor Plan Administrator with the approval of the Bankruptcy Court upon notice and an opportunity for a hearing, provided that such amendment is not in contradiction of the Plan; provided, however, technical amendments to these Guidelines may be made, as necessary to clarify these Guidelines or enable the Reorganized Debtor Plan Administrator and the DCR Overseers to effectuate the terms of these Guidelines, by the Reorganized Debtor Plan Administrator without the consent of the Creditors' Committee or the approval of the Bankruptcy Court so long as notice of such technical amendment is filed as soon as reasonably practicable with the Bankruptcy Court following its effectiveness.

VIII. GOVERNING LAW

These Guidelines shall be governed by the internal laws of the State of Delaware, without giving effect to the principles of conflict of laws that would require the application of the law of another jurisdiction.

HISTORY OF THE PLAN

In accordance with the Bankruptcy Court's orders, the Debtors retained SFC to provide and perform management services. Throughout the development of the Plan, SFC's fiduciary duties and responsibilities were to each of the Debtors' estates. In November 2001, the Debtors retained The Blackstone Group ("Blackstone") as their financial advisors to assist in the evaluation of restructuring alternatives and options. In December 2001, the Debtors asked Blackstone to develop an approach for the structuring of a Chapter 11 plan.

The Debtors' Chapter 11 cases raised numerous complex issues arising principally from the interrelationships among the Debtors and their approximately 2,400 subsidiaries. These interrelationships required examination of the Debtors' respective liabilities, rights to assets, extensive inter-company claims and varying degrees of entanglement. The Debtors and the Unsecured Creditors' Committee determined that a resolution was necessary if a Chapter 11 plan for any Debtor were to succeed and before any distribution to creditors could occur.

The Debtors' efforts to negotiate the global compromise and the Plan were aimed at maximizing creditors' recoveries and minimizing the risks and costs of litigation. Given the diverse creditor body and the many complex issues posed by the Chapter 11 Cases and mindful of their respective fiduciary duties to creditors, the Debtors and the Unsecured Creditors' Committee engaged in intensive analysis, and spirited discussions and debate, regarding the terms of a chapter 11 plan and related matters.

The discussions or negotiations with the Unsecured Creditors' Committee began as early as February 2002. These negotiations involved discussions on a variety of issues that led to the development of the Plan, including (a) maximizing value to creditors, (b) resolving issues regarding substantive consolidation and other inter-estate and inter-creditor disputes, and (c) facilitating an orderly and efficient distribution of value to creditors. The Plan, and the global compromise and settlement embodied therein, represent the culmination of these efforts.

On October 29, 2002, the Debtors made a presentation to the Unsecured Creditors' Committee regarding a plan structure, which considered a variety of scenarios. Between October 29, 2002 and January 15, 2003, the Debtors and their professionals and professionals for the Unsecured Creditors' Committee met three or four times to further analyze the distribution model in connection with the development of the Plan.

On January 15, 2003, the Debtors made a presentation to the Unsecured Creditors' Committee suggesting an approach to consider the treatment of Claims and the mechanics of distributions. The Debtors and the Unsecured Creditors' Committee continued to engage in substantive discussions regarding the outlines of a plan and subsequently agreed to the distribution formula included in the global compromise and the Plan to resolve a variety of inter-estate issues, including substantive consolidation. Thereafter, the Debtors and their professionals met with the professionals of the Unsecured Creditors' Committee on a weekly basis.

Consistent with the expanded role of the ENA Examiner as plan facilitator for the ENA Creditors, the ENA Examiner and his professionals were also involved in the Plan negotiations on behalf of stakeholders of ENA and its subsidiaries, particularly those stakeholders that held guaranties issued by ENE and other entities.

On February 14, 2003, the Debtors made a detailed presentation to the ENA Examiner and certain Creditors of ENA and its subsidiaries, which represented a cross-section of creditors (including traders, insurers and institutional investors), with respect to the concepts underlying the global compromise embodied in the Plan.

In the summer of 2003, the Debtors and the Unsecured Creditors' Committee reached a compromise with the ENA Examiner, which was incorporated into the Initial Plan filed on July 11, 2003, along with the disclosure statement filed in connection therewith.

At that time, the ENA Examiner executed and delivered a letter agreement, dated July 10, 2003, wherein he informed the Debtors and the Unsecured Creditors' Committee that he believed the compromises and settlements incorporated into the Initial Plan were reasonable and that the economic treatment to Creditors of ENA and its subsidiaries was fair and worthy of being accepted by such creditors.

In October 2003, the ENA Examiner notified the Court, the Debtors and the Unsecured Creditors' Committee that he was withdrawing his support for the Initial Plan and the First Amended Plan due to certain misunderstandings between the ENA Examiner, on the one hand, and the Debtors and the Unsecured Creditors' Committee, on the other hand, regarding the terms of the global compromise. In an effort to preserve the global compromise, the Debtors, the Unsecured Creditors' Committee and the ENA Examiner resumed discussions and negotiations over the terms of a joint chapter 11 plan through November 2003. The parties could not reach a mutual understanding and, on November 13, 2003, the Debtors, with the support of the Unsecured Creditors' Committee but without the support of the ENA Examiner, filed the Second Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code (the "Second Amended Plan"), as well as the disclosure statement filed in connection therewith. The ENA Examiner objected to the disclosure statement for the Second Amended Plan. On November 13, 2003, the Debtors and the Unsecured Creditors' Committee filed a joint reply to the ENA Examiner's objection.

After the filing of the Second Amended Plan on November 13, 2003, the Court convened a chambers' conference among the Debtors, Unsecured Creditors' Committee, ENA Examiner and their respective professionals and strongly urged the parties to continue to attempt to achieve a global resolution satisfactory to the Debtors, the Unsecured Creditors' Committee and the ENA Examiner. Following additional negotiations, on December 5, 2003, the Debtors, the Unsecured Creditors' Committee and the ENA Examiner agreed to modify certain provisions of the previous global compromise. These modifications were incorporated in the Debtors' Third Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code (the "Third Amended Plan"), filed on December 17, 2003, along with the disclosure statement filed in connection therewith.

On January 4, 2004, the Debtors filed the Fourth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code (the "Fourth Amended Plan") and a disclosure statement in connection therewith. The Fourth Amended Plan addressed certain objections that had been raised to the adequacy of the information contained in the disclosure statement and Third Amended Plan.

The hearing to approve the disclosure statement commenced on January 4, 2004. On January 9, 2004, the Debtors filed the Fifth Amended Joint Plan of Affiliated Debtors pursuant to Chapter 11 of the United States Bankruptcy Code (the "Fifth Amended Plan") and a disclosure statement in connection therewith. The Fifth Ameded Plan reflected additional changes made in connection with the Bankruptcy Court's approval of the disclosure statement and was the Plan submitted to all Creditors for approval.

The Bankruptcy Court found that the Plan was proposed in good faith and not by any means forbidden by law, and further, that the Plan is the result of extensive arm's-length discussions, debate and/or negotiations among the Debtors, the Unsecured Creditors' Committee and the ENA Examiner.

Substantially all of the major economic parties in interest in the Chapter 11 Cases supported the Plan , including (a) the unanimous support of the Unsecured Creditors' Committee, which represented all unsecured claimholders of the Debtors' estates, (b) the various parties with whom the Debtors negotiated settlements and which supported, or did not object to confirmation of, the Plan, including National City Bank and Baupost Group, and (c) the ENA Examiner on behalf of ENA's Creditors. Both the Unsecured Creditors' Committee and the ENA Examiner submitted letters in support of the Plan, which were transmitted to Creditors along with their solicitation packages. The Bankruptcy Court found that no evidence was submitted by any objector sufficient to rebut the Debtors' evidence concerning the good faith, arm's-length nature of negotiations regarding the Plan.

SECURITIES AND EXCHANGE COMMISSION

(Release No. 35-27810; 70-10199)

Memorandum Opinion and Order Approving Plan of Reorganization Under Section 11(f) and Issuing Report Under Section 11(g)

March 9, 2004

THIS ORDER AND REPORT IS REQUIRED BY THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935. SECURITY HOLDERS SHOULD READ THE DISCLOSURE STATEMENT PROVIDED TO THEM BY THE DEBTORS-IN-POSSESSION BEFORE DETERMINING WHETHER OR NOT TO ACCEPT THE PLAN.

Enron Corp. ("Enron"), a public-utility holding company,[1] has filed an application, as amended, with the Securities and Exchange Commission ("Commission"), on its own behalf and on behalf of its subsidiaries and affiliates in the bankruptcy cases under Chapter 11 ("Chapter 11 Cases") of the United States Bankruptcy Code ("Bankruptcy Code") in the United States Bankruptcy Court for the Southern District of New York ("Bankruptcy Court") (together with Enron, "Debtors"),[2] for an order: (i) approving the Debtors' Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the Bankruptcy Code, dated January 9, 2004 ("Plan") under section 11(f) of the Public Utility Holding Company Act of 1935, as amended ("Act"); (ii) issuing a report on the Plan under section 11(g) of the Act; and (iii) authorizing Debtors under rules 62 and 64 to continue the Bankruptcy Court's authorized solicitation of votes of the Debtors' creditors for acceptances or rejections of the Plan and to make available to

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[1] Enron is a public-utility holding company by reason of its ownership of Portland General Electric Company ("Portland General" and "PGE"), an Oregon electric utility.

[2] The Debtors, other than Enron, are identified in Exhibit H of the application. Portland General is not a Debtor.

creditors a report on the Plan, as prescribed in section 11(g) of the Act. The application is sometimes referred to below as the "Plan Application."

The Commission issued a notice of the application on February 6, 2004.[3] No request for a hearing was received.

I. Background

A. Enron and its Subsidiaries

From 1985 through mid-2001, Enron grew from a domestic natural gas pipeline company into a large global natural gas and power company. Headquartered in Houston, Texas, Enron and its subsidiaries provided products and services related to natural gas, electricity and communications to wholesale and retail customers. As of December 2001, the Enron companies employed approximately 32,000 individuals worldwide. The companies were principally engaged in: (i) the marketing of natural gas, electricity and other commodities, and related risk management and financial services worldwide; (ii) the delivery and management of energy commodities and capabilities to end-use retail customers in the industrial and commercial business sectors; (iii) the generation, transmission, and distribution of electricity to markets in the northwestern United States; (iv) the transportation of natural gas through pipelines to markets throughout the United States; and (v) the development, construction, and operation of power plants, pipelines, and other energy-related assets worldwide.

Enron became a public-utility holding company when it acquired Portland General in 1997. Portland General is engaged in the generation, purchase, transmission,

[3] Holding Co. Act Release No. 27800.

distribution, and retail sale of electricity in Oregon. It also sells wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States.[4] As of and for the nine months ended September 30, 2003, Portland General and its subsidiaries on a consolidated basis had operating revenues of $1,375 million, net income of $30 million, retained earnings of $517 million and assets of $3,185 million.

Portland General is not a Debtor in the Chapter 11 Cases. The application states that the utility is extensively insulated from Enron as a result of conditions imposed under Oregon law at the time of the acquisition by Enron in 1997. In addition, in an effort to preserve Portland General's investment grade credit rating, a bankruptcy-remote structure for Portland General was created in 2002.[5]

B. Status of Enron under the Act

After Enron acquired Portland General, it originally claimed exemption from registration under section 3(a)(1) of the Act by filings pursuant to rule 2. Enron subsequently filed two applications for exemption, one requesting an order under section 3(a)(1) of the Act and the other seeking an exemption by order under section 3(a)(3) or section 3(a)(5) of the Act. By order dated December 29, 2003, the Commission denied

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[4] The Oregon Public Utility Commission ("Oregon Commission") regulates Portland General with regard to its rates, terms of service, financings, affiliate transactions and other aspects of its business. The Federal Energy Regulatory Commission ("FERC") regulates the utility with respect to its activities in the interstate wholesale power markets.

[5] This structure requires the affirmative vote of an independent shareholder, who holds a share of limited voting junior preferred stock of Portland General, before the company can be placed into bankruptcy unilaterally by Enron, except in certain carefully prescribed circumstances in which the reason for the bankruptcy is to implement a transaction pursuant to which all of Portland General's debt will be paid or assumed without impairment.

the requests for exemption.[6] Enron subsequently filed an application for exemption under section 3(a)(4) of the Act on behalf of itself and two other entities.[7] This application, as it related to Enron but not the other two applicants, was set for hearing by order of the Commission dated January 14, 2004.[8]

The application in this file ("Plan Application") and the companion application in File No. 70-10200 ("Omnibus Application") seeking various authorizations necessary to implement the Plan would result in Enron's withdrawing its remaining application for exemption and registering under the Act.[9] The Omnibus Application supplements the Plan Application. The Enron group companies seek sufficient authorization under the Act to continue the solicitation of acceptances to the Plan, obtain the confirmation of the Plan before the Bankruptcy Court, implement the Plan, and conduct business within the parameters specified in the Omnibus Application, pending the confirmation and full implementation of the Plan. The Plan Application and the Omnibus Application are predicated on Enron registering under the Act prior to or simultaneously with the Commission's issuances of the requested orders.

If, as proposed under the Plan and discussed further below, Enron sells the common stock of Portland General to an unaffiliated purchaser or distributes the stock to

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[6] Holding Co. Act Release No. 27782.

[7] File No. 70-10190.

[8] Holding Co. Act Release No. 27793.

[9] The Commission issued a notice of the Omnibus Application on February 6, 2004 (Holding Co. Act Release No. 27799).

the Debtors' creditors or to a trust, Enron would deregister as a holding company upon the completion of the transaction.[10]

C. The Chapter 11 Cases

In the last quarter of 2001, the Enron group companies lost access to the capital markets, both debt and equity, and had insufficient liquidity and financial resources to satisfy their current financial obligations. On December 2, 2001 ("Initial Petition Date"), Enron and certain of its subsidiaries each filed a voluntary petition for relief under Chapter 11 of the Bankruptcy Code. As of February 3, 2004, one hundred eighty (180) Enron-related entities had filed voluntary petitions.[11] Pursuant to sections 1107 and 1108 of the Bankruptcy Code, the Debtors continue to operate their businesses and manage their properties as debtors in possession.

As noted above, Portland General is not in bankruptcy. Many other Enron companies have not filed bankruptcy petitions and continue to operate their businesses.

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[10] Enron will file a separate application with the Commission to seek authorization under section 12(d) of the Act for the sale of Portland General to a third party or the distribution of the common stock of Portland General to creditors or to a trust.

[11] As referred to below and in the Plan and Disclosure Statement, the Chapter 11 Cases are those commenced by the Debtors on or after the Initial Petition Date, Docket No. 15303, *In re Enron Corp., et al.*, Chapter 11 Case No. 01-16034 (AJG), Jan. 9, 2004 (U.S. Bankruptcy Court, S.D.N.Y.) ("Disclosure Statement Order").

On November 29, 2001, and on various subsequent dates, certain foreign affiliates of Enron in England went into administration. Shortly thereafter, various other foreign affiliates also commenced (either voluntarily or involuntarily) insolvency proceedings in Australia, Singapore and Japan. Additional filings have continued worldwide and insolvency proceedings for foreign affiliates are continuing for various companies registered in Argentina, Bahamas, Bermuda, Canada, the Cayman Islands, France, Germany, Hong Kong, India, Italy, Mauritius, the Netherlands, Peru, Spain, Sweden and Switzerland.

II. The Plan[12]

A. Introduction

On July 11, 2003, the Debtors filed a joint Chapter 11 plan and a related Disclosure Statement, both of which were subsequently amended several times. A hearing to consider the adequacy of the information in the Disclosure Statement was held commencing on January 6, 2004. On January 9, 2004, the Bankruptcy Court issued two orders approving the Disclosure Statement, establishing voting procedures, and ordering the solicitation of votes approving or rejecting the Plan.[13] The Bankruptcy Court established April 20, 2004 as the date for commencement of the Confirmation Hearing and March 24, 2004 as the last date for filing objections to confirmation of the Plan. To confirm the Plan, the Bankruptcy Court must find that (i) the Plan is feasible, (ii) it is proposed in good faith, and (iii) the Plan and the proponent of the Plan are in compliance with the Bankruptcy Code.

[12] All capitalized terms used hereinafter follow the definitions specified in the Plan and attached to this order as Attachment 1. The Plan and Disclosure Statement are attached as Exhibits I-1 and I-2 to the Plan Application. The Plan, Disclosure Statement and other documents related to the Chapter 11 Cases are also available at www.enron.com.

[13] *See* Order on motion of Enron Corp. approving the Disclosure Statement, setting record date for voting purposes, approving solicitation packages and distribution procedures, approving forms of ballots and vote tabulation procedures, and scheduling a hearing and establishing notice and objection procedures in respect of confirmation of the plan, Disclosure Statement Order, *supra* note 10; Order establishing voting procedures in connection with the plan process and temporary allowance of claims procedures related thereto, Docket No. 15296, *In re Enron Corp., et al.*, Chapter 11 Case No. 01-16034 (AJG), Jan. 9, 2004 (U.S. Bankruptcy Court, S.D.N.Y.) ("Voting Procedures Order"). Representatives of the Commission were present at the hearing to consider approval of the Disclosure Statement. The orders are attached to the Plan Application as Exhibits J-1 and J-2.

In accordance with the Disclosure Statement Orders, the Debtors have placed solicitation materials online at www.enron.com, prepared documents and diskettes for distribution and begun distribution of the materials to creditors and equity interest holders. The Debtors note that the order and report of the Commission requested in the Plan Application could be included in the Plan Supplement that is scheduled to be filed with the Bankruptcy Court and placed online at www.enron.com no later than March 9, 2004 or such date as the Bankruptcy Court may authorize. Creditors would then have the opportunity to consider the order and report prior to the expiration of the period to vote on the Plan.

B. Overview of the Plan

The Plan does not provide for Enron to survive in the long term as an ongoing entity with any material operating businesses. Enron's role as a Reorganized Debtor will be to hold and sell assets and to manage the litigation of the estates pending the final conclusion of the Chapter 11 Cases. Although it is expected that several years may be required to conclude the extensive litigation in which the Debtors' estates are involved, the three Operating Entities, including Portland General, are expected to be divested relatively soon after confirmation of the Plan.[14]

The Debtors believe that holders of all Allowed Claims impaired under the Plan will receive payments under the Plan having a present value as of the Effective Date not less than the amounts that they would likely receive if the Debtors were liquidated in a case under Chapter 7 of the Bankruptcy Code. At the Confirmation Hearing, the

[14] The Operating Entities are Portland General, Prisma Energy International Inc. ("Prisma") and CrossCountry Energy Corp. ("CrossCountry").

Bankruptcy Court will determine whether holders of Allowed Claims would receive greater distributions under the Plan than they would have received in a liquidation under Chapter 7 of the Bankruptcy Code.[15]

The Plan is premised upon the distribution of all of the value of the Debtors' assets. Since the commencement of the Chapter 11 Cases, the Debtors have been engaged in the rehabilitation and disposition of their assets to satisfy the claims of creditors. They have been consolidating, selling businesses and assets, dissolving entities and simplifying their complex corporate structure.[16] They are holding cash from prior sales pending distribution under the Plan and are positioning other assets for sale or other disposition.[17] The Debtors also have been involved in the settlement of numerous contracts related to wholesale and retail trading of various commodities.[18]

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[15] Disclosure Statement at 626.

[16] In this process, hundreds of corporations have been liquidated. On the Initial Petition Date, the Enron group totaled approximately 2,400 legal entities. Approximately 600 have been sold, merged or dissolved and approximately 1,800 remain. It is anticipated that, by the end of 2004, the number of legal entities will be reduced to that necessary for Enron's operating businesses and the liquidation of assets.

[17] The Debtors and other Enron group companies have completed a number of significant asset sales during the pendency of the Chapter 11 Cases, resulting in gross consideration to the Debtors' bankruptcy estates, non-Debtor associate companies and certain other related companies that aggregates approximately $3.6 billion. In many instances, proceeds from these sales either are segregated or are in escrow accounts. The distribution of the proceeds will require either the consent of the Creditors' Committee or an order of the Bankruptcy Court.

[18] At the commencement of the Chapter 11 Cases, both Debtor and non-Debtor companies had a significant number of non-terminated and terminated positions arising out of physical and financial contracts relating to numerous commodities. The companies have evaluated these contracts and undertaken efforts to perform, sell or settle these positions. The settlement of the contracts is approved under pre-established protocols that the Bankruptcy Court has approved.

The Debtors state that, since the Initial Petition Date, they have conducted sales efforts for substantially all of the Enron companies' core domestic and international assets.[19] In those instances where an immediate sale maximized the value of the interest, the assets either were sold or are the subject of pending sales. Following consultation with the Creditors' Committee, in those instances where the long-term prospects were anticipated ultimately to produce greater value, assets were retained. As discussed below, these retained assets will either (i) be located in one of the Operating Entities, *i.e.*, Portland General, Prisma and CrossCountry, with the stock or other equity of the Operating Entities to be distributed to Creditors pursuant to the Plan, or (ii) be sold at a later date.

Specifically, when and to the extent that an interest in any of these businesses or related businesses is sold, the resulting net sale proceeds held by a Debtor will be distributed to Creditors in the form of Creditor Cash. To the extent that Portland General, Prisma and CrossCountry have not been sold as of the Initial Distribution Date, then the value in these Operating Entities will be distributed to Creditors in the form of Plan Securities,[20] free and clear of all liens, claims, interests and encumbrances. Section 32.1(c) of the Plan provides that, commencing on or as soon as practicable after the Effective Date, the stock of the Operating Entities shall be distributed to holders of

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[19] As explained in the Disclosure Statement, Chapter 11 is the chapter of the Bankruptcy Code primarily used for business reorganization. Asset sales, stock sales and other disposition efforts, however, can also be conducted during a Chapter 11 case or pursuant to a Chapter 11 plan. Disclosure Statement at 1.

[20] Plan Securities means Prisma Common Stock, CrossCountry Common Equity and PGE Common Stock.

specified claims upon (i) allowance of General Unsecured Claims in an amount that would result in the distribution of 30% of the issued and outstanding shares of the Operating Entity, and (ii) obtaining the requisite consents for the issuance of the shares.

While the Debtors hope that the 30% threshold is reached before December 31, 2003, there can be no assurance, due to the vagaries of litigation. In the event that the threshold is not reached, the stock of the Operating Entities will be placed in Operating Trusts, discussed in section II., H., *infra*. In addition to Creditor Cash and Plan Securities, distribution will involve (to the extent that such trusts are created) interests in the Operating Trusts and in the Remaining Asset Trusts, Litigation Trust and the Special Litigation Trust.[21]

[21] The Remaining Asset Trust, the Litigation Trust and the Special Litigation Trust are Entities that, if jointly determined by the Reorganized Debtors and (provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan) the Creditors' Committee, may be created on or after the Confirmation Date in accordance with the relevant provisions of the Plan and the relevant trust agreement for the benefit of holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims and certain others, in accordance with the terms and provisions of the Plan.

To the extent that the Litigation Trust and Special Litigation Trust are implemented, these causes shall be deemed transferred to such Creditors on account of their Allowed Claims, and the Creditors will then be deemed to have contributed the causes of actions to either the Litigation Trust or the Special Trust in exchange for beneficial interests in the trusts. Pursuant to the Plan, upon the Effective Date, the Debtors will distribute Litigation Trust Interests and the Special Litigation Trust interests to holders of Allowed Unsecured Claims.

The Remaining Asset Trust is discussed further in section II., J., *infra*. The Litigation Trust and the Special Litigation Trust are discussed further in section II., I., *infra*.

It is anticipated that Creditor Cash will constitute approximately two-thirds of the Plan Currency. In the event that the Portland General sale transaction described below is consummated, the percentage would increase. Excluding the potential value of interests in the Litigation Trust and Special Litigation Trust, the Debtors estimate that the value of total recoveries will be approximately $12 billion.

B. Treatment of Claims

The Plan generally classifies the creditors of, and other investors in, the Debtors into several classes. The list below illustrates the descending order of priority of the distributions to be made under the Plan:

- Secured Claims
- Priority Claims
- General Unsecured and Convenience Claims
- Section 510 Senior Note Claims and Enron Subordinated Debenture Claims
- Penalty Claims and other Subordinated Claims
- Section 510 Enron Preferred Equity Interest Claims
- Enron Preferred Equity Interests
- Section 510 Enron Common Equity Interests and Enron Common Equity Interests

In accordance with the Bankruptcy Code, distributions are made based on this order of priority so that, absent consent, holders of Allowed Claims or Equity Interests in a given Class must be paid in full before a distribution is made to a more junior Class. Notably, the Debtors continue to believe that existing Enron common stock and preferred stock have no value. However, the Plan provides Enron stockholders with a contingent right to receive a recovery in the event that the total amount of Enron's assets, including recoveries in association with litigation and the subordination, waiver or disallowance of Claims in connection with the litigation, exceeds the total amount of Allowed Claims against Enron. No distributions will be made to holders of equity interests, unless and until all unsecured claims are fully satisfied.

In addition to the distributions on pre-petition Claims described above, the Plan provides for payment of Allowed Administrative Expense Claims in full. The Plan further provides that Administrative Expense Claims may be fixed either before or after the Effective Date.

The recovery estimates set forth in the Disclosure Statement are based on various estimates and assumptions, including those regarding the allowance and disallowance of Claims. As a result, if the estimate amount of Allowed Claims relied upon to calculate the estimated recoveries varies significantly from the actual amount of Allowed Claims, the actual creditor recoveries will vary significantly as well.[22]

More than 24,000 proofs of claim have been filed in the Chapter 11 Cases. The aggregate amount of Claims filed and schedules exceeds $900 billion, including duplication, but excluding any estimated amounts for the approximately 5,800 filed unliquidated Claims. These unliquidated Claims currently render it impossible for the Debtors to determine the maximum amount of their potential liability. In addition, the priority of claims and assertions by certain parties as to their entitlement to liens and/or constructive trusts may change the value available to satisfy Allowed General Unsecured Claims.[23]

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[22] Disclosure Statement at 570.

[23] *Id.* at 570-571.

D. Basis for Global Resolution of Chapter 11 Cases Embodied in the Plan

The Debtors state that the Plan represents a compromise and settlement of significant issues disputed by the Debtors, the Official Committee of Unsecured Creditors appointed in the Debtors' Chapter 11 Cases ("Creditors' Committee"), the Bankruptcy Court-appointed examiner to review transactions related to Enron North America Corp. ("ENA") and to represent the creditors of ENA ("ENA Examiner"),[24] and other parties in interest.[25]

The Debtors explain that, because of the diverse creditor body and the myriad of complex issues posed, the Debtors, the ENA Examiner and the Creditors' Committee spent more than one year engaged in analysis and negotiations concerning the terms of what eventually became the Plan and related matters. These discussions focused on a variety of issues, including: (i) maximizing value to creditors, (ii) resolving issues regarding substantive consolidation[26] and other inter-estate and inter-creditor disputes,

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[24] The Debtors state that ENA is the single largest creditor of Enron and its intercompany claim against Enron is its single largest asset. The ENA Examiner was appointed, among other things, to serve as a plan facilitator for ENA and its subsidiaries. The ENA Examiner has performed this function by engaging in dialogue with the Debtors, representatives of the Creditors' Committee, and certain parties in interest that assert claims against ENA and its subsidiaries, and by filing reports concerning various issues related to the Plan.

[25] The global compromise does not apply to the Portland Debtors, *i.e.*, Portland General Holdings, Inc. and Portland Transition Company, Inc. The Portland Debtors were excluded from the global compromise embedded in the Plan for various reasons, including the fact that, in contrast to the other Debtors, the Portland Debtors were not integrated into the Enron Companies' centralized processes. *See* Disclosure Statement, Appendix M: Substantive Consolidation Analysis at M-5.

[26] Generally, substantive consolidation is a judicially created equitable remedy whereby the assets and liabilities of two or more entities are pooled, and the pooled assets are aggregated and used to satisfy the claims of creditors of all the consolidated entities. Disclosure Statement at 10.

and (iii) facilitating an orderly and efficient distribution of value to creditors. The Debtors state that the Plan represents the culmination of these efforts and reflects agreements and compromises reached among the Debtors, the ENA Examiner and the Creditors' Committee concerning these issues. The Debtors note that the Creditors' Committee and the ENA Examiner fully support the Plan. The members of the Creditors' Committee have unanimously recommended that creditors vote to accept it, and both the Creditors' Committee and the ENA Examiner have included letters in the solicitation materials endorsing the Plan and urging parties to support confirmation.

The Plan incorporates various inter-Debtor, Debtor-Creditor and inter-Creditor settlements and compromises designed to achieve a global resolution of the Chapter 11 Cases. Thus, the Plan is premised upon a settlement, rather than litigation, of these disputes.[27] The settlements and compromises embodied in the Plan represent, in effect, a linked series of concessions by Creditors of every individual Debtor in favor of each other. The agreements are interdependent.

To reach the global compromise, the Debtors and the Creditors' Committee considered, among other things, the most significant inter-estate disputes (including certain issues between Enron and ENA), the issue of substantive consolidation, and the cost and delay that would be occasioned by full-blown, estate-wide litigation of such issues. The Debtors and the Creditors' Committee believe that the Plan will reduce the duration of the Chapter 11 Cases and the expenses that attend protracted disputes.

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[27] Nevertheless, as noted above and discussed in section II., I, *infra*, the Plan does provide for litigation trusts to pursue avoidance and other types of claims against numerous financial institutions, individuals and other entities, including some which may be Creditors of the Debtors' estates.

Although a litigated outcome of each issue might differ from the result produced by the Plan, the Debtors and the Creditors' Committee believe that, if the issues resolved by the Plan were litigated to conclusion, the Chapter 11 Cases would be prolonged for, at a minimum, an additional year, and probably much longer. In that regard, it is important to bear in mind that the professional fees incurred in the Chapter 11 Cases, even without such estate-wide litigation, have been approximately $330 million per year.

E. Major Components of the Global Compromise

There are several components of the global compromise, including, among others: (i) substantive consolidation of the Debtors' estates; (ii) the use of a common currency (referred to as Plan Currency)[28] to make distributions under the Plan; (iii) the treatment of Intercompany Claims and resolution of other inter-estate issues; (iv) the resolution of certain asset ownership disputes between Enron and ENA; (v) the resolution of interstate issues regarding rights to certain claims and causes of action; (vi)

[28] Art. 1.193 of the Plan defines "Plan Currency" to mean the mixture of Creditor Cash, Prisma Common Stock, CrossCountry Common Equity and PGE Common Stock to be distributed to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims pursuant to the Plan; provided, however, that, if jointly determined by the Debtors and the Creditors' Committee, "Plan Currency" may include Prisma Trust Interests, CrossCountry Trust Interests, PGE Trust Interests and the Remaining Asset Trust Interests. Prisma and CrossCountry are described below, as are the Prisma Trust, CrossCountry Trust and PGE Trust. Prisma Common Stock, Cross Country Common Equity and PGE Common Stock are referred to collectively as "Plan Securities." Art. 1.194 of the Plan. With limited exceptions, each holder of an Allowed Unsecured Claim against each Debtor shall receive the same Plan Currency, regardless of the asset composition of such Debtor's estate, on or subsequent to the Effective Date. The mixture of Plan Currency will bear direct relationship to the amount of Creditor Cash available for distribution and the value of the respective Plan Securities, as recalculated in accordance with provisions of Section 32.1(d) of the Plan. Plan Currency is discussed further in section E.3., *infra*.

the treatment of Allowed Guaranty Claims, and (vii) a reduction in the administrative costs post-confirmation. Some features of the global compromise are discussed below.

1. Issue of Substantive Consolidation

The global compromise and settlement forged by the Debtors and the Creditors' Committee is predicated upon a negotiated formula. The formula is a proxy for resolving the numerous inter-estate issues without protracted and expensive litigation. The formula would distribute value to Creditors based on hypothetical cases of substantive consolidation and no substantive consolidation. Specifically, under the global compromise of inter-estate issues embodied in the Plan (except with respect to the Portland Debtors, as noted previously), distributions of Plan Currency will be made on account of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims based on agreed percentages being applied to two scenarios for making distributions: (i) substantive consolidation of all of the Debtors, or (ii) no substantive consolidation of any of the Debtors. Accordingly, for example, subject to certain adjustments, a holder of an Allowed General Unsecured Claim will receive the sum of (i) 30% of the distribution that the Creditor would receive if the Debtors' estates were substantively consolidated, but notwithstanding such substantive consolidation, one-half of Allowed Guaranty Claims were included in the calculation; and (ii) 70% of the distribution that the Creditor would receive if the Debtors were not substantively consolidated. As noted, the 30/70 weighted average is not a precise mathematical quantification of the likelihood of substantive consolidation of each Debtor into each of the other Debtors, but, instead, a negotiated approximation of the likely recoveries if numerous inter-estate issues, including substantive consolidation, were litigated to judgment as to all Debtors.

2. Intercompany Claims

Typically, substantive consolidation eliminates all intercompany claims among the consolidated entities. In contrast, without substantive consolidation, such intercompany claims may either be treated pari passu with similarly situated third-party claims, subordinated to third-party claims or re-characterized as equity contributions. Moreover, absent substantive consolidation, each debtor may seek to disallow a given intercompany claim or to recover affirmatively on various claims or causes of action against another debtor.[29]

Prior to the Initial Petition Date, the Debtors maintained a complex corporate structure consisting of thousands of entities, which, in the aggregate, engaged in millions of inter-company transactions in the years leading to the bankruptcy filings. The myriad of prepetition intercompany claims arose from a variety of transactions, including, but not limited to, payables and receivables resulting from the centralized cash management system, asset transfers, and agreements regarding services and operations.

Under the global compromise, except with respect to the Portland Debtors, Debtors holding Allowed Intercompany Claims (*i.e.*, accounts and notes owed by one Debtor to another Debtor) will receive 70% of the distribution that the Debtor would receive if the Debtors were not substantively consolidated. As the 30% scenario is based on the hypothetical substantive consolidation of all Debtors, no distribution will be made on Intercompany Claims under this scenario.

[29] Disclosure Statement at 14.

All other potential inter-Debtor remedies, such as the potential disallowance, subordination, or re-characterization of Intercompany Claims, and certain affirmative claims or causes of action against any other Debtor, will be waived. Given the sheer volume of intercompany transactions, in an effort to conserve the estates' resources and expedite the Plan process, neither the Debtors nor the Creditors' Committee has conducted detailed diligence or analysis regarding each and every potential inter-Debtor cause of action or remedy being waived by the Debtors under the Plan. The inter-Debtor waivers were negotiated as an integral part of the global compromise in order to ensure that the efficient resolution of the Chapter 11 Cases would not be jeopardized by ongoing inter-estate disputes. These waivers will not affect, however, the Debtors' ability to pursue third parties (including non-Debtor affiliates) on any claims, causes of action or challenges available to any of the Debtors in the absence of substantive consolidation, including any avoidance actions or defenses to setoff for lack of mutuality. Similarly, for purposes of litigation commenced by the Debtors against third parties, these waivers and compromises respecting Intercompany Claims will not constitute a judicial finding that can be used by or against any of the parties to such litigation that any particular Intercompany Claims are valid debt obligations, as opposed to equity contributions or dividends.

2. Plan Currency

In light of the global compromise and the settlement of inter-estate issues, the actual consideration to be distributed on account of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims will be derived from a common pool consisting of a mixture of Creditor Cash, Prisma Common Stock, CrossCountry Common Equity and PGE Common Stock (collectively, "Plan Currency").[30] Generally, for purposes of making distributions to Creditors of each of the Debtors, a portion of Plan Currency is allocated to each Debtor following application of the 30/70 weighted average reflecting the likelihood of substantive consolidation. Each Debtor's allocated portion of Plan Currency is referred to in the Plan as the Distributive Assets attributable to the Debtor.

The following represent certain components of Plan Currency:

a. Creditor Cash

In addition to Cash available to pay Secured Claims, Administrative Expense Claims, Priority Claims and Convenience Class Claims as provided for in the Plan, Cash distributions will be made from available Creditor Cash to holders of Allowed General Unsecured Claims, Allowed Intercompany Claims and Allowed Guaranty Claims. Creditor Cash available as of the Effective Date will be equal to, or greater than, the amount of Creditor Cash as jointly determined by the Debtors and the Creditors' Committee and set forth in the Plan Supplement, which may be subsequently adjusted with the consent of the Creditors' Committee.[31]

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[30] In the event that the Litigation Trust or Special Litigation Trust is created, Plan Currency will not include interests in those trusts. *See supra* note 21 and section II., I,, *infra*. In the event that the Remaining Asset Trusts are created, however, interests in such trusts will be valued at the projected realizable value for the assets contained therein and, accordingly, will be included as a component of Plan Currency pending their distribution to Creditors in the form of Cash. *See also* section II., J., *infra*.

[31] Notwithstanding the foregoing, upon the joint determination of the Debtors and the Creditors' Committee, the Remaining Assets will be transferred to the Remaining Asset Trust, and the appropriate holders of Allowed Claims will be allocated Remaining Asset Trust Interests. As the Remaining Assets are liquidated, Creditor Cash will be distributed to the holders of the Remaining Asset Trust Interests.

b. PGE Common Stock

Enron recently announced an agreement to sell the common stock of Portland General to Oregon Electric Utility Company, LLC ("Oregon Electric"), a newly formed entity financially backed by investment funds managed by the Texas Pacific Group, a private equity investment firm.[32] The transaction is valued at approximately $2.35 billion, including the assumption of debt. The sale is subject to the receipt of Bankruptcy Court, Commission and Oregon Commission approvals and certain other regulatory authorizations.

On December 5, 2003, the Bankruptcy Court issued a bidding procedures order specifying January 28, 2004 as the last date on which competing prospective buyers could submit bids to acquire Portland General.[33] Under the Purchase and Sale Agreement, Enron is permitted to accept a bid that represents a "higher or better" offer for Portland General. No qualifying bid was received prior to the January 28, 2004 deadline. Thereafter, by order dated February 5, 2004, the Bankruptcy Court approved the purchase agreement and authorized the sale of Portland General to Oregon Electric.

In the event that Portland General is sold pursuant to the Purchase and Sale Agreement described above, the net proceeds will be distributed to Creditors in the form of Creditor Cash. If Portland General has not been sold, is no longer the subject of the Purchase and Sale Agreement, and is not the subject of another purchase agreement, then, when there are sufficient Allowed General Unsecured Claims to permit distribution of

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[32] Enron Corp. Press Release dated November 18, 2003. The Purchase and Sale Agreement is attached to the Plan Application as Exhibit B-2.

[33] Docket No. 14665, *In re Enron Corp., et al.*, Chapter 11 Case No. 01-16034 (AJG), Dec. 5, 2003 (U.S. Bankruptcy Court, S.D.N.Y.).

30% of the PGE Common Stock to holders of Allowed General Unsecured Claims, Enron will cause Portland General to distribute the PGE Common Stock to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims.[34]

Upon the joint determination of the Debtors and the Creditors' Committee, before the PGE Common Stock is released to the holders of Allowed Claims, the PGE Common Stock may first be issued to the PGE Trust, with the PGE Trust Interests being allocated to the appropriate holders of Allowed Claims and the reserve for Disputed Claims.[35] The issuance of the PGE Common Stock to the PGE Trust is an option available to the Debtors and the Creditors' Committee and, in their sole discretion, may or may not be utilized.

If formed, the PGE Trust would hold Enron's interest in Portland General as a liquidating vehicle, for the purpose of distributing, directly or indirectly, the shares of Portland General (or the proceeds of a sale of the utility) to the Debtor's creditors and

[34] To determine the date upon which the PGE Common Stock (and the CrossCountry Common Equity and the Prisma Common Stock, also discussed in this section) will be distributed, the Reorganized Debtor Plan Administrator must determine that the amount of the Allowed General Unsecured Claims against all Debtors constitute 30% or more of the total potential Claims (essentially, the sum of the Allowed Claims, the liquidated non-contingent filed and scheduled Claims and the estimated unliquidated and contingent Claims). At the time that this calculation exceeds 30% in the aggregate for all Debtors, the stock may be distributed. Disclosure Statement at 26, n.15.

[35] The PGE Trust is one of three proposed Operating Trusts under the Plan concerning Portland General, Prisma and CrossCountry. The Operating Trusts are discussed below. To allow the PGE Trust to be formed, as and when necessary under the Plan, Enron is seeking the necessary regulatory approvals for the creation of the trust.

equity holders as required by the Plan.[36] It is possible that PGE Trust also would hold Enron's interest in Portland General for the purposes of consummating the sale of the utility to Oregon Electric.[37]

As noted previously, Enron will file a separate application with the Commission to seek authorization under section 12(d) of the Act for the sale of Portland General to a third party or the distribution of the common stock of Portland General to creditors or to the PGE Trust.

c. CrossCountry Common Equity

CrossCountry is a newly formed Delaware non-Debtor indirect subsidiary of Enron.[38] As a (nonutility) holding company, CrossCountry will hold Enron's interests in several gas transportation pipelines located in the United States.[39] Pursuant to the

[36] The PGE Trust is an applicant in File No. 70-11373 for an exemption from registration under section 3(a)(4) of the Act.

[37] *See* Article XXIV of the Plan.

[38] CrossCountry was incorporated in Delaware on May 22, 2003. On June 24, 2003, CrossCountry and the CrossCountry Enron Parties entered into the original CrossCountry Contribution and Separation Agreement providing for the contribution of Enron's direct and indirect interests in its interstate pipelines and other related assets to CrossCountry. On September 25, 2003, the Bankruptcy Court issued an order approving the transfer of the pipeline interests and the related assets from the CrossCountry Enron Parties to CrossCountry and other related transactions, pursuant to the original CrossCountry Contribution and Separation Agreement. That order contemplates that the parties may make certain modifications to the original Contribution and Separation Agreement. The parties are negotiating an Amended and Restated Contribution and Separation Agreement that incorporates certain changes to the original Contribution and Separation Agreement.

[39] Among other things, CrossCountry Energy LLC ("CrossCountry LLC") replaces CrossCountry as the holding company that owns the pipeline interests. Docket No. 13381, *In re Enron Corp., et al.*, Chapter 11 Case No. 01-16034 (AJG), Oct. 8, 2003 (U.S. Bankruptcy Court, S.D.N.Y.); Docket No. 14560, *In re Enron Corp., et al.*, Chapter 11 Case No. 01-16034 (AJG), Dec. 1, 2003 (U.S. Bankruptcy Court, S.D.N.Y.).

Amended and Restated Contribution and Separation Agreement, Enron and certain of its affiliates would contribute their ownership interests in certain gas transmission pipeline businesses and certain nonutility service companies to CrossCountry LLC in exchange for equity interests in CrossCountry LLC.[40] The closing of the transactions contemplated by the Amended and Restated Contribution and Separation Agreement is expected to occur as soon as possible. It is anticipated that, following confirmation of the Plan and prior to the CrossCountry Distribution Date, the equity interests in CrossCountry LLC will be exchanged for equity interests in CrossCountry Distributing Company in the CrossCountry Transaction. As a result of the CrossCountry Transaction, CrossCountry Distributing Company will obtain direct or indirect ownership in the Pipeline Businesses and certain services companies.[41]

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[40] The Debtors expect that the contribution of the interests in the gas pipeline businesses to CrossCountry LLC under the Contribution and Separation Agreement, in exchange for equity interests in CrossCountry LLC, would be exempt capital contributions under rule 45(b)(4) under the Act.

[41] CrossCountry LLC's principal assets will, upon closing of the formation transactions, consist of the following:

- A 100% indirect ownership interest in Transwestern Holdings Company, Inc. ("Transwestern"), which, through its subsidiary Transwestern Pipeline Company, owns an approximately 2,600-mile interstate natural gas pipeline system that transports natural gas from western Texas, Oklahoma, eastern New Mexico, the San Juan basin in northwestern New Mexico and southern Colorado to California, Arizona, and Texas markets. Transwestern's net income for the year ended December 31, 2002 was $20.7 million.

- A 50% ownership interest in Citrus Corp. ("Citrus"), a holding company that owns, among other businesses, Florida Gas Transmission Company a company with an approximately 5,000-mile natural gas pipeline system that extends from South Texas to South Florida. An affiliate of CrossCountry operates Citrus and certain of its subsidiaries. Citrus's net income for the year ended

Unless CrossCountry has been sold or is subject to a purchase agreement, when there are sufficient Allowed General Unsecured Claims to permit distribution of 30% of the CrossCountry Common Equity to holders of Allowed General Unsecured Claims, Enron will cause CrossCountry Distributing Company to distribute the CrossCountry Common Equity to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims. In the event that CrossCountry is sold prior to distribution of the CrossCountry Common Equity, the net proceeds will be distributed to Creditors as Creditor Cash in lieu of CrossCountry Common Equity.

Upon the joint determination of the Debtors and the Creditors' Committee, before the CrossCountry Common Equity is released to the holders of Allowed Claims, the CrossCountry Common Equity may first be issued to the CrossCountry Trust, with the

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December 31, 2002 was $96.6 million, 50% of which, or $48.3 million, comprised Enron's equity earnings. CrossCountry LLC is expected to hold its interest in Citrus through its wholly owned subsidiary, CrossCountry Citrus Corp.

- A 100% interest in Northern Plains Natural Gas Company ("Northern Plains"), which directly or through its subsidiaries holds 1.65% out of an aggregate 2% general partner interest and a 1.06% limited partner interest in Northern Border Partners, L.P. ("Northern Border") a publicly traded limited partnership that is a leading transporter of natural gas imported from Canada to the Midwestern United States. Pursuant to operating agreements, Northern Plains operates Northern Border's interstate pipeline systems, including Northern Border Pipeline, Midwestern, and Viking. Northern Border also has (i) extensive gas gathering operations in the Powder River Basin in Wyoming, (ii) natural gas gathering, processing and fractionation operations in the Williston Basin in Montana and North Dakota, and the western Canadian sedimentary basin in Alberta, Canada, and (iii) ownership of the only coal slurry pipeline in operation in the United States. Northern Border's net income for the year ended December 31, 2002 was $113.7 million, of which $9.1 million comprised Enron's equity earnings.

CrossCountry Trust Interests being allocated to the appropriate holders of Allowed Claims and the reserve for Disputed Claims. Unless CrossCountry has been sold or is the subject of a purchase agreement, when there are sufficient Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims to permit distribution of 30% of the CrossCountry Common Equity to holders of Allowed Claims, the CrossCountry Common Equity will be released from the CrossCountry Trust to holders of Allowed Claims, with the remainder to be held in reserve for Disputed Claims. The issuance of the CrossCountry Common Equity to the CrossCountry Trust is an option available to the Debtors and the Creditors' Committee and, in their sole discretion, it may or may not be utilized.

d. Prisma Common Stock

Prisma is a Cayman Islands entity formed initially as a (nonutility) holding company pending the transfer of certain international energy infrastructure businesses that are indirectly owned by Enron and certain of its affiliates. Prisma was organized on June 24, 2003 for the purpose of acquiring the Prisma Assets, which include equity interests in the identified businesses, intercompany loans to the businesses held by affiliates of Enron and contractual rights held by affiliates of Enron. Enron and its affiliates will contribute the Prisma Assets to Prisma in exchange for shares of Prisma Common Stock commensurate with the value of the Prisma Assets contributed.

It is expected that the contribution of the Prisma Assets will be effected pursuant to the Prisma Contribution and Separation Agreement to be entered into among Prisma and Enron and several of its affiliates. The Debtors anticipate that the Prisma Contribution and Separation Agreement, which is currently being negotiated, will be submitted for Bankruptcy Court approval, either as part of the Plan Supplement or by a separate motion.

To date, no operating businesses or assets have been transferred to Prisma. Subject to obtaining requisite consents, however, the Debtors intend to transfer the businesses described above, either in connection with the Plan or at such earlier date as may be determined by Enron and approved by the Bankruptcy Court.[42] Prisma will be engaged in the generation and distribution of electricity, the transportation and distribution of natural gas and liquefied petroleum gas, and the processing of natural gas liquids.[43] Applicants intend that Prisma will be a foreign utility company ("FUCO") under section 33 under the Act prior to the transfer of the businesses described above to Prisma. The transfer of such businesses to Prisma in exchange for interests in Prisma would generally be exempt under section 33(c)(1) of the Act.

Unless Prisma has been sold or is subject to a purchase agreement, when there are sufficient Allowed General Unsecured Claims to permit distribution of 30% of the Prisma Common Stock to holders of Allowed General Unsecured Claims, Enron will cause Prisma to distribute its common stock to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims. In the event that Prisma is

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[42] In addition to Bankruptcy Court approval, the transfer of the businesses will require the consent of other parties, including, but not limited to, governmental authorities in various jurisdictions. If any of these consents are not obtained, then at the discretion of Enron, with the consent of the Creditors' Committee, as contemplated in the Plan, one or more of these businesses may not be transferred to Prisma, but remain instead, directly or indirectly, with Enron.

[43] If all businesses are transferred to Prisma as contemplated, the company will own interests in businesses with assets that include over 9,600 miles of natural gas transmission and distribution pipelines, over 56,000 miles of electric transmission and distribution lines and over 2,100 megawatts of electric generating capacity. The businesses will serve 6.5 million liquefied petroleum gas, gas and electricity customers in 14 countries.

sold prior to distribution of the Prisma common stock, the net proceeds will be distributed to Creditors as Creditor Cash in lieu of Prisma Common Stock.

Upon the joint determination of the Debtors and the Creditors' Committee, before the Prisma Common Stock is released to the holders of Allowed Claims, the Prisma Common Stock may first be issued to the Prisma Trust, with the Prisma Trust Interests being allocated to the appropriate holders of Allowed Claims and the reserve for Disputed Claims. Unless Prisma has been sold or is the subject of a purchase agreement, when there are sufficient Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims to permit distribution of 30% of the Prisma Common Stock to holders of Allowed Claims, the stock will be released from the Prisma Trust to holders of Allowed Claims, with the remainder to be held in reserve for Disputed Claims. The issuance of the Prisma Common Stock to the Prisma Trust is an option available to the Debtors and the Creditors' Committee and, in their sole discretion, it may or may not be utilized.

Of the approximately 1,800 entities in the Enron group currently, approximately 82 entities would become part of Prisma and 15 would be contributed to CrossCountry. The remaining entities would be sold or liquidated in accordance with the Plan.

F. <u>Effectiveness of the Plan</u>

The Plan will become effective upon the satisfaction of certain conditions. Section 1.94 of the Plan specifies that the Effective Date will occur on the first business day after the Plan is confirmed after which the conditions to the effectiveness of the Plan have been satisfied or waived, but in no event later than December 31, 2004.[44] The conditions to the effectiveness of the Plan, set forth in Section 37.1, are: (i) entry of the Bankruptcy Court confirmation order; (ii) the execution of documents and other actions necessary to implement the Plan; (iii) the receipt of consents necessary to transfer assets to and establish Prisma and CrossCountry, and (iv) the receipt of consents necessary to issue the PGE Common Stock under the Plan.[45]

Implementation of the Plan will involve the required distributions to creditors, reporting on the status of Plan consummation, and applying for a final decree that closes the Chapter 11 Cases after they have been fully administered, including, without limitation, reconciliation of claims. Administration of the estates in conjunction with the Bankruptcy Court will continue post confirmation, in the manner described above, including the resolution of over one thousand adversary proceedings.

G. Administration of the Estates

1. Post-Confirmation Administration

As part of the Plan, the governance and oversight of the Chapter 11 Cases will be streamlined. On the Effective Date, a five-member board of directors of Reorganized

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[44] Under Section 1.94, the Debtors and the Creditors' Committee, in their discretion, may designate another Effective Date that falls after the Confirmation Date.

[45] As noted previously, in preparation for the distribution of Portland General under the Plan, upon receipt of all appropriate regulatory approvals, Enron may transfer its ownership interest in Portland General to PGE Trust, a to-be-formed entity. There may be an adjustment in the number of Portland common shares prior to contribution to the PGE Trust and in all events prior to distribution to creditors. If the PGE Common Stock is distributed to creditors rather than sold, it is intended that the current Portland General shares of common stock will be canceled and 80 million shares of new Portland General common stock will be authorized and approximately 62.5 million shares issued pursuant to the Plan.

Enron will be appointed, with four of the directors to be designated by the Debtors after consultation with the Creditors' Committee and one of the directors to be designated by the Debtors after consultation with the ENA Examiner.[46] The Debtors intend to file the information required by Section 1129(a)(5) of the Bankruptcy Code in the Plan Supplement no later than fifteen (15) days prior to the Ballot Date. The terms and manner of selection of the directors of each of the other Reorganized Debtors will be as provided in the Reorganized Debtors Certificate of Incorporation and the Reorganized Debtors By-laws, as they may be amended.

The ENA Examiner will (i) cease his routine reporting duties, unless otherwise directed by the Bankruptcy Court, and (ii) retain his status (other than his limited investigatory role) pursuant to orders of the Bankruptcy Court entered as of the date of the Disclosure Statement order. Pending the Effective Date of the Plan, the ENA Examiner will continue his current oversight and advisory roles as set forth in prior orders of the Bankruptcy Court, subject to the right of the Debtors, in their sole discretion, to streamline existing internal processes, including cash management and other transaction review committees.

Although the Debtors may streamline their internal processes, the information typically provided to the ENA Examiner will continue to be provided to ensure that the

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[46] Section 1129(a)(5) of the Bankruptcy Code requires that, to confirm a Chapter 11 plan, the plan proponent disclose the identity and affiliations of the proposed officers and directors of the reorganized debtors; that the appointment or continuance of such officers and directors be consistent with the interests of creditors and equity security holders and with public policy; and that there be disclosure of the identity and compensation of any insiders to be retained or employed by the reorganized debtors.

ENA Examiner can fulfill his oversight functions. The Creditors' Committee will be dissolved on the Effective Date, except as provided below.

2. Post-Effective Date Administration

Upon appointment of the new board of Reorganized Enron, from and after the Effective Date, the Creditors' Committee will continue to exist only for limited purposes relating to the ongoing prosecution of estate litigation. Specifically, the Creditors' Committee will continue to exist only (i) to continue prosecuting claims or causes of action previously commenced by it on behalf of the Debtors' estates, (ii) to complete other litigation, if any, to which the Creditors' Committee is a party as of the Effective Date (unless, in the case of (i) or (ii), the Creditors' Committee's role in such litigation is assigned to another representative of the Debtors' estates, including the Reorganized Debtors, the Litigation Trust or the Special Litigation Trust) and (iii) to participate, with the Creditors' Committee's professionals and the Reorganized Debtors and their professionals, on the joint task force created with respect to the prosecution of the Litigation Trust Claims pursuant to the terms and conditions and to the full extent agreed between the Creditors' Committee and the Debtors as of the date of the Disclosure Statement Order. Thus, virtually all of the decisions that will need to be made with respect to, among other things, (i) the disposition of the Debtors' Remaining Assets, (ii) the reconciliation of Claims and (iii) the prosecution or settlement of numerous claims and causes of action (other than specific litigation involving the Creditors' Committee, as set forth above), will be made by Reorganized Enron through its agents, and the board of Reorganized Enron will oversee such administration. The Debtors believe that this post-Effective Date administration is consistent with the goals of reducing the expenses in the

Chapter 11 Cases and will maximize recoveries to Creditors entitled to distributions under the Plan.

The Plan does provide, however, that the ENA Examiner may have a continuing role during the post-Effective Date period. Within 20 days after the Confirmation Date, the ENA Examiner or any creditor of ENA or its subsidiaries will be entitled to file a motion requesting that the Bankruptcy Court define the duties of the ENA Examiner for the period following the Effective Date. If no such pleading is timely filed, the ENA Examiner's role will conclude on the Effective Date.[47] The Debtors and the Creditors' Committee intend to object to the continuation of the ENA Examiner during the post-Effective Date period.

The Plan also provides for the appointment of a Reorganized Debtor Plan Administrator ("Administrator") on the Effective Date for the purpose of carrying out the provisions of the Plan. Pursuant to Section 1.226 of the Plan, the Administrator would be

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[47] The Plan's flexibility in this regard is not intended, nor will it be deemed, to create a presumption that the role or duties of the ENA Examiner should or should not be continued after the Effective Date; provided, however, that in no event will the ENA Examiner's scope be expanded beyond the scope approved by orders entered as of the date of the Disclosure Statement Order. In the event that the Bankruptcy Court enters an order defining the post-Effective Date duties of the ENA Examiner, notwithstanding the narrower scope of the Creditors' Committee envisioned by the Plan, the Creditors' Committee will continue to exist following the Effective Date to exercise all of its statutory rights, powers and authority until the date the ENA Examiner's rights, powers and duties are fully terminated pursuant to a Final Order.

Stephen Forbes Cooper, LLC, an entity headed by Stephen Forbes Cooper, Enron's Acting President, Acting Chief Executive Officer and Chief Restructuring Officer.[48]

In accordance with Section 36.2 of the Plan, the Administrator shall be responsible for (i) facilitating the Reorganized Debtors' prosecution or settlement of objections to, and estimations of, claims, (ii) prosecution or settlement of claims and causes of action held by the Debtors, (iii) assisting the litigation trustees in performing their duties, (iv) calculating and assisting the Disbursing Agent in implementing all distributions in accordance with the Plan, (v) filing all required tax returns and paying taxes and all other obligations on behalf of the Reorganized Debtors from funds held by the Reorganized Debtors, (vi) periodic reporting to the Bankruptcy Court of the status of the claims resolution process, distributions on allowed claims and prosecution of causes of action, (vii) liquidating the Remaining Assets and providing for the distribution of the net proceeds thereof, in accordance with the Plan, (viii) consulting with, and providing information to, the Disputed Claims Reserve overseers in connection with the voting or sale of Plan Securities to be deposited in the Disputed Claims Reserve, and (ix) such other responsibilities as may be vested in the Administrator under the Plan, the

[48] Mr. Cooper assumed this role at Enron on January 29, 2002, after Enron filed for bankruptcy under Chapter 11. Mr. Cooper is also the chairman of Kroll Zolfo Cooper, LLC ("Kroll"), and Kroll's Corporate Advisory and Restructuring Group. Kroll is a consulting company that provides services in corporate recovery and crisis management, forensic accounting, technology, intelligence, investigations and background screening. The Debtors state that Mr. Cooper, in his capacity as Enron's CEO, has worked with the Enron board, the Creditors' Committee, and other stakeholders in the bankruptcy process to sell non-core businesses, rehabilitate assets, prosecute the Debtors' claims against banks and professional advisors, and to assist employees. Mr. Cooper works under the supervision of Enron's board of directors, which is comprised of four individuals with extensive business and energy industry experience. The Enron board is wholly independent and each has the support of the Creditors' Committee.

Reorganized Debtor Plan Administration Agreement, Bankruptcy Court order or as may be necessary and proper to carry out the provisions of the Plan.[49] If the PGE Trust is not formed, the Administrator would also manage, administer, operate and otherwise control Portland General, subject to the supervision of the Board of Directors of the Reorganized Debtors and the consent of the Creditors' Committee.[50]

In addition, pursuant to the Plan, as of the Effective Date, the Reorganized Debtors will assist the Administrator in performing the following activities: (i) holding the Operating Entities, including Portland General, for the benefit of Creditors and providing certain transition services to such entities, (ii) liquidating the Remaining Assets, (iii) making distributions to Creditors pursuant to the terms of the Plan, (iv) prosecuting Claim objections and litigation, (v) winding up the Debtors' business affairs, and (vi) otherwise implementing and effectuating the terms and provisions of the Plan.

Finally, in connection with the prosecution of litigation claims against financial institutions, law firms, accounting firms and similar defendants, a joint task force comprised of the Debtors, Creditors' Committee representatives and certain of their professionals was formed in order to maximize coordination and cooperation between the Debtors and the Creditors' Committee. Each member of the joint task force is entitled to, among other things, notice of, and participation in, meetings, negotiations, mediations, or other dispute resolution activities with regard to such litigation. Following the Effective

[49] Section 36.2 of the Plan.

[50] Section 40.1 of the Plan provides that the board of directors of reorganized Enron shall consist of five persons selected by the Debtors, after consultation with the Creditors' Committee (with respect to four members) and the ENA Examiner (with respect to one member).

Date, the Creditors' Committee representatives, together with the Creditors' Committee's professionals, may continue to participate in the joint task force.

H. Operating Trusts

The Plan describes the purpose of the Operating Trusts (the PGE Trust, the Prisma Trust and the CrossCountry Trusts) and the proposed management of the trusts. The Operating Trusts would be established on behalf of the Debtors and the holders of allowed claims in certain specified classes.[51]

For all federal income tax purposes, all parties (including the Debtors, the Operating Trustee and the beneficiaries of the Operating Trusts) must treat the transfer of assets to the respective Operating Trusts as a transfer to the holders of certain allowed claims, followed by a transfer by these holders to the respective Operating Trusts. The beneficiaries of the Operating Trusts are treated as the grantors of the trusts.[52]

The rights of the Operating Trustees to invest assets transferred to the Operating Trusts, the proceeds of the investments, or any income earned by the respective Operating Trusts, will be limited to the right and power to invest the assets (pending

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[51] Each Trust will be managed in accordance with an Operating Trust Agreement, which must be satisfactory to the Creditors' Committee in form and substance. The Operating Trust Agreement will provide for the management of the trust by the Operating Trustee.

The Operating Trusts would be formed by the execution of the respective Operating Trust Agreements as soon as is practical after the receipt of all appropriate or required governmental, agency or other consents authorizing the transfer of the respective assets to the Operating Trusts. *See* Plan Section 24.1. With respect to the PGE Trust, the authorization of the Oregon Commission and the FERC may be required prior to the contribution of the common stock of Portland General into the PGE Trust and the distribution of the stock to the creditors.

[52] Consistent with this view, under the Operating Trust Agreements, the Debtors on the Effective Date will have no obligation to provide any funding with respect to any of the Operating Trusts.

periodic distributions) in cash equivalents. The Operating Trustees must distribute at least annually to the holders of the respective Operating Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets, but the Operating Trustees may retain amounts necessary to satisfy liabilities and to maintain the value of the assets of the Operating Trusts during liquidation and to pay reasonable administrative expenses. The Operating Trusts must terminate no later than the third anniversary of the Confirmation Date, provided, however, that the Bankruptcy Court may extend the term of the Operating Trusts for additional periods not to exceed three years in the aggregate if it is necessary to liquidate the assets of the Operating Trusts.[53]

I. Litigation Trust and Special Litigation Trust

The Plan provides that the Plan Currency and, if applicable, the Trust Interests[54] to be distributed to each holder of an Allowed General Unsecured Claim against each Debtor, shall equal the sum of (i) 70% of the distribution such holder would receive if the Debtors were not substantively consolidated and (ii) 30% of the distribution such holder would receive if all of the Debtors' estates were substantively consolidated, but

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[53] The United States Internal Revenue Service has stated that an organization created under Chapter 11 of the Bankruptcy Code to be a liquidating trust will be characterized as such if it meets certain requirements. In particular, the IRS requires the trustee of a liquidating trust to commit to make continuing efforts to dispose of the trust assets, make timely distributions, and not unduly prolong the duration of the trust. The Debtors state that these requirements are all incorporated into the Plan. *See generally*, Plan Article XXIV. *See also*, Rev. Proc. 94-45, 1994-2 CB 684, *amplifying and modifying* Rev. Proc. 82-58, 1982-2 CB 847, and Rev. Proc. 91-15, 1991-1 CB 484.

[54] Art. 1.262 defines Trust Interests to mean Litigation Trust Interests in the event that the Litigation Trust is created and Special Litigation Trust Interests in the event that the Special Litigation Trust is created.

notwithstanding such substantive consolidation, one-half of Allowed Guaranty Claims were included in such calculation.

The Plan provides for holders of Allowed Unsecured Claims against Enron (which includes Allowed Guaranty Claims and Allowed Intercompany Claims) to share the proceeds, if any, from numerous potential causes of action. To the extent that the Litigation Trust and Special Litigation Trust are implemented, these causes of action shall be deemed transferred to Creditors, on account of their Allowed Claims, and then be deemed to have contributed such causes of actions to either the Litigation Trust or the Special Litigation Trust, in exchange for beneficial interests in the trusts. The Debtors shall include, in the Plan Supplement, a listing of the claims and causes of action, comprising Litigation Trust Claims and Special Litigation Trust Claims, and which may be transferred to and prosecuted by the Litigation Trust and the Special Litigation Trust.

J. Remaining Assets

It is anticipated that the Reorganized Debtors will retain all assets that will not be transferred to the Litigation Trust, Special Litigation Trust, Severance Settlement Fund Trust, Operating Trusts or Operating Entities. These Remaining Assets may include, among other things, Cash, claims and causes of action against third parties on behalf of the Debtors' estates (including, but not limited to, avoidance actions), proceeds of liquidated assets, the Debtors' stock in the Enron Companies, trading contracts, equity investments, inventory, real property and other miscellaneous assets.

The Reorganized Debtor Plan Administrator, with assistance from the Reorganized Debtors, will collect and liquidate the Remaining Assets and distribute the proceeds to Creditors pursuant to the terms of the Plan. The board of directors of the Reorganized Debtors will supervise this process.

Nonetheless, upon joint determination of the Debtors and the Creditors' Committee, the Debtors' interests in the Remaining Assets will be transferred to the holders of certain Allowed Claims, which will be held by the Debtors acting on their behalf. Immediately thereafter, on behalf of the holders of the Allowed Claims, the Debtors will transfer the assets, subject to Remaining Asset Trust Agreements, to the Remaining Asset Trusts for the benefit of the holders of the Allowed Claims in accordance with the Plan. In the event that the Debtors and the Creditors' Committee jointly determine to create the Remaining Asset Trusts on or prior to the date on which the Litigation Trust is created, interests in the Remaining Asset Trusts will be deemed to be allocated to holders of Allowed Claims at the then estimated value of Remaining Assets. The allocation of Remaining Asset Trust Interests will form part of the Plan Currency, in lieu of Creditor Cash, and Creditors holding Allowed Claims will receive distributions on account of such interests in Cash, as and when Remaining Assets are realized upon.

III. Discussion

The Debtors request Commission approval of the Plan under section 11(f) of the Act. The Debtors further seek Commission authorization under section 11(g) of the Act and related rules to disseminate the Plan, together with the Disclosure Statement, to parties of interest in order to solicit votes to approve the Plan. Applicants request that the

Commission issue a report pursuant to section 11(g) of the Act to accompany the solicitation.[55]

Section 11(f) of the Act does not provide a specific standard for the Commission to use in analyzing a plan of reorganization. Instead, in approving a plan of reorganization, the Commission must conclude that the plan meets any applicable requirements of the Act.[56] The record in this matter demonstrates that approval of the Debtors' requests would likely not be detrimental to the protected interests under the Act, *i.e.*, the public interest and the interests of investors and consumers. For the reasons discussed below, it appears that the Plan is fair to the Debtors and their respective Creditors.

The Plan Application states that the Debtors and the Creditors' Committee firmly believe that the global compromise embodied in the Plan is fair to each of the Debtors and their respective Creditors and falls within the range of reasonableness required for

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[55] Section 11(g) of the Act in pertinent part makes it unlawful for any person to solicit any consent in respect of a reorganization plan of a registered holding company or subsidiary unless the plan, containing such information as the Commission may deem necessary or appropriate in the public interest or for the protection of investors and consumers, has been submitted to the Commission; each solicitation is accompanied by a copy of a report on the plan made by the Commission after an opportunity for a hearing on the plan; and each solicitation is made not in contravention of such rules or orders as the Commission may deem necessary or appropriate in the public interest or for the protection of investors or consumers.

[56] The Commission has noted that Congress, in imposing the duty under section 11(f) to pass upon reorganizations of registered holding companies and their subsidiaries, recognized that the Commission's efforts should be coordinated with the work of the courts in reorganization cases. The objectives of the Act could not be achieved if, while the Commission was applying the standards of the Act in some cases, reorganizations could be effected through the courts without the application of such standards. *Xcel Energy, Inc.*, Holding Co. Act Release No. 27736 (Oct. 10, 2003), citing *Utilities Power and Light Co.*, 5 SEC 483, 512 (1939), quoting *Peoples Light and Power Co.*, 2 SEC 829, 844 (1937) (Comm. Healy concurring). *See also Columbia Gas Transmission Corporation*, Holding Co. Act Release No. 26361 (Aug. 25, 1995).

approval by the Bankruptcy Court. The ENA Examiner has also agreed that the global compromise is within the range of reasonableness as to the creditors of ENA and its subsidiaries, and has recommended that the ENA Creditors vote in favor of the Plan.[57]

Although the Debtors and the Creditors' Committee believe that the settlements contained in the Plan are reasonable, they also emphasize the benefits of avoiding estate-wide litigation by Creditors having conflicting interests. Specifically, they believe that, if a compromise had not been reached, the cost, delay and uncertainty attendant to litigating the complex inter-estate issues resolved by the Plan would have resulted in substantially lower recoveries for most, if not all, Creditors.

With respect to the common Plan Currency concept for all Creditors, the Debtors and the Creditors' Committee believe that this feature of the global compromise promotes efficiency without being unfair or inequitable. They note that concerns have previously been raised by certain Creditors of ENA that the filing of a joint plan involving ENA and the other Debtors would be unfair, because ENA has been in liquidation since shortly after the Initial Petition Date, and should not be unnecessarily entangled with the estates of the other Debtors, including Enron. However, the ENA Creditors would not be materially disadvantaged by the common Plan Currency feature between the estates of ENA and Enron because, as noted previously, ENA is the single largest Creditor of Enron and its intercompany claim against Enron is ENA's single largest asset. Thus, distributions to ENA Creditors necessarily depend in large part on what ENA recovers on

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[57] The ENA Examiner has stated that the settlement contained in the Plan is reasonable and that the treatment of the Creditors of ENA and its subsidiaries is fair and reasonable. Accordingly, the ENA Examiner endorses a vote by the Creditors in favor of the Plan and supports its confirmation.

its Intercompany Claim against Enron. Similarly, Enron's intercompany claims against Enron Power Marketing, Inc. and numerous other Debtors would result in assets of such other Debtors being transferred to Enron for further distribution to Enron's Creditors, including ENA. Thus, while it is an integral feature of the global compromise, the common Plan Currency feature of the Plan is also justifiable for many of the Debtors because of the way in which value is transferred through intercompany claims. In any event, based on the Debtors' current estimates of asset values and Allowed Claims, Plan Currency is expected to be approximately two-thirds in the form of Creditor Cash and approximately one-third in the form of Plan Securities.

As noted above, the Plan is constructed to conform to the provisions of section 1129 of the Bankruptcy Code. As such, it adheres to the dictates of the "absolute priority" provisions of the Bankruptcy Code and applicable law. Although current valuations of the Debtors' assets do not indicate that a distribution will be made to the Debtors' preferred and common interest holders, the Plan does provide that, if (i) asset sales yield proceeds greater than currently projected, and if (ii) recoveries associated with the resolution of litigation (including, without limitation, the subordination, waiver or disallowance of claims as a result of the Litigation Claims and the Special Litigation Claims) are at a level that Creditors shall have received distributions which, in the aggregate, are equal to 100% of their Claims, the Plan shall be modified to provide for distributions to preferred and common interest holders. In addition, the Plan does not affect in any manner the recoveries that public bondholders and equity interest holders may receive as a result of pending class actions or other third party actions or with respect to the funds that have been recovered by the Commission for the benefit of such entities and individuals.[58]

The Plan does not otherwise contravene the requirements of the Act. The Commission is today approving the Omnibus Application described above in section I., B., *supra*, of this order. That application supplements the Plan Application and seeks sufficient authorization under the Act, among other things, to implement the Plan and to conduct business within the parameters specified in the application, pending the confirmation and full implementation of the Plan. As discussed in the companion order, the requested authorizations satisfy the requirements of the Act and do not appear to be detrimental to the public interest and the interest of consumers.

IV. Conclusion

The Commission has examined the Debtors' requests and has concluded, based on the complete record before it, that the applicable standards of the Act and rules are satisfied and that no adverse findings are warranted.

Applicants state that fees, commissions and expenses in the estimated amount of $200,000 are expected to be incurred in connection with the Plan Application.[59] In addition, the Applicants have incurred and will incur fees and expenses related to the

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[58] *See* Section 42.4 of the Plan.

[59] Applicants state that professional fees incurred in their chapter 11 cases, even without such estate-wide litigation, have been approximately $330 million per year. As of December 23, 2003, the Bankruptcy Court had provided interim approval for approximately $271 million in professional fees. Under rule 63 under the Act, the Commission shall approve the "maximum amount" of fees that can be incurred by a registered holding company and its subsidiaries in a bankruptcy proceeding, but carves out from that requirement "any payments approved by a court ... in any proceeding in which the Commission has filed a notice of appearance...." The Commission's appearance in this case has eliminated its obligation to approve the fees, which are subject to review by the Bankruptcy Court.

ongoing Chapter 11 Cases and expenses related to the consummation of the transactions contemplated in the Plan. Pursuant to rule 63, these fees are not subject to Commission approval.

Due notice of the filing of the Application has been given in the manner prescribed in rule 23 under the Act, and no hearing has been requested of or ordered by the Commission. Upon the basis of the facts in the record, it is hereby found that the applicable standards of the Act and rules under the Act are satisfied, and that no adverse findings are necessary.

IT IS ORDERED, under the applicable provisions of the Act and rules under the Act, that the Application, as amended, be granted and permitted to become effective immediately, subject to the terms and conditions prescribed in rule 24 under the Act. Further, because certain contemplated transactions may be accomplished over a period of time after this order is issued, authorization is granted to implement the proposed transactions as described in the Application (except for those authorizations that are the subject of the Omnibus Application in SEC File No. 70-10200).

IT IS FURTHER ORDERED that this order is conditioned upon Enron registering under the Act prior to the issuance of this order and the ordering of the Omnibus Application.

By the Commission.

Jill M. Peterson
Assistant Secretary

ATTACHMENT 1

GLOSSARY

Term	Definition	Source
ACFI	Atlantic Commercial Finance, Inc., a Delaware corporation and a Debtor.	Disclosure Statement: A-1
ACFI Guaranty Claim	Any Unsecured Claim, other than an Intercompany Claim, against ACFI arising from or relating to an agreement by ACFI to guarantee or otherwise satisfy the obligations of another Debtor, including, without limitation, any Claim arising from or relating to rights of contribution or reimbursement.	Disclosure Statement: A-1
Adequately Protected Debtor	Any Debtor which transfers property (including cash) following the Petition Date to or for the benefit of any other Debtor.	Amended Cash Management Order
Administrative Expense Claim	Any Claim constituting a cost or expense of administration of the chapter 11 cases asserted or authorized to be asserted in accordance with sections 503(b) and 507(a)(1) of the Bankruptcy Code during the period up to and including the Effective Date, including, without limitation, any actual and necessary costs and expenses of preserving the estates of the Debtors, any actual and necessary costs and expenses of operating the businesses of the Debtors in Possession, any post-Petition Date loans and advances extended by one Debtor to another Debtor, any costs and expenses of the Debtors in Possession for the management, maintenance, preservation, sale or other disposition of any assets, the administration and implementation of the Plan, the administration, prosecution or defense of Claims by or against the Debtors and for distributions under the Plan, any guarantees or indemnification obligations extended by the Debtors in Possession, any Claims for reclamation in accordance with section 546(c)(2) of the Bankruptcy Code allowed pursuant to final order, any Claims for compensation and reimbursement of expenses arising during the period from and after the respective Petition Dates and prior to the Effective Date and awarded by the Bankruptcy Court in accordance with sections 328, 330, 331 or 503(b) of the Bankruptcy Code or otherwise in accordance with the provisions of the Plan, whether fixed before or after the Effective Date, and any fees or charges assessed against the Debtors' estates pursuant to section 1930, chapter 123, Title 28, United States Code.	Disclosure Statement: A-3
Aggregate Commitment	The aggregate of the Commitments of all the lenders, as changed from time to time pursuant to the terms of the Portland General Credit	Portland General

	Agreement.	Credit Agreement
Aggregate Outstanding Credit Exposure	At any time, the aggregate of the Outstanding Credit Exposure of all the Lenders under the Portland General Credit Agreement.	Portland General Credit Agreement
Allowed Claim/Allowed Equity Interest	Any Claim against or Equity Interest in any of the Debtors or the Debtors' estates, (i) proof of which was filed on or before the date designated by the Bankruptcy Court as the last date for filing such proof of Claim against or Equity Interest in any such Debtor or such Debtor's estate, (ii) if no proof of Claim or Equity Interest has been timely filed, which has been or hereafter is listed by such Debtor in its Schedules as liquidated in amount and not disputed or contingent or (iii) any Equity Interest registered in the stock register maintained by or on behalf of the Debtors as of the Record Date, in each such case in clauses (i), (ii) and (iii) above, a Claim or Equity Interest as to which no objection to the allowance thereof, or action to equitably subordinate or otherwise limit recovery with respect thereto, has been interposed within the applicable period of limitation, or as to which an objection has been interposed and such Claim has been allowed in whole or in part by a final order. For purposes of determining the amount of an "Allowed Claim", there shall be deducted therefrom an amount equal to the amount of any claim which the Debtors may hold against the holder thereof, to the extent such claim may be set off pursuant to applicable non-bankruptcy law. Without in any way limiting the foregoing, "Allowed Claim" shall include any Claim arising from the recovery of property in accordance with sections 550 and 553 of the Bankruptcy Code and allowed in accordance with section 502(h) of the Bankruptcy Code, any Claim allowed under or pursuant to the terms of the Plan or any Claim to the extent that it has been allowed pursuant to a final order; provided, however, that (i) Claims allowed solely for the purpose of voting to accept or reject the Plan pursuant to an order of the Bankruptcy Court shall not be considered "Allowed Claims" hereunder unless otherwise specified herein or by order of the Bankruptcy Court, (ii) for any purpose under the Plan, other than with respect to an Allowed ETS Debenture Claim, "Allowed Claim" shall not include interest, penalties, or late charges arising from or relating to the period from and after the Petition Date, and (iii) "Allowed Claim" shall not include any Claim subject to disallowance in accordance with section 502(d) of the Bankruptcy Code.	Disclosure Statement: A-4
Allowed ETS Debenture Claim	An ETS Debenture Claim, to the extent it is or has become an Allowed Claim and set forth on Exhibit "E" to the Plan.	Disclosure Statement: A-5

Allowed General Unsecured Claims	A General Unsecured Claim, to the extent it is or has become an Allowed Claim.	Disclosure Statement: A-5
Allowed Guaranty Claim	A Guaranty Claim, to the extent it is or has become an Allowed Claim.	Disclosure Statement: A-5
Allowed Intercompany Claim	An Intercompany Claim, to the extent it is or has become an Allowed Claim and as set forth on Exhibit "F" to the Plan; provided, however, that, based upon a methodology or procedure agreed upon by the Debtors, the Creditors' Committee and the ENA Examiner and set forth in the Plan Supplement, the amount of each such Intercompany Claim may be adjusted pursuant to a final order of the Bankruptcy Court entered after the date of the Disclosure Statement Order to reflect (a) Allowed Claims, other than Guaranty Claims, arising from a Debtor satisfying, or being deemed to have satisfied, the obligations of another Debtor, (b) Allowed Claims arising under section 502(h) of the Bankruptcy Code solely to the extent that a Debtor does not receive a full recovery due to the effect of the proviso set forth in Section 28.1 of the Plan or (c) Allowed Claims arising from the rejection of written executory contracts or unexpired leases between or among the Debtors, other than with respect to Claims relating to the rejection damages referenced in Section 34.3 of the Plan.	Disclosure Statement: A-5
Alternate Base Rate	For any day, a rate of interest per annum equal to the higher of (i) the Prime Rate for such day and (ii) the sum of the federal funds effective rate for such day plus 0.5% per annum.	Portland General Credit Agreement
Amended Cash Management Order	The Amended order Authorizing Continued Use of Existing Bank Accounts, Cash Management System, Checks and Business Forms, and Granting Inter-Company Superprioity Claims, Pursuant to 11 U.S.C. §§ 361, 363(e), 362 and 507(b), as Adequate Protection (Docket #1666).	Disclosure Statement: A-6
Amended DIP Credit Agreement	That certain Amended and Restated Revolving Credit and Guaranty Agreement dated as of June 14, 2002, by and among Enron, as borrower, each of the direct or indirect subsidiaries of Enron as party thereto, as guarantors, the DIP Lenders, JPMCB and Citicorp, as co-administrative agents, Citicorp, as paying agent, and JPMCB, as collateral agent.	Disclosure Statement: A-6
Applicable Margin	(a) With respect to Eurodollar Ratable Advances at any time, the percentage rate per annum under the heading "Eurodollar Applicable Margin" in the Pricing Schedule which is applicable at such time; and (b) with respect to Floating Rate Advances at any time, the percentage rate per annum under the heading "Base Rate Applicable Margin" in the Pricing Schedule which is applicable at such time.	Portland General Credit Agreement

Ardmore Data Center	The primary internet/telecommunications center for Enron and its Affiliates, including the Pipeline Businesses.	Disclosure Statement: A-7
Assets	With respect to a Debtor, (a) all "property" of such Debtor's estate, as defined in section 541 of the Bankruptcy Code, including such property as is reflected on such Debtor's books and records as of the date of the Disclosure Statement Order, unless modified pursuant to the Plan or a final order and (b) all claims and causes of action, including those that may be allocated or reallocated in accordance with the provisions of Articles II, XXII, XXIII and XXVIII of the Plan, that have been or may be commenced by such Debtor in Possession or other authorized representative for the benefit of such Debtor's estate, unless modified pursuant to the Plan or a final order; provided, however, that, "Assets" shall not include claims and causes of action which are the subject of the Severance Settlement Fund Litigation or such other property otherwise provided for in the Plan or by a final order; and, provided, further, that, in the event that the Litigation Trust or the Special Litigation Trust is created, Litigation Trust Claims or Special Litigation Claims, as the case may be, shall not constitute "Assets."	Disclosure Statement: A-7
Bighorn	Bighorn Gas Gathering, L.L.C.	Omnibus: 35
Bridgeline	Bridgeline Holdings, L.P., Bridgeline Storage and Bridgeline Distribution, collectively.	Disclosure Statement: A-10
Business Day	A day other than a Saturday, a Sunday or any other day on which commercial banks in New York, New York are required or authorized to close by law or executive order.	Disclosure Statement: A-10
CES	CrossCountry Energy Services, LLC, (successor-in-interest to CGNN Holding Company, Inc.), a non-Debtor affiliate of Enron and a wholly owned subsidiary of ETS.	Disclosure Statement: A-12
Citicorp.	Citicorp USA, Inc.	Disclosure Statement: A-12
Citrus	Citrus Corp.	Disclosure Statement: A-12
Claim	Any right to payment from the Debtors or from property of the Debtors or their estates, whether or not such right is reduced to judgment, liquidated, unliquidated, fixed, contingent, matured, unmatured, disputed, undisputed, legal, equitable, secured, or unsecured, known or unknown or asserted; or any right to an equitable remedy for breach of performance if such breach gives rise to a right of payment from the Debtors or from property of the Debtors, whether or not such right to an	Disclosure Statement: A-12

	equitable remedy is reduced to judgment, fixed, contingent, matured, unmatured, disputed, undisputed, secured, or unsecured.	
Commitment	For each Lender under the Portland General Credit Agreement, the obligation of such Lender to make Ratable Loans to, and participate in Facility LCs issued upon the application of, Portland General in an aggregate amount not exceeding the amount set forth on Schedule 3 or as set forth in any notice of assignment relating to any assignment that has become effective pursuant to Section 12.3.2 of the Portland General Credit Agreement as such amount may be modified from time to time pursuant to the term thereof.	Portland General Credit Agreement
Common Equity Interest	A common Equity Interest.	Disclosure Statement: A-13
Confirmation Date	The date the clerk of the Bankruptcy court enters the Confirmation Order on the docket of the Bankruptcy Court with respect to the Debtors' chapter 11 cases.	Disclosure Statement: A-14
Confirmation Hearing	The hearing to consider confirmation of the Plan in accordance with section 1129 of the Bankruptcy Code, as such hearing may be adjourned or continued from time to time.	Disclosure Statement: A-14
Confirmation Order	The order of the Bankruptcy Court confirming the Plan.	Disclosure Statement: A-14
Convenience Claim	Except as provided in Section 16.2 of the Plan, any Claim equal to or less than Fifty Thousand Dollars ($50,000.00) or greater than Fifty Thousand Dollars ($50,000.00) but with respect to which the holder thereof voluntarily reduces the Claim to Fifty Thousand Dollars ($50,000.00) on the ballot; provided, however, that, for purposes of the Plan and the distributions to be made thereunder, "Convenience Claim" shall not include (i) an Enron Senior Note Claim, (ii) an Enron Subordinated Debenture Claim, (iii) an ETS Debenture Claim, (iv) an ENA Debenture Claim, (v) an Enron TOPRS Debenture Claim and (vi) any other Claim that is a component of a larger Claim, portions of which may be held by one or more holders of Allowed Claims.	Disclosure Statement: A-16
Creditor	Any person or entity holding a Claim against the Debtors' estates or, pursuant to section 102(2) of the Bankruptcy Code, against property of the Debtors that arose or is deemed to have arisen on or prior to the Petition Date, including, without limitation, a Claim against any of the Debtors or Debtors in Possession of a kind specified in sections 502(g), 502(h) or 502(i) of the Bankruptcy Code.	Disclosure Statement: A-16

CrossCountry	CrossCountry Energy, LLC, a Delaware limited liability company, formed on or prior to the Effective Date, the assets of which shall consist of the CrossCountry Assets; provided, however, unless the context required otherwise, references to "CrossCountry" shall also be deemed references to the entity that the Debtors and the Creditors' Committee designate as CrossCountry Distributing Company in accordance with the Plan, whether by consummation of the CrossCountry Transaction or the declaration of CrossCountry as CrossCountry Distributing Company, whether in its current form as a limited liability company or as converted to a corporation.	Disclosure Statement: A-16
CrossCountry Distributing Company	The Entity designated jointly by the Debtors and the Creditor's Committee pursuant to the Plan to distribute shares of capital stock or equity interests in accordance with Section 32.1(c) of the Plan representing interests in the CrossCountry Assets.	Disclosure Statement: A-18
CrossCountry Enron Parties	Enron, ETS, EOC Preferred (as successor to Enron Operations, L.P.) and EOS, which comprise the parties, in addition to CrossCountry, CrossCountry Citrus Corp. and CrossCountry Energy Corp., which are parties to the CrossCountry Contribution and Separation Agreement.	Disclosure Statement: A-18
CrossCountry Transaction	The transaction, described in the Disclosure Statement, Section IX.F.1 "Formation of CrossCountry," entered into by the CrossCountry Enron Parties, CrossCountry and CrossCountry Distributing Company, with the consent of the Creditors' Committee and consistent with the Plan, pursuant to which the equity interests in CrossCountry would be exchanged for equity interests in CrossCountry Distributing Company and CrossCountry Distributing Company obtains the direct or indirect ownership of the Pipeline Businesses and services companies held by CrossCountry.	Disclosure Statement: A-18
Debtor in Possession or DIP	The Debtors as Debtors in possession pursuant to sections 1101(1) and 1107(a) of the Bankruptcy Code.	Disclosure Statement: A-21
DIP Credit Agreement	Revolving Credit and Guaranty Agreement, dated as of December 3, 2001, by and among Enron and ENA, as borrowers, each of the direct or indirect Debtor subsidiaries of Enron and ENA party thereto, as guarantors, JPMCB and Citicorp, as co-administrative agents, Citicorp, as paying agent, JPMCB, as collateral agent, and the lenders party thereto, as lenders.	Disclosure Statement: A-22
DIP Lenders	The lenders under the DIP Credit Agreement, as amended.	Disclosure Statement: A-22
Disbursing Agent	Solely in its capacity as agent of the Debtors to effectuate distributions pursuant to the Plan, the Reorganized Debtors, the Reorganized Debtor Plan Administrator or such other Entity as may be designated by the Debtors, with the consent of the Creditors' Committee, and appointed	Disclosure Statement: A-22

by the Bankruptcy Court and set forth in the Confirmation Order.

Disputed Claim; Disputed Equity Interest	Any Claim against or Equity Interest in the Debtors, to the extent the allowance of such Claim or Equity Interest is the subject of a timely objection or request for estimation, or is otherwise disputed by the Debtors in accordance with applicable law, which objection, request for estimation or dispute has not been withdrawn, with prejudice or determined by a final order.	Disclosure Statement: A-23
Disputed Claims Reserve	From and after the Effective Date, and until such time as all Disputed Claims have been compromised and settled or determined by final order, the Disbursing Agent shall reserve and hold in escrow for the benefit of each holder of a Disputed Claim, Cash, Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests and any dividends, gains or income attributable thereto, in an amount equal to the pro rata share of distributions which would have been made to the holder of such Disputed Claim if it were an Allowed Claim in an amount equal to the lesser of: (i) the Disputed Claim Amount, (ii) the amount in which the Disputed Claim shall be estimated by the Bankruptcy Court pursuant to section 502 of the Bankruptcy Code for purposes of allowance, which amount, unless otherwise ordered by the Bankruptcy Court, shall constitute and represent the maximum amount in which such Claim may ultimately become an Allowed Claim, or (iii) such other amount as may be agreed upon by the holder of such Disputed Claim and the Reorganized Debtors; provided, however, that, under no circumstances, shall a holder of an Allowed Convenience Claim be entitled to distributions of Litigation Trust Interests, Special Litigation Trusts Interests or the proceeds thereof. Any Cash, Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests reserved and held for the benefit of a holder of a Disputed Claim shall be treated as a payment and reduction on account of such Disputed Claim for purposes of computing any additional amounts to be paid in Cash or distributed in Plan Securities in the event the Disputed Claim ultimately becomes an Allowed Claim. Such Cash and any dividends, gains or income paid on account of Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests reserved for the benefit of holders of Disputed Claims shall be either: (x) held by the Disbursing Agent, in an interest-bearing account or (y) invested in interest-bearing obligations issued by the United States government, or by an agency of the United States government and guaranteed by the United States government, and having (in either case) a maturity of not more than thirty (30) days, for the benefit of such holders pending determination of their entitlement thereto under the terms of the Plan. No payments or distributions shall be made with	Disclosure Statement: A-22

	respect to all or any portion of any Disputed Claim pending the entire resolution thereof by final order.	
Effective Date	The earlier to occur of: (a) the first (1st) Business Day following the Confirmation Date that (i) the conditions to effectiveness of the Plan set forth in Section 37.1 of the Plan have been satisfied or otherwise waived in accordance with Section 37.2 of the Plan, but in no event earlier than December 31, 2004, and (ii) the effectiveness of the Confirmation Order shall not be stayed and (b) such other date following the Confirmation Date that the Debtors and the Creditors' Committee, in their joint and absolute discretion, designate.	Disclosure Statement: A-29
ENA Examiner	Harrison J. Goldin, appointed as examiner of ENA pursuant to the Bankruptcy Court's order, dated March 12, 2002.	Disclosure Statement: A-33
Enron Common Equity Interest	An Equity Interest represented by one of the one billion two hundred million (1,200,000,000) authorized shares of common stock of Enron as of the Petition Date or any interest or right to convert into such an equity interest or acquire any equity interest of the Debtors which was in existence immediately prior to or on the Petition Date.	Disclosure Statement: A-36
Enron Preferred Equity Interest	An Equity Interest represented by an issued and outstanding share of preferred stock of Enron as of the Petition Date, including, without limitation, that certain (a) Cumulative Second Preferred Convertible Stock, (b) 9.142% Perpetual Second Preferred Stock, (c) Mandatorily Convertible Junior Preferred Stock, Series B, and (d) Mandatorily Convertible Single Reset Preferred Stock, Series C, or any other interest or right to convert into such a preferred equity interest or acquire any preferred equity interest of the Debtors which was in existence immediately prior to the Petition Date.	Disclosure Statement: A-38
Enron TOPRS Debenture Claim	Any General Unsecured Claim arising from or relating to the Enron TOPRS Indentures.	Disclosure Statement: A-39
Enron TOPRS Debentures	The 7.75% subordinated debentures due 2016, issued in the original aggregate principal amount of $181,926,000.00 and the 7.75% subordinated debentures Due 2016, Series II, issued in the original aggregate principal amount of $136,450,000.00, pursuant to the Enron TOPRS Indentures.	Disclosure Statement: A-40
Enron TOPRS Indentures	That certain (1) Indenture, dated as of November 21, 1996, between ENE, as Issuer, and The Chase Manhattan Bank, as Indenture Trustee, and (2) Indenture, dated as of January 16, 1997, between Enron, as Issuer, and The Chase Manhattan Bank, as Indenture Trustee.	Disclosure Statement: A-40
EOC Preferred	EOC Preferred, L.L.C., a non-Debtor affiliate of Enron.	Disclosure Statement: A-40

EOS	Enron Operations Services, LLC, a Debtor.	Disclosure Statement: A-40
EPC	Enron Power Corp., a Delaware corporation and a Debtor.	Disclosure Statement: A-41
EPC Guaranty Claim	Any Unsecured Claim, other than an Intercompany Claim, against EPC arising from or relating to an agreement by EPC to guarantee or otherwise satisfy the obligations of another Debtor, including, without limitation, any Claim arising from or relating to rights of contribution or reimbursement.	Disclosure Statement: A-41
Equity Interests	Any equity interest in any of the Debtors represented by duly authorized, validly issued and outstanding shares of preferred stock or common stock or any interest or right to convert into such an equity interest or acquire any equity interest of the Debtors which was in existence immediately prior to or on the Petition Date.	Disclosure Statement: A-43
ETS	Enron Transportation Services, LLC, a Delaware limited liability company and successor-in-interest to Enron Transportation Services Company, one of the Debtors.	Disclosure Statement: A-44
ETS Debenture Claim	Any General Unsecured Claim arising from or relating to the ETS Indentures.	Disclosure Statement: A-44
ETS Indentures	That certain (1) Indenture, dated as of November 21, 1996, by and among Enron Pipeline Company, now known as ETS, as issuer, Enron, as guarantor, and The Chase Manhattan Bank, as Indenture Trustee, and (2) Indenture, dated as of January 16, 1997, by and among Enron Pipeline Company, now known as ETS, as issuer, Enron, as guarantor, and The Chase Manhattan Bank, as Indenture Trustee.	Disclosure Statement: A-44
ETS Indenture Trustee	National City Bank, solely in its capacity as successor in interest to The Chase Manhattan Bank, as indenture trustee under the ETS Indentures, or its duly appointed successor.	Disclosure Statement: A-44
Eurodollar Advance	A Eurodollar Ratable Advance, a Eurodollar Bid Rate Advance, or both, as the context may require.	Portland General Credit Agreement
Eurodollar Bid Rate	With respect to a Eurodollar Bid Rate Loan made by a given Lender for the relevant Eurodollar Interest Period, the sum of (i) the quotient of (a) the Eurodollar Base Rate applicable to such Interest Period, divided by (b) one minus the Reserve Requirement (expressed as a decimal) applicable to such Interest Period, plus (ii) the Competitive Bid Margin offered by such Lender and accepted by Portland General.	Portland General Credit Agreement

Eurodollar Bid Rate Loan	A loan which bears interest at a Eurodollar Bid Rate.	Portland General Credit Agreement
Eurodollar Interest Period	With respect to an Eurodollar Advance, a period of one, two, three or six months commencing on a business day selected by the Borrower pursuant to the Portland General Credit Agreement. Such Eurodollar Interest Period shall end on the day which corresponds numerically to such date one, two, three or six months thereafter, provided that if there is no such numerically corresponding day in such next, second, third or sixth succeeding month, such Eurodollar Interest Period shall end on the last business day of such next, second, third or sixth succeeding month. If a Eurodollar Interest Period would otherwise end on a day which is not a business day, such Eurodollar Interest Period shall end on the next succeeding business day, provided that if said next succeeding business day falls in a new calendar month, such Eurodollar Interest Period shall end on the immediately preceding business day.	Portland General Credit Agreement
Eurodollar Ratable Advance	A Ratable Advance which bears interest at a Eurodollar Rate requested by Portland General pursuant to Section 2.2 of the Portland General Credit Agreement.	Portland General Credit Agreement
Eurodollar Ratable Loan	A Ratable Loan which bears interest at a Eurodollar Rate requested by Portland General pursuant to Section 2.2 of the Portland General Credit Agreement.	Portland General Credit Agreement
Eurodollar Rate	With respect to a Eurodollar Ratable Advance for the relevant Eurodollar Interest Period, the sum of (i) the quotient of (a) the Eurodollar Base Rate applicable to such Eurodollar Interest Period, divided by (b) one minus the Reserve Requirement (expressed as a decimal) applicable to such Eurodollar Interest Period, plus (ii) the Applicable Margin.	Portland General Credit Agreement
Facility LCs	Existing and standby letters of credit under the Portland General Credit Agreement.	Portland General Credit Agreement
Floating Rate	For any day, a rate per annum equal to the sum of (i) the Alternate Base Rate for such day, changing when and as the Alternate Base Rate changes, plus (ii) the Applicable Margin.	Portland General Credit Agreement
Floating Rate Advance	An Advance which, except as otherwise provided in Section 2.9 of the Portland General Credit Agreement, bears interest at the Floating Rate.	Portland General Credit Agreement

Initial Petition Date	December 2, 2001, the date on which Enron and thirteen of its direct and indirect subsidiaries filed their voluntary petitions for relief commencing the chapter 11 cases.	Disclosure Statement: A-50
Intercompany Claims	Any Unsecured Claim held by any Debtor, other than the Portland Debtors, against any other Debtor, other than the Portland Debtors.	Disclosure Statement: A-50
Interim DIP Order	Bankruptcy Court order (Docket #63) approving the DIP Credit Agreement on an interim basis.	Disclosure Statement: A-51
IRS	Internal Revenue Service, an agency of the United States Department of Treasury.	Disclosure Statement: A-51
IRS Code	Internal Revenue Code of 1986, as amended from time to time.	Disclosure Statement: A-51
General Unsecured Claim	An unsecured Claim, other than a Guaranty Claim, or an Intercompany Claim.	Disclosure Statement: A-48
Guaranty Claims	ACFI Guaranty Claims, ENA Guaranty Claims, Enron Guaranty Claims, EPC Guaranty Claims and Wind Guaranty Claims.	Disclosure Statement: A-48
Guardian	Guardian Pipeline, LLC.	Disclosure Statement: A-49
Junior Liens	Has the meaning set forth in Section IV.A.3 of the Disclosure Statement.	Disclosure Statement: A-52
Junior Reimbursement Claims	Has the meaning set forth in Section IV.A.3 of the Disclosure Statement.	Disclosure Statement: A-52
LC Obligations	At any time, the sum, without duplication, of (i) the aggregate undrawn stated amount under all Facility LCs outstanding at such time plus (ii) the aggregate unpaid amount of all Reimbursement Obligations at such time.	Portland General Credit Agreement
Lenders	The financial institutions and their respective successors and assigns, which are parties to the Portland General Credit Agreement.	Portland General Credit Agreement
Litigation Trust	The Entity, if jointly determined by the Debtors and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, to be	Disclosure Statement: A-

	created on or prior to December 31st of the calendar year in which the Effective Date occurs, unless such date is otherwise extended by the Debtors and the Creditors' Committee, in their joint and absolute discretion and by notice filed with the Bankruptcy Court, in accordance with the provisions of Article XXII of the Plan and the Litigation Trust Agreement for the benefit of holders of Allowed Claims, as if Litigation Trust Claims were owned by Enron, in accordance with the terms and provisions of the Distribution Model and Article XXII of the Plan.	53
Litigation Trust Claims	All claims and causes of action asserted, or which may be asserted, by or on behalf of the Debtors or the Debtors' estates (i) in the MegaClaim Litigation, (ii) in the Montgomery County Litigation (other than claims and causes of action against insiders or former insiders of the Debtors), (iii) of the same nature against other financial institutions, law firms, accountants and accounting firms, certain of the Debtors' other professionals and such other Entities as may be described in the Plan Supplement and (iv) arising under or pursuant to sections 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code against the entities referenced in subsections (i), (ii) and (iii) above; provided, however, that, under no circumstances, shall such claims and causes of action include (a) Special Litigation Trust Claims to be prosecuted by the Special Litigation Trust and the Special Litigation Trustee pursuant to Article XXIII of the Plan or (b) any claims and causes of action of the estates of the Debtors waived and released in accordance with the provisions of Sections 28.3 and 42.6 of the Plan; and, provided, further, that, in the event that the Debtors and the Creditors' Committee jointly determine not to form the Litigation Trust, the claims and causes of action referred to in clauses (i), (ii), (iii) and (iv) above shall be deemed to be Assets of Enron, notwithstanding the inclusion of Enron and other Debtors or their estates as a plaintiff in such litigation and without the execution and delivery of any additional documents or the entry of any order of the Bankruptcy Court or such other court of competent jurisdiction.	Disclosure Statement: A-54
MegaClaim Litigation	The litigation styled *Enron Corp. and Enron North America Corp. v. Citigroup, Inc., et al*, Adversary Proceeding No. 03-9266 (AJG), pending in the Bankruptcy Court.	Disclosure Statement: A-56
Montgomery County Litigation	The litigation styled *Official Committee of Unsecured Creditors of Enron Corp. v. Fastow*, et al., Case No. 02-10-06531, pending in the District Court for the 9th Judicial District, Montgomery County, Texas.	Disclosure Statement: A-57
Northern Plains	Northern Plains Natural Gas Company.	Disclosure Statement: A-58
Operating Entities	CrossCountry, PGE, and Prisma, together the operating subsidiaries of	Disclosure

	the Reorganized Debtors.	Statement: A-59
Outstanding Credit Exposure	As to any Lender at any time, the sum of (i) the aggregate principal amount of its loans outstanding at such time, plus (ii) an amount equal to its pro rata share of the LC Obligations at such time.	Portland General Credit Agreement
Petition Date	The Initial Petition Date; provided, however, that, with respect to those Debtors which commenced their chapter 11 cases subsequent to December 2, 2001, "*Petition Date*" shall refer to the respective dates on which such chapter 11 cases were commenced.	Disclosure Statement: A-61
PGE Trust	The Entity, if jointly determined by the Debtors and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, to be created on or subsequent to the Confirmation Date, but in no event later than the date on which the Litigation Trust is created, to hold as its sole assets the Existing PGE Common Stock or the PGE Common Stock in lieu thereof, but in no event the assets of PGE.	Disclosure Statement: A-61
Pipeline Businesses	Those pipeline businesses or other energy related businesses associated with the pipeline businesses which are owned or operated by Enron, ETS and EOC Preferred that are anticipated to be contributed for equity interests in CrossCountry pursuant to the CrossCountry Contribution and Separation Agreement.	Disclosure Statement: A-62
Plan Currency	The mixture of Creditor Cash, Prisma Common Stock, CrossCountry Common Equity, and PGE Common Stock to be distributed to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims pursuant to the Plan; provided, however, that, if jointly determined by the Debtors and the Creditors' Committee, "Plan Currency" may include Prisma Trust Interests, CrossCountry Trust Interests, PGE Trust Interests and the Remaining Asset Trust Interests.	Disclosure Statement: A-63
Plan Securities	Prisma Common Stock, CrossCountry Common Equity and PGE Common Stock.	Disclosure Statement: A-63
Plan Supplement	A separate volume, to be filed with the clerk of the Bankruptcy Court and posted as a "Related Document" at http://www.enron.com/corp/por/, including, among other documents, forms of (1) the Litigation Trust Agreement, (2) the Special Litigation Trust Agreement, (3) the Prisma Trust Agreement, (4) the CrossCountry Trust Agreement, (5) the PGE Trust Agreement, (6) the Remaining Asset Trust Agreement(s), (7) the Common Equity Trust Agreement, (8) the Preferred Equity Trust Agreement, (9) the Prisma Articles of Association, (10) the Prisma Memorandum of Association, (11) the	Disclosure Statement: A-63

CrossCountry By-laws/Organizational Agreement, (12) the CrossCountry Charter, (13) the PGE By-Laws, (14) the PGE Certificate of Incorporation, (15) the Reorganized Debtor Plan Administration Agreement, (16) the Reorganized Debtors By-laws, (17) the Reorganized Debtors Certificate of Incorporation, (18) the Severance Settlement Fund Trust Agreement, (19) a schedule of the types of Claims entitled to the benefits of subordination afforded by the documents referred to and the definitions set forth on Exhibit "L" to the Plan, (20) a schedule of Allowed General Unsecured Claims held by affiliated non-Debtor Entities and structures created by the Debtors and which are controlled or managed by the Debtors or their Affiliates, (21) a schedule setting forth the identity of the proposed senior officers and directors of Reorganized Enron, (22) a schedule setting forth the identity and compensation of any insiders to be retained or employed by Reorganized Enron, (23) a schedule setting forth the litigation commenced by the Debtors on or after December 15, 2003 to the extent that such litigation is not set forth in the Disclosure Statement, (24) the methodology or procedure agreed upon by the Debtors, the Creditors' Committee and the ENA Examiner with respect to the adjustment of Allowed Intercompany Claims, as referenced in Section 1.21 of the Plan, and to the extent adjusted or to be adjusted pursuant to such methodology or procedure, an updated Exhibit "F" to the Plan and a range of adjustment, which may be made in accordance with Section 1.21(c) of the Plan, (25) the guidelines of the Disputed Claims reserve to be created in accordance with Section 21.3 of the Plan, (26) the guidelines for the DCR Overseers in connection with the Disputed Claims reserve and (27) a schedule or description of Litigation Trust Claims and Special Litigation Trust Claims, in each case, consistent with the substance of the economic and governance provisions contained in the Plan, (a) in form and substance satisfactory to the Creditors' Committee and (b) in substance satisfactory to the ENA Examiner. The Plan Supplement shall also set forth the amount of Creditor Cash to be available as of the Effective Date as jointly determined by the Debtors and the Creditors' Committee, which amount may be subsequently adjusted with the consent of the Creditors' Committee. The Plan Supplement (containing drafts or final versions of the foregoing documents) shall be (i) filed with the clerk of the Bankruptcy Court as early as practicable (but in no event later than fifteen (15) days) prior to the Ballot Date, or on such other date as the Bankruptcy Court establishes and (ii) provided to the ENA Examiner as early as practicable (but in no event later than thirty (30) days) prior to the Ballot Date. Poliwatt means Poliwatt Limitada. Ponderosa means Ponderosa Assets, LP. Ponderosa Ltd. means Ponderosa Pine Energy Partners, Ltd. Portland Creditor Cash means at any time, the excess, if any, of (a) all Cash and Cash Equivalents in the Disbursement Account(s) relating to each of the Portland Debtors over (b) such

	amounts of Cash (i) reasonably determined by the Disbursing Agent as necessary to satisfy, in accordance with the terms and conditions of the Plan, Administrative Expense Claims, Priority Non-Tax Claims, Priority Tax Claims, Convenience Claims and Secured Claims relating to each of the Portland Debtors, (ii) necessary to make pro rata distributions to holders of Disputed Claims as if such Disputed Claims relating to each of the Portland Debtors were, at such time, Allowed Claims and (iii) such other amounts reasonably determined by each of the Reorganized Portland Debtors as necessary to fund the ongoing operations of each of the Reorganized Portland Debtors during the period from the Effective Date up to and including the date such Debtors' chapter 11 cases are closed.	
Portland Debtors	Portland General Holdings, Inc. and Portland Transition Company, Inc.	Disclosure Statement: A-64
Portland General Credit Agreement	The 364-Day Credit Agreement, dated May 28, 2003, among Portland General and the Lenders thereunder and Bank One, NA as administrative agent for the Lenders.	Portland General Credit Agreement
Pricing Schedule	The Schedule attached to the Portland General Credit Agreement and identified as such.	Portland General Credit Agreement
Prime Rate	A rate per annum equal to the prime rate of interest announced by Bank One or by its parent, Bank One Corporation, from time to time, changing when and as said prime rate changes.	Portland General Credit Agreement
Priority Non-Tax Claim	Any Claim against the Debtors, other than an Administrative Expense Claim or a Priority Tax Claim, entitled to priority in payment in accordance with sections 507(a)(3), (4), (5), (6), (7) or (9) of the Bankruptcy Code, but only to the extent entitled to such priority.	Disclosure Statement: A-65
Priority Tax Claim	Any Claim of a governmental unit against the Debtors entitled to priority in payment under sections 502 (i) and 507(a)(8) of the Bankruptcy Code.	Disclosure Statement: A-65
Prisma	Prisma Energy International Inc., a Cayman Islands company, the assets of which shall consist of the Prisma Assets.	Disclosure Statement: A-65
Prisma Assets	The assets to be contributed into or transferred to Prisma, including, without limitation (a) those assets set forth on Exhibit "H" to the Plan; provided, however, that, in the event that, during the period from the date of the Disclosure Statement Order up to and including the date of	Disclosure Statement: A-66

	the initial distribution of Plan Securities pursuant to the terms and provisions of Section 32.1 of the Plan, the Debtors, with the consent of the Creditors' Committee, determine not to include in Prisma a particular asset set forth on Exhibit "H" to the Plan, the Debtors shall file a notice thereof with the Bankruptcy Court and the value of the Prisma Common Stock shall be reduced by the Value attributable to such asset, as set forth in the Disclosure Statement or determined by the Bankruptcy Court at the Confirmation Hearing, and (b) such other assets as the Debtors, with the consent of the Creditors' Committee, determine on or prior to the date of the initial distribution of Plan Securities pursuant to the terms and provisions of Section 32.1 of the Plan to include in Prisma and the Value of the Prisma Common Stock shall be increased by the Value attributable to any such assets.	
Prisma Articles of Association	The articles of association of Prisma, which articles of association shall be in form and substance satisfactory to the Creditors' Committee and in substantially the form included in the Plan Supplement.	Disclosure Statement: A-65
Prisma Common Stock	The ordinary shares of Prisma authorized and to be issued pursuant to the Plan, which shares shall have a par value of $0.01 per share, of which fifty million (50,000,000) shares shall be authorized and of which forty million (40,000,000) shares shall be issued pursuant to the Plan, and such other rights with respect to dividends, liquidation, voting and other matters as are provided for by applicable nonbankruptcy law or the Prisma Memorandum of Association or the Prisma Articles of Association.	Disclosure Statement: A-66
Prisma Contribution and Separation Agreement	The agreement to be entered into by the Prisma Enron Parties and Prisma to govern the contribution of the Prisma Assets to Prisma.	Disclosure Statement: A-66
Prisma Distribution Date	The date on which the Prisma Distribution occurs.	Disclosure Statement: A-66
Prisma Enron Parties	Enron and its affiliates, other than Prisma, that are party to the Prisma Contribution and Separation Agreement.	Disclosure Statement: A-66
Prisma Memorandum of Association	Memorandum of association of Prisma, which memorandum of association shall be in form and substance satisfactory to the Creditors' Committee and in substantially the form included in the Plan Supplement.	Disclosure Statement: A-66
Prisma Trust	The entity, if jointly determined by the Debtors and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, to be created on or subsequent to the Confirmation Date, but in no event later than the date on which the Litigation Trust is created, in addition to the	Disclosure Statement: A-67

	creation of Prisma, and to which Entity shall be conveyed one hundred percent (100%) of the Prisma Common Stock.	
Prisma Trust Agreement	In the event that the Prisma Trust is created, the Prisma Trust Agreement, which agreement shall be in form and substance satisfactory to the Creditors' Committee and substantially in the form contained in the Plan Supplement, pursuant to which the Prisma Trust Board and the Prisma Trustee shall manage, administer, operate and liquidate the assets contained in the Prisma Trust and distribute the proceeds thereof or the Prisma Common Stock.	Disclosure Statement: A-67
Prisma Trust Board	In the event that the Prisma Trust is created, the persons selected by the Debtors, after consultation with the Creditors' Committee, and appointed by the Bankruptcy Court, or any replacements thereafter selected in accordance with the provisions of the Prisma Trust Agreement.	Disclosure Statement: A-67
Prisma Trustee	In the event that the Prisma Trust is created, Stephen Forbes Cooper, LLC or such other Entity appointed by the Prisma Trust Board and approved by the Bankruptcy Court to administer the Prisma Trust in accordance with the provisions of Article XXIV of the Plan and the Prisma Trust Agreement.	Disclosure Statement: A-67
RAC	The Risk Assessment and Control Group for the Enron Companies.	Disclosure Statement A-68
Remaining Asset Trust(s)	One or more Entities, if jointly determined by the Debtors and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, to be created on or after the Confirmation Date, but in no event later than the date on which the Litigation Trust is created, occurs in accordance with the provisions of Article XXV of the Plan and the Remaining Asset Trust Agreement(s) for the benefit of holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims and such other Allowed Claims and Allowed Equity Interests in accordance with the terms and provisions of the Plan.	Disclosure Statement: A-69
Remaining Assets	From and after the Effective Date, all Assets of the Reorganized Debtors; provided, however, that, under no circumstances, shall "Remaining Assets" include (a) Creditor Cash on the Effective Date, (b) the Litigation Trust Claims, (c) the Special Litigation Trust Claims, (d) the Plan Securities and (e) claims and causes of action subject to the Severance Settlement Fund Litigation.	Disclosure Statement: A-69
Reorganized Debtors	The Debtors, other than the Portland Debtors, from and after the Effective Date.	Disclosure Statement: A-70
Reorganized	The respective by-laws of the Reorganized Debtors, including	Disclosure

Debtors By-laws	Reorganized Enron, which by-laws shall be in form and substance satisfactory to the Creditors' Committee and in substantially the form included in the Plan Supplement.	Statement: A-70
Reorganized Debtors Certificate of Incorporation	The respective Certificates of Incorporation of the Reorganized Debtors, which certificates of incorporation shall be in form and substance satisfactory to the Creditors' Committee and in substantially the form included in the Plan Supplement.	Disclosure Statement: A-70
Reorganized Debtor Plan Administrator	Stephen Forbes Cooper, LLC, retained, as of the Effective Date, by the Reorganized Debtors as the employee responsible for, among other things, the matters described in Section 36.2 of the Plan.	Disclosure Statement: A-70
Reorganized Portland Debtors	The Portland Debtors, from and after the Effective Date.	Disclosure Statement: A-70
Ratable Advance	A borrowing (i) made by the Lenders on the same Borrowing Date, or (ii) converted or continued by the Lenders on the same date of conversion or continuation, consisting in either case, of the aggregate amount of the several Ratable Loans of the same type and, in the case of Eurodollar Ratable Loans, for the same interest period.	Portland General Credit Agreement
Reserve Requirement	With respect to an Interest Period, the maximum aggregate reserve requirement (including all basic, supplemental, marginal and other reserves) which is imposed under Regulation D on Eurocurrency liabilities.	
S&P	Standard & Poor's, a division of The McGraw-Hill Companies, Inc.	Disclosure Statement: A-71
Second Amended DIP Credit Agreement	The Second Amended and Restated Revolving Credit and Guaranty Agreement dated as of May 9, 2003, by and among Enron, as borrower, each of the direct or indirect subsidiaries of Enron party thereto, as guarantors, the DIP Lenders, JPMCB and Citicorp, as co-administrative agents, Citicorp, as paying agent, and JPMCB, as collateral agent.	Disclosure Statement: A-72
Secured Claim	A Claim against the estates of the Debtors (a) secured by a lien on Collateral or (b) subject to setoff under section 553 of the Bankruptcy Code, to the extent of the value of the Collateral or to the extent of the amount subject to setoff, as applicable, as determined in accordance with section 506(a) of the Bankruptcy Code or as otherwise agreed to, in writing, by the (1) Debtors and the holder of such Claim, subject to the consent of the Creditors' Committee, or (2) the Reorganized Debtors and the holder of such Claim, as the case may be; provided, however, that, to the extent that the value of such interest is less than the amount of the Claim which has the benefit of such security, the unsecured portion of such Claim shall be treated as a General Unsecured Claim	Disclosure Statement: A-73

	unless, in any such case, the Class of which such Claim is a part makes a valid and timely election in accordance with section 1111(b) of the Bankruptcy Code to have such Claim treated as a Secured Claim to the extent allowed.	
Securities Act	Securities Act of 1933.	Disclosure Statement: A-73
Severance Settlement Fund Litigation	Those claims and causes of action arising from and relating to the payment of the Employee Prepetition Stay Bonus Payments to certain of the Debtors' employees, which claims and causes of action were assigned to the Employee Committee pursuant to the Severance Settlement Order, including, without limitation, the claims and causes of action which are the subject of litigation styled (a) Theresa A. Allen et al. v. Official Employment-Related Issues Committee; Enron Corp.; Enron North America Corp.; Enron Net Works, L.L.C., Adversary Proceeding No. 03-02084-AJG, currently pending in the Bankruptcy Court, (b) Official Employment-Related Issues Committee of Enron Corp., et al. v. John D. Arnold, et al., Adversary Proceeding No. 03-3522, currently pending in the United States Bankruptcy Court for the Southern District of Texas, (c) Official Employment-Related Issues Committee of Enron Corp., et al. v. James B. Fallon, et al., Adversary Proceeding No. 03-3496, currently pending in the United States Bankruptcy Court for the Southern District of Texas, (d) Official Employment-Related Issues Committee of Enron Corp., et al. v. Jeffrey McMahon, Adversary Proceeding No. 03-3598, currently pending in the United States Bankruptcy Court for the Southern District of Texas, and (e) Official Employment-Related Issues Committee of Enron Corp. v. John J. Lavorato, et al., Adversary No. 03-3721, currently pending in the United States Bankruptcy Court for the Southern District of Texas.	Disclosure Statement: A-74
Special Litigation Trust	The Entity, if jointly determined by the Debtors and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, Creditors' Committee, to be created on or prior to December 31st of the calendar year in which the Effective Date occurs, unless such date is otherwise extended by the Debtors and the Creditors' Committee, in their joint and absolute discretion and by notice filed with the Bankruptcy Court, in accordance with the provisions of Article XXIII of the Plan and the Special Litigation Trust Agreement for the benefit of holders of Allowed Claims against Enron in accordance with the terms and provisions of Article XXIII of the Plan.	Disclosure Statement: A-76
Special Litigation Trust Claims	All claims and causes of action of the Debtors or Debtors in Possession, if any, that asserted, or which may be asserted, by or on behalf of the Debtors or the Debtors' estates (i) in the Montgomery County Litigation	Disclosure Statement: A-

	(solely with respect to claims and causes of action against insiders or former insiders of the Debtors), (ii) of the same nature against other of the Debtors' current or former insiders and such other Entities as may be described in the Plan Supplement and (iii) arising under or pursuant to sections 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code against the Entities referenced in subsections (i) and (ii) above; provided, however, that under no circumstances, shall such claims and causes of action include (a) Litigation Trust Claims to be prosecuted by the Litigation Trust, the Debtors or Reorganized Debtors, as the case may be, and (b) any claims and causes of action waived and released in accordance with the provisions of Sections 28.3 and 42.6 of the Plan, and, provided, further, that, in the event that the Debtors and the Creditors' Committee jointly determine not to form the Special Litigation Trust, the claims and causes of action referred to in clauses (i), (ii) and (iii) above shall be deemed to be Assets of Enron, notwithstanding the inclusion of Enron and other Debtors or their estates as a plaintiff in such litigation and with the execution and delivery of any additional documents or the entry of any order of the Bankruptcy Court or such other court of competent jurisdiction.	77
Subordinated Claim	A Section 510 Enron Senior Notes Claim, a Section 510 Enron Subordinated Debenture Claim, a Section 510 Enron Preferred Equity Interest Claim, a Section 510 Enron Common Equity Interest Claim, a Penalty Claim, an Enron TOPRS Subordinated Guaranty Claim or an Other Subordinated Claim.	Disclosure Statement: A-78
Transwestern	Transwestern Holding Company, Inc.	Disclosure Statement: A-80
Treasury Regulations	Regulations promulgated by the U.S. Department of Treasury pursuant to the IRC.	Disclosure Statement: A-80
Unsecured Claim	Any Claim against the Debtors, other than an Administrative Expense Claim, a Secured Claim, a Priority Non-Tax Claim, a Priority Tax Claim, a Subordinated Claim, or a Convenience Claim.	Disclosure Statement: A-81

REORGANIZED DEBTOR PLAN ADMINISTRATION AGREEMENT

This REORGANIZED DEBTOR PLAN ADMINISTRATION AGREEMENT (this "Agreement"), dated as of November 16, 2004, between Enron Corp., an Oregon corporation ("Enron"), each of the other Debtors that are signatories hereto and Stephen Forbes Cooper, LLC (the "SFC").

WITNESSETH:

WHEREAS, commencing on December 2, 2001, Enron and certain of its subsidiaries filed voluntary petitions for relief under chapter 11 of the Bankruptcy Code (as defined in the Plan); and

WHEREAS, by order, dated July 15, 2004, the Bankruptcy Court confirmed the Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated July 2, 2004, including, without limitation, the Plan Supplement and all schedules and exhibits thereto (as the same has been or may be amended, the "Plan"); and

WHEREAS, in accordance with Article XXXVI of the Plan, certain duties and responsibilities shall be borne by the Reorganized Debtor Plan Administrator; and

WHEREAS, effective upon the Effective Date of the Plan, Enron desires to appoint SFC to serve as Reorganized Debtor Plan Administrator under the Plan, and SFC is willing to serve in such capacity, in each case upon the terms set forth herein and pursuant to the Plan;

NOW, THEREFORE, the parties hereby agree as follows.

1. Definitions. Capitalized terms used herein without definition shall have the respective meanings assigned to such terms in the Plan.

2. Appointment. Enron hereby appoints SFC to serve as Reorganized Debtor Plan Administrator under the Plan, and SFC hereby accepts such appointment and agrees to serve in such capacity, in each case effective upon the Effective Date of the Plan. On the Effective Date, compliance with the provisions of the Plan shall become the general responsibility of the Reorganized Debtor Plan Administrator, as an employee of the Reorganized Debtors, (subject to the supervision of the Board of Directors of the Reorganized Debtors) pursuant to and in accordance with the provisions of the Plan and this Agreement.

3. Responsibilities. The responsibilities of the Reorganized Debtor Plan Administrator shall include (a) facilitating the Reorganized Debtors' prosecution or settlement of objections to and estimations of Claims, (b) prosecution or settlement of claims and causes of action held by the Debtors and Debtors in Possession, (c) assisting

the Litigation Trustee and the Special Litigation Trustee in performing their respective duties, (d) calculating and assisting the Disbursing Agent in implementing all distributions in accordance with the Plan, (e) causing to be filed all required tax returns and paying taxes and all other obligations on behalf of the Reorganized Debtors from funds held by the Reorganized Debtors, (f) quarterly reporting (in a manner determined by the Reorganized ENE Board or as otherwise required by the Bankruptcy Code, the Plan or by the Bankruptcy Court) to the Bankruptcy Court of the status of the Claims resolution process, distributions on Allowed Claims and prosecution of causes of action, (g) liquidating the Remaining Assets and providing for the distribution of the net proceeds thereof in accordance with the provisions of the Plan, (h) consulting with, and providing information to, the DCR Overseers in connection with the voting or sale of the Plan Securities to be deposited into the Disputed Claims reserve to be created in accordance with Section 21.3 of the Plan, and (i) such other responsibilities as may be vested in this Agreement pursuant to the Plan, this Agreement or Bankruptcy Court order or as may be necessary and proper to carry out the provisions of the Plan. Notwithstanding anything to the contrary the Plan Administrator shall report to, and follow, as if it were an officer of each of the Reorganized Debtors, the direction, guidance and oversight of the Board of Directors of Reorganized ENE.

4. Powers. The powers of the Reorganized Debtor Plan Administrator shall, without any further Bankruptcy Court approval in each of the following cases, include (a) the power to invest funds in, and withdraw, make distributions and pay taxes and other obligations owed by the Reorganized Debtors from funds held by the Reorganized Debtor Plan Administrator and/or the Reorganized Debtors in accordance with the Plan, (b) the power to compromise and settle claims and causes of action on behalf of or against the Reorganized Debtors, other than Litigation Trust Claims, Special Litigation Trust Claims and claims and causes of action which are the subject of the Severance Settlement Fund Litigation, and (c) such other powers as may be vested in or assumed by the Reorganized Debtor Plan Administrator pursuant to the Plan, this Agreement or as may be deemed necessary and proper to carry out the provisions of the Plan.

5. Certain Limitations on Powers. Notwithstanding anything to the contrary contained herein or in the Plan, prior to taking the following actions, the Plan Administrator shall be required to obtain approval of the board of directors of Reorganized ENE and, if requested by the board of directors, the Bankruptcy Court:

(a) Allowance of Claims. Compromise or settle any Claim to the extent such resolution (i) provides for the allowance of a Claim against a Debtor that exceeds one hundred million dollars ($100,000,000), (ii) provides for the allowance of a Claim against a Debtor that exceeds one million dollars ($1,000,000) and constitutes more than twenty percent (20%) of such Debtor's Book Value (hereinafter defined) of Claims, (iii) provides for the allowance of a Claim that exceeds twenty million dollars ($20,000,000) and constitutes more than one hundred five percent (105%) of such Claim's Book Value and (iv) provides for the allowance of a Claim of a current or former employee or insider of the Debtors that exceeds one hundred thousand dollars ($100,000).

(b) Disposition of Assets. Enter into definitive documentation concerning any sale, transfer or other disposition (a "Sale") of any Asset that has a Book Value greater than two million dollars ($2,000,000) unless (i) the aggregate proceeds to be received from such Sale are exclusively Cash or Cash Equivalents, (ii) the aggregate proceeds from such Sale exceed ninety-five percent (95%) of the Book Value of such Asset and (iii) the documentation for the Sale specifies that the transaction is on an "as is, where is" basis, with no indemnification obligations of the Reorganized Debtors and no survival of representations, warranties or covenants made by the Reorganized Debtors.

(c) Causes of Action. Compromise or settle any claim or cause of action that constitutes an Asset for which the initial amount demanded exceeds two million dollars ($2,000,000).

As used in this section, "Book Value" shall mean the value attributed to an Asset or Claim in Appendix C to the Disclosure Statement and/or in any supporting documentation and information upon which Appendix C is based.

6. Other Activities. The Reorganized Debtor Plan Administrator shall be entitled to perform services for and be employed by third parties, provided that such performance or employment affords the Reorganized Debtor Plan Administrator sufficient time to carry out its responsibilities as Reorganized Debtor Plan Administrator.

7. Representatives.

(a) To satisfy its obligations under the Agreement to provide services to the Reorganized Debtors, SFC may utilize (i) the Associate Directors of Restructuring (each an "Associate Director") approved by Enron's Board of Directors and/or the Bankruptcy Court prior to the Effective Date to provide services to the Debtors on behalf of SFC, and (ii) each Associate Director designated by SFC after the Effective Date (A) in a written notice given to Enron's Board of Directors or (B) in a verbal notice given to Enron's Board of Directors as reflected in the Minutes of a meeting of such Board of Directors, to provide services to the Reorganized Debtors pursuant to this Agreement (each a "Post Effective Date Appointed Associate Director"), provided, that, (X) if Enron's Board of Directors objects to the use of any Post Effective Date Appointed Associate Director by SFC for such services, SFC shall obtain the approval of the Bankruptcy Court, after notice and an opportunity for hearing, and (Y) if Enron's Board of Directors approves of the use of a Post Effective Date Appointed Associate Director by SFC for such services, SFC shall follow and satisfy the notice procedures with regard to such Post Effective Date Appointed Associate Director set forth in Schedule 2, in each case prior to utilizing such Post Effective Date Appointed Associate Director.

(b) In the event that the Board of Directors of Enron requests that SFC reduce the number of Associate Directors utilized to provide the services set forth herein, and SFC refuses to make such a reduction, such Board of Directors may request the Bankruptcy Court to reduce the number of Associate Directors authorized to provide such services. If the Bankruptcy Court grants such request, the Associate Directors authorized to provide such services pursuant to clause (a) above shall be adjusted as set forth in the applicable order of the Bankruptcy Court.

(c) Prior to the Effective Date, SFC shall cause Stephen F. Cooper ("Cooper") and each of SFC's other employees and principals that will provide services on behalf of the Reorganized Debtors (collectively with Cooper, the "Representatives") pursuant to this Agreement to enter into an agreement in the form attached hereto as Exhibit A, and shall undertake diligent efforts to cause each Representative to comply with the terms and conditions of such agreement.

8. Compensation and Reimbursement of SFC.

(a) SFC's compensation shall consist of the following:

(i) an annual payment of $1,320,000, payable monthly in the amount of $110,000 in immediately available funds throughout the term hereof for the services of SFC. The initial monthly payment under this Agreement shall be on the Effective Date in a prorated amount based upon the remaining days following the Effective Date in the month of the Effective Date. The monthly payment for each subsequent month shall be on the first day of each calendar month for which the services are being provided.

(ii) an annual payment of $864,000 for each Associate Director permitted to provide services to the Reorganized Debtors pursuant to Section 7(a) on the basis of 160 hours per month as a full time equivalent ("FTE") for an Associate Director, such fee to be payable monthly in the amount of $72,000 in immediately available funds. The initial monthly payment under this Agreement shall be on the Effective Date in a prorated amount based upon the remaining days following the Effective Date in the month of the Effective Date. The monthly payment for each subsequent month shall be on the first day of each calendar month and will be determined as set forth in Section 8(c). Additionally, a quarterly adjustment to the amounts paid monthly pursuant to Sections 8(a) and 8(b) shall be made beginning with the first calendar quarter ending after the Effective Date, in accordance with Section 8(c).

(iii) a fee requested by SFC of, and subject to the approval of, Enron's Board of Directors and the Bankruptcy Court, which shall be reasonable under the circumstances, to be fixed and paid promptly after the earlier of either (i) termination of this Agreement other than for Cause (hereinafter defined)(in addition to any fee payable to Section 12(d)), or (ii) liquidation of substantially all of the Reorganized Debtors' material assets, in an amount to take into account, among other things, SFC's dedication to Reorganized Debtors after the effectiveness of the Plan to the exclusion of other business, comparable fees, results achieved, value maximization, and diligent progress and efforts towards the liquidation of the Reorganized Debtors and their affiliates; provided, however, if Enron's Board of Directors does not approve such fee requested by SFC, SFC may request approval of such fee by the Bankruptcy Court, in which case such fee shall be payable as approved by the Bankruptcy Court without approval of Enron's Board of Directors.

(b) The Reorganized Debtors shall reimburse SFC for all reasonable out-of-pocket expenses incurred and billed consistent with practices used prior to the Effective Date, including, but not limited to, reasonable costs of travel, reproduction, typing, computer usage, reasonable fees of legal counsel (including legal counsel to draft and enforce this Agreement) and other similar direct expenses and any and all taxes (other than state, local and federal income taxes) on any of the foregoing.

(c) The Reorganized Debtors shall pay to SFC the compensation set forth in Section 8(a) and shall reimburse expenses in accordance with Section 8(b) based upon the submission of monthly invoices by SFC setting forth the number of Associate Directors for the prior calendar month, a general description of the services provided and a detailed listing of the expenses sought to be reimbursed. SFC shall make a retroactive upward or downward adjustment on a quarterly basis to the fee calculated pursuant to Sections 8(a)(i) and 8(a)(ii) hereof based on the actual level of efforts (i.e., the FTE's actually worked during the quarter) and experience (as indicated on Schedule 1 by the normal billing rate for similar engagements) of the individuals providing services. Any hourly rate increases shall only be effective to the extent they are generally effective for other similar clients of SFC or Kroll Zolfo Cooper LLC. Such retroactive adjustment shall be reported to the Board of Directors of Enron and shall be binding upon the Reorganized Debtors, unless the Board of Directors of Enron affirmatively objects to the calculation of such adjustment and gives written notice of such objection to SFC within ten (10) days after date such adjustment is reported to the Board of Directors. In the event of such objection SFC may seek approval of such adjustment from the Bankruptcy Court, in which case such adjustment shall be binding upon the Reorganized Debtors only upon its approval by the Bankruptcy Court.

(d) Notwithstanding anything to the contrary, the fees and expenses payable to SFC pursuant to the terms of this Agreement shall serve as sole compensation and reimbursement for all services rendered by SFC or any of its employees or affiliates to the Reorganized Debtors or any of the Reorganized Debtors' Affiliates as Plan Administrator, Disbursing Agent or trustee of any trust formed pursuant to the Plan (the "Services"). No other fees or expenses shall be paid on account of the rendering of such Services.

(e) Each time that SFC adjusts the hourly rates charged for its Associate Directors, it shall provide a notice setting forth such rates to Enron's Board of Directors as promptly as practicable after such rates are determined.

9. Confidentiality.

(a) The Reorganized Debtors and their Boards of Directors shall treat any information received from SFC or any Representative as confidential, and, except as specified in this Section 9(a), will not publish, distribute or otherwise disclose in any manner any information developed by or received from SFC or any Representative without SFC's or such Representative's prior approval. Such approval shall not be required if (i) the information sought is required to be disclosed by an order binding on the Reorganized Debtor and issued by a court having competent jurisdiction over such Reorganized Debtor and such information is disclosed only pursuant to the terms of such order, (ii) such information is required to be disclosed by applicable law based on the advice of legal counsel, (iii) the information is otherwise publicly available other than, to the knowledge of such disclosing Person, through disclosure by a party in breach of a confidentiality obligation with respect thereto, or (iv) any of such Boards of Directors determines that it is required to disclose such information to satisfy its fiduciary duties and such Board of Directors obtains (A) approval of the Bankruptcy Court to make such disclosure, or (B) an opinion of counsel affirming that such disclosure is required.

(b) SFC agrees, and shall cause each Representative, to treat any information received from the Reorganized Debtors or their representatives as confidential, and, except as specified in this Section 9(b), will not publish, distribute or otherwise disclose in any manner any information developed by or received from the Reorganized Debtors or their representatives without the Enron's prior approval. Such approval shall not be required if (i) the information sought is required to be disclosed by an order binding on SFC or such Representative, as the case may be, and issued by a court having competent jurisdiction over SFC or such Representative, as the case may be, and such information is disclosed only pursuant to the terms of such order, (ii) such information is required to be disclosed by applicable law based on the advice of legal counsel or (iii) the information is otherwise publicly available other than, to the knowledge of such disclosing Person, through disclosure by a party in breach of a confidentiality obligation with respect thereto.

10. Exculpation; Indemnification.

(a) None of the Reorganized Debtor Plan Administrator nor any Representative shall be liable to any Persons or Entities, including, without limitation, holders of Claims or Equity Interests or other parties in interest, for any claim, cause of action and other assertion of liability arising out of the discharge of the powers and duties conferred upon the Reorganized Debtor Plan Administrator by the Plan or any order of the Bankruptcy Court entered pursuant to or in furtherance of the Plan, or applicable law, except for actions or omissions to act arising out of recklessness, gross negligence, willful misconduct, breach of fiduciary duty or knowing violation of law of Reorganized Debtor Plan Administrator or such Representative. No holder of a Claim or Equity Interest or other party in interest will have any claim or cause of action against the Reorganized Debtor Plan Administrator or any Representative for making payments in accordance with the Plan or for implementing the provisions of the Plan, except for actions or omissions to act arising out of recklessness, gross negligence, willful misconduct, breach of fiduciary duty or knowing violation of law.

(b) The Reorganized Debtors shall indemnify and hold harmless the Reorganized Debtor Plan Administrator and each Representative to the fullest extent permitted under (i) the Articles of Incorporation and by-laws of the Reorganized Debtors, (ii) the laws of the jurisdiction in which the applicable Reorganized Debtor is organized applicable to an officer of a corporation.

11. Term. This Agreement shall terminate on the earlier of: (a) the termination of the Reorganized Debtors Plan Administrator by the board of directors of Reorganized ENE with or without Cause or the effectiveness of its resignation pursuant to Section 12 and (b) thirty (30) days following the closing of the bankruptcy cases of the Reorganized Debtors. Notwithstanding the foregoing, the Bankruptcy Court, upon motion by the board of directors of Reorganized ENE on notice with an opportunity for a hearing at least three (3) months before the expiration of the original term or an extended term, may extend, for a fixed period, the term of this Agreement if it is necessary to facilitate or complete the transactions contemplated herein and by the Plan. The Bankruptcy Court may approve multiple extensions of the term of this Agreement.

12. Removal & Resignation of Reorganized Debtor Plan Administrator.

(a) Removal. The Reorganized Debtor Plan Administrator may be removed with or without Cause by resolution of the board of directors of Reorganized ENE, a copy of which shall be delivered to the removed Reorganized Debtor Plan Administrator, and, in the case of a Section 12(a)(v) removal, such notice shall be provided not less than ten (10) days prior to the effectiveness of such removal. For purposes of this Agreement, "Cause" shall be defined as: (i) the Reorganized Debtor Plan Administrator's theft or embezzlement or attempted theft or embezzlement of money or tangible or intangible assets or property; (ii) the Reorganized Debtor Plan Administrator's violation of any law (whether foreign or domestic), which results in a felony indictment or similar judicial proceeding; (iii) the Reorganized Debtor Plan Administrator's recklessness, gross negligence, willful misconduct, breach of fiduciary duty or knowing violation of law, in the performance of its duties; (iv) the Reorganized Debtor Plan Administrator's failure to perform any of its other material duties under this Agreement; or (v) the Reorganized Debtor Plan Administrator's failure to follow any lawful direction of the board of directors of Reorganized ENE with respect to the responsibility of the Reorganized Debtor Plan Administrator as specified in Sections 3, 4 and 5 above; provided, however, the Reorganized Debtor Plan Administrator has been given (A) a reasonable period to cure any alleged Cause under clauses (iii) (other than willful misconduct) and (iv) and (B) ten (10) days to cure any alleged Cause under clause (v).

(b) Simultaneous Removal and Resignation. To the extent that the Reorganized Debtor Plan Administrator is removed pursuant to the terms specified in Section 12(a) above (a "Removal") or the Reorganized Debtor Plan Administrator resigns pursuant to the terms specified in Section 12(c) below (a "Resignation"), and such Reorganized Debtor Plan Administrator is then serving in any other capacity for or on behalf of any of the Reorganized Debtors or any of their Affiliates or is serving as Disbursing Agent or as trustee of any trust formed pursuant to the Plan (service by the Reorganized Debtor Plan Administrator in each such additional capacity, a "Duty" and collectively, the "Duties"), the Reorganized Debtor Plan Administrator shall be deemed to be terminated (for all purposes and without any further action) from each of its other Duties upon its Removal or Resignation.

(c) Resignation. SFC may resign as Reorganized Debtor Plan Administrator hereunder upon delivery of forty five (45) days' written notice to the board of directors of Reorganized ENE. If a successor Reorganized Debtor Plan Administrator has not been appointed by the end of such forty five (45) day period, the Reorganized Debtor Plan Administrator shall continue as Reorganized Debtor Plan Administrator for up to an additional forty five (45) days if so requested by the board of directors of Reorganized ENE pursuant to the terms specified herein.

(d) Termination Fee. In the event of a termination of the Reorganized Debtor Plan Administrator without Cause, the Reorganized Plan Administrator shall be paid a fee of $2,900,000. This fee represents liquidated damages intended by the parties to compensate SFC for the lost opportunity costs and reallocation of resources upon termination without Cause.

(e) Expiration of Rights and Obligations. The duties, responsibilities and powers of the Reorganized Debtor Plan Administrator and the Reorganized Debtors will terminate upon the termination of this Agreement.

13. Notices. Any notices or other communications required or permitted hereunder shall be sufficiently given if in writing and personally delivered or sent by registered or certified mail, postage prepaid, return receipt requested, or sent by facsimile, addressed as follows or to such other address as any party shall have given notice of pursuant hereto:

In the case of the Reorganized Debtor Plan Administrator:

Stephen Forbes Cooper LLC
900 Third Avenue
New York, New York 10022
Telephone: (212) 213-5555
Telecopier: (212) 213-1749
Attn: Stephen F. Cooper

with a copy to:

Stephen Forbes Cooper LLC
101 Eisenhower Parkway, 3rd Floor
Roseland, New Jersey 07068
Telephone: (973) 618-5100
Telecopier: (973) 618-9430
Attn: Elizabeth S. Kardos,
General Counsel

In the case of Enron or any other Debtor:

Enron Corp.
1221 Lamar, Suite 1600
Houston, Texas 77010-1221
Attention: General Counsel
Telephone: (713) 853-6161
Telecopier: (713) 853-3129

with a copy to:

Weil, Gotshal & Manges LLP
767 Fifth Avenue
New York, New York 10153
Attention: Brian S. Rosen, Esq.
Telephone: (212) 310-8000
Telecopier: (212) 310-8007

14. Jurisdiction. The Bankruptcy Court shall have the continuing and exclusive jurisdiction to interpret and enforce this Agreement and to determine all disputes arising hereunder.

15. Governing Law; Jurisdiction; Board Standing.

(a) This Agreement shall be governed and construed in accordance with the laws of the State of New York, without giving effect to rules governing the conflict of laws. Without limiting any Person or Entity's right to appeal any order of the Bankruptcy Court, (i) the Bankruptcy Court shall retain exclusive jurisdiction to enforce the terms of this Agreement and to decide any claims or disputes which may arise or result from, or be connected with, this Agreement, any breach or default hereunder, or the transactions contemplated hereby, and (ii) any and all actions related to the foregoing shall be filed and maintained only in the Bankruptcy Court, and the parties hereby consent to and submit to the exclusive jurisdiction and venue of the Bankruptcy Court.

(b) In the event that (i) SFC makes a request of the Bankruptcy Court with regard to any matter arising out of this Agreement, and any Board of Directors of the Reorganized Debtors desires to object to the granting of such request, or (ii) any Board of Directors of the Reorganized Debtors is required, or desires, to obtain approval, or an order, of the Bankruptcy Court pursuant to this Agreement, such Board of Directors may retain counsel or other advisors at the reasonable expense of the Reorganized Debtor to advise or otherwise represent such Board of Directors in connection with the matters specified in (i) and (ii) of the clause (b), including, without limitation, to object to, seek approval or an order with regard to, and/or appear at the hearing regarding, such matters. Nothing in this clause (b) shall be deemed to require the approval of any Board of Directors of the Reorganized Debtors for the granting of any request by SFC of the Bankruptcy Court.

16. Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be an original, and which together shall constitute a single instrument.

17. Entire Agreement. This Reorganized Debtor Plan Administrator Agreement constitutes the entire agreement by and among the parties hereto regarding the subject matter hereof. This Reorganized Debtor Plan Administrator Agreement supersedes all prior and contemporaneous agreements, understandings, negotiations, discussions, written or oral, of the parties hereto, relating to any transaction contemplated hereunder, including without limitation the [set forth all prior SFC Engagement Letters]; provided, however, this Agreement shall not limit any compensation due to SFC for services provided prior to the Effective Date pursuant to any other agreement or order of the Bankruptcy Court.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date first above written.

Enron Corp.

By:________________________
Name: K. Wade Cline
Title: Managing Director and Assistant General Counsel

Enron Metals & Commodity Corp.

By:________________________
Name: K. Wade Cline
Title: Vice President

Enron North America Corp.

By:________________________
Name: K. Wade Cline
Title: Vice President

Enron Power Marketing, Inc.

By:________________________
Name: K. Wade Cline
Title: Vice President

PBOG Corp.

By:________________________
Name: K. Wade Cline
Title: President

Smith Street Land Company

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron Broadband Services, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Energy Services Operations, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Energy Marketing Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Energy Services, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ALL OK
LYONS

Enron Energy Services, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Transportation Services, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

BAM Lease Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ENA Asset Holdings L.P.
By: Blue Heron I LLC, General Partner
By: Whitewing Associates L.P., Sole Member
By: Egret I LLC, Managing Member

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Gas Liquids, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

All on

Enron Global Markets LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Net Works LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Industrial Markets LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Operational Energy Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Engineering & Construction Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Engineering & Operational Services Company

By: KWade Cl
Name: K. Wade Cline
Title: Vice President

Garden State Paper Company, LLC

By: KWade Cl
Name: K. Wade Cline
Title: Vice President

Palm Beach Development Company, L.L.C.

By: KWade Cl
Name: K. Wade Cline
Title: Vice President

Tenant Services, Inc.

By: KWade Cl
Name: K. Wade Cline
Title: Vice President

Enron Energy Information Solutions, Inc.

By: KWade Cl
Name: K. Wade Cline
Title: Vice President

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EESO Merchant Investments, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Federal Solutions, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Freight Markets Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Broadband Services, L.P.
By: Enron Broadband Services, Inc.,
General Partner

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Energy Services North America, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

All OK

Enron LNG Marketing LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Calypso Pipeline, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Global LNG LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron International Fuel Management
Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Natural Gas Marketing Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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LYONS

ENA Upstream Company LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Liquid Fuels, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron LNG Shipping Company

By: K Wade Cline
Name: K. Wade Cline
Title: Chairman

Enron Property & Services Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron Capital & Trade Resources
International Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Communications Leasing Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Wind Systems, LLC, f/k/a
EREC Subsidiary I, LLC and successor
toEnron Wind Systems Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Wind Constructors LLC, f/k/a
EREC Subsidiary II, LLC and successor
to Enron Wind Constructors Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Wind Energy Systems LLC, f/k/a
EREC Subsidiary III, LLC and successor
to Enron Wind Energy Systems Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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Lyons

Enron Wind Maintenance LLC, f/k/a
EREC Subsidiary IV, LLC and
successor to Enron Wind Maintenance
Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Wind LLC, f/k/a
EREC Subsidiary V, LLC and successor
to Enron Wind Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Intratex Gas Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Processing Properties, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Methanol Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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LYONS

Enron Ventures Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

The New Energy Trading Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

EES Service Holdings, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Wind Development LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ZWHC LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ML or

Lyons

Zond Pacific, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Reserve Acquisition Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

EPC Estates Services, Inc., f/k/a
National Energy Production Corporation

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Power & Industrial Construction
Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

NEPCO Power Procurement Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

NEPCO Services International, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Caribe Verde (SJG) Inc., f/k/a
San Juan Gas Company, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

EBF LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Zond Minnesota Construction Company
LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Fuels International, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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E Power Holdings Corp.

By:______________________________
Name: K. Wade Cline
Title: President

EFS Construction Management Services, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

Enron Management, Inc.

By:______________________________
Name: K. Wade Cline
Title: President

Enron Expat Services, Inc.

By:______________________________
Name: K. Wade Cline
Title: President

Artemis Associates, L.L.C.

By:______________________________
Name: K. Wade Cline
Title: Vice President

Clinton Energy Management Services, Inc.

By: K Wade Cl

Name: K. Wade Cline
Title: Vice President

LINGTEC Constructors L.P.
By: Enron Power Construction Company, General Partner

By:

Name: Stephen D. Dowd
Title: President and Chief Executive Officer

EGS New Ventures Corp.

By: K Wade Cl

Name: K. Wade Cline
Title: Vice President

Louisiana Gas Marketing Company

By: K Wade Cl

Name: K. Wade Cline
Title: Vice President

Louisiana Resources Company

By: K Wade Cl

Name: K. Wade Cline
Title: Vice President

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LYONS

LGMI, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

LRCI, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

Enron Communications Group, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

EnRock Management, LLC

By:______________________________
Name: K. Wade Cline
Title: Vice President

ECI-Texas, L.P.
By: Enron Broadband Services, Inc.,
General Partner

By:______________________________
Name: K. Wade Cline
Title: Vice President

EnRock, L.P.
By: Enrock Management, LLC,
General Partner

By: K Wade Cline
Name: K. Wade Cline
Title: Authorized Representative

ECI-Nevada Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Alligator Alley Pipeline Company

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron Wind Storm Lake I LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ECT Merchant Investments Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

EnronOnLine, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

St. Charles Development Company, L.L.C.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Calcasieu Development Company, L.L.C.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Calvert City Power I, L.L.C.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron ACS, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

LOA, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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Enron India LLC.

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron International Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron International Holdings Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron Middle East LLC

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron WarpSpeed Services, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ARL OK
L-YOUS

Modulus Technologies, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

Enron Telecommunications, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

DataSystems Group, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

Risk Management & Trading Corp.

By:______________________________
Name: K. Wade Cline
Title: Vice President

Omicron Enterprises, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

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LYONS

EFS I, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

EFS II, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

EFS III, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

EFS V, Inc.

By:______________________________
Name: K. Wade Cline
Title: Vice President

EFS VI, L.P.
By: EFS IV, Inc., General Partner

By:______________________________
Name: K. Wade Cline
Title: Vice President

Lyons

EFS VII, Inc.

By: __________________________
Name: K. Wade Cline
Title: Vice President

EFS IX, Inc.

By: __________________________
Name: K. Wade Cline
Title: Vice President

EFS X, Inc.

By: __________________________
Name: K. Wade Cline
Title: Vice President

EFS XI, Inc.

By: __________________________
Name: K. Wade Cline
Title: Vice President

EFS XII, Inc.

By: __________________________
Name: K. Wade Cline
Title: Vice President

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LYONS

EFS XV, Inc.

By: ______________________________
Name: K. Wade Cline
Title: Vice President

EFS XVII, Inc.

By: ______________________________
Name: K. Wade Cline
Title: Vice President

Jovinole Associates
By: EFS I, Inc. and EFS XIII, Inc., it's Partners

By: ______________________________
Name: K. Wade Cline
Title: Vice President

EFS Holdings, Inc.

By: ______________________________
Name: K. Wade Cline
Title: Vice President

Enron Operations Services LLC

By: ______________________________
Name: K. Wade Cline
Title: President

Green Power Partners I LLC

By:______________________________
Name: K. Wade Cline
Title: Vice President

TLS Investors, L.L.C.

By:______________________________
Name: K. Wade Cline
Title: Vice President

ECT Securities Limited Partnership
By: ECT Securities GP Corp., General Partner

By:______________________________
Name: K. Wade Cline
Title: Vice President

ECT Securities LP Corp.

By:______________________________
Name: K. Wade Cline
Title: Vice President

ECT Securities GP Corp.

By:______________________________
Name: K. Wade Cline
Title: Vice President

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LYONS

KUCC Cleburne, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron International Asset Management Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron Brazil Power Holdings XI Ltd.

By: K Wade Cline
Name: K. Wade Cline
Title: Chairman

Enron Holding Company L.L.C.

By: K Wade Cline
Name: K. Wade Cline
Title: President

Enron Development Management Ltd.

By: K Wade Cline
Name: K. Wade Cline
Title: Chairman

Enron International Korea Holdings Corp.

By: ______________________________
Name: K. Wade Cline
Title: President

Enron Caribe VI Holdings Ltd.

By: ______________________________
Name: K. Wade Cline
Title: Chairman

Enron International Asia Corp.

By: ______________________________
Name: K. Wade Cline
Title: President

Enron Brazil Power Investments XI Ltd.

By: ______________________________
Name: K. Wade Cline
Title: Chairman

Paulista Electrical Distribution, L.L.C.

By: ______________________________
Name: K. Wade Cline
Title: Vice President

Enron Pipeline Construction Services Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Pipeline Services Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Trailblazer Pipeline Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Liquid Services Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Machine and Mechanical Services, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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Enron Commercial Finance Ltd.

By: ______________________
Name: K. Wade Cline
Title: Chairman

Enron Permian Gathering Inc.

By: ______________________
Name: K. Wade Cline
Title: Vice President

Transwestern Gathering Company

By: ______________________
Name: K. Wade Cline
Title: Vice President

Enron Gathering Company

By: ______________________
Name: K. Wade Cline
Title: Vice President

EGP Fuels Company

By: ______________________
Name: K. Wade Cline
Title: Vice President

Enron Asset Management Resources, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Brazil Power Holdings I Ltd.

By: K Wade Cline
Name: K. Wade Cline
Title: Chairman

Enron do Brazil Holdings Ltd.

By: K Wade Cline
Name: K. Wade Cline
Title: Chairman

Enron Wind Storm Lake II LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Renewable Energy Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

All OK
Lyons

Enron Acquisition III Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Wind Lake Benton LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Superior Construction Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

EFS IV, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

EFS VIII, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

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EFS XIII, Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Credit Inc.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Power Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Richmond Power Enterprise, L.P.
By: Enron-Richmond Power Corp. and
Richmond Power Holdings, Inc.,
General Partners

By: ______________________
Name: Charles E. Schneider
Title: President and Chief
Executive Officer

ECT Strategic Value Corp.

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

ALL OK
LYONS

Enron Development Funding Ltd.

By:______________________________
Name: K. Wade Cline
Title: Chairman

Atlantic Commercial Finance, Inc.

By:______________________________
Name: K. Wade Cline
Title: President

The Protane Corporation

By:______________________________
Name: K. Wade Cline
Title: President

Enron Asia Pacific/Africa/China LLC

By:______________________________
Name: K. Wade Cline
Title: President

Enron Development Corp.

By:______________________________
Name: K. Wade Cline
Title: President

ET Power 3 LLC

By: ______________________
Name: K. Wade Cline
Title: President

Nowa Sarzyna Holding B.V.

By: ______________________
Name: K. Wade Cline
Title: Authorized Representative

Enron South America LLC

By: ______________________
Name: K. Wade Cline
Title: President

Enron Global Power & Pipelines LLC

By: ______________________
Name: K. Wade Cline
Title: President

Cabazon Power Partners LLC

By: ______________________
Name: K. Wade Cline
Title: Vice President

ALL OK
Lyons

Cabazon Holdings LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Caribbean Basin LLC

By: K Wade Cline
Name: K. Wade Cline
Title: President

Victory Garden Power Partners I LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Oswego Cogen Company, LLC

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

Enron Equipment & Procurement Company

By: K Wade Cline
Name: K. Wade Cline
Title: Vice President

All OK

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Stephen Forbes Cooper, LLC, as Trustee

By: ____________________
Name: STEPHEN FORBES COOPER
Title: MANAGER

Schedule 1

Rates

[see attached]

Employee	Position	Age/Yrs Experience	Current Billing Rate ($/Hr) *	Hours/ Week	Role
Steve Cooper	Partner	55/30+	$760	40+	Overall management of the reorganization process.
1. Scott Winn	Partner	45/20	$670	50+	Day to day management of various chapter 11 issues.
2. Eva Anderson	Director	39/15	$545	50+	Overhead analysis/SPE analysis/bank communications.
3. Jerry Barbanel	Senior Director	39/18	$575	50±	Litigation/forensic coordination.
4. Robert Bingham	Director	53/25	$545	50+	Liquidity management/reporting/supervision.
5. Robert Semple	Director	56/30	$520	50+	Business planning/asset disposition/special projects.
6. James Moffett	Director	57/35	$500	50±	Litigation support/coordination.
7. Mick Holtzleiter	Director	50/28	$495	50+	Manage liquidation/asset disposition/claims resolution/litigation management/reporting requirements of non-core businesses.
8. J. Robert Cotton	Director	53/25	$545	50+	Business planning for reorganized platform and special projects
9. Bret Fernandes	Manager	33/10	$465	50+	Liquidity management/reporting/special projects.
10. Matthew Sandoval	Manager	37/5	$465	50+	Project management support of the chapter 11 plan.
11. Kevin Townsend	Manager	53/20	$450	50+	Project management support of the chapter 11 plan.
12. Molly McCallum	Associate	33/9	$385	50+	Day to day support.
13. Regina Lee	Associate	27/5	$400	50+	Litigation/preference and fraudulent conveyance analyses.
14. Michael Stanton	Director	50/27	$495	55+	Litigation support.
15. Ivette Morales	Manager	45/20	$475	55+	Litigation support.
16. Xavier Oustalniol	Manager	34/12	$500	55+	Litigation support.
17. Lorraine Ciechanowicz	Manager	37/12	$425	55+	Litigation support.
18. James Agar	Manager	31/9	$450	55+	Litigation support.
19. Erik Ringoen	Manager	34/8	$400	55+	Litigation support.
20. Paul Donato	Associate	25/1	$325	55+	Litigation support.

Employee	Position	Age/Yrs Experience	Current Billing Rate ($/Hr) *	Hours/ Week	Role
21. Ryan Tomme	Associate	25/3	$350	55+	Litigation support.
22. Russell Kemp	Manager	53/26	$450	55+	Litigation support.
23. Bassem Marcos	Manager	39/14	$450	55+	Litigation support.
24. Stan Wilson	Associate Director	30/10	$500	55+	Specialized technical litigation support.
25. Jeffrey E. Tuley	Associate Director	24/5	$450	55+	Specialized technical litigation support.
26. Bryan Thornton	Associate Director	28/6	$475	55+	Specialized technical litigation support.
27. J. Luke Tenery	Associate Director	23/2	$425	55+	Specialized technical litigation support.
28. D. Lance Fielder	Associate Director	35/13	$450	55+	Specialized technical litigation support.
29. Andy Bass	Associate Director	32/4	$425	55+	Specialized technical litigation support.
30. Gabriel Kraft	Associate Director	26/3	$400	55+	Specialized technical litigation support.
31. James Yerges	Associate Director	46/23	$350	55+	Asset location and investigative services.
32. David Shapiro	Associate Director	45/16	$425	55+	Litigation Support
33. Richard Fogarty	Associate Director	39/11	$250	55+	Asset location and investigative services.
34. Marsha Shulman	Associate Director	54/30	$250	55+	Asset location and investigative services.
35. Cory Martin	Associate Director	24/3	$350	55+	Specialized technical litigation support.
36. Gregg Gardiner	Associate Director	43/12	$520	55+	Litigation support.
37. Ken Bara	Associate Director	34/12	$390	55+	Litigation support.
38. Mark Cervi	Associate Director	28/7	$390	55+	Litigation support.

* Billing rates have been revised to reflect rates effective July 1, 2004.

Schedule 2

Post Effective Date Appointed Associate Director

SFC will file a Notice of Proposed Employment of Approved Professional (the "Notice") with the Bankruptcy Court listing which Post Effective Date Appointed Associate Director(s) it would like to deploy. Such deployment may be to replace departing employees of the Reorganized Debtors or to handle workload that the existing employees of Reorganized Debtors are unable to handle.

If such deployment is to replace departing employees of the Reorganized Debtors, the Notice shall provide certain comparable statistics between the additional Post Effective Date Appointed Associate Director(s) and the Reorganized Debtor employee(s) that the Post Effective Date Appointed Associate Director(s) are intended to replace. In particular, the Notice shall state the age, salary, experience and education of both the additional Post Effective Date Appointed Associate Director(s) and the Reorganized Debtor employee(s) being replaced. In the event that a Post Effective Date Appointed Associate Director is being deployed to work on additional work, as opposed to replacing a departing Reorganized Debtor employee, the Notice shall make a statement to that effect and set forth the name, age, salary, experience, education and reason for deployment of such Post Effective Date Appointed Associate Director.

If no party in interest objects to the Notice within 10 days of the Notice being filed, the deployment of the approved Post Effective Date Appointed Associate Director(s) listed in the notice shall be deemed approved without further order of the Bankruptcy Court.

If a party in interest objects to a Post Effective Date Appointed Associate Director listed in the Notice within 10 days of the Notice being filed and the objection cannot be consensually resolved, the employment of the such Post Effective Date Appointed Associate Director(s) shall be subject to the entry of an order by the Bankruptcy Court following a noticed hearing.

STEPHEN D. BENNETT

Mr. Bennett graduated in the top 5% of the West Point class of 1971. Following commissioning in the U.S. Army Corps of Engineers, he served in a variety of command and staff assignments between 1971 and 1976, rising to the rank of Captain. He resigned his commission in 1976 to pursue a career in industry. Mr. Bennett returned to graduate school twice, and earned masters degrees in engineering and business administration.

Mr. Bennett joined U.S. Steel Corporation in 1976 as a production manager at the Gary, Indiana, steel works. Between 1976 and 1986 he advanced through a number of management positions of increasingly higher responsibility in the operating and engineering functions at Gary Works. In 1986 Mr. Bennett was named Plant Manager of the Double Eagle Steel Coating Company of Dearborn, Michigan, a 50/50 joint venture of U.S. Steel and Ford Motor Company, which produced 800,000 tons per year of high quality coated steel for automotive and appliance applications. In this capacity he was responsible for all operations at Double Eagle, and reported to the joint venture's Board of Directors. He led the efforts to complete the construction and successful start-up of this new facility.

In 1987 Mr. Bennett was named General Manager of U.S. Steel's Fairfield Works in Birmingham, Alabama. In this position he was responsible for all operations at a facility producing 2.2 million tons of steel per year, with annual revenues of approximately $900 million. During this assignment he also oversaw the construction and commissioning of nearly $250 million in new steel production facilities.

In 1990 Mr. Bennett was recruited by Acme Steel Company of Chicago, Illinois to be Vice President of Operations for Acme's steel and industrial packaging businesses. In this position he was responsible for all manufacturing, technical, and production support activities for a seven-plant operation, with facilities in four states. Acme Steel Company reorganized in 1992 to become Acme Metals Incorporated, a public holding company with four wholly owned operating subsidiaries. Mr. Bennett was named Group Vice President of Acme Metals, assuming full P&L responsibility for Metals' new Acme Steel and Acme Packaging subsidiaries, having combined sales of $400 million.

Mr. Bennett was elected President and Chief Operating Officer of Acme Metals in 1993, joining the Acme Board of Directors at the same time. As COO his duties expanded to include full P&L responsibility for all four of Acme's operating subsidiaries, including Alpha Tube Corporation and Universal Tool and Stamping. As such, he oversaw all business activities for eleven manufacturing facilities in six states, with combined annual sales of $525 million. As an Acme Director he served on the Finance and Strategic Planning, and Executive Committees. During this period Mr. Bennett also participated directly in raising $400 million in new public equity and debt, to finance a major modernization project at the Acme Steel subsidiary. He oversaw the procurement, construction, and commissioning of these new state-of-the-art steel production facilities.

Mr. Bennett was elected President and Chief Executive Officer of Acme Metals in 1996, becoming responsible for all aspects of the business. At this time he was also elected to the Board of Directors of the American Iron and Steel Institute. In 1997 he successfully concluded the refinancing of all the Corporation's debt. Mr. Bennett was elected Chairman of the Board of Acme Metals in 1999.

When the marketplace for steel collapsed in 1998, severe liquidity problems at the Acme Steel subsidiary forced the Company to file for protection under Chapter 11 of the Bankruptcy Code. At the time of the filing, Acme's other businesses were stable and profitable, but cross guarantees on Acme Metals debt required all the subsidiaries to enter bankruptcy. During the ensuing five years, in addition to fulfilling his responsibilities related to the on-going operations of the business units, Mr. Bennett led the efforts to reorganize the Corporation and emerge from Chapter 11. While the initial objective was to successfully reorganize Acme Metals in its entirety, including all subsidiaries, a second, deeper collapse in the steel market in 2001 dictated other outcomes. To recover maximum value for creditors it became necessary to reorganize each subsidiary independently, which ultimately required dissolution of the Corporation. Mr. Bennett oversaw this process, which variously included the sale, transfer, closure, or liquidation of Acme's assets. This process was completed in 2004.

In November 2004 Mr. Bennett was appointed to the Board of Directors of reorganized Enron Corporation (post-bankruptcy).

**Rob Deutschman,
President, Cappello Partners, LLC**

Rob Deutschman has specialized in investment and merchant banking activities for nearly 20 years, with a particular emphasis on executing private placements of institutional capital for growing public and private companies. Mr. Deutschman's ability to deliver financing solutions to companies facing complex circumstances is enhanced by his experience as a founder and operator of companies and his background advising and accessing capital for companies in distressed situations. Mr. Deutschman's diverse background also encompasses venture capital, law, entertainment, real estate, financial services, service industry operations, and restructurings and workouts.

Prior to joining Cappello, Mr. Deutschman was a Managing Director of Saybrook Capital Corp. where he focused on corporate finance, venture capital and defaulted/troubled municipal bond issues and related workouts and restructurings. Previously, he was a principal of Cheviot Capital Corporation, a financial advisory and investment firm specializing in bankruptcy, insolvency and distressed situations, which was sold to Houlihan Lokey Howard & Zukin in 1988, commencing the formation of Houlihan's Financial Restructuring Group. Mr. Deutschman subsequently became a Senior Vice President and Director of Principal Investments of Houlihan's Public Finance Group, where he oversaw numerous restructuring and workout assignments, including the acquisition of defaulted and troubled securities on behalf of the firm's principals and its clients.

Mr. Deutschman began his career in 1982 as a practicing attorney with Gibson, Dunn & Crutcher in Los Angeles. Mr. Deutschman serves as the Vice Chairman of the Board of Directors of Enron Corp., a position he assumed upon the company's emergence from bankruptcy. Mr. Deutschman also currently serves on the Board of First Bank of Beverly Hills, F.S.B. and as a member of the Board of Directors of Beverly Hills Bancorp Inc. (NASDAQ:BHBC). Mr. Deutschman is an active speaker on accessing capital. He chairs the Strategic Research Institute's Annual PIPEs Conference and regularly presents to the Los Angeles Venture Association, industry groups and regional law firms. Mr. Deutschman serves on the Executive Committee of the Water Buffalo Club, a Los Angeles-based charity that fulfills the tangible, lasting wishes of various children's charities. He is a former member of the Santa Monica Chapter of the Young President's Organization.

Mr. Deutschman earned his undergraduate degree, with honors, in political science at Haverford College and his law degree from Columbia University School of Law, where he was a Harlan Fiske Stone Scholar. Born and raised in New York City, Mr. Deutschman is an active participant in a variety of sports.

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ConocoPhillips

R. A. Harrington
Senior Vice President
Retired

Rick A. Harrington served as senior vice president, legal and general counsel for ConocoPhillips, based in Houston, Texas until May 1, 2003 and then as Senior Vice President and Special Advisor to the CEO until his retirement August 15, 2003.

Harrington joined DuPont in 1979 as a senior litigation attorney in Wilmington, Delaware and was promoted to managing counsel, special litigation. In 1990, he transferred to Pittsburgh as vice president and general counsel for Consolidation Coal Company, then a DuPont subsidiary. He was named vice president and general counsel for Conoco in 1994 and senior vice president, legal and general counsel for ConocoPhillips in 1998. He served on the Conoco and ConocoPhillips management committee from 1996 through 2003.

During his tenure as general counsel of Conoco, the company separated from DuPont in the largest IPO in U.S. history, acquired Gulf Canada in the largest energy company acquisition in Canadian history, and then merged with Phillips Petroleum Company in 2002.

Prior to joining DuPont in 1979, Harrington was an antitrust litigator and partner at Arent, Fox, Kintner, Plotkin & Kahn in Washington, DC.

Born in Columbus, Ohio, in 1945, Harrington was awarded a bachelor of arts degree, with highest distinction, in political science and Soviet area studies from the University of Kansas. He earned a doctor of jurisprudence degree, with distinction, from Harvard Law School in 1970.

Harrington was the 2000-2001 Chairman of the American Petroleum Institute General Committee on Law and served on the American Corporate Counsel Board of Directors from 1999 through 2001. He was a member of the Minority Corporate Counsel Association Board of Directors from 1999 to 2004 and was awarded the MCCA Diversity 2000 Award. He served on the faculty of the Texas State Bar Advanced In-House Counsel Course in 2002 and 2003. His chapter entitled "Business Practices and Ethics in a Multicultural Environment" appeared in International Oil and Gas Ventures: A Business Perspective published in 2000.

JAMES R. LATIMER, III.

Over the past thirteen years, Mr. Latimer has headed Explore Horizons, Incorporated, a privately held exploration and production company based in Dallas, Texas. He is also a partner in two financial advisory partnerships, a director of Enron, and a director and chairman of the audit committee of NGP Capital Resources Company (NASDAQ: NGPC). Previously, Mr. Latimer was co-head of the regional office of what is now The Prudential Capital Group in Dallas, Texas, which handled energy and other financing for The Prudential Insurance Company. In addition, Mr. Latimer's prior experience has included senior executive positions with several private energy companies, consulting with the firm of McKinsey & Co., service as an officer in the United States Army Signal Corps., and several directorships. Mr. Latimer received a B.A. degree in economics from Yale University and an M.B.A. with distinction from Harvard University. He is a Chartered Financial Analyst.

Avidity Partners, LLC

John J. Ray III is Managing Director of Avidity Partners, LLC, a firm specializing in Bankruptcy related services, primarily related to Chapter 11 post confirmation liquidation and administration services. Through Avidity Partners, Mr. Ray has served as post confirmation Trustee of companies emerging from Chapter 11. In addition, Avidity Partners specializes as a Chapter 11 post confirmation Trustee of Litigation Trusts in pursuit of causes of action on behalf of creditor constituencies related to preference and avoidance actions, breach of fiduciary duty and fraud actions and professional negligence actions.

Mr. Ray has over 20 years legal experience in private practice and as General Counsel and Corporate Secretary of public companies; most recently at Fruit of the Loom, Ltd. where Mr. Ray served as the principal officer in charge of a Chapter 11 restructuring in which secured creditors received over a 90% recovery. Mr. Ray has also served in various administrative capacities of public companies with a wide range of administrative responsibilities including Human Resources, Risk Management, Environmental Affairs and Government Affairs.

Mr. Ray graduated from University of Massachusetts at Amherst and Drake Law School, Order of the Coif.

280 Shuman Blvd. – Suite 170 Naperville, IL 60563 Phone (630) 305-7400 Fax (630) 305-6900

AMENDED AND RESTATED ARTICLES OF INCORPORATION OF PORTLAND GENERAL ELECTRIC COMPANY

The Articles of Incorporation, as amended, of Portland General Electric Company (the "Corporation") are hereby amended and restated under 60.451 of the Oregon Business Corporation Act (the "Act"). The date of filing of the Corporation's Articles of Incorporation was July 25, 1930.

ARTICLE I.
Name

The name of the Corporation is:

Portland General Electric Company

ARTICLE II.
Duration

The Corporation shall exist perpetually.

ARTICLE III.
Purposes

The Corporation is organized for the following purposes:

1. To construct, purchase, lease, and otherwise acquire ownership of and improve, maintain, use and operate every type and kind of real and personal property for the generation, manufacture, production and furnishing of electric energy, and to use, furnish and sell to the public, including other corporations, towns, cities and municipalities, at wholesale and retail, electric energy.

2. To engage in any lawful activity for which corporations may be organized under the Act and any amendment thereto.

3. To engage in any lawful activity and to do anything in the operation of the Corporation or for the accomplishment of any of its purposes or for the exercise of any of its powers which shall appear necessary for or beneficial to the Corporation.

The authority conferred in this Article III shall be exercised consistently with the requirements of applicable state and federal laws and regulations governing the activities of a public utility.

ARTICLE IV.
Classes of Capital Stock

The amount of the capital stock of the Corporation is:

COMMON STOCK. Common Stock of the Corporation shall consist of a class without par value consisting of 80,000,000 shares.

PREFERRED STOCK. Preferred Stock of the Corporation shall consist of a class without par value consisting of 30,000,000 shares issuable in series as hereinafter provided.

LIMITED VOTING JUNIOR PREFERRED STOCK. Limited Voting Junior Preferred Stock of the Corporation shall consist of a class of one share having a par value of $1.00.

A statement of the preferences, limitations, and relative rights of each class of the capital stock of the Corporation, namely, the Preferred Stock without par value, the Limited Voting Junior Preferred Stock and the Common Stock, of the variations and relative rights and preferences as between series of the Preferred Stock insofar as the same are fixed by these Amended and Restated Articles of Incorporation (these "Articles") and of the authority vested in the Board of Directors of the Corporation to establish series of Preferred Stock, and to fix and determine the variations in the relative rights and preferences as between series insofar as the same are not fixed by these Articles is as follows:

PREFERRED STOCK

(a) As used in these Articles, the term "Preferred Stock" shall mean the Preferred Stock without par value, and shall not include the Limited Voting Junior Preferred Stock. The Preferred Stock may be divided into and issued in series. Each series shall be so designated as to distinguish the shares thereof from the shares of all other series of the Preferred Stock and all other classes of capital stock of the Corporation. To the extent that these Articles shall not have established series of the Preferred Stock and fixed and determined the variations in the relative rights and preferences as between series, the Board of Directors shall have authority, and is hereby expressly vested with authority, to divide the Preferred Stock into series and, with the limitations set forth in these Articles and such limitations as may be provided by law, to fix and determine the relative rights and preferences of any series of the Preferred Stock so established. Such action by the Board of Directors shall be expressed in a resolution or resolutions adopted by it prior to the issuance of shares of each series, which resolution or resolutions shall also set forth the distinguishing designation of the particular series of the Preferred Stock established thereby. Without limiting the generality of the foregoing, authority is hereby expressly vested in the Board of Directors to fix and determine with respect to any series of the Preferred Stock:

(1) The rate of dividend;

(2) The price at which and the terms and conditions on which shares may be sold or redeemed;

(3) The amount payable upon shares in the event of voluntary liquidation and the amount payable in the event of involuntary liquidation, but such

involuntary liquidation amount shall not exceed the price at which the shares may be sold as fixed in the resolution or resolutions creating the series;

(4) Sinking fund provisions for the redemption or purchase of shares; and

(5) The terms and conditions on which shares maybe converted.

All shares of the Preferred Stock of the same series shall be identical except that shares of the same series issued at different times may vary as to the dates from which dividends thereon shall be cumulative; and all shares of the Preferred Stock, irrespective of series, shall constitute one and the same class of stock, shall be of equal rank, and shall be identical except as to the designation thereof, the date or dates from which dividends on shares thereof shall be cumulative, and the relative rights and preferences set forth above in clauses (1) through (5) of this subdivision (a), as to which there may be variations between different series. Except as may be otherwise provided by law, by subdivision (g) of this Article IV, or by the resolutions establishing any series of Preferred Stock in accordance with the foregoing provisions of this subdivision (a), whenever the presence, written consent, affirmative vote, or other action on the part of the holders of the Preferred Stock may be required for any purpose, such consent, vote or other action shall be taken by the holders of the Preferred Stock as a single body irrespective of series and shall be determined by weighing the vote cast for each share so as to reflect the involuntary liquidation amount fixed in the resolution or resolutions creating the series, such that each share shall have one vote per $100 of involuntary liquidation value.

(b) The holders of shares of the Preferred Stock of each series shall be entitled to receive dividends, when and as declared by the Board of Directors, out of any funds legally available for the payment of dividends, at the annual rate fixed and determined with respect to each series in accordance with subdivision (a) of this Article IV, and no more, payable quarterly on the first days of January, April, July and October in each year or on such other date or dates as the Board of Directors shall determine. Such dividends shall be cumulative in the case of shares of each series either from the date of issuance of shares of such series or from the first day of the current dividend period within which shares of such series shall be issued, as the Board of Directors shall determine, so that if dividends on all outstanding shares of each particular series of the Preferred Stock, at the annual dividend rates fixed and determined by the Board of Directors for the respective series, shall not have been paid or declared and set apart for payment for all past dividend periods and for the then current dividend periods, the deficiency shall be fully paid or dividends equal thereto declared and set apart for payment at said rates before any dividends on the Common Stock shall be paid or declared and set apart for payment. In the event more than one series of the Preferred Stock shall be outstanding, the Corporation, in making any dividend payment on the Preferred Stock, shall make payments ratably upon all outstanding shares of the Preferred Stock in proportion to the amount of dividends accumulated thereon to the date of such dividend payment. No interest, or sum of money in lieu of interest, shall be payable in respect of any dividend payment or payments which may be in arrears.

(c) In the event of any dissolution, liquidation or winding up of the Corporation, before any distribution or payment shall be made to the holders of the Common Stock or the Limited Voting Junior Preferred Stock, the holders of the Preferred Stock of each series then outstanding shall be entitled to be paid out of the net assets of the Corporation available for distribution to its shareholders the respective involuntary liquidation amount for each share as fixed and determined with respect to each series in accordance with Subdivision (a) of this Article IV, plus in all cases unpaid accumulated dividends thereon, if any, to the date of payment, and no more, unless such dissolution, liquidation or winding up shall be voluntary, in which event the amount which such holders shall be entitled so to be paid shall be the respective voluntary liquidation amounts per share fixed and determined with respect to each series in accordance with subdivision (a) of this Article IV, and no more. If upon any dissolution, liquidation or winding up of the Corporation, whether voluntary or involuntary, the net assets of the Corporation available for distribution to its shareholders shall be insufficient to pay the holders of all outstanding shares of Preferred Stock of all series the full amounts to which they shall be respectively entitled as aforesaid, the entire net assets of the Corporation available for distribution shall be distributed ratably to the holders of all outstanding shares of Preferred Stock of all series in proportion to the amounts to which they shall be respectively so entitled. For the purposes of this subdivision (c), any dissolution, liquidation or winding up which may arise out of or result from the condemnation or purchase of all or a major portion of the properties of the Corporation by (1) the United States Government or any authority, agency or instrumentality thereof, (2) a State of the United States or any political subdivision, authority, agency or instrumentality thereof, or (3) a district, cooperative or other association or entity not organized for profit, shall be deemed to be an involuntary dissolution, liquidation or winding up; and a consolidation, merger or amalgamation of the Corporation with or into any other corporation or corporations shall not be deemed to be a dissolution, liquidation or winding up of the Corporation, whether voluntary or involuntary.

(d) Subject to the limitations set forth in subdivision (c) of Article V, the Preferred Stock of all series, or of any series thereof, or any part of any series thereof, at any time outstanding, may be redeemed by the Corporation, at its election expressed by resolution of the Board of Directors, at any time or from time to time, at the then applicable redemption price fixed and determined with respect to each series in accordance with subdivision (a) of this Article IV. If less than all of the shares of any series are to be redeemed, the redemption shall be made either pro rata or by lot in such manner as the Board of Directors shall determine.

In the event the Corporation shall so elect to redeem shares of the Preferred Stock, notice of the intention of the Corporation to do so and of the date and place fixed for redemption shall be mailed not less than thirty days before the date fixed for redemption to each holder of shares of the Preferred Stock to be redeemed at his address as it shall appear on the books of the Corporation, and on and after the date fixed for redemption and specified in such notice (unless the Corporation shall default in making payment of the redemption price), such holders shall cease to be shareholders of the Corporation with respect to such shares and shall have no interest in or claim against the Corporation with respect to such shares, excepting only the right to receive the redemption price therefor from the Corporation on the date fixed for redemption, without interest, upon endorsement, if required, and surrender of their certificates for such shares.

Contemporaneously with the mailing of notice of redemption of any shares of the Preferred Stock as aforesaid or at any time thereafter on or before the date fixed for redemption, the Corporation may, if it so elects, deposit the aggregate redemption price of the shares to be redeemed with any bank or trust company doing business in the City of New York, N. Y., the City of Chicago, Illinois, the City of San Francisco, California, or the City of Portland, Oregon, having a capital and surplus of at least $5,000,000, named in such notice, payable on the date fixed for redemption in the proper amounts to the respective holders of the shares to be redeemed, upon endorsement, if required, and surrender of their certificates for such shares, and on and after the making of such deposit such holders shall cease to be shareholders of the Corporation with respect to such shares and shall have no interest in or claim against the Corporation with respect to such shares, excepting only the right to exercise such redemption or exchange rights, if any, on or before the date fixed for redemption as may have been provided with respect to such shares or the right to receive the redemption price of their shares from such bank or trust company on the date fixed for redemption, without interest, upon endorsement, if required, and surrender of their certificates for such shares.

If the Corporation shall have elected to deposit the redemption moneys with a bank or trust company as permitted by this subdivision (d), any moneys so deposited which shall remain unclaimed at the end of six years after the redemption date shall be repaid to the Corporation, and upon such repayment holders of Preferred Stock who shall not have made claim against such moneys prior to such repayment shall be deemed to be unsecured creditors of the Corporation for an amount, without interest, equal to the amount they would theretofore have been entitled to receive from such bank or trust company. Any redemption moneys so deposited which shall not be required for such redemption because of the exercise, after the date of such deposit, of any right of conversion or exchange or otherwise, shall be returned to the Corporation forthwith. The Corporation shall be entitled to receive any interest allowed by any bank or trust company on any moneys deposited with such bank or trust company as herein provided, and the holders of any shares called for redemption shall have no claim against any such interest.

Except as set forth in subdivision (c) of Article V, nothing herein contained shall limit any legal right of the Corporation to purchase or otherwise acquire any shares of the Preferred Stock.

(e) The holders of shares of the Preferred Stock shall have no right to vote in the election of directors or for any other purpose except as may be otherwise provided by law, by subdivisions (f), (g) and (h) of this Article IV, or by resolutions establishing any series of Preferred Stock in accordance with subdivision (a) of this Article IV. Holders of Preferred Stock shall be entitled to notice of each meeting of shareholders at which they shall have any right to vote, but shall not be entitled to notice of any other meeting of shareholders.

(f) If at any time dividends payable on any share or shares of Preferred Stock shall be in arrears in an amount equal to four full quarterly dividends or more per share, a default in preferred dividends for the purpose of this subdivision (f) shall be deemed to have occurred, and, having so occurred, such default shall be deemed to exist thereafter until, but only until, all unpaid accumulated dividends on all shares of Preferred Stock shall have been paid to the last preceding dividend period. If and whenever a default in preferred dividends shall occur, a special meeting of shareholders of the Corporation shall be held for the purpose of electing directors upon the written request of the holders of at least 10% of the Preferred Stock then outstanding. Such meeting shall be called by the secretary of the Corporation upon such written request and shall be held at the earliest practicable date upon like notice as that required for the annual meeting of shareholders of the Corporation and at the place for the holding of such annual meeting. If notice of such special meeting shall not be mailed by the secretary within thirty days after personal service of such written request upon the secretary of the Corporation or within thirty days of mailing the same in the United States of America by registered mail addressed to the secretary at the principal office of the Corporation, then the holders of at least 10% of the Preferred Stock then outstanding may designate in writing one of their number to call such meeting and the person so designated may call such meeting upon like notice as that required for the annual meeting of shareholders and to be held at the place for the holding of such annual meeting. Any holder of Preferred Stock so designated shall have access to the stock books of the Corporation for the purpose of causing a meeting of shareholders to be called pursuant to the foregoing provisions of this paragraph.

At any such special meeting, or at the next annual meeting of shareholders of the Corporation for the election of directors and at each other meeting, annual or special, for the election of directors held thereafter (unless at the time of any such meeting such default in preferred dividends shall no longer exist), the holders of the outstanding Preferred Stock, voting separately as herein provided, shall have the right to elect the smallest number of directors which shall constitute at least one-fourth of the total number of directors of the Corporation, or two directors, whichever shall be the greater, and the holders of the outstanding shares of Common Stock, voting as a class, shall have the right to elect all other members of the Board of Directors, anything herein or in the Bylaws of the Corporation to the contrary notwithstanding. The terms of office, as directors, of all persons who may be directors of the Corporation at any time when such special right to elect directors shall become vested in the holders of the Preferred Stock shall terminate upon the election of any new directors to succeed them as aforesaid.

At any meeting, annual or special, of the Corporation, at which the holders of Preferred Stock shall have the special right to elect directors as aforesaid, the presence in person or by proxy of the holders of a majority of the Preferred Stock then outstanding shall be required to constitute a quorum of such stock for the election of directors, and the presence in person or by proxy of the holders of a majority of the Common Stock then outstanding shall be required to constitute a quorum of such stock for the election of directors; provided, however, that the absence of a quorum of the holders of either stock shall not prevent the election at any such meeting or adjournment thereof of directors by the other stock if the necessary quorum of the holders of such other stock shall be present at such meeting or any adjournment thereof; and, provided further, that in the absence of a quorum of holders of either stock a majority of the holders of such stock who are present in person or by proxy shall have power to adjourn the election of the directors to be elected by such stock from time to time, without notice other than announcement at the meeting, until the requisite quorum of holders of such stock shall be present in person or by proxy, but no such adjournment shall be made to a date beyond the date for the mailing of the notice of the next annual meeting of shareholders of the Corporation or special meeting in lieu thereof.

So long as a default in preferred dividends shall exist, any vacancy in the office of a director elected by the holders of the Preferred Stock may be filled at any meeting of shareholders, annual or special, for the election of directors held thereafter, and a special meeting of shareholders, or of the holders of shares of the Preferred Stock, may be called for the purpose of filling any such vacancy. So long as a default in preferred dividends shall exist, any vacancy in the office of a director elected by the holders of the Common Stock may be filled by majority vote of the remaining directors elected by the holders of Common Stock.

If and when the default in preferred dividends which permitted the election of directors by the holders of the Preferred Stock shall cease to exist, the holders of the Preferred Stock shall be divested of any special right with respect to the election of directors, and the voting power of the holders of the Preferred Stock and of the holders of the Common Stock shall revert to the status existing before the first dividend payment date on which dividends on the Preferred Stock were not paid in full, subject to revesting in the event of each and every subsequent like default in preferred dividends. Upon the termination of any such special right, the terms of office of all persons who may have been elected directors by vote of the holders of the Preferred Stock pursuant to such special right shall forthwith terminate, and the resulting vacancies shall be filled by the majority vote of the remaining directors.

(g) So long as any shares of the Preferred Stock shall be outstanding, the Corporation shall not without the written consent or affirmative vote of the holders of at least two-thirds of the Preferred Stock then outstanding, (1) create or authorize any new stock ranking prior to the Preferred Stock as to dividends or upon dissolution, liquidation or winding up, or (2) amend, alter or repeal any of the express terms of the Preferred Stock then outstanding in a manner substantially prejudicial to the holders thereof. Notwithstanding the foregoing provisions of this subdivision (g), if any proposed amendment, alteration or repeal of any of the express terms of any outstanding shares of the Preferred Stock would be substantially prejudicial to the holders of shares of one or more, but not all, of the series of the Preferred Stock, only the written consent or affirmative vote of the holders of at least two-thirds of the total number of outstanding shares of all series so affected shall be required. Any affirmative vote of the holders of the Preferred Stock, or of any one or more series thereof, which may be required in accordance with the foregoing provisions of this subdivision (g), upon a proposal to create or authorize any stock ranking prior to the Preferred Stock or to amend, alter or repeal the express terms of outstanding shares of the Preferred Stock or of any one or more series thereof in a manner substantially prejudicial to the holders thereof may be taken at a special meeting of the holders of the Preferred Stock or of the holders of one or more series thereof called for the purpose, notice of the time, place and purposes of which shall have been given to the holders of the shares of the Preferred Stock entitled to vote upon any such proposal, or at any meeting, annual or special, of the shareholders of the Corporation, notice of the time, place and purposes of which shall have been given to holders of shares of the Preferred Stock entitled to vote on such a proposal.

(h) So long as any shares of the Preferred Stock shall be outstanding, the Corporation shall not, without the written consent or affirmative vote of the holders of at least a majority of the Preferred Stock then outstanding:

(1) issue any shares of Preferred Stock, or of any other class of stock ranking prior to or on a parity with the Preferred Stock as to dividends or upon dissolution, liquidation or winding up, unless (a) the net income of the Corporation available for the payment of dividends for a period of twelve consecutive calendar months within the fifteen calendar months immediately

preceding the issuance of such shares (including, in any case in which such shares are to be issued in connection with the acquisition of new property, the net income of the property so to be acquired, computed on the same basis as the net income of the Corporation) is at least equal to two times the annual dividend requirements on all shares of the Preferred Stock, and on all shares of all other classes of stock ranking prior to or on a parity with the Preferred Stock as to dividends or upon dissolution, liquidation or winding up, which will be outstanding immediately after the issuance of such shares, including the shares proposed to be issued, and (b) the gross income (defined as the sum of net income and interest charges, to securities evidencing indebtedness deducted in arriving at such net income) of the Corporation available for the payment of interest for a period of twelve consecutive calendar months within the fifteen calendar months immediately preceding the issuance of such shares (including, in any case in which such shares are to be issued in connection with the acquisition of new property, the gross income, as heretofore defined, of the property so to be acquired, computed on the same basis as the gross income, as heretofore defined, of the Corporation) is at least equal to one and one-half times the aggregate of the annual interest requirements on all securities evidencing indebtedness of the Corporation, and the annual dividend requirements on all shares of the Preferred Stock and on all shares of all other classes of stock ranking prior to or on a parity with the Preferred Stock as to dividends or upon dissolution, liquidation or winding up, which will be outstanding immediately after the issuance of such shares, including the shares proposed to be issued; or

(2) issue any shares of the Preferred Stock, or of any other class of stock ranking prior to or on a parity with the Preferred Stock as to dividends or upon dissolution, liquidation or winding up, unless the aggregate of the capital of the Corporation applicable to the Common Stock and the surplus of the Corporation (paid-in, earned or other, if any) shall be not less than the aggregate amount payable on the involuntary dissolution, liquidation, or winding up of the Corporation on all shares of the Preferred Stock, and on all shares of all other classes of stock ranking prior to or on a parity with the Preferred Stock as to dividends or upon dissolution, liquidation or winding up, which will be outstanding immediately after the issuance of such shares, including the shares proposed to be issued; provided, however, that if, for the purposes of meeting the requirements of this subparagraph (2), it shall become necessary to take into consideration any surplus of the Corporation, the Corporation shall not thereafter pay any dividends on shares of the Common Stock which would result in reducing the aggregate of the capital of the Corporation applicable to the Common Stock and the surplus of the Corporation to an amount less than the aggregate amount payable on involuntary dissolution, liquidation or winding up of the Corporation, on all shares of the Preferred Stock and of any stock ranking prior to or on a parity with the Preferred Stock, as to dividends or upon dissolution, liquidation or winding up, at the time outstanding.

In any case where it would be appropriate, under generally accepted accounting principles, to combine or consolidate the financial statements of any predecessor or subsidiary of the Corporation with those of the Corporation, the foregoing computations may be made on the basis of such combined or consolidated financial statements. Any affirmative vote of the holders of the Preferred Stock which may be required in accordance with the foregoing provisions of this subdivision (h) may be taken at a special meeting of the holders of the Preferred Stock called for the purpose, notice of the time, place and purposes of which shall have been given to the holders of the outstanding shares of the Preferred Stock, or at any meeting, regular or special, of the shareholders of the Corporation, notice of the time, place and purposes of which shall have been given to the holders of the outstanding shares of the Preferred Stock.

LIMITED VOTING JUNIOR PREFERRED STOCK

(i) The Limited Voting Junior Preferred Stock shall not be entitled to receipt of any dividends, and no dividends shall be paid thereon.

(j) Subject to the limitations set forth in subdivision (c) of this Article IV (and subject to the rights of any other class of stock hereafter authorized), in the event of any dissolution, liquidation or winding up of the Corporation, whether voluntary or involuntary, before any distribution or payment shall be made to the holders of the Common Stock, the holder of the Limited Voting Junior Preferred Stock shall be entitled to be paid out of the net assets of the Corporation available for distribution to its shareholders the par value of the Limited Voting Junior Preferred Stock and no more. For the purposes of this subdivision, a consolidation, merger or amalgamation of the Corporation with or into any other corporation or corporations shall not be deemed to be a dissolution, liquidation or winding up of the Corporation, whether voluntary or involuntary.

(k) Subject to the final sentence of this subdivision (k) of this Article IV, so long as the share of Limited Voting Junior Preferred Stock shall be outstanding, the Corporation shall not, without the written consent or affirmative vote of the holder of the Limited Voting Junior Preferred Stock: (i) make an assignment for the benefit of creditors; (ii) file a petition for relief under the United States Bankruptcy Code; (iii) petition or apply to any tribunal for the appointment of a custodian, receiver or any trustee for a substantial part of its property; (iv) commence any proceeding under any bankruptcy, reorganization, arrangement, readjustment of debt, dissolution or liquidation law or statute of any jurisdiction, whether now or hereafter in effect; (v) accept or acquiesce in the filing of any such petition, application, proceeding or appointment of or taking possession by the custodian, receiver, liquidator, assignee, trustee, sequestrator (or other similar official) of the Corporation or any substantial part of its properly; or (vi) admit the Corporation's inability to pay its debts generally as they become due, on behalf of the Corporation; provided, however, that notwithstanding the foregoing, the affirmative vote of the holder of the Limited Voting Junior Preferred Stock shall not be required to file a petition for relief under the United States Bankruptcy Code if (a) the Corporation or any person or entity in Control (as defined in subdivision 1 of this Article IV) of the Corporation has entered into a contract to sell (whether by direct sale, merger or otherwise) the Corporation or its assets and the buyer conditions its obligations to consummate such transaction on obtaining the entry of an order pursuant to section 363 or section 1129 of the United States Bankruptcy Code approving such transaction and (b) if, but only if, such transaction involves the sale of assets by the Corporation in a case where ownership of the Corporation is not being transferred, following consummation of such sale, all of the indebtedness for borrowed money of the Corporation shall have been paid in full (or adequate provision for the payment thereof shall have been made) or assumed by the buyer. In exercising discretion under this subdivision (k) of this Article IV, the holder of Limited Voting Junior Preferred Stock shall be entitled to, and shall, consider and have due regard for, the interests of the shareholders of the Corporation and its creditors in addition to such other considerations as such holder shall consider relevant and in the best interests of the Corporation;

provided that nothing in this sentence is intended to create any contractual rights in any person other than the Corporation and such holder. Except as provided by applicable law, the holder of the Limited Voting Junior Preferred Stock shall be entitled to notice of each meeting of shareholders at which such holder shall have any right to vote, but shall not be entitled to notice of any other meeting of shareholders. Notwithstanding the foregoing provisions, the holder of the Limited Voting Junior Preferred Stock shall not have any voting rights under this subdivision (k) of this Article IV at any time when the Corporation has the right to redeem the Limited Voting Junior Preferred Stock pursuant to subdivision (1) of this Article IV (and regardless of whether there may then exist any restriction not set forth in such subdivision (1) on the Corporation's ability to redeem the Limited Voting Junior Preferred Stock). Except as provide in this subdivision (k) of this Article IV or as otherwise provided by law, the holder of the Limited Voting Junior Preferred Stock shall have no right to vote in the election of directors or for any other purpose.

(1) The Limited Voting Junior Preferred Stock may be redeemed by the Corporation, at its election expressed by resolution of the Board of Directors, at any time by payment of an amount equal to the par value of such share; provided, that the Corporation shall not be empowered to call the Limited Voting Junior Preferred Stock for redemption at any time in which Control of the Corporation shall be held or exercised by any person or entity, or by any Affiliate of such person or entity, which person or entity shall be subject to an order for relief under the United States Bankruptcy Code or any successor statute. For purposes of this subdivision (1), "Control" shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a person or entity, whether through the ownership of voting securities or general partnership or managing member interests, by contract or otherwise, and "Affiliate" shall mean with respect to any person or entity, any other person or entity directly or indirectly Controlling or Controlled by, or under direct or indirect common Control with such person or entity.

(m) The Limited Voting Junior Preferred Stock shall be issued and held, and may be transferred on the shareholder records of the Corporation, only upon approval of the Oregon Public Utility Commission, and only to persons or entities which are during the period of such ownership, and shall have been for the five-year period prior to such ownership, Independent. For purposes of this subdivision (m), "Independent" shall mean a person or entity which is not (i) an Affiliate (as defined in subdivision (1) above), employee, director, equity security holder, partner, member or officer of the Corporation or any of its Affiliates; (ii) employed by, or an Affiliate of, a supplier of goods or services to the Corporation or any of its Affiliates that derives more than ten percent of its revenues from the Corporation or any of its Affiliates; or (iii) a member of the immediate family of a person or entity that is an Affiliate of or that Controls (as defined in subdivision (1) above) the Corporation. Certificates or other evidence of ownership of the Limited Voting Junior Preferred Stock shall bear a legend or other prominent notice of the restriction contained in this subdivision (m).

(n) The Limited Voting Junior Preferred Stock shall not be convertible into Common Stock, Preferred Stock or any other class or series of securities issued by the Corporation.

(o) If the share of the Limited Voting Junior Preferred Stock is redeemed, purchased or otherwise acquired by the Corporation, it shall be cancelled and shall not be reissued.

COMMON STOCK

(p) Subject to the limitations set forth in subdivision (b) of this Article IV (and subject to the rights of any class of stock hereafter authorized) dividends may be paid upon the Common Stock when and as declared by the Board of Directors of the Corporation out of any funds legally available for the payment of dividends.

(q) Subject to the limitations set forth in subdivision (c) and (j) of this Article IV (and subject to the rights of any other class of stock hereafter authorized), upon any dissolution, liquidation or winding up of the Corporation, whether voluntary or involuntary, the net assets of the Corporation shall be distributed ratably to the holders of the Common Stock.

(r) Subject to the limitations set forth in subdivisions (f), (g), (h) and (k) of this Article IV (and subject to the rights of any class of stock hereafter created), and except as may be otherwise provided by law, the holders of the Common Stock shall have the exclusive right to vote for the election of directors and for all other purposes.

(s) Upon the issuance for money or other consideration of any shares of capital stock of the Corporation, or of any security convertible into capital stock of the Corporation, no holder of shares of the capital stock, irrespective of the class or kind thereof, shall have any preemptive or other right to subscribe for, purchase, or receive any proportionate or other amount of such shares of capital stock, or such security convertible into capital stock, proposed to be issued; and the Board of Directors may cause the Corporation to dispose of all or any of such shares of capital stock, or of any such security convertible into capital stock, as and when said Board may determine, free of any such right, either by offering the same to the Corporation's then shareholders or by otherwise selling or disposing of such shares or other securities, as the Board of Directors may deem advisable.

(t) The Corporation from time to time, with the approving vote of the holders of at least a majority of its then outstanding shares of Common Stock, may authorize additional shares of its capital stock, with or without nominal or par value, including shares of such other class or classes, and having such designations, preferences, rights, and voting powers, or restrictions or qualifications thereof, as may be approved by such vote and be stated in amended or restated articles of incorporation executed and filed in the manner provided by law.

(u) The provisions of subdivision (s) and of this subdivision (u) of this Article IV shall not be changed unless the holders of at least a majority of the outstanding shares of Common Stock shall consent thereto in writing, or by vote at a meeting in the notice of which action on the proposed change shall have been set forth.

ARTICLE V.
Designation of Series Preferred Stock

7.75% SERIES CUMULATIVE PREFERRED STOCK, WITHOUT PAR VALUE.

7.75% Series Cumulative Preferred Stock, Without Par Value of the Corporation shall consist of 300,000 shares. Such series of Preferred Stock is hereinafter referred to as "Preferred Stock of the First Series, Without Par Value." Shares of Preferred Stock of the First Series, Without Par Value shall have the following relative rights and preferences in addition to those fixed in Article IV above:

(a) The rate of dividend payable upon shares of Preferred Stock of the

First Series, Without Par Value shall be 7.75 percent per annum. Dividends upon shares of Preferred Stock of the First Series, Without Par Value shall be cumulative from the date of original issue and shall be payable on the 15th day of January, April, July and October of each year thereafter.

(b) Subject to the provisions of subdivision (d) of Article IV of the Articles, prior to June 15, 2002, and prior to June 15 in each year thereafter until June 15, 2006, so long as any of the Preferred Stock of the First Series, Without Par Value shall remain outstanding, the Corporation shall deposit with its Transfer Agent, as a Sinking Fund for the Preferred Stock of the First Series, Without Par Value, an amount sufficient to redeem a minimum of 15,000 shares of the Preferred Stock of the First Series, Without Par Value, plus an amount equal to dividends accrued thereon to each such June 15 and, in addition, the Corporation may, at its option, prior to each such June 15, deposit an amount sufficient to retire through the operation of the Sinking Fund not more than 15,000 additional shares of Preferred Stock of the First Series, Without Par Value, but the right to make such optional deposit shall not be cumulative and shall not reduce any subsequent mandatory Sinking Fund payment for the Preferred Stock of the First Series, Without Par Value, and prior to June 15, 2007 the Corporation shall deposit with its Transfer Agent, as the final Sinking Fund payment, an amount sufficient to redeem all shares of the Preferred Stock of the First Series, Without Par Value outstanding on June 15, 2007. The Corporation shall not declare or pay or set apart for, or make or order any other distribution in respect of, or purchase or otherwise acquire for value any shares of, the Common Stock of the Corporation, or any class of stock as to which the Preferred Stock of the Corporation has priority as to payments of dividends, unless all amounts required to be paid or set aside for any Sinking Fund payment to retire shares of the Preferred Stock of the First Series, Without Par Value, shall have been paid or set aside. The Corporation's Transfer Agent shall, in accordance with the provisions set forth herein, apply the moneys in the Sinking Fund to redeem (i) pro rata, or by lot if so determined by the Board of Directors, on June 15, 2002, and on June 15 in each year thereafter until June 15, 2006, shares of the Preferred Stock of the First Series, Without Par Value, and (ii) on June 15, 2007 all outstanding shares of Preferred Stock of the First Series, Without Par Value, in each case at One hundred Dollars ($100.00) per share plus dividends accrued to the date of redemption. The Corporation may, upon notice to its Transfer Agent prior to a date 45 days prior to June 15 in any year, commencing with the year 2002 through and including the year 2006, in which the Corporation shall be obligated to redeem shares of the Preferred Stock of the First Series, Without Par Value through the operation of the Sinking Fund, elect to reduce its obligation in respect of the redemption of shares required to be redeemed pursuant to the Sinking Fund by directing that any shares of the Preferred Stock of the First Series, Without Par Value previously purchased by the Corporation (other than shares purchased pursuant to the operation of the Sinking Fund or previously applied as a credit against the Sinking Fund) shall be applied as a credit, in whole or in part, in an amount equal to the aggregate liquidation value of the shares so applied, against the aggregate liquidation value of the shares required to be redeemed in such year pursuant to the operation of the Sinking Fund.

(c) The Preferred Stock of the First Series, Without Par Value shall not be subject to redemption, except pursuant to the Sinking Fund established for such Series.

(d) In the event of (i) any voluntary dissolution, liquidation or winding up of the Corporation, holders of the Preferred Stock of the First Series, Without Par Value shall be entitled to be paid out of the net assets of the Corporation available for distribution to its shareholders One hundred Dollars ($100.00) per share, plus unpaid accumulated dividends thereon, if any, to the date of payment, and no more, and (ii) any involuntary dissolution, liquidation or winding up of the Corporation, holders of the Preferred Stock of the First Series, Without Par Value shall be entitled to be paid out of the net assets of the Corporation One hundred Dollars ($100.00) per share, plus unpaid accumulated dividends thereon, if any, to the date of payment, and no more.

ARTICLE VI.
Vacancy on Board of Directors

Any vacancy occurring on the Board of Directors, including a vacancy created by reason of an increase in the number of directors, may be filled by the affirmative vote of a majority of directors then in office, although less than a quorum, provided that so long as a default in preferred dividends shall exist, any vacancy in the office of a director elected by the holders of the Preferred Stock may be filled only as provided in subdivision (f) of Article IV.

ARTICLE VII.
Limitation of Liability

To the fullest extent permitted by law, no director of the Corporation shall be personally liable to the Corporation or its shareholders for monetary damages for conduct as a director. No amendment or repeal of this provision shall adversely affect any right or protection of a director existing at the time of such amendment or repeal. No change in the law shall reduce or eliminate the right and protections applicable at the time this provision became effective unless the change in law shall specifically require such reduction or elimination. If the law is amended, after this Article VII shall become effective, to authorize corporate action further eliminating or limiting the personal liability of directors, officers, employees or agents of the Corporation, then the liability of directors, officers, employees or agents of the Corporation shall be eliminated or limited to the fullest extent permitted by the law, as so amended.

ARTICLE VIII.
Indemnification

The Corporation may indemnify to the fullest extent permitted by law any person who is made or threatened to be made a party to, witness in, or otherwise involved in, any action, suit, or proceeding, whether civil, criminal, administrative, investigative, or otherwise (including an action, suit, or proceeding by or in the right of the Corporation) by reason of the fact that the person is or was a director, officer, employee or agent of the Corporation or any of its subsidiaries, or a fiduciary within the meaning of the Employee Retirement Income Security Act of 1974, as amended, with respect to any employee benefit plan of the Corporation or any of its subsidiaries, or serves or served at the request of the Corporation as a director, officer, employee or agent, or as a fiduciary of an employee benefit plan, of another corporation, partnership, joint venture, trust or other enterprise. Any indemnification provided pursuant to this Article VIII shall not be exclusive of any rights to which the person indemnified may otherwise be entitled under any provision of articles of incorporation, bylaws, agreement, statute, policy of insurance, vote of shareholders or Board of Directors, or otherwise.

ARTICLE IX.
Shareholder Action Without a Meeting

Except as otherwise provided under these Articles of Incorporation and applicable law, and subject to restrictions on the taking of shareholder action without a meeting under applicable law or rules of a national securities association or exchange, action required or permitted by the Act to be taken at a shareholders' meeting may be taken without a meeting if the action is taken by shareholders having not less than the minimum number of votes that would be necessary to take such action at a meeting at which all shareholders entitled to vote on the action were present and voted.

THIRD AMENDED AND RESTATED BYLAWS

OF

PORTLAND GENERAL ELECTRIC COMPANY
(An Oregon corporation)

ARTICLE I
OFFICES

1.1. Registered Office. The registered office of the corporation required by the Oregon Business Corporation Act (the "Act") to be maintained in the State of Oregon shall be CT Corporation System, 520 S.W. Yamhill, Suite 800, Portland, Oregon 97204, or such other office as may be designated from time to time by the Board of Directors in the manner provided by law.

1.2. Other Offices. The corporation may also have offices at such other places both within and without the State of Oregon as the Board of Directors may from time-to-time determine or the business of the corporation may require.

ARTICLE II
SHAREHOLDERS

2.1 Annual Meeting. The annual meeting of the shareholders shall be held on the date and at the time as fixed by the Board of Directors and stated in the notice of the meeting.

2.2 Special Meetings. Special meetings of the shareholders may be called by the Chairman of the Board, the Chief Executive Officer, the President or by the Board of Directors, and shall be called by the President (or in the event of absence, incapacity or refusal of the President, by the Secretary or any other officer) at the request of the holders of not less than 10 percent (unless the Articles of Incorporation provide otherwise) of all votes entitled to be cast on any issue proposed to be considered at the proposed special meeting. The requesting shareholders shall sign, date and deliver to the Secretary a written demand describing the purpose or purposes for holding the special meeting.

2.3 Place of Meetings. Meetings of the shareholders shall be held at the principal business office of the corporation or at such other places within or without the State of Oregon as may be determined by the Board of Directors.

2.4 Notice of Meetings. Written notices stating the date, time and place of the meeting and, in the case of a special meeting, the purpose or purposes for which the meeting is called, shall be mailed to each shareholder entitled to vote at the meeting at the shareholder's address shown in the corporation's current record of shareholders, with postage thereon pre-paid, not less than 10 nor more than 60 days before the date of the meeting and to nonvoting shareholders as required by law. Any previously scheduled meeting of the shareholders called by or at the direction of Board of Directors may be postponed, and (unless the Articles of Incorporation or applicable law otherwise provide) any such meeting of the shareholders may be cancelled, by resolution of the Board of Directors upon public notice given prior to the date previously scheduled for such meeting of shareholders.

2.5 Waiver of Notice. A shareholder may at any time waive any notice required by law, the Articles of Incorporation or these Bylaws. The waiver must be in writing, be signed by the shareholder entitled to the notice and be delivered to the corporation for inclusion in the minutes for filing with the corporate records. A shareholder's attendance at a meeting waives objection to lack of notice or defective notice of the meeting, unless the shareholder at the beginning of the meeting objects to holding the meeting or transacting business at the meeting. The shareholder's attendance also waives objection to consideration of a particular matter at the meeting that is not within the purpose or purposes described in the meeting notice, unless the shareholder objects to considering the matter when it is presented.

2.6 Record Date.

(a) For the purpose of determining shareholders entitled to notice of a shareholders' meeting, to demand a special meeting or to vote or to take any other action, the Board of Directors of the corporation may fix a future date as the record date for any such determination of shareholders, such date in any case to be not more than 70 days nor less than ten days before the meeting or action requiring a determination of shareholders. The record date shall be the same for all voting groups.

(b) A determination of shareholders entitled to notice of or to vote at a shareholders' meeting is effective for any adjournment of the meeting unless the Board of Directors fixes a new record date, which it must do if the meeting is adjourned to a date more than 120 days after the date fixed for the original meeting.

(c) If a court orders a meeting adjourned to a date more than 120 days after the date fixed for the original meeting, it may provide that the original record date continue in effect or it may fix a new record date.

2.7 Shareholders' List for Meeting. After a record date for a meeting is fixed, the corporation shall prepare an alphabetical list of the names of all its shareholders entitled to notice of a shareholders' meeting. The list must be arranged by voting group and within each voting group by class or series of shares and show the address of and number of shares held by each shareholder. The shareholders' list must be available for inspection by any shareholder, beginning two business days after notice of the meeting is given for which the list was prepared and continuing through the meeting, at the corporation's principal office or at a place identified in the meeting notice in the city where the meeting will be held. The corporation shall make the shareholders' list available at the meeting, and any shareholder or the shareholder's agent or attorney is entitled to inspect the list at any time during the meeting or any adjournment. Refusal or failure to prepare or make available the shareholder's list does not affect the validity of action taken at the meeting.

2.8 Quorum: Adjournment. Shares entitled to vote may take action on a matter at a meeting only if a quorum of those shares exists with respect to that matter. A majority of the votes entitled to be cast on the matter constitutes a quorum for action on that matter. If, however, such quorum is not present or represented at any meeting of the shareholders, then either: (i) the Chairman of the meeting, or (ii) the shareholders by the vote of the holders of a majority of votes present in person or represented by proxy at the meeting, shall have power to adjourn the meeting to a different time and place without further notice to any shareholder of any adjournment except that notice is required if a new record date is or must be set for the new meeting. At such adjourned meeting at which a quorum is present, any business may be transacted that might have been transacted at the meeting originally held. Once a share is represented for any purpose at a meeting, it shall be deemed present for quorum purposes for the remainder of the meeting and for any adjournment of that meeting unless a new record date is set for the adjourned meeting.

2.8 Voting Requirements. If a quorum exists, action on a matter, other than the election of directors, is approved if the votes cast by the shares entitled to vote favoring the action exceed the votes cast opposing the action, unless a greater number of affirmative votes is required by law or the Articles of Incorporation. Directors are elected by a plurality of votes cast by the shares entitled to vote in an election at a meeting at which a quorum is present. Except as provided in the Act, or unless the Articles of Incorporation provide otherwise, each outstanding share is entitled to one vote on each matter voted on at a shareholders' meeting. Unless otherwise provided in the Articles of Incorporation, cumulative voting for the election of directors shall be prohibited.

2.9 Proxies.

(a) A shareholder may vote shares in person or by proxy by signing an appointment, either personally or by the shareholder's designated officer, director, employee, agent, or attorney-in-fact. An appointment of a proxy shall be effective when received by the Secretary or other officer of the corporation authorized to tabulate votes. An appointment is valid for 11 months unless a longer period is expressly provided for in the appointment form. An appointment is revocable by the shareholder unless the appointment form conspicuously states that it is irrevocable and the appointment is coupled with an interest that has not been extinguished.

(b) The death or incapacity of the shareholder appointing a proxy shall not affect the right of the corporation to accept the proxy's authority unless notice of the death or incapacity is received by the Secretary or other officer authorized to tabulate votes before the proxy exercises the proxy's authority under the appointment.

2.11 Organization. Meetings of shareholders shall be presided over by the Chairman of the Board of Directors, if any, or in his or her absence by the Vice Chairman of the Board of Directors, if any, or in his or her absence by Chief Executive Officer or in his or her absence by the President. The Secretary, or in his or her absence, an Assistant Secretary, or, in the absence of the Secretary and all Assistant Secretaries, a person whom the chairman of the meeting shall appoint shall act as secretary of the meeting and keep a record of the proceedings thereof.

The Board of Directors of the corporation shall be entitled to make such rules or regulations for the conduct of meetings of shareholders as it shall deem necessary, appropriate or convenient. Subject to such rules and regulations of the Board of Directors, if any, the chairman of the meeting shall have the right and authority to prescribe such rules, regulations and procedures and to do all such acts as, in the judgment of such chairman, are necessary, appropriate or convenient for the proper conduct of the meeting, including, without limitation, establishing an agenda or order of business for the meeting, rules and procedures for maintaining order at the meeting and the safety of those present, limitations on participation in such meeting to shareholders of record of the corporation and their duly authorized and constituted proxies, and such other persons as the chairman shall permit, restrictions on entry to the meeting after the time fixed for the commencement thereof, limitations on the time allotted to questions or comments by participants, and regulation of the opening and closing of the polls for balloting and matters which are to be voted on by ballot. Unless and to the extent determined by the Board of Directors or the chairman of the meeting, meetings of shareholders shall not be required to be held in accordance with rules of parliamentary procedure.

2.12 Inspectors of Election. Before any meeting of shareholders, the Board of Directors shall appoint one or more inspectors of election to act at the meeting or its adjournment. If any person appointed as inspector fails to appear or fails or refuses to act, then the chairman of the meeting may, and upon the request of any shareholder or a shareholder's proxy shall, appoint a person to fill that vacancy.

Such inspectors shall:

(a) determine the number of shares outstanding and the voting power of each, the number of shares represented at the meeting, the existence of a quorum, and the authenticity and validity of proxies and ballots;

(b) receive votes, ballots or consents;

(c) hear and determine all challenges and questions in any way arising in connection with the right to vote;

(d) count and tabulate all votes or consents;

(e) determine the result; and

(f) do any other acts that may be proper to conduct the election or vote with fairness to all shareholders.

The inspector(s) of election shall perform their duties impartially, in good faith, to the best of their ability and as expeditiously as is practical. If there are more than one (1) inspector of election, the decision, act or certificate of a majority is effective in all respects as the decision, act or certificate of all. Any report or certificate made by the inspectors of election is prima facie evidence of the facts stated therein.

2.13 Action Without a Meeting. Except as otherwise provided under the Articles of Incorporation and applicable law, and subject to restrictions on the taking of shareholder action without a meeting under applicable law or the rules of a national securities association or exchange, action required or permitted by law to be taken at a shareholders meeting may be taken without a meeting if the action is taken by all shareholders entitled to vote on the action. The action will be evidenced by one or more written consents describing the action taken, signed by all the shareholders entitled to vote on the action and delivered to the corporation for inclusion in the minutes or filing with the corporate records. Action taken under this Section 2.13 is effective when the last shareholder signs the consent or consents, unless the consent or consents specify an earlier or later effective date. If not otherwise determined by law, the record date for determining shareholders entitled to take action without a meeting under this Section 2.13 is the date the first shareholder signs the consent, A consent signed under this Section 2.13 has the effect of a meeting vote and may be described as such in any document.

ARTICLE III
BOARD OF DIRECTORS

3.1 Duties of Board of Directors. All corporate powers shall be exercised by or under the authority of and the business and affairs of the corporation shall be managed by its Board of Directors. In addition to the powers and authorities these Bylaws expressly confer upon them, the Board of Directors may exercise all such powers of the corporation and do all such lawful acts and things as are not required by the Act, the Articles of Incorporation, or these Bylaws to be exercised or done by the shareholders.

3.2 Number, Election and Qualification. The number of directors of the corporation shall be determined from time to time by the Board of Directors. The Board of Directors may periodically change the number of directors by resolution, provided that no decrease shall have the effect of shortening the term of any incumbent director. The directors shall hold office until the next annual meeting of shareholders, and until their successors shall have been elected and qualified, until earlier death, resignation or removal or until there is a decrease in the number of directors. Directors need not be residents of the State of Oregon or shareholders of the corporation.

3.3 Regular Meetings, Election of Chairman. A regular meeting of the Board of Directors shall be held without other notice than this Bylaw immediately after, and at the same place as, the annual meeting of shareholders. The Board of Directors may provide, by resolution, the time and place, either within or without the State of Oregon, for the holding of additional regular meetings without other notice than the resolution. At this regular meeting held after the annual meeting of shareholders, or at any other time, the Board of Directors may appoint one of its members as Chairman of the Board. The Chairman of the Board shall not be an officer of the corporation unless so designated by the Board of Directors. The Chairman of the Board of Directors shall preside at all meetings of the Board of Directors and shall perform such other duties as may be prescribed from time to time by the Board of Directors. In the absence of a Chairman of the Board of Directors, the directors then present shall select one member to act as Chairman of each meeting.

3.4 Special Meetings. Special meetings of the Board of Directors may be called by or at the request of the Chairman of the Board, by a majority of the directors or, if the Chief Executive Officer is a director, by the Chief Executive Officer or, if the President is a director, by the President. The person or persons authorized to call special meetings of the Board of Directors may fix any place, either within or without the State of Oregon, as the place for holding any special meeting of the Board of Directors called by them.

3.5 Notice. Notice of the date, time and place of any special meetings of the Board of Directors shall be given in any manner reasonably likely to be received at least 24 hours prior to the meeting orally or in writing by mail, telephone, voice mail or any other means provided by law. Neither the business to be transacted at, nor the purpose of, any regular or special meeting of the Board of Directors need be specified in the notice or waiver of notice of such meeting.

3.6 Waiver of Notice. A director may at any time waive any notice required by law, the Articles of Incorporation or these Bylaws. A director's attendance at or participation in a meeting waives any required notice to the director of the meeting unless the director at the beginning of the meeting, or promptly upon the director's arrival, objects to holding the meeting or transacting business at the meeting and does not thereafter vote for or assent to action taken at the meeting.

3.7 Quorum. Majority Vote. Unless otherwise set forth in these Bylaws or the Articles of Incorporation, a majority of the number of directors established by the Board of Directors shall constitute a quorum for the transaction of business at any meeting of the Board of Directors. The act of the majority of the directors present at a meeting at which a quorum is present shall be the act of the Board of Directors, unless a greater number is required by law, the Articles of Incorporation or these Bylaws. A meeting at which a quorum is initially present may continue to transact business notwithstanding the withdrawal of directors, if any action taken is approved by at least a majority of the required quorum for that meeting.

3.8 Meeting by Telephone Conference: Action Without Meeting.

(a) Members of the Board of Directors may hold a board meeting by conference telephone or other communications equipment by means of which all persons participating in the meeting can simultaneously hear each other. Participation in such a meeting shall constitute presence in person at the meeting.

(b) Any action that is required or permitted to be taken by the directors at a meeting may be taken without a meeting if one or more written consents setting forth the action so taken shall be signed by each director entitled to vote on the matter. The action shall be effective on the date when the last director signs the consent, unless the consent specifies an earlier or later time. Such consent, which shall have the same effect as a unanimous vote of the directors, shall be filed with the minutes of the corporation.

3.9 Vacancies. Any vacancy, including a vacancy resulting from an increase in a number of directors, occurring on the Board of Directors may be filled by the shareholders, the Board of Directors or the affirmative vote of a majority of the remaining directors if less than a quorum of the Board of Directors or by a sole remaining director. If the vacant office is filled by the shareholders and was held by a director elected by a voting group of shareholders, then only the holders of shares of that voting group are entitled to vote to fill the vacancy. Any directorship not so filed by the directors may be filled by election at an annual meeting or at a special meeting of shareholders called for that purpose. A director elected to fill a vacancy shall be elected to serve until the next annual meeting of shareholders and until a successor shall be elected and qualified. A vacancy that will occur at a specific later date, by reason of a resignation or otherwise, may be filled before the vacancy occurs, and the new director shall take office when the vacancy occurs.

3.10 Compensation. By resolution of the Board of Directors, the directors may be paid their expenses, if any, of attendance at each meeting of the Board of Directors and may be paid a fixed sum for attendance at each meeting of the Board of Directors or a stated salary as director.

3.11 Presumption of Assent. A director of the corporation who is present at a meeting of the Board of Directors or a committee of the Board of Directors shall be deemed to have assented to the action taken unless: (a) the director's dissent to, or abstention from, the action is entered in the minutes of the meeting, (b) a written dissent or abstention to the action is filed with the presiding officer of the meeting before the adjournment thereof or forwarded by certified or registered mail to the Secretary of the corporation immediately after the adjournment of the meeting, or (c) the director objects at the beginning of the meeting, or promptly upon arrival, to the holding of the meeting or transacting business at the meeting. The right to dissent or abstention shall not apply to a director who voted in favor of the action.

3.12 Director Conflict of Interest.

(a) A transaction in which a director of the corporation has a direct or indirect interest shall be valid notwithstanding the director's interest in the transaction if: (1) the material facts of the transaction and the director's interest are disclosed or known to the Board of Directors or a committee thereof and it authorizes, approves or ratifies the transaction, (2) the material facts of the transaction and the director's interest are disclosed or known to shareholders entitled to vote and they authorize, approve or ratify the transaction, or (3) the transaction is fair to the corporation.

(b) For purposes of Section 3.12(a)(l) above, a conflict of interest transaction may be authorized, approved or ratified if it receives the affirmative vote of a majority of directors or committee members thereof, who have no direct or indirect interest in the transaction. If such a majority of such members vote to authorize, approve or ratify the transaction, a quorum is present for the purpose of taking action.

(c) For purposes of Section 3.12(a)(2) above, a conflict of interest transaction may be authorized, approved or ratified by a majority vote of shareholders entitled to vote thereon. Shares owned by or voted under the control of a director, or an entity controlled by a director, who has a direct or indirect interest in the transaction may be counted in a vote of shareholders to determine whether to authorize, approve or ratify a conflict of interest transaction.

(d) A director has an indirect interest in a transaction if another entity in which the director has a material financial interest or in which the director is a general partner is a party to the transaction or another entity of which the director is a director, officer or trustee is a party to the transaction and the transaction is or should be considered by the Board of Directors of the corporation.

3.13 Removal. The shareholders may remove one or more directors with or without cause at a meeting called expressly for that purpose, unless the Articles of Incorporation provide for removal for cause only. A director may be removed only if the number of votes cast to remove a director exceed the number cast not to remove the director. If a director is elected by a voting group of shareholders, only those shareholders may participate in the vote to remove the director.

3.14 Resignation. Any director may resign by delivering written notice to the Board of Directors, its chairperson or the corporation. Such resignation shall be effective: (a) on receipt, (b) five days after its deposit in the United States mails, if mailed postpaid and correctly addressed, or (c) on the date shown on the return receipt, if sent by registered or certified mail, return receipt requested, and the receipt is signed by addressee, unless the notice specifies a later effective date. Once delivered, a notice of resignation is irrevocable unless revocation is permitted by the Board of Directors.

ARTICLE IV

COMMITTEES OF THE BOARD

4.1 Appointment. Unless the Articles of Incorporation provide otherwise, the Board of Directors may create one or more committees and appoint members of the Board of Directors to serve on them. Each committee shall have one or more members who serve at the pleasure of the Board of Directors. A majority of all directors in office must approve the creation of a committee and the appointment of its members. The Board of Directors shall have the power at any time to increase or decrease the number of members of any committee, to fill vacancies thereon, to change any member thereof and to change the functions or terminate the existence thereof.

4.2 Limitation on Powers of a Committee. A committee shall not have or exercise any power or authority of the Board of Directors prohibited by the Act.

4.3 Conduct of Meetings. Each committee shall conduct its meetings in accordance with the applicable provisions of these Bylaws relating to meetings and action without meetings of the Board of Directors. Each committee shall adopt any further rules regarding its conduct, keep minutes and other records and appoint subcommittees and assistants as it deems appropriate and in accordance with the Act.

4.4 Compensation. By resolution of the Board of Directors, committee members may be paid reasonable compensation for services on committees and their expenses of attending committee meetings.

ARTICLE V

OFFICERS

5.1 Number. The Board of Directors shall appoint a President and a Secretary and other officers and assistant officers as may be deemed necessary or desirable, with such powers and duties as set forth in these Bylaws and as prescribed by the Board of Directors or the officer authorized by the Board of Directors to prescribe the duties of other officers. A duly appointed officer may appoint one or more officers or assistant officers and may prescribe the powers and duties of officers or assistant officers if such appointment and authority is authorized by the Board of Directors. Any two or more offices may be held by the same person.

5.2 Appointment and Term of Office. The officers of the corporation shall be appointed annually by the Board of Directors at the first meeting of the Board of Directors held after the annual meeting of the shareholders and at such other times as determined by the Board of Directors. If the appointment of officers shall not be held at such meeting, they shall be held as soon thereafter as is convenient. Each officer shall hold office until a successor shall have been duly appointed and shall have qualified or until the officer's death, resignation or removal in the manner hereinafter provided.

5.3 Qualification. No officer need be a director, shareholder or Oregon resident.

5.4 Resignation and Removal. An officer may resign at any time by delivering notice to the corporation. A resignation is effective on receipt unless the notice specifies a later effective date. If the corporation accepts a specified later effective date, the Board of Directors may fill the pending vacancy before the effective date but the successor may not take office until the effective date. Once delivered, a notice of resignation is irrevocable unless revocation is permitted by the Board of Directors. Any officer appointed by the Board of Directors may be removed from the officer position at any time with or without cause. Appointment of an officer shall not of itself create contract rights. Removal or resignation of an officer shall not affect the contract rights, if any, of the corporation or the officer.

5.5 Vacancies. A vacancy in any office because of death, resignation, removal, disqualification or otherwise may be filled by the Board of Directors for the unexpired portion of the term.

5.6 Chairman of the Board. The Chairman of the Board of Directors shall preside at all meetings of the Board of Directors and shall perform such other duties as may be prescribed from time to time by the Board of Directors.

5.7 President. Unless otherwise determined by the Board of Directors, the President shall be the Chief Executive Officer of the corporation and shall be in general charge of its business and affairs, subject to the control of the Board of Directors. The President shall from time to time report to the Board of Directors all matters within the President's knowledge affecting the corporation that should be brought to the attention of the Board of Directors. The President shall have authority to vote all shares of stock in other corporations owned by the corporation and to execute proxies, waivers of notice, consents and other instruments in the name of the corporation with respect to such stock and has authority to delegate this authority to any other officer. The President shall perform such other duties as may be prescribed by the Board of Directors. The President has authority to sign stock certificates representing the shares of the corporation.

5.8 Secretary. The Secretary shall keep the minutes of all meetings of the directors and shareholders and shall have custody of the minute books and other records pertaining to the corporate business. The Secretary shall countersign all stock certificates and other instruments requiring the seal of the corporation and shall perform such other duties assigned by the Board of Directors.

5.9 Vice President. Each Vice president shall perform the duties and responsibilities prescribed by the Board of Directors or the President. The Board of Directors or the President, as Chief Executive Officer, may confer a special title upon a Vice President.

5.10 Treasurer. The Treasurer shall keep correct and complete records of accounts showing the financial condition of the corporation. The Treasurer shall be legal custodian of all moneys, notes, securities and other valuables that may come into the possession of the corporation. The Treasurer shall deposit all funds of the corporation that come into the Treasurer's hands in depositories that the Board of Directors may designate. The Treasurer shall pay the funds out only on the check of the corporation signed in the manner authorized by the Board of Directors. The Treasurer shall perform such other duties as assigned by the Board of Directors may require.

ARTICLE VI

INDEMNIFICATION

6.1 Directors and Officers. The corporation shall indemnify to the fullest extent not prohibited by applicable law each current or former officer or director who is made, or threatened to be made, a party to an action, suit or proceeding, whether civil, criminal, administrative, investigative or otherwise (including an action, suit or proceeding by or in the right of the corporation) by reason of the fact that the person is or was acting as a director, officer or agent of the corporation or as a fiduciary within the meaning of the Employee Retirement Income Security Act of 1974 with respect to any employee benefit plan of the corporation, or serves or served at the request of the corporation as a director or officer, or as a fiduciary of an employee

benefit plan, of another corporation, partnership, joint venture, trust or other enterprise. The indemnification specifically provided hereby shall not be deemed exclusive of any other rights to which such person may be entitled under any bylaw, agreement, vote of shareholders or disinterested directors or otherwise, both as to action in the official capacity of the person indemnified and as to action in another capacity while holding such office.

6.2 Employees and Other Agents. The corporation shall have power to indemnify its employees and other agents as set forth in the Act.

6.3 No Presumption of Bad Faith. The termination of any proceeding by judgment, order, settlement, conviction or upon a plea of nolo contendere or its equivalent shall not, of itself, create a presumption that the person did not act in good faith and in a manner which the person reasonably believed to be in or not opposed to the best interests of the corporation, and, with respect to any criminal proceeding, that the person had reasonable cause to believe that the conduct was unlawful.

6.4 Advances of Expenses. The expenses incurred by a director or officer in any proceeding shall be paid by the corporation in advance at the written request of the director or officer, if the director or officer:

(a) furnishes the corporation a written affirmation of such person's good faith belief that such person has met the standard of conduct required by the Act and is entitled to be indemnified by the corporation; and

(b) furnishes the corporation a written undertaking to repay such advance to the extent that it is ultimately determined by a court that such person is not entitled to be indemnified by the corporation. Such advances shall be made without regard to the person's ability to repay such expenses, and without regard to the person's ultimate entitlement to indemnification under this Article VI or otherwise.

6.5 Enforcement. Without the necessity of entering into an express contract, all rights to indemnification and advances under this Article VI shall be deemed to be contractual rights and to be effective to the same extent and as if provided for in a contract between the corporation and the director or officer who serves in such capacity at any time while this Article VI and relevant provisions of the Act and other applicable law, if any, are in effect. Any right to indemnification or advances granted by this Article VI to a director or officer shall be enforceable by or on behalf of the person holding such right in any court of competent jurisdiction if: (a) the claim for indemnification or advances is denied, in whole or in part, or (b) no disposition of such claim is made within ninety (90) days of request therefor. The claimant in such enforcement action, if successful in whole or in part, shall be entitled to be paid also the expense of prosecuting a claim. It shall be a defense to any such action (other than an action brought to enforce a claim for expenses incurred in connection with any proceeding in advance of its final disposition when the required affirmation and undertaking have been tendered to the corporation) that the claimant has not met the standards of conduct which make it permissible under the Act for the corporation to indemnify the claimant for the amount claimed, but the burden of proving such defense shall be on the corporation. Neither the failure of the corporation (including its Board of Directors, independent legal counsel or its shareholders) to have made a determination prior to a commencement of such action that indemnification of the claimant is proper in the circumstances because the claimant has met the applicable standard of conduct set forth in the Act, nor an actual determination by the corporation (including its Board

of Directors, independent legal counsel or its shareholders) that the claimant has not met such applicable standard of conduct, shall be a defense to the action or create a presumption that the claimant has not met the applicable standard of conduct.

6.6 Non-Exclusivity of Rights. The right conferred on any person by this Article VI shall not be exclusive of any other right which such person may have or hereafter acquire under any statute, provision of the Articles of Incorporation, bylaws, agreement, vote of shareholders or disinterested directors or otherwise, both as to action in the person's official capacity and as to action in another capacity while holding office. The corporation is specifically authorized to enter into individual contracts with any or all of its directors, officers, employees or agents respecting indemnification and advances, to the fullest extent permitted by applicable law.

6.7 Survival of Rights. The right conferred on any person by this Article VI shall continue as to a person who has ceased to be a director, officer, employee or other agent and shall inure to the benefit of the heirs, executors and administrators of such a person.

6.8 Insurance. To the fullest extent permitted by the Act, the corporation, upon approval by the Board of Directors, may purchase insurance on behalf of any person required or permitted to be indemnified pursuant to this Article VI.

6.9 Amendments. Any repeal of or modification or amendment to this Article VI shall only be prospective and no repeal or modification hereof shall adversely affect the rights under this Article VI in effect at the time of the alleged occurrence of any action or omission to act that is the cause of any proceeding against any agent of the corporation.

6.10 Savings Clause. If this Article VI or any portion hereof shall be invalidated on any ground by any court of competent jurisdiction, the corporation shall indemnify each director and officer to the fullest extent permitted by any applicable portion of this Article VI that shall not have been invalidated, or by any other applicable law.

6.11 Certain Definitions. For the purposes of this Article VI, the following definitions shall apply:

(a) The term "proceeding" shall be broadly construed and shall include, without limitation, the investigation, preparation, prosecution, defense, settlement and appeal of any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative.

(b) The term "expenses" shall be broadly construed and shall include, without limitation, expense of investigations, judicial or administrative proceedings or appeals, attorneys' fees and disbursements and any expenses of establishing a right to indemnification under Section 6.5 of this Article VI, but shall not include amounts paid in settlement by the indemnified party or the amount of judgments or fines against the indemnified party.

(c) The term "corporation" shall include, in addition to the resulting or surviving corporation, any constituent corporation (including any constituent of a constituent) absorbed in a consolidation or merger which, if its separate existence had continued, would have had power and authority to indemnify its directors, officers, employees or agents, so that any person who is or was a director, officer, employee or agent of such constituent corporation, or is or was serving at the request of such constituent corporation as a director, officer, employee or

agent of another corporation, partnership, joint venture, trust or other enterprise, shall stand in the same position under the provisions of this Article VI with respect to the resulting or surviving corporation as the person would have with respect to such constituent corporation if its separate existence had continued.

(d) References to a "director," "officer," "employee," or "agent" of the corporation shall include, without limitation, situations where such person is serving at the request of the corporation as a director, officer, employee, trustee or agent of another corporation, partnership, joint venture, trust or other enterprise.

(e) References to "other enterprises" shall include employee benefit plans; references to "fines" in the Act shall include any excise taxes assessed on a person with respect to an employee benefit plan; and references to "serving at the request of the corporation" shall include any service as a director, officer, employee or agent of the corporation which imposes duties on, or involved services by, such director, officer, employee, or agent with respect to an employee benefit plan, its participants, or beneficiaries; and a person who acted in good faith and in a manner the person reasonably believed to be in the interest of the participants and beneficiaries of an employee benefit plan shall be deemed to have acted in a manner "not opposed to the best interests of the corporation" as referred to in this Article VI.

ARTICLE VII

ISSUANCE OF SHARES

7.1 Certificate for Shares.

(a) Certificates representing shares of the corporation shall be in such form as shall be determined by the Board of Directors. Such certificates shall be signed, either manually or in facsimile, by two officers of the corporation, at least one of whom shall be the Chief Executive Officer, President or a Vice President and by the Secretary or an Assistant Secretary and may be sealed with the seal of the corporation or a facsimile thereof. All certificates or shares shall be consecutively numbered or otherwise identified.

(b) Every certificate for shares of stock that are subject to any restriction on transfer pursuant to the Articles of Incorporation, the Bylaws, applicable securities laws, agreements among or between shareholders or any agreement to which the corporation is a party shall have conspicuously noted on the face or back of the certificate either the full text of the restriction or a statement of the existence of such restriction and that the corporation retains a copy of the restriction. Every certificate issued when the corporation is authorized to issue more than one class or series of stock shall set forth on its face or back either the full text of the designations, relative rights, preferences and limitations of the shares of each class and series authorized to be issued and the authority of the Board of Directors to determine variations for future series or a statement of the existence of such designations, relative rights, preferences and limitations and a statement that the corporation will furnish a copy thereof to the holder of such certificate upon written request and without charge.

(c) The name and mailing address of the person to whom the shares represented thereby are issued, with the number of shares and date of issue, shall be entered on the stock transfer books of the corporation. Each shareholder shall have the duty to notify the corporation of his or her mailing address. All certificates surrendered to the corporation for transfer shall be canceled, and no new certificates shall be issued until a former certificate for a like number of shares shall have been surrendered and canceled, except that in case of a lost, destroyed or mutilated certificate a new one may be issued therefor upon such terms and indemnity to the corporation as the Board of Directors prescribes.

7.2 Transfer of Shares. Transfer of shares of the corporation shall be made only on the stock transfer books of the corporation by the holder of record thereof or by the holder's legal representative, who shall furnish proper evidence of authority to transfer, or by the holder's attorney thereunto authorized by power of attorney duly executed and filed with the Secretary of the corporation. The person in whose name shares stand on the books of the corporation shall be deemed by the corporation to be the owner thereof for all purposes.

7.3 Transfer Agent and Registrar. The Board of Directors may from time to time appoint one or more Transfer Agents and one or more Registrars for the shares of the corporation, with such powers and duties as the Board of Directors determines by resolution. The signature of officers upon a certificate may be facsimiles if the certificate is manually signed on behalf of a Transfer Agent or by a Registrar other than the corporation itself or an employee of the corporation.

7.4 Officer Ceasing to Act. If the person who signed a share certificate, either manually or in facsimile, no longer holds office when the certificate is issued, the certificate is nevertheless valid.

7.5 Fractional Shares. The corporation shall not issue certificates for fractional shares.

ARTICLE VIII
CONTRACTS, LOANS, CHECKS AND OTHER INSTRUMENTS

8.1 Contracts. The Board of Directors may authorize any officer or officers and agent or agents to enter into any contract or execute and deliver any instrument in the name of and on behalf of the corporation, and such authority may be general or confined to specific instances.

8.2 Loans. No loans shall be contracted on behalf of the corporation and no evidence of indebtedness shall be issued in its name less authorized by a resolution of the Board of Directors. Such authority may be general or confined to specific instances.

8.3 Checks, Drafts, Etc. All checks, drafts or other orders for the payment of money and notes or other evidences of indebtedness issued in the name of the corporation shall be signed by such officer or officers and agent or agents of the corporation and in such manner as shall from time to time be determined by the Board of Directors.

ARTICLE IX

MISCELLANEOUS PROVISIONS

9.1 Seal. The seal of the corporation, if any, shall be circular in form and shall have inscribed thereon the name of the corporation and the state of incorporation and the words "Corporate Seal."

9.2 Severability. Any determination that any provision of these Bylaws is for any reason inapplicable, invalid, illegal or otherwise ineffective shall not affect or invalidate any other provision of these Bylaws.

ARTICLE X

AMENDMENTS

These Bylaws may be amended or repealed and new Bylaws may be adopted by the Board of Directors or the shareholders of the corporation.

ARTICLE XXXV

RIGHTS AND POWERS OF DISBURSING AGENT

35.1 Exculpation: From and after the Effective Date, the Disbursing Agent shall be exculpated by all Persons and Entities, including, without limitation, holders of Claims and Equity Interests and other parties in interest, from any and all claims, causes of action and other assertions of liability arising out of the discharge of the powers and duties conferred upon such Disbursing Agent by the Plan or any order of the Bankruptcy Court entered pursuant to or in furtherance of the Plan, or applicable law, except for actions or omissions to act arising out of the gross negligence or willful misconduct of such Disbursing Agent. No holder of a Claim or an Equity Interest or other party in interest shall have or pursue any claim or cause of action against the Disbursing Agent for making payments in accordance with the Plan or for implementing the provisions of the Plan.

35.2 Powers of the Disbursing Agent: Except to the extent that the responsibility for the same is vested in the Reorganized Debtor Plan Administrator pursuant to the Reorganized Debtor Plan Administration Agreement, the Disbursing Agent shall be empowered to (a) take all steps and execute all instruments and documents necessary to effectuate the Plan, (b) make distributions contemplated by the Plan, (c) comply with the Plan and the obligations thereunder, (d) file all tax returns and pay taxes in connection with the reserves created pursuant to Article XVIII of the Plan, and (e) exercise such other powers as may be vested in the Disbursing Agent pursuant to order of the Bankruptcy Court, pursuant to the Plan, or as deemed by the Disbursing Agent to be necessary and proper to implement the provisions of the Plan.

35.3 Fees and Expenses Incurred From and After the Effective Date: Except as otherwise ordered by the Bankruptcy Court, the amount of any reasonable fees and expenses incurred by the Disbursing Agent from and after the Effective Date and any reasonable compensation and expense reimbursement claims, including, without limitation, reasonable fees and expenses of counsel, made by the Disbursing Agent, shall be paid in Cash by the Reorganized Debtors without further order of the Bankruptcy Court within fifteen (15) days of submission of an invoice by the Disbursing Agent. In the event that the Reorganized Debtors object to the payment of such invoice for post-Effective Date fees and expenses, in whole or in part, and the parties cannot resolve such objection after good faith negotiation, the Bankruptcy Court shall retain jurisdiction to make a determination as to the extent to which the invoice shall be paid by the Reorganized Debtors.

ARTICLE XXXVI

THE REORGANIZED DEBTOR PLAN ADMINISTRATOR

36.1 Appointment of Reorganized Debtor Plan Administrator: On the Effective Date, compliance with the provisions of the Plan shall become the general responsibility of the Reorganized Debtor Plan Administrator, an employee of the Reorganized Debtors, (subject to the supervision of the Board of Directors of the Reorganized Debtors) pursuant to and in accordance with the provisions of the Plan and the Reorganized Debtor Plan Administration Agreement.

36.2 <u>**Responsibilities of the Reorganized Debtor Plan Administrator**</u>: In accordance with the Reorganized Debtor Plan Administration Agreement, the responsibilities of the Reorganized Debtor Plan Administrator shall include (a) facilitating the Reorganized Debtors' prosecution or settlement of objections to and estimations of Claims, (b) prosecution or settlement of claims and causes of action held by the Debtors and Debtors in Possession, (c) assisting the Litigation Trustee and the Special Litigation Trustee in performing their respective duties, (d) calculating and assisting the Disbursing Agent in implementing all distributions in accordance with the Plan, (e) filing all required tax returns and paying taxes and all other obligations on behalf of the Reorganized Debtors from funds held by the Reorganized Debtors, (f) periodic reporting to the Bankruptcy Court, of the status of the Claims resolution process, distributions on Allowed Claims and prosecution of causes of action, (g) liquidating the Remaining Assets and providing for the distribution of the net proceeds thereof in accordance with the provisions of the Plan, (h) consulting with, and providing information to , the DCR Overseers in connection with the voting or sale of the Plan Securities to be deposited into the Disputed Claims reserve to be created in accordance with Section 21.3 of the Plan, and (i) such other responsibilities as may be vested in the Reorganized Debtor Plan Administrator pursuant to the Plan, the Reorganized Debtor Plan Administration Agreement or Bankruptcy Court order or as may be necessary and proper to carry out the provisions of the Plan.

36.3 <u>**Powers of the Reorganized Debtor Plan Administrator**</u>: The powers of the Reorganized Debtor Plan Administrator shall, without any further Bankruptcy Court approval in each of the following cases, include (a) the power to invest funds in, and withdraw, make distributions and pay taxes and other obligations owed by the Reorganized Debtors from funds held by the Reorganized Debtor Plan Administrator and/or the Reorganized Debtors in accordance with the Plan, (b) the power to compromise and settle claims and causes of action on behalf of or against the Reorganized Debtors, other than Litigation Trust Claims, Special Litigation Trust Claims and claims and causes of action which are the subject of the Severance Settlement Fund Litigation, and (c) such other powers as may be vested in or assumed by the Reorganized Debtor Plan Administrator pursuant to the Plan, the Reorganized Debtor Plan Administration Agreement or as may be deemed necessary and proper to carry out the provisions of the Plan.

36.4 <u>**Compensation of the Reorganized Debtor Plan Administrator**</u>: In addition to reimbursement for actual out-of-pocket expenses incurred by the Reorganized Debtor Plan Administrator, the Reorganized Debtor Plan Administrator shall be entitled to receive reasonable compensation for services rendered on behalf of the Reorganized Debtors in an amount and on such terms as may be reflected in the Reorganized Debtor Plan Administration Agreement.

36.5 <u>**Termination of Reorganized Debtor Plan Administrator**</u>: The duties, responsibilities and powers of the Reorganized Debtor Plan Administrator shall terminate pursuant to the terms of the Reorganized Debtor Plan Administration Agreement.

1.195 **PGE Trustee**: In the event the PGE Trust is created, Stephen Forbes Cooper, LLC, or such other Entity appointed by the PGE Trust Board and approved by the Bankruptcy Court to administer the PGE Trust in accordance with the provisions of Article XXIV hereof and the PGE Trust Agreement.

1.196 **PGE Trust Interests**: The sixty-two million five hundred thousand (62,500,000) beneficial interests in the PGE Trust to be allocated to holders of Allowed Claims in the event that Enron transfers the Existing PGE Common Stock, or issues the PGE Common Stock, as the case may be, to the PGE Trust.

1.197 **Plan**: This Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, including, without limitation, the Plan Supplement and the exhibits and schedules hereto or thereto, as the same is amended, modified or supplemented from time to time in accordance with the terms and provisions hereof.

1.198 **Plan Currency**: The mixture of Creditor Cash, Prisma Common Stock, CrossCountry Common Equity and PGE Common Stock to be distributed to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims pursuant to the Plan; provided, however, that, if jointly determined by the Debtors and the Creditors' Committee, "Plan Currency" may include Prisma Trust Interests, CrossCountry Trust Interests, PGE Trust Interests and the Remaining Asset Trust Interests.

1.199 **Plan Securities**: Prisma Common Stock, CrossCountry Common Equity and PGE Common Stock.

1.200 **Plan Supplement**: A separate volume, to be filed with the Clerk of the Bankruptcy Court including, among other documents, forms of (a) the Litigation Trust Agreement, (b) the Special Litigation Trust Agreement, (c) the Prisma Trust Agreement, (d) the CrossCountry Trust Agreement, (e) the PGE Trust Agreement, (f) the Remaining Asset Trust Agreement(s), (g) the Common Equity Trust Agreement, (h) the Preferred Equity Trust Agreement, (i) the Prisma Articles of Association, (j) the Prisma Memorandum of Association, (k) the CrossCountry By-laws/Organizational Agreement, (l) the CrossCountry Charter, (m) the PGE By-Laws, (n) the PGE Certificate of Incorporation, (o) the Reorganized Debtor Plan Administration Agreement, (p) the Reorganized Debtors By-laws, (q) the Reorganized Debtors Certificate of Incorporation, (r) the Severance Settlement Fund Trust Agreement, (s) a schedule of the types of Claims entitled to the benefits of subordination afforded by the documents referred to and the definitions set forth on Exhibit "L" to the Plan, (t) a schedule of Allowed General Unsecured Claims held by affiliated non-Debtor Entities and structures created by the Debtors and which are controlled or managed by the Debtors or their Affiliates, (u) a schedule setting forth the identity of the proposed senior officers and directors of Reorganized ENE, (v) a schedule setting forth the identity and compensation of any insiders to be retained or employed by Reorganized ENE, (w) a schedule setting forth the litigation commenced by the Debtors on or after December 15, 2003 to the extent that such litigation is not set forth in the Disclosure Statement, (x) the methodology or procedure agreed upon by the Debtors, the Creditors' Committee and the ENA Examiner with respect to the adjustment of Allowed Intercompany Claims, as referenced in Section 1.21 of the Plan, and to the extent adjusted or to be adjusted

1.185 Penalty Claim: Any Claim for a fine, penalty, forfeiture, multiple, exemplary or punitive damages or otherwise not predicated upon compensatory damages and that is subject to subordination in accordance with section 726(a)(4) of the Bankruptcy Code or otherwise, as determined pursuant to a Final Order.

1.186 Person: A "person" as defined in section 101(41) of the Bankruptcy Code.

1.187 Petition Date: The Initial Petition Date; provided, however, that, with respect to those Debtors which commenced their Chapter 11 Cases subsequent to December 2, 2001, "Petition Date" shall refer to the respective dates on which such Chapter 11 Cases were commenced.

1.188 PGE: Portland General Electric Company, an Oregon corporation.

1.189 PGE By-laws: The by-laws of PGE, which by-laws shall be in form and substance satisfactory to the Creditors' Committee and in substantially the form included in the Plan Supplement.

1.190 PGE Certificate of Incorporation: The Certificate of Incorporation of PGE, which certificate of incorporation shall be in form and substance satisfactory to the Creditors' Committee and in substantially the form included in the Plan Supplement.

1.191 PGE Common Stock: The shares of PGE Common Stock authorized and to be issued pursuant to the Plan, which shares shall have no par value per share, of which eighty million (80,000,000) shares shall be authorized and of which sixty-two million five hundred thousand (62,500,000) shares shall be issued pursuant to the Plan, and such other rights with respect to dividends, liquidation, voting and other matters as are provided for by applicable nonbankruptcy law or the PGE Certificate of Incorporation or the PGE By-laws.

1.192 PGE Trust: The Entity, if jointly determined by the Debtors and, provided that the Creditors' Committee has not been dissolved in accordance with the provisions of Section 33.1 of the Plan, the Creditors' Committee, to be created on or subsequent to the Confirmation Date, but in no event later than the date on which the Litigation Trust is created, to hold as its sole assets the Existing PGE Common Stock or the PGE Common Stock in lieu thereof, but in no event the assets of PGE.

1.193 PGE Trust Agreement: In the event the PGE Trust is created, the PGE Trust Agreement, which agreement shall be in form and substance satisfactory to the Creditors' Committee and substantially in the form contained in the Plan Supplement, pursuant to which the PGE Trustee shall manage, administer, operate and liquidate the assets contained in the PGE Trust, either the Existing PGE Common Stock or the PGE Common Stock, as the case may be, and distribute the proceeds thereof or the Existing PGE Common Stock or the PGE Common Stock, as the case may be.

1.194 PGE Trust Board: In the event the PGE Trust is created, the Persons selected by the Debtors, after consultation with the Creditors' Committee, and appointed by the Bankruptcy Court, or any replacements thereafter selected in accordance with the provisions of the PGE Trust Agreement.

ARTICLE V

PROVISION FOR TREATMENT OF PRIORITY NON-TAX CLAIMS (CLASS 1)

5.1 <u>Payment of Allowed Priority Non-Tax Claims</u>: Unless otherwise mutually agreed upon by the holder of an Allowed Priority Non-Tax Claim and the Reorganized Debtors, each holder of an Allowed Priority Non-Tax Claim shall receive in full satisfaction, settlement, release, and discharge of, and in exchange for such Allowed Priority Non-Tax Claim, Cash in an amount equal to such Allowed Priority Non-Tax Claim on the later of the Effective Date and the date such Allowed Priority Non-Tax Claim becomes an Allowed Priority Non-Tax Claim, or as soon thereafter as is practicable.

ARTICLE VI

PROVISION FOR TREATMENT OF SECURED CLAIMS (CLASS 2)

6.1 <u>Treatment of Secured Claims</u>: On the Effective Date, each holder of an Allowed Secured Claim shall receive in full satisfaction, settlement, release, and discharge of, and in exchange for such Allowed Secured Claim one of the following distributions: (a) the payment of such holder's Allowed Secured Claim in full, in Cash; (b) the sale or disposition proceeds of the property securing any Allowed Secured Claim to the extent of the value of their respective interests in such property; (c) the surrender to the holder or holders of any Allowed Secured Claim of the property securing such Claim; or (d) such other distributions as shall be necessary to satisfy the requirements of chapter 11 of the Bankruptcy Code. The manner and treatment of each Secured Claim shall be determined by the Debtors, subject to the consent of the Creditors' Committee and transmitted, in writing, to holder of a Secured Claim on or prior to the commencement of the Confirmation Hearing.

ARTICLE VII

PROVISION FOR TREATMENT OF GENERAL UNSECURED CLAIMS (CLASSES 3-182)

7.1 <u>Treatment of General Unsecured Claims Other than Those Against the Portland Debtors (Classes 3 through 180)</u>: Commencing on the Effective Date and subject to the provisions of Sections 7.3, 7.4, 7.5 and 7.8 hereof, each holder of an Allowed General Unsecured Claim against a Debtor, other than a Portland Debtor, shall be entitled to receive on account of such Allowed General Unsecured Claim distributions in an aggregate amount equal to such holder's Pro Rata Share of (i) the Distributive Assets and Distributive Interests attributable to such Debtor and (ii) such amounts of Cash or Distributive Interests as may be allocated to a holder of an Allowed General Unsecured Claim against such Debtor in accordance with the provisions of Section 10.1 of the Plan; <u>provided</u>, <u>however</u>, that, notwithstanding the foregoing, for purposes of making distributions to a holder of an Allowed Joint Liability Claim against more than one Debtor, such holder's Pro Rata Share of Distributive Assets and Distributive Interests shall include the amounts calculated pursuant to sub-clause (B) of Sections 1.89 and

1.90 of the Plan, respectively, with respect to only one Debtor; and, provided, further, that, notwithstanding the foregoing, the contractual subordination rights, if any, of holders of "Senior Indebtedness" or any similar term under the Enron MIPS Agreements shall be preserved and enforced hereunder pursuant to section 510(a) of the Bankruptcy Code and, in the event such rights are determined to be enforceable, any such distributions shall be distributed to holders of Allowed Claims that constitute "Senior Indebtedness", as identified on Exhibit "L" hereto, until such time as such holder's Claims have been satisfied in accordance with the terms and provisions of the Enron MIPS Agreements.

7.2 **Treatment of General Unsecured Claims Against the Portland Debtors (Classes 181 and 182)**: Commencing on the Effective Date and subject to the provisions of Section 7.4 hereof, each holder of an Allowed General Unsecured Claim against either of the Portland Debtors shall be entitled to receive on account of such Allowed General Unsecured Claim distributions in an aggregate amount equal to such holders' Pro Rata Share of the Portland Creditor Cash.

7.3 **Election to Receive Additional Cash Distributions in Lieu of Partial Plan Securities**: Notwithstanding the provisions of Section 7.1 of the Plan, any holder of an Allowed General Unsecured Claim against Enron North America Corp., Enron Power Marketing, Inc., Enron Gas Liquids, Inc., Enron Global Markets LLC, Enron Industrial Markets LLC, Enron Natural Gas Marketing Corp., ENA Upstream Company LLC, Enron Capital & Trade Resources International Corp. and Enron Reserve Acquisition Corp. may elect to receive such holder's Pro Rata Share of One Hundred Twenty-Five Million Dollars ($125,000,000.00) in lieu of all or a portion of the Plan Securities to which such holder is otherwise entitled to receive pursuant to the Plan. In the event that any such holder elects to receive such additional Cash distribution, (a) such holder's distribution of Plan Securities shall be reduced on a dollar-for-dollar basis and (b) distributions of Plan Securities to be made to holders of Allowed General Unsecured Claims against ENE shall be increased on a dollar-for-dollar basis. Such election must be made on the Ballot and be received by the Debtors on or prior to the Ballot Date. Any election made after the Ballot Date shall not be binding upon the Debtors unless the Ballot Date is expressly waived, in writing, by the Debtors; provided, however, that, under no circumstances, may such waiver by the Debtors occur on or after the Effective Date.

7.4 **Allowed Claims of Fifty Thousand Dollars or More/Election to be Treated as a Convenience Claim**: Notwithstanding the provisions of Sections 7.1 and 7.3 of the Plan, any holder of an Allowed General Unsecured Claim, other than (i) an Enron Senior Notes Claim, (ii) an Enron Subordinated Debenture Claim, (iii) an ETS Debenture Claim, (iv) an ENA Debenture Claim and (v) any other General Unsecured Claim that is a component of a larger General Unsecured Claim, portions of which may be held by such or any other holder whose Allowed General Unsecured Claim, is more than Fifty Thousand Dollars ($50,000.00), and who elects to reduce the amount of such Allowed Claim to Fifty Thousand Dollars ($50,000.00), shall, at such holder's option, be entitled to receive, based on such Allowed Claim as so reduced, distributions pursuant to Article XVI hereof. Such election must be made on the Ballot and be received by the Debtors on or prior to the Ballot Date. Any election made after the Ballot Date shall not be binding upon the Debtors unless the Ballot Date is expressly waived, in writing, by the Debtors; provided, however, that, under no circumstances, may such waiver by the Debtors occur on or after the Effective Date.

1.110 <u>ENA Indenture Trustee</u>: National City Bank, solely in its capacity as successor in interest to The Chase Manhattan Bank, as Indenture Trustee under the ENA Indentures, or its duly appointed successor.

1.111 <u>ENE</u>: Enron Corp., an Oregon corporation.

1.112 <u>ENE Examiner</u>: Neal A. Batson, appointed as examiner of ENE pursuant to the Bankruptcy Court's order, dated May 24, 2002.

1.113 <u>ENE Examiner Orders</u>: The Bankruptcy Court orders, dated December 17, 2003, December 18, 2003 and February 19, 2004, together with such other orders of the Bankruptcy Court, relating to, among other things, the termination of the ENE Examiner's duties and obligations.

1.114 <u>Enron Affiliate</u>: Any of the Debtors and any other direct or indirect subsidiary of ENE.

1.115 <u>Enron Common Equity Interest</u>: An Equity Interest represented by one of the one billion two hundred million (1,200,000,000) authorized shares of common stock of ENE as of the Petition Date or any interest or right to convert into such an equity interest or acquire any equity interest of the Debtors which was in existence immediately prior to or on the Petition Date.

1.116 <u>Enron Guaranty Claim</u>: Any Unsecured Claim, other than an Intercompany Claim, against ENE arising from or relating to an agreement by ENE to guarantee or otherwise satisfy the obligations of another Debtor, including, without limitation, any Claim arising from or relating to rights of contribution or reimbursement.

1.117 <u>Enron Guaranty Distributive Assets</u>: The Plan Currency to be made available to holders of Allowed Enron Guaranty Claims in an amount derived from the Distribution Model equal to the sum of (A) the product of (i) seventy percent (70%) times (ii) the lesser of (a) the sum of ENE's Enron Guaranty Claims and (b) the product of (y) the Value of ENE's Assets minus an amount equal to the sum of (1) one hundred percent (100%) of ENE's Administrative Expense Claims, Secured Claims and Priority Claims plus (2) an amount equal to the product of ENE's Convenience Claim Distribution Percentage times ENE's Convenience Claims times (z) a fraction, the numerator of which is equal to the amount of ENE's Enron Guaranty Claims and the denominator of which is equal to the sum of ENE's (1) General Unsecured Claims, (2) Enron Guaranty Claims and (3) Intercompany Claims plus (B) the product of (i) thirty percent (30%) times (ii) the Value of all of the Debtors' Assets, calculated as if the Debtors' chapter 11 estates were substantively consolidated, minus an amount equal to the sum of (1) one hundred percent (100%) of all Debtors' Administrative Expense Claims, Secured Claims and Priority Claims, calculated on a Consolidated Basis, plus (2) the sum of the products of each Debtor's Convenience Claims times its respective Convenience Claim Distribution Percentage times (iii) a fraction, the numerator of which is equal to fifty percent (50%) times an amount equal to the sum of the lesser of, calculated on a Claim-by-Claim basis, (1) the amount of Enron Guaranty Claims and (2) the corresponding primary General Unsecured Claim, calculated on a Consolidated Basis, and the denominator of which is equal to the sum of the amount of (y) all Debtors'

General Unsecured Claims, calculated on a Consolidated Basis and (z) fifty percent (50%) of all Guaranty Claims; provided, however, that, for purposes of calculating "Enron Guaranty Distributive Assets", such calculation shall not include the Assets of or the General Unsecured Claims against either of the Portland Debtors.

1.118 **Enron Guaranty Distributive Interests**: The Litigation Trust Interests or the Special Litigation Trust Interests, as the case may be, to be made available to holders of Allowed Enron Guaranty Claims in an amount derived from the Distribution Model equal to the quotient of (I) the sum of (A) the product of (i) seventy percent (70%) times (ii) the lesser of (a) the sum of ENE's Enron Guaranty Claims and (b) the product of (y) the sum of the Value of ENE's Assets and the Fair Market Value of ENE's Litigation Trust Interests or Special Litigation Trust Interests, as the case may be, minus an amount equal to the sum of (1) one hundred percent (100%) of ENE's Administrative Expense Claims, Secured Claims and Priority Claims plus (2) an amount equal to the product of ENE's Convenience Claim Distribution Percentage times ENE's Convenience Claims times (z) a fraction, the numerator of which is equal to the amount of ENE's Enron Guaranty Claims and the denominator of which is equal to the sum of ENE's (1) General Unsecured Claims, (2) Enron Guaranty Claims and (3) Intercompany Claims plus (B) the product of (i) thirty percent (30%) times (ii) the sum of the Value of all of the Debtors' Assets and the Fair Market Value of all of the Debtors' Litigation Trust Interests or Special Litigation Trust Interests, as the case may be, calculated as if the Debtors' chapter 11 estates were substantively consolidated, minus an amount equal to the sum of (1) one hundred percent (100%) of all Debtors' Administrative Expense Claims, Secured Claims and Priority Claims, calculated on a Consolidated Basis, plus (2) the sum of the products of each Debtor's Convenience Claims times its respective Convenience Claim Distribution Percentage times (iii) a fraction, the numerator of which is equal to fifty percent (50%) times an amount equal to the sum of the lesser of, calculated on a Claim-by-Claim basis, (1) the amount of Enron Guaranty Claims and (2) the corresponding primary General Unsecured Claim, calculated on a Consolidated Basis, and the denominator of which is equal to the sum of the amount of (y) all Debtors' General Unsecured Claims, calculated on a Consolidated Basis and (z) fifty percent (50%) of all Guaranty Claims, minus (C) Enron Guaranty Distributive Assets, divided by (II) the Fair Market Value of a Litigation Trust Interest or a Special Litigation Trust Interest, as the case may be; provided, however, that, for purposes of calculating "Enron Guaranty Distributive Interests", such calculation shall not include the Assets of or the General Unsecured Claims against either of the Portland Debtors.

1.119 **Enron MIPS Agreements**: That certain (a) Loan Agreement, dated as of November 15, 1993, between ENE and Enron Capital LLC, executed and delivered in connection with the issuance of 8% Cumulative Guaranteed Monthly Income Preferred Shares, and relating to a loan in the original principal amount of Two Hundred Seventy Million Five Hundred Sixty-Nine Thousand Six Hundred Twenty-One Dollars ($270,569,621.00), and (b) Loan Agreement, dated as of August 3, 1994, between ENE and Enron Capital Resources, L.P., executed and delivered in connection with the issuance of 9% Cumulative Preferred Securities, Series A, and relating to a loan in the original principal amount of Ninety-Four Million Nine Hundred Thirty-Six Thousand Seven Hundred Nine Dollars ($94,936,709.00).

1.120 **Enron Preferred Equity Interest**: An Equity Interest represented by an issued and outstanding share of preferred stock of ENE as of the Petition Date, including, without limitation, that certain (a) Cumulative Second Preferred Convertible Stock, (b) 9.142% Perpetual Second Preferred Stock, (c) Mandatorily Convertible Junior Preferred Stock, Series B, and (d) Mandatorily Convertible Single Reset Preferred Stock, Series C, or any other interest or right to convert into such a preferred equity interest or acquire any preferred equity interest of the Debtors which was in existence immediately prior to the Petition Date.

1.121 **Enron Senior Notes**: The promissory notes and debentures issued and delivered by ENE in accordance with the terms and conditions of the Enron Senior Notes Indentures and set forth on Exhibit "B" hereto.

1.122 **Enron Senior Notes Claim**: Any General Unsecured Claim arising from or relating to the Enron Senior Notes Indentures.

1.123 **Enron Senior Notes Indentures**: That certain (a) Indenture, dated as of November 1, 1985, as supplemented on December 1, 1995, May 8, 1997, September 1, 1997 and August 17, 1999, between ENE, as Issuer, and The Bank of New York, as Indenture Trustee, (b) Indenture, dated as of October 15, 1985, as supplemented, between ENE, as Issuer, and Wells Fargo Bank Minnesota, as Indenture Trustee, (c) Indenture, dated as of April 8, 1999, as supplemented, between ENE, as Issuer, and Wells Fargo Bank Minnesota, as Indenture Trustee, and (d) Indenture, dated as of February 7, 2001, as supplemented, between ENE, as Issuer, and Wells Fargo Bank Minnesota, as Indenture Trustee.

1.124 **Enron Senior Notes Indenture Trustees**: The Bank of New York, solely in its capacity as successor in interest to Harris Trust and Savings Bank, as Indenture Trustee, or its duly appointed successor, and Wells Fargo Bank Minnesota, solely in its capacity as successor in interest to JPMorgan Chase Bank, as Indenture Trustee, or its duly appointed successor, solely in their capacities as indenture trustees with regard to the respective Enron Senior Notes Indentures.

1.125 **Enron Subordinated Debentures**: The 8.25% Subordinated Debentures and the 6.75% Subordinated Debentures.

1.126 **Enron Subordinated Debenture Claim**: Any General Unsecured Claim arising from or relating to the Enron Subordinated Indenture.

1.127 **Enron Subordinated Indenture**: That certain Indenture, dated February 1, 1987, between ENE, as Issuer, and the Enron Subordinated Indenture Trustee, as Indenture Trustee.

1.128 **Enron Subordinated Indenture Trustee**: The Bank of New York, solely in its capacity as successor in interest to InterFirst Bank Houston, N.A., as indenture trustee under the Enron Subordinated Indenture, or its duly appointed successor.

1.129 **Enron TOPRS Debenture Claim**: Any General Unsecured Claim arising from or relating to the Enron TOPRS Indentures.

1.130 **Enron TOPRS Debentures**: The 7.75% Subordinated Debentures Due 2016, issued in the original aggregate principal amount of $181,926,000.00 and the 7.75%

1.141 EPF II: Enron Preferred Funding II, a Delaware limited partnership formed pursuant to the EPF II Partnership Agreement.

1.142 EPF II Partnership Agreement: That certain Agreement of Limited Partnership, dated as of December 23, 1996, as amended by that certain Amended and Restated Agreement of Limited Partnership of Enron Preferred Funding II, dated as of January 16, 1997.

1.143 Equity Interest: Any equity interest in any of the Debtors represented by duly authorized, validly issued and outstanding shares of preferred stock or common stock or any interest or right to convert into such an equity interest or acquire any equity interest of the Debtors which was in existence immediately prior to or on the Petition Date.

1.144 ERISA: Employee Retirement Income Security Act of 1974, as amended, to the extent codified in Title 29, United States Code.

1.145 ETS: Enron Transportation Services, LLC, a Delaware limited liability company and successor-in-interest to Enron Transportation Services Company, one of the Debtors.

1.146 ETS Debenture Claim: Any General Unsecured Claim arising from or relating to the ETS Indentures.

1.147 ETS Indentures: That certain (1) Indenture, dated as of November 21, 1996, by and among Enron Pipeline Company, now known as ETS, as Issuer, ENE, as Guarantor, and The Chase Manhattan Bank, as Indenture Trustee, and (2) Indenture, dated as of January 16, 1997, by and among Enron Pipeline Company, now known as ETS, as Issuer, ENE, as Guarantor, and The Chase Manhattan Bank, as Indenture Trustee.

1.148 ETS Indenture Trustee: National City Bank, solely in its capacity as successor in interest to The Chase Manhattan Bank, as indenture trustee under the ETS Indentures, or its duly appointed successor.

1.149 Exchanged Enron Common Stock: The common stock of Reorganized ENE authorized and to be issued pursuant to the Plan, having a par value of $0.01 per share, of which the same number of shares as the number of shares of authorized Enron Common Equity Interests shall be authorized, and the same number of shares as the number of shares of Enron Common Equity Interests consisting of common stock (not interests or rights to convert into, or acquire, common stock) outstanding on the Effective Date shall be issued pursuant to the Plan with such rights with respect to dividends, liquidation, voting and other matters as are provided for by applicable nonbankruptcy law or the Reorganized Debtors Certificate of Incorporation and the Reorganized Debtors By-laws, and which are being issued in exchange for, and on account of, each Enron Common Equity Interest consisting of outstanding common stock (not interests or rights to convert into, or acquire, common stock) and transferred to the Common Equity Trust with the same economic interests and rights to receive distributions from ENE or Reorganized ENE, after all Claims have been satisfied, in full, as such Enron Common Equity Interest.

1.150 Exchanged Enron Preferred Stock: The Series 1 Exchanged Preferred Stock, the Series 2 Exchanged Preferred Stock, the Series 3 Exchanged Preferred Stock and the Series 4

Exchanged Preferred Stock, and such other issues of preferred stock which may be issued on account of preferred stock in existence as of the Confirmation Date.

1.151 Existing PGE Common Stock: The issued and outstanding shares of PGE common stock, having a par value of $3.75 per share, held by ENE as of the date hereof.

1.152 Fair Market Value: The value of the Litigation Trust Claims and the Special Litigation Trust Claims determined in accordance with the provisions of Sections 22.5 and 23.5 of the Plan, respectively.

1.153 Fee Committee: The committee appointed by the Bankruptcy Court pursuant to an order, dated April 26, 2002, to, among other things, review the amounts and propriety of the fees and expenses incurred by professionals retained in the Chapter 11 Cases pursuant to an order of the Bankruptcy Court.

1.154 Final Order: An order or judgment of the Bankruptcy Court as to which the time to appeal, petition for certiorari or move for reargument or rehearing has expired and as to which no appeal, petition for certiorari or other proceedings for reargument or rehearing shall then be pending; and if an appeal, writ of certiorari, reargument or rehearing thereof has been sought, such order shall have been affirmed by the highest court to which such order was appealed, or certiorari shall have been denied or reargument or rehearing shall have been denied or resulted in no modification of such order, and the time to take any further appeal, petition for certiorari or move for reargument or rehearing shall have expired; provided, however, that the possibility that a motion under section 502(j) of the Bankruptcy Code, Rule 59 or Rule 60 of the Federal Rules of Civil Procedure or any analogous rule under the Bankruptcy Rules, may be but has not then been filed with respect to such order, shall not cause such order not to be a Final Order.

1.155 General Unsecured Claim: An Unsecured Claim, other than a Guaranty Claim or an Intercompany Claim.

1.156 Guaranty Claims: ACFI Guaranty Claims, ENA Guaranty Claims, Enron Guaranty Claims, EPC Guaranty Claims and Wind Guaranty Claims.

1.157 Indentures: The Enron Senior Notes Indenture, the Enron Subordinated Indenture, the ETS Indentures, the ENA Indentures and the Enron TOPRS Indentures.

1.158 Indenture Trustees: The Enron Senior Notes Indenture Trustees, the Enron Subordinated Indenture Trustee, the ETS Indenture Trustee, the ENA Indenture Trustee and the Enron TOPRS Indenture Trustee.

1.159 Indenture Trustee Claims: The Claims of the Enron Senior Notes Indenture Trustees, the Enron Subordinated Indenture Trustee, the ETS Indenture Trustee, the ENA Indenture Trustee and the Enron TOPRS Indenture Trustee pursuant to the Enron Senior Notes Indenture, the Enron Subordinated Indenture, the ETS Indentures, the ENA Indentures and the Enron TOPRS Indentures, respectively, for reasonable fees and expenses, including, without limitation, reasonable attorney's fees and expenses.

Equity Interests in accordance with the provisions of the documents, instruments and agreements governing such Equity Interests, including, without limitation, the contractual subordination provisions set forth therein and the Bankruptcy Code.

ARTICLE XVIII

PROVISIONS FOR TREATMENT OF ENRON PREFERRED EQUITY INTERESTS (CLASS 383)

18.1 **Treatment of Allowed Enron Preferred Equity Interests (Class 383)**: Except as otherwise provided in Section 18.2 of the Plan, on the Effective Date, each holder of an Allowed Enron Preferred Equity Interest shall be entitled to receive such holder's Pro Rata Share of the separate class of Preferred Equity Trust Interests relating to such holder's class of Exchanged Enron Preferred Stock to be allocated pursuant to Article XXVI of the Plan. For purposes of this Section 18.1, a holder's class of Exchanged Enron Preferred Stock is the class of Exchanged Enron Preferred Stock to be issued in lieu of such holder's class of Enron Preferred Equity Interest.

18.2 **Contingent Distribution/Limitation on Recovery**: Notwithstanding anything contained herein to the contrary, in the event that (a) Plan Currency and Trust Interests are deemed redistributed to a holder of an Allowed Enron Preferred Equity Interest, and, as a result of the issuance and transfer of the Exchanged Enron Preferred Stock, to the Preferred Equity Trustee for and on behalf of the holders of Preferred Equity Trust Interests, in accordance with the provisions of Sections 7.5, 8.2, 9.2 and 17.2 of the Plan, and (b) the sum of such distributions to such holder are equal or in excess of to one hundred percent (100%) of such holder's Allowed Enron Preferred Equity Interests, then, the Plan Currency and Trust Interests remaining to be distributed to such holder in excess of such one hundred percent (100%) shall be deemed redistributed to holders of Allowed Section 510 Enron Common Equity Interest Claims and Allowed Enron Common Equity Interests and accordingly shall be distributed in accordance with the provisions of the documents, instruments and agreements governing such Equity Interests, including, without limitation, the contractual subordination provisions set forth therein, and the Bankruptcy Code.

18.3 **Cancellation of Enron Preferred Equity Interests and Exchanged Enron Preferred Stock**: On the Effective Date, the Enron Preferred Equity Interests shall be deemed cancelled and of no force and effect and the Exchanged Enron Preferred Stock shall be issued in lieu thereof. On the later to occur of (a) the entry of a Final Order resolving all Claims in the Chapter 11 Cases and (b) the final distribution made to holders of Allowed Claims and Allowed Equity Interests in accordance with Article XXXII of the Plan, the Exchanged Enron Preferred Stock shall be deemed extinguished and the certificates and all other documents representing such Equity Interests shall be deemed cancelled and of no force and effect.

ARTICLE XIX

PROVISION FOR TREATMENT OF ENRON COMMON EQUITY INTERESTS (CLASS 384)

19.1 **Treatment of Allowed Enron Common Equity Interests (Class 384)**: Except as otherwise provided in Section 19.2 of the Plan, on the Effective Date, each holder of an Allowed Enron Common Equity Interest shall be entitled to receive such holder's Pro Rata Share of Common Equity Trust Interests to be allocated pursuant to Article XXVII of the Plan.

19.2 **Contingent Distribution to Common Equity Trust**: Notwithstanding anything contained herein to the contrary, in the event that Plan Currency and Trust Interests are deemed redistributed to a holder of an Allowed Enron Common Equity Interest in accordance with the provisions of Sections 7.5, 8.2, 9.2, 17.2 and 18.2 of the Plan, as a result of the issuance and transfer of Exchanged Enron Common Stock, such Plan Currency shall be distributed to the Common Equity Trustee for and on behalf of the holders of Common Equity Trust Interests.

19.3 **Cancellation of Enron Common Equity Interests and Exchanged Enron Common Stock**: On the Effective Date, the Enron Common Equity Interests shall be deemed cancelled and of no force and effect and the Exchanged Enron Common Stock shall be issued in lieu of the Enron Common Equity Interests consisting of outstanding common stock (not interests or rights to convert into, or acquire, common stock). On the later to occur of (a) the entry of a Final Order resolving all Claims in the Chapter 11 Cases and (b) the final distribution made to holders of Allowed Claims and Allowed Equity Interests in accordance with Article XXXII of the Plan, the Exchanged Enron Common Stock shall be deemed extinguished and the certificates and all other documents representing such Equity Interests shall be deemed cancelled and of no force and effect.

ARTICLE XX

PROVISIONS FOR TREATMENT OF OTHER EQUITY INTERESTS (CLASS 385)

20.1 **Cancellation of Other Equity Interests (Class 385)**: On the latest to occur of (1) the Effective Date, (2) the entry of a Final Order resolving all Claims in the Chapter 11 Cases and (3) the final distribution made to holders of Allowed Claims and Allowed Equity Interests in accordance with Article XXXII of the Plan, unless otherwise determined by the Debtors and the Creditors' Committee, (a) all Other Equity Interests shall be deemed extinguished and the certificates and all other documents representing such Equity Interests shall be deemed cancelled and of no force and effect and (b) the Reorganized Debtor Plan Administrator shall administer the assets of such Entity in accordance with the provisions of Article XXXVI hereof; provided, however, that no Other Equity Interests shall be cancelled if the result of such cancellation shall adversely economically impact the estate of any Debtor.

ARTICLE XXXI

PROVISIONS FOR THE ESTABLISHMENT AND MAINTENANCE OF DISBURSEMENT ACCOUNTS

31.1 Establishment of Disbursement Account: On or prior to the Effective Date, the Debtors shall establish one or more segregated bank accounts in the name of the Reorganized Debtors as Disbursing Agent under the Plan, which accounts shall be trust accounts for the benefit of Creditors and holders of Administrative Expense Claims pursuant to the Plan and utilized solely for the investment and distribution of Cash consistent with the terms and conditions of the Plan. On or prior to the Effective Date, and periodically thereafter, the Debtors shall deposit into such Disbursement Account(s) all Cash and Cash Equivalents of the Debtors, less amounts reasonably determined by the Debtors or the Reorganized Debtors, as the case may be, as necessary to fund the ongoing implementation of the Plan and operations of the Reorganized Debtors.

31.2 Maintenance of Disbursement Account(s): Disbursement Account(s) shall be maintained at one or more domestic banks or financial institutions of the Reorganized Debtors' choice having a shareholder's equity or equivalent capital of not less than One Hundred Million ($100,000,000.00). The Reorganized Debtors shall invest Cash in Disbursement Account(s) in Cash Equivalents; provided, however, that sufficient liquidity shall be maintained in such account or accounts to (a) make promptly when due all payments upon Disputed Claims if, as and when they become Allowed Claims and (b) make promptly when due the other payments provided for in the Plan.

ARTICLE XXXII

PROVISIONS REGARDING DISTRIBUTIONS

32.1 Time and Manner of Distributions: Distributions under the Plan shall be made to each holder of an Allowed Unsecured Claim as follows:

(a) Initial Distributions of Cash: On or as soon as practicable after the Effective Date, the Disbursing Agent shall distribute, or cause to be distributed, to the Reorganized Debtor Plan Administrator on behalf of holders of Disputed Claims, and to each holder of an Allowed General Unsecured Claim, an Allowed Guaranty Claim, an Allowed Intercompany Claim and an Allowed Convenience Claim, such Creditor's share, if any, of Creditor Cash as determined pursuant to Articles VII, X, XI, XII, XIII, XIV, XV and XVI hereof.

(b) Subsequent Distributions of Cash: On the first (1st) Business Day that is after the close of one (1) full calendar quarter following the date of the initial Effective Date distributions, and, thereafter, on each first (1st) Business Day following the close of two (2) full calendar quarters, the Disbursing Agent shall distribute, or cause to be distributed, to the Reorganized Debtor Plan Administrator on behalf of holders of Disputed Claims, and to each holder of an Allowed General Unsecured Claim, an Allowed Guaranty Claim, an Allowed Intercompany Claim, and an Allowed Convenience Claim, an amount equal to such Creditor's share, if any, of Creditor Cash as determined pursuant to Articles VII, X, XI, XII, XIII, XIV, XV and XVI hereof, until such time as there are no longer any potential Creditor Cash.

(c) Distributions of Plan Securities: Notwithstanding anything contained herein to the contrary, commencing on or as soon as practicable after the Effective Date, subject to the availability of any historical financial information required to comply with applicable securities laws, the Disbursing Agent shall commence distributions, or cause to be distributed, to the Reorganized Debtor Plan Administrator on behalf of holders of Disputed Claims, and to each holder of an Allowed General Unsecured Claim, an Allowed Guaranty Claim and an Allowed Intercompany Claim, an amount equal to such Creditor's share, if any, of Plan Securities, as determined pursuant to Articles VII, X, XI, XII, XIII, XIV, XV and XVI hereof, and semi-annually thereafter until such time as there is no longer any potential Plan Securities to distribute, as follows:

(i) Prisma: Distribution of Prisma Common Stock to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims shall commence upon (a) allowance of General Unsecured Claims in an amount which would result in the distribution of thirty percent (30%) of the issued and outstanding shares of Prisma Common Stock and (b) obtaining the requisite consents for the transfer of the Prisma Assets to Prisma and the issuance of the Prisma Common Stock;

(ii) CrossCountry: Distributions of CrossCountry Common Equity to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims shall commence upon (a) allowance of General Unsecured Claims in an amount which would result in the distribution of thirty percent (30%) of the issued and outstanding shares of CrossCountry Common Equity and (b) obtaining the requisite consents for the issuance of the CrossCountry Common Equity; and

(iii) PGE: Distributions of PGE Common Stock to holders of Allowed General Unsecured Claims, Allowed Guaranty Claims and Allowed Intercompany Claims shall commence upon (a) allowance of General Unsecured Claims in an amount which would result in the distribution of thirty percent (30%) of the issued and outstanding shares of PGE Common Stock and (b) obtaining the requisite consents for the issuance of the PGE Common Stock;

provided, however, that, in the event that a Sale Transaction has occurred, or an agreement for a Sale Transaction has been entered into and has not been terminated, prior to the satisfaction of the conditions for the distribution of such Plan Securities pursuant to this Section 32.1(c), the proceeds thereof shall be distributed in accordance with the provisions of Section 32.1(a) of the Plan in lieu of the Plan Securities that are the subject of such Sale Transaction or agreement, or in the case of a Sale Transaction involving a sale of all or substantially all of the assets of an issuer of Plan Securities, the Plan Securities of such issuer (unless the agreement for such Sale Transaction terminates subsequent to the satisfaction of such applicable conditions in this

Section 32.1(c), in which case, such Plan Securities shall be distributed pursuant to this Section 32.1(c)), with the balance of such Plan Securities distributed in accordance with the provisions of this Section 32.1(c); and, provided, further, that, if in the joint determination of the Debtors or the Reorganized Debtors, as the case may be, and the Creditors' Committee, the Prisma Trust Interests, CrossCountry Trust Interests and/or PGE Trust Interests are created, on or as soon as practicable following the creation of the Operating Trusts, such interests shall be allocated to the appropriate holders thereof in accordance with Article XXIV of the Plan in lieu of the distributions of Prisma Common Stock, CrossCountry Common Equity and/or PGE Common Stock, respectively; and, provided, further, that during the period of retention of any such Plan Securities, the Disbursing Agent shall distribute, or cause to be distributed, to the Reorganized Debtor Plan Administrator on behalf of holders of Disputed Claims, and to each holder of an Allowed General Unsecured Claim, an Allowed Guaranty Claim and an Allowed Intercompany Claim, an amount equal to such Creditor's share, if any, of dividends declared and distributed with respect to any of the Plan Securities; and, provided, further, until such time as all Disputed Claims have been allowed by Final Order, in whole or in part, the Disbursing Agent shall hold in reserve at least one percent (1%) of the Plan Securities to be distributed in accordance with Section 21.3 of the Plan and this Section 32.1.

(d) Distribution of Trust Interests: In the event that the Litigation Trust or the Special Litigation Trust is created, on or as soon as practicable thereafter, the Disbursing Agent shall commence distributions, or cause to be distributed, to the Reorganized Debtor Plan Administrator on behalf of holders of Disputed Claims, and to each holder of an Allowed General Unsecured Claim, an Allowed Guaranty Claim, and an Allowed Intercompany Claim, such Creditor's share, if any, of Trust Interests as determined pursuant to Articles VII, X, XI, XII, XIII, XIV, XV and XVI hereof, and semi-annually thereafter until such time as there is no longer any Trust Interests to distribute.

(e) Allocation of Remaining Asset Trust Interests: In the event the Remaining Asset Trusts are created, on or as soon as practicable thereafter, the Disbursing Agent shall allocate, or cause to be allocated, to the Reorganized Debtor Plan Administrator on behalf of holders of Disputed Claims, and to each holder of an Allowed General Unsecured Claim, an Allowed Guaranty Claim, and an Allowed Intercompany Claim, such Creditor's share, if any, of Remaining Asset Trust Interests as determined pursuant to Articles VII, X, XI, XII, XIII, XIV, XV and XVI hereof.

(f) Recalculation of Distributive Assets, Guaranty Distributive Assets and Intercompany Distributive Assets: Notwithstanding anything contained herein to the contrary, in connection with each of the distributions of Plan Currency to be made in accordance with this Section 32.1, the Disbursing Agent shall calculate, or cause to be calculated, Distributive Assets, Enron Guaranty Distributive Assets, Wind Guaranty Distributive Assets, ACFI Guaranty Distributive Assets, ENA Guaranty Distributive Assets, EPC Guaranty Distributive Assets and Intercompany Distributive Assets as of the date thereof, taking into account, among other things, (i) sales of Remaining Assets, prior to the creation of the Remaining Asset Trust(s), (ii) proceeds, if any, of Sale Transactions and (iii) the allowance or disallowance of Disputed Claims, as the case may be.

SEPARATION AGREEMENT

BETWEEN

ENRON CORP.

AND

PORTLAND GENERAL ELECTRIC COMPANY

Dated as of [________], 200[_]

TABLE OF CONTENTS

TABLE OF CONTENTS
(Cont'd)

SEPARATION AGREEMENT

SEPARATION AGREEMENT, dated as of [________], 200[_] (this "Agreement"), between Enron Corp., an Oregon corporation ("Enron"), and Portland General Electric Company, an Oregon corporation ("PGE"). Certain terms used in this Agreement are defined in Section 4.1.

W I T N E S S E T H:

WHEREAS, commencing on December 2, 2001, Enron and certain of its subsidiaries filed voluntary petitions for relief under chapter 11 of the Bankruptcy Code; and

WHEREAS, prior to the execution and delivery of this Agreement, Enron owns all of the issued and outstanding common stock, par value $3.75 per share, of PGE (the "PGE Common Stock"); and

WHEREAS, Enron and PGE desire to enter into this Agreement in connection with the Stock Issuance which is occurring concurrently with the execution and delivery of this Agreement.

NOW, THEREFORE, in consideration of the premises and the representations, warranties, covenants and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the parties hereby agree as follows:

ARTICLE I

COVENANTS

1.1 Preservation of Records; Cooperation. Each of Enron and PGE shall preserve and keep in its possession all records held by it on and after the date hereof which may relate to the businesses of or any claim, action, investigation or proceeding involving the Enron Group, on the one hand, and the PGE Group, on the other hand, until the earlier of (x) seven (7) years from the date of this Agreement or (y) the closing of the Bankruptcy Cases, or such longer period as may be required by Applicable Law or any other Transaction Document, and shall make such records and then existing personnel available to the other party as may reasonably be requested by such party in connection with, among other things, any insurance claims, legal proceedings, or governmental investigations of the Enron Group or the PGE Group or in order to enable Enron or PGE to comply with their respective obligations under this Agreement and each other agreement, document or instrument contemplated hereby or thereby; provided, however, that in no event shall the Enron Group or the PGE Group be obligated to provide any information (i) the disclosure of which would jeopardize any privilege available to the Enron Group or the PGE Group, as applicable, relating to such information, (ii) the disclosure of which would cause the Enron Group or the PGE Group, as applicable, to breach a confidentiality obligation to which it is bound or (iii) the disclosure of which would cause the Enron Group or the PGE Group, as applicable, to be in violation of Applicable Law. After the expiration of any applicable retention period, before any party shall dispose of any of such records, at least ninety (90) days' prior notice to such effect shall be given by such party to the other party hereto (or a Person designated by such party) and such party shall have the opportunity (but not the obligation), at its sole cost and expense, to remove and retain all or any part of such records as it may in its sole discretion select. From and after the date of this Agreement and until the Final Release Date, each of Enron and PGE shall, and shall cause each of its Subsidiaries to, (A) provide the other party with notice of any governmental inquiries or investigations or any litigation initiated against the Enron Group or the PGE Group, as applicable, which may relate to the business, assets or operations of any member of the Enron Group or the PGE Group, as applicable, and (B) make good faith efforts to provide such other party with information which such party believes to be beneficial to such other party in connection with investigations of or matters involving claims against the Enron Group or the PGE Group, as applicable; provided, however, that in no event shall the Enron Group or the PGE Group, as applicable, be obligated to provide any information (i) the disclosure of which would jeopardize any privilege available to the Enron Group or the PGE Group, as applicable, relating to such information, (ii) the disclosure of which would cause the Enron Group or the PGE Group, as applicable, to breach a confidentiality obligation to which it is bound or (iii) the disclosure of which would cause the Enron Group or the PGE Group, as applicable, to be in violation of Applicable Law.

1.2 Confidentiality.

(a) Subject to Section 1.2(c), Enron shall not, and shall cause its Affiliates and their respective officers, directors, employees, attorneys and other agents and representatives, including attorneys, agents and other representatives of any Person providing financing (collectively, "Representatives"), not to, directly or indirectly, disclose, reveal, divulge or communicate to any Person other than Representatives of Enron or of its Affiliates who reasonably need to know such information in providing services to any member of the Enron Group, any PGE Confidential Information (as defined below). For purposes of this Section 1.2, any information, material or documents relating to the businesses currently or formerly conducted by the PGE Group furnished to or in possession of the Enron Group, irrespective of the form of communication, and all notes, analyses, compilations, forecasts, data, translations, studies, memoranda or other documents prepared by the Enron Group and their respective Representatives, that contain or otherwise reflect such information, material or documents is hereinafter referred to as "PGE Confidential Information". "PGE Confidential Information" does not include, and there shall be no obligation hereunder with respect to, information that (i) is or becomes generally available to the public, other than as a result of a disclosure by Enron not otherwise permissible hereunder, (ii) is deemed by Enron to be necessary or appropriate to disclose in connection with (A) the administration of the Bankruptcy Cases, (B) any investigation, proceeding or litigation, including, but not by means of limitation, any such investigation, proceeding or litigation related to ERISA or federal income tax liability, or (C) one or more Releases, including without limitation obtaining consents in connection with such Releases, or (iii) Enron can demonstrate was or became available to Enron from a source other than the PGE Group; provided, however, that, in the case of clause (iii), the source of such information was not known by Enron to be bound by a confidentiality agreement with, or other contractual, legal or fiduciary obligation of confidentiality to, the PGE Group with respect to such information. For the avoidance of doubt, PGE Confidential Information includes all electronic information, including emails, prepared by the PGE Group or the Enron Group, including any electronic information which may reside on systems in which the Enron Group has an ownership interest, which are controlled, in whole or in part, by the Enron Group, or to which the Enron Group has access.

(b) Subject to Section 1.2(c), PGE shall not, and shall cause its Subsidiaries and their respective Representatives, not to, directly or indirectly, disclose, reveal, divulge or communicate to any Person other than Representatives of such party or of its Affiliates who reasonably need to know such information in providing services to the PGE Group or use or otherwise exploit for its own benefit or for the benefit of any third party, any Enron Confidential Information (as defined below). For purposes of this Section 1.2, any information, material or documents relating to the businesses currently or formerly conducted by the Enron Group furnished to or in possession of the PGE Group, irrespective of the form of communication, and all notes, analyses, compilations, forecasts, data, translations, studies, memoranda or other documents prepared by the PGE Group or their respective Representatives, that contain or otherwise reflect such information, material or documents is hereinafter referred to as "Enron Confidential Information". "Enron Confidential Information" does not include, and there shall be no obligation hereunder with respect to, information that (i) is or becomes generally available to the public, other than as a result of a disclosure by the PGE Group not otherwise permissible hereunder, or (ii) PGE can demonstrate was or became available to PGE from a source other than the Enron Group; provided, however, that, in the case of clause (ii), the source of such information was not known by PGE to be bound by a confidentiality agreement with, or other contractual, legal or fiduciary obligation of confidentiality to, the Enron Group with respect to such information. For the avoidance of doubt, Enron Confidential Information includes all electronic information, including emails, prepared by any member of the Enron Group or the PGE Group, including any electronic information which may reside on systems in which the PGE Group has an ownership interest, are controlled, in whole or in part, by the PGE Group, or to which the PGE Group has access.

(c) If Enron, on the one hand, or PGE, on the other hand, is requested or required (by oral question, interrogatories, requests for information or documents, subpoena, civil investigative demand or similar process) by any Governmental Authority to disclose any PGE Confidential Information or Enron Confidential Information, as applicable, the Person receiving such request or demand shall use all reasonable efforts to provide the other party with written notice of such request or demand as promptly as practicable under the circumstances so that such other party shall have an opportunity to seek an appropriate protective order. The party receiving such request or demand agrees to take, and cause its representatives to take, all other reasonable steps necessary to obtain confidential treatment by the recipient. The covenants and agreements of the parties set forth in Sections 1.2(a), (b) and (c) shall survive for a period of two (2) years after the date of this Agreement.

1.3 Use of Name.

(a) PGE shall not have any right, title or interest in the name "Enron" (or any variation thereof) or any trademarks, trade names, logo or symbols related thereto. As soon as reasonably practicable following the date of this Agreement (and in any event, within three hundred sixty five (365) days thereafter), PGE shall, to the extent applicable, amend its organizational documents and the organizational documents of any Subsidiary to the extent necessary to remove the "Enron" name (and any variation thereof) from its name and to remove, at the sole expense of PGE, all trademarks, trade names, logos and symbols related to the name "Enron" from any properties and assets (including all signs) that are visible to, or obtainable by, members of the public.

(b) Enron shall not have any right, title or interest in the name "Portland General Electric" (or any variation thereof) or any trademarks, trade names, logos or symbols related thereto. As soon as reasonably practicable following the date of this Agreement (and in any event, within three hundred and sixty-five (365) days thereafter), Enron shall, to the extent applicable, amend its organizational documents and the organizational documents of any Subsidiary to the extent necessary to remove the "Portland General Electric" name (and any variation thereof) from its name and to remove, at the sole expense of Enron, all trademarks, trade names, logos and symbols related to the name "Portland General Electric" from any properties and assets (including all signs) that are visible to, or obtainable by, members of the public.

1.4 Intercompany Amounts and Agreements. Immediately prior to or at the execution and delivery of this Agreement, PGE has caused any amounts owed by any member of the Enron Group to any member of the PGE Group (whether liquidated or unliquidated, known or unknown, but excluding obligations under any Transaction Document) to be dividended or otherwise distributed to Enron. Any amounts owed by any member of the PGE Group to any member of the Enron Group, to the extent not paid concurrently with the execution and delivery of this Agreement, will remain obligations of the applicable obligor. Except as otherwise provided on Schedule 1.4, all agreements between any member of the Enron Group, on the one hand, and any member of the PGE Group, on the other hand, are hereby terminated.

1.5 Further Assurances. Each of Enron and PGE agree that each of them will, and will cause their respective Affiliates to, execute and deliver such instruments and take such other commercially reasonable action as may reasonably be requested by any party hereto to carry out the purposes and intents hereof.

1.6 The Plan and Stock Issuance.

(a) PGE shall take all actions necessary to ensure that all shares of its capital stock being issued in the Stock Issuance pursuant to the Plan are duly authorized, validly issued, fully paid and nonassessable and free of any preemptive (or similar) rights. As soon as practicable after the execution and delivery of this Agreement, PGE shall cause its transfer agent to mail to the recipients of its capital stock certificates (as directed by Stephen Forbes Cooper

LLC or its successor under the Plan) for the applicable number of shares, unless the transfer agent uses a book entry system of stock recordkeeping, in which case no certificates for shares of PGE Common Stock shall be issued unless a shareholder so requests.

(b) The appropriate procedures in connection with any Release Date shall be governed by the terms of the Plan. All expenses incurred by PGE in connection with a Release, including expenses incurred in preparing, filing with the SEC, and obtaining an effective order with respect to the registration of the class of PGE Common Stock pursuant to the Securities Exchange Act, shall be borne by PGE.

ARTICLE II

CONCURRENT DELIVERIES AND TRANSACTIONS

2.1 Documents Delivered by the Enron Group. Concurrently with the execution and delivery of this Agreement, Enron is delivering, or causing to be delivered, to PGE or the other appropriate parties originally executed versions of each of the Transaction Documents executed by all parties thereto other than PGE.

2.2 Documents to Be Delivered by PGE. Concurrently with the execution and delivery of this Agreement, PGE is delivering to Enron or the other appropriate parties originally executed versions of each of the Transaction Documents executed by PGE.

2.3 Stock Issuance. Concurrently with the execution and delivery of this Agreement, the Stock Issuance is occurring. In order to effect the Stock Issuance, (i) PGE is canceling all shares of PGE Common Stock heretofore owned by Enron (and Enron hereby directs PGE to effect such cancellation), (ii) PGE is issuing ____ shares of PGE Common Stock to Stephen Forbes Cooper LLC pursuant to the Plan and (iii) PGE is issuing an aggregate ____ shares of PGE Common Stock to other Persons pursuant to the Plan.

2.4 Termination of Tax Allocation Agreement. The parties hereto hereby agree that, effective immediately upon the execution and delivery of this Agreement, the Tax Allocation Agreement is hereby terminated; provided, however, that Articles III and IV of the Tax Allocation Agreement shall remain in effect for the sole purpose of determining the payment required to be made under the Tax Allocation Agreement in respect of the current taxable year of Enron and the PGE Group (determined as though such taxable year ended on the date hereof).

ARTICLE III

INDEMNIFICATION

3.1 Tax Indemnification.[1]

(a) Enron hereby agrees to indemnify and hold the PGE Indemnified Parties harmless from and against any and all Taxes of any member of the PGE Group that are imposed upon such member of the PGE Group by reason of such member of the PGE Group being severally liable for any Taxes of any member of the Enron Group which is not a member of the PGE Group pursuant to Treasury Regulation §1.1502-6(a) or any analogous state, local or foreign law; provided, that such Taxes are (x) imposed upon or assessed against any PGE Indemnified Party or the assets or the properties thereof and (y) assessed before assessment of such Tax is barred under the applicable statute of limitations relating to such Tax and provided, further, that the indemnity set forth in this Section 3.1(a) shall not affect the obligation of any member of the PGE Group to make payments pursuant to any order of the Bankruptcy Court, the Tax Allocation Agreement or any other agreement between any member of the Enron Group, on one hand, and any member of the PGE Group, on the other hand, to allocate liability for Taxes.

(b) Enron also shall indemnify and hold harmless the PGE Indemnified Parties from and against any Liabilities (other than Taxes assessed on any indemnification payment received by the PGE Indemnified Parties pursuant to this Article V) incurred in connection with the Taxes for which Enron is responsible to indemnify the PGE Indemnified Parties pursuant to Section 3.1(a).]

3.2 Employee Benefits Indemnification.[2] Enron hereby agrees to indemnify and hold the PGE Indemnified Parties harmless from and against any and all Liabilities arising out of any employee benefit plan sponsored by Enron or its ERISA Affiliates (other than members of the PGE Group) that are imposed upon or assessed against a member of the PGE Group or the assets thereof (i) under Title IV of ERISA or (ii) due to participating employer status in the Enron Corp. Savings Plan; provided, that such Liabilities are not barred from recovery under the relevant statute of limitations and provided, further, that the indemnity set forth in this Section 3.2 shall not affect the obligation of any member of the PGE Group to make payments pursuant to any order of the Bankruptcy Court or any other agreement between any member of the Enron Group, on one hand, and any member of the PGE Group, on the other hand, relating to the allocation of costs of providing employee benefits to the employees of the PGE Group.

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[1] Assuming that, as expected, the pending settlement with the IRS is finalized prior to the execution and delivery of this Agreement, this section will be modified to apply only to periods not covered by the IRS settlement (i.e. periods after 2001).

[2] Assuming that, as expected, the pending settlement with the PBGC is finalized prior to the execution and delivery of this Agreement, this section will be eliminated.

3.3 Indemnification Procedures. All claims for indemnification under this Article III shall be resolved as follows:

(a) A party claiming indemnification under this Agreement (an "Indemnified Party") shall promptly (i) notify the party from whom indemnification is sought (the "Indemnifying Party") of any Third Party Claim asserted against the Indemnified Party which could give rise to a right of indemnification under this Agreement and (ii) transmit to the Indemnifying Party a written notice ("Claim Notice") describing the nature of the Third Party Claim, a copy of all papers served with respect to such claim (if any), and the basis of the Indemnified Party's request for indemnification under this Agreement.

(b) Within ten (10) days after receipt of any Claim Notice (the "Election Period"), the Indemnifying Party shall notify the Indemnified Party (i) whether the Indemnifying Party disputes its potential liability to the Indemnified Party under this Agreement with respect to such Third Party Claim and (ii) whether the Indemnifying Party desires, at the sole cost and expense of the Indemnifying Party, to defend the Indemnified Party against such Third Party Claim.

(c) If the Indemnifying Party notifies the Indemnified Party within the Election Period that the Indemnifying Party elects to assume the defense of the Third Party Claim, then the Indemnifying Party shall have the right to defend, at its sole cost and expense, such Third Party Claim by all appropriate proceedings, which proceedings shall be prosecuted diligently by the Indemnifying Party to a final conclusion or settled at the discretion of the Indemnifying Party in accordance with this Section 3.3 The Indemnifying Party shall have full control of such defense and proceedings including any compromise or settlement thereof; provided, however, that any such compromise or settlement that imposes any material limitation on the business activities of the Enron Group or the PGE Group, as the case may be, shall be subject to the consent of the Indemnified Party (such consent not to be unreasonably withheld, delayed or conditioned). If requested by the Indemnifying Party, the Indemnified Party shall cooperate with the Indemnifying Party and its counsel in contesting any Third Party Claim which the Indemnifying Party elects to contest, including, without limitation, the making of any related counterclaim against the Person asserting the Third Party Claim or any cross-complaint against any Person; provided, that the Indemnifying Party shall pay the reasonable, out-of-pocket expenses incurred by the Indemnified Party in connection therewith. The Indemnified Party may participate in, but not control, any defense or settlement of any Third Party Claim controlled by the Indemnifying Party pursuant to this Section 3.3 and, except as provided in the preceding sentence, shall bear its own costs and expenses with respect to such participation.

(d) If the Indemnifying Party fails to notify the Indemnified Party within the Election Period that the Indemnifying Party elects to defend the Indemnified Party pursuant to this Section 3.3 then the Indemnified Party shall have the right to defend the Third Party Claim, at the sole cost and expense of the Indemnifying Party. The Indemnified Party shall have full control of such defense and proceedings; provided, however, that the Indemnified Party may not enter into, without the Indemnifying Party's consent, which shall not be unreasonably withheld, conditioned or delayed, any compromise or settlement of such Third Party Claim. The Indemnifying Party may participate in, but not control, any defense or settlement controlled by the Indemnified Party pursuant to this Section 3.3 and the Indemnifying Party shall bear its own costs and expenses with respect to such participation.

(e) Payments of all amounts owing by the Indemnifying Party pursuant to Sections 3.3(c) and (d) shall be made not later than thirty (30) days after the latest of (A) the settlement of the Third Party Claim, (B) the expiration of the period for appeal of a final adjudication of such Third Party Claim or (C) the expiration of the period for appeal of a final adjudication of the Indemnifying Party's liability to the Indemnified Party under this Agreement.

(f) The failure to provide notice as provided in this Section 3.3 shall not excuse any party from its continuing obligations hereunder; provided, however, any claim shall be reduced by the damages resulting from such party's delay or failure to provide notice as provided in this Section 3.3

3.4 Limitation on Indemnification.

(a) Enron's obligations to indemnify pursuant to Section 3.1 and 3.2 shall terminate upon the closing of the Bankruptcy Cases. Notwithstanding the foregoing, any matter as to which a Claim Notice has been delivered to the Indemnifying Party that is pending or unresolved as of the date on which the corresponding obligation to indemnify otherwise terminates pursuant to this Section 3.4 shall continue to be covered by this Article III until such matter is finally terminated or otherwise resolved by the parties under this Agreement or by a court of competent jurisdiction and any amounts payable hereunder are finally determined and paid.

(b) The aggregate amount of Liabilities for which indemnification is provided under this Article III shall be net of any amounts actually recovered by the Indemnified Party under any insurance policies and shall be reduced to take account of any net tax benefit actually realized by the Indemnified Party arising from the incurrence of such Liability.

3.5 Remedies Exclusive. EXCEPT FOR ANY PARTIES' RIGHT TO SEEK INJUNCTIVE RELIEF FOR A BREACH OF SECTION 1.2, THE PARTIES ACKNOWLEDGE AND AGREE THAT THE REMEDIES SET FORTH IN THIS ARTICLE III, INCLUDING THE DISCLAIMERS AND LIMITATIONS ON SUCH REMEDIES, ARE INTENDED TO BE, AND SHALL BE, THE SOLE AND EXCLUSIVE REMEDIES UNDER THIS AGREEMENT.

ARTICLE IV

DEFINITIONS

4.1 Certain Definitions. For purposes of this Agreement, the following terms shall have the meanings specified in this Section 4.1:

"Action" means any action, suit, arbitration, claim, inquiry, proceeding or investigation by or before any Governmental Authority of any nature, civil, criminal, regulatory or otherwise, in law or in equity.

"Affiliate" (and, with a correlative meaning "affiliated") means, with respect to any Person, any direct or indirect subsidiary of such Person, and any other Person that directly, or through one or more intermediaries, controls or is controlled by or is under common control with such first Person; provided, however, that no member of the PGE Group shall be deemed an Affiliate of any member of the Enron Group for purposes of this Agreement; and provided, further, that no member of the Enron Group shall be deemed an Affiliate of any member of the PGE Group for purposes of this Agreement. As used in this definition, "control" (including with correlative meanings, "controlled by" and "under common control with") means possession, directly or indirectly, of power to direct or cause the direction of management or policies (whether through ownership of securities or partnership or other ownership interests, by Contract or otherwise).

"Agreement" shall have the meaning set forth in the preamble hereto.

"Applicable Law" means, with respect to any Person, any Law applicable to such Person or its business, properties or assets.

"Bankruptcy Cases" means the chapter 11 cases commenced by Enron and certain of its direct and indirect subsidiaries on or after December 2, 2001 (including any case commenced after the date of this Agreement), jointly administered under Case No. 01-16034-(AJG).

"Bankruptcy Code" means title 11 of the United States Code, as amended.

"Bankruptcy Court" means the United States Bankruptcy Court for the Southern District of New York or any other court having jurisdiction over the Bankruptcy Cases from time to time.

"Claim Notice" shall have the meaning set forth in Section 3.3(a).

"Contract" means any written contract, indenture, note, bond, loan, instrument, lease, commitment or other agreement.

"Election Period" shall have the meaning set forth in Section 3.3(b).

"Enron" shall have the meaning set forth in the preamble hereto.

"Enron Confidential Information" shall have the meaning set forth in Section 1.2(b).

"Enron Group" means Enron and each Person that is an Affiliate of Enron immediately after the execution and delivery of this Agreement. For sake of clarity, it is expressly agreed that "Enron Group" does not include PGE or its Subsidiaries.

"Enron Indemnified Parties" means each member of the Enron Group and their respective directors, officers, employees, Affiliates, agents, representatives, successors and assigns.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

"ERISA Affiliate" means any trade or business (whether or not incorporated) that, together with Enron, is treated as a single employer under Section 414(b) or (c) of the Internal Revenue Code of 1986, as amended.

"Final Release Date" shall mean the date on which the final Release occurs.

"Governmental Authority" means any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to government, including any governmental authority, agency, department, board, commission or instrumentality of the United States, any state of the United States or any political subdivision thereof, and any tribunal, court or arbitrator(s) of competent jurisdiction, and shall include the Bankruptcy Court.

"Indemnified Party" shall have the meaning set forth in Section 3.3(a).

"Indemnifying Party" shall have the meaning set forth in Section 3.3(a).

"Law" means any federal, state or local law (including common law), statute, code, ordinance, rule, regulation, order, judgment or other requirement enacted, promulgated, issued or entered by a Governmental Authority.

"Liabilities" means any and all debts, losses, liabilities, claims (including claims as defined in the Bankruptcy Code), damages, expenses, fines, costs, royalties, proceedings, deficiencies or obligations (including those arising out of any Action, such as any settlement or compromise thereof or judgment or award therein), of any nature, whether known or unknown, absolute, accrued, contingent or otherwise and whether due or to become due, and whether or not resulting from Third Party Claims, and any reasonable out-of-pocket costs and expenses (including reasonable legal counsels', accountants', or other fees and expenses incurred in defending any Action or in investigating any of the same or in asserting any rights hereunder), but not including consequential, exemplary, special, incidental and punitive damages and loss of revenue or income, cost of capital, and loss of business reputation or opportunity.

"Person" means and includes natural persons, corporations, limited partnerships, limited liability companies, general partnerships, joint stock companies, joint ventures, associations, companies, trusts, banks, trust companies, land trusts, business trusts or other organizations, whether or not legal entities, and all Governmental Authorities.

"PGE" has the meaning set forth in the preamble hereto.

"PGE Common Stock" shall have the meaning set forth in the recitals hereto.

"PGE Confidential Information" shall have the meaning set forth in Section 1.2(a).

"PGE Group" means PGE, each Subsidiary of PGE immediately after the execution and delivery of this Agreement and each other Person that is either controlled directly or indirectly by PGE immediately after the execution and delivery of this Agreement.

"PGE Indemnified Parties" means each member of the PGE Group and their respective Representatives, successors and assigns.

"Plan" means the Joint Plan of Affiliated Debtors pursuant to Chapter 11 of the Bankruptcy Code for Enron Corp., as proposed by Enron, including, without limitation, the exhibits and schedules attached thereto, as the same may be modified and supplemented from time to time.

"Release" means any release by Stephen Forbes Cooper LLC of shares of PGE Common Stock pursuant to the Plan.

"Release Date" means any date on which a Release occurs.

"Representatives" shall have the meaning set forth in Section 1.2(a).

"SEC" means the Securities and Exchange Commission.

"Securities Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Stock Issuance" means the issuance of PGE Common Stock that is occurring pursuant to the Plan concurrently with the execution and delivery of this Agreement.

"Subsidiary" or "subsidiary" means, with respect to any Person, any corporation, limited liability company, joint venture or partnership of which such Person (a) beneficially owns, either directly or indirectly, more than fifty percent (50%) of (i) the total combined voting power of all classes of voting securities of such entity, (ii) the total combined equity interests, or (iii) the capital or profit interests, in the case of a partnership; or (b) otherwise has the power to vote, either directly or indirectly, sufficient securities to elect a majority of the board of directors or similar governing body.

"Tax" means all federal, state, provincial, territorial, municipal, local or foreign income, profits, franchise, gross receipts, environmental (including taxes under Code Section 59A), customs, duties, net worth, sales, use, goods and services, withholding, value added, *ad valorem*, employment, social security, disability, occupation, pension, real property, personal property (tangible and intangible), stamp, transfer, conveyance, severance, production, excise and other taxes, withholdings, duties, levies, imposts and other similar charges and assessments (including any and all fines, penalties and additions attributable to or otherwise imposed on or with respect to any such taxes, charges, fees, levies or other assessments, and interest thereon) imposed by or on behalf of any Taxing Authority, in each case whether such Tax arises by Law, Contract or otherwise.

"Tax Allocation Agreement" means that certain Tax Allocation Agreement dated on or about December 23, 2002 between Enron and members of the PGE Group.

"Taxing Authority" means any Governmental Authority exercising any authority to impose, regulate, levy, assess or administer the imposition of any Tax.

"Third Party Claim" means any claim brought by any Person other than a member of the Enron Group, the PGE Group or their respective Affiliates.

"Transaction Documents" means this Agreement and the documents necessary to effect the Stock Issuance.

4.2 Other Terms. Other terms may be defined elsewhere in this Agreement and, unless otherwise indicated, shall have such meaning throughout this Agreement.

ARTICLE V

MISCELLANEOUS

5.1 Survival of Covenants and Agreements. The covenants and agreements of the parties made herein or in any other agreement delivered pursuant to this Agreement shall survive the execution and delivery of this Agreement for the applicable period set forth therein.

5.2 Expenses. Except as otherwise set forth in Sections 1.1 and Article III (or except as expressly provided in any other Transaction Document), each party shall bear all expenses incurred by it in connection with this Agreement, the Transaction Documents and each other agreement, document and instrument contemplated by this Agreement and the consummation of the transactions contemplated hereby and thereby.

5.3 Incorporation of Exhibits and Schedules. The exhibits and schedules identified in this Agreement are incorporated herein by reference and made a part hereof. Any information disclosed on any schedule hereto shall be deemed disclosed for all schedules hereto. Any matter disclosed in any section of a schedule shall be deemed disclosed in each section of such schedule.

5.4 Submission to Jurisdiction; Consent to Service of Process.

(a) Without limiting any party's right to appeal any Order of the Bankruptcy Court, (i) the Bankruptcy Court shall retain exclusive jurisdiction to enforce the terms of this Agreement and to decide any claims or disputes which may arise or result from, or be connected with, this Agreement, any breach or default hereunder, or the transactions contemplated hereby, and (ii) any and all Actions related to the foregoing shall be filed and maintained only in the Bankruptcy Court, and the parties hereby consent to and submit to the jurisdiction and venue of the Bankruptcy Court and shall receive notices at such locations as indicated in Section 5.11; provided, however, that if the Bankruptcy Cases have closed, the parties agree to unconditionally and irrevocably submit to the exclusive jurisdiction of the United States District Court for the Southern District of Texas sitting in Harris County or the Civil Trial Division of the District Courts of the State of Texas sitting in Harris County and any appellate court from any thereof, for the resolution of any such claim or dispute.

(b) The parties hereby unconditionally and irrevocably waive, to the fullest extent permitted by Applicable Law, any objection which they may now or hereafter have to the laying of venue of any dispute arising out of or relating to this Agreement or any of the transactions contemplated hereby brought in any court specified in paragraph (a) above, or any defense of inconvenient forum for the maintenance of such dispute. Each of the parties hereto agrees that a judgment in any such dispute may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law.

(c) Each of the parties hereto hereby consents to process being served by any party to this Agreement in any suit, Action or proceeding by the mailing of a copy thereof in accordance with the provisions of Section 5.11.

5.5 Waiver of Jury Trial. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT THAT THEY MAY HAVE TO TRIAL BY JURY OF ANY CLAIM OR CAUSE OF ACTION, OR IN ANY LEGAL PROCEEDING, DIRECTLY OR INDIRECTLY BASED UPON OR ARISING OUT OF THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT (WHETHER BASED ON CONTRACT, TORT, OR ANY OTHER THEORY). EACH PARTY (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT, OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTIES WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND

(B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION.

5.6 No Consequential or Punitive Damages. No party hereto (or its Affiliates) shall, under any circumstance, be liable to any other party (or its Affiliates) for any consequential, exemplary, special, incidental or punitive damages claimed by such other party under the terms of or due to any breach of this Agreement, including, but not limited to, loss of revenue or income, cost of capital, or loss of business reputation or opportunity.

5.7 Entire Agreement; Amendments and Waivers. This Agreement (including the schedules and exhibits hereto) and the other Transaction Documents represent the entire understanding and agreement between the parties hereto with respect to the subject matter hereof and can be amended, supplemented or changed, and any provision hereof can be waived, only by written instrument making specific reference to this Agreement signed by the party against whom enforcement of any such amendment, supplement, modification or waiver is sought. No action taken pursuant to this Agreement, including, without limitation, any investigation by or on behalf of any party, shall be deemed to constitute a waiver by the party taking such action of compliance with any representation, warranty, covenant or agreement contained herein. The waiver by any party hereto of a breach of any provision of this Agreement shall not operate or be construed as a further or continuing waiver of such breach or as a waiver of any other or subsequent breach. No failure on the part of any party to exercise, and no delay in exercising, any right, power or remedy hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of such right, power or remedy by such party preclude any other or further exercise thereof or the exercise of any other right, power or remedy. All remedies hereunder are cumulative and are not exclusive of any other remedies provided by law. In the event of any conflict between the provisions of this Agreement and the provisions of the Plan, the provisions of the Plan shall govern.

5.8 Governing Law. THIS AGREEMENT, THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS AGREEMENT, AND ANY CLAIM OR CONTROVERSY DIRECTLY OR INDIRECTLY BASED UPON OR ARISING OUT OF THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT (WHETHER BASED ON CONTRACT, TORT, OR ANY OTHER THEORY), INCLUDING ALL MATTERS OF CONSTRUCTION, VALIDITY AND PERFORMANCE, SHALL IN ALL RESPECTS BE GOVERNED BY AND INTERPRETED, CONSTRUED, AND DETERMINED IN ACCORDANCE WITH, THE APPLICABLE PROVISIONS OF THE BANKRUPTCY CODE AND THE INTERNAL LAWS OF THE STATE OF TEXAS (WITHOUT REGARD TO ANY CONFLICTS OF LAW PROVISION THAT WOULD REQUIRE THE APPLICATION OF THE LAW OF ANY OTHER JURISDICTION).

5.9 Table of Contents and Headings. The table of contents and section headings of this Agreement are for reference purposes only and are to be given no effect in the construction or interpretation of this Agreement.

5.10 No Strict Construction. The parties to this Agreement have participated jointly in the negotiation and drafting of this Agreement. In the event an ambiguity or question of intent or interpretation arises with respect to this Agreement or any other Transaction Document, this Agreement or such other Transaction Documents shall be construed as if drafted jointly by the parties, and no presumption or burden of proof shall arise favoring or disfavoring a party by virtue of the authorship of any of the provisions of this Agreement or such other Transaction Documents.

5.11 Notices. All notices and other communications under this Agreement shall be in writing and shall be deemed duly given (i) when delivered personally or by prepaid overnight courier, with a record of receipt, (ii) the fourth day after mailing if mailed by certified mail, return receipt requested, or (iii) the day of transmission, if sent by facsimile or telecopy during regular business hours, or the day after transmission, if sent after regular business hours (with a copy promptly sent by prepaid overnight courier with record of receipt or by certified mail, return receipt requested), to the parties at the following addresses or telecopy numbers (or to such other address or telecopy number as a party may have specified by notice given to the other party pursuant to this provision or, in the case of the Enron Group, as specified in the Plan):

If to the Enron Group, to:

Enron Corp.
Four Houston Center
1221 Lamar, Suite 1600
Houston, TX 77010
Attn: General Counsel
Facsimile: (713) ____-______

with a copy to:

Weil, Gotshal & Manges LLP
200 Crescent Court
Suite 300
Dallas, Texas 75201
Attention: R. Jay Tabor
Facsimile: (214) 746-7777

If to PGE, to:

Portland General Electric Company
121 Salmon Street
Portland, OR 97204
Attention: General Counsel
Facsimile: (503) 778-5566

5.12 Severability. If any provision of this Agreement is invalid or unenforceable, the balance of this Agreement shall remain in effect.

5.13 Binding Effect; Assignment. This Agreement shall be binding upon and inure to the benefit of the parties and their respective successors and permitted assigns, including, with respect to Enron, any reorganized debtor entity or plan administrator appointed pursuant to the Plan. Except as set forth in Article V, nothing in this Agreement shall create or be deemed to create any third party beneficiary rights in any Person not a party to this Agreement. No assignment of this Agreement or of any rights or obligations hereunder may be made by Enron or PGE (by operation of law or otherwise) without the prior written consent of the other party hereto and any attempted assignment without the required consents shall be void.

5.14 Counterparts. This Agreement may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

[The remainder of this page is intentionally left blank]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, as of the date first written above.

ENRON CORP.

By: ______________________________
Name: [________]
Title: [________]

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________________
Name: [________]
Title: [________]

AMENDED AND RESTATED OPERATING AGREEMENT
OF
STEPHEN FORBES COOPER, LLC

This AMENDED AND RESTATED OPERATING AGREEMENT ("Agreement") is entered into as of the 4th day of September, 2002, by and among the persons referred to in Section 1.3 hereof (the "Members"), in their capacity as Members of Stephen Forbes Cooper, LLC, a limited liability company organized and existing under the laws of the State of New Jersey (the "Company"),

BACKGROUND

A. Pursuant to that certain Operating Agreement of Stephen Forbes Cooper, LLC dated as of January 29, 2002 (the "Initial Operating Agreement"), by and among the individuals therein, those individuals formed a limited liability company organized and existing under the laws of the State of New Jersey to transact in such business as the Members may determine from time to time.

B. The Members wish, by this Agreement, to amend and restate the terms of the Initial Operating Agreement to clarify the purpose of the Company and the administration of the business and affairs of the Company.

NOW THEREFORE, in consideration of the mutual promises herein contained and intending to be legally bound hereby, the parties hereto agree as follows:

ARTICLE I

GENERAL PROVISIONS

1.1 Name. The name of the Company shall be:

Stephen Forbes Cooper, LLC

1.2 Place of Business. The principal office of the Company shall be located at 101 Eisenhower Parkway, Roseland, New Jersey 07068. The Company shall have offices at such other localities within or without the State of New Jersey as may be agreed upon by the Members who hold a majority of the Votes (as defined in Section 1.7 hereof),

1.3 Members. The Company shall have Members which shall consist of the following natural persons; Stephen Forbes Cooper ("Cooper"), Michael Earl France and Leonard LoBiondo.

1.4 Term. This Agreement shall be effective as of September 4, 2002 (the "Effective Date") and shall continue in force until terminated in accordance with the provisions of Article VI.

1.5 Purposes. The Company shall be a limited liability company under the New Jersey Limited Liability Company Act (the "Act"). The Company shall only transact such business as is required for the Company to perform its obligations under the Agreement, dated as of January 30, 2002, between Enron Corp. and the Company (the "Enron Engagement") and the Services Agreement, dated as of January 29, 2002, between Zolfo Cooper, LLC and the Company ("Services Agreement").

1.6 Business Expenses. It shall be each Member's responsibility to incur expenditures in the conduct of Company business and in furtherance of the Company's interests, including expenditures for business transportation, telephone, meals and other expenses while traveling away from home on matters related to the Company.

1.7 Voting and Management. As used in this Agreement, each Member shall have a vote (the "Vote") equal to the Member's nominal percentage in the Company (a Member's "Percentage Interest"). The initial Percentage Interests of the Members are as set forth on Exhibit A hereto. The right of a Member to vote terminates under the circumstances specified in Section 4.1 hereof.

(a) Except as otherwise provided in Article IV hereof, no Member shall, without the unanimous affirmative Vote of the Members:

(1) terminate a Member's interest or participation as such under this Agreement prior to the dissolution and winding up of the Company;

(2) admit additional Members to the Company; or

(3) pledge, transfer, assign, mortgage, hypothecate or in any manner encumber any Member's rights or interests under this Agreement.

(b) The majority affirmative Vote of all of the Members and the affirmative vote of the Independent Manager shall be required for the Company or any Member on behalf of the Company to:

(1) file, consent to the filing of or join in any filing of a bankruptcy or insolvency petition or otherwise institute insolvency proceedings;

(2) dissolve, liquidate, consolidate, merge or sell all or substantially all of the Company's assets;

(3) purchase the assets of any person or entity;

(4) engage in any business activity other than as set forth in Section 1.5;

(5) borrow money in the Company's name for Company purposes or utilize property owned by the Company as security for such loans;

(6) assign, transfer, pledge, compromise or release any of the claims or debts due the Company except upon payment in full;

(7) make, execute or deliver any assignment on behalf of the Company for the benefit of creditors or any bond, confession of judgment, chattel mortgage, deed, guarantee, indemnity bond or surety bond; or

(8) lease or mortgage any Company real estate or any interest therein or enter into any contract for such purposes.

1.8 Manager; Independent Manager. (a) The day-to-day management of the Company's business shall be the responsibility of the Manager, which shall initially be Cooper until the voting interest of Cooper in the Company is terminated pursuant to Section 4.1 of Article IV, or until Cooper is, for any other reason, unable or unwilling to act as Manager, following which the Members shall annually elect, by majority Vote, a Manager, provided no Manager so elected may serve for more than five (5) consecutive terms. The duties of the Manager shall include those management duties and powers normally exercised by the Chief Executive Officer of a business.

(b) The Members agree to elect any person designated by Kroll Inc. ("Kroll") reasonably acceptable to the Members to act as the Independent Manager. The Independent Manager shall hold office until a successor is duly elected by the majority Vote of Members, subject to the approval of Kroll. The Independent Manager may resign at any time upon written notice to the Company and may be removed, with or without cause, at any time by the unanimous Vote of Members, with the approval of Kroll, and a successor Independent Manager shall be appointed by the majority Vote of Members, subject to the approval of Kroll; provided, however, no resignation or removal of the Independent Manager shall be effective until a successor Independent Manager shall have accepted the appointment as Independent Manager.

(c) Except as otherwise expressly limited herein, the Manager shall have the power to take such actions and enter into such agreements on behalf of the Company as the Manager shall determine to be necessary or desirable. Except as otherwise provided herein, no Person other than the Manager or persons designated by the Manager shall have any right to take any action on behalf of the Company or otherwise bind the Company. Unless otherwise agreed to in writing, the Manager shall be the "tax matters partner" for the purposes of the Internal Revenue Code of 1986, as amended (the "Code").

(d) Reasonable expenses incurred by the Manager, either directly or in the name of the Company, for the management or operation of the Company or in connection with the property or business of the Company shall be paid by the Company in accordance with the Company's reimbursement policy prior to any distributions to Members.

1.9 The Company, its receiver and its trustee, if any, shall, to the fullest extent permitted by applicable law, indemnify, save harmless and pay all judgments and claims against the Manager or Independent Manager relating to any liability or damage incurred by reason of any act performed or omitted to be performed by the Manager or Independent Manager arising from or relating to the taking of any action within the scope of authority conferred to it by this Agreement and made in good faith, including reasonable attorneys' fees and disbursements incurred by the Manager or Independent Manager in connection with the defense of any action based on any such act or omission, which reasonable attorneys' fees and disbursements may be paid as incurred. Any indemnity under this Section 1.9 or otherwise shall be paid out of and to the extent of the Company's assets only.

1.10 Notwithstanding the provisions of Section 1.9, no Manager or Independent Manager shall be indemnified for any liability arising out of its fraud, gross negligence or willful misconduct.

1.11 Company Books. Fiscal Year. Quarterly and annual profit and loss statements and balance sheets of the Company, including a statement of each Member's Account, shall be prepared by the Company and distributed to the Members. The Company's books shall be kept on the accrual basis of accounting but the federal and state income tax returns of the Company shall be prepared and filed on the cash basis of accounting. The Company's fiscal year for both financial reporting and tax purposes shall end on December 31st of each year. All Members shall have access to the Company's books and records during normal business hours and upon reasonable notice to the Manager.

1.12 Bank Accounts. The Company shall maintain a bank account or bank accounts in such banks or depositories as the Manager may direct in the Manager's sole discretion.

ARTICLE II

ACCOUNTS

2.1 Capital Account Contributions. Each Member shall be required to make a combination of cash contributions of capital and loans to the Company in an amount which equals the Member's Percentage Interest.

2.2 Accounts. A separate capital account shall be maintained for each Member. (The Member's capital accounts are sometimes collectively referred to hereinafter as "Accounts.") The Accounts shall reflect each Member's capital contributions and share of the Company's profits and losses.

2.3 Allocation of Profit and Loss. The profits and losses of the Company for each Company fiscal year shall be allocated to the Account of each Member according to each Member's Profit Percentage (as herein defined) as of the beginning of each such Company fiscal year. The allocation to each Member's Account shall be made within ninety (90) calendar days of the end of the Company's fiscal year. All items of depreciation, gain, loss, deduction or credit shall, for tax purposes, be allocated according to the Member's Profit Percentages.

2.4 Member's Profit Percentages.

The Profit Percentages of the Members shall be memorialized by an annual letter from the Manager to each Member, setting forth that Member's Profit Percentage.

2.5 Net Profits. As used in this Agreement, "net profits" shall mean profits resulting from the operations of the Company (i.e., gross income less business expenses) as determined in accordance with generally accepted accounting principles on the accrual method of accounting; or in a method consistent with prior years even if not in accordance with generally accepted accounting principles.

ARTICLE III

DISTRIBUTION TO MEMBERS- INSURANCE EXPENSES

3.1 Distribution. Other than as expressly provided in Section 3.2, Members will not be entitled to any distributions prior to the dissolution of the Company. All such distributions shall be made by the Manager in accordance with Section 5.2.

3.2 Mandatory Tax Distributions. On or prior to March 15 following the end of each fiscal year of the Company, and at such other times as the Manager deems appropriate, the Manager shall cause the Company to distribute to each Member an amount equal to such Member's Required Tax Amount out of Net Cash From Operations. To the extent that there is not sufficient Net Cash From Operations to distribute the full amount of each Member's

Required Tax Amount, but there is some Net Cash From Operations, the Net Cash From Operations shall be distributed to each Member in proportion to each Member's Required Tax Amount. If for any fiscal year the amount of any Member's Required Tax Amount exceeds the aggregate amounts distributed to such Member pursuant to this Section 3.2 (such excess hereinafter referred to as a "Tax Amount Shortfall"), then prior to making any distributions of Net Cash From Operations in any subsequent fiscal year, the Company shall distribute any Net Cash From Operations first to each Member in an amount equal to such Member's Tax Amount Shortfall.

3.3 Definitions. Capitalized terms used in Section 3.2 have the following meanings:

"Effective Tax Rate" means, with respect to any Member, the highest marginal combined effective tax rate of federal and applicable state and local individual income taxes for any fiscal year of the Company..

"Net Cash From Operations" means the gross cash proceeds from Company operations (including sales and dispositions in the ordinary course of business) less the portion thereof used to pay or establish reasonable reserves for all Company Expenses, debt payments, capital improvements, replacements and contingencies, all as determined by the Manager. "Net Cash From Operations" shall not be reduced by depreciation, amortization, cost recovery deductions or other similar allowances, but shall be increased by any reductions of reserves previously established pursuant to the first sentence of this definition and the definition of "Net Cash From Sales or Refinancings."

"Net Cash From Sales or Refinancings" means the net cash proceeds from all sales and other dispositions (other than in the ordinary course of business) and all refinancings of

Company property (in each case other than in connection with or in contemplation of a Liquidation Event or an acquisition), less any portion thereof used to establish reasonable reserves, all as determined by the Managers. "Net Cash From Sales or Refinancings" shall include all principal and interest payments with respect to any note or other obligation received by the Company in connection with sales and other dispositions of Company property.

"Required Tax Amount" for any Member in respect of any fiscal year of the Company means the product of (x) the Effective Tax Rate for such fiscal year multiplied by (y) the Net Income attributable to Company operations (including sales and dispositions in the ordinary course of business) and other items of income and gain attributable Company operations (including sales and dispositions in the ordinary course of business), if any, allocated to such Member in such year.

3.4 Expenses. All Members shall be reimbursed in accordance with the Company's reimbursement policy as determined by the Manager for business expenses that are incurred in the normal transaction of business for the betterment of the Company, including without limitation, expenses incurred pursuant to Article I, Section 1.6 hereof.

ARTICLE IV

TERMINATION OF A MEMBER'S VOTING RIGHTS

4.1 Involuntary Termination.

(a) A Member's voting rights in the Company shall terminate:

(1) On the Member's death;

(2) For cause, as such cause may be reasonably determined by the majority of the Members (other than the Member being terminated);

(3) On the Member's total disability for an aggregate of one hundred twenty (120) days within any period of twelve (12) consecutive months as determined

by both (i) the Company's disability insurance carrier and (ii) the unanimous Vote of the remaining Members. The period of disability shall not begin until the disabled Member receives notice from the Company of the determination of such total disability; or

(4) On the unanimous Vote of all Members, except the Member subject to the vote, to suspend the Member's voting rights for any of the following reasons: habitual intoxication; drug addiction (excluding cigarette usage); illegal gambling; conviction of a felony; adjudication as an incompetent; misconduct or willful inattention to the business or welfare of the Company which injures the business of the Company; material violation of any provision of this Agreement; insolvency or bankruptcy; or assignment of his assets for the benefit of creditors. Notice of such suspension of voting rights shall be given in writing immediately to the suspended Member and the voting rights of the Member in the Company shall be deemed suspended as of the date of the notice, provided, however, that:

(i) Suspension of the voting rights of a Member, under this subsection 4.1(a)(4) due to the following shall be automatic, requiring no further action of the Members:

(A) Conviction of a felony;

(B) Adjudication as an incompetent; or

(C) Insolvency or bankruptcy or assignment of his assets for the benefit of creditors.

The Members may, however, by unanimous Vote, elect to suspend the automatic suspension provision of this subsection 4.1(a)(4)(i).

(ii) Suspension of the voting rights of a Member under this subsection 4.1(a)(4) due to the following shall not be automatic and shall require the unanimous Vote of all

Members, except the Member subject to the Vote, in order to suspend the voting rights of the Member:

(A) Habitual intoxication;

(B) Drug addiction (as specified in subsection 4.1(a)(4));

(C) Illegal gambling;

(D) Misconduct or willful inattention to the business or welfare of the Company which injures the business of the Company;

(E) Material violation of any provision of this Agreement; or

(F) The unanimous Vote of all Members and the affirmative vote of the Independent Manager, except the Member subject to the vote, for any other grounds whatsoever.

4.2 Effect of Termination of Voting Rights. Upon the occurrence of any of the events specified in Section 4.1, all of the rights of the Member who is affected by the provisions of Section 4.1 to participate in the management, decision making and/or control of the Company shall cease, effective as of the date of the first occurrence of any event specified in Section 4.1. The suspended Member's rights under this Agreement shall be limited to:

(a) The right to the economic benefits and liabilities specified in Sections 2.3 and 2.5 of this Agreement; and

(b) The right to receive quarterly and annual profit and loss statements and balance sheets of the Company and to have access to the Company's books and records, as specified in Section 1.9 of this Agreement.

The suspended Member shall continue to be subject to all duties and obligations to the Company and the other Members specified in this Agreement, including, without limitation, Sections 6 and 8 of this Agreement.

ARTICLE V

DISSOLUTION AND LIQUIDATION OF THE COMPANY

5.1 Dissolution. The Company shall dissolve upon the first to occur of the following:

(a) completion of the Company's obligations and receipt of all amounts payable under the Enron Engagement and the Services Agreement;

(b) the unanimous Vote of the Members and the affirmative vote of the Independent Manager; or

(c) the entry of a decree of judicial dissolution by the Superior Court for the State of New Jersey.

The Manager shall act as the liquidator of the Company and shall liquidate the Company pursuant to the terms of this Agreement. The Manager shall be entitled to reasonable compensation, as fixed by the Members by majority Vote, for services performed as the liquidator of the Company.

5.2 Liquidation. Upon dissolution of the Company by unanimous Vote of all Members with power and authority to vote and the affirmative vote of the Independent Manager, the Manager shall expeditiously liquidate the Company. The Manager shall wind up the affairs of the Company and, after payment or provision for payment of obligations to third parties and the provision for the maintenance and final distribution of Company records as provided in Section 5.3 hereof, shall cause the net proceeds of liquidation to be distributed in the order of priority determined pursuant to the Act.

5.3 Books. Records and Files. Upon dissolution and liquidation, all books and records of the Company, and all client files (unless otherwise transferred) shall be retained by the Manager for a period of five (5) years after the calendar year in which dissolution occurred. All such books, records and files shall be available to any Member for any purpose during such five year period. Thereafter, any of such books, records and files may be transferred or destroyed as the Members shall agree by majority Vote of the Members and the affirmative vote of the Independent Manager.

ARTICLE VI

CONFIDENTIAL INFORMATION

6.1 Confidential Information. The Members agree that, in consideration of the opportunities afforded to each of them by their association with the Company pursuant to this Agreement and payments to be made by the Company, upon the termination of the voting rights of a Member's interest in the Company herein, for any reason (each a "Terminating Event"), any terminated Member shall not, without the prior written consent of the Independent Manager, disclose, for any reason or purpose whatsoever, any Confidential Information (as herein defined) to any person or entity.

For the purposes of this Agreement, "Confidential Information" shall mean, without limitation, the affairs, trade secrets, lists, methods and systems, techniques and methods of operations and other proprietary information of the Company including, without limitation: (i) the lists of present, former and potential accounts of any affiliate of the Company and/or the services rendered, strategies, disposition programs and all opportunities relating to the creation of value for the Company and/or any of its affiliates; (ii) unique marketing and technical information and systems developed by and for the Company and/or any of its affiliates; and (iii) records, notes and other information concerning present and former projects and the business affairs of the Company and/or any of its affiliates.

ARTICLE VII

- ADDITIONAL COMPANY OBLIGATIONS

7.1 Professional Liability Insurance. The Company may purchase and maintain professional liability insurance in the aggregate and per claim amount of $10,000,000, or such lesser sum as the majority of Members may elect. The Company shall also purchase and maintain such professional liability coverage or endorsements as will continue, without interruption, professional liability insurance coverage and directors and officers liability insurance coverage for all Members. It shall not be required of the Company to purchase and maintain separate additional professional liability insurance for terminated Members; rather, it is the intent that the Company shall be obligated to effectuate the continuation of coverage, by way of the purchase of so-called "tail" coverage, by endorsement or otherwise, for the benefit of those terminated Members specified in this Section following their termination.

ARTICLE VIII

MISCELLANEOUS

8.1 Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of each of the Members and such Member's successors and permitted assigns, executors, administrators, heirs and legal representatives. Each and every successor in interest to any Member, however such successor acquires such interest, shall hold such interest subject to all of the terms and provisions of this Agreement. It is the intention of the Members that during the term of this Agreement, the rights of the Members and their successors in interest shall be governed by the terms of this Agreement.

8.2 Indemnification. Any Member found by a court of competent jurisdiction to be grossly negligent or guilty of willful misconduct in the conduct of Company affairs shall indemnify and hold the Company and each of the other Members harmless for any costs or expenses, including attorneys' fees resulting or incurred as a result of such Member's conduct, and the Company shall be entitled to deduct from such Member's Account or offset against any amounts owed by the Company to such Member any indemnity amount due from such Member.

8.3 Amendments. Any proposed amendment to this Agreement must be approved by a majority Vote of Members and the affirmative vote of the Independent Manager.

8.4 Prohibited Activities. Without the prior written consent of a majority of the Votes of all Members and the affirmative vote of the Independent Manager, no Member may:

(a) Engage in any activity which may put such Member's or the Company's professional liability insurance at risk; or

(b) Engage in any activity which may put such Member's accounting license at risk.

8.5 Headings; Pronouns; Enforceability. The paragraph headings are used for convenience only and shall not be utilized to assist in the interpretation of this Agreement. Wherever the context so requires, the masculine shall include the feminine and neuter and the singular shall include the plural. If any portion of this Agreement is held to be void or unenforceable, the balance of this Agreement shall continue to be valid and enforceable in law or in equity.

8.6 Notices. All notices provided for under this Agreement shall be in writing and shall be sufficient if sent by registered mail to the last address on file with the Company of the party to whom such notice is to be given.

8.7 Waivers. No forbearance to enforce any provision of this Agreement or waiver of any breach hereof shall be deemed a waiver of any such provision or right hereunder or of any subsequent breach or default.

8.8 Entire Agreement. This Agreement sets forth the entire understanding and agreement among the Members with respect to the subject matter hereof. No amendment of this Agreement shall be effective unless embodied in a written instrument executed by all of the Members.

8.9 Governing Law. This Agreement shall be governed by and construed in accordance with the internal laws of the State of New Jersey, without regard to conflicts of laws principles.

IN WITNESS WHEREOF, the Members have executed this Amended and Restated Operating Agreement as of the day and year first above written.

Stephen Forbes Cooper

Michael Earl France

Leonard LoBiondo

EXHIBIT A

Initial Capital Contributions and Percentage Interests

Name of Member	Initial Capital Contribution	Initial Percentage Interest
Stephen Forbes Cooper	$100	50%
Michael Earl France	$50	25%
Leonard LoBiondo	$50	25%
Total:	**$200**	**100%**

SERVICES AGREEMENT

THIS SERVICES AGREEMENT (this "Agreement") is made as of the 29th day of January, 2002, by and between ZOLFO COOPER, LLC, a New Jersey limited liability company ("ZCLLC") and STEPHEN FORBES COOPER, LLC, a New Jersey limited liability company ("SFCLLC"). Each of ZCLLC and SFCLLC is sometimes referred to herein individually as a "Company" and together, as the "Companies."

WITNESSETH:

WHEREAS, the Companies are engaged in the provision of business advisory, consulting and interim management services to the business community; and

WHEREAS, the Companies wish to enter into an administrative services and "shared employee" arrangement, pursuant to which certain individuals would provide services to and on behalf of each Company from time to time, and would be considered employees of a particular Company only when and to the extent that such individuals are performing services on behalf of such Company and certain related administrative services will be performed by ZCLLC for SFCLLC;

NOW, THEREFORE, in consideration of the premises, covenants, representations and agreements contained herein, and intending to be legally bound hereby, the parties hereto agree as follows:

1. Shared Employee Services. The individuals employed by each Company from time to time are hereinafter referred to as the "Employees." The Companies hereby agree that the Employees may provide services to and on behalf of one or more of the Companies from time to time, as the Companies shall mutually agree, and subject to and in accordance with the terms and provisions of this Agreement. An Employee shall be deemed to be an employee of a Company at all times during which such Employee is performing services to or on behalf of such Company, but at no other time shall such Employee be considered an employee of such Company. For ease of administration, ZCLLC shall be responsible for all administrative functions relating to the Employees including the payment of the Employees' compensation, benefits and applicable taxes attributable to the services provided to SFCLLC by the Employees.

2. Additional Administrative Services and Support. ZCLLC shall provide additional administrative services and support to SFCLLC as necessary to support SFCLLC's provision of services to its customers including, but not limited to, the reasonable use of ZCLLC's offices, computers, copiers, fax machines, telephones and other communications systems, office supplies and human resource, accounting, billing, finance and secretarial services.

3. Supervision and Control. Each Company shall retain the exclusive right to supervise and control the Employees in the performance of their duties for such Company.

4. Assignment. This Agreement is expressly for the benefit of the parties hereto, and it shall not be assigned by any party without the prior written consent of each of the other parties hereto.

5. Term of Agreement. This Agreement shall commence on the date hereof and shall remain in full force and effect with respect to each Company until terminated by such Company by giving to the other Company at least 30 days prior written notice of its intent to terminate, provided, however, that this Agreement may not be terminated by SFCLLC without the consent of ZCLLC prior to the termination of that agreement dated as of January 30, 2002 between SFCLLC and Enron Corp., a copy of which is attached hereto as Exhibit A. This Agreement may also be terminated at any time upon the mutual agreement of the Companies.

6. Fees. In consideration for ZCLLC's entering into this Agreement and providing administrative services to SFCLLC, and in recognition of the substantial value of the Employees to ZCLLC, SFCLLC shall pay to ZCLLC, immediately upon request from ZCLLC, a fee equal to one hundred percent (100%) of all fees, including success fees, paid to SFCLLC by its customers, including, but not limited to, Enron Corp. Such fees shall be net of all fees refunded or otherwise returned by SFCLLC to its customers and their estates and ZCLLC shall pay SFCLLC its pro rata share of all such refunded or otherwise returned fees. SFCLLC shall also pay ZCLLC, immediately upon request from ZCLLC, an amount equal to all expense reimbursements paid to SFCLLC by its customers to the extent such expenses were incurred by ZCLLC.

7. Work Environment. The Companies agree to comply with all federal, state and municipal safety and health regulations, laws, directives and ordinances as are applicable to the Employees.

8. Integration. This Agreement embodies the final and complete expression of the intentions of the parties hereto with regard to the subject matter hereof. There are no other prior or contemporaneous oral agreements, representations, covenants, promises and/or undertakings relating to such subject matter.

9. Choice of Law. It is understood and agreed to by the parties hereto that the validity of this Agreement and the parties' performance of their respective obligations hereunder shall be governed by the applicable laws of the State of New Jersey, without regard to conflicts of laws principles.

10. Contractual Relationship. The Companies hereby covenant and agree that none of them is the employee, employer, principal or agent of the other, and no Company shall have any authority to bind or commit any other Company to any contract or to incur any expense on behalf of such other Company. Nothing in this Agreement is intended, and nothing herein shall be

construed, to create an employer/employee relationship, a partnership or a joint venture relationship between or among any of the Companies.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day, month and year first above written.

ZOLFO COOPER, LLC

By:________________________
Name: Stephen Forbes Cooper
Title: Manager

STEPHEN FORBES COOPER, LLC

By:________________________
Name: Stephen Forbes Cooper
Title: Manager

(g) Prior and Subsequent Bankruptcy Court Orders Regarding Non-Conforming Distributions: For purposes of calculating distributions to be made in accordance with Section 32.1 of the Plan, including, without limitation, the payment of Allowed Claims in full, the Debtors, the Reorganized Debtors, the Disbursing Agent and the Reorganized Debtor Plan Administrator shall take into account those payments made or to be made to holders of Allowed Enron Senior Note Claims and Allowed Enron Subordinated Debenture Claims pursuant to the provisions of prior or subsequent orders of the Bankruptcy Court.

32.2 **Timeliness of Payments**: Any payments or distributions to be made pursuant to the Plan shall be deemed to be timely made if made within twenty (20) days after the dates specified in the Plan. Whenever any distribution to be made under this Plan shall be due on a day other than a Business Day, such distribution shall instead be made, without interest, on the immediately succeeding Business Day, but shall be deemed to have been made on the date due.

32.3 **Distributions by the Disbursing Agent**: All distributions under the Plan shall be made by the Disbursing Agent at the direction of the Reorganized Debtor Plan Administrator. The Disbursing Agent shall be deemed to hold all property to be distributed hereunder in trust for the Persons entitled to receive the same. The Disbursing Agent shall not hold an economic or beneficial interest in such property.

32.4 **Manner of Payment under the Plan**: Unless the Entity receiving a payment agrees otherwise, any payment in Cash to be made by the Reorganized Debtors shall be made, at the election of the Reorganized Debtors, by check drawn on a domestic bank or by wire transfer from a domestic bank; provided, however, that no Cash payments shall be made to a holder of an Allowed Claim or an Allowed Equity Interest until such time as the amount payable thereto is equal to or greater than Ten Dollars ($10.00).

32.5 **Delivery of Distributions**: Subject to the provisions of Rule 9010 of the Bankruptcy Rules and the TOPRS Stipulation, and except as provided in Section 32.4 of the Plan, distributions and deliveries to holders of Allowed Claims shall be made at the address of each such holder as set forth on the Schedules filed with the Bankruptcy Court unless superseded by the address set forth on proofs of claim filed by such holders, or at the last known address of such a holder if no proof of claim is filed or if the Debtors has been notified in writing of a change of address. Subject to the provisions of Section 9.1 of the Plan and the TOPRS Stipulation, distributions for the benefit of holders of Enron Senior Notes shall be made to the appropriate Enron Senior Notes Indenture Trustee. Each such Enron Senior Note Indenture Trustee shall in turn administer the distribution to the holders of Allowed Enron Senior Note Claims in accordance with the Plan and the applicable Enron Senior Notes Indenture. The Enron Senior Notes Indenture Trustee shall not be required to give any bond or surety or other security for the performance of their duties unless otherwise ordered by the Bankruptcy Court.

32.6 **Fractional Securities**: No fractional shares of Plan Securities shall be issued. Fractional shares of Plan Securities shall be rounded to the next greater or next lower number of shares in accordance with the following method: (a) fractions of one-half (1/2) or greater shall be rounded to the next higher whole number, and (b) fractions of less than one-half (1/2) shall be rounded to the next lower whole number. The total number of shares or interests of Plan Securities to be distributed to a Class hereunder shall be adjusted as necessary to account for the

ENCLOSURE (2)

NAMES, ADDRESSES, AND CITIZENSHIP OF THE OVERSEERS OF THE RESERVE FOR DISPUTED CLAIMS

DCR Overseers

The current DCR Overseers are as follows:

Name	Address	Citizenship
Stephen D. Bennett	10650 Yankee Ridge Drive Frankfort, IL 60423	U.S.
Robert M. Deutschman	100 Wilshire Blvd. Santa Monica, CA 90401	U.S.
Rick A. Harrington	40022 North 111th Place Scottsdale, AZ 85262	U.S.
James R. Latimer, III	2602 McKinney Avenue Dallas, TX 75204	U.S.
John J. Ray, III	280 Schuman Blvd. Naperville, IL 60563	U.S.

ENCLOSURE (3)

NAMES, ADDRESSES, AND CITIZENSHIP OF THE CURRENT MEMBERS OF THE PGE BOARD OF DIRECTORS AND PRINCIPAL OFFICERS

PGE Board of Directors

The current board of directors of PGE is composed as follows:

Name	Address	Citizenship
John W. Ballantine	1500 North Lake Shore Drive Chicago, IL 60610	U.S.
Robert S. Bingham	At Enron Corp 1221 Lamar, Suite 1600 EB 5011 Houston, TX 77010	U.S.
Peggy Y. Fowler	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Corbin A. McNeill, Jr.	Skyline Ranch #8 525 NW Ridge Road Jackson Hole, WY 83001	U.S.
Raymond S. Troubh	Ten Rockefeller Plaza, Suite 712 New York, NY 10020	U.S.
Robert H. Walls, Jr.	771 Kuhlman Road Houston, TX 77024	U.S.

PGE Principal Officers

The current principal officers of PGE are as follows:

Name	Address	Citizenship
Peggy Y. Fowler Chief Executive Officer & President	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
James J. Piro Executive Vice President, Finance, Chief Financial Officer & Treasurer	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Arleen Barnett Vice President, Administration	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Carol A. Dillin Vice President, Public Policy	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Stephen R. Hawke Vice President, Customer Service & Delivery	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S
Ronald W. Johnson Vice President, Business & Government Customers; Economic Development	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Pamela G. Lesh Vice President, Regulatory Affairs & Strategic Planning	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
James F. Lobdell Vice President, Power Operations & Resource Planning	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.

Name	Address	Citizenship
Joe A. McArthur Vice President, Distribution	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Douglas R. Nichols Vice President, General Counsel & Secretary	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Stephen M. Quennoz Vice President, Nuclear & Power Supply / Generation	Portland General Electric Company 121 SW Salmon Street 1WTC 17 Portland, OR 97204	U.S.
Kirk M. Stevens Controller and Assistant Treasurer	Portland General Electric Company 121 SW Salmon Street 1WTC 05 Portland, OR 97204	U.S.
William J. Valach Assistant Treasurer	Portland General Electric Company 121 SW Salmon Street 1WTC 04 Portland, OR 97204	U.S.
Steven F. McCarrel Assistant Secretary	Portland General Electric Company 121 SW Salmon Street 1WTC 13 Portland, OR 97204	U.S.
J. Mack Shively Assistant Secretary	Portland General Electric Company 121 SW Salmon Street 1WTC 13 Portland, OR 97204	U.S.

ENCLOSURE (4)

OPUC ORDER NO. 95-322, ENTERED MARCH 29, 1995
IN DOCKET UE 88

ORDER NO. **95-322**

ENTERED MAR 29 1995

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 88

In the Matter of the Revised Tariff	)	
Schedules for Electric Service in Oregon	)	ORDER
filed by PORTLAND GENERAL	)	
ELECTRIC COMPANY.	)	

TABLE OF CONTENTS

APPENDICES

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GLOSSARY
OF ABBREVIATIONS

A&G	Administrative and general
BPA	Bonneville Power Administration
BWR	Boiling water reactor
CO_2	Carbon dioxide
CP	Coincident peak
CUB	Citizens' Utility Board
DSM	Demand-side management
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
HVEA	High-value electrical applications
KW	Kilowatt
KWh	Kilowatt hour
LCP	Least-cost plan
LRIC	Long-run incremental cost
MTI	Maintenance Team Inspection
MW	Megawatt
MWh	Megawatt hour
NCP	Noncoincident peak
NRC	Nuclear Regulatory Commission
NWPPC	Northwest Power Planning Council
O&M	Operations and maintenance
OCEUR	Oregon Committee for Equitable Utility Rates
ODOE	Oregon Department of Energy
PGC	Portland General Corporation
PGE	Portland General Electric Company
PPC	Public Power Council
PWR	Pressurized water reactor
QA	Quality assurance
SALP	Systematic Assessment of Licensee Performance
TBA	Theodore Barry & Associates
TMI	Three-Mile Island
URP	Utility Reform Project
USDOE	United States Department of Energy

ORDER NO. 95-32
ENTERED MAR 29 1995

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 88

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY.	))))	ORDER

SUMMARY

This order approves new rate schedules for Portland General Electric Company (PGE). Under the new schedules, PGE's rates increase approximately 5.8 percent overall. PGE's original filing, which included a proposal to accelerate the Boardman gain amortization, sought an increase in revenues of $58,974,927 for 1995, and $60,783,781 for 1996. PGE subsequently withdrew its Boardman proposal, which increased the company's revenue need to $92,275,240 in 1995 and $95,105,468 in 1996. In this order, the Commission grants PGE an increase in revenues of $50,970,243 for 1995 and $51,812,359 for 1996.

Undepreciated Trojan Investment. The dominant issue in this docket is the allocation of undepreciated investment and other costs resulting from the premature closure of the Trojan Nuclear Power Plant (Trojan).

In January 1993, PGE retired the 1200 megawatt (MW) plant, which was licensed to operate until 2011. Degradation of the plant's steam generator tubes led PGE to retire the plant 19 years before the expiration of its 35-year license life. As of January 1, 1995, PGE's net undepreciated investment in Trojan totaled approximately $288 million. In this proceeding, PGE seeks full recovery of and return on that undepreciated investment, plus other costs related to service.

We reject PGE's request for full recovery of Trojan costs. We conclude that the allocation of the Trojan costs is properly determined by a "net benefits" analysis. A net benefits analysis compares the costs of a plant's continued operation with the costs associated with retiring the plant plus the expected long-term costs of replacing the plant's output. The purpose of a net benefits test is to identify the point at which ratepayers are indifferent between the options of continued operation of Trojan and shutdown and construction or acquisition of replacement resources.

• Full recovery of undepreciated Trojan costs is not guaranteed to PGE, nor is it required of the Commission. Granting full recovery in rates where there is not a net benefit to ratepayers would insulate the utility from risk no matter what its actions. On the other hand, granting no recovery of undepreciated investment would not encourage PGE to engage in prudent management and responsible least-cost planning, goals the Commission wishes to promote. The net benefits analysis is a tool to determine where ratepayers are held harmless for imprudent operation or management of Trojan, and to share costs between ratepayers and shareholders on that basis.

The Commission staff (staff) conducted a net benefits analysis, using PGE's least-cost plan (LCP) as a starting point. The final result of PGE's least-cost planning process indicated that immediately closing Trojan was the least-cost option. The LCP, however, considered the plant as it actually existed and projected those costs forward to 2011. To determine whether there was a net benefit to ratepayers from closing Trojan, staff sought to determine whether the costs on which PGE's least-cost planning process was based would have been allowed in rates. If PGE's LCP projections were based on costs that had been driven up by management problems, for instance, the net benefits analysis would disallow the costs if they were imprudently incurred.

Staff hired an independent consulting firm, Theodore Barry and Associates (TBA), to evaluate whether the costs of operating Trojan were prudently incurred. TBA assessed the reasonableness of PGE's operation and management of Trojan from the plant's initial commercial operation in 1976 through its current delicensing and decommissioning activities. TBA explored Trojan's comparative performance, reviewed management issues, and analyzed the steam generator issue. Its examination focused on whether PGE's actions, based on all the information PGE knew or should have known at the time, were reasonable and prudent in light of all the circumstances. TBA did not base conclusions on hindsight or knowledge acquired after the fact, and recognized that one or more courses of action may be reasonable in a given set of circumstances.

TBA also quantified the effects of PGE's management and operation deficiencies, and staff projected TBA's figures out over the period from 1995 to 2011, a period beginning with the first test year in this rate case and running through Trojan's originally scheduled closure. Staff compared these imputed costs with the cost of replacement resources to determine whether there was a net benefit from closing Trojan.

After an examination of the net benefits analysis, we conclude that the premature closure of Trojan resulted in a negative net benefit of approximately $20.4 million. We find that continued operation of Trojan would have cost less than immediate shutdown but for steam generator defects and management problems at Trojan. Management problems resulted in avoidable costs that should be borne by shareholders, not ratepayers.

We adopt TBA's finding that PGE behaved prudently with respect to the steam generator degradation. However, we disallow the steam generator costs incurred since 1991 and exclude the cost of replacing the steam generators from the imputed costs of running Trojan in the net benefits analysis. Although PGE's behavior was not faulty, PGE and the ratepayers are the only two parties to whom we can assign or impute steam-generator costs. As between those two parties, PGE is better situated to recover its costs from the manufacturer of the steam generators. Moreover, it is fair that shareholders bear some of the consequences of management investment decisions.

To hold PGE's ratepayers harmless for the effects of steam generator defects and management failures, we are disallowing recovery in rates of $20.4 million of the company's remaining investment in Trojan.

Post-1991 Capital Expenditures. We also disallow PGE's post-1991 capital expenditures to repair Trojan's steam generators and costs for the purchase of a spare nuclear reactor coolant pump. Although we find that PGE acted prudently with regard to its maintenance and operation of the steam generators, PGE is better situated to pursue remedies for any manufacturing defects against Westinghouse, the steam generator manufacturer, than are the ratepayers. PGE's purchase of the spare reactor coolant pump was not prudent and will not be allowed in rates. These disallowances total an additional $17.1 million, for a total Trojan-related disallowance of $37.5 million.

These conclusions result in a disallowance of 13.0 percent of the remaining Trojan costs, which will be borne by shareholders, not ratepayers. That result approximates a scenario in which Trojan was reasonably operated and managed. In the main, the disallowances correct for avoidable costs.

Decommissioning and Transition Costs. In this order, we also approve funds to decommission Trojan and to pay for the transition to shutdown. Decommissioning costs are the costs of physically dismantling the plant and packaging and storing the radioactive components and spent fuel. Transition costs are the operations and maintenance (O&M) and administrative and general (A&G) costs associated with plant closure.

PGE would incur decommissioning and transition costs regardless of when the plant was taken out of service, and the company has already been paying into a decommissioning fund. Because Trojan was shut down before the end of its license life, however, payments into the fund will have to increase for a time. Even with the increase in annual contribution, PGE will have to borrow to bridge its needs. As currently estimated, however, the cash flows will eventually be sufficient to fund the cost of decommissioning including repayment of the interim financing.

PGE has submitted a decommissioning plan for approval by the Nuclear Regulatory Commission (NRC). We approve PGE's plan subject to our review and monitoring of costs. There are a great many unknowns as regards decommissioning, and we need to retain the flexibility to modify PGE's plan if circumstances change significantly.

Decoupling. Another major issue in this docket is decoupling. Decoupling is a mechanism that eliminates the automatic connection between utility sales and profits. Breaking that connection is designed to encourage utilities to find cost-effective ways of reducing sales and conserving energy. If sales are linked to profits, a utility has every incentive to keep sales, and hence energy consumption, high.

Decoupling creates a mechanism to adjust for actual sales deviating from a preestablished level. A utility cannot increase its earnings by increasing sales, because additional sales margins are returned to ratepayers and the utility's net revenues are reset to the preestablished level. If the utility's revenues are less than forecast, the decoupling mechanism would restore those lost margins so that net revenues are again adjusted to reflect the preestablished level. The company does not gain or lose net revenues by selling larger or smaller amounts of power. The key step in decoupling is to establish the revenue targets.

In Order No. 92-1673, the majority of the Commission directed PGE to develop a decoupling mechanism suitable to its circumstances. Working as part of a collaborative, PGE designed a process that uses a two-year test period to establish revenue targets and deals with monthly revenue benchmarks, weather normalization, rate spread, and other issues.

At issue in this docket is whether and how to implement decoupling. Some parties argue that decoupling has not proven to be as effective as hoped in other jurisdictions. Some contend that forecasting over the two-year test period introduces too much uncertainty. Other parties argue for decoupling, but suggest different ways of treating rate spread or other features of the collaborative's plan.

A majority of the Commission finds that decoupling should be implemented. It is a relatively simple mechanism to remove a variety of perverse incentives inherent in the existing structure of rate regulation and it has low administrative costs. Its benefits clearly outweigh its disadvantages. Chairman Smith writes separately in dissent on this issue.

We adopt the collaborative's mechanism, subject to certain reporting and monitoring requirements. The reporting requirements are designed to make it easier to administer and review the mechanism. The monitoring requirements are designed to protect ratepayers from the potential problem of a decline in the level of PGE's service.

Rate Spread. In setting electric utility rates, this Commission has traditionally been guided by the cost of serving various customer classes, as measured by marginal costs. The marginal cost study approved in this order indicates that commercial and industrial customers pay a higher rate relative to the costs of providing service than residential customers.

In this order, we reaffirm the use of a "4-to-1" rate spread methodology to help set rates more in line with the actual costs caused by each customer class. This 4-to-1 methodology, which was adopted in PGE's last general rate case (UE 79), assigns residential customers a percentage increase of four times that assigned to medium and large commercial and industrial customers. This rate spread methodology will not eliminate the current rate disparity, but will achieve a more balanced distribution of the costs of service without subjecting residential customers to rate shock.

Other Issues. Commission staff asked the Commission to impose on PGE an additional reduction in discretionary costs (operating and maintenance expense accounts excluding Trojan O&M, amortization of energy efficient balances, uncollectible accounts, regulatory expenses, and rents) if the Commission found that PGE's cost reduction efforts were insufficiently diligent in the circumstances. We have imposed an additional one percent cost reduction on PGE, which reduces PGE's revenue requirement by approximately $1.6 million in each test year.

Most other major issues in this docket were resolved by stipulation between staff and PGE. We have reviewed these stipulations carefully, find that they are reasonable, and adopt them.

Overview of PGE's cost structure. This proceeding used a two-year test period to comport with the decoupling approach suggested by PGE's collaborative on decoupling. Due to the closure of Trojan, PGE's cost structure has changed significantly. The major factor causing the rate change authorized by this order involves power supply costs. As compared with the costs adopted in PGE's last rate order (UE 79, Order No. 91-186), fixed operation and maintenance costs decrease by $49.8 million for 1995 and by $47.6 million for 1996. However, power supply costs increase by $147.7 million for 1995 and by $152.7 million for 1996. Both of these factors are affected significantly, but not exclusively, by the closure of Trojan. Other factors offset to some extent the increases in costs, notably a lower rate of return to stockholders due to more favorable capital markets. In addition, the Commission has disallowed certain of the unrecovered Trojan costs. The decision on the Trojan cost recovery issue has the effect of reducing PGE's request by $9.7 million for 1995 and by $9.3 million for 1996.

INTRODUCTION

Procedural Background

On November 9, 1993, PGE filed Advice No. 93-26, a general tariff revision designed to increase rates to its Oregon electric retail customers, to be effective December 8, 1993. PGE's proposed price schedules are based on the company's expected revenue requirement for a two-year test period covering 1995 and 1996. The two-year test period reflects the decoupling mechanism designed by PGE and a collaborative work group pursuant to Order No. 92-1673.

On December 7, 1993, we found good and sufficient cause to investigate the propriety and reasonableness of the rates and initially ordered the suspension of Advice No. 93-26 for a period of six months. *See* Order No. 93-1754. Shortly thereafter, PGE waived the statutory suspension period and, on June 1, 1994, we ordered a further suspension of the Advice until January 1, 1995. *See* Order No. 94-899.

Prehearing Conference

On December 13, 1993, Ruth Crowley, a Hearings Officer for the Commission, held a prehearing conference in Salem, Oregon, to identify parties and interested persons and to adopt a procedural schedule. A list of the parties to this proceeding is set forth in Appendix A.

Public Comment Hearings

In February 1994, we held public comment hearings in Portland, Gresham, Aloha, and Salem. At each hearing, a representative of PGE made an informal presentation explaining the terms of the proposed rate schedules and other aspects of the filing. A member of the Commission staff also appeared to explain staff's role in this proceeding and to answer questions from the public. Many PGE customers and interest groups attended the hearings and testified in opposition to the proposed rate increase. During the course of this proceeding, we also received numerous written comments from the public opposing PGE's proposed tariffs.

Bifurcation

On March 21, 1994, staff moved to amend the schedule and to defer examination of issues related to PGE's investment in the Trojan Nuclear Power Plant and cost of capital to a later phase of this proceeding. Staff requested the bifurcation to allow time to hire a consultant and time for the consultant to review Trojan-related issues.[1] On May 3, 1994, the Hearings Officers granted the motion and bifurcated this proceeding into Phase I and Phase II.

UM 692 and Further Extension of Suspension Period

On May 26, 1994, staff moved to further amend the schedule to allow additional time for its consultant to complete work. Staff concurrently filed a motion for an order authorizing PGE to use, upon the expiration of the suspension period, deferred accounting

[1] For purposes of this proceeding, Trojan-related issues are defined to include any issue encompassed by Docket No. DR 10, Order Nos. 93-1117 and 93-1763.

treatment for increased revenues resulting from the implementation of PGE's revised tariffs.

Staff subsequently withdrew its motions. On July 29, 1994, PGE applied to defer for later ratemaking treatment 40 percent of the increased power costs resulting from the closure of Trojan for the period from January 1, 1995, until March 31, 1995, or the effective date of new tariffs approved in this proceeding, whichever is earlier. We docketed PGE's application as UM 692 and consolidated it with this proceeding. On September 30, 1994, we granted PGE's request for deferral of costs. *See* Order No. 94-1456. With approval of its application, PGE agreed to stipulate to a further extension of the suspension period to no later than March 31, 1995.

PHASE I

Issues List

After a review of PGE's tariff filing, staff identified 44 potential issues in what has been designated as Phase I of this proceeding. Staff listed those issues numerically in its preliminary issues list, filed on May 3, 1994. We use staff's numbering system in our discussion of those issues. A complete issue list is found on page 1 of Appendix F, Adjustment Summary, attached.

Stipulations

On July 1, 1994, PGE and staff submitted a stipulation intended to resolve many of the disputed issues in this portion of the proceeding, subject to our approval. The stipulation is attached as Appendix B. The stipulation was supported by joint testimony of Ray Lambeth of staff and Kelley Marold of PGE on numerous revenue, expense and rate base issues.

On July 15, 1994, PGE and staff submitted a stipulation supplement intended to resolve additional disputed issues not covered in the first stipulation. The stipulation supplement is attached as Appendix C. The stipulation was supported by joint testimony of Lynn Plamondon of staff and Chris Ryder of PGE.

On February 27, 1995, PGE and staff submitted an additional stipulation intended to resolve issues relating to Issue S-13: Variable Power Costs. The additional stipulation is attached as Appendix D.

All stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-14-085(1).

Evidentiary Hearing

On July 14, 1994, Hearings Officers Ruth Crowley and Michael Grant held a Phase I evidentiary hearing in Salem, Oregon. Randy Childress and Melinda Horgan, Attorneys at Law, appeared on behalf of PGE. Paul Graham, Mike Weirich, and Kimberly Cobrain, Assistant Attorneys General, appeared on behalf of staff. Grant Tanner, Attorney at Law, appeared on behalf of the Oregon Committee for Equitable Utility Rates (OCEUR). John Stephens, Attorney at Law, appeared on behalf of the Citizens' Utility Board (CUB). Phil Carver appeared on behalf of the Oregon Department of Energy (ODOE).

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Stipulated Issues

The Phase I stipulations cover most of the issues identified by staff in this portion of the proceeding. ODOE and OCEUR are not parties to the stipulations and object to portions of the proposed resolution of Issue S-44: Rate Design. OCEUR also challenges the proposed resolution of Issue S-13: Variable Power Costs, and Issue S-37: Boardman Gain Acceleration. Accordingly, we will treat issues S-13, S-37 and S-44 as a contested issues and address them with the other issues not covered in the proposed stipulations.

We have reviewed the Phase I stipulations with regard to the other noncontested issues (S-1 through S-12, S-14, S-17 through S-28 except for one issue in S-20, S-30, S-31, S-33, S-34 through S-36, S-39, S-40, S-42 and S-43). We find the stipulations on these issues reasonable. Accordingly, the stipulations on those issues, set forth in Appendices B, C and D, are adopted.

Contested Issues

The Phase I stipulation did not cover six identified issues (S-15: Wage and Salary; S-20: Medical Insurance Pooling; S-29: HVEA Promotions; S-32: PGC Allocations; S-38: Decoupling; and S-41, LRIC and Rate Spread). Furthermore, as discussed above, issues S-13: Variable Power Costs, S-37: Boardman Gain Acceleration, and S-44: Rate Design, are treated as contested issues. We address these nine issues separately in numerical order.

Applicable Law

As the petitioner in this rate case, PGE has the burden of proof on all issues. ORS 757.210 provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable."

S-13: Variable Power Costs

PGE incurs variable power costs to meet its retail and firm wholesale requirements and to make economic wholesale sales in the secondary market. To estimate its variable power costs for the two-year test period, PGE used PROSCREEN, a computer forecasting model.[2]

PGE and staff entered into a stipulation with respect to PGE's variable power costs. The parties propose to include in UE 88 base rates variable costs savings expected from the commercial operation of the Coyote Springs generating plant using a forecast in-service date of December 15, 1995. The parties also agree that PGE may file proposed revised rates to address a change in BPA's transmission and power rates through a tracking procedure when such change occurs. As a result of those proposals, PGE and staff further agree that the following amounts are a reasonable forecast of variable power costs for the test period: $304,624,300 (1995); $310,103,700 (1996).

OCEUR is not a party to that stipulation, however, and objects to the use of the PROSCREEN model because the model was developed for use in thermal-based systems. OCEUR does not suggest an alternative but urges caution in use of the model. For 1996, OCEUR proposes to increase the 1995 estimate only by a load growth factor. We find that proposal unacceptable, because OCEUR's approach does not rigorously forecast power costs for 1996 and hence is not factually based.

We have reviewed the stipulation between staff and PGE on variable power costs and find it reasonable. We adopt that stipulation, attached as Appendix D.

S-15: Wage and Salary

Staff proposes certain adjustments to PGE's filing with respect to estimated increases in wages and salaries. Specifically, staff recommends reductions in straight-time labor of $504,691 in 1995 and $923,640 in 1996, and allocates those reductions between operations and maintenance expense and capital. Staff also recommends a reduction in related payroll tax expense.

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[2] The PROSCREEN model calculates a power cost forecast based primarily on: 1) PGE's nondispatchable firm purchases and sales; 2) hydro capacity, both average energy and peaking, under different water conditions and based on PGE and regional hydro resources; 3) hourly loads of PGE, the Northwest, and California; 4) the variable costs of PGE's thermal plants; and 5) the marginal cost curves of other resources in the Northwest and California. The model then applies the Network Economy Interchange logic to make purchases and sales that minimize the marginal cost of the entire system, making as many economic transactions as possible prior to dispatching PGE's plants and other dispatchable resources and making purchases to meet the remaining load.

Staff and PGE arrive at their positions by using two different analytical methods. PGE relies on a market-based approach to determine its labor budget. PGE first defined five labor markets, differentiated in terms of size and demographics, in which it competes for employees. For each market, PGE reviews annual surveys from various sources to determine competitive base pay rates for its employees.

Staff relies on a three-year wage and salary formula to estimate appropriate payroll levels. As a starting point, staff's formula uses PGE's actual nonunion average wage and salary level for 1992 and 1993. From there, staff applies the Consumer Price Index change for each of the three subsequent years to establish a forecast of test-year wage and salary levels. In staff's method, if PGE's projected wage and salary level is within ten percent of staff's projection, the difference between projections is shared equally between customers and shareholders. Outside the ten percent band, shareholders keep all the benefit or pay all the cost.

We find the three-year wage and salary formula more reasonable than PGE's approach for this proceeding and adopt staff's recommendations. As staff points out, this Commission has relied on staff's model for over ten years to monitor energy utilities' wages and salaries for both general rate cases and earning tests associated with deferred accounting. The current model produces a reasonable and reliable result.

PGE faults staff's model for not being market based. Staff's model is based on market data. Its starting point is actual PGE wages for 1992 and 1993. Moreover, staff's method of sharing the difference between the two payroll projections equally between ratepayers and shareholders also allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.

Although we adopt staff's method for this proceeding, we do not preclude more extensive use of market data in future proceedings. We will not direct staff to investigate further the use of market data, as PGE requests. However, the company may introduce appropriate market data in support of its filings in the future.

S-20: Medical Insurance

Issue S-20 is covered by the stipulation with the exception of staff's proposal that PGE explore the possibility of becoming part of a larger insurance pool to reduce its medical insurance costs. Staff asks us to order PGE to assess the possibility of pooling arrangements with other companies. PGE objects and argues that the possibility of national health care reform creates uncertainty in the medical insurance area and notes that it unsuccessfully attempted medical insurance pooling in the early 1980s.

Staff counters that it requires only a feasibility study. Staff urges that PGE should submit a proposal for an assessment study within 45 days of the entry of the order in this docket. PGE opposes the requirement to perform an additional study on pooling costs because the requirement duplicates or contradicts other PGE efforts in this area;

because staff's proposal is unclear; and because the required study may be very costly and time consuming. PGE argues that it should be allowed to provide staff a status report on its efforts to reduce medical insurance costs within 90 days from the date of this order. Once staff has had an opportunity to review the report, the Commission may hold a hearing to see what additional steps are needed to implement insurance cost reduction.

PGE's suggestion is the more efficient and reasonable approach. We adopt PGE's proposal for exploring ways of reducing medical insurance expenses. PGE's status report will be due within 90 days from the date of entry of this order.

S-29: HVEA Promotions

PGE's proposed revenue requirements for 1995 and 1996 include over $1 million each year to provide customers with information about High-Value Electrical Applications (HVEA). These applications include electric forklifts, electric lawnmowers and grass trimmers, electric barbecues, and dual-fuel heat pumps. PGE contends that providing customers with information about HVEA is a valuable customer service and proposes to budget related expenditures under Federal Energy Regulatory Commission (FERC) Account 908.

Staff objects to PGE's proposal and recommends that the Commission disallow all expenses relating to HVEA promotions. Staff contends that the HVEA activities are intended to either promote or retain load. For that reason, staff argues that the costs related to the HVEA marketing activities are more appropriately treated as promotional expenses under FERC Account 912.

To recover HVEA expenses, PGE must demonstrate that the promotional activities are reasonable by quantifying net ratepayer benefits. In Docket No. UG 81, the Commission recognized that ratepayer benefits must be established by "a showing that the specific expenditures incurred provided a recognizable benefit to the people from whom the utility seeks reimbursement. . . . It may be difficult to quantify benefits, but the utility company needs to show the Commission that there is a sound basis for passing the costs on to the ratepayers." Order No. 89-1372 at 7.

After a review of PGE's testimony, exhibits, work papers, and other evidence submitted in this matter, we conclude that PGE has failed to establish specific benefits to ratepayers from HVEA expenditures. Although PGE maintains that HVEA activities are a customer satisfaction strategy designed to help the company move into a more competitive environment, it acknowledges that HVEA may increase the use of electricity by up to an average of four to five MW per year. Thus, while the information provided may prove useful to some customers, a primary purpose of the activities is to create new customers or increase sales to existing customers. Because PGE has not demonstrated that the promotion of HVEA will provide specific benefits to its ratepayers, we adopt staff's recommendation that these costs not be allowed.

In reaching this decision, we note staff's concerns that PGE is inconsistent in promoting both energy efficiency and load growth when the company is acquiring new resources. PGE's efforts to promote load growth may undermine its ability to promote customer adoption of energy efficiency measures. We recognize that there are some circumstances in which the increased use of electricity can provide benefits that may not directly relate to rates, such as environmental benefits. PGE, however, must provide sufficient evidence to support a finding that those benefits exist.

S-32: PGC Allocation

PGE's filing allocates certain joint and common costs incurred by Portland General Corporation (PGC) to PGE, a wholly owned subsidiary. This issue concerns allocations to PGE of PGC's Board of Directors costs and PGC's Executive costs. PGE proposes to change its cost allocation method from the direct labor costs method to the Equity Method for Board of Directors costs and the Massachusetts Formula for the Executive costs. Staff has usually used the direct labor costs method. The Commission adopted that method in UE 79,Order No. 91-186. PGE's filing for FERC Account Nos. 921 (Office Supplies and Expenses), 926 (Employee Pensions and Benefits), and 408.1 (Taxes Other Than income Taxes) was $6,294,769 for 1995 and $6,844,271 for 1996. Those accounts reflect PGC cost allocations.

The Equity Method distributes costs on the proportionate investment of the parent company, PGC, in its various subsidiaries. The Massachusetts Formula distributes costs on an equal weighting of subsidiaries' payroll, revenue, and assets. PGE did not present reasons for changing from the direct labor costs method.

Staff argues that the proposed methods are inappropriate for the S-32 cost allocation categories. PGE's revision with respect to the Equity Method, staff contends, is based on assertions unsupported by verifiable cost causation linkages. There should be a high degree of correlation between PGC employees' time and the PGC Board of Directors' time allocation, according to staff, because both groups are concerned with shareholder wealth maximization. Staff further argues that if PGC has nonoperating subsidiaries with investment but no demand on PGC employees' or directors' time, the existing method will achieve a more correct allocation of cost than the Equity Method.

Staff points out that the Massachusetts Formula could be a fair and reasonable method for homogeneous subsidiaries, as measured by line of business and maturity. Staff contends that that is not the case here, however, because PGE has inherent biases as to capital and labor intensity when compared to the nonregulated subsidiaries of PGC. These biases, according to staff, skew costs to the utility and provide an improper cross-subsidization. Staff also expresses reservations about inclusion of revenues, which are cost derivative, not cost causative, in the formula. Staff takes the position that the best reflection of effort and resource expenditures by the parent is its directly assigned labor expense. Staff has recalculated PGE's original filing for FERC Account Nos. 921, 926, and 408.1 to $5,793,297 for 1995 and $5,992,097 for 1996. Those reductions reflect corrections of inflation errors and eliminate the effects of PGE's proposed allocations revisions.

PGE does not counter staff's arguments. We are persuaded that staff is correct and adopt staff's adjustments to the PGC cost allocations.

S-38: Decoupling

Definition of Decoupling. Decoupling is a regulatory tool designed to eliminate disincentives for a utility to promote cost-effective energy conservation. Decoupling mechanisms break the link between profits and sales by creating a mechanism to adjust for actual sales deviating from a preestablished level. Under this mechanism, a utility cannot increase its earnings by increasing its sales, because additional sales margins are returned to ratepayers and the utility's net revenues are reset to the preestablished level. If the utility's revenues are less than forecast, the decoupling mechanism would restore those lost margins so that actual net revenues are again adjusted to reflect the preestablished level. Thus, the company does not gain or lose net revenues by selling larger or smaller amounts of power.

Decoupling Policy and Collaborative Recommendations. In 1991, the Commission opened an investigation docket, UM 409, to develop a set of policies that would encourage utilities to acquire cost-effective demand-side resources. In Order No. 92-1673, at 13, the majority of the Commission made a policy decision to decouple utility profits from sales levels:

> We are persuaded that the connection between profits and sales should be severed. As long as the regulatory system provides that increased sales may lead to increased profits, a conflict will exist between the motivation to sell energy and the motivation to promote reduction in energy consumption. No other change in the regulatory system can ensure that we will move toward the goals of this proceeding.

The Commission directed PGE to undertake collaborative processes to develop a decoupling mechanism suited to the company's particular circumstances. PGE, staff, and representatives of a broad group of interests worked together to develop a decoupling mechanism for PGE. The collaborative, as the working group was called, presented its mechanism at the Commission's April 20, 1993, public meeting.

To establish revenue targets for PGE, the collaborative decided to use a two-year test period. Revenue targets are to be set once for each two-year period, so that there is one rate change for the period. The mechanism also establishes monthly revenue benchmarks and incremental cost estimates; restates actual revenues and sales as if normal weather had occurred; implements decoupling-related rate adjustments every six months as needed; amortizes any decoupling adjustment over an 18-month period; spreads the decoupling adjustment among the customer classes using, in part, the rate spread adopted by the Commission in PGE's 1991 general rate order, Order No. 91-186 (UE 79); and caps the overall revenues collected from the decoupling rate adjustment at any time at 3 percent of base revenues.

How and Whether to Implement Decoupling. The Oregon Department of Energy (ODOE), and the Northwest Conservation Act Coalition (NCAC) do not oppose decoupling. Staff states that the Commission has already made the policy decision that profits should be decoupled from kilowatt hour (KWh) sales. Therefore, staff did not discuss whether decoupling should be implemented. PGE agrees to decoupling if the Commission finds that its benefits outweigh its disadvantages. PGE also conditioned its agreement on the Commission following PGE's request with respect to the treatment of variable power costs (Issue S-13). PGE signed a stipulation resolving that issue, so PGE's concerns in that regard have been met. ODOE and NCAC also support the collaborative's decoupling mechanism.

OCEUR raises a number of arguments against decoupling. First, OCEUR contends that decoupling abandons the regulatory premise that utility rates should be based on the utility's prudently incurred costs of providing service. It argues that decoupling not only leaves a utility indifferent to declining revenues from conservation, but also insulates it from revenue attrition resulting from any source, including warm weather, recession, or disappearing rate base. In short, OCEUR believes that decoupling makes a utility insensitive to costs and profits.

Second, OCEUR points out problems associated with decoupling, especially the difficulties of estimating costs for a two-year period with sufficient accuracy for ratemaking purposes. The two-year period, OCEUR contends, fails to account for the time value of money. Costs are estimated on a year-by-year basis and then averaged over two years. In a time of rising costs, this leads to collection of a greater amount in rates than is actually incurred for that year, and a subsequent lesser collection the second year. Therefore, OCEUR contends that the decoupling mechanism functions as an interest-free loan to the utility in such a case. OCEUR also believes that the mechanism gives the utility an incentive to overestimate its power costs in the second year of a two-year test period.

Staff noted that OCEUR's concern is less about decoupling than about accurately estimating variable power costs. Staff stated that the Commission frequently uses estimates of variable power costs in such areas as avoided costs and conservation cost effectiveness. Because these other areas are extensively scrutinized, staff does not believe an "error" exists in the methodology for estimating variable power costs and notes that OCEUR has not raised this concern in any of those other areas.

Finally, OCEUR contends that the decoupling mechanism allows the company to game the mechanism. OCEUR believes that the incremental costs used in the mechanism understate the "true" short-run variable cost. OCEUR contends that the company can inappropriately increase its profits through the decoupling mechanism by reducing its sales.

Consistent with its argument on Issues S-41 below, CUB requests that we undo the 4-to-1 rate spread for decoupling adjustments.

Disposition. We adopt the decoupling mechanism the collaborative presented, subject to the recommendations staff has made (see below). It is still the Commission's policy to encourage conservation by severing the link between sales levels and profits. The difficulties of forecasting a two-year test period are not significant enough to outweigh the potential benefits from decoupling.

Decoupling is an attempt to align the utility's financial interest with the interests of its customers. Decoupling removes the utility's incentive to promote new sales and does not provide utilities with an incentive to adopt ineffective demand-side management programs. The current system of regulation produces incentives for utilities to increase electricity sales and corresponding disincentives to the pursuit of energy efficiency. Because decoupling separates profits from fluctuating sales levels *regardless* of the cause of the changed sales, it addresses efficiency impacts resulting from *all* effects, including rate design, all utility-sponsored demand-side management activities, and all energy efficiency measures. Moreover, decoupling does not require sophisticated measurement or estimation. A utility that does not actually produce savings simply does not profit from demand-side management.

Decoupling does not take the next step and provide a positive incentive for good planning. But it does provide a relatively simple mechanism to remove a variety of short-term perverse incentives inherent in the existing regulatory structure.

Breaking the link between sales levels and profitability does not mean that the utility is left with no incentive to minimize costs and maximize profits. The utility can increase its profitability through activities not related to sales. Also, the collaborative's decoupling mechanism specifically chose to use expected rather than actual incremental power costs, giving the utility another opportunity to increase profits by minimizing its actual KWh costs.

The Commission is persuaded by staff's rebuttal of OCEUR's concerns about variable power costs. As to OCEUR's arguments about the time value of money, where rising costs are averaged over two years, the first year's actual average cost will be less than the two-year average, and the second year's actual average cost will be more than the two-year average. This is a natural outcome of averaging. This averaging also occurs in a single-year test year, the result being that a single set of rates for the test year will necessarily be overstated for the first six months and understated for the last six months. Normal regulatory practice does not make an adjustment to costs to take into account what may be considered an interest-free loan due to this type of stream of payments. As with other aspects of the collaborative's mechanism, the Commission is not inclined to dismantle the collaborative's recommendations. The Commission appreciates OCEUR's concern, however, and directs staff to consider this issue in future developments of regulatory mechanisms.

The fact that the decoupling mechanism presents the utility an incentive to inflate its second year's estimated costs raises a concern. However, we believe that problem has been contained by staff's monitoring of the costs in this docket. As to CUB's request, we will not dismantle the collaborative's recommendations piecemeal by changing the rate spread that the collaborative agreed on.

In terms of specific implementation, Paragraph 36 of the July 1, 1994, stipulation sets forth the agreement to use one set of weather normalization coefficients for both years of the test period.[3] Further, staff recommends that we require a decoupling tariff design that contains information on monthly revenues, incremental costs, and margins that result from this rate case. Having this information in the tariff will make the task of administering the mechanism easier, staff maintains, and will allow review of the mechanism. Staff also recommends that the tariff include information on the weather normalization procedure that staff and PGE have agreed on. No party opposes these recommendations about the tariff, and we adopt them.

Because PGE will no longer have the incentive to sell more KWh or to sell at higher prices the KWh it currently markets, we need to consider service quality to PGE's customers. To address the issue of service quality, staff also recommends that we direct staff to monitor PGE's service to protect ratepayers and assess the impacts of decoupling on the utility's behavior. No party opposes this recommendation, and we adopt it.

Paragraph 8 of the July 15, 1994, stipulation covers implementation of the decoupling mechanism. The mechanism functions as a comparison of benchmark net revenues to weather-adjusted actual net revenues. Revenue targets are based on the assumption that the new rates, to be set in this docket, are in effect. Consequently, PGE and staff agree that the decoupling comparison should occur when revenues reflect new rates. Accrual adjustments for decoupling should therefore not begin until the effective date of the new rates.

Incremental Power Costs. PGE and staff disagree on how to treat incremental power costs under the decoupling mechanism. Monthly incremental power costs are needed to determine the margin earned or lost because of changes in sales from those forecast in the rate case. The decoupling collaborative stated that these 24 monthly

[3] Weather normalization coefficients are used to adjust sales and revenues to reflect a normal weather pattern. Using only one set of coefficients will reduce the cost and difficulty of implementing decoupling. It will obviate the need to update the coefficient at the end of 1995 and will ensure that the level of revenues set in the rate case and the decoupling adjustment mechanism will use the same factors to describe the effect of weather on sales.

estimates should be set in the rate case but did not specify a methodology.[4] In its filing, PGE proposed using the PROSCREEN model to determine incremental power costs, using the actual differences between forecast loads and weather-adjusted loads. Staff proposed generating incremental power cost estimates by averaging the incremental power costs associated with positive and negative load increments of the same size. We adopt staff's rather than PGE's proposal, because the use of estimated incremental power costs is consistent with the collaborative's recommendation.

Staff originally proposed using +/- 5 MW as the increment for purposes of estimating incremental power costs. PGE countered with a proposal of +/- 10 MW, an increment, PGE contends, that is large enough to ensure meaningful results. Staff does not object to the 10 MW figure, provided staff has the right to review PGE's calculation of estimates. Lack of such review could result in inaccurate incremental cost estimates that could create perverse sales incentives. We adopt the +/- 10 MW increment figure for estimating incremental power costs, and order that staff shall have the right to review PGE's calculation of estimates.

The February 27, 1995, variable power costs stipulation between PGE and staff could result in revisions in late 1995 or early 1996 to the monthly targets contained in the decoupling tariff.

S-37: Boardman Gain Amortization

PGE had originally proposed accelerating the Boardman gain amortization to three years instead of the 27-year period approved in UE 47/48, Order No. 87-1017. Staff opposed the proposal, and PGE withdrew it. OCEUR still supports acceleration of the Boardman gain amortization for ratemaking purposes.

OCEUR argues in favor of the acceleration because it believes that customers paid a disproportionate share of overall Boardman costs in the plant's early years. According to staff, that is true of every plant. The Commission allows return on unrecovered investment. In the early years of a plant, staff points out, unrecovered investment is large; later it shrinks. Staff contends that OCEUR's argument assumes without stating that PGE sold Boardman for more than the book value of the plant. In fact, staff maintains, PGE realized no profit from sale of the plant.

Staff is correct about the Boardman sale. *See* Order No. 87-1017 at 28. That order established the Boardman gain amortization and found that most of the money PGE received from the transaction represented profit from a wholesale power sale between

[4] Incremental power cost estimates reflect the additional power cost incurred per MWh given a small increase or decrease in loads. The collaborative chose to use incremental power cost estimates developed in the rate case rather than actual power costs. The purpose of this choice was to give the utility an incentive to minimize its power costs. That is, if the utility can improve on the estimated power costs, its stockholders benefit, but if the actual power costs are greater than expected, the utility must shoulder the extra costs.

PGE and San Diego Gas & Electric. $51.3 million of the $78.7 million to be amortized came from the power sale. The power sale to San Diego Gas and Electric that generated the majority of the gain at issue was a system sale, and thus we continue to maintain that the gain be amortized as prescribed in Order No. 87-1017. We are persuaded by staff's argument and adopt the resolution of the issue contained in the Phase I stipulation, Appendix B at 13.

S-41: LRIC and Rate Spread

As part of its filing, PGE submitted a long-run incremental cost (LRIC) study. LRIC is a measure of the long-run costs or savings from providing one unit more or less of service. The Commission has traditionally used LRIC studies to determine cost causation and to help allocate those costs.

PGE's cost study indicates that commercial and industrial customers pay a higher rate relative to the cost of providing service than residential customers. The study, as revised by adjustments recommended by staff, shows that current residential rates collect 92.5 percent of average recovery of total LRIC, while large commercial and industrial rates collect 120.1 percent of the average. To help rectify this disparity and to achieve a more balanced distribution of the costs of service, PGE proposes to apply a "4-to-1" methodology in determining rate spread between customer classes. The 4-to-1 methodology assigns residential customers a percentage increase of four times that assigned to medium and large commercial and industrial customers. A 4-to-1 approach would increase residential rates to 95.6 percent of average recovery and reduce large commercial and industrial schedules to 113.0 percent of the average. The Commission adopted the 4-to-1 methodology in PGE's last general rate case. *See* UE 79, Order No. 91-186 at 25.

PGE's revised LRIC study and its proposed 4-to-1 rate spread are supported by all parties participating in Phase I of this proceeding with the exception of CUB. CUB argues that PGE's use of a "minimum system"[5] approach to allocate distribution costs in the LRIC study assigns too many of those costs to residential customers. CUB suggests the use of a "basic customer allocation"[6] method, which would assign a greater share of distribution costs to commercial and industrial customers. Using that approach to allocate distribution costs, CUB contends that a corrected cost study shows that residential customers would actually pay 102.6 percent of indexed costs under a 4-to-1 rate spread. Due to this fact, CUB argues that the marginal cost study does not support

[5] The minimum system approach divides distribution costs between customer-related and demand-related costs by determining the cost of building a theoretical distribution system using the smallest size components. The costs of this minimum system, which includes poles, underground conduits, conductors, transformers, service drops, and meters, are defined as customer related. Additional costs associated with expanding the minimum-sized system to meet a customer's demand are defined as demand related.

[6] The basic customer allocation method treats distribution costs that vary directly with the addition or subtraction of a single customer as customer related. These exclusive customer cost components primarily consist of service drops and meters. All other distribution costs are considered demand related.

PGE's rate spread proposal and recommends that any increase in rates be spread equally among all rate classes.[7]

We are not persuaded by CUB's recommendation for two reasons. First, as noted by PGE, when CUB recalculated the marginal costs for residential customers in preparing its cost study, it failed to adjust the marginal costs for the nonresidential customer classes. That error led CUB to overstate the indexed percent of marginal costs for the residential class at 102.6 percent. Using CUB's estimates of marginal distribution and customer costs and recalculating marginal costs for the nonresidential classes, the corrected figure for residential customers under CUB's approach is 101.0 percent of indexed costs, under a 4-to-1 rate spread. Because that figure is based on PGE's original filing and does not reflect revenue requirement reductions and other adjustments embodied in the stipulation, we add that a 4-to-1 rate spread will not likely raise residential rates as high as that reduced figure.

Second, CUB failed to use the appropriate definition of demand in allocating distribution costs under the basic customer allocation approach. Under CUB's proposed methodology, any costs other than service drops and meters are classified as demand-related costs. In applying that method, however, CUB improperly assigned marginal costs using a coincident peak (CP)[8] allocator, rather than using a weighted allocation of distribution costs that considers both CP and noncoincident peak (NCP).[9] Because distribution facilities are primarily designed to meet a customer's maximum NCP, the costs associated with the system must be allocated on that basis. Thus, CUB's vastly different distribution cost allocation results from its different definition of demand, not from inherent differences between allocation methods. Had CUB used a correct allocator for distribution demand costs, its spread of distribution costs to various rate classes would have been similar to that of PGE's study.

We have reviewed PGE's revised LRIC study and find the minimum system approach appropriate for allocating distribution costs in this proceeding. PGE has used that methodology in the development of its marginal costs for over 15 years. Moreover, while no unanimity exists on the treatment of distribution costs, a study by the National

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[7] In its brief, CUB also implies that PGE is unconcerned about residential rate design due to the availability of residential exchange funds from the Bonneville Power Administration (BPA). The Commission addresses CUB's comments only to clarify that there is no relationship between rate spread and the residential exchange credit. The residential exchange credit is paid by BPA to investor-owned utilities based on the difference between the utility's average system cost and BPA's priority firm rate for its customer utilities. BPA, not the Commission, determines the amount of the credit. Rate spread is calculated by the Commission. That is a separate analysis that distributes the utility's revenue requirement among customer classes based on the costs incurred by the utility in serving that particular class of customers.

[8] CP is the measure of the maximum aggregate customer usage at a single point of time during the year. This is the coincident point in time at which generation and transmission facilities are used to the maximum.

[9] NCP measures individual rate class or customer peak demand, which may be significantly higher that at the time of system coincident peak.

Economic Research Associates found that the minimum system approach was the most frequently used method in the treatment of distribution costs. Accordingly, we conclude that the revised LRIC study reasonably estimates marginal costs and should be used to guide rate spread and rate design.

We further conclude that PGE's revised rate study supports the 4-to-1 rate spread proposal. As noted above, the Commission previously adopted the use of a 4-to-1 methodology in PGE's last general rate case to help set rates more in line with the actual costs caused by each customer class. With increasing competition in the electric services industry, public policy dictates continued movement toward rate parity. We believe that the continued use of a 4-to-1 rate spread will help accomplish that goal without subjecting residential customers to rate shock.

In reaching these decisions, we request the parties to address and study other cost allocation methods for possible use in PGE's next general rate case. All marginal cost studies use simplifying assumptions and conventions to attempt to best estimate cost causation. While we have found that PGE's LRIC study reasonably estimates those costs and should be used in this rate proceeding, several parties, including PGE, OCEUR, and staff, have suggested possible improvements to the study. These suggested improvements include the use of a "facilities approach"[10] method for allocating distribution costs. In addressing possible adjustments to the marginal cost study, the parties should complete discussions in time to implement and recommend changes prior to PGE's next general rate case. PGE should take the lead in conducting such discussions.

S-44: Rate Design

PGE proposed several changes relating to its electric rate design. PGE's filing includes: (1) an increase in customer charges for the residential and small commercial classes; (2) the elimination of the seasonal differential in demand charges; (3) an increase in demand charges and reduction of energy charges for most commercial and industrial customers; (4) the addition of a time-of-day differential to energy charges for large commercial and industrial service (over 1 MW); and (5) an increase in power factor requirements.

Staff and PGE have stipulated that PGE should implement the proposed overall rate design, with the exception of proposed Schedules 103 (energy efficiency recovery adjustment) and 107 (adder for the Boardman sale refund adjustment), and the increase to the customer charge on Schedule 7 (residential service). The parties also agree that minor deviations may be necessary in implementing these rate design changes to achieve a

[10] The facilities cost approach recognizes that distribution systems are designed using engineering standards that consider the number of customers and the expected loads of these customers. Costs are therefore determined on a cost-per-design-kilovolt-ampere basis.

smooth transition between rate schedules. The stipulated agreement is set forth in the July 1, 1994 Stipulation, paragraph 41 (Appendix B, attached).

ODOE and OCEUR are not parties to the stipulation and raise several issues related to PGE's proposed rate design. ODOE advocates the addition of a new tailblock rate for residential rates and the inclusion of environmental adders in marginal costs. OCEUR objects to the proposed increase in power factor requirements and recommends a reduced level. We address each issue separately.

ODOE's Inverted Rate Design. PGE's present residential rate tariff employs a two-block inverted rate structure. Customers pay one rate for the first 300 KWh per month, then pay a higher rate for all additional KWh used in that month. ODOE contends that this rate design does not correspond to LRIC and recommends a three-block rate structure. ODOE's proposal would retain the current initial block of 0 to 300 KWh per month, but change the second block to 300 to 2,300 KWh per month and add a third block, priced at LRIC, for use greater than 2,300 KWh per month. ODOE contends that this inverted rate design will help send proper price signals and promote energy conservation.

To support its proposed rate design, ODOE asserts that households that use over 2,300 KWh per month have more opportunities for conservation than households that use less electricity. ODOE fails to provide any studies to support that assertion, however. PGE's 1992 Integrated Resource Plan found that over 60 percent of potential savings were related to lighting, water heating, and appliances. Thus, all customers, regardless of their usage levels, have opportunities to conserve. Moreover, as noted by PGE, less than six percent of its residential customers use more than 2,300 KWh per month. With so few customers facing this higher tailblock rate, it is uncertain that ODOE's proposal will actually promote energy conservation and reduce inefficient electricity use. Given these uncertainties, and in the absence of an supporting empirical studies, we are unwilling to adopt ODOE's proposed rate structure in this proceeding.

ODOE's Inclusion of Environmental Externalities. ODOE also recommends the use of externality costs in designing residential rates. Specifically, ODOE recommends that LRIC should include a $10 per ton of carbon dioxide (CO_2) adder. ODOE contends that such an adder will account for the risk that carbon dioxide emissions will be taxed or otherwise internalized in the near future.

In UM 424, Order No. 93-695, the Commission adopted guidelines for the treatment of external environmental costs related to energy resources. Although this Commission decided that it was appropriate to consider external environmental costs in a utility's LCP, we recognized that our authority to impose such costs on a utility or its customers was limited by law. *Id.* at 2. Accordingly, we declined to determine whether to apply environmental externalities to rate design, and indicated that any decision doing so would require further examination of our authority and a full airing of views on the merits of including external costs and on the specific cost figures to be used. *Id.* at 16.

We are aware of numerous state, federal and international efforts to reduce CO_2 emissions. Uncertainties remain, however, whether future regulation will internalize the cost of CO_2 emissions by utilities. In light of questions regarding our authority to impose external environmental costs on a utility, and in the absence of a more complete record on this issue, we decline to adopt ODOE's recommendation to include a CO_2 adder in LRIC.

OCEUR's Opposition to Proposed Power Factor Requirements. Currently, PGE charges customers $0.50 for each kilovolt-ampere of reactive demand in excess of 60 percent of the KW billing demand. This occurs when the customer's power factor[11] drops below 85.7 percent. PGE and staff have stipulated to lowering the threshold level for its reactive demand charge from 60 percent of KW billing demand to 40 percent. Under that level, customers with power factors below 93 percent will be subject to the charge. OCEUR objects to the proposed increase in power factor requirement. OCEUR believes that raising the threshold from 85.7 to 93 percent would result in a too drastic rate increase for affected customers. It proposes the threshold be changed from 60 percent of KW billing to 50 percent. That proposal would result in a charge being imposed on customers with a power factor less that 89.4 percent.

We are not persuaded by OCEUR's argument and find the stipulated reduction to 40 percent of KW billing reasonable. We take official notice of staff's 1990 Research Report on Electric Energy Efficiency Opportunities in Oregon Industries.[12] In that report, staff concluded that the power factor threshold should be raised to 90 percent or higher to promote customer energy efficiency and reduce energy losses on the utility's distribution system. The stipulated proposal would accomplish that recommendation. Furthermore, while we acknowledge OCEUR's concerns regarding the extent of the increase, the stipulated power factor requirement is similar to that of other Northwest utilities, such as the BPA, whose power factor requirement is set at 95 percent, and Pacific Power & Light, whose power factor requirement is at 93 percent.

[11] A low power factor may reflect poorly loaded motors and causes increased energy losses on a utility's distribution system.

[12] Pursuant to OAR 860-14-050(1), a party may explain or rebut the noticed fact within 15 days of notification.

PHASE II

Issues List

On September 15, 1994, staff filed a supplemental list of issues it identified for Phase II of this proceeding. As with staff's Phase I issues list, we use staff's numbering of Phase II issues in this section of the order. *See* Appendix F, Adjustment Summary, page 1, for a complete list of issues.

Stipulations

On November 15, 1994, PGE and staff submitted a stipulation intended to resolve rate of return and equity issuance cost issues. The stipulation is attached as Appendix E. The stipulation was supported by testimony of John Thornton, Jr., of staff and Joseph Hirko and Patrick Hager of PGE.

On February 27, 1995, PGE and staff submitted an additional stipulation intended to resolve Trojan balancing account issues. The stipulation is attached as Appendix D.

The stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-14-085.

Evidentiary Hearing

During the week of January 9, 1995, Hearings Officers Ruth Crowley and Michael Grant held a Phase II evidentiary hearing in Salem, Oregon. Randy Childress, Melinda Horgan, and Rochelle Lessner, Attorneys at Law, appeared on behalf of PGE. Paul Graham and Michael Weirich, Assistant Attorneys General, appeared on behalf of staff. John Stephens, Attorney at Law, appeared on behalf of the Citizens' Utility Board (CUB). Geoffrey M. Kronick, Attorney at Law, appeared on behalf of the Bonneville Power Administration (BPA). John A. Kullberg, ratepayer, appeared on his own behalf.

Procedural Rulings

At the outset, we must address several procedural matters raised by URP in its Phase II brief. URP first asserts that the procedural history of this case has prejudiced the rights of the contested case participants, because the Hearings Officers issued a ruling on evidentiary matters the day before Phase II opening briefs were due. URP also argues procedural harm from the fact that the Hearings Officers faxed their ruling to Linda Williams without checking that she was there to receive the fax, rather than to Daniel Meek, URP's counsel of record.

We conclude that URP has not suffered prejudice because of the procedural history of this case. URP did not ask for an extension to mitigate any prejudice it might have experienced from the ruling. Nor does URP demonstrate how it was prejudiced. In fact, although the ruling struck some of URP's evidence, URP included argument about that evidence in its brief. URP's argument about the fax is disingenuous. Ms. Williams specifically requested the Hearings Division to fax her the ruling, because Mr. Meek was out of the country.

Second, URP alleges that its request to hold hearings in Portland, made at the January 6, 1995, prehearing conference for Phase II, was denied "without any findings why access to the hearings was being arbitrarily denied to the vast majority of affected customers." That motion had already been made and denied almost a year earlier, by ruling dated January 19, 1994. It was not necessary to repeat the grounds for a ruling that had already been made.

URP further argues that refusal to hold hearings in Multnomah County violates the equal protection clause of the fourteenth amendment and the privileges and immunities clause of the Oregon constitution. We have reviewed URP's arguments and are not persuaded by them.

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Stipulated Issues

The Phase II stipulations submitted by PGE and staff cover three issues: S-0: Rate of Return; S-33: Equity Issuance Costs; and an unnumbered issue relating to a Trojan Cost Balancing Account. The parties have agreed to: (1) a stipulated rate of return of 9.51 percent for 1995 and 9.60 percent for 1996; (2) a stipulated common equity issuance cost of $1.75 million for both 1995 and 1996; and (3) a stipulated method to vary the amortization of the Trojan investment to take into account the actual revenue collected from ratepayers as a result of this order.

We have reviewed the stipulations and testimony and find the agreement on these three issues reasonable. Accordingly, the stipulations, attached as Appendices E and D, are adopted.

Contested Issues

The contested Phase II issues relate to PGE's Trojan Nuclear Power Plant (Trojan). The most significant of these issues concerns the ratemaking treatment of PGE's remaining investment in Trojan: S-50: Remove Additional Fixed Costs - Net

Benefits Analysis. Other issues include: S-45: Trojan Overtime; S-46: Trojan Investment Reclassification; S-47: Added Trojan Salvage Recoveries; S-48: Trojan Decommissioning; S-49: Remove Plugging, Sleeving, Analysis and Spare Nuclear Reactor Coolant Pump Motor; S-51: Remove Trojan Power Cost Deferral; S-52: Trojan Income Tax Write-off; S-53: and Trojan Intangible Asset Reclassification.

We will begin with a brief history of Trojan and review of the legal framework of this case, including a discussion of the assumed facts and conditions for recovery set forth in DR 10, Order No. 93-1117. That will be followed by a review of staff's net benefits analysis (Issue S-50), succeeded by the other contested issues in numerical order.

History of Trojan

Trojan began commercial operation in 1976. It was licensed to operate until 2011. Trojan was a single-unit 1200 MW plant, the largest in the Northwest at the time of its construction. PGE owns 67.5 percent of the plant. BPA owns 30 percent under net billing agreements with the Eugene Water and Electric Board and several other publicly owned utilities. PacifiCorp owns 2.5 percent.

Trojan was a pressurized water reactor (PWR) nuclear generating facility. PWRs rely on steam generators to heat and cool the water that powers the generating turbine. Steam generators are large pressure vessels that transfer heat from the water in the reactor coolant system (primary system) to the water in the turbine system (secondary system). The water in the primary system is pressurized to keep it from boiling. The heat transfer occurs through the walls of thousands of tubes in the steam generator. The primary system water flows inside the tubes and the secondary system water flows around the outside of the tubes. The heat transferred to the water on the secondary side of the steam generator causes it to boil, producing steam.

The steam produced in the steam generators flows through piping to the turbine generator, where it passes through and drives the turbine. The steam passes through a condenser, where it is turned to water, and the water flows through feedwater heaters and back into the steam generators.

The steam generators, particularly the generator tubes, contain the primary system radioactive water and prevent the release of radioactive water to the secondary system. Trojan contained four steam generators, each with 3,388 tubes, which PGE purchased from Westinghouse in 1968. PGE is currently engaged in a civil suit against Westinghouse with respect to the steam generators, which degraded badly starting in 1989. By 1991, PGE had plugged or sleeved (permanently attach another tube inside a degraded tube) more than 25 percent of its steam generator tubes.

During its least-cost planning process in 1992, PGE weighed Trojan's continued viability. Among other things, PGE considered the cost of replacing the four steam generators in 1996, the loss of generation that would occur until they were replaced, and the replacement power costs such a loss would entail. In its 1992 Least-Cost Plan (LCP), PGE decided to close Trojan in 1996. As further steam generator degradation became apparent, however, PGE realized that closing Trojan immediately was its least-cost option. On January 4, 1993, the company announced the permanent shutdown of Trojan. PGE's February 1993 Update to its LCP shows its analysis.[13]

Applicable Law

As the petitioner in this rate case, PGE has the burden of proof on all issues. ORS 757.210 provides that, in a rate case, "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." The requirement applies to PGE's entire case, including the allocation of Trojan costs.

Further, ORS 757.140(2) provides:

> In the following cases the commission may allow in rates, directly or indirectly, amounts on the utility's books of account which the commission finds represent undepreciated investment in a utility plant, including that which has been retired from service:
>
> * * * * *
>
> (b) When the commission finds that the retirement is in the public interest.

This statute requires that PGE make an affirmative showing that retirement of Trojan was in the public interest in order to include Trojan costs in rates.

The Commission established the legal framework for the Trojan issues in this case in DR 10, Order No. 93-1117. In that order, the Commission adopted the reasoning of the Attorney General's Opinion Letter OP-6454, which advised that the Commission may allow a utility to recover undepreciated investment in retired plant and a return on that investment if the Commission finds such recovery to be in the public interest under ORS 757.140(2)(b).

In their Phase II briefs, CUB, URP, and the Public Power Council argue against our conclusions in DR 10. They contend that ORS 757.355 bars recovery of and return on undepreciated investment in retired plant.[14] We fully addressed that argument and

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[13] At the Phase II hearing, the Hearings Officers took official notice of both PGE's 1992 LCP and its February 1993 Update. The LCP was acknowledged by the Commission in Order No. 93-803 (LC 7).
[14] ORS 757.355 provides:

rejected it in our resolution of DR 10. Our decision was appealed to and affirmed by the Marion County Circuit Court, and is currently pending before the Oregon Court of Appeals. We will not revisit that issue here.

Standard for Recovery of Undepreciated Investment

The Concept of Net Benefits. In Order No. 93-1117, we concluded that one way a utility may show that a plant closure is in the public interest is if there is a "net benefit" from early closure of the plant. In other words, if the costs of continued operation of the plant are greater than the costs associated with retiring the plant plus the expected long-term costs of replacing the plant's output, there is a net benefit to closure.

The DR 10 Requirements. The language of ORS 757.140 is discretionary: the Commission **may** allow the utility to recover undepreciated investment in rates. In Order No. 93-1117, we set forth the conditions under which we would favor allowing PGE to recover some or all of its undepreciated investment in Trojan and a return on that investment. First, we assumed six facts:

Assumed Facts:

1. Trojan began commercial operation in 1976. The Commission approved the inclusion in rate base of PGE's investment in Trojan in Order No. 75-832 as construction work in progress and in Order No. 76-601 as completed plant.

2. PGE has made additional investments in Trojan, most of which the Commission has approved for inclusion in rate base through 1991, the test year approved in Order No. 91-186 (UE 79).

3. Since January 1, 1992, PGE has made additional investments in Trojan. The investments were prudent and necessary for the provision of utility service.

4. PGE has depreciated and is presently depreciating its investment in Trojan over a useful life assumed to end in 2011. Since 1976, the Commission has set PGE's prices to include amounts for annual depreciation expense and a return on the undepreciated balance of PGE's Trojan investment.

No public utility shall, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates which are derived from a rate base which includes within it any construction, building, installation or real or personal property not presently used for providing utility service to that customer.

5. PGE has accrued, and is presently accruing, and depositing in an external trust, funds to decommission Trojan based on a schedule of charges designed to produce the estimated amount necessary for decommissioning in 2011. Since 1976, the Commission has set PGE's prices to include amounts for future decommissioning of the plant.

6. Closing Trojan permanently in January 1993 was PGE's least-cost option.

Disposition:

PGE and staff agree that PGE has met its burden of proof with respect to five of the six assumed facts, including the fact that permanent closure of Trojan was PGE's least-cost option. They disagree on assumed Fact 3.

Facts 1 and 2. We find that Fact 1 is verified by Order Nos. 75-832 and 76-601, while Fact 2 is verified by Order No. 91-186.

Fact 3. We find that certain of PGE's post-1991 investments in Trojan were not prudent. We disallow costs for steam generator plugging, sleeving, and analysis and a spare reactor coolant pump motor. *See* discussion at S-49 below.

Fact 4. In Order No. 76-601, the Commission included the investment in Trojan in plant in service. The depreciation rates to be used on that investment were specified in a PGE memo dated January 8, 1976. Trojan has been included in plant in service in several general rate orders in the intervening years, the most recent being order No. 91-186. We find that this verifies Fact 4.

Fact 5. We conclude that Fact 5 is verified. In Order No. 76-601, which included Trojan in plant in service, the depreciation rates in use included a negative net salvage percentage to cover the cost of removing the plant from service. This percentage was not identified as decommissioning at that time, nor was a specific amount of money identified as a decommissioning cost. However, negative net salvage and a decommissioning accrual are conceptually equivalent (see discussion below, S-48: Trojan Decommissioning).

In Order No. 80-612, the Commission adopted a decommissioning study prepared by Nuclear Energy Services, Inc. That study estimated the cost of removing Trojan from service and established a decommissioning fund. PGE was to make regular accruals to that internal sinking fund. The fund was to finance decommissioning when the plant was removed from service. The internal sinking fund was maintained until Order No. 91-186 (UE 79). In that order, the Commission approved a new decommissioning plan; approved the cost estimate associated with the plan; provided for an external decommissioning fund to be established and managed by an independent trustee; and provided for annual contributions to be made to the fund, which would grow to an amount equal to the decommissioning cost estimate at the time of decommissioning in 2011. PGE is currently depositing the amount prescribed in Order No. 91-186 in the external trust fund.

Fact 6. PGE relies on its LCP to prove Fact 6. In the November 1992 Plan, PGE compared the costs of three Trojan options: continued operation through 2011, phase-out in 1996, when the steam generators would otherwise need to be replaced, and immediate closure with the plant kept on standby for two years. PGE compared these three options over a range of assumptions about future Trojan operation and the cost of replacement resources. In its LCP, PGE concluded that phase-out was the least-cost option. In its February 1993 Update, it compared phase-out with immediate closure and not keeping the plant on standby. Based on the analysis in its Update, PGE concluded that closing Trojan permanently in January 1993 was its least-cost option.

Staff agrees that the LCP proves Fact 6. Staff reviewed PGE's model design, Trojan cost and operating assumptions, and replacement cost assumptions and determined that PGE's analysis of its least-cost option was correct. Staff's review showed that PGE used two approaches to model the Trojan cost options. The probabilistic model used probability distributions on values for key inputs to generate a distribution of outcomes, measured in terms of the present value of avoidable costs. PGE used a range of values for Trojan capacity factor, fixed operations and maintenance costs, and capital additions. PGE used the Northwest Power Planning Council's (NWPPC) regional planning model as one basis for replacement power costs.

PGE also used a scenario approach, in which costs were derived from specific input values. The company combined different assumptions about loads, gas prices, nuclear and emission externalities, and Trojan operations and costs. Replacement costs in the scenario approach were based on resources available to PGE instead of the regional portfolio developed in the NWPPC model. In its Update, PGE changed its assumptions about Trojan costs and operations and about replacement power costs in 1993-1996. It examined scenarios based on different assumptions for forced outages, plant repair costs, and replacement costs.

After reviewing PGE's LCP and staff's evaluation, we conclude that PGE has proved Fact 6.

Although PGE has not proven Fact 3, PGE has substantially complied with the requirement that it prove all six facts in a rate case. We have the discretion to disallow those costs found to be imprudent and to allow a recovery of some or all of the undepreciated Trojan investment.

Conditions on Recovery:

After setting out the six assumed facts that PGE must prove, we listed six conditions that PGE must meet in order for the Commission to allow it to recover some or all of its undepreciated investment in Trojan:

1. PGE's questions are based on six assumed facts regarding Trojan. PGE must prove all six facts in a rate case or similar forum.

2. PGE must show that it has made a diligent effort to reduce other company costs to offset the inclusion of any Trojan costs in rates. For instance, PGE may show that the Trojan closure decision is consistent with least-cost planning criteria over the longer term, but that near-term rates may be higher as a result of the decision. PGE must show that it has made reasonable efforts to keep costs down, especially discretionary costs, before asking customers to pay higher bills in the near term to support its closure decision.

3. PGE must show why it is reasonable to allow 100 percent recovery of Trojan-related costs in rates. Issues regarding cost recovery are complex and significant. After review, the Commission may decide that PGE is entitled to full recovery of unrecovered plant costs, or it may determine that some cost sharing should occur between customers and investors.

4. PGE must show that it has aggressively attempted to maximize the salvage value of the Trojan facility. If customers are asked to bear some unrecovered costs, PGE must show it is making every reasonable effort to mitigate those costs.

5. PGE must report within 30 days any settlement or award related to replacement power costs, unamortized investment, or any other costs of owning or operating the Trojan plant.

6. PGE must provide satisfactory evidence with regard to any other matter the Commission deems relevant to this issue in a rate proceeding.

Disposition:

The first condition, proving the assumed facts, is addressed immediately above. As to cost reduction, the second condition, staff concluded that PGE had made good efforts to reduce company costs to offset Trojan cost recovery. However, staff compared PGE's administrative and general (A&G) costs with those of Puget Sound Power and Light, a comparable utility in terms of size and service area.[15] PGE's costs were materially higher for 1989 through 1993, and staff concluded that PGE could find ways to reduce A&G costs still more.

[15] A&G costs are largely discretionary. Discretionary costs include operating and maintenance expense accounts (company labor and benefits, contract labor, office supplies and expenses, insurances, transportation, and outside services). They exclude Trojan O&M, amortization of energy efficiency balances, uncollectible accounts, regulatory expenses, and rents.

We agree with staff that it is possible for PGE to be more aggressive in its efforts to reduce discretionary costs. Trojan's closure is having and will continue to have an adverse effect on customer rates in the near term. Amortization of replacement power cost deferrals will add approximately $150 million to PGE's revenue requirement from 1992 through completion of amortization. While PGE has made some efforts at cost reduction, we believe that the company can and should do more to mitigate the adverse rate effects discussed above. Accordingly, PGE's rates should recognize a reduction of 1 percent in discretionary costs over and above that approved in Phase I of this Order. We find this a reasonable allowance for discretionary costs. We decline to identify particular program areas that may be susceptible to reassessment or to impose specific cost reductions. These discretionary costs are best managed by the company.

We acknowledge that these reductions will require difficult choices. Nonetheless, we expect the company to make those choices if it is asking customers to pay higher bills in the near term to support PGE's closure decision. This reduction in discretionary costs reduces PGE's revenue requirement by $1.631 million in 1995 and $1.687 million in 1996.

The third of the DR 10 conditions merely puts forth in condensed form PGE's entire Phase II case. We address this condition below as Issue S-50: Remove Additional Fixed Costs - Net Benefits Analysis. The fourth condition, dealing with salvage value, is also addressed below under Issue S-47, Added Trojan Salvage Recoveries. The fifth condition, requiring PGE to report any settlement or award, is not yet ripe. We continue to impose this requirement on PGE. We did not impose any additional requirements pursuant to the sixth condition.

The Net Benefits Test

As Order No. 93-1117 set out, the first step in determining whether closing Trojan was in the public interest under ORS 757.140(2) is to ask whether there is a net benefit from closure. In its initial filing in November 1993, PGE relied on its least-cost planning analysis to justify its position that it should receive 100 percent recovery of Trojan costs. PGE maintains that closing Trojan was its least-cost option.

Staff agrees that closing Trojan was PGE's least-cost option. Staff argues, however, that an LCP analysis does not serve to determine whether an action is in the public interest for purposes of allocating undepreciated Trojan investment. The LCP takes the plant as it exists at the time of LCP review. It does not question whether actual costs *should* have been incurred. It then projects costs based on the plant's actual operation out over the time until Trojan's license would have expired. Under an LCP, a poorly run plant may be so expensive to operate that closure would be the least-cost option. That outcome is appropriate and desirable in the framework of the least-cost planning process.

Staff contends, however, that the LCP is not the appropriate tool to determine who should pay for the remaining undepreciated investment in a prematurely retired plant. Using the LCP to allocate remaining undepreciated costs could allow a utility to shift the capital or operating costs of its own imprudence to ratepayers. If PGE managed Trojan imprudently and the costs and capacity factor used to model continued Trojan operation were adversely affected as a result, the apparent benefit of closing the plant would be overstated.

Staff argues that the net benefits analysis is the appropriate vehicle for deciding how to allocate the remaining Trojan costs. A net benefits analysis is not used to decide whether a plant should be kept in operation. Instead, it compares the *allowable* projected costs of continuing to operate a plant with the allowable costs of closure. Allowable costs are those costs the Commission would deem reasonable and allow PGE to collect from its ratepayers.

Consequently, staff performed a net benefits analysis of PGE's operation of Trojan. Like the LCP, the net benefits analysis projected the costs of operating Trojan out to 2011, the year in which the plant would have closed. The starting point for staff's study was 1995, the first test year in this proceeding. Staff's review differed from an LCP analysis in two significant ways. First, it asked what projected costs are allowable, and disallowed those costs that it considered not reasonable to impose on ratepayers. Second, it used updated information, while the LCP used information as of the time the decision was made to close the plant.[16]

PGE argues that it is bad policy for the Commission to modify the outcome of the LCP. The utility notes that its decision to close Trojan was reached in the least-cost planning process and acknowledged by this Commission. Actions pursuant to an acknowledged LCP are in the public interest, PGE argues. The utility maintains that it must be able to rely on cost recovery for prudent actions, such as taking a facility out of service where that is the least-cost option. If not, PGE contends, utilities will have no incentive to discontinue operation of such facilities.

Disposition:

We agree with staff that the net benefits analysis is the appropriate vehicle for determining whether closure of Trojan was in the public interest for purposes of determining recovery of undepreciated investment. PGE argues that failure to grant recovery for least-cost actions could lead to utilities operating plants that should be closed. The Commission responds that if an LCP dictates closure of a plant and a

[16] The net benefits analysis and the LCP differ in a further particular also. Under the net benefits analysis, sunk investment cost is added to the cost of each option. An LCP focuses on the avoidable or deferrable costs of a resource option. The net benefit treatment of sunk investment cost does not, however, change the difference between the costs of any two options, so it does not play a role in staff's assessment of net benefits.

company continues to operate it, the company may not be allowed the full cost of operating the plant in rates. Thus a utility would have no incentive to keep a poorly run, expensive plant on line. Staff's net benefits methodology will be discussed and evaluated immediately below (S-50: Remove Additional Fixed Costs - Net Benefits Analysis). We also agree that the relevant study period for the net benefits analysis is 1995-2011.

Post-1991 Capital Expenditures

In addition to its net benefits analysis, staff reviewed PGE's post-1991 Trojan-related capital expenditures. Those expenditures have never been in PGE's rate base, because they were incurred after PGE's last general rate case, UE 79. These expenditures include all post-1991 steam generator costs (deferred or capitalized plugging, sleeving, and analysis activities), which amount to about $14.9 million, and a spare reactor coolant pump motor, purchased in March 1991 for $2.2 million and never used.

ORS 757.140 does not apply to these expenditures. They are evaluated simply as capital expenditures proposed for rate base treatment and excluded for reasons discussed under Issue S-49 below.

S-50: Remove Additional Fixed Costs - Net Benefits Analysis

As stated, a net benefit exists when the dollars saved by prematurely retiring plant are greater than the costs associated with building new plant. Here, staff made that determination with regard to the early retirement of Trojan by taking the difference between (1) the expected allowable long-term costs of continued operation of Trojan and (2) the costs associated with closing the plant plus expected long-term costs of replacing its output. Stated in algebraic terms, a net benefit exists if:

$$(X + Y) > (X + Z)$$

where: X = Unamortized investment in Trojan
Y = Expected allowable long-term costs of continued Trojan operation
Z = Replacement resource costs

Calculating the long-term costs of Trojan's operation and replacement resources is a difficult matter. Staff's net benefits analysis is necessarily detailed and complex. Difficulties arise in quantifying the long-term effects of a series of past choices and projecting them out 17 years. Relatively small changes in some key allowable cost inputs adjustments produce a large change in results. This sensitivity is a result of the fact that Trojan closed 19 years prior to the expiration of its 35-year license life.

To explain the net benefits analysis, we will describe briefly the numerous steps involved in staff's review and summarize staff's findings. PGE and, to a lesser extent, CUB, recommend a number of changes to staff's analysis. We address those arguments as they arise, and resolve disputed issues in the course of our discussion.

1. Least-Cost Plan (LCP) as a Starting Point

As noted above, staff concluded that PGE's least cost planning analysis was not appropriate for determining the net benefits of closing Trojan. However, staff determined that the company's LCP was a good starting point to establish both the long-term cost of replacing Trojan's output and the expected allowable long-term total capital and operating cost of the plant. For purposes of the net benefits analysis, however, staff found that it had to resolve two basic problems with the LCP before beginning its review. First, because PGE prepared the LCP in two parts--the November 1992 Plan and the 1993 Update--staff first had to combine and reconcile the results. Second, because the LCP relied on different planning "scenarios," staff had to identify and select the scenarios most compatible with a net benefits review.

Staff began its analysis by choosing the results of: (1) Case 1b in the 1992 Plan, which showed that continued operation of Trojan until 2011 would cost $110 million more than phase-out in 1996; and (2) Scenario 3 in the Update, which concluded that phase-out would cost $78 million more than immediate shutdown. Staff then combined the results of the two planning scenarios to obtain a beginning estimate of the higher cost of continued operation of Trojan relative to immediate shutdown, i.e., $188 million. Staff further determined that two additional adjustments were necessary to account for different assumptions about phase-out in Case 1b and Scenario 3. Staff removed additional O&M and A&G costs that PGE included in the 1993 Update. Staff also adjusted for capacity factor differences in 1993-1995 as part of the first step in its overall capacity factor adjustment

PGE raises two arguments relating to staff's use of the LCP as a starting point for its net benefits analysis. First, PGE challenges staff's reliance on Case 1b from the 1992 Plan. It believes that the LCP's probabilistic analysis, not the scenario approach, provides a more complete view of all potential outcomes and should be used in staff's net benefits test. Using the $168 million expected net present value of phase-out over continued operation determined from the probabilistic analysis instead of the $110 million figure from Case 1b would reduce the negative net benefit to about one-third of staff's estimate.

We are not persuaded by PGE's argument. As staff notes, the discrete input values used in Case 1b closely approximate the expected values of the probability distributions PGE constructed for the Trojan inputs. Moreover, Case 1b is based on replacement resources available to PGE, unlike the probabilistic analysis run with replacement costs derived from the Northwest Power Planning Council's regional model. Staff's use of Case 1b also allowed it to use the sensitivity analysis results reported by PGE for various Trojan and replacement cost inputs. For these reasons, we agree with staff that the Case 1b result, combined with Scenario 3, should be the starting point of the net benefits analysis.

PGE next contends that the least-cost planning results should be modified to reflect the use of different nuclear fuel assumptions in the 1992 Plan and the Update. We find PGE's proposed adjustment reasonable and accept it. This adjustment is further addressed below as part of our resolution of Issue S-50.

2. Adjustments to Update the LCP with Current Information

Staff next revised the least-cost planning results to incorporate currently available information. Staff made a total of four such adjustments. Three of the adjustments are not disputed: (1) to reflect lower transition costs experienced and projected by PGE for 1993-1995; (2) to recognize lower replacement power costs in 1993-1995, based on PGE's recent experience and current projections; and (3) to show lower gas prices, using the gas price forecast it sponsored in Phase I of this proceeding.

Staff's fourth adjustment revised the LCP to incorporate new information about the capital costs of long-run replacement resources. Staff modified the LCP to reflect (1) lower estimates of the installed cost of new gas-fired resources; and (2) a 100 MW reduction in PGE's reserve margin requirement. PGE challenges both elements of this adjustment.

First, PGE contends that staff's analysis overstates the costs of a new gas-fired resource by not correcting an error in the carrying charges[17] used in the 1992 Plan. We find PGE's proposed adjustment reasonable and adopt it. We address this adjustment below as part of our resolution of Issue S-50.

Second, PGE contends that the net benefits analysis should assume a 145 MW reduction in its planning reserve margin requirement, rather than staff's proposed 100 MW reduction. PGE contends that, in addition to a 100 MW reduction in its forced outage reserve requirements brought about by Trojan's closure, its operating reserve needs have also decreased by approximately 45 MW as a result of replacement power purchases. Because these power purchases carry their own operating reserves, PGE contends that staff's adjustment should reflect this additional reduction in the company's operating reserve requirements.

We find that staff's 100 MW reduction is more appropriate for a net benefits analysis. Although PGE claims to have experienced a reduction in its operating reserves, it admitted that it has not completed studies required to quantify any effect of closing Trojan on its operating reserve requirements. Furthermore, as staff points out, the replacement power purchases that purportedly reduce PGE's operating reserves are short-

[17] Carrying charges are factors used to convert capital costs into annual revenue requirements.

run replacements for Trojan. When long-run resources become operational, PGE's required operating reserves will increase.

3. Adjustment to LCP for 1995-2011 Study Period

To reflect a 1995-2011 study period, staff adjusted the LCP to remove the costs of continued Trojan operation and immediate shutdown for 1993-1994. Because the costs of continued operation are less than the costs of shutdown in 1993-1994, the adjustment increases the net benefits of closing Trojan.

4. Adjustments to LCP to Reflect Allowable Costs

As previously stated, a net benefits analysis compares the allowable costs of continuing to operate a plant to the costs of closure. To help determine the correct amount of present and future allowable costs, staff retained the services of Theodore Barry and Associates (TBA), an independent firm specializing in providing consulting services pertaining to the energy and telecommunications industries. TBA has performed many nuclear plant reviews, management assessments, and audits, and it has testified in numerous power plant rate case proceedings. We find TBA qualified to advise staff in its net benefits review.

TBA evaluated the reasonableness of PGE's operation and management of Trojan from its initial commercial operation in 1976 through current delicensing and decommissioning activities. TBA described its standard of review as follows:

> Whether PGE personnel, in managing activities associated with operations, maintenance, outages, engineering, modifications, quality assurance, and other activities at Trojan, made the decisions and took the actions, including the allocation of resources and the implementation of management and control systems, that a reasonable, experienced and competent manager of a licensed nuclear power facility would be expected to take, to operate and maintain the Trojan Nuclear Plant in a safe, reliable and cost effective manner. Where it appeared that such actions had possibly not been taken, and systems not implemented, we looked to see whether PGE management personnel took reasonable and timely actions to correct the situation.
>
> TBA focused on those factors that represented the controllable elements of plant-related activities, in the context of information that was known, or was available to, and should have been known by PGE at the time. We were careful not to judge PGE's actions based on the results of its actions; rather we ascertained whether PGE made a reasonable choice from among the

> alternatives that were, or should have been available, i.e., we were careful to avoid the use of hindsight in our assessments.
>
> In addition, we recognized that one or more courses of action can be deemed reasonable for a given set of circumstances, and did not limit our determination of reasonableness to only the best course of action, but considered the applicable range of reasonable actions in making our assessments.

TBA examined key areas of PGE's management and operation of Trojan to determine its reasonableness as well as its impact on key inputs for staff's net benefits analysis. Generally, TBA's evaluation can be divided into three major areas: (1) comparative performance analysis; (2) review of management issues; and (3) analysis of steam generator issues. TBA's evaluation and findings in these three areas are addressed separately, followed by a discussion of TBA's quantification of its findings for the net benefits analysis.

A. TBA's Comparative Performance Analysis

TBA compared Trojan's performance to that of other nuclear plants to help quantify the cumulative impact of the numerous controllable and uncontrollable factors on the plant's performance in the context of the performance achieved by comparable plants. TBA included several factors in its comparative analysis, including capacity factors,[18] availability factors,[19] O&M expenditures, Nuclear Regulatory Commission (NRC) Systematic Assessment of Licensee Performance (SALP) Report ratings, NRC Maintenance Team Inspection (MTI) Report ratings, and planned refueling outage duration.

Using these factors, TBA compared Trojan's performance to: (1) other single-unit nuclear plants; (2) other single-unit nuclear plants with pressurized water reactor (PWR) nuclear supply systems; (3) nuclear plants that began commercial operation between 1971 and 1981; and (4) all domestic nuclear plants. TBA selected those comparison groups to provide the maximum number of comparable nuclear plants for each parameter and include the plants with the characteristics most suitable for comparative purposes. In each comparison, TBA attempted to use as large a comparison group as possible in order to avoid skewing the data presented in the comparisons. At the same time, TBA was careful to exclude certain plants when the use of all nuclear plants would have been unfair to PGE. For instance, TBA excluded multiple-unit nuclear plants from O&M cost comparisons, because they typically have a lower O&M than single-unit

[18] Capacity factor is defined as the ratio of actual generation to maximum possible generation, based on the rating of the unit, expressed as a percentage.
[19] Availability factor is defined as the ratio, expressed as a percentage, of the total amount of generation a plant could have produced, without discretionary shutdowns or power outage reductions, to the maximum possible generation a plant could have produced without any outages, discretionary or not.

plants such as Trojan. These comparison groups typically included from 26 to 40 nuclear units out of a total of approximately 100 units currently operating in the United States.

After its review, TBA determined that Trojan's lifetime performance on a total O&M cost/MWh generated basis was good, compared to plants that faced similar regulatory and management challenges. TBA further determined, however, that the favorable cost comparison was largely due to Trojan's relatively low O&M costs for most years prior to 1987, which compensated for the plant's relatively poor capacity factor performance. O&M costs increased significantly beginning in 1987, and TBA concluded that Trojan did not compare favorably to other single-unit nuclear plants in 1993, the year PGE decided to close Trojan.

TBA also drew several conclusions regarding specific factors identified above to be used in its analysis. Stated briefly, TBA found that:

- Trojan's lifetime capacity and availability factors were significantly lower than the same factors for all domestic nuclear power plants through 1992.

- Trojan had an economy of scale advantage over smaller single-unit plants.

- Trojan performed favorably over its life on a nonfuel O&M cost/MWh generated basis, but significant O&M cost increases in 1987 and thereafter were an important factor in PGE's decision to close Trojan.

- Trojan's low average capacity factor, together with its increasing O&M costs, caused the plant to be more costly in the early 1990s than the average for other single-unit plants.

- PGE's SALP scores deteriorated from the early 1980s through the early 1990s.

- Trojan's MTI performance was in the lowest (worst) quartile of plants reviewed, suggesting that PGE did not pay appropriate attention to Trojan maintenance activities.

- Trojan's outage performance had a negative impact on capacity factor.

PGE disputes the validity of TBA's comparative analysis. It contends that TBA's findings are suspect for several reasons, including: (1) biased and improper comparison group selection; (2) biased and improper time period selection; and (3) incomplete data selection. PGE provides its own comparative performance analysis, which it believes establishes that Trojan cost performance throughout the period from

1976 through 1992 was exceptional as compared to a cross section of subgroups of nuclear plants.

After a review of both comparative analyses, we find TBA's study more reliable to help quantify the impact of numerous factors on Trojan's performance. TBA's conclusions are well reasoned and based on the most complete and appropriate information. We do not find PGE's comparative analysis persuasive and, for the following reasons, give it little weight. First, PGE's conclusions are based on a comparison of average performance over the life of Trojan and other nuclear plants. The use of lifetime performance averages, however, inappropriately masks Trojan's declining performance from 1987 through 1992, as well as industry trends in outage durations. Moreover, PGE did not base its LCP inputs on Trojan's lifetime average performance, but rather on Trojan's performance immediately prior to the formulation of the LCP.

Second, PGE inappropriately compared Trojan's performance to small subsets of plants that masked the impact of Trojan's regulatory compliance problems on its performance. For example, for its most comparable group of plants, PGE used selection criteria that resulted in a comparison group of only five other plants, many of which had poor performance characteristics. Similarly, PGE limited its comparison group for capacity factor and availability factor to 12 plants, eight of which were on the NRC's Watch List of Troubled Plants. We are more persuaded by the comparative analysis performed by TBA, which appropriately used minimum selection criteria to produce a large data set to dampen the effects of the best and worst performing plants, as well as the effects of individual plant performance anomalies.

We acknowledge that PGE made two comparisons that TBA did not -- comparisons on the basis of revenue requirements and capital expenditures. However, revenue requirements are heavily influenced by historical factors, such as initial capitalization and subsequent capital additions. These factors are generally not as controllable by management as other cost components, such as O&M. Furthermore, PGE inappropriately assumed an identical return on book value for all nuclear plants. To adopt that assumption, PGE erroneously assumes an identical capital structure for all nuclear plants as well as equivalent authorized rates of return on each category of capital fund. PGE made additional errors that cast doubt on the reliability of its comparisons. For example, PGE compared initial and total nuclear plant capitalization costs after inflating to 1993 dollars, when annual revenue requirements are based on historical costs.

Finally, PGE criticizes TBA's use of SALP scores. The NRC generates a SALP report approximately once a year for each licensee. For the functional areas reviewed, the NRC assigns a numerical rating of 1, 2, or 3, with 1 being the highest rating and 3 the lowest. PGE argues that TBA's use of SALP scores to define reasonable management performance is improper. We agree that a determination of imprudence should not be based solely on a licensee's SALP score. Nonetheless, TBA properly used SALP scores to identify areas warranting further investigation, such as quality assurance, engineering management, and other areas addressed below.

B. TBA Review of PGE Management

TBA next examined PGE's management of the Trojan plant. Based on the comparative performance analysis and a preliminary review of Trojan documentation, TBA identified and examined several areas it believed had the greatest impact on Trojan's performance, particularly during the years immediately prior to PGE's decision to close the plant. The areas reviewed by TBA included PGE's quality assurance, engineering management, operations management, maintenance management, outage management, and regulatory compliance performance.

TBA's review found several areas where PGE's performance was good or exceptional. TBA found that Trojan placed twelfth among thirty-nine plants on the basis of lifetime O&M costs/MWh generated. TBA characterized PGE's overall emergency preparedness as good, noting that Trojan was one of the first plants to have a public warning system. TBA also rated PGE's performance in nuclear fuel management, steam generator inspection and repair, and delicensing as excellent. With regard to nuclear fuel management, TBA found that Trojan's fuel costs since the mid-1980s were generally ranked among the lowest of all domestic PWR plants. It concluded that PGE's actions to address steam generator degradation, once it realized that serious problems existed, were extensive, timely, and appropriate. Finally, TBA noted that PGE's delicensing activities allowed it to reduce staffing at the plant more rapidly than anticipated and achieve significant costs savings.

TBA further concluded that PGE's operations management was generally good. Although PGE's operations management of Trojan deteriorated significantly from 1980 through 1984, TBA found that PGE was able to sustain improved performance into the 1990s. By the late 1980s, TBA believes that PGE's operations management was so good that it may have saved Trojan from being added to the NRC's Watch List of Troubled Plants.

TBA also found several areas where PGE's performance was poor or deficient, however. Those areas are as follows:

Quality Assurance: Quality assurance (QA) comprises all planned and systematic actions necessary to ensure that the plant and its components will perform satisfactorily in service. QA requirements are prescribed in Title 10 of the Code of Federal Regulations (CFR), Part 50, Appendix B, and are enforced by the NRC.

TBA found that PGE's QA program was either deficient or seriously deficient throughout most of Trojan's commercial operation. TBA determined that the root causes for the deficiencies were: (1) insufficient management involvement in the QA program direction and review; and (2) an inappropriate focus on administrative audits rather than performance audits. TBA concluded that, despite warnings and opportunities to improve QA performance, PGE did not make the necessary changes until the 1990s. TBA believes that these avoidable deficiencies had a noticeable impact on PGE's regulatory compliance and engineering and maintenance performance in the mid-to-late 1980s.

Engineering Management: The primary engineering activities associated with an operating nuclear plant include the design and engineering of plant modifications and additions; providing technical input regarding the operation of plant equipment, components and systems; providing technical support regarding the resolution of plant problems; providing technical input regarding plant licensing issues; and directing and coördinating activities regarding the nuclear fuel cycle.

TBA found that PGE's overall engineering and engineering management performance was significantly deficient. TBA determined that: (1) PGE's propensity to minimize the use of outside engineering firms, and to maintain relatively low salaries for permanent engineering personnel, required it to rely heavily on contractor personnel, which caused dissatisfaction among permanent employees and affected performance; (2) PGE's cost consciousness tended to limit opportunities for PGE's engineers to interface with others in the nuclear industry; (3) PGE's delay in moving engineers to the site limited their ability to become involved in plant-related activities; and (4) PGE's overall inability to effectively manage its engineering work force limited the effectiveness of its engineering support of plant activities. TBA concluded that the deficiencies were avoidable and severely affected PGE's regulatory compliance performance.

Maintenance management: Maintenance management comprises the management of the activities necessary to keep plant equipment, components, and systems in a state suitable for safe and reliable operation.

TBA found that PGE's overall maintenance performance deteriorated during the 1980s. TBA believes that these deficiencies contributed to PGE's overall declining performance in the mid-to-late 1980s and that the resulting cost impacts, while not as significant as in quality assurance and engineering, were avoidable.

Outage planning and management: Outage planning comprises the actions necessary, prior to an outage, to plan, schedule and prepare for outage activities in an efficient and timely manner. Outage management comprises the actions necessary to coordinate and perform the outage activities in an efficient and timely manner, including revising plans and schedules to accommodate changing conditions and emerging problems.

TBA found that Trojan's refueling outage performance was dismal starting in 1987. Among other things, TBA determined that Trojan's outages generally took significantly longer than planned. TBA concludes that the outage management deficiencies were avoidable and had a negative effect on Trojan's capacity factor.

Regulatory compliance: TBA examined PGE's recognition of and compliance with the regulatory requirements governing the engineering, design, operation, maintenance, and testing associated with Trojan's safety-related structures, systems, equipment and components. In its examination, TBA reviewed (1) the frequency of NRC-assessed violations at Trojan in the 1980s; (2) the impact of PGE's actions that were at the root of the violations; (3) the need to significantly improve PGE's performance on Trojan expenditures; and (4) the impact of all of the above factors on PGE's decision to close the plant prematurely.

TBA found that PGE's Trojan regulatory compliance was poor. This inadequacy, TBA determined, was caused by previously discussed management deficiencies, particularly in the areas of QA, engineering, operations management in the early 1980s, and maintenance management. TBA concluded that an important impact of PGE's poor regulatory compliance was increased O&M expenditures as the company attempted to "catch up" and improve performance. TBA noted that, during the period from 1986 to 1989, Trojan's nonfuel O&M expenditures increased from approximately $52 million to $102.3 million, an increase of almost 100 percent.

TBA also concluded that PGE ran a considerable risk in adopting a management strategy to minimize regulatory margin. The NRC defines minimum regulatory requirements for every aspect of nuclear operations. A nuclear plant's performance should exceed this minimum level to provide additional assurance that the plant operator will meet the minimum requirements. The level of performance above minimum regulatory requirements is called regulatory margin; the greater the margin, the greater assurance that the minimum requirements will be maintained. In order to maintain relatively low costs, PGE adopted a strategy of minimizing regulatory margin. TBA concluded, however, that the company's implementation of that strategy was seriously deficient. TBA found that PGE had failed to adopt appropriate criteria to guide its implementation activities, which prevented it from reacting appropriately to NRC feedback and concerns regarding its regulatory performance. TBA further found that the cumulative effect of these prior deficiencies made the implementation of corrective action in 1986 difficult, costly, and time consuming. TBA finally observed that, throughout the 1980s, the NRC assessed PGE with several Severity Level II and III violations and associated civil penalties as a result of the deficient regulatory compliance performance that resulted from its precarious strategy.

Summary: To summarize, TBA drew the following conclusions:

- Trojan was among the best performing nuclear plants in the early 1980s in terms of O&M cost/MWh generated and regulatory compliance.

- After 1982, Trojan's regulatory compliance began to deteriorate and, by 1987, Trojan's economic performance was declining due to significantly increased O&M costs with no offsetting improvement in capacity factors.

- By 1988, Trojan was among the worst nuclear plants.

- By 1992, Trojan had lost virtually all the prior cost advantage over other single-unit plants that it had achieved in the early 1980s through good management.

C. TBA's Analysis of the Steam Generator Issue

As a final area of its analysis, TBA examined numerous issues relating to the design, operation, and maintenance of the Trojan steam generators. TBA's review began with PGE's purchase of the steam generators from Westinghouse in 1968 and ran through PGE's decision to close Trojan in 1993.

TBA reviewed the steam generator design, PGE's purchase decision, and PGE's operation and care of the steam generators to determine, in part, how the equipment's degradation factored into the LCP and the net benefits analysis. TBA concluded that PGE acted prudently with regard to its steam generator degradation activities.

D. Quantification of Deficiencies for Net Benefits Analysis

In addition to its review of PGE's operation and management of Trojan, and partly in reliance on the findings from that investigation, TBA helped staff forecast certain key allowable costs of future Trojan operation. These three key components of the continued operation forecasts include: (1) O&M costs; (2) capacity factor; and (3) steam generator costs. In quantifying the impacts of PGE's management deficiencies, TBA applied a performance standard of what PGE could reasonably have achieved. TBA's quantification methodologies resulted in a range of values for the various inputs. The two extremes of each range are equally likely for the purpose of determining allowable costs. However, because the range reflects a prediction of costs that would have been allowed in future rate cases, only one value in the range would have been allowed and any amount above that would have been disallowed.

For the purposes of the net benefits analysis, staff used the midpoint of each range, because it represents the middle point between equally likely higher and lower values. Staff assumed a flat distribution, because it had no basis for concluding that any one point in the range was more likely than another. PGE challenges staff's use of midpoints, asserting that staff's methodology ignores other potentially acceptable values in the ranges of assumptions. We disagree. Staff supported its use of the midpoint values with a probabilistic analysis by: (1) assuming a uniform probability distribution over each range, i.e., assuming that all values in a range are equally probable and values outside the range have zero probability of occurring; (2) selecting a value from each range at random; (3) calculating the net benefit with the values selected; (4) repeating the input selection and the net benefit calculation many times; and (5) averaging the resulting net benefits estimates. Staff's analysis determined that the average expected net benefit is approximately the same as that determined by selecting the midpoint values. Furthermore, staff's approach is similar to the one PGE used in its least-cost planning analysis. PGE reported the expected value of the difference in costs between continued plant operation and phase-out from its probabilistic analysis, just as staff has done for net benefits.

As discussed above, TBA's review of PGE's operation of Trojan revealed management deficiencies that resulted in significant cost increases from 1987 to 1992. From those findings, TBA concluded that PGE's least-cost planning analysis forecasted significantly greater, and inappropriate, O&M costs, an inappropriately low capacity factor, and inappropriate costs related to steam generators. We address each issue separately.

O&M Costs and Escalation Rates: TBA considered three primary factors in determining a reasonable level of Trojan's 1993 O&M expenditures: (1) PGE's actual budget for Trojan's 1993 expenditures; (2) the impact of the steam generator issue on Trojan's 1993 O&M budget; and (3) the impact of PGE's management deficiencies, prior to and during 1992, on Trojan's O&M budget. On a related issue, TBA also calculated appropriate O&M cost escalation factors for use in staff's updated net benefits analysis.

In its cost calculation, TBA started with Trojan's 1993 nonfuel O&M budget of $115.8 million. It then reduced that figure by $5.3 million to account for avoidable steam generator inspection and repair costs. This left $110.5 million. TBA then reduced the $110.5 million O&M cost level by 5 to 10 percent. TBA concluded that this additional reduction was necessary to reflect a previous management cost advantage that PGE should have been able to maintain due to its management strategy of minimizing costs while attempting to minimize regulatory margin. TBA's result is an allowable 1993 nonfuel O&M range of $99.5 to $105.0 million. The midpoint of TBA's range, $102.3 million, is within a range for the average nonfuel O&M expenditure for single-unit plants in 1993, adjusted for Trojan's economy of scale and management strategy cost advantage.

With regard to O&M cost escalation factors, TBA looked at industry data for the period 1981 through 1993. Based on that historical industry data, as well as current regulatory reform initiatives and increased competitiveness in electricity markets, TBA believes a 0 percent real O&M escalation factor is appropriate for the period from the present through 1996, while an O&M projected real growth rate of 0 to 3 percent is appropriate for the period 1997 through 2011.

PGE challenges both of TBA's calculations. First, PGE contends that TBA's projection for Trojan's 1993 O&M expenditures is too low, asserting that TBA applied a standard of perfection in determining the input for the net benefits analysis. PGE contends that the proper standard of performance for quantifying the company's imprudence should be based on industry average performance, rather than the performance PGE could reasonably have achieved with its management strategy advantage and the economy of scale advantage inherent in a plant with Trojan's capacity. We disagree. In recognition of the fact that Trojan was located in a low-cost market, PGE adopted a management strategy that minimized costs while also attempting to minimize regulatory margin. TBA's quantification of PGE's imprudence, therefore, is appropriately based on PGE's failure to maintain its management strategy, while also recognizing that PGE's actual regulatory margin was inappropriate. In other words, TBA did not apply a standard of perfection, but rather an appropriate performance standard of what PGE could have reasonably achieved.

PGE also challenges TBA's inclusion of newer single-unit plants in its comparison group to verify the reasonableness of the results of its quantification of Trojan's 1993 nonfuel O&M expenditures. PGE contends that Trojan costs are more appropriately compared with those plants that began operation between 1971 and 1981. We find TBA's comparison group appropriate. Trojan's MW rating made it the largest single-unit plant placed into operation prior to 1982. Trojan's economy of scale advantage, therefore, can and should be measured against the average of all single-unit plants. Similarly, PGE's management advantage was a function of economics, which relates to all single-unit plants, not merely a particular vintage of plant.

PGE further argues that Trojan's 1993 budget is not appropriate to use as a starting point for determining the nonfuel O&M cost input, because PGE had already made a decision to phase out the plant in 1996 and had begun to cut back on programs and costs. However, PGE's 1993 budget was approximately $11 million greater than its actual 1992 nonfuel O&M expenditures, a significantly greater increase than the average nonfuel O&M costs increases for other single-unit plants for that period. Moreover, PGE identified a reduction in its 1993 budget of only $2.2 million for programs that were to be either scaled back or eliminated due to its decision to phase out the plant in 1996.

With regard to TBA's O&M escalation factors, PGE claims that O&M escalation should be three percent real from 1993 forward, rather than TBA's proposed 0 percent real until 1997 and a range of 0 to 3 percent thereafter. However, TBA reviewed the nuclear industry's real nonfuel O&M per KW for 1989-1993 and found that it declined by an average of 0.53 percent per year. This fact was partially anticipated by PGE in its 1992 Plan, in which PGE stated:

> In addition, hindsight now shows that increased regulatory activity following Three Mile Island (TMI) caused many of the historical increases above inflation in fixed O&M and capital costs. The industry has essentially completed the TMI-related work, and industry data indicates that recent nuclear O&M expenditures have leveled and may possibly indicate a decreasing trend.

Moreover, TBA persuasively argues that this downward trend is sustainable and may even intensify because of: (1) industry-wide efforts to reduce regulatory costs; and

(2) increasing competition in the electric utility industry. For these reasons, we find TBA's 1993 O&M cost estimates and O&M escalation factors appropriate for inclusion in staff's net benefits analysis.

Capacity Factor: To determine an appropriate capacity factor for Trojan for 1993, TBA considered the following five factors: (1) PGE's capacity factor projections for Trojan; (2) the capacity factor achieved at similar plants; (3) the impact of the steam generator issue on Trojan's capacity factor; (4) the impact of PGE's outage planning deficiencies; and (5) the impact of Trojan's twelve-month operating cycle.

To make its determination, TBA utilized the median of 1991-1993 average design electrical rating net capacity factors for 50 large domestic reactors like Trojan, rated at 1020 MW and above. It then adjusted that figure to eliminate the impact of steam generator tube problems, then credited Trojan for the adverse impact of its twelve-month operating cycle. TBA's quantification determined that Trojan's capacity factor should have been at least 67.6 to 71.6 percent. Staff chose the midpoint of this range, 69.6 percent, as its imputed capacity factor for Trojan.

PGE contends that staff's projection is too high. It first challenges TBA's use of the median 1991-1993 average design electrical rating net capacity factors for domestic reactors rated at 1020 MW and above. It contends that the most appropriate comparison group for a capacity factor quantification consists of plants larger than 1000 MW and placed in service between 1971 and 1981. We disagree. Again, PGE's narrowly defined comparison group inappropriately skews the results of its analysis. Its comparison group consists of only twelve plants, many of which were out of service during extended periods of time, thus lowering the capacity factor average. It is also important to note that TBA's comparison group included many boiling water reactors (BWR), which had an average capacity factor that was 8.6 percent less than pressurized water reactors like Trojan in 1991-1993. The influence of BWR units in TBA's comparison group, combined with PGE's own projection for a significant capacity factor improvement after steam generator replacement, supports TBA's conclusion that Trojan's capacity factor should have been at least 67.6 to 71.6 percent.

PGE also challenges TBA's adjustment to the capacity factor to account for steam generator problems. TBA's adjustment was based on an Electric Power Research Institute (EPRI) report formulated specifically for the purpose of determining the impact of steam generator problems on capacity factor. We do not find PGE's argument persuasive and reject it.

Steam Generator: PGE's least-cost plan analysis includes steam generator repair costs in O&M expenditure projections, steam generator replacement costs in capital expenditure projections, and capacity factor reductions for steam generator repair and replacement activities through 1996. TBA concluded that PGE's liability for the steam generator problems was not accounted for in its LCP. This issue is further addressed below as part of Issue S-49, Steam Generator Plugging, Sleeving, and Analysis and Spare Reactor Coolant Pump Motor. We disallow both the inclusion of steam generator replacement costs from the LCP (approximately $183.1 million) and the post-1991 capital expenditures.

As an additional issue, PGE contends that staff's use of the LCP inappropriately assigns the benefit of a planned 45 MW uprate to the ratepayers. An uprate is an increase in a plant's electrical production capacity and usually comprises a change in plant operating parameters, such as pressure or temperature, that allow existing plant equipment to produce a greater amount of electricity. PGE's 1992 Plan includes a 45 MW increase in Trojan capacity at the time of planned steam generator replacement in 1996. PGE argues that the benefits of the added capacity should be removed if no steam generator replacement is included in the net benefits analysis. PGE explains in its rebuttal testimony:

> If we must assume that customers would not pay for the cost of the new steam generators, then we must also assume that they do not receive any incremental benefits associated with the new steam generators.

The replacement of the Trojan steam generators would have provided PGE with the opportunity to "piggyback" the costs associated with obtaining regulatory approval for a power uprating onto the costs necessary to obtain regulatory approval for operation with the replacement steam generators. TBA concluded, however, that PGE could have achieved the 45 MW uprate with the original steam generators, had they not been defective. In fact, PGE considered a 45 MW uprate using the original steam generators in the late 1980s. PGE ultimately determined that the uprating was not feasible, however, due to the defects in the original steam generators that required a significant number of tubes to be plugged. Moreover, without the many plugged tubes, an uprating could have been accomplished at a cost of only a few million dollars, as compared to the significant costs of steam generator replacement. For these reasons, we conclude that the benefits of the additional 45 MW of additional capacity that PGE included in its least-cost plan scenario are properly included in the net benefits analysis.

Staff's Conclusions from Net Benefits Analysis

Adjusting PGE's least-cost planning results, staff concluded that, for the 1995-2011 test period, the premature closure of Trojan resulted in a negative net benefit of approximately $23.6 million. In reaching that conclusion, staff used the midpoints of the ranges developed by TBA for 1993 fixed O&M, fixed O&M escalation factors, and capacity factors. Staff also removed the costs of steam generator replacement from the LCP results, for reasons addressed below as part of Issue S-49, Steam Generator Plugging, Sleeving, and Analysis and Spare Reactor Coolant Pump Motor.

Based on its net benefits analysis, staff concludes that continued operation of Trojan would have cost less than immediate shutdown in the absence of steam generator defects and management errors at Trojan. Accordingly, staff recommends that we should hold PGE's ratepayers harmless from the effects of the steam generator defects and management failures by disallowing $23.6 million of the company's remaining investment in the plant.

Position of Other Parties

As an additional issue, CUB and Kullberg argue that the decision to build Trojan was imprudent in and of itself. CUB compares Trojan's cost with the cost and performance of coal plants after Trojan was completed and brought on line. The comparison is not well supported. A prudence review takes into account the information that was available to decision makers at the time the decision was made. It does not engage in hindsight or second-guessing; to do so would be unfair. PGE could not have known those data about coal plants at the time it decided to build Trojan. The record does not contain evidence about what information was available to PGE when it decided to build Trojan, and it cannot support a decision of any kind on that issue.

Moreover, every rate case the Commission has decided since Trojan began operating has included Trojan in rate base. It would be inappropriate now to overturn the decisions in each of those rate orders from 1976 on.

Disposition - S-50: Remove Additional Fixed Costs--Net Benefits Analysis

We conclude that the allocation of the remaining Trojan investment is properly determined by a net benefits analysis. The purpose of a net benefits test is to identify the point at which ratepayers are indifferent between the options of continued operation of Trojan and shutdown and construction or acquisition of replacement resources. Application of the test is intended to hold ratepayers harmless for a utility's poor operation or management.

Staff evaluated numerous issues presented by a net benefits review. It retained an expert witness, TBA, to review PGE's operation and management of Trojan. In its review, TBA applied a reasonable person standard, similar to that commonly employed in utility prudence review proceedings. TBA based its evaluation on information available to a decision maker at the time of the decision. Based on TBA's findings, staff completed a quantitative analysis to determine whether assessing ratepayers 100 percent of Trojan's remaining costs is in the public interest. After revising its net benefits analysis to incorporate some changes suggested in PGE's rebuttal testimony, staff determined that the premature closure of Trojan resulted in a negative net benefit of approximately $23.6 million. With the adjustments described below, we adopt staff's net benefits analysis.

Adjustments to Staff's Net Benefits Case: Staff's initial net benefits analysis did not include seven potential adjustments that were not quantified or that were raised during the Phase II hearings. We have reviewed those adjustments and adopt them with the correction and exception noted below. We also adjust the estimated net benefit to recognize the interaction among the individual adjustments, as discussed below.

1. 45 MW Increase in Trojan Capacity. Staff's analysis assumed that the 45 MW uprate would have taken place in 1996, along with the steam generator replacement, as PGE had assumed in its LCP. However, if the steam generator degradation had not occurred, the increase could have been achieved without replacing the steam generators. Assuming a date earlier than 1996 would reduce the net benefit of closing Trojan, because the extra 45 MW would obviate the need for 45 MW of power from other resources. Staff included the 45 MW capacity increase in its net benefits analysis starting in July 1996.

CUB calculated that moving the start date back to the beginning of the test period (January 1995) would reduce the net benefit of closing Trojan by $7.7 million (PGE share, 1995 dollars). We find that CUB's calculation is incorrect because: (1) it does not account for the variable O&M associated with additional generation; (2) it does not recognize that the costs used are expressed in 1993 dollars; and (3) it does not discount the value of the additional generation properly. The corrected figure (using CUB's assumed 65 percent capacity factor) is $6.1 million.

We find the corrected adjustment reasonable and adopt it.

2. Capacity factor. In its capacity factor quantification, TBA determined that the industry median capacity factor was depressed as a result of steam generator problems. Relying on a study by EPRI, TBA concluded that the capacity factor should be increased by 2.6 percent to adjust for the steam generator tube problems. At hearing, however, CUB demonstrated that TBA had overlooked the fact that the EPRI study also indicated that steam generator replacement activities reduced capacity factors by an additional .65 percent. TBA testified that its imputed capacity factor range should be increased by this amount to accurately account for all of the effects of the steam generator problems. Staff, in turn, testified that such an adjustment in TBA's range would also increase its mid-point imputed capacity factor by .65 percent, for a value of 70.25 percent. Increasing capacity factor by .65 percent reduces the net benefits of closure by $20.5 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt it.

3. Fixed O&M. Staff's base case used the mid-point of TBA's O&M range, $102.25 million, for allowable fixed O&M for 1993. TBA's nonfuel O&M, however, is not the same as PGE's fixed O&M. PGE treated variable O&M as separate from nuclear fuel costs. Therefore, allowable fixed O&M should be determined by subtracting variable O&M from TBA's nonfuel O&M estimates.

At the 60 percent Trojan capacity factor assumed for 1993, variable O&M totals $5.8 million. Subtracting this figure from TBA's nonfuel O&M produces a range for fixed O&M of $93.7 million to $99.2 million, with a midpoint of $96.45 million. This $5.8 million reduction in fixed O&M, extrapolated out over the study period, and using the O&M escalation figure in staff's surrebuttal testimony, reduces the net benefit of closure by $51.8 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt it.

4. Nuclear Fuel Costs. Nuclear fuel estimates are necessary to compare the cost of operating Trojan at a given capacity factor to the cost of replacement resources used to generate an equivalent amount of energy. In combining the results from the two parts of the LCP, staff assumed that the 1992 Plan numbers for fuel costs in Case 1b were calculated in the same manner and contained the same assumptions as the Update's Scenario 3. Based on that assumption, staff combined the results of Case 1b and Scenario 3 for use in its net benefits analysis. PGE explained, however, that it used lower nuclear fuel costs during phase-out in the Update than in the 1992 Plan. Accordingly, the net benefits analysis should use consistent assumptions to estimate nuclear fuel costs. This correction increases the net benefit of closure by $25.7 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt the updated figure.

5. Transition Costs. Staff reduced the cost of the immediate shutdown alternative to recognize the fact that PGE has experienced lower transition costs than assumed in the least cost plan. Staff's net benefit estimates do not include any corresponding transition cost savings under continued Trojan operation with shutdown in 2011. If transition costs in PGE's LCP were overestimated for immediate closure, staff believes that they may also have been overstated for continued plant operation. Staff concluded that some savings in transition costs after 2011 would be likely. Recognizing these savings would reduce the net benefit of immediate closure. Staff does not suggest a figure to represent savings in transition costs after 2011, although CUB quantifies the savings at $30.8 million, starting from the same $65.6 million for which staff adjusted the cost of immediate closure (PGE share, 1995 dollars).

PGE describes its reduction in transition costs over its LCP projections as the result of aggressive and quick cutting of costs. Staff does not challenge that description.

We do not adopt this post-2011 adjustment. Staff was not certain that transition costs were actually overstated for continued plant operation, and did not quantify the amount. CUB's quantification, in view of staff's circumspect approach to this issue, is not supported by the record. CUB simply assumes that the savings would be the same for continued operation. Moreover, PGE achieved some of the savings by aggressive action. Imputing a lower than projected cost to transition in 2011 is tantamount to penalizing PGE for acting quickly to cut costs.

6. **Carrying charges.** It is standard industry practice to recognize a small amount of capital replacement in the fixed O&M assumptions for combustion turbines. While PGE's fixed O&M assumptions were consistent with this practice, the company also accounted for capital replacement costs in carrying charges in the 1992 Plan. To conform with other forecasts in the industry, and to eliminate any double-counting of costs, PGE subsequently reduced the carrying charges to eliminate the allowance of capital replacements beginning with its 1993 avoided cost filing.

PGE argues that the net benefit analysis should also use the carrying cost rate from the 1992 Plan corrected to eliminate the inclusion of interim capital additions for new combustion turbine generating plants. We agree. Although the reduction in capital costs exceeds PGE's fixed O&M assumptions, the adjustment to the carrying charges reflects industry practice of assuming very small capital additions for combustion turbines. Moreover, we approved PGE's projections of the capital costs of combustion turbines in acting on the company's 1993 and 1994 avoided cost filings. The net benefits test should use the capital additions assumptions as updated in those avoided cost filings. Using corrected carrying cost rates increases the net benefit of closure by $68.9 million (PGE share, 1995 dollars).

We find this adjustment reasonable and adopt it.

7. **Capital Costs of New Gas-Fired Resource.** Staff's net benefit figures for the cost of replacement resources are based on PGE's least-cost planning estimate of the capital cost of a combined-cycle combustion turbine, the principal resource replacing Trojan. PGE's figure is lower than those being used by PacifiCorp and the NWPPC in their current planning processes. PGE estimates the capital costs for the turbine at $550/KW, PacifiCorp at $586/KW, and NWPPC at $630/KW. PGE has not shown why its estimate is so much lower than that of the other entities. Substituting PacifiCorp's estimate for PGE's would make the net benefits analysis more negative by $16.0 million (PGE share, 1995 dollars).

We conclude that PGE has not shown why its estimate is more reasonable than the other, higher estimates in question. We find it more reasonable to adopt the middle estimate, $586/KW, and adjust staff's analysis accordingly.

Adjustment for Interactions. A further change in the net benefits estimate is needed to account for interactions among the individual adjustments described above. Increasing capacity factor by .65 percent, for example, increases the value of advancing the 45 MW capacity increase at Trojan to January 1995. Revising carrying charges changes the effect of updating the capital cost of replacement resources. Using the staff's net benefits model, we find that recognizing all the interactions increases net benefits by $3.0 million, and we adjust the net benefits estimate accordingly.

Summary of Adjustments

The following table summarizes the effects of the adjustments discussed above:

Staff's net benefits analysis result	-$23.6 million
Adjustments to Staff's Calculations	
January 1995-June 1996 uprate to 45 MW.	-$ 6.1 million
Increase capacity factor by .65 percent	-$20.5 million
Decreasing Imputed Fixed O&M by $5.8 million	-$51.8 million
Update to nuclear fuel assumptions	+$25.7 million
Update to staff's carrying costs	+$68.9 million
Update to capital costs of replacement resources	-$16.0 million
Adjustment for interaction	+$ 3.0 million
Total effect of adjustments	+$3.2 million
Total of adjustments and staff's net benefits calculation	-$20.4 million
Post-1991 disallowances	-$17.1 million
Total disallowance including post-1991 expenditures	-$37.5 million

Remaining Trojan Investment	Ratepayer Share	
$288.2 million	$250.7 million	87 percent

We find that with these adjustments, the net benefits analysis approximates the point at which ratepayers are indifferent between continued operation of Trojan and shutdown, with replacement of the generating resource. We also find that this recovery under the adjusted net benefits analysis is in the public interest. ORS 757.140(2).

Transition Costs

TBA also reviewed PGE's 1993-1996 transition costs. PGE defined transition costs as "the operations and corporate overhead costs associated with closing Trojan, operating and maintaining the spent fuel pool, and securing the plant until dismantlement can begin." TBA determined that the transition costs included in the proposed test years are reasonable, and staff recommends full recovery of the amount requested by PGE. We adopt staff's recommendation.

S-45: Trojan Overtime

Staff proposes the removal of all overtime compensation budgeted by PGE for the Trojan plant in its filing. Staff notes that the plant was permanently shut down in January 1993, and requires only security, monitoring, and maintenance staff. Staff believes that PGE's personnel levels are adequate to accomplish those activities without the need for overtime. PGE disputes staff's proposed adjustment, but does not provide sufficient explanation to justify recovery of those costs. After a review of this matter, we agree that the budgeted overtime should be removed.

S-46: Trojan Investment Classification

The Commission has adopted the FERC Uniform System of Accounts as a basis for utility accounting requirements. The Uniform System of Accounts is a comprehensive basis of accounting and provides, among other things, distinct accounts for assets and other debits.

In its filing, PGE proposes to leave certain Trojan assets in FERC Account 101, Plant in Service, an account designated for original costs of electric plant owned and used by the utility in its electric utility operations. PGE believes that the assets, which primarily include the spent fuel pool and related systems, as well as the administrative buildings, should continue to be classified as plant in service because they remain used and useful for the purpose for which they were intended. Staff disagrees with PGE's proposal and recommends that all net investment in Trojan systems, including Trojan Material and Supplies Inventory, be placed in FERC Account 182.2, Unrecovered Plant and Regulatory Study Costs. That account is defined to include significant unrecovered costs of plant facilities that have been prematurely retired. Because both accounts are included in PGE's rate base, transferring investment between the accounts will not affect the rate base.

PGE and staff agree that the placement of plant in FERC Account 101 means that the plant is "used and useful in the public service." PGE contends that that requirement is met, because the Trojan plant remaining in that account protects public health and safety, provides security, or provides office space and facilities for the employees that remain on the site. As staff notes, however, the original purpose of the assets in question was to be part of an operating plant that was providing service to rate payers. That plant has now been permanently shut down, and those assets are now used only to provide the service necessary for safety and asset preservation pending decommissioning and dismantling of the plant. Moreover, while the spent fuel at Trojan is the result of "used and useful" service by the plant, it is being stored at Trojan only because the United States Department of Energy (USDOE) has failed to establish a permanent federal repository for nuclear waste. In short, the continuing activities at Trojan are related to decommissioning, not productive operation of the facility.

We acknowledge that there is no prescribed method of accounting for nuclear plants that are in the process of being decommissioned. FERC is currently working on a position paper regarding this issue, but it has not yet been issued. The Financial Accounting Standards Board (FASB), however, has taken a position on accounting for plant that is removed from service. In its Statement 90, the FASB states:

> When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-progress or plant-in-service.

For these reasons, we find that the Trojan plant is no longer used and useful. All the Trojan plant investment, including accumulated depreciation, accumulated deferred income tax, and deferred investment tax credit, as well as Trojan Materials and Supplies Inventory, should be transferred to FERC Account 182.2, Unrecovered Plant and Regulatory Study Costs. PGE's filing should be modified accordingly.

S-47: Trojan Salvage Proceeds

Staff also recommends that the unrecovered Trojan plant placed in FERC Account 182.2 be reduced to reflect a greater amount of projected recovery through salvage sales of surplus Trojan assets. Staff believes that PGE's original estimate of salvage recovery of $6.7 million is reasonable for the equipment that was included in the estimate, but adds that the estimate does not include any recovery for the buildings or certain installed plant equipment. Because the costs of the installed plant equipment and unused buildings are significant, staff proposes that the estimated salvage proceeds be increased by $6 million, for a total amount of $12.7 million, PGE share.

PGE acknowledges that the revised estimate of salvage recovery does not include any recovery for buildings and only $506,000 for installed plant equipment. The company argues, however, that it is unrealistic to expect that salvage sales will exceed the level predicted. PGE notes that it has aggressively attempted to market installed plant equipment to foreign nations, but adds that no major sales are pending. It also cites numerous efforts to market the approximate 149,000 square feet of space available for sale or lease at Trojan. Those efforts, however, have generated little interest.

Both PGE and staff agree that the sales of surplus Trojan assets through 1995 and 1996 are difficult to determine. The book value of the underlying Trojan assets, however, is significant. According to PGE's numbers and classification, the value of plant items and materials and supplies is approximately $232 million after reductions of PGE's estimated salvage sales. We share staff's concern that the use of low salvage estimates for those assets would cause the rate base and amortization expense to be too high.

Accordingly, we find staff's proposed adjustments reasonable and adopt them. If actual salvage is less than staff's projection, PGE's loss will be limited to the return on the difference between staff's estimate and the company's estimate for the period between the end of this rate case and the end of the next one. Actual recovery will have been determined by the time of that next rate case, and any shortfall can be returned to PGE's rate base.

S-48: Trojan Decommissioning

Definition of Decommissioning. According to the Rules and Regulations of the NRC (10 CFR 50.2), "'Decommission' means to remove [a facility] safely from service and reduce residual radioactivity to a level that permits release of the property for unrestricted use." In this docket, staff has used a more inclusive definition of decommissioning. The NRC's definition refers only to those portions of a facility affected by radioactivity, but staff uses the term to include all activities related to removing total plant from service and restoring the site to unrestricted use. We adopt staff's usage of "decommission." We also adopt staff's definition of decommissioning cost as the total cost of removing Trojan from service, net of any salvage recovery.

Decommissioning Costs: Capital or Noncapital? When we entered our decision in DR 10, staff considered decommissioning costs to be a noncapital expense. *See* Order No. 93-1117 at 14. In the meantime, staff has reconsidered its position. It now considers decommissioning costs to be capital costs. Capital costs may be recovered under ORS 757.140(2).

Staff reached its current conclusion about decommissioning costs by determining that decommissioning costs are conceptually equivalent to the negative net salvage value of property removed from service.[20] If that equivalence is valid, decommissioning costs are capital costs because salvage value is associated with capital investment (property).

Net salvage value (the difference between salvage value and cost of removal) is a depreciation concept. Depreciation is the method this Commission uses to provide for the recovery of the total investment in property and the cost of removal of that property from service at the end of its estimated life.[21] Positive net salvage value reduces the rate of depreciation. Negative net salvage value increases the depreciation rate. If the cost of removal is greater than the salvage value of the property, then the sum to be recovered will be greater than the original investment.

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[20] Staff's determination is supported by Frank K. Wolf and W. Chester Fitch, *Depreciation Systems* (Ames, IA: Iowa State U/ Press, 1994), who refer to decommissioning as "large negative salvage" (p. 7) and as "significant negative net salvage"(p. 52).
[21] ORS 757.140(1) requires each public utility to carry an adequate depreciation account. Under that provision, the Commission ascertains and determines the proper rates of depreciation.

The following formula expresses the equivalence of decommissioning costs and net negative salvage:

$$D = SV - CR$$

where D = decommissioning costs; SV = salvage value; and CR = cost of removal. We agree with staff that decommissioning costs are equivalent to negative net salvage value and are therefore capital costs.

Background of Trojan Decommissioning. When Trojan went into service in 1976, PGE included an allowance for net salvage in its depreciation rates. Negative net salvage percentages were attributed to the Structure & Improvements account and the Reactor Plant Equipment account. By Order No. 79-055, the Commission required the company to make a decommissioning cost study as the basis for estimating the cost of taking the plant out of service. PGE submitted the study and a funding proposal in 1979. The Commission approved the plan and the funding proposal in Order No. 80-612, issued August 18, 1980.

PGE's 1979 plan called for the plant to lie dormant for 100 years after its closing, at which time it was to be dismantled. PGE proposed to fund the decommissioning through an internal sinking fund account within its depreciation reserve.[22]

In Order No. 91-186 (UE 79), consistent with rule changes of the NRC, the Commission adopted a new decommissioning plan and cost estimate. The new plan called for the immediate dismantling of the plant at the end of its estimated life (2011). The decommissioning fund was changed from an internal fund to an external trust fund administered by an independent trustee, pursuant to NRC requirements. The fund balance was $48.9 million at the end of 1993.

Current Plan. In this docket, PGE has proposed a revised decommissioning plan. The principal elements of its plan are:

1. Early large component removal. The company plans to remove the steam generators and pressurizer for burial by December 1995.

2. Construction of a "dry" on-site fuel storage facility for long-term storage of spent nuclear fuel. The facility would be completed by 1998 and the spent fuel

[22] A sinking fund is designed to produce a desired sum of money at the end of a given time period. A payor makes a series of payments into an interest-bearing account throughout the period. The sum of the payments plus accrued interest will equal the desired total at the end of the period. "Internal" in this discussion means internal to PGE. PGE established the sinking fund as part of its depreciation reserve. Interest accrued at the company's rate of return. The company was to maintain the fund.

would be stored there until shipment to a permanent federal storage facility (target date: 2018).

3. Removal and dismantling of all contaminated systems and some building demolition from 1998 through 2002.

4. Site restoration activities. After the shipment off-site of the spent fuel in 2018, all facilities with no further value will be dismantled and the site made available for unrestricted use. This will occur from 2018 through 2023.

PGE notes that early implementation of decommissioning will give its customers the benefit of current low burial rates and mitigate the risk of losing access to a low-level radioactive waste burial site.

Funding of the Current Decommissioning Plan. Beginning in 1995, PGE proposes to contribute $14,041,000 annually to the external trust fund. The contribution will continue through the year 2011. The period ending in 2011 was chosen for distributing decommissioning costs because that is the period over which the Trojan closure is expected to produce benefits. After 2011, Trojan would have been replaced by other resources in any case, so the generation of ratepayers after 2011 should not share in decommissioning costs.

PGE's proposal to contribute an equal amount each year to the external trust fund is a departure from the method of contribution adopted in UE 79. In that docket, it was assumed that Trojan would operate until 2011, and the Commission adopted a funding plan under which each generation of customers would contribute equally on a real levelized basis, with payments increasing over time to offset the effect of inflation. The real levelized funding plan would have matched costs with benefits received by the ratepayers. That is, ratepayers receiving the benefit of the plant would pay for its decommissioning. PGE's current contribution under this plan is $11,220,000 in 1994, which would have increased to $21,120,000 by 2011.

Trojan was shut down in 1993, however. The company now proposes a nominal level contribution. The payment into the decommissioning fund will be the same each year. Under this plan, in real terms, decommissioning costs to future ratepayers will decline because of inflation. The increased level of current contribution is required because Trojan shut down earlier than expected. The current payment to the decommissioning fund is inadequate and must be increased.

Even with the proposed increase in annual contribution, the company will have to borrow to bridge its needs. As currently estimated, however, the cash flows will eventually fund the cost of decommissioning including repayment of the interim financing. The company's investment strategy concentrates on municipal and corporate bonds.

PGE's Efforts to Involve Other Entities. In DR 10, we imposed the condition that PGE involve other entities in its decommissioning efforts. PGE has held discussions with the NRC, USDOE, EPRI, and other utilities. It has performed work relating to steam generators for Duke Power's Catawba plant, and has other proposed programs. The NRC has shown interest in performing containment tendon grease leakage studies and electrical cable aging studies at the Trojan facility.

Staff's Review of PGE's Plan and Funding Proposal. As part of its case, staff reviewed both PGE's decommissioning plan itself and the proposal for funding it. Staff asserts that PGE's decommissioning plan meets all criteria of the NRC and the Oregon Energy Facility Siting Council and recommends that we adopt it. In addition, staff states that PGE's proposal is the least-cost decommissioning option.[23] Staff also notes that, as the process of decommissioning evolves, PGE will doubtless find it necessary to make changes in its total cost estimate. The plan and its funding mechanism should therefore be subject to regular, ongoing review by the Commission and staff. Necessary changes in authority granted to PGE by the Commission can be made in future dockets.

Positions of URP and Kullberg. URP first contends that PGE's proposal is not prudent under the circumstances and that ratepayers should not have to pay for it. URP believes that PGE's decommissioning plan disadvantages PGE in its pending suit against Westinghouse because the large component removal destroys evidence that PGE needs in its lawsuit and possibly in other forums.

Second, URP contends that the NRC may order modifications to PGE's decommissioning plan and that Commission approval is therefore premature. Kullberg also argues that decommissioning costs should not be reflected in rates prior to NRC approval of the plan. Kullberg has specific disagreements with PGE's plan as well, and urges that decommissioning should be delayed to gather more information and reduce uncertainty about a number of elements of the plan.

In response to URP's first contention, we are not persuaded that PGE's removal of the steam generators will harm ratepayers, especially since this order disallows the post-1991 steam generator costs. The first of URP's arguments is rejected.

As to waiting for NRC approval, we understand that the final plan may differ in some respects from the current proposal. We also understand that as decommissioning proceeds, it may be necessary to make still further revisions in the plan or its financing. We acknowledge that there is a great deal of uncertainty in the whole area of decommissioning. Therefore, PGE's decommissioning plan and its funding mechanism will be subject to regular, ongoing review by the Commission and staff. Necessary changes in authority granted to PGE by the Commission can be made in future dockets.

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[23] As part of the planning process, PGE's consultant evaluated four decommissioning options available to PGE and estimated their cost in 1993 dollars. PGE's option is the least costly of these four options.

We conclude that it is not necessary to wait for NRC approval before approving PGE's decommissioning proposal.

As to the request that decommissioning be delayed pending further study, we find it more likely than not, based on the record before us, that delay in implementing the plan will increase the costs of decommissioning. That is an undesirable outcome. Moreover, early decommissioning allows PGE to take advantage of disposal site availability. Continued Commission oversight of the decommissioning process will address the question of changing circumstances as decommissioning proceeds. The arguments for delay are rejected.

DR 10 and Recovery of Decommissioning Costs. In DR 10, Order No. 93-1117, we concluded that we would consider favorably allowing PGE to recover Trojan's decommissioning costs in rates, if PGE met the following conditions:

> 1. PGE must prove all six assumed facts in a rate case or similar forum. (See the section above, "Applicable Law," for the six assumed facts.)
>
> 2. PGE must show that it pursued the least-cost decommissioning option consistent with directives from the Nuclear Regulatory Commission and other agencies.
>
> 3. PGE must show that it has made a reasonable effort to ascertain if other entities wishing to gain valuable experience in decommissioning a nuclear plant of this size would participate in and support its decommissioning activities.
>
> 4. PGE must report within 30 days any settlement or award related to decommissioning costs for the Trojan plant.
>
> 5. PGE must provide satisfactory evidence with regard to any other matter the Commission deems pertinent to a decision in a rate proceeding.

Disposition of the DR 10 Conditions. We conclude that PGE has met the DR 10 conditions. The first condition, proof of the six assumed facts, was discussed above, in the section titled "The DR 10 Requirements," p. 27. We found that PGE has shown all but one of the six facts. We have discretion to allow recovery of decommissioning costs, however, in view of PGE's substantial compliance with the requirement that it prove the assumed facts.

As to the second condition, based on current information, PGE's chosen plan is the least-cost option. Third, PGE has made good faith efforts to involve other entities in its decommissioning efforts; we note its efforts to contact the NRC, EPRI, the USDOE, and other utilities. The fourth condition, report of any settlement or award related to decommissioning costs, is not yet ripe. We continue to impose this requirement on PGE. We have not imposed the fifth condition.

We approve PGE's decommissioning plan and funding plan for inclusion in rate base on the effective date of the tariffs adopted in this order.

S-49: Steam Generator Plugging, Sleeving, and Analysis and Spare Nuclear Reactor Coolant Pump Motor

Steam Generator Issues:

The steam generators figure in the analysis of Trojan-related costs in two ways. First, the cost of *replacing* the degraded steam generators was imputed in PGE's 1992 Least-Cost Plan and 1993 Update. Second, PGE incurred capital expenses relating to *repairing* the steam generators in the time between its last general rate case, UE 79, and this rate case. TBA's evaluation of the steam generator issue addresses both of these costs.

Replacing the generators: In its least-cost planning process, PGE considered replacing the steam generators. PGE included the cost of replacement in its least-cost analysis of closing Trojan. The expected cost of replacing the generators in 1996 is $183.1 million. Staff recommends removing from the net benefits analysis all costs associated with replacing the steam generators. If the cost of replacing the steam generators were included in the net benefits analysis, the cost of continued operation would be higher and the net benefit of closure would therefore be greater. Staff's proposal imputes to PGE the cost of replacing the steam generators, for purposes of the net benefits analysis.

Repairing the generators: After January 1, 1992, PGE incurred capital costs for plugging and sleeving the generators and analyzing the problem. Post-1991 Trojan-related capital expenditures have never been in PGE's rate base. PGE proposed to have them become rate base items for UE 88 recovery purposes. Staff recommends disallowance of the steam generator capital expenditures. The total amount of recommended disallowance is approximately $14.9 million.

In considering how to treat the cost recovery associated with the steam generators, TBA reviewed Westinghouse engineering and design activities and PGE's purchase, operation, maintenance, and care of the Trojan steam generators. The review covers the period from 1968, when PGE purchased the generators from Westinghouse, through 1993, when PGE decided to close Trojan.

PGE noted significant degradation of the steam generators in 1989. By 1991, over 25 percent of the steam generator tubes were either plugged or sleeved.[24] The

[24] Sleeving is a process whereby another tube is permanently inserted into a degraded tube.

generators had degraded to the point that PGE had planned to replace them in 1996. TBA concluded that Westinghouse design flaws were the root cause of the steam generator degradation. TBA found no imprudence on PGE's part with respect to its maintenance and operation of the generators.

Staff argues that we have the discretion to hold PGE responsible for the costs associated with the steam generator problems and recommends that we exercise our discretion in favor of the ratepayers. Staff's position derives from TBA's recommendation that PGE be held liable for steam generator costs even absent a finding of negligence on PGE's part.

Staff notes that the Commission has broad discretion when it comes to ratemaking. As the Oregon Supreme Court said, "The [Commission] appears, therefore, to have been granted the broadest authority -- commensurate with that of the legislature itself -- for the exercise of [its] regulatory function." *Pacific N.W. Bell v. Sabin*, 21 Or App 200, 214 (1975). Staff concludes that we have the discretion to disallow the costs associated with steam generators and to remove the cost of replacing them from the net benefits analysis.

Staff supports its conclusion by referring to *Pennsylvania Public Utility Commission v. Philadelphia Electric Company*, 561 A2d 1224 (1989). In that case, the Pennsylvania Supreme Court dealt with an order of the Pennsylvania Public Utility Commission in which that commission disallowed replacement power costs stemming from two shutdowns of a nuclear power plant. The second shutdown occurred because of a manufacturing defect, which the court said could not be attributed to the utility. The court nevertheless held that the commission was correct in assigning replacement power costs to the utility rather than to ratepayers. The court reasoned:

> By disallowing the replacement costs, the Commission held that the utility and not the ratepayers were in a far superior position to seek redress for the defects and negotiate contractual protections to minimize any future problems. [W]e believe a utility company is in a better position to prevent an occurrence or provide for protection against any such occurrence. After all, it was the utility which chose the contractor, negotiated the contract, and is in a position to seek damages for any losses sustained under the contract. While the utility may have to bear the initial losses incurred as the result of its contractor's negligence, it is in a far better position to aggressively pursue the tort-feasor for reimbursement. If we were to hold otherwise, the utility would have no incentive to pursue the tort-feasor, having already received full compensation for its losses. 561 A2d at 1228.

Staff also supports its position with reference to product liability law, which illustrates that the law can impose a burden on a party not judged to be at fault. If a customer is injured by a product through no fault of her own, for instance, product liability law imposes liability on the merchant, even if faultless, because the merchant is better situated than the customer to pursue remedies against the manufacturer. Restatement (Second) of Torts, Section 402A.

PGE argues that there is no legal precedent for holding it strictly liable for the defective steam generators; that TBA took a contrary position in another case; that staff's various legal analogies (see below) are inapposite because this is not a tort case but a ratemaking proceeding; and that to hold it strictly liable would be to set a dangerous new precedent. PGE also makes the policy argument that if we impose steam generator costs on PGE without a showing of imprudence, it will eliminate a protection now available to utilities when they seek cost recovery for expenditures.

Disposition:

We are persuaded by staff's arguments. Even if PGE is faultless, PGE is better situated to pursue remedies against Westinghouse than its ratepayers are. PGE is correct when it argues that this is a rate case, not a tort case, and that the legal precedent staff cites can be distinguished factually from the present case. However, someone must bear the costs relating to the steam generator defects. As between PGE and the ratepayers, we find it fairer to assign the costs to PGE, based on the reasoning in *Pennsylvania Public Utility Commission v. Philadelphia Electric Company.* That case is different on its facts because the vendor and the utility were in an ongoing contractual relationship, but the principle enunciated applies to the present case, as does the principle of product liability law stated above.

The fact that TBA took a contrary position in another case does not decide the issue now before us.

Finally, PGE argues that imposing steam generator costs on it in the absence of imprudence means that utilities lose the protection of prudence as the basis for cost recovery when they purchase goods or services from another. The Commission decides cost recovery issues on a case by case basis. No future outcome is determined by the decision to impute the cost of steam generator replacement to PGE by removing their cost from the net benefits analysis and disallowing the post-1991 plugging, sleeving, and analysis costs.

Spare Reactor Coolant Pump Motor:

This is another post-1991 Trojan-related expense that staff recommends should be disallowed. Trojan had four coolant pump motors that circulated water to cool the reactor. These pumps were required for the safe operation of Trojan, and if one motor had failed, Trojan would have had to be taken off line. It could have taken up to nine months to repair or replace a motor.

In 1986, PGE assessed the need for a spare motor. PGE inspected the existing motors, which had operated since 1976, and found them to be in excellent condition. PGE decided against purchasing a spare motor. In 1988 and 1989, PGE again studied the issue of purchasing a spare motor and explored several options, none of which involved PGE's sole purchase of a spare motor. PGE explored sharing a spare motor with another plant, for instance, and purchasing a motor stator (a motor component subject to the highest proportion of motor problems). PGE again decided against purchase. In Spring of 1991, it decided to purchase a spare motor from Westinghouse for $2.2 million. When PGE decided to close the plant in 1993, the motor had not yet been delivered. PGE decided not to accept delivery, because to do so would significantly reduce the motor's salvage value.

PGE argues that its decision to purchase the motor was prudent, pointing out that between 1984 and 1988, 19 reactor coolant pump motors failed in the industry. Moreover, PGE is aware of at least 20 other nuclear power plants that purchased or had access to a spare reactor coolant pump motor. PGE argues that the costs of the motor should therefore be included in rates.

Staff opposes including the cost of the spare reactor coolant pump motor in rates. Staff argues that the 1991 decision to purchase the motor is not supported by an adequate analysis. Although PGE assessed its need for a spare motor in 1986 and 1988, it did not do a new assessment in 1991. There is therefore no record to show why PGE decided to purchase the spare motor by itself, or why it purchased an entire motor rather than a stator. Staff maintains that PGE's general discussion of the impact of an outage and its relatively old data on motor failures do not support such a large capital investment.

Disposition:

We conclude that the $2.2 million investment in the spare reactor coolant pump motor was not prudent and that the investment will not be allowed in rates. The 1988 studies explored options that are different from the one PGE chose in 1991, so PGE cannot use those studies to support its 1991 decision. The data from 1986 are too remote to rely on. Here, as with all issues in a rate case, PGE has the burden of proof, and has not carried it.

S-51: Remove Trojan Power Cost Deferral
S-52: Trojan Plant Income Tax Write-off Revision

PGE's initial filing included an estimate of the accumulated deferred income taxes associated with Trojan, including the write-off for tax purposes of the portion of Trojan that PGE considered to be no longer in service. Accumulated deferred taxes reduce rate base and give customers the time value of the income tax reductions. Total Trojan accumulated deferred income tax includes amounts related to several timing differences other than the Trojan write-off, including depreciation, decommissioning, retention plan, and other costs.

Staff originally accepted the amounts that PGE included in its filing for deferred taxes and write-off. In its rebuttal testimony, however, PGE revised the amount of accumulated deferred taxes for two reasons: to remove deferred taxes associated with Trojan excess power cost deferrals (Issue S-51) and to reflect a substantially reduced actual Trojan income tax write-off (Issue S-52).

On Issue S-51, PGE proposes to remove from rate base included in PGE's November 1993 filing the accumulated deferred income taxes for Trojan excess replacement power costs. The November filing incorrectly included $24.4 million of deferred taxes related to PGE's UE 85 and UM 594 power cost deferrals in the 1995 and 1996 rate bases. We will address those deferrals in separate dockets. That removal increases revenue requirement by $3,305,000 in 1995 and $3,337,000 in 1996. Staff agrees with PGE that these excess accumulated deferred taxes should be removed from rate base, and agrees as to the amount of taxes to be removed. We conclude that the Trojan excess power cost deferrals should be removed from rate base.

Issue S-52 deals with PGE's November 1993 filing, which forecast a Trojan tax write-off of $120.5 million. The actual write-off was only $66.6 million, which, PGE argues, increases the 1995 and 1996 rate base by $21.4 million and $22.3 million, respectively. According to PGE's revised calculation, the January 1, 1995, rate base reduction for accumulated tax deferrals related to a write-off would be $26.2 million, a $21.0 million change from the $47.2 million in PGE's initial filing.

Staff agrees that write-off tax deferrals should be revised, but differs with PGE on the proper amount. Staff challenges two elements of PGE's revisions. First, PGE's figures do not incorporate the effects of a tax write-off associated with the property it continues to classify as utility plant in service. In the discussion of Issue S-46 (Trojan Plant Classification) above, we concluded that Trojan assets are no longer used and useful for providing service, and are thus no longer to be classified as plant in service. According to staff, PGE's recommended rate base increases should be reduced by an initial amount of about $13 million, with appropriate changes for each of the test years.

Second, staff argues that we should use a different reserve for salvage than PGE does when it calculates the effects of a full tax write-off. PGE uses $19.3 million, or 20 percent of original cost, to lower the estimated total write-off. In its investment projections, PGE estimated salvage sales at $3.9 million. We have determined that the value of salvage sales should be set at $12.7 million (see discussion of Trojan salvage sales, Issue S-47 above). Staff proposes to use the same figure, $12.7 million, for both the reserve for salvage and the value of salvage sales. Staff's proposed figure is lower than PGE's, produces a higher initial deferred tax reserve, and lowers rate base by $2.6 million.

To summarize the effects of these two proposed changes, PGE supports a beginning amount of write-off of accumulated deferred taxes of $26.2 million. Staff proposes a beginning write-off of $41.7 million. $13 million of the difference derives from whether a full write-off is taken and $2.6 million is associated with the amount of salvage reserve to be included in estimates.

We previously found that Trojan should no longer be considered plant in service (Issue S-46). Accordingly, we adopt staff's position that the revision should incorporate the effects of a full write-off. We also determined that $12.7 million is the appropriate figure to use for Trojan salvage sales (Issue S-47). Therefore, we also adopt staff's position that $12.7 million is appropriate to use for salvage reserve. These adjustments increase revenue requirement by $871,000 for 1995 and $1,119,000 for 1996.

S-53: Trojan Intangible Asset Reclassification

PGE's November 1993 filing included Trojan Intangible Assets in total rate base but did not specifically identify them as Trojan rate base and did not include them in the "Trojan Only" analysis. Reclassifying them now will make them part of any Trojan Only analysis and result in a proper matching of Trojan rate base to the Trojan intangible depreciation expense. This adjustment increases 1995 and 1996 Trojan revenue requirement by $303,000 and $156,000, but is offset by a matching reduction to non-Trojan revenue requirement. Staff supports this reclassification. We find that Trojan intangible assets should be reclassified as PGE proposes.

Trojan Balancing Account

In the February 27, 1995, stipulation, PGE and staff agree that it is appropriate to vary the amortization of the Trojan investment to take into account the actual revenue collected from customers as a result of our decision in this case. Rather than creating a balancing account, the parties agree that incremental or decremental amortization expense amounts generated as a result of the stipulation will be accumulated in a Trojan Investment Recovery Account (TIRA). The TIRA is designed to provide a procedure to precisely accumulate actual revenue received by PGE as recovery of the Trojan investment based on amounts authorized in this order.

No party opposes the balancing account. We have reviewed this stipulation, attached as Appendix D, and find it reasonable. We adopt the stipulation in its entirety.

Other Adjustments

Staff and PGE agree on the following adjustments as well:

(1) To correct the nuclear fuel construction work in progress;

(2) To remove from all staff-proposed Trojan-specific revenue requirement recommendations and alternatives, all amortization expense, deferred income tax expense, and deferred investment related to the United States Department of Energy Decommissioning and Decontamination payment.

(3) To incorporate in the calculation of Trojan deferred income taxes the proper Schedule M adjustments, including the Trojan materials inadvertently left out of staff's Phase II Trojan deferred investment.

After reviewing these matters, we find these adjustments reasonable and approve them.

Appendix F attached shows the stipulated and unstipulated adjustments to PGE's original filing, along with their revenue requirement effect for 1995 and 1996. Appendix G shows the rate consequences of our decision, broken down by rate class, without and with the BPA residential exchange credit. Appendix H, attached, shows the percent of marginal costs attributable to each customer class.

CONCLUSIONS

1. Portland General Electric Company is a public utility subject to the Commission's jurisdiction.

2. The Commission should adopt the stipulations attached as Appendices B, C, D, and E.

3. Based on the record in this case, Portland General Electric Company's rates that result from the stipulations and the Commission's conclusions in the body of the Order are just and reasonable.

ORDER

IT IS ORDERED that:

1. The stipulations attached as Appendices B, C, D, and E are adopted in their entirety.

2. The other adjustments the Commission has made in the body of this Order are adopted.

3. PGE may file revised tariffs consistent with the stipulations and the findings of fact and conclusions in this Order to be effective April 1, 1995. PGE shall file such tariffs by March 30, 1995, or as soon thereafter as possible.

Made, entered, and effective MAR 29 1995.

Ron Eachus
Commissioner

Roger Hamilton
Commissioner

Chairman Smith concurs in part and dissents on the following issue:

S-38: Decoupling

I dissent from the Commission's conclusions and direction to PGE to proceed with decoupling, for the same reasons I dissented in Order No. 92-1673 (UM 409).

Decoupling was designed to promote energy efficiency and demand-side management (DSM). It is meant to remove disincentives to a utility's acquisition of demand-side resources from the traditional rate of return regulation framework. Order No. 92-1673 asserts that "[n]o other change in the regulatory system can ensure that we will move toward the goals of [reducing energy consumption]."

That assertion is even less supportable today than it was at the conclusion of UM 409. The marketplace has changed and will continue to change dramatically, requiring traditional regulation to evolve toward a more market-based approach. In the face of competition in generation and the prospect of comparability in the transmission system, electric utilities are responding by looking for ways to be and become lowest-cost providers.

This need (or perceived need) to be competitive drives inefficiencies out of the utilities' systems and produces a new, lower set of price signals. By definition, neither the customer nor PGE is likely to make uneconomic energy decisions. In the short term, the effect on DSM programs will be more than "perverse"; it could be close to fatal. That is, regulators may not have the leverage to require energy efficiency or DSM programs, because it will be even more difficult for programs to meet cost-effectiveness standards while remaining price competitive.

Not only will market prices be the controlling factor in customer response choices, but the inherent inability of traditional regulation to promote DSM will surface as well. Managing the proposed decoupling mechanism may well prove even more difficult, costly, and problematic than administering past and current DSM programs. For example, the administrative costs may be high, because the tariff will require "information on monthly revenues, incremental costs, and margin" as well as six-month reviews. I note that with regard to *incentive* mechanisms, the SAVE tariff (Schedule 101), which was considered a particularly effective DSM incentive mechanism, bogged down early in administrative burdens and disputes over measurements. Now the Commission has no way to require its continuation, and PGE has determined that its benefits do not outweigh its costs and rate impacts.

As this order issues, the legislature is considering alternatives to traditional rate-of-return regulation. States are studying how to restructure the electric industry. The FERC is aggressively promoting comparability in wholesale transmission access and wheeling. In the West, regions and subregions are forming transmission groups to manage cooperative arrangements for wheeling power across systems. The federal marketing agencies face the first real change in how they do business since their formation.

Decoupling is not consistent with these and other movements toward greater competition, because decoupling insulates a utility from lost margins that result from lost retail sales. For example, if PGE should lose a customer to self-generation, decoupling would restore those lost margins to PGE. I believe these business risks are more appropriately left with PGE than shifted to the ratepayers through decoupling. PGE is better situated to manage these risks and compete on price or service quality whenever necessary. As the market becomes more competitive and firms compete for their share of energy sales, it does not seem apposite to institute a policy that essentially guarantees the utility a fixed level of sales and resulting margins. The standard competitive framework does not guarantee each company a fixed sales level and resulting margins. Rather, the sales level and profitability of a company is directly related to how well and efficiently the company satisfies the needs of its customers.

The time for decoupling has passed. The changes in energy markets, the burdens and difficulty in administration, and PGE's reluctance all militate against use of this mechanism to meet the Commission's goals of promoting energy efficiency. Decoupling should not be implemented.

Nevertheless, the goal of using energy resources efficiently and wisely remains. The goal of diversifying the resource base remains. It is just that circumstances have loosened regulators' grip on traditional levers. We must find other ways of meeting the need and the challenge. Decoupling is not the solution. The doubts and questions voiced in my dissent in Order No. 92-1673 have not been answered. It is time to consider other forms of regulation more attuned to the evolving energy marketplace.

Joan H. Smith
Chairman

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of this order. The request must comply with the requirements of OAR 860-14-095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-13-070(2)(a). A party may appeal this order to a court pursuant to ORS 756.580.

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UE 88

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10/27/94

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon Filed by PORTLAND GENERAL ELECTRIC COMPANY - Advice No. 93-26	)))))	STIPULATION

RECITALS

1. On November 8, 1993, Portland General Electric Company filed for a general rate change affecting its price schedules in Advice No. 93-26. Docket UE-88 is the proceeding for resolution of the issues in Advice No. 93-26.

2. The new price schedules are based on PGE's expected revenue requirement for a two-year test period covering 1995 and 1996. On November 8, 1993, PGE filed testimony, exhibits, and workpapers in support of its 1995 and 1996 revenue requirements (the November 8 filing).

3. On March 21, 1994, the Staff of the Public Utility Commission of Oregon (Staff) filed a motion to amend the schedule and to bifurcate. In this motion, Staff requested that issues considered by the Commission in the DR 10 proceeding related to PGE's Trojan Nuclear Plant (Trojan) and cost of capital be considered apart from all other issues. The Hearings Officers granted the Motion to Bifurcate on May 3, 1994 and established a schedule for the Trojan-related issues and cost of capital. For purposes of this Stipulation, Phase I refers to proceedings

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related to issues other than Trojan and cost of capital, Phase II refers to the proceedings related to Trojan and cost of capital. This stipulation primarily covers Phase I issues.

4. Pursuant to the Hearings Officers' Memorandum and Ruling of December 15, 1993, the Staff filed for discussion at the Phase I settlement conferences, a "Staff Issues List" dated March 25, 1994. The Staff Issues List identified Phase I adjustments Staff proposed to PGE's requested revenue requirements components for test years 1995 and 1996 as set forth in the November 8 filing.

5. On May 10, 1994, PGE filed supplemental testimony concerning power cost issues. On May 13, 1994, Staff filed testimony, exhibits, and workpapers in support of its position concerning PGE's 1995 and 1996 Phase I revenue requirements. On June 9, 1994, Staff filed supplemental testimony concerning power cost issues.

TERMS OF STIPULATION

WHEREFORE, PGE and Staff hereby agree to the following with respect to PGE's requested revenue requirements, rate spread, and rate design as set forth in the November 8 filing. Designations beginning with "S-" are from the March 25, 1994 Staff Issues List.

1. PGE and Staff agree that the revenue sensitive factors shown in Attachment 1, attached to and made a part of

this stipulation, should be used in the determination of PGE's required revenues for test years 1995 and 1996. PGE and Staff further agree that adjustments to test years' expenses, including tax deductible interest, should have related tax effects calculated using the following effective rates: Federal, 35%; State, 6.672%; Environmental, 0.12%.

PGE and Staff also agree that a factor of 4.55% should be applied to all operating expense and tax adjustments to the November 8 filing data to derive the appropriate revisions to the working cash rate base allowance.

Corrections to the November 8 filing (S-1 through S-11)

2. S-1. PGE will decrease its operation and maintenance (O&M) expenses in 1995 by $299,000 and in 1996 by $628,000 and will decrease taxes other than income in 1995 by $7,000 and in 1996 by $15,000 to correct an error in the November 8 filing. The November 8 filing mistakenly and inappropriately included a double inflation of PGC direct charges to PGE.

3. S-2. PGE deferred the savings from terminating its membership in EPRI in October 1993 pursuant to Order No. 91-186. Rather than amortize the savings of $1,715,000 in 1995 and $1,717,000 in 1996 through Docket UE-88, PGE will file to amortize them simultaneously with its 1995 SAVE rate changes. No revision of November 8 filing data is required.

4. S-3. PGE will decrease its requested O&M expenses in 1995 by $23,000 and in 1996 by $24,000 to remove Category "C" advertising mistakenly and inappropriately included in the November 8 filing.

5. S-4. PGE will decrease its requested O&M expenses in 1995 by $1,230,000 and in 1996 by $1,488,000 to correct an error in the calculation of costs for the retirement savings plan. PGE inadvertently and inappropriately escalated the matching fund expense for inflation twice and did not reduce expense to reflect a tax deduction for stock dividends used to pay off ESOP debt.

6. S-5. PGE will decrease its requested O&M expenses in 1995 by $1,497,000 and in 1996 by $160,000 to reduce legal expenses that were overstated in the November 8 filing.

7. S-6. PGE will decrease its requested O&M expenses in 1995 by $314,000 and in 1996 by $702,000 to reflect a reduction in the escalation rate of its active health and dental costs from 15 percent to 12 percent per year.

8. S-7. PGE will increase its requested other revenues at current rates in 1995 by $687,000 and in 1996 by $688,000 to refund to customers the 1990 through 1994 accruals for carrying costs originally expensed on PGE's books but subsequently charged to Trojan and Boardman co-owners. In addition, PGE will decrease O&M expenses in 1995 by $73,000 and in 1996 by $71,000 to reflect ongoing charges to co-owners.

9. S-8. PGE will increase its requested O&M expenses

in 1995 by $1,870,000 and in 1996 by $2,953,000 to correct service provider costs that the November 8 filing understated primarily because World Trade Center rent and facility costs were charged to a deferral account and not allocated to appropriate expense accounts. The November 8 filing service provider budgets were also understated because they were preliminary and were not escalated for inflation.

10. S-9. PGE will increase its requested net utility plant in 1995 by $438,000 and in 1996 by $414,000 to reflect an inclusion in rate base of tenant improvements to the conference rooms in Building 2 of the World Trade Center. These tenant improvements are consistent with associated revenues included in the November 8 filing.

11. S-10. PGE will increase its requested O&M expenses in 1995 by $692,000 and in 1996 by $808,000 to include interest on the Managers' and Directors' Deferred Compensation Plan balances that was excluded from the pool of PGC costs billed to PGE per the November 8 filing.

12. S-11. PGE will decrease its requested income tax expense in 1995 by $192,000 and in 1996 by $608,000 and increase accumulated deferred income taxes in 1995 by $1,478,000 and in 1996 by $3,483,000 to correct several errors discovered in the calculation of income taxes included in the November 8 filing.

<u>Adjustments to the November 8 filing (S-12 through S-44)</u>

13. S-12. PGE will change its requested revenue requirement elements as shown below to reflect an increase in anticipated loads resulting from updating PGE's load forecast model with more recent economic data.

	1995	1996
Sales to consumers	$4,392,000	$1,854,000
Net variable power costs	$2,126,000	$1,021,000
Distribution operation and maintenance	$ 260,000	$ 232,000
Depreciation	$ 85,000	$ 75,000
Property taxes	$ 33,000	$ 29,000
Utility plant	$2,135,000	$1,863,000
Accumulated depreciation	$(85,000)	$(75,000)

The parties agree to include an estimate for variable power costs but do not agree on the amount. This can be calculated following a final decision in Issue S-13. The new load forecast includes the Smurfit displacement loads identified by Staff.

14. S-13. No agreement has been reached on appropriate test years' variable power costs.

15. S-14. PGE will increase its requested other operating revenues in 1995 by $1,574,000 and in 1996 by $1,609,000 to reflect revenues from NSF/reconnect/field service fees, temporary connections, billing job profits, and the BPA irrigation discount inadvertently and inappropriately excluded from the November 8 filing. No agreement has been reached on appropriate revenues from operation of the Energy Resource Center

(ERC).

16. S-15. No agreement has been reached on appropriate test years' employee wage and salary levels.

17. S-16. PGE will decrease its requested O&M expenses in 1995 by $3,745,000 and in 1996 by $3,861,000 and taxes other than income in 1995 by $412,000 and in 1996 by $425,000 to reflect removal of some incentive pay. Reductions equal 50 percent of the Our Teamworks program costs, 75 percent of the non-officer Annual Cash Incentive (ACI) Program expenses and 100 percent of the officer ACI Program expenses.

18. S-17. PGE will decrease its requested O&M expenses in 1995 by $1,957,000 and in 1996 by $2,046,000 to remove from the November 8 filing those costs associated with the supplemental executive retirement program. In addition, PGE will increase rate base in 1995 by $1,200,000 and in 1996 by $2,389,000 to reflect reduced accumulated unfunded liabilities for which customers have paid.

19. S-18. PGE will decrease its requested O&M expenses in 1995 by $1,845,000 and in 1996 by $2,172,000 and increase rate base in 1995 by $477,000 and in 1996 by $542,000 to remove from the November 8 filing all elements associated with the managers' deferred compensation program.

20. S-19. PGE will decrease its requested O&M expenses in 1995 by $204,000 and in 1996 by $194,000 to remove from the November 8 filing all costs associated with the directors' deferred compensation and pension plans.

21. S-20. PGE will decrease its requested O&M expenses in 1995 by $314,000 and in 1996 by $748,000 to reflect a reduction from the November 8 filing of costs associated with medical/dental insurance. The change results from a reduction in the annual escalation factor from 12 percent to 7 percent. In addition, rate base will decrease by $65,000 in 1995 and $276,000 in 1996 to reflect the related capitalized medical costs' impact on utility plant in service.

22. S-21. PGE's November 8 filing includes O&M expenses associated with membership in the Electric Power Research Institute (EPRI). The parties agree that $1.782 million for 1995 and $1.879 million for 1996, in expenses related to EPRI membership may be included in rates subject to the conditions outlined below.

PGE plans to rejoin EPRI on January 1, 1995, if EPRI revises its fee structure to allow varying levels of participation and targeted research. If PGE does not rejoin EPRI on January 1, 1995, because EPRI does not revise its fee structure or for some other reason, or if the annual EPRI expenses are less than the amounts specified above, PGE will defer for refund to customers the revenues associated with the EPRI-related expenses included in UE 88, except for revenues associated with such amounts as PGE demonstrates it has spent pursuant to the following criteria:

A. The expenditure is for outside services or materials only. No PGE labor or overheads will be included.

B. The requesting department shows that the expenditure for outside services or materials is incremental to amounts budgeted for such items in the test period.

C. The requesting department demonstrates that the cost incurred is a direct result of not being a member of EPRI; i.e., the project or research was previously an EPRI project or EPRI provided similar research or support.

D. The requesting department prepares a statement on the need for the research expenditure and the desired result. Only expenditures related to distinct and tangible research activities will be accepted. Expenditures related to other more general activities, including, but not limited to, strategic planning, performance measurement, reporting processes, corporate strategy, budgeting, and forecasting are not acceptable.

The decision as to what qualifies as an acceptable expenditure in this regard will reside solely with the Commission and its staff.

No later than March 1 of 1996 and 1997, the Company will submit a report as to the expenses it believes qualify for treatment under this Stipulation for the preceding year. Any amounts falling short of the annual sums specified above will be deferred, as of year end, for future disposition by the Commission. Interest on deferrals will accrue at the authorized rate of return in UE 88 with one-half years' interest added to each vintage year's initial accrual.

This procedure will continue until the Commission issues a rate order in the general rate proceeding immediately subsequent to UE 88.

23. S-22. PGE will decrease its requested O&M expenses in 1995 by $1,073,000 and in 1996 by $1,594,000 to reflect the application of WEFA Fourth Quarter inflation forecasts to PGE's operation and maintenance expenses in place of the WEFA June inflation forecasts used in the November 8 filing.

24. S-23. PGE will decrease its requested O&M expenses in 1995 by $103,000 and in 1996 by $108,000 to remove from the November 8 filing certain non-labor expenses forecasted in the Customer Accounting area.

25. S-24. PGE will decrease its requested O&M expenses in 1995 by $278,000 and in 1996 by $286,000 and taxes other than income in 1995 by $15,000 and in 1996 by $16,000 to remove from the November 8 filing expenses associated with its Community Development program.

26. S-25. PGE will decrease its requested O&M expenses in 1995 by $203,000 and in 1996 by $212,000 and taxes other than income in 1995 by $15,000 and in 1996 by $16,000 to reduce the forecasted cost of PGE's market information function.

27. S-26. For 1995, PGE will decrease its requested net utility plant $687,000. For 1996, PGE will decrease its requested net utility plant by $7,421,000 , O&M expense by $700,000, and amortization expense by $2,562,000 to reflect a reduction in the forecasted rate base for the CS/2 customer information system, an on-line date of July 1, 1996, rather than January 1 as forecast in the November 8 filing, amortization over ten years rather than five years, and a forecast decrease in operation and maintenance costs following implementation of CS/2. As PGE receives revenue from the sale of CS/2 to other utilities, it will credit 91.2 percent to the unamortized balance of CS/2 and 8.8 percent to other income and deductions.

28. S-27 through S-30. No agreement has been reached on appropriate test years' category A advertising, power smart expenses, HVEA program expense or Energy Resource Center (ERC) expenses.

29. S-31. PGE will revise its requested revenue requirement elements as follows to include a forecast of energy efficiency investment and savings in each year in base prices,

rather than Schedule 103 as proposed by PGE.

	1995	1996
Sales to consumers	$(4,086,000)	$(12,226,000)
Other operating revenues	$ 254,000	$ 244,000
Net variable power costs	$(4,059,000)	$(8,576,000)
Other operation and maintenance	$ 1,160,000	$ 3,128,000
Energy efficiency investment	$19,916,000	$ 47,856,000

The parties support continued use of an energy efficiency investment true-up mechanism, such as presently exists in Schedule 101, and agree that such mechanism is appropriate to implement a change in the overall energy efficiency amortization period, should PGE propose such and the Commission approve that proposal. The parties agree to include an estimate for variable power costs but do not agree on the amount. This can be calculated following a final decision on Issue S-13.

30. S-32 and S-33. No agreement has been reached on appropriate test years' Portland General Corporation allocations or equity issuance cost treatment.

31. S-34. PGE will decrease its requested taxes other than income in 1995 by $19,000 and in 1996 by $379,000 to reflect a forecast effective payroll tax rate of 11 percent in both test years. In addition, PGE will reduce its requested rate base element for utility plant in service by $4,000 in 1995 and by $81,000 in 1996 to reflect reduced capitalized payroll taxes.

32. S-35. The parties will address the tax effect of any change in PGE's rate of return from the November 8 filing in the next phase of the case.

33. S-36. PGE will decrease its requested non-fuel materials and supplies investment in 1995 by $553,000 and in 1996 by $1,089,000 to reflect the application of WEFA Fourth Quarter inflation forecasts to PGE's materials and supplies rate base balances in place of the WEFA June inflation forecasts used in the November 8 filing.

34. S-37. PGE will withdraw proposed Schedule 107. PGE will reduce requested amortization credits in 1995 by $36,707,000 and in 1996 by $36,417,000. PGE will also increase the Boardman gain rate base credit in 1995 by $18,354,000 and in 1996 by $54,916,000 as well as increase accumulated deferred income taxes in 1995 by $7,233,000 and in 1996 by $22,149,000.

35. S-38. No agreement has been reached on appropriate incremental power cost calculations for the decoupling mechanism.

36. S-39. PGE will use the weather-normalization coefficients used in the Docket UE-88 load forecast to weather-adjust actual revenues during the decoupling period. The monthly weather-adjusted "actual" sales (WAAS) for the decoupling period will be calculated using the sales model developed by PGE. The weather-adjustment process is implemented by running the sales model at "actual" weather conditions and at "normal" weather conditions. The difference between these two model runs yields

the "weather-adjustment" quantities. For example, during the heating season colder weather would result in kWh quantities being subtracted from actual or recorded sales and warmer weather would lead to kWh quantities being added to actual sales, all else being equal. The "normal" weather values are defined as averages over the most recent 30 year period. The weather coefficients are specified in Attachment 2.

37. S-40. PGE and Staff will use their best efforts to obtain appropriate treatment of decoupling adjustments by the Bonneville Power Administration (BPA) in the determination of average system cost for purposes of the Residential Exchange Program. Regardless of the treatment adopted by BPA, however, PGE will pass through to residential and farm customers all Residential Exchange Program benefits actually received, no less and no more.

38. S-41. No agreement has been reached on appropriate corrections to PGE's marginal cost study and appropriate rate spread policy.

39. S-42. As a result of withdrawing proposed Schedules 103 (Issue S-31) and 107 (Issue S-37), PGE will include 1995/1996 energy efficiency costs and refund of the Boardman gain in overall revenue requirements for rate spread purposes.

40. S-43. The revenue adjustment of $540,000 per year for an interruptible service tariff will be included only under the following conditions:

1. PGE files a tariff for interruptible service by August 1, 1994, with a copy to all UE-88 parties.

2. PGE demonstrates in its filing or during subsequent review of the filing that a) all customers will benefit from the offer of interruptible service, and b) the offer will reduce net revenues by at least $540,000 a year. The net revenue estimate must recognize new sales (not just the shift of existing sales from firm to interruptible service) and cost savings to the company.

3. The Commission decides before October 1, 1994 to allow the tariff for interruptible service to go into effect.

The increase in expected annual displacement sales to Smurfit to 30,000 mWh is recognized in the load forecast adjustment (Issue S-12).

41. S-44. With the exception of proposed schedules 103, 107, and the increase to the customer charge on Schedule 7, PGE will implement its proposed overall rate design described in PGE Exhibit 800. Minor deviations from PGE's proposed rate design may be necessary to achieve a smooth transition between rate schedules. In addition, in implementing the demand charge changes on Schedules 31/32, 82/83, and 89, PGE may propose to phase-in the change, provided that this is done without affecting the overall rate spread between classes and is revenue neutral. Furthermore, the shifts from energy to demand will be limited,

however, so that energy charges for any affected schedule remain at or above the marginal cost of energy.

The residential customer charge will be set based on the revenue increase allocated to Schedule 7 as follows:

Schedule 7 Increase*	Customer Charge
Less than $5 million	$5.00
$5 to $10 million	$5.50
Over $10 million	$6.00

* Based on a two year test period. For a one-year test period, the allocated increase values should be halved.

The energy charges for the two blocks of Schedule 7 will then be adjusted on an equal percentage basis to achieve the total allocated revenue requirement, except that the tailblock rate will not be reduced if there is an overall increase.

42. Staff and PGE agree that a change in accounting method whereby depreciation is simplified for the specific PGE general plant accounts listed below is appropriate.

- 39100 - Office furniture and equipment
- 39102 - Computer and office equipment (excludes mainframe)
- 39300 - Stores equipment
- 39400 - Tools, shop, and garage equipment
- 39706 - Cellular phones, mobile phones, and pagers
- 39800 - Miscellaneous equipment

Under the revised accounting method, records will no longer be maintained at the individual retirement unit level.

Instead, the Continuing Property Record will be maintained at a vintage level with the entire vintage retired from the record upon reaching the authorized depreciable life.

These accounts comprise a small percentage (1.7%) of total net plant investment, are relatively inexpensive, and are considered portable and are frequently relocated. Because of their size and mobility they are very difficult to track and maintain valid location, retirement, and transfer records. The Commission has previously approved this method for Washington Water Power.

The undepreciated cost of pre-1995 assets will be depreciated over the remaining depreciation lives approved in UM-541, and then retired from plant in-service in total along with associated depreciation reserve amounts. The depreciation expense to be implemented with a UE-88 general rate case order will be calculated using a whole-life equivalent depreciation rate. The broad group depreciation rates will assume no retirement dispersion. Depreciation of post-1994 assets will begin the month after the job is closed to plant in-service. The depreciation reserve will be maintained by vintage, and depreciation in the year of retirement will be calculated by subtracting the depreciation reserve balance from the vintage plant in-service balance.

Ongoing review and future revisions of the depreciation lives and salvage rates will continue to be authorized by the Commission based on input from Staff and the Company. The

Company will provide information to support any potential change to the stipulated depreciation lives and salvage rates as part of future depreciation studies. Such support will be the best available information from such sources as engineering estimates, tax lives, and/or industry surveys.

This change in accounting method will not precipitate a change in PGE's revenue requirement. The only differences between the two methodologies is that the revised method will simplify the process of tracking and reporting net asset values and will create a change in the way retirements are recorded during the asset service lives.

43. PGE agrees to withdraw its application for deferred accounting docketed UM-444 coincident with a Commission order in this proceeding authorizing full recovery of and on the Trojan steam generator analysis, plugging, and sleeving costs referenced in Commission Order 92-1062 and PGE's UM-494 request for an accounting order.

44. Staff and PGE agree that these stipulations are reasonable under the standards and perspectives usually applied in a general rate proceeding.

45. Staff and PGE have entered into these stipulations in good faith. Cost recovery considerations associated with the Trojan Nuclear Plant, however, particularly with respect to the issues raised in Commission Order No. 93-1117, will lead to further assessment of the Trojan and cost of capital elements of PGE's required revenues. Should Staff propose adjustments to

PGE's 1995 and/or 1996 revenue requirements in Phase II of Docket UE-88, none of the items stipulated above will prevent PGE from presenting any evidence in rebuttal to issues raised by Staff in Phase II it deems necessary.

Furthermore, if Staff or PGE proposes changes in the revenue requirements for any of the items covered by this Stipulation which are inconsistent with the terms of the Stipulation during the Phase II proceeding, both Staff and PGE reserve the right to be released from the terms of any or all elements of this Stipulation.

Nevertheless, it is the intent of the parties, unless either exercises the release option previously described, that Phase I stipulations remain in effect should the Commission reject further adjustments Staff may propose in Phase II of Docket UE-88.

If the Commission rejects any part of this Stipulation, the stipulating parties may withdraw from the whole Stipulation unless the parties agree to the modification. To the extent any party proposes changes that are inconsistent with the terms of one or more issues in this Stipulation, such changes shall not disturb any other issues addressed in the Stipulation. To the extent the Stipulation is partially modified or withdrawn, neither the Stipulation nor any information obtained in settlement discussions may be used as evidence against any party.

46. This Stipulation shall be entered in the record in Phase I of this proceeding as evidence pursuant to OAR 860-14-

085(1). PGE and Staff agree that all of the testimony filed in Phase I of this docket shall be entered in the record of proceeding. The parties agree to waive cross-examination of the other parties' testimony on items included in this Stipulation. If any issue covered by this Stipulation is challenged by someone not a party to this Stipulation, then the parties agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

47. Staff and PGE have executed this Stipulation to resolve identified issues in Phase I of this proceeding. Neither Staff nor PGE shall be deemed to have agreed that this Stipulation is appropriate for resolving issues in any other proceeding except for Docket UM-444 (see item 43 above). Neither Staff nor PGE shall be deemed to have accepted or consented to the principles, methods or theories employed in arriving at this Stipulation.

EXECUTED this 1st day of July, 1994.

Paul A. Graham
Attorney for the Staff of the
Oregon Public Utility Commission

Randall W. Childress
Attorney for
Portland General Electric Company

Attachment 1

PORTLAND GENERAL ELECTRIC CO.
General Rate Case Stipulation - UE 88
(000)

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectibles/Advert.OPUC*	0.00555
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97345
State Income Tax @ 6.672%**	0.06495
Federal Taxable Income	0.90850
Federal Income Tax @ 35%	0.31798
ITC	0.00000
Current FIT	0.31798
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38401
Total Revenue Sensitive Costs	0.41056
Utility Operating Income	0.58944
Net-to-Gross Factor	1.69654

* Uncollectible Rate	0.00230
Advertising Allow.	0.00125
OPUC Fee	0.00200
Total	0.00555

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	0.06334
Total	0.06672

PGE Weather Adjustment Model (WAM) Weather Variables Coefficients

RESIDENTIAL SECTOR EQUATIONS							
	Winter Months Temperature 1/	Spring Months Temperature 1/	Swing Months Temperature	Summer Months Temperature	Cooling Degree Days (@75°F)	Wind Speed	Minutes of Sunshine
Single-Family Heat	-824.49	-712.51	-25.72	-11.96	3.96	17.76	-0.0059
Single-Family NonHeat	-139.03	-132.58	- 2.67		1.52	6.26	-0.0026
Multi-Family Heat	-660.48	-546.37	-19.38	- 9.56	1.87	12.04	-0.0024
Multi-Family NonHeat	-107.08	- 97.65	- 1.60		1.12	3.47	-0.0017
Mobile Home Heat	-865.35	-694.65	-26.59	-12.32	4.55	21.28	-0.0080
Mobile Home NonHeat	- 41.53	- 29.71	-11.03		2.83	13.20	-0.0060
Other Residential	-1401.34	-1281.34	-37.19		4.61	18.26	-0.0021
COMMERCIAL SECTOR EQUATIONS							
	Winter Months Heating Degree Days (@65°F)	Spring Months Heating Degree Days (@65°F)	Swing Months Heating Degree Days (@65°F)	Cooling Degree Days (@65°F)			
Trans., Comm. & Utility	7.74	7.04		17.85			
Department Stores /Malls	9.92	5.84		17.91			
Food Stores	2.29			11.36			
Restaurants	5.07	3.64		18.58			
Other Trade	15.51	14.84		21.77			
Fin., Ins, Real Est. & Offices	19.69	15.32		24.28			
Lodging	6.79	6.50	2.66	5.22			
Other Services	21.42	21.02	4.93	22.98			
Health Services	8.49	2.65		16.74			
Government & Education	20.96	17.45		22.68			
Miscellaneous Commercial	14.46	14.23	3.99	5.74			

1/ square root of temperature

Attachment 2

95-322

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon Filed by PORTLAND GENERAL ELECTRIC COMPANY - Advice No. 93-26	)))))	STIPULATION SUPPLEMENT #1

1. On November 8, 1993, Portland General Electric Company filed for a general rate change affecting its price schedules in Advice No. 93-26. Docket UE-88 is the proceeding for resolution of the issues in Advice No. 93-26.

2. The new price schedules are based on PGE's expected revenue requirement for a two-year test period covering 1995 and 1996. On November 8, 1993, PGE filed testimony, exhibits, and workpapers in support of its 1995 and 1996 revenue requirements (the November 8 filing).

3. On March 21, 1994, the Staff of the Public Utility Commission of Oregon (Staff) filed a motion to amend the schedule and to bifurcate. In this motion, Staff requested that issues considered by the Commission in the DR 10 proceeding related to PGE's Trojan Nuclear Plant (Trojan) and cost of capital be considered apart from all other issues. The Hearings Officers granted the Motion to Bifurcate on May 3, 1994 and established a schedule for the Trojan-related issues and cost of capital. For purposes of this Stipulation, Phase I refers to proceedings related to issues other than Trojan and cost of capital, Phase II

refers to the proceedings related to Trojan and cost of capital. This stipulation primarily covers Phase I issues.

4. Pursuant to the Hearings Officers' Memorandum and Ruling of December 15, 1993, the Staff filed for discussion at the Phase I settlement conferences, a "Staff Issues List" dated March 25, 1994. The Staff Issues List identified Phase I adjustments Staff proposed to PGE's requested revenue requirements components for test years 1995 and 1996 as set forth in the November 8 filing.

5. On July 1, 1994 PGE filed testimony and exhibits (the July 1 Rebuttal) responding to certain issues raised by Staff and other parties.

6. Also on July 1, 1994, PGE and Staff filed a Stipulation describing agreement between them on numerous revenue, expense, and rate base issues identified in the Staff Issues List.

TERMS OF STIPULATION

WHEREFORE, PGE and Staff hereby agree to the following issues in addition to those covered in the July 1 Stipulation. Designations beginning with "S-" are from the March 25, 1994 Staff Issues List.

1. S-14. PGE will increase its requested other operating revenues in 1995 by $75,000 and in 1996 by $75,000 to

reflect revenues from seminars and conferences it may offer through its Energy Resource Center (ERC).

2. S-27. PGE will decrease its operation and maintenance (O&M) expenses in 1995 by $105,790 and in 1996 by $373,578 to remove from the November 8 filing certain Category "A" advertising expenses. These amounts are not subject to further adjustment for any change in the amount of advertising set as presumptively reasonable by operation of the formula in OAR 860-26-022(3)(a) on final revenues established in this Docket.

3. S-28. PGE will decrease its O&M expenses in 1995 by $107,619 and in 1996 by $112,075 to remove from the November 8 filing certain expenses associated with the non-advertising costs of PGE's Power Smart program.

4. S-30. PGE will decrease its O&M expenses in 1995 by $211,106 and in 1996 by $211,106 to remove from the November 8 filing the lease costs associated with the Tualatin ERC facility.

5. S-33. Staff and PGE agree to stipulate into the record in this proceeding the nine pages attached to this Stipulation Supplement 1 as Attachment 1.

6. PGE will withdraw from its July 1 Rebuttal PGE Exhibit 1316 in total and from PGE Exhibit 1300 the sentences on page 22, lines 15 through 17, beginning with the words "Exhibit 1316 describes . . . ." In addition, PGE will revise PGE Exhibit

1300, page 22, line 18 to replace the word "results" with the word "test".

7. PGE and Staff agree that PGE may add to PGE Exhibit 1302 the pages attached to this Stipulation Supplement 1 as Attachments 2 and 3 and may revise PGE Exhibit 1300, page 6, lines 2 through 3 to replace the sentence "PGE Exhibit 1302 contains several ads produced by Alberta Power on various electrical applications that increase the use of electricity" with the sentence "PGE Exhibit 1302 contains several ads produced by Canadian utilities on various electrical applications, some of which increase the use of electricity."

8. Staff and PGE agree that, if the Commission implements the decoupling mechanism proposed in this docket for PGE, that mechanism will not take effect until, and PGE will not calculate the decoupling adjustment for any months prior to, the effective date of tariffs in this proceeding. Regardless of the effective date of the tariffs, and thus the decoupling mechanism, PGE will maintain the decoupling periods and filing schedule contemplated by the mechanism. Accordingly, PGE's first decoupling filing would occur August 1, 1995, for the period from the effective date of the tariffs through June 30, 1995. If the amount of any decoupling adjustment is small, PGE may defer the adjustment to its next decoupling filing. Staff and PGE further agree that, with respect to the calculations of revenue under the UE 88 tariffs needed for purposes of amortization of deferred

power costs for the period January 1, 1995 through March 31, 1995, such revenues shall be calculated without weather-adjustment and without the effects of the decoupling mechanism.

9. Staff and PGE agree that this stipulation is reasonable under the standards and perspectives usually applied in a general rate proceeding.

10. Staff and PGE have entered into these stipulations in good faith. Cost recovery considerations associated with the Trojan Nuclear Plant, however, particularly with respect to the issues raised in Commission Order No. 93-1117, will lead to further assessment of the Trojan and cost of capital elements of PGE's required revenues. Should Staff propose adjustments to PGE's 1995 and/or 1996 revenue requirements in Phase II of Docket UE-88, none of the items stipulated above will prevent PGE from presenting any evidence in rebuttal to issues raised by Staff in Phase II it deems necessary.

Furthermore, if Staff or PGE proposes changes in the revenue requirements for any of the items covered by this Stipulation which are inconsistent with the terms of the Stipulation during the Phase II proceeding, both Staff and PGE reserve the right to be released from the terms of any or all elements of this Stipulation.

Nevertheless, it is the intent of the parties, unless either exercises the release option previously described, that Phase I stipulations remain in effect should the Commission reject further adjustments Staff may propose in Phase II of Docket UE-88.

If the Commission rejects any part of this Stipulation, the stipulating parties may withdraw from the whole Stipulation unless the parties agree to the modification. To the extent any party proposes changes that are inconsistent with the terms of one or more issues in this Stipulation, such changes shall not disturb any other issues addressed in the Stipulation. To the extent the Stipulation is partially modified or withdrawn, neither the Stipulation nor any information obtained in settlement discussions may be used as evidence against any party.

11. This Stipulation shall be entered in the record in Phase I of this proceeding as evidence pursuant to OAR 860-14-085(1). PGE and Staff agree that all of the testimony filed in Phase I of this docket shall be entered in the record of proceeding. If any issue covered by this Stipulation is challenged by someone not a party to this Stipulation, then the parties agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

12. Staff and PGE have executed this Stipulation to resolve identified issues in Phase I of this proceeding. Neither Staff nor PGE shall be deemed to have agreed that this Stipulation is appropriate for resolving issues in any other proceeding. Neither Staff nor PGE shall be deemed to have

accepted or consented to the principles, methods or theories employed in arriving at this Stipulation.

EXECUTED this 14th day of July, 1994.

Michael T. Weirich
Attorney for the Staff of the
Oregon Public Utility Commission

Melinda Horgan
Attorney for
Portland General Electric Company

95-322

TO: Janice Fulker
Oregon Public Utility Commission

May 22, 1990

FROM: Warren Winter, PGE
Manager - Economic Regulation

PORTLAND GENERAL ELECTRIC COMPANY
GENERAL FILING UE-79
PGE RESPONSE TO OPUC Staff Data Requests No. 60

Request 60-1

When does PGE expect to achieve a capital structure containing 46 percent common equity, as recommended by Warren Winter on page 50 of PGE's Exhibit 3D? Provide all workpapers demonstrating the achievement of the recommended capital structure.

Response

PGE expects to achieve a capital structure containing 46 percent common equity by year end 1993. Attached is a spreadsheet detailing the common equity forecast for year end 1991 to 1993. The analysis assumes the following: (1) year end 1991 values are based upon the PGE forecast provided in response to OPUC Data Request No. 28; (2) annual earnings on common equity are conservatively based on prior year end common equity as opposed to an average; (3) capital expenditures are 100 percent internally funded (which is consistent with PGE's financial strategy); (4) percentage of utility capital is based on 1991 general filing ratio of ratebase to total capital; (5) utility ROE remains constant at 13.5 percent; (6) non-utility ROE is based on the earnings power of the WNP3 exchange contract; (7) debt remains constant; (8) preferred is reduced at the rate of \$1.8 million a year; and (9) the annual dividend remains constant at \$1.20 per share.

A. Exhibit 3D-10, Cost of Preferred Stock, shows the amount and the effective cost of the Company's outstanding preferred stock for the test period. Preferred stock is shown by issue. No new issues are projected through the 1991 test year. The calculation of the outstanding balances is based on a 12-month average of the average amounts outstanding during the test period. The effective rates represent the internal rate of return of the cash flows associated with each preferred issue. All preferred stock issues, except for the 8.875% Series and the 8.10% series are perpetual issues. The total cost of the preferred issues during the test period is 8.632%.

Common Equity Cost

Q. What is PGE's amount and cost for common equity?

A. The amount of average common equity for the 1991 test year is based on a target of 46% of total capitalization. The market-required return on common equity is discussed in the testimony of Mr. Lyman.

Q. Please explain why PGE has adopted a 46 percent common equity target.

A. The average common equity level for "A"-rated electric utilities is currently 43 to 44% of total capitalization. However, there is a wide spread about this average which recognizes unique company characteristics or circumstances. PGE's earnings are subject to higher volatility than the average A-rated utility. As a result, we have decided that PGE should be on the higher end of the average equity capitalization in order to maintain a sound A-rating. An A-rating is important because it gives us access to debt capital at a lower cost.

Q. Why are PGE's earnings subject to higher volatility?

A. PGE's earnings are more volatile due to its operating characteristics. Under normal circumstances, we have very low variable power costs for a large portion of our energy because of the large hydro base and low cost of nuclear fuel. These benefits of normal operations are passed to customers. Without a power cost adjustment mechanism, disruptions to these low cost supplies can cause us to incur a higher cost for generating or buying replacement power from coal and gas fired plants. We pay for these higher costs by reducing retained earnings. Furthermore, assuming critical water conditions in 1991, we do not project an excess of PGE resources over PGE load for the test year. In the absence of a power cost adjustment mechanism, the potential of critical water increases PGE's financial risk.

Q. What steps is the Company taking to reach the 46% equity level?

A. PGE's common equity at December 31, 1989, after the $89 million reduction for the establishment of a reserve (largely for contested issues currently before the court), was 40%. In order to restore PGE's earnings power and improve its debt coverage ratios[4], Portland General Corporation has reduced its annual common dividend from $1.96 per share to $1.20. In addition, PGE may not pay a dividend to PGC before the fourth quarter of 1990. These two actions will accelerate the restoration of retained earnings at PGE and, thus, common equity. By the end of 1991, in conjunction with the revenue increase requested and dividend management to PGC, PGE will achieve a common equity percentage of between 44 and 46%.

Q. Has PGE been regulated based on a target common equity capitalization structure in the past?

A. In effect, yes. In past cases, our actual structure was not sufficiently different from the desired target that it was an issue. In effect, we were regulated based on a target capital structure. Our goal is to close the gap between actual and desired common equity capitalization as rapidly as is practical. In this case, we are filing with a "normalized"

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[4] Coverage ratios are important indicators used by credit analysts and rating agencies to assess our financial health and ability to meet debt interest and preferred dividend obligations.

capital structure. We have and are taking some strong steps to restore the financial health of the Company.

Composite Cost of Capital

Q. Please explain Exhibit 3D-11 showing the composite cost of capital.

A. Exhibit 3D-11, Composite Cost of Capital, shows the calculation of cost of capital for PGE during the test period. The average amount and costs of long-term debt and preferred stock were taken from Exhibits 3D-9 and 3D-10, respectively. The average common stock equity balance assumes the targeted 46% of total capitalization target and a market-required return on common equity of 13.5%. The resulting cost of capital for the test period is 11.099%.

95-322

PGE Exhibit 1
2-2D
3-3B
4-4E
5-5C
6-6B
7-7B
8-8E

BEFORE THE PUBLIC UTILITY COMMISSIONER
OF THE STATE OF OREGON

PORTLAND GENERAL ELECTRIC COMPANY

Testimony and Exhibits of

Charles L. Heinrich
Warren H. Winter
Charles E. Allcock
Larry A. Soderquist
N. Richard King
James N. Woodcock
Robert P. McCullough
James E. Baggenstos

January 10, 198[illegible]

95-322

PGE Exhibit 6
Witness: J. N. Woodcock

fourth quarter of 1983 and preferred stock in the first or second quarter of 1984. The timing and amount of these equity issues will depend on construction expenditures, financial markets, and, in the case of common stock, the ratio of market value to book value.

Q. What other financing options are under consideration?

A. In 1981, the Company financed its share of the Colstrip project's pollution control equipment by issuing $80 million of 3-year pollution control bonds. These bonds must be refinanced on a long-term basis. We will consider this refinancing if market conditions permit.

Q. Does the timing and amount of rate relief received in 1983 affect the Company's financial picture?

A. Yes. Interim rate relief would have a positive effect on PGE's financial picture, including increased cash flow and earnings. Increased earnings could result in a higher market price for the Company's common stock. If this were to happen, the planned common stock sale would improve the common equity ratio with the issuance of less shares.

Delay in rate relief may require additional external financing. These funds most likely would be obtained from our short-term credit agreements under which we presently have a total of $160 million available.

Q. Would you please discuss the Trojan fuel financing and bank credit agreements.

A. The Trojan fuel agreement was arranged primarily because

A. Exhibit 8B, Cost of Long-Term Debt Capital, shows the amount and effective cost of the Company's long-term debt capital for the test period. This exhibit includes the Company's Bank Credit Agreement (commercial paper), Trojan trust notes, and the bond issues projected in the Company's test period financing plan. The average amounts outstanding have been calculated using a 12-month average of the average amounts outstanding each month. The cost of each issue is determined by multiplying the amount outstanding each period by the effective interest rate for each bond issue. The total test period composite cost of long-term debt for PGE is shown in Exhibit 8B to be 10.662 percent.

Q. What is shown on Exhibit 8C?

A. Exhibit 8C shows the cost of the Company's preferred stock by issue. Like long-term debt, the amounts outstanding are based on a 12-month average of the average amounts outstanding each month, and the cost is determined by multiplying the effective rate for each issue times the amount outstanding during the period. The composite cost of preferred stock to PGE during the test period is 12.689 percent.

Q. Could you please summarize the Company's proposed financings during the test period?

A. Yes. The financings (included in my Exhibits 8B, 8C, and average equity in Exhibit 8D) for the test period are:

PGE Exhibit 8
Witness: J. H. Baggenstos

Month of Issue	Type of Security	Total Dollars Raised (Millions)	Interest Rate or Per Share Price*
September 1983	Common Stock	$50	$16.50
March 1984	Preferred Stock	70	13.00%
Various	Colstrip Pollution Control Bonds	19	8.75%

* Market price before issuance expense.

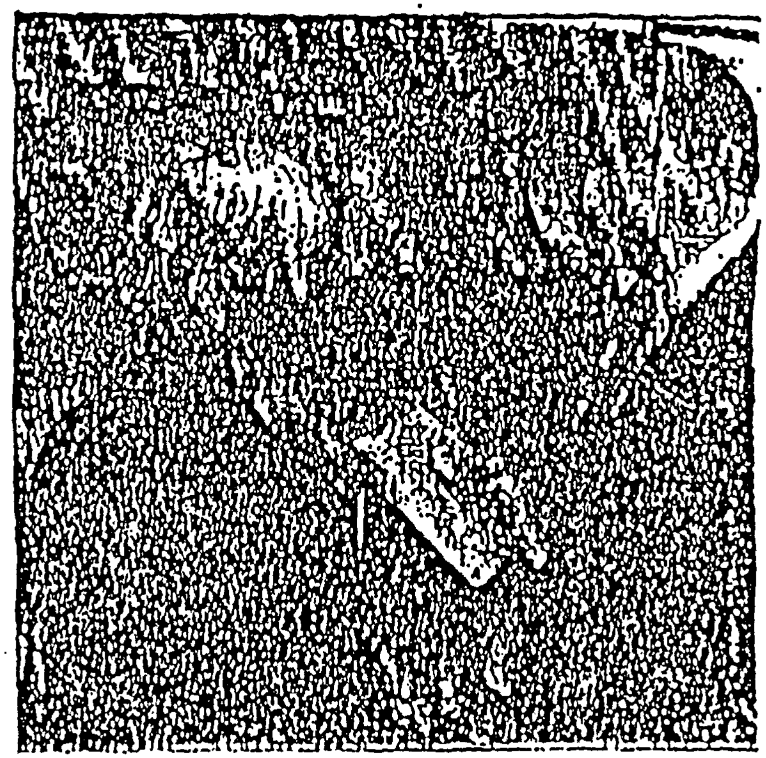
In addition, we plan to raise $25 million from common stock sales through our Common Stock Investment Plan and Employee Stock Purchase Plan.

The Company also intends to issue $80 million of pollution control bonds in April 1984 at 10.25 percent for the purpose of refunding the 8.75 percent issue that is due June 1, 1984. No drawdown from this fund is expected during the test period.

Q. Please explain Exhibit 8D.

A. Exhibit 8D calculates the composite cost of capital for PGE during the test period. The average amount and costs of long-term debt and preferred stock were taken from Exhibits 8B and 8C, respectively. The average common equity has been calculated based upon a 12-month average of the average common equity outstanding each month. This amount includes projected common stock issues during the test period and the increase in average common equity resulting from anticipated retained earnings. The return on common equity is discussed in the testimony of

Straight Talk From The Energy Experts



INTERRUPT

Question:
What type of heating system is the most popular choice of Newfoundlanders?

Answer: Electric Heat.

Electric heat is popular for many reasons. When all costs are considered, for the average home, electric heat is less expensive than oil or propane.

Electric heat is reliable. If one heater fails, you won't be left out in the cold. And there are no annual service costs or maintenance fees.

Electric heat is comfortable. Today's better quality thermostats will maintain a constant temperature, without noisy burners or blower motors.

Electric heat saves you valuable space because it does not require a furnace, duct work, fuel tank, chimney or vents.

Electric heat is convenient. You have control over individual room temperatures so you're not heating unused areas of the home.

Electric heat is safe. There are no fumes, or combustible fuels inside home and no worry over oil leaks associated clean-up costs.

Call the Power Smart number and talk to our energy experts. We'll g the facts, without the fine print.

POW
SMA
1 800 667

Electric Heat...the smart choice.

SPRING 93

APPENDIX C
PAGE 16 OF 17

95-322

DON'T BE "FUELED" BY THE OIL COMPANIES

Converting to oil will COST you money!

Annual Cost of Electric Heat*	
Electric heating cost only	*$1,163.55*
Annual Cost of Oil Heat**	
Furnace payments	*$1,020.00*
Electricity for furnace	*$58.00*
Furnace oil	*$783.52*
Total Oil Heat	***$1,861.52***

CONVERTING TO OIL HEAT WILL COST YOU $697.97 MORE PER YEAR

For the TRUE cost of oil or propane heating, call the energy experts for a free personalized home heating analysis:

STAY ELECTRIC AND SAVE!

*Annual figures based on heating portion of average [illegible] electric home - 16,878 kWh electricity - 6.541 cents/kWh.

**Annual figures based on first five years of conversion: $85/month for furnace (includes financing, labour, duct work, chimney and tank); 57.8 M. [illegible] oil at 35.07 cents/litre; furnace efficiency - 75%.

POWER SMART
1 888 567 8700

COPY

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon Filed by PORTLAND GENERAL ELECTRIC COMPANY (Advice No. 93-26)	)))))	STIPULATION

RECITALS

1. On November 8, 1993, Portland General Electric Company (PGE) filed for a general rate change in Advice No. 93-26. Docket UE 88 is the proceeding for resolution of the issues in advice No. 93-26.

2. On May 3, 1994, the Hearings Officers granted the Staff of the Public Commission of Oregon (Staff) Motion to Bifurcate on, and establish a schedule for, the Trojan-related issues and cost of capital. For purposes of this Stipulation, Phase I refers to proceedings related to issues other than Trojan and cost of capital; Phase II refers to the proceedings related to Trojan and cost of capital. This Stipulation covers Staff Issue S-13, variable power costs and the remaining variable power cost portions of Issues S-12, load forecast, and S-31, energy efficiency from Phase I and Staff's proposed Trojan cost balancing account from Phase II.

3. On July 1, 1994, PGE and Staff entered into a Stipulation regarding agreement on most of the Phase I issues in this proceeding. Staff and PGE did not include the treatment of

variable power costs and left open the variable power cost effects associated with adjustments to PGE's load forecast and energy efficiency forecast included in the July 1, 1994 Stipulation.

4. On July 14, 1994, PGE and Staff entered into Stipulation Supplement 1 regarding additional Phase I matters. Stipulation Supplement 1 did not cover variable power costs.

TERMS OF STIPULATION

WHEREFORE, PGE and Staff hereby agree to the following with respect to PGE's variable power costs and Staff's Trojan Cost Balancing Account proposal:

1. Issue S-13 Variable Power Costs - The parties agree to include in UE 88 base rates variable cost savings expected from the commercial operation of the Coyote Springs generating plant using a forecast in-service date of December 15, 1995.

The December 15th date is the mid-point of the expected range of most likely in-service dates for Coyote Springs: November 8, 1995 through January 21, 1996. November 8th represents the in-service date for which the construction contractor will receive the maximum potential performance incentive. January 21st represents the in-service date beyond which the construction contractor will begin to incur penalties for late performance. Attachment 1 to this Stipulation contains pages from the agreement between PGE and the construction contractor for Coyote Springs that support these dates.

2. The parties agree that, at least 90 days prior to the expected in-service date for Coyote Springs, PGE will file to track the projected capital and fixed costs associated with the plant into the UE 88 base rates. Neither PGE nor any party to this stipulation will propose a change to the variable power cost forecast already reflected in base rates, whether related to Coyote Springs or any other issue, with the exception described in paragraph 3 below. PGE agrees to assume the variable power cost risk associated with a Coyote in-service date later than December 15.

PGE agrees to provide attestation by a corporate officer of Coyote's having met the following minimum requirements prior to the effective date of any Coyote tracker rate increase:

(a) Completion of any operational testing required by the construction contract;

(b) Release of the plant operation to the system dispatcher for full commercial operation; and

(c) Continuous operation at greater than 90 percent of full power for 24 hours.

The parties further agree that the above treatment for Coyote Springs in variable power costs eliminates any need for interest on the "over-collection" in 1995 of 1996 variable power costs that results from the two-year test period associated with decoupling.

3. PGE may file proposed revised rates to address a change in BPA's transmission and power rates at the time such

change occurs through the tracking procedure described below. This procedure is identical to that used to quantify the effects of BPA rate changes on PGE in the variable power cost forecast included in UE 88. PGE will run its Proscreen model, using the same version and inputs which give the identical result of the variable power costs adopted by paragraph 4 of this stipulation, except that PGE will adjust Proscreen for:

(a) Wheeling rates for demand ($/kwmo) and energy (mills/kwh) for all resources covered under the General Transmission Agreement between BPA and PGE dated December 5, 1989, by the percent change in BPA's demand and energy IR wheeling rates; and

(b) The New Resources demand charge for the BPA capacity purchase by the percent change in BPA's NR demand charge.

Since PGE's non-firm purchases and sales are estimated by the Network Economy Interchange (NEI) secondary model in Proscreen, which is independent of BPA's Non-Firm energy rate, no direct adjustment will be made for that rate. However, the NEI may model a different level of secondary purchases and sales as a result of the changes in the BPA rates under (a) and (b), above.

This adjustment is expected to occur at the time of the Coyote tracker described in paragraph 2 above. The basis of the adjustment will be BPA's approved price changes, included in Proscreen as of their effective date. PGE will file proposed revised tariffs reflecting a BPA adjustment at least 30 days prior to the effective date of a Coyote tracker rate change. In the event that BPA's new rates are not approved such that PGE can file at least 30 days prior to a Coyote tracker, the adjustment will occur at the next opportunity PGE has to modify its rates (e.g., at the time of a SAVE tariff adjustment or a decoupling adjustment, if implemented, or some other such time).

Staff agrees that it will support rate changes to reflect BPA increases if such cost increases are material in amount.

4. Tracking rate changes proposed under Sections 2 and 3 of this Stipulation will be subject to a review of PGE's earnings. Accordingly, PGE shall file information to allow an earnings review (which may consist of the most recently filed semi-annual adjusted earnings report to the Commission) with any proposed rate changes.

5. As a result of the stipulations in paragraphs 1 and 3, the parties agree that the following amounts are a reasonable forecast of variable power costs for the test period and include the effects of issues S-12 and S-31 discussed below:

1995: $304,624,300

1996: $310,103,700

6. Issue S-12 Load Forecast - Given the forecast of variable power costs for the test period agreed to in paragraph 5 above, the parties agree that the following represents the variable power cost increase associated with the July 1, 1994 stipulation regarding PGE's load forecast:

1995: $2,554,000

1996: $1,198,000

7. Issue S-31 Energy Efficiency - Given the forecast of variable power costs for the test period agreed to in paragraph 5 above, the parties agree that the following represents the variable power cost decrease associated with the July 1, 1994 stipulation regarding energy efficiency:

1995: $(2,656,000)

1996: $(8,079,000)

8. Trojan Cost Balancing Account - The parties agree that it is appropriate to vary the amortization of the Trojan investment to take into account the actual revenue collected from customers as a result of the Commission's decision in UE 88. The parties therefore agree to a method to modify PGE's actual Trojan amortization expense rather than creating a balancing account. Incremental or decremental amortization expense amounts generated as a result of this stipulation, as described below, will be accumulated in a Trojan Investment Recovery Account (TIRA). The TIRA is designed to provide a procedure to precisely accumulate actual revenue received by PGE as recovery of the Trojan

investment based on amounts authorized by the Commission. As a result, interest will not be added to the TIRA.

The TIRA will operate based on the following:

a) Amounts will be accumulated in the TIRA based on the difference between PGE's actual base calendar revenue from Sales to Ultimate Customers plus miscellaneous operating revenues (base revenue) and PGE's authorized calendar revenue for recovery of Trojan's investment related revenue requirement. PGE's authorized Trojan investment related revenue requirement is defined in d) below.

b) The TIRA will be established as a subaccount to PGE's Trojan Accumulated Amortization Account. The Trojan Accumulated Amortization Account will show the Trojan investment costs recovered from customers based on the Commission authorized rate of recovery. The TIRA will show the incremental or decremental Trojan investment costs recovered as a result of differences between actual and 1995-96 test period forecast calendar revenue. The offsetting entry to the TIRA accumulated amortization subaccount is amortization expense.

c) Actual Trojan investment related calendar revenue will be determined based on a predetermined Trojan Recovery Percentage (TRP) (see section d) multiplied by PGE's total base revenue. For purposes of the TIRA, base revenue is PGE's calendar revenue excluding any other adjustments (i.e., calendar revenue from separate tariffs such as those for SAVE, deferred power cost recoveries, energy efficiency true-up, ballot measure 5 refunds, and the Residential Exchange Program are to be excluded from both actual revenue and test period forecast revenue for purpose of the TIRA).

d) The TRP arising from Docket No. UE 88 will be calculated separately for 1995 and 1996 based on the Commission's final authorized Trojan investment recovery in each year and the following formula:

$$\text{TRP} = \frac{\text{Authorized Trojan Investment Revenue Requirement}}{\text{Total PGE Authorized Revenue Requirement}^{1}}$$

The components of Trojan Investment recovery will be limited to those associated with a return on and of the Trojan investment including related current and deferred tax effects. Elements not to be included in the TRP include the revenue

[1] The authorized revenue requirement includes miscellaneous operating revenue.

requirement effects of Trojan related normal operating costs such as transition O&M, property insurance and taxes, and decommissioning expense.

e) For periods subsequent to the end of 1996, until PGE implements a general rate change after December 31, 1996 based on an order of the Commission, PGE will base adjustments to the TIRA on the following differences:

   1) actual Trojan investment related calendar revenue based on application of the 1996 TRP as described in a) through c) above; and,

   2) the 1996 authorized Trojan investment revenue requirement used to calculate the 1996 TRP.

f) When PGE's Trojan related rate base, including the TIRA and any future Trojan capital additions, proceeds from salvage activities, property transfers, and/or tax basis adjustments (all as approved by the Commission), nets to zero, the full Commission authorized investment will have been recovered. Any residual balance, whether debit or credit, will be disposed of only at the direction of the Commission.

g) If decoupling is adopted and implemented as a result of this proceeding, the parties agree that the actual Trojan investment related revenue based on the TRP will not be subject to any decoupling related adjustment. The decoupling mechanism authorized by the Commission, if any, will be modified to eliminate the possibility of duplication with the TIRA.

h) PGE agrees to report the balance in the TIRA within, and as of the end of the period covered by, each semi-annual adjusted results of operations report filed with the Commission.

i) Staff agrees that the TIRA as described herein is a reasonable substitute for the Trojan Cost Balancing Account (TCBA) recommended in testimony and briefed in Docket No. UE 88. Then if the Commission adopts this Stipulation and the TIRA, Staff would withdraw its recommendation for a TCBA.

9. Staff and PGE agree that this stipulation is reasonable under the standards and perspectives usually applied in a general rate proceeding.

10. If the Commission rejects any part of this Stipulation, the stipulating parties may withdraw from the whole Stipulation unless the parties agree to the modification. To the extent any party proposes changes that are inconsistent with the terms of one or more issues in this Stipulation, such changes shall not disturb any other issues addressed in this Stipulation.

To the extent the Stipulation is partially modified or withdrawn, neither the Stipulation nor any information obtained in settlement discussions may be used as evidence against any party.

11. This Stipulation shall be entered in the record in Phase II of this proceeding as evidence pursuant to OAR 860-14-085(1). If any issue covered by this Stipulation is challenged by someone not a party to this Stipulation, then the parties agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

12. Staff and PGE have executed this Stipulation to resolve identified issues in this proceeding. Neither Staff nor PGE shall be deemed to have accepted or consented to the principles, methods or theories employed in arriving at this Stipulation.

EXECUTED this 27th day of February, 1995.

Paul A. Graham

Paul A. Graham
Attorney for the Staff of the
Oregon Public Utility Commission

Melinda J. Horgan

Melinda J. Horgan
Attorney for
Portland General Electric Company

Amendment No. 3
To
Turnkey Engineering, Procurement and Construction Agreement

This Amendment No. 3 to that certain Turnkey Engineering, Procurement and Construction Agreement dated as of August 13, 1993 by and between Portland General Electric Company ("Owner") and Ebasco Constructors Inc. ("Contractor") (the "EPC Contract") is made and entered into as of January 19, 1995.

RECITALS

A. Raytheon Constructors, Inc., a Delaware corporation with offices at 3000 W. MacArthur Boulevard, Santa Ana, California 97204 has been assigned and has assumed all rights and obligations of Ebasco Constructors Inc. as Contractor under the EPC Contract;

B. Notice to Proceed With Construction was not issued on or prior to March 1, 1994 as provided in Section 4 of the EPC Contract but instead was issued September 19, 1994;

C. A Stop Work Order was issued to the Contractor by the Owner on November 18, 1994 and was subsequently lifted on November 23, 1994;

D. Contractor has advised Owner that the delays in issuance of the Notice to Proceed With Construction and the delays resulting from issuance of the Stop Work Order referred to in Recital C, above, will affect the Substantial Completion Deadline and the parties have, therefore, as complete, final and binding resolution, compromise, waiver and release of all claims of Contractor which have arisen or may hereafter arise as a result of or related to such delays, negotiated an adjustment to the Substantial Completion Deadline as set forth in Section 2, below; and

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C-1

Amended Exhibit C

KEY DATES

95-322

EARLY START	EARLY FINISH	ACTIVITY (1993 – 1995)
		MILESTONES
1MAR93A		A100 NOTICE TO PROCEED
1MAR93A		A105 PHASE I ENGINEERING
1JUL93A		A107 TURNKEY PRICE
19SEP94A		A110 SITE CERTIFICATION
19SEP94A		A130 SITE MOBILIZATION
26MAY95		A150 STANDBY POWER AVAILABLE
7JUN95		A170 MAKE-UP WATER AVAILABLE
5JUL95		A155 BACKFEED POWER AVAILABLE
5JUL95		A165 LINE READY TO ACCEPT BKFD POWER
24JUL95		A140 FUEL GAS AVAILABLE
	22JAN96	A160 CONTRACTUAL SUBSTANTIAL COMPLETION
		ENGINEERING & DESIGN
1MAR93A	30JUN93A	72000 PHASE I ENGINEERING
1MAR93A	31OCT94A	72040 MECHANICAL ENGNG & DESIGN
1MAR93A	31OCT94A	72080 ELECTRICAL ENGINEERING & DESIGN
1APR93A	31OCT94A	72020 CIVIL ENGINEERING & DESIGN
1APR93A	30NOV94A	72060 I&C ENGINEERING & DESIGN
31OCT94A	3NOV95	72100 PROJECT ENGIN'RING SUPPORT FOR SITE CONSTRUCTION
		PROCUREMENT
16AUG93A	1NOV94A	072010 FAB & DELIVER GAS TURBINE
16AUG93A	9DEC94	071010 FAB & DELIVER STEAM TURBINE
22SEP93A	20SEP94A	005010 FAB & DELIVER HRSG
11NOV93A	9FEB95	151010 FAB & DELIVER MAIN TRANSFO
		CONSTRUCTION - CIVIL
6APR94A	15APR94A	010001 OFFSITE MOBILIZATION
10APR94A	30SEP94A	010002 RECEIVE/PREFAB PERM PLANT MAT'L OFFSITE
26APR94A	17JUN94A	011000 SITE PREPARATION
19SEP94A	30SEP94A	01100 SITE MOBILIZATION
6OCT94A	26OCT94A	031300 HRSG AREA FOUNDATIONS
11OCT94A	10NOV94A	031200 GAS TURBINE AREA FOUNDATIONS
24OCT94A	13JAN95	031100 STEAM GENERATOR FOUNDATIONS
24OCT94A	24APR95	031400 TURBINE BUILDING FOUNDATION
11NOV94A	15MAR95	031600 AUXILIARY BOILER FOUNDATIONS (STK.BLR, DEAR.)

Plot Date 20DEC94
Data Date 10DEC94
Project Start 1MAR93
Project Finish 22JAN96

(c) Primavera Systems, Inc.

Activity Bar/Early Dates
Critical Activity
Progress Bar
Milestone/Flag Activity

PORTLAND GENERAL ELECTRIC
COYOTE SPRINGS
REVISED BASE SUMMARY SCHEDULE

REVISED BASE SUMMARY SCHEDULE FROM 7FA

Date	Revision	Checked	Approved

EARLY START	EARLY FINISH	ACTIVITY
		CONSTRUCTION - CIVIL
1DEC94	17JAN95	031500 CONTROL BUILDING FOUNDATION
1DEC94	30JAN95	031700 DEMINERALIZER FOUNDATIONS
1DEC94	27FEB95	051200 ERECT TURBINE BUILDING
12JAN95	23JUN95	051100 ERECT CONTROL BUILDING
		CONSTRUCTION - HRSG
31OCT94A	3JAN95	085100 SET AND ALIGN HRSG MODULAR UNITS
18NOV94A	21JUN95	085120 SET BALANCE MAJOR COMPONENTS/INTERCON. PPG (HRSG)
1DEC94	21DEC94	085130 ERECT HRSG STACK
4JAN95	17JAN95	085110 SET STEAM DRUMS & DEARATOR
25JAN95	14JUN95	085140 COMPLETE TRIM AND SMALL BORE PIPE - HRSG
		CONSTRUCTION - GAS TURBINE
1DEC94	19JAN95	072100 ROUGH SET GAS TURBINE
20JAN95	30CT95	072900 INSTALL GAS TURBINE
		CONSTRUCTION - STEAM TURBINE
24JAN95	10FEB95	071105 SET STEAM TURBINE GENERATOR
13FEB95	23JUN95	071110 ALIGN/TRIM OUT STEAM TURBINE GENERATOR
12JUL95	21JUL95	071115 LUBE OIL FLUSH
		CONSTRUCTION - BOP MECH & ELECT
4JAN95	1MAR95	105100 ERECT COOLING TOWER
4JAN95	5MAY95	101100 INSTALL AUXILIARY BOILERS
17JAN95	16OCT95	159900 INSTALL BALANCE OF PLANT ELECTRICAL
31JAN95	24APR95	121300 INSTALL DEMINERALIZER SYSTEM
13MAR95	19JUN95	109900 INSTALL BALANCE OF PLANT EQUIPMENT
9MAY95	28SEP95	121200 INSTALL BALANCE OF PLANT PIPING
		CONSTRUCTION - CHECKOUT, TEST & START-UP
19MAY95	12SEP95	701800 SYSTEM CHECKOUT
13SEP95	7NOV95	701900 COMPLETION OF START-UP AND TESTING
	7NOV95	701925 SCHEDULED SUBSTANTIAL COMPLETION
8NOV95	22JAN96	701950 NON-ESSENTIAL PUNCHLIST ITEMS/DEMOB

Timeline: 1993 – 1995 (FEB 1993 through JAN 1996)

PORTLAND GENERAL ELECTRIC
COYOTE SPRINGS
REVISED BASE SUMMARY SCHEDULE

KEY DATES

95-322

(i)

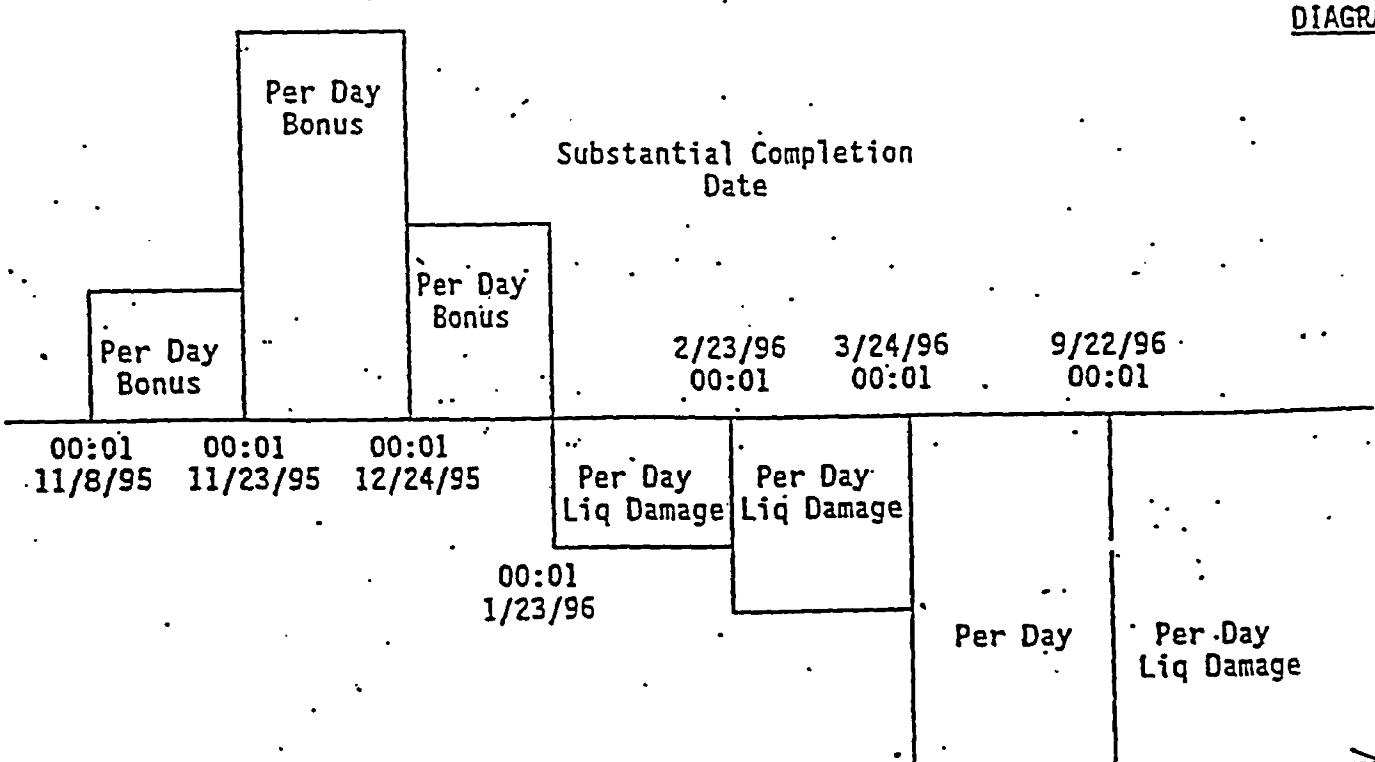
(ii)

(iii)

In no event will the Early Completion Bonus be calculated for a period of time greater than seventy-six (76) days.

The following diagram is designed to represent visually the foregoing description of the calculation of Delay Liquidated Damages and Early Completion Bonus.

DIAGRAM 3



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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 88

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon Filed by PORTLAND GENERAL ELECTRIC COMPANY - Advice No. 93-26	)))))	STIPULATION

RECITALS

1. On November 8, 1993, Portland General Electric Company (PGE) filed for a general rate change affecting its price schedules in Advice No. 93-26. Docket UE-88 is the proceeding for resolution of the issues in Advice 93-26.

2. The new price schedules are based on PGE's expected revenue requirement for a two-year test period covering 1995 and 1996. On November 8, 1993, PGE filed testimony, exhibits, and work papers in support of its 1995 and 1996 revenue requirements.

3. On March 21, 1994, the Staff of the Public Utility Commission of Oregon (Commission) filed a motion to amend the schedule and to bifurcate UE-88. Staff requested separate consideration of issues related to PGE's Trojan Nuclear Plant that fell within the scope of the Commission's order in the DR-10 proceeding, and issues related to the cost of capital.

4. The Hearings Officers granted the motion to bifurcate on May 3, 1994 and established

a separate schedule for Phase II of UE-88, for the Trojan-related issues and cost of capital. Based on a March 25, 1994 Staff Issues List, cost of capital is identified as issue S-0 for purposes of UE-88. Equity issuance costs are identified as issue S-33. This Stipulation concerns cost of capital, in Phase II and equity issuance costs in Phase I.

5. On September 30, 1994, Staff filed its testimony, exhibits, and work papers on cost of capital, issue S-0. On November 8 and 10, 1994, conferences were noticed and held pursuant to OAR 860-14-085(3) for purposes of discussing settlement of cost of capital issues as well as equity issuance costs, issue S-33, from Phase I of UE-88.

TERMS OF STIPULATION

PGE and Staff hereby agree as follows:

6. PGE's revenue requirement will reflect the following capital structure and costs for the test years 1995 and 1996:

I. Test Year 1995

	Capital Structure	Cost%	Weighted Cost (%)
a. Long-Term Debt	49.14	7.71	3.79
b. Preferred Stock	5.42	8.27	0.45
c. Common Equity	45.44	11.60	5.27
	100.00		
Rate of Return			9.51

II. Test Year 1996

	Capital Structure%	Cost%	Weighted Cost (%)
a. Long-Term Debt	48.86	7.82	3.82
b. Preferred Stock	4.67	8.27	0.39
c. Common Equity	46.47	11.60	5.39
	100.00		
Rate of Return			9.60

7. This Stipulation for cost of capital issues is entered into notwithstanding any determination by the Commission on decoupling, issue S-38. The capital structure and costs for each year are stipulated regardless whether decoupling is implemented.

8. In resolution of issue S-33 from Phase I, PGE will increase its O&M expense and applicable income tax expense for the effect of adding $1.75 million of common equity issuance costs for both 1995 and 1996.

9. Staff and PGE will each submit separate testimony on or before November 30, 1994 supporting the provisions of this Stipulation and arguing in good faith for their adoption by the Commission.

10. This Stipulation shall be entered in the record in this proceeding as evidence pursuant to OAR 860-14-045 and 860-14-085.

11. PGE and Staff agree that all of the testimony filed in this docket on issue S-0 shall be entered into the record of UE-88. Staff and PGE further agree to waive cross-examination of the each others' testimony on items included in this Stipulation and issue S-0, and to make their respective witnesses available for cross-examination by any other party to UE-88.

12. If any issue covered by this Stipulation or related to issue S-0 is challenged by someone not a party to this Stipulation, Staff and PGE agree to support and argue in good faith for the Commission's approval of all of the provisions of this Stipulation.

13. Staff and PGE have entered into this Stipulation to resolve issue S-0, related to the cost of capital. They shall not be deemed to have agreed that this Stipulation is appropriate for resolving issues in any other proceeding. Further, they shall not be deemed to have accepted or consented to the principles, methods, or theories employed in arriving at this Stipulation.

14. If the Commission rejects any portion of this Stipulation, Staff or PGE may withdraw from the Stipulation in its entirety.

Signed this 15th day of November, 1994.

Kimberly R Cobrain
Kim Cobrain
of Attorneys for the Staff of the
Oregon Public Utility Commission

Rochelle Lessner
of Attorneys for Portland General
Electric Company

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PORTLAND GENERAL ELECTRIC CO.
Adjustment Summary
UE 88 - 1995 & 1996 Test Years
($ x 1,000)

Item	Issue	Revenue Requirement Effect 1995	Revenue Requirement Effect 1996
	Company-calculated added revenues required	**$46,498**	**$109,267**
	STIPULATED ADJUSTMENTS		
S-0,S-35	Rate of Return and Capital Structure	(61)	(3,124)
S-1	PGC Inflation	(315)	(662)
S-2	EPRI Deferral	0	0
S-3	Advertising - Category "C"	(24)	(25)
S-4	Retirement Savings Plan	(1,267)	(1,532)
S-5	Legal Escalation	(1,541)	(165)
S-6	Health Insurance Escalation	(323)	(723)
S-7	Overhead Billing	(778)	(777)
S-8	Service Provider Costs	1,926	3,041
S-9	WTC Improvements	59	57
S-10	Managers' Deferred Compensation	713	832
S-11	Income Tax Adjustments	(89)	(467)
S-12	Load Forecast	(1,622)	(26)
S-13	Variable Power Costs	(13,853)	(61,334)
S-14	Miscellaneous Electric Revenues	(1,504)	(1,539)
S-16	Incentive Pay Adjustment	(4,280)	(4,413)
S-17	Supplemental Executive Retirement	(1,852)	(1,780)
S-18	Managers' Deferred Compensation	(1,835)	(2,162)
S-19	Directors' Deferred Compensation and Pensions	(210)	(200)
S-20	Medical Insurance	(332)	(808)
S-21	EPRI Membership Replacement	0	0
S-22	Escalation Rate Update	(1,105)	(1,641)
S-23	Non-Labor Customer Accounts	(106)	(111)
S-24	Community Development	(302)	(311)
S-25	Market Intelligence	(224)	(235)
S-26	CS2 Project	(93)	(4,428)
S-27	Advertising - Category "A"	(109)	(384)
S-28	Power Smart	(116)	(120)
S-30	Energy Resource Center	(217)	(217)
S-31	Energy Efficiency	5,001	13,473
S-33	Equity Issuance Costs	0	(3,571)
S-34	Payroll Tax Rate	(20)	(401)
S-35	Revised Interest from ROR Change (RR included in S-O)	0	0
S-36	Non-Fuel Material and Supplies	(75)	(149)
S-37	Remove Boardman Gain Acceleration	36,313	31,309
	Total Stipulated Adjustments	11,759	(42,593)
	UNSTIPULATED ADJUSTMENTS		
S-15	Wage and Salary Adjustment	(446)	(834)
S-29	HVEA Promotions	(1,292)	(1,555)
S-32	PGC Allocation	(202)	(216)
S-45	Trojan Overtime	(427)	(382)
S-46	Trojan Plant Reclassification	0	0
S-47	Trojan Salvage Recovery	(843)	(818)
S-48	Decommissioning Trust Accrual Reduction	(664)	(789)
S-49	Remove Plugging, Sleeving, Analysis and Reactor Pump	(3,945)	(3,808)
S-50	Remove Additional Trojan Fixed Costs to Reach 86.9 Percent	(5,798)	(5,491)
S-51	Remove Trojan Power Cost Deferral	3,305	3,337
S-52	Update Trojan Plant Income Tax Write-Off	871	1,119
S-53	Trojan Intangible Asset	0	0
	One Percent Discretionary Costs Reduction	(1,631)	(1,687)
	Total Unstipulated Adjustments	(11,072)	(11,124)
	Total Adjustments	**687**	**(53,717)**
	Revenue Requirements Change	**$47,185**	**$55,550**

23-Mar-95
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PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1995
(000)

		1995 Per Company Filing (1)	Adjustments (2)	1995 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Operating Revenues					
2	Sales to Consumers	$885,257	$846	$886,103	$47,185	$933,288
3	Other Revenues	8,385	2,410	10,795	0	10,795
4	**Total Operating Revenues**	$893,642	$3,256	$896,898	$47,185	$944,083
5	Operating Expenses and Taxes					
6	Operation & Maintenance.					
7	Net Variable Power Costs	$320,346	($13,547)	$306,799	$0	$306,799
8	Fixed Power Costs	71,532	0	71,532	0	71,532
9	Other Oper.& Maint.	147,951	(13,311)	134,640	203	134,843
10	**Total Operation & Maintenance**	$539,829	($26,858)	$512,971	$203	$513,174
11	Depreciation & Amortization	115,170	31,712	146,882	0	146,882
12	Taxes Other than Income	49,471	(892)	48,579	991	49,570
13	Income Taxes	62,438	(481)	61,957	18,139	80,096
14						
15	**Total Operating Expenses and Taxes**	$766,908	$3,481	$770,389	$19,333	$789,722
16	**Utility Operating Income**	$126,734	($225)	$126,509	$27,848	$154,357
17	Average Rate Base					
18	Utility Plant In Service	$2,651,345	($155,912)	$2,495,433	$0	$2,495,433
19	Accumulated Depreciation	(1,099,656)	72,395	(1,027,261)	0	(1,027,261)
20	Accumulated Deferred Income Taxes	(235,810)	134,771	(101,039)	0	(101,039)
21	Accumulated Deferred Inv. Tax Credit	(54,317)	8,912	(45,405)	0	(45,405)
22	**Net Utility Plant**	$1,261,562	$60,166	$1,321,728	$0	$1,321,728
23	Energy Efficiency	66,801	19,916	86,717	0	86,717
24	Boardman Gain	(99,463)	(18,354)	(117,817)	0	(117,817)
25	Deferred Trojan Investment	291,467	(51,330)	240,137	0	240,137
26	Materials & Supplies - Fuel	14,811	0	14,811	0	14,811
27	- Other	25,973	(5,164)	20,809	0	20,809
28	Working Cash	36,634	92	36,726	880	37,606
29	Misc. Deferred Debits	33,273	0	33,273	0	33,273
30	Misc. Deferred Credits	(15,501)	1,677	(13,824)	0	(13,824)
31	**Total Average Rate Base**	$1,615,557	$7,003	$1,622,560	$880	$1,623,440
32	**Rate of Return**	7.84%		7.80%		9.51%
33	**Implied Return on Equity**	7.67%		7.83%		11.60%

APPENDIX F
PAGE 2 OF 35

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Corrections to Company Filing					
		PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
1	Operating Revenues						
2	Sales to Consumers	$0	$0	$0	$0	$0	$0
3	Other Revenues		0				
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes						
6	Operation & Maintenance						
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs						
9	Other Oper.& Maint.	(299)	0	(23)	(1,230)	(1,497)	(314)
10	**Total Operation & Maintenance**	($299)	$0	($23)	($1,230)	($1,497)	($314)
11	Depreciation & Amortization	0	0	0	0	0	0
12	Taxes Other than Income	(7)	0	0	0	0	0
13	Income Taxes	121	(0)	9	486	591	124
14							
15	**Total Operating Expenses and Taxes**	($185)	($0)	($14)	($744)	($906)	($190)
16	**Utility Operating Income**	$185	$0	$14	$744	$906	$190
17	Average Rate Base						
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0
19	Accumulated Depreciation	0	0	0	0	0	0
20	Accumulated Deferred Income Taxes	0	0	0	0	0	0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0
23	Energy Efficiency						
24	Boardman Gain	0	0	0	0	0	0
25	Trojan Investment						
26	Materials & Supplies - Fuel						
27	- Other						
28	Working Cash	(8)	(0)	(1)	(34)	(41)	(9)
29	Misc. Deferred Debits						
30	Misc. Deferred Credits						
31	**Total Average Rate Base**	($8)	($0)	($1)	($34)	($41)	($9)
32	**Revenue Requirement Effect**	($315)	$0	($24)	($1,267)	($1,541)	($323)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Corrections to Company Filing						
		Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$4,932	$0
3	Other Revenues	687						
4	**Total Operating Revenues**	$687	$0	$0	$0	$0	$4,932	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$2,554	($13,445)
8	Fixed Power Costs							
9	Other Oper.& Maint.	(73)	1,870	0	692	0	281	0
10	**Total Operation & Maintenance**	($73)	$1,870	$0	$692	$0	$2,835	($13,445)
11	Depreciation & Amortization	0					85	
12	Taxes Other than Income	0	0	0	0	0	137	0
13	Income Taxes	300	(738)	(7)	(273)	(192)	707	5,310
14								
15	**Total Operating Expenses and Taxes**	$227	$1,132	($7)	$419	($192)	$3,763	($8,135)
16	**Utility Operating Income**	$460	($1,132)	$7	($419)	$192	$1,169	$8,135
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$690	$0	$0	$2,135	$0
19	Accumulated Depreciation	0		(252)			(85)	
20	Accumulated Deferred Income Taxes	0				1,478	0	
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$438	$0	$1,478	$2,050	$0
23	Energy Efficiency	0	0	0	0	0		0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other			0		0		0
28	Working Cash	10	51	(0)	19	(9)	171	(437)
29	Misc. Deferred Debits	0						
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	$10	$51	$438	$19	$1,469	$2,221	($437)
32	**Revenue Requirement Effect**	($778)	$1,926	$59	$713	($89)	($1,622)	($13,853)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues	1,469						
4	**Total Operating Revenues**	$1,469	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(383)	(3,745)	(1,957)	(1,845)	(204)	(314)
10	**Total Operation & Maintenance**	$0	($383)	($3,745)	($1,957)	($1,845)	($204)	($314)
11	Depreciation & Amortization	0	0		0			0
12	Taxes Other than Income	0	(42)	(412)	0	0	0	0
13	Income Taxes	579	169	1,642	755	721	81	125
14								
15	**Total Operating Expenses and Taxes**	$579	($256)	($2,515)	($1,202)	($1,124)	($123)	($189)
16	**Utility Operating Income**	$890	$256	$2,515	$1,202	$1,124	$123	$189
17	Average Rate Base							
18	Utility Plant in Service	$0	($61)	$0	$0	$0	$0	($65)
19	Accumulated Depreciation	0	0		0			0
20	Accumulated Deferred Income Taxes	0	0		0			0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	($61)	$0	$0	$0	$0	($65)
23	Energy Efficiency			0		0	0	
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other			0		0	0	
28	Working Cash	26	(12)	(114)	(55)	(51)	(6)	(9)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits				1,200	477	0	
31	**Total Average Rate Base**	$26	($73)	($114)	$1,145	$426	($6)	($74)
32	**Revenue Requirement Effect**	($1,504)	($446)	($4,280)	($1,852)	($1,835)	($210)	($332)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts. (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category "A" (S-27)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(1,073)	(103)	(278)	(203)	0	(106)
10	**Total Operation & Maintenance**	$0	($1,073)	($103)	($278)	($203)	$0	($106)
11	Depreciation & Amortization			0				
12	Taxes Other than Income	0	0	0	(15)	(15)	0	0
13	Income Taxes	(0)	424	41	116	86	10	42
14								
15	**Total Operating Expenses and Taxes**	($0)	($649)	($62)	($177)	($132)	$10	($64)
16	**Utility Operating Income**	$0	$649	$62	$177	$132	($10)	$64
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	($687)	$0
19	Accumulated Depreciation			0				
20	Accumulated Deferred Income Taxes			0				
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	($687)	$0
23	Energy Efficiency	0	0	0	0	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other	0	0					
28	Working Cash	(0)	(30)	(3)	(8)	(6)	0	(3)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($0)	($30)	($3)	($8)	($6)	($687)	($3)
32	**Revenue Requirement Effect**	$0	($1,105)	($106)	($302)	($224)	($93)	($109)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Allocation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	($4,086)	$0	$0	$0
3	Other Revenues			0	254			
4	**Total Operating Revenues**	$0	$0	$0	($3,832)	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	($2,656)	$0	$0	$0
8	Fixed Power Costs		0	0			0	
9	Other Oper.& Maint.	(108)	(1,203)	(211)	1,165	(196)	0	0
10	**Total Operation & Maintenance**	($108)	($1,203)	($211)	($1,491)	($196)	$0	$0
11	Depreciation & Amortization						0	
12	Taxes Other than Income	(5)	(52)	0	(86)	0	0	(19)
13	Income Taxes	45	496	83	(1,186)	77	(0)	8
14								
15	**Total Operating Expenses and Taxes**	($68)	($759)	($128)	($2,762)	($119)	($0)	($11)
16	**Utility Operating Income**	$68	$759	$128	($1,070)	$119	$0	$11
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0	($4)
19	Accumulated Depreciation							
20	Accumulated Deferred Income Taxes				0			
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	($4)
23	Energy Efficiency	0	0	0	19,916	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment			0				
26	Materials & Supplies - Fuel							
27	- Other					0		
28	Working Cash	(3)	(35)	(6)	(126)	(5)	(0)	(1)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($3)	($35)	($6)	$19,790	($5)	($0)	($5)
32	**Revenue Requirement Effect**	($116)	($1,292)	($217)	$5,001	($202)	$0	($20)

APPENDIX F
PAGE 7 OF 35

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0.	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	0	0	(365)	0	0	0
10	**Total Operation & Maintenance**	$0	$0	$0	($365)	$0	$0	$0
11	Depreciation & Amortization			36,707	0	0	(353)	(1,072)
12	Taxes Other than Income	0	0	0	(40)	0	0	0
13	Income Taxes	448	8	(14,315)	161	0	192	375
14								
15	**Total Operating Expenses and Taxes**	$448	$8	$22,392	($244)	$0	($161)	($697)
16	**Utility Operating Income**	($448)	($8)	($22,392)	$244	$0	$161	$697
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	($71)	($155,559)	$0	$0
19	Accumulated Depreciation			0	0	72,732	0	0
20	Accumulated Deferred Income Taxes			7,233	0	102,367	0	(664)
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	8,912	0	0
22	**Net Utility Plant**	$0	$0	$7,233	($71)	$28,452	$0	($664)
23	Energy Efficiency	0	0					
24	Boardman Gain	0	0	(18,354)	0	0	0	0
25	Trojan Investment					(23,841)	(3,529)	3,908
26	Materials & Supplies - Fuel							
27	- Other		(553)			(4,611)		
28	Working Cash	20	0	1,019	(11)	0	(7)	(32)
29	Misc. Deferred Debits			0	0	0	0	0
30	Misc. Deferred Credits			0	0	0	0	0
31	**Total Average Rate Base**	$20	($553)	($10,102)	($82)	$0	($3,536)	$3,212
32	**Revenue Requirement Effect**	$762	($75)	$36,313	($427)	$0	($843)	($664)

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

		Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$846
3	Other Revenues							2,410
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$3,256
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	($13,547)
8	Fixed Power Costs							0
9	Other Oper.& Maint.	0	(6)	0	0	0	(1,584)	(13,311)
10	**Total Operation & Maintenance**	$0	($6)	$0	$0	$0	($1,584)	(26,858)
11	Depreciation & Amortization	(1,652)	(2,003)	0	0	0	0	31,712
12	Taxes Other than Income	0	(336)	0	0	0	0	(892)
13	Income Taxes	906	820	(364)	(87)	0	626	(481)
14								
15	**Total Operating Expenses and Taxes**	($746)	($1,525)	($364)	($87)	$0	($958)	$3,481
16	**Utility Operating Income**	$746	$1,525	$364	$87	$0	$958	($225)
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	($2,290)	$0	($155,912)
19	Accumulated Depreciation	0	0	0	0	0	0	72,395
20	Accumulated Deferred Income Taxes	0	0	24,357	0	0	0	134,771
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	8,912
22	**Net Utility Plant**	$0	$0	$24,357	$0	($2,290)	$0	$60,166
23	Energy Efficiency							19,916
24	Boardman Gain	0	0	0	0	0	0	(18,354)
25	Trojan Investment	(16,606)	(19,878)		6,326	2,290	0	(51,330)
26	Materials & Supplies - Fuel							0
27	- Other							(5,164)
28	Working Cash	(34)	(69)	(17)	(4)	0	(44)	92
29	Misc. Deferred Debits	0	0	0	0	0	0	0
30	Misc. Deferred Credits	0	0	0	0	0	0	1,677
31	**Total Average Rate Base**	($16,640)	($19,947)	$24,340	$6,322	$0	($44)	$7,003
32	**Revenue Requirement Effect**	($3,945)	($5,798)	$3,305	$871	$0	($1,631)	$1,508

95-322

23-Mar-95
05:28 PM

PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1995
(000)

Income Tax Calculations	1995 Per Company Filing (1)	Adjustments (2)	1995 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
Book Revenues	$893,642	$3,256	$896,898	$47,185	$944,083
Book Expenses Other than Depreciation	589,300	(27,751)	561,549	1,194	562,743
State Tax Depreciation	115,170	(4,642)	110,528		110,528
Interest	62,350	(871)	61,479	33	61,512
Book-Tax (Schedule M) Differences	(17,306)	(10,913)	(28,219)		(28,219)
State Taxable Income	$144,128	$47,433	$191,561	$45,958	$237,518
State Income Tax @ 6.672%	$9,634	$3,165	$12,799	$3,066	$15,865
	166	0	166		166
Net State Income Tax	**$9,468**	**$3,165**	**$12,633**	**$3,066**	**$15,699**
Additional Tax Depreciation	0	0	0		0
Other Schedule M Differences	0	0	0		0
Federal Taxable Income	$135,168	$43,760	$178,928	$42,892	$221,820
Federal Tax @ 35%	$47,309	$15,316	$62,625	$15,022	$77,647
ITC	0	0	0	0	0
Current Federal Tax	**$47,309**	**$15,316**	**$62,625**	**$15,022**	**$77,647**
Environmental Tax @ 0.12%	**$152**	**$53**	**$205**	**51**	**$256**
ITC Adjustment					
Deferral	$0	$0	$0	$0	$0
Restoration	2,039	(54)	1,985		1,985
Total ITC Adjustment	**($2,039)**	**$54**	**($1,985)**	**$0**	**($1,985)**
Provision for Deferred Taxes	**$7,548**	**($19,068)**	**($11,520)**	**$0**	**($11,520)**
Total Income Tax	**$62,438**	**($481)**	**$61,957**	**$18,139**	**$80,096**

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

Miscellaneous Corrections to Company Filing

	Income Tax Calculations	PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
33	Book Revenues	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	(306)	0	(23)	(1,230)	(1,497)	(314)
35	State Tax Depreciation	0	0	0	0	0	0
36	Interest	(0)	(0)	(0)	(1)	(2)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0
38	State Taxable Income	$306	$0	$23	$1,231	$1,499	$314
39	State Income Tax @ 6.672%	$20	$0	$2	$82	$100	$21
40	State Tax Credit						
41	**Net State Income Tax**	$20	$0	$2	$82	$100	$21
42	Additional Tax Depreciation	0	0	0	0	0	0
43	Other Schedule M Differences						
44	Federal Taxable Income	$286	$0	$21	$1,149	$1,399	$293
45	Federal Tax @ 35%	$100	$0	$8	$402	$490	$103
46	ITC	0	0	0	0	0	0
47	**Current Federal Tax**	$100	$0	$8	$402	$490	$103
48	**Environmental Tax @ 0.12%**	$0	$0	$0	$1	$2	$0
49	ITC Adjustment						
50	Deferral	$0	$0	$0	$0	$0	$0
51	Restoration						
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$121	$0	$9	$486	$591	$124

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
		Miscellaneous Corrections to Company Filing						
33	Book Revenues	$687	$0	$0	$0	$0	$4,932	$0
34	Book Expenses Other than Depreciation	(73)	1,870	0	692	0	2,972	(13,445)
35	State Tax Depreciation	0	0	0	0	0	85	0
36	Interest	0	2	17	1	56	84	(17)
37	Book-Tax (Schedule M) Differences	0	0	0	0	(7,512)	0	0
38	State Taxable Income	$760	($1,872)	($17)	($693)	$7,456	$1,791	$13,462
39	State Income Tax @ 6.672%	$51	($125)	($1)	($46)	$497	$119	$898
40	State Tax Credit							
41	**Net State Income Tax**	$51	($125)	($1)	($46)	$497	$119	$898
42	Additional Tax Depreciation	0	0	0	0		0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$709	($1,747)	($15)	($647)	$6,451	$1,672	$12,563
45	Federal Tax @ 35%	$248	($611)	($5)	($226)	$2,258	$585	$4,397
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$248	($611)	($5)	($226)	$2,258	$585	$4,397
48	**Environmental Tax @ 0.12%**	$1	($2)	($0)	($1)	$8	$2	$15
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	($2,955)	$0	$0
54	**Total Income Tax**	$300	($738)	($7)	($273)	($192)	$707	$5,310

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
33	Book Revenues	$1,469	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(425)	(4,157)	(1,957)	(1,845)	(204)	(314)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	1	(3)	(4)	43	16	(0)	(3)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$1,468	$428	$4,161	$1,914	$1,829	$204	$317
39	State Income Tax @ 6.672%	$98	$29	$278	$128	$122	$14	$21
40	State Tax Credit							
41	Net State Income Tax	$98	$29	$278	$128	$122	$14	$21
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$1,370	$399	$3,884	$1,786	$1,707	$191	$296
45	Federal Tax @ 35%	$480	$140	$1,359	$625	$597	$67	$103
46	ITC	0	0	0	0	0	0	0
47	Current Federal Tax	$480	$140	$1,359	$625	$597	$67	$103
48	Environmental Tax @ 0.12%	$2	$0	$5	$2	$2	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	Total ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
53	Provision for Deferred Taxes	$0	$0	$0	$0	$0	$0	$0
54	Total Income Tax	$579	$169	$1,642	$755	$721	$81	$125

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	EPRI Membership Replacement (S-21)	Escalation. Rate Update (S-22)	Non-Labor Cust. Accts. (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category 'A' (S-27)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(1,073)	(103)	(293)	(218)	0	(106)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(1)	(0)	(0)	(0)	(26)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$0	$1,074	$103	$293	$218	$26	$106
39	State Income Tax @ 6.672%	$0	$72	$7	$20	$15	$2	$7
40	State Tax Credit							
41	**Net State Income Tax**	$0	$72	$7	$20	$15	$2	$7
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$0	$1,002	$96	$274	$204	$24	$99
45	Federal Tax @ 35%	$0	$351	$34	$96	$71	$8	$35
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$0	$351	$34	$96	$71	$8	$35
48	**Environmental Tax @ 0.12%**	$0	$1	$0	$0	$0	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$0	$424	$41	$116	$86	$10	$42

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Alloc/Inflation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
33	Book Revenues	$0	$0	$0	($3,832)	$0	$0	$0
34	Book Expenses Other than Depreciation	(113)	(1,255)	(211)	(1,576)	(196)	0	(19)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(1)	(0)	750	(0)	(0)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$113	$1,256	$211	($3,005)	$196	$0	$19
39	State Income Tax @ 6.672%	$8	$84	$14	($201)	$13	$0	$1
40	State Tax Credit							
41	**Net State Income Tax**	$8	$84	$14	($201)	$13	$0	$1
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$106	$1,172	$197	($2,805)	$183	$0	$18
45	Federal Tax @ 35%	$37	$410	$69	($982)	$64	$0	$6
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$37	$410	$69	($982)	$64	$0	$6
48	**Environmental Tax @ 0.12%**	$0	$1	$0	($3)	$0	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$45	$496	$83	($1,186)	$77	$0	$8

APPENDIX F
PAGE 15 OF 35

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	0	0	(405)	0	0	0
35	State Tax Depreciation	0	0	0	0	0	0	(1,072)
36	Interest	(1,136)	(21)	(383)	(3)	0	(134)	122
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	(3,381)
38	State Taxable Income	$1,136	$21	$383	$408	$0	$134	$4,331
39	State Income Tax @ 6.672%	$76	$1	$26	$27	$0	$9	$289
40	State Tax Credit							
41	Net State Income Tax	$76	$1	$26	$27	$0	$9	$289
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences	0		0	0	0	0	0
44	Federal Taxable Income	$1,060	$20	$357	$381	$0	$125	$4,042
45	Federal Tax @ 35%	$371	$7	$125	$133	$0	$44	$1,415
46	ITC	0	0	0	0	0	0	0
47	Current Federal Tax	$371	$7	$125	$133	$0	$44	$1,415
48	Environmental Tax @ 0.12%	$1	$0	$0	$0	$0	$0	$5
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	Total ITC Adjustment	$0	$0	$0	$0	$0	$0	$0
53	Provision for Deferred Taxes	$0	$0	($14,466)	$0	$0	$139	($1,334)
54	Total Income Tax	$448	$8	($14,315)	$161	$0	$192	$375

APPENDIX F
PAGE 16 OF 35

95-322

23-Mar-95
05:28 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1995
(000)

	Income Tax Calculations	Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
33	Book Revenues	$0	$0	$0	$0	$0	$0	$3,256
34	Book Expenses Other than Depreciation	0	(342)	0	0	0	(1,584)	($27,751)
35	State Tax Depreciation	0	(3,655)	0	0	0	0	($4,642)
36	Interest	(630)	(756)	922	240	0	(2)	($871)
37	Book-Tax (Schedule M) Differences	0	4,440	0	(4,460)	0	0	($10,913)
38	State Taxable Income	$630	$313	($922)	$4,220	$0	$1,586	$47,433
39	State Income Tax @ 6.672%	$42	$21	($62)	$282	$0	$106	$3,165
40	State Tax Credit							$0
41	**Net State Income Tax**	$42	$21	($62)	$282	$0	$106	$3,165
42	Additional Tax Depreciation	0	0	0	0	0	0	$0
43	Other Schedule M Differences	0	0	0	0	0	0	$0
44	Federal Taxable Income	$588	$292	($861)	$3,939	$0	$1,480	$43,760
45	Federal Tax @ 35%	$206	$102	($301)	$1,379	$0	$518	$15,316
46	ITC	0	0	0	0	0	0	$0
47	**Current Federal Tax**	$206	$102	($301)	$1,379	$0	$518	$15,316
48	**Environmental Tax @ 0.12%**	$1	$0	($1)	$5	$0	$2	$53
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration		(54)					($54)
52	**Total ITC Adjustment**	$0	$54	$0	$0	$0	$0	$54
53	**Provision for Deferred Taxes**	$657	$643	$0	($1,752)	$0	$0	($19,068)
54	**Total Income Tax**	$906	$820	($364)	($87)	$0	$626	($461)

95-322

PORTLAND GENERAL ELECTRIC CO.
General Rate Case Settlement - UE 88
(000)

COST OF CAPITAL - 1995	AMOUNTS	% OF CAPITAL	COST	COST
Long Term Debt	$964,369	49.14%	7.71%	3.79%
Preferred Stock	106,370	5.42%	8.27%	0.45%
Common Equity	891,644	45.44%	11.60%	5.27%
Total	$1,962,383	100.00%		9.51%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectibles/OPUC Fee*	0.00430
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97470
State Income Tax @ 6.672%**	0.06503
Federal Taxable Income	0.90967
Federal Income Tax @ 35%	0.31838
ITC	0.00000
Current FIT	0.31838
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38451
Total Revenue Sensitive Costs	0.40981
Utility Operating Income	0.59019
Net-to-Gross Factor	1.69436

*	
Uncollectible Rate	0.00230
OPUC Fee	0.00200
Total	0.00430

** State Income Tax	
Montana (.0675*.050008)	0.00338
Oregon (.0660*.959764)	0.06334
Total	0.06672

APPENDIX F
PAGE 18 OF 35

95-322

23-Mar-95
05:45 PM

PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1996
(000)

		1996 Per Company Filing (1)	Adjustments (2)	1996 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Operating Revenues					
2	Sales to Consumers	$910,200	($10,372)	$899,828	$55,550	$955,378
3	Other Revenues	8,719	2,436	11,155	0	11,155
4	**Total Operating Revenues**	$918,919	($7,936)	$910,983	$55,550	$966,533
5	Operating Expenses and Taxes					
6	Operation & Maintenance					
7	Net Variable Power Costs	$378,238	($66,424)	$311,814	$0	$311,814
8	Fixed Power Costs	73,745	0	73,745	0	73,745
9	Other Oper.& Maint.	152,949	(12,865)	140,084	239	140,323
10	**Total Operation & Maintenance**	$604,932	($79,289)	$525,643	$239	$525,882
11	Depreciation & Amortization	124,955	26,846	151,801	0	151,801
12	Taxes Other than Income	49,092	(1,467)	47,625	1,167	48,792
13	Income Taxes	43,748	15,821	59,569	21,354	80,923
14						
15	**Total Operating Expenses and Taxes**	$822,727	($38,089)	$784,638	$22,760	$807,398
16	**Utility Operating Income**	$96,192	$30,153	$126,345	$32,785	$159,130
17	Average Rate Base					
18	Utility Plant in Service	$2,778,739	($162,981)	$2,615,759	$0	$2,615,759
19	Accumulated Depreciation	(1,200,062)	78,752	(1,121,310)	0	(1,121,310)
20	Accumulated Deferred Income Taxes	(241,948)	141,668	(100,280)	0	(100,280)
21	Accumulated Deferred Inv. Tax Credit	(50,164)	8,252	(41,912)	0	(41,912)
22	**Net Utility Plant**	$1,286,565	$65,692	$1,352,257	$0	$1,352,257
23	Energy Efficiency	59,853	47,856	107,709	0	107,709
24	Boardman Gain	(60,904)	(54,916)	(115,820)	0	(115,820)
25	Deferred Trojan Investment	268,921	(44,082)	224,839	0	224,839
26	Materials & Supplies - Fuel	14,810	0	14,810	0	14,810
27	- Other	27,205	(5,827)	21,378	0	21,378
28	Working Cash	39,388	(1,882)	37,506	1,036	38,542
29	Misc. Deferred Debits	27,498	0	27,498	0	27,498
30	Misc. Deferred Credits	(16,196)	2,931	(13,265)	0	(13,265)
31	**Total Average Rate Base**	$1,647,140	$9,772	$1,656,912	$1,036	$1,657,947
32	of Return	5.84%		7.63%		0%
33	ed Return on Equity	3.08%		7.36%		%

APPENDIX F
PAGE 19 OF 35

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Corrections to Company Filing					
		PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
1	Operating Revenues						
2	Sales to Consumers	$0	$0	$0	$0	$0	$0
3	Other Revenues		0				
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes						
6	Operation & Maintenance						
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs						
9	Other Oper.& Maint.	(628)	0	(24)	(1,488)	(160)	(702)
10	**Total Operation & Maintenance**	($628)	$0	($24)	($1,488)	($160)	($702)
11	Depreciation & Amortization	0	0	0	0	0	0
12	Taxes Other than Income	(15)	0	0	0	0	0
13	Income Taxes	254	(0)	9	588	63	277
14							
15	**Total Operating Expenses and Taxes**	($389)	($0)	($15)	($900)	($97)	($425)
16	**Utility Operating Income**	$389	$0	$15	$900	$97	$425
17	Average Rate Base						
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0
19	Accumulated Depreciation	0	0	0	0	0	0
20	Accumulated Deferred Income Taxes	0	0	0	0	0	0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0
23	Energy Efficiency						
24	Boardman Gain	0	0	0	0	0	0
25	Trojan Investment						
26	Materials & Supplies - Fuel						
27	- Other						
28	Working Cash	(18)	(0)	(1)	(41)	(4)	(19)
29	Misc. Deferred Debits						
30	Misc. Deferred Credits						
31	**Total Average Rate Base**	($18)	($0)	($1)	($41)	($4)	($19)
32	**Revenue Requirement Effect**	($662)	$0	($25)	($1,532)	($165)	($723)

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Corrections to Company Filing						
		Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers/Dir. Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$1,854	$0
3	Other Revenues	688						
4	**Total Operating Revenues**	$688	$0	$0	$0	$0	$1,854	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$1,198	($59,543)
8	Fixed Power Costs							
9	Other Oper.& Maint.	(71)	2,953	0	808	0	239	0
10	**Total Operation & Maintenance**	($71)	$2,953	$0	$808	$0	$1,437	($59,543)
11	Depreciation & Amortization	0					75	
12	Taxes Other than Income	0	0	0	0	0	68	0
13	Income Taxes	299	(1,166)	(6)	(319)	(607)	80	23,516
14								
15	**Total Operating Expenses and Taxes**	$228	$1,787	($6)	$489	($607)	$1,660	($36,027)
16	**Utility Operating Income**	$460	($1,787)	$6	($489)	$607	$194	$36,027
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$690	$0	$0	$1,863	$0
19	Accumulated Depreciation	0		(276)			(75)	
20	Accumulated Deferred Income Taxes	0				3,483	0	
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$414	$0	$3,483	$1,788	$0
23	Energy Efficiency	0	0	0	0	0		0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other			0		0		0
28	Working Cash	10	81	(0)	22	(28)	76	(1,788)
29	Misc. Deferred Debits	0						
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	$10	$81	$414	$22	$3,455	$1,864	($1,788)
32	**Revenue Requirement Effect**	($777)	$3,041	$57	$832	($467)	($26)	($61,334)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues	1,504						
4	**Total Operating Revenues**	$1,504	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(702)	(3,861)	(2,046)	(2,172)	(194)	(748)
10	**Total Operation & Maintenance**	$0	($702)	($3,861)	($2,046)	($2,172)	($194)	($748)
11	Depreciation & Amortization	0	0		0			0
12	Taxes Other than Income	0	(77)	(425)	0	0	0	0
13	Income Taxes	593	311	1,692	772	850	77	300
14								
15	**Total Operating Expenses and Taxes**	$593	($468)	($2,593)	($1,274)	($1,322)	($117)	($448)
16	**Utility Operating Income**	$911	$468	$2,593	$1,274	$1,322	$117	$448
17	Average Rate Base							
18	Utility Plant In Service	$0	($233)	$0	$0	$0	$0	($276)
19	Accumulated Depreciation	0		0		0		0
20	Accumulated Deferred Income Taxes	0		0		0		0
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	($233)	$0	$0	$0	$0	($276)
23	Energy Efficiency		0		0		0	
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other		0		0		0	
28	Working Cash	27	(21)	(118)	(58)	(60)	(5)	(20)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits				2,389	542	0	
31	**Total Average Rate Base**	$27	($254)	($118)	$2,331	$482	($5)	($296)
32	**Revenue Requirement Effect**	($1,539)	($834)	($4,413)	($1,780)	($2,162)	($200)	($808)

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts. (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category 'A' (S-27)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	(1,594)	(108)	(286)	(212)	(700)	(373)
10	**Total Operation & Maintenance**	$0	($1,594)	($108)	($286)	($212)	($700)	($373)
11	Depreciation & Amortization			0			(2,562)	
12	Taxes Other than Income	0	0	0	(16)	(16)	0	0
13	Income Taxes	(0)	629	43	119	90	1,369	147
14								
15	**Total Operating Expenses and Taxes**	($0)	($965)	($65)	($183)	($138)	($1,893)	($226)
16	**Utility Operating Income**	$0	$965	$65	$183	$138	$1,893	$226
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	($8,400)	$0
19	Accumulated Depreciation			0			1,469	
20	Accumulated Deferred Income Taxes			0			(490)	
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	($7,421)	$0
23	Energy Efficiency	0	0	0	0	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment							
26	Materials & Supplies - Fuel							
27	- Other	0	0					
28	Working Cash	(0)	(44)	(3)	(8)	(6)	(86)	(10)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($0)	($44)	($3)	($8)	($6)	($7,507)	($10)
32	**Revenue Requirement Effect**	$0	($1,641)	($111)	($311)	($235)	($4,428)	($384)

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Allocation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	($12,226)	$0	$0	$0
3	Other Revenues			0	244			
4	**Total Operating Revenues**	$0	$0	$0	($11,982)	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	($8,079)	$0	$0	$0
8	Fixed Power Costs		0	0			0	
9	Other Oper.& Maint.	(112)	(1,449)	(211)	3,143	(210)	0	
10	**Total Operation & Maintenance**	($112)	($1,449)	($211)	($4,936)	($210)	$0	$0
11	Depreciation & Amortization						(2,100)	
12	Taxes Other than Income	(5)	(61)	0	(257)	0	0	(379)
13	Income Taxes	46	596	83	(3,394)	83	1	151
14								
15	**Total Operating Expenses and Taxes**	($71)	($914)	($128)	($8,586)	($127)	($2,099)	($228)
16	**Utility Operating Income**	$71	$914	$128	($3,396)	$127	$2,099	$228
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	$0	$0	($81)
19	Accumulated Depreciation							
20	Accumulated Deferred Income Taxes				0			
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0
22	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	($81)
23	Energy Efficiency	0	0	0	47,856	0	0	0
24	Boardman Gain	0	0	0	0	0	0	0
25	Trojan Investment			0				
26	Materials & Supplies - Fuel							
27	- Other					0		
28	Working Cash	(3)	(42)	(6)	(391)	(6)	(95)	(10)
29	Misc. Deferred Debits							
30	Misc. Deferred Credits							
31	**Total Average Rate Base**	($3)	($42)	($6)	$47,465	($6)	($95)	($91)
32	**Revenue Requirement Effect**	($120)	($1,555)	($217)	$13,473	($216)	($3,571)	($401)

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	$0
3	Other Revenues							
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	$0
8	Fixed Power Costs							
9	Other Oper.& Maint.	0	0	0	(310)	0	0	0
10	**Total Operation & Maintenance**	$0	$0	$0	($310)	$0	$0	$0
11	Depreciation & Amortization			36,417	0	0	(353)	(1,072)
12	Taxes Other than Income	0	0	0	(34)	0	0	0
13	Income Taxes	644	16	(14,888)	139	0	189	390
14								
15	**Total Operating Expenses and Taxes**	$644	$16	$21,529	($205)	$0	($164)	($682)
16	**Utility Operating Income**	($644)	($16)	($21,529)	$205	$0	$164	$682
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	($200)	($155,182)	$0	$0
19	Accumulated Depreciation			0	0	77,634	0	0
20	Accumulated Deferred Income Taxes			22,149	0	93,796	0	(1,627)
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	8,252	0	0
22	**Net Utility Plant**	$0	$0	$22,149	($200)	$24,500	$0	($1,627)
23	Energy Efficiency	0	0					
24	Boardman Gain	0	0	(54,916)	0	0	0	0
25	Trojan Investment					(19,762)	(3,315)	3,908
26	Materials & Supplies - Fuel							
27	- Other		(1,089)			(4,738)		
28	Working Cash	29	1	980	(9)	0	(7)	(31)
29	Misc. Deferred Debits			0	0	0	0	0
30	Misc. Deferred Credits			0	0	0	0	0
31	**Total Average Rate Base**	$29	($1,088)	($31,787)	($209)	$0	($3,322)	$2,250
32	**Revenue Requirement Effect**	$1,095	($149)	$31,309	($382)	$0	($818)	($789)

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

		Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
1	Operating Revenues							
2	Sales to Consumers	$0	$0	$0	$0	$0	$0	($10,372)
3	Other Revenues							2,436
4	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	($7,936)
5	Operating Expenses and Taxes							
6	Operation & Maintenance							
7	Net Variable Power Costs	$0	$0	$0	$0	$0	$0	($66,424)
8	Fixed Power Costs							0
9	Other Oper.& Maint.	0	(9)	0	0	0	(1,639)	(12,865)
10	**Total Operation & Maintenance**	$0	($9)	$0	$0	$0	($1,639)	(79,289)
11	Depreciation & Amortization	(1,638)	(1,921)	0	0	0	0	26,846
12	Taxes Other than Income	0	(250)	0	0	0	0	(1,467)
13	Income Taxes	893	725	(367)	(115)	0	647	15,821
14								
15	**Total Operating Expenses and Taxes**	($745)	($1,455)	($367)	($115)	$0	($992)	($38,089)
16	**Utility Operating Income**	$745	$1,455	$367	$115	$0	$992	$30,153
17	Average Rate Base							
18	Utility Plant in Service	$0	$0	$0	$0	($1,162)	$0	($162,981)
19	Accumulated Depreciation	0	0	0	0	0	0	78,752
20	Accumulated Deferred Income Taxes	0	0	24,357	0	0	0	141,668
21	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	8,252
22	**Net Utility Plant**	$0	$0	$24,357	$0	($1,162)	$0	$65,692
23	Energy Efficiency							47,856
24	Boardman Gain	0	0	0	0	0	0	(54,916)
25	Trojan Investment	(15,619)	(18,536)		8,080	1,162	0	(44,082)
26	Materials & Supplies - Fuel							0
27	- Other							(5,827)
28	Working Cash	(34)	(66)	(17)	(5)	0	(45)	(1,882)
29	Misc. Deferred Debits	0	0	0	0	0	0	0
30	Misc. Deferred Credits	0	0	0	0	0	0	2,931
31	**Total Average Rate Base**	($15,653)	($18,602)	$24,340	$8,075	$0	($45)	$9,772
32	**Revenue Requirement Effect**	($3,808)	($5,491)	$3,337	$1,119	$0	($1,687)	($49,501)

95-322

23-Mar-95
05:45 PM

PORTLAND GENERAL ELECTRIC CO.
Summary of Adjusted Oregon Results
UE-88 Test Year Based on 1996
(000)

Income Tax Calculations	1996 Per Company Filing (1)	Adjustments (2)	1996 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
Book Revenues	$918,919	($7,936)	$910,983	$55,550	$966,533
Book Expenses Other than Depreciation	654,024	(80,756)	573,268	1,406	574,674
State Tax Depreciation	124,955	(4,556)	120,399		120,399
Interest	64,570	(1,259)	63,311	40	63,350
Book-Tax (Schedule M) Differences	(27,907)	(3,252)	(31,159)		(31,159)
State Taxable Income	$103,277	$81,887	$185,164	$54,104	$239,269
State Income Tax @ 6.672%	$6,903	$5,464	$12,367	$3,610	$15,977
State Tax Credit	83	0	83		83
Net State Income Tax	$6,820	$5,464	$12,284	$3,610	$15,894
Additional Tax Depreciation	0	0	0		0
Other Schedule M Differences	0	0	0		0
Federal Taxable Income	$96,985	$75,896	$172,881	$50,494	$223,375
Federal Tax @ 35%	$33,946	$26,564	$60,510	$17,683	$78,193
ITC	0	0	0	0	0
Current Federal Tax	$33,946	$26,564	$60,510	$17,683	$78,193
Environmental Tax @ 0.12%	$93	$91	$184	61	$245
ITC Adjustment					
Deferral	$0	$0	$0	$0	$0
Restoration	2,039	(54)	1,985		1,985
Total ITC Adjustment	($2,039)	$54	($1,985)	$0	($1,985)
Provision for Deferred Taxes	$4,928	($16,351)	($11,423)	$0	($11,423)
Total Income Tax	$43,748	$15,821	$59,569	$21,354	$80,923

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	PGC Inflation (S-1)	EPRI Deferral (S-2)	Category 'C' Advertising (S-3)	Retirement Savings Plan (S-4)	Legal Escalation (S-5)	Health Insurance Escalation (S-6)
		Miscellaneous Corrections to Company Filing					
33	Book Revenues	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	(643)	0	(24)	(1,488)	(160)	(702)
35	State Tax Depreciation	0	0	0	0	0	0
36	Interest	(1)	(0)	(0)	(2)	(0)	(1)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0
38	State Taxable Income	$644	$0	$24	$1,490	$160	$703
39	State Income Tax @ 6.672%	$43	$0	$2	$99	$11	$47
40	State Tax Credit						
41	Net State Income Tax	$43	$0	$2	$99	$11	$47
42	Additional Tax Depreciation	0	0	0	0	0	0
43	Other Schedule M Differences						
44	Federal Taxable Income	$601	$0	$22	$1,390	$149	$656
45	Federal Tax @ 35%	$210	$0	$8	$487	$52	$230
46	ITC	0	0	0	0	0	0
47	Current Federal Tax	$210	$0	$8	$487	$52	$230
48	Environmental Tax @ 0.12%	$1	$0	$0	$2	$0	$1
49	ITC Adjustment						
50	Deferral	$0	$0	$0	$0	$0	$0
51	Restoration						
52	Total ITC Adjustment	$0	$0	$0	$0	$0	$0
53	Provision for Deferred Taxes	$0	$0	$0	$0	$0	$0
54	Total Income Tax	$254	$0	$9	$588	$63	$277

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Overhead Billing (S-7)	Service Provider Costs (S-8)	WTC Improvements (S-9)	Managers/Dir. Def. Comp. (S-10)	Income Tax Adjustments (S-11)	Load Forecast (S-12)	Variable Power Costs (S-13)
		Miscellaneous Corrections to Company Filing						
33	Book Revenues	$688	$0	$0	$0	$0	$1,854	$0
34	Book Expenses Other than Depreciation	(71)	2,953	0	808	0	1,505	(59,543)
35	State Tax Depreciation	0	0	0	0	0	75	0
36	Interest	0	3	16	1	132	71	(68)
37	Book-Tax (Schedule M) Differences	0	0	0	0	(1,740)	0	0
38	State Taxable Income	$759	($2,956)	($16)	($809)	$1,608	$203	$59,611
39	State Income Tax @ 6.672%	$51	($197)	($1)	($54)	$107	$14	$3,977
40	State Tax Credit							
41	**Net State Income Tax**	**$51**	**($197)**	**($1)**	**($54)**	**$107**	**$14**	**$3,977**
42	Additional Tax Depreciation	0	0	0	0		0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$708	($2,759)	($15)	($755)	$973	$189	$55,634
45	Federal Tax @ 35%	$248	($966)	($5)	($264)	$340	$66	$19,472
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	**$248**	**($966)**	**($5)**	**($264)**	**$340**	**$66**	**$19,472**
48	**Environmental Tax @ 0.12%**	**$1**	**($3)**	**($0)**	**($1)**	**$1**	**$0**	**$67**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**$0**	**$0**	**($1,056)**	**$0**	**$0**
54	**Total Income Tax**	**$299**	**($1,166)**	**($6)**	**($319)**	**($607)**	**$80**	**$23,516**

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Miscellaneous Electric Revenues (S-14)	Wage & Salary Adjustment (S-15)	Incentive Pay Adjustment (S-16)	Supplemental Executive Retirement (S-17)	Managers' Deferred Compensation (S-18)	Directors' Deferred Comp. & Pensions (S-19)	Medical Insurance (S-20)
33	Book Revenues	$1,504	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(779)	(4,286)	(2,046)	(2,172)	(194)	(748)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	1	(10)	(5)	89	18	(0)	(11)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$1,503	$789	$4,290	$1,957	$2,154	$194	$759
39	State Income Tax @ 6.672%	$100	$53	$286	$131	$144	$13	$51
40	State Tax Credit							
41	**Net State Income Tax**	**$100**	**$53**	**$286**	**$131**	**$144**	**$13**	**$51**
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$1,403	$736	$4,004	$1,826	$2,010	$181	$709
45	Federal Tax @ 35%	$491	$258	$1,401	$639	$703	$63	$248
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	**$491**	**$258**	**$1,401**	**$639**	**$703**	**$63**	**$248**
48	**Environmental Tax @ 0.12%**	**$2**	**$1**	**$5**	**$2**	**$2**	**$0**	**$1**
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
53	**Provision for Deferred Taxes**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
54	**Total Income Tax**	**$593**	**$311**	**$1,692**	**$772**	**$850**	**$77**	**$300**

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	EPRI Membership Replacement (S-21)	Escalation Rate Update (S-22)	Non-Labor Cust. Accts, (S-23)	Community Development (S-24)	Market Intelligence (S-25)	CS2 Project (S-26)	Advertising Category 'A' (S-27)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	(1,594)	(108)	(302)	(228)	(700)	(373)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(2)	(0)	(0)	(0)	(287)	(0)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$0	$1,596	$108	$302	$228	$987	$373
39	State Income Tax @ 6.672%	$0	$106	$7	$20	$15	$66	$25
40	State Tax Credit							
41	**Net State Income Tax**	$0	$106	$7	$20	$15	$66	$25
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$0	$1,489	$101	$282	$213	$921	$348
45	Federal Tax @ 35%	$0	$521	$35	$99	$75	$322	$122
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$0	$521	$35	$99	$75	$322	$122
48	**Environmental Tax @ 0.12%**	$0	$2	$0	$0	$0	$1	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$980	$0
54	**Total Income Tax**	$0	$629	$43	$119	$90	$1,369	$147

95-322

23-Mar-95
05:45 PM

Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Power Smart (S-28)	HVEA Promotions (S-29)	Energy Resource Center (ERC) (S-30)	Energy Efficiency (S-31)	PGC Alloc/Inflation (S-32)	Equity Issuance Costs (S-33)	Payroll Tax Rate (S-34)
33	Book Revenues	$0	$0	$0	($11,982)	$0	$0	$0
34	Book Expenses Other than Depreciation	(117)	(1,510)	(211)	(5,192)	(210)	0	(379)
35	State Tax Depreciation	0	0	0	0	0	0	0
36	Interest	(0)	(2)	(0)	1,814	(0)	(4)	(3)
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	0
38	State Taxable Income	$117	$1,512	$211	($8,603)	$210	$4	$382
39	State Income Tax @ 6.672%	$8	$101	$14	($574)	$14	$0	$26
40	State Tax Credit							
41	**Net State Income Tax**	$8	$101	$14	($574)	$14	$0	$26
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences							
44	Federal Taxable Income	$109	$1,411	$197	($8,029)	$196	$3	$357
45	Federal Tax @ 35%	$38	$494	$69	($2,810)	$69	$1	$125
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$38	$494	$69	($2,810)	$69	$1	$125
48	**Environmental Tax @ 0.12%**	$0	$2	$0	($10)	$0	$0	$0
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	$0	$0	$0	$0	$0
54	**Total Income Tax**	$46	$596	$83	($3,394)	$83	$1	$151

95-322

23-Mar-95
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Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Revised Interest from ROR Change (S-35)	Non-Fuel Materials & Supplies (S-36)	Remove Boardman Gain Accel. (S-37)	Trojan Overtime (S-45)	Trojan Plant Reclassification (S-46)	Trojan Salvage Recovery (S-47)	Decommissioning Trust Accrual Reduction (S-48)
33	Book Revenues	$0	$0	$0	$0	$0	$0	$0
34	Book Expenses Other than Depreciation	0	0	0	(344)	0	0	0
35	State Tax Depreciation	0	0	0	0	0	0	(1,072)
36	Interest	(1,632)	(42)	(1,215)	(8)	0	(127)	86
37	Book-Tax (Schedule M) Differences	0	0	0	0	0	0	(1,517)
38	State Taxable Income	$1,632	$42	$1,215	$352	$0	$127	$2,503
39	State Income Tax @ 6.672%	$109	$3	$81	$23	$0	$8	$167
40	State Tax Credit							
41	**Net State Income Tax**	$109	$3	$81	$23	$0	$8	$167
42	Additional Tax Depreciation	0	0	0	0	0	0	0
43	Other Schedule M Differences	0		0	0	0	0	0
44	Federal Taxable Income	$1,523	$39	$1,134	$329	$0	$118	$2,336
45	Federal Tax @ 35%	$533	$14	$397	$115	$0	$41	$818
46	ITC	0	0	0	0	0	0	0
47	**Current Federal Tax**	$533	$14	$397	$115	$0	$41	$818
48	**Environmental Tax @ 0.12%**	$2	$0	$1	$0	$0	$0	$3
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration							
52	**Total ITC Adjustment**	$0	$0	$0	$0	$0	$0	$0
53	**Provision for Deferred Taxes**	$0	$0	($15,367)	$0	$0	$139	($597)
54	**Total Income Tax**	$644	$16	($14,888)	$139	$0	$189	$390

95-322

23-Mar-95
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Portland General Electric Co.
Adjustments to Oregon Results
UE-88 Test Year Based on 1996
(000)

	Income Tax Calculations	Remove Plugging, Sleeving, Analysis & Reactor Pump (S-49)	Remove Additional Trojan Fixed Costs to Reach 86.9% (S-50)	Remove Trojan Power Cost Deferral (S-51)	Update Trojan Plant Income Tax Write-off (S-52)	Trojan Intangible Asset (S-53)	Reduce Discretionary Costs by 1%	Total Adjustments
33	Book Revenues	$0	$0	$0	$0	$0	$0	($7,936)
34	Book Expenses Other than Depreciation	0	(259)	0	0	0	(1,639)	($80,756)
35	State Tax Depreciation	0	(3,559)	0	0	0	0	($4,556)
36	Interest	(598)	(711)	930	309	0	(2)	($1,259)
37	Book-Tax (Schedule M) Differences	0	4,474	0	(4,469)	0	0	($3,252)
38	State Taxable Income	$598	$55	($930)	$4,160	$0	$1,640	$81,887
39	State Income Tax @ 6.672%	$40	$4	($62)	$278	$0	$109	$5,464
40	State Tax Credit							$0
41	**Net State Income Tax**	$40	$4	($62)	$278	$0	$109	$5,464
42	Additional Tax Depreciation	0	0	0	0	0	0	$0
43	Other Schedule M Differences	0	0	0	0	0	0	$0
44	Federal Taxable Income	$558	$51	($868)	$3,883	$0	$1,531	$75,896
45	Federal Tax @ 35%	$195	$18	($304)	$1,359	$0	$536	$26,564
46	ITC	0	0	0	0	0	0	$0
47	**Current Federal Tax**	$195	$18	($304)	$1,359	$0	$536	$26,564
48	**Environmental Tax @ 0.12%**	$1	$0	($1)	$5	$0	$2	$91
49	ITC Adjustment							
50	Deferral	$0	$0	$0	$0	$0	$0	$0
51	Restoration		(54)					($54)
52	**Total ITC Adjustment**	$0	$54	$0	$0	$0	$0	$54
53	**Provision for Deferred Taxes**	$657	$649	$0	($1,756)	$0	$0	($16,351)
54	**Total Income Tax**	$893	$725	($367)	($115)	$0	$647	$15,821

APPENDIX F
PAGE 34 OF 35

95-322

PORTLAND GENERAL ELECTRIC CO.
General Rate Case - UE 88
(000)

COST OF CAPITAL - 1996	AMOUNTS	% OF CAPITAL	COST	WEIGHTED COST
Long Term Debt	$1,044,215	48.86%	7.82%	3.82%
Preferred Stock	99,703	4.67%	8.27%	0.39%
Common Equity	993,333	46.47%	11.60%	5.39%
Total	$2,137,251	100.00%		9.60%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
O&M - Uncollectible/OPUC Fee*	0.00430
Other Taxes-Franchise	0.02100
Short-Term Interest	0.00000
Other Taxes	0.00000
State Taxable Income	0.97470
State Income Tax @ 6.672%**	0.06503
Federal Taxable Income	0.90967
Federal Income Tax @ 35%	0.31838
ITC	0.00000
Current FIT	0.31838
ITC Adjustment/Env. Tax	0.00109
Total Income Taxes	0.38451
Total Revenue Sensitive Costs	0.40981
Utility Operating Income	0.59019
Net-to-Gross Factor	1.69436

*	Uncollectible Rate	0.00230
	OPUC	0.00200
	Total	0.00430

**	State Income Tax	
	Montana (.0675*.050008)	0.00338
	Oregon (.0660*.959764)	0.06334
	Total	0.06672

95-322

PORTLAND GENERAL ELECTRIC COMPANY
RATE DESIGN SUMMARY TABLE FORECAST STFPUC94
25-Mar-95 MONTHLY REVENUE MODEL SCH102 at PF-93 Rate

For CALENDAR Years
1995-96 Test Period

CUSTOMER CLASSIFICATION	RATE SCHEDULE	AVERAGE CUSTOMERS	KWH SALES (000'S)	REVENUES: BEFORE RPA E-15 PH I W/O ADJUSTMENTS	REVENUES: BEFORE RPA E-16 PH I W/O ADJUSTMENTS	INCREASE IN REVENUES: AMOUNT	INCREASE IN REVENUES: PERCENT
RESIDENTIAL:							
SERVICE	7	569,338	13,811,054	$809,727,203	$882,204,684	$72,477,481	9.0%
OUTDOOR LIGHTING RES	14R	(670)	7,904	1,336,018	1,309,255	(26,763)	-2.0%
REVENUE CLASS TOTAL		569,338	13,818,958	$811,063,221	$883,513,938	$72,450,718	8.9%
GENERAL SERVICE:							
OUTDOOR LIGHTING FARM	14C	(269)	4,734	$756,322	$736,181	($20,141)	-2.7%
OUTDOOR LIGHTING GEN SER	15C	(864)	27,531	3,098,909	3,046,847	(52,062)	-1.7%
FARM & RESIDENTIAL GEN SER							
DEMAND LEVEL I	31-I	17,245	417,967	$27,034,536	$28,920,340	$1,885,804	7.0%
DEMAND LEVEL II	31-II	892	478,311	23,752,243	24,502,341	750,099	3.2%
DEMAND LEVEL III (TOD)	31-III	1	25,631	1,182,164	1,179,651	(2,514)	-0.2%
GENERAL SECONDARY VOLTAGE							
DEMAND LEVEL I	32-I	45,972	1,940,248	119,151,360	125,889,649	6,738,289	5.7%
DEMAND LEVEL II	32-II	9,179	7,721,341	381,580,267	394,423,914	12,843,647	3.4%
DEMAND LEVEL III (TOD)	32-III	126	1,621,316	76,912,393	78,285,588	1,373,195	1.8%
TOTAL 31 & 32		73,414	12,204,815	$629,612,962	$653,201,483	$23,588,521	3.7%
FARM AND RES OPTIONAL (TOD)	37	12	1,992	111,422	111,944	522	0.5%
GEN SER OPTIONAL (TOD)	38	205	119,709	6,624,303	6,774,245	149,942	2.3%
IRRIG AND DRAINAGE FARM	48	4,347	139,992	6,524,501	7,122,771	598,270	9.2%
IRRIG AND DRAINAGE OTHER	49	139	13,955	599,766	638,681	38,916	6.5%
DRAINAGE DISTRICTS	97	2	1,522	68,306	72,337	4,031	5.9%
REVENUE CLASS TOTAL		78,119	12,514,250	$647,396,491	$671,704,490	$24,307,999	3.8%
LARGE GENERAL SERVICE:							
FARM & RESIDENTIAL LGS							
DEMAND LEVEL I	82-I	2	11,599	$524,437	$526,857	$2,419	0.5%
DEMAND LEVEL II (TOD)	82-II	1	9,614	463,172	470,966	7,794	1.7%
GENERAL PRIMARY VOLTAGE							
DEMAND LEVEL I	83-I	66	336,557	15,378,330	15,507,419	129,089	0.8%
DEMAND LEVEL II (TOD)	83-II	107	3,410,621	152,166,305	152,712,972	546,666	0.4%
TOTAL 82 & 83		176	3,768,392	$168,532,245	$169,218,213	$685,969	0.4%
LARGE INDUSTRIAL (TOD):							
TRANSMISSION VOLTAGE	89	2	454,521	$18,832,864	$18,193,332	($639,532)	-3.4%
STREETLIGHTING:							
STREET AND HIGHWAY LIGHTING	91	547	158,501	$21,348,168	$20,801,275	($546,893)	-2.6%
TRAFFIC SIGNALS	92	96	34,719	1,714,755	1,816,133	101,379	5.9%
RECREATIONAL FIELD LIGHTING	93	34	1,150	101,039	107,005	5,966	5.9%
REVENUE CLASS TOTAL		677	194,370	$23,163,962	$22,724,413	($439,549)	-1.9%
CONTRACTUAL SALES	99	5	3,681,231	$117,304,965	$123,744,583	$6,439,618	5.5%
REVENUE ADJUSTMENTS	-	-	(6,833)	($828,000)	($828,000)		
EMPLOYEE DISCOUNT	-	-	-	(1,346,924)	(1,435,070)		
TOTAL (CYCLE YEAR BASIS)		648,317	34,424,889	$1,784,118,824	$1,886,835,900	$102,717,076	5.8%
CONVERSION ADJ. - CYCLE TO CALENDAR YEAR			36,908	1,813,075	1,878,601		
TOTAL ULTIMATE SALES (CALENDAR YEAR BASIS)			34,461,797	$1,785,931,899	$1,888,714,501	$102,782,602	5.8%

APPENDIX G
PAGE 1 OF 3

95-322

Percent of Marginal Costs
Based on 1995/1996 Loads and Costs
Base Revenues w/o Adjustment Clauses

	Loads (a)	Marginal Costs ($000) (b)	Marginal Costs mills/kWh (c)	Present Revenue ($000) (d)	Present Revenue mills/kWh (e)	% of Marg Cost (f)=(e)/(c)	Indexed(1) % of Marg Cost (g)	Proposed Revenue ($000) (h)	Proposed Revenue mills/kWh (i)	% of Marg Cost (j)=(i)/(c)	Indexed(1) % of Marg Cost (k)
Residential	13,811,054	$1,175,680	85.13	$809,727	58.63	68.9%	91.7%	$882,205	63.88	75.0%	94.4%
Small Commercial	2,358,215	$196,105	83.16	$146,186	61.99	74.5%	99.2%	$154,810	65.65	78.9%	99.4%
Medium Commercial/ Industrial (2)	8,547,808	$529,544	61.95	$421,235	49.28	79.5%	105.9%	$434,961	50.89	82.1%	103.4%
Large Commercial/ Industrial (3)	5,521,703	$279,044	50.54	$249,557	45.20	89.4%	119.1%	$250,843	45.43	89.9%	113.1%
Optional Time-of-Day	121,701	$7,192	59.10	$6,736	55.35	93.7%	124.7%	$6,886	56.58	95.7%	120.5%
Irrigation & Drainage Pumping Service	153,947	$19,342	125.64	$7,124	46.28	36.8%	49.0%	$7,761	50.42	40.1%	50.5%
Lighting (4) (Energy Charges Only)	233,389	$13,974	59.87	$12,606	54.01	90.2%	120.1%	$13,331	57.12	95.4%	120.1%
Grand Total (5)	30,780,566	$2,221,244	72.16	$1,668,627	54.21	75.1%	100.0%	$1,764,970	57.34	79.5%	100.0%

Notes:

(1) To index, each classes' percent of marginal costs was multiplied by the ratio of total marginal costs to total present/proposed revenue.
(2) Sch 31/32 II, Sch 82/83 I
(3) Sch 31/32 III, Sch 82/83 II, and Sch 89
(4) Sch 14, 15, 91, and 92
(5) Includes misc. schedules, adjustments to revenue, and fixed streetlight costs.

95-322

ENCLOSURE (5)

OPUC ORDER NO. 01-777, ENTERED AUGUST 31, 2001
IN DOCKET UE 115

ORDER NO. 01-777

ENTERED AUG 31 2001

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149.	))))	ORDER

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

ORDER NO. 01-777

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149.	))))	ORDER

SUMMARY

In this order, the Commission approves new rate schedules for Portland General Electric Company (PGE). The new schedules reflect the unprecedented increases in the prices for electricity on the wholesale power markets. Due to a combination of increased demand, lack of new generating facilities, low water conditions, and the troubled deregulation effort in California, wholesale electricity prices have nearly tripled since PGE's last general rate change in late 1997. At that time, power costs averaged 1.37 cents/kilowatt-hour (kWh). Power costs have since increased some 173 percent, and now average 3.74 cents/kWh. The power markets have also become extremely volatile, with peak power prices exceeding $1.20/kWh at various times last winter.

The new schedules also restructure and reprice PGE's services, beginning March 1, 2002, to meet the requirements of Senate Bill 1149, an electric industry restructuring bill.[1] SB 1149 requires electric utilities to functionally separate their power generation from distribution services and provide consumers with access to power supply options.

The exact impact on customer rates will not be known until September 12, 2001, the date that energy rates will be calculated based on PGE's forward price curves and the value of the company's resources. Based on PGE's latest power cost calculations and the terms of this order, however, the Commission projects an overall rate increase in customer rates of approximately 35 percent. Applying this estimate to the rate spread adopted for the new schedules, residential rates will increase about 26 percent, and industrial rates will increase about 46 percent. In its September 12, 2001 filing, PGE will submit a rate design table identifying, for each rate schedule, the specific percentage increase resulting from the updated power cost estimates and consistent with the terms of this order.

In an effort to help offset rising power costs, the Commission imposes reductions to PGE's non-power Operation and Management (O&M) budget. Given the largely unavoidable power cost increases and the resulting impact on customer rates, the Commission concludes that it is prudent for PGE to reduce other discretionary internal operating costs. With the decisions in

[1] In House Bill 3633, the 2001 Legislative Assembly delayed the implementation of SB 1149 from October 1, 2001 to March 1, 2002.

this order adopting stipulations among the parties and resolving contested issues, the authorized increase, aside from the effect of power costs, is almost $50 million less than the company requested.

In addition, the Commission adopts a Power Cost Adjustment (PCA) mechanism that will lower rates if the company's power costs decline. The PCA establishes how PGE will account for variations between expected power costs included in base rates and actual power costs, and describes the method by which the company and its customers will share in the benefits and burdens of such variations. This mechanism will track the fluctuations in power costs and require a refund to customers of overcollections exceeding a preset amount. The PCA balances the interests of customers and PGE and helps ensure the company's continued ability to secure a reliable source of energy to meet demand.

The Commission also adopts a tiered rate structure for residential customers that will benefit consumers who use lower amounts of energy. The first 225 kWh of electricity used is priced lower than electricity used above and beyond that amount. The rate design also ensures that residential and small farm customers receive the full benefit of low-cost subscription power managed by the Bonneville Power Administration (BPA).

INTRODUCTION

On October 2, 2000, Portland General Electric (PGE) filed Advice No. 00-14, an application for revised tariff schedules. The tariffs were designed to implement a general rate revision and put into operation the provisions of Senate Bill 1149.[2] Among other things, PGE's filing unbundled the company's services into generation, transmission, distribution, ancillary, and customer services, established charges to electricity service suppliers, formulated market-priced standard offers, and calculated competitive transition amounts.

At its October 20, 2000 Public Meeting, the Commission found good cause to investigate the filing and suspended Advice No. 00-14 pursuant to ORS 757.215. Because the Commission determined that the rate investigation could not be completed within an initial six-month suspension period, it ordered that the filing be suspended for a total period of nine months from November 1, 2000.[3] PGE later waived the statutory suspension period and agreed to an extension of the suspension through August 31, 2001, with rates to become effective October 1, 2001.[4]

Prehearing Conference

On October 24, 2000, Michael Grant, an Administrative Law Judge (ALJ), held a prehearing conference to identify parties and to establish a procedural schedule. The following participated as parties to this proceeding: PGE, Industrial Customers of Northwest Utilities

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[2] PGE's filing originally included the company's proposal to reclassify its transmission assets. That proposal, however, was later bifurcated to allow timely review by the Federal Energy Regulatory Commission (FERC). On March 14, 2001, PGE, Oregon Office of Energy, and Staff filed a stipulation intended to resolve all issues related to reclassification of transmission assets. No party opposed the stipulation, which was also signed by Fred Meyer Stores. We reviewed the stipulation and adopted it in Order No. 01-325.

[3] Order No. 00-669.

[4] Orders No. 01-575 and 01-724.

(ICNU), the Citizens' Utility Board (CUB), Fred Meyer Stores (Fred Meyer), City of Portland (Portland), League of Oregon Cities (League), Oregon Office of Energy (OOE), Oregon Steel Mills, Inc. (OSM), City of Glendale (Glendale), PG&E National Energy Group, Inc., Northwest Natural Gas Company, Associated Oregon Industries, PacifiCorp, Northwest Energy Coalition, Renewable Northwest Project, ATOFINA Chemicals, Portland BOMA, Warren Parrish, and the Commission Staff (Staff).

Public Hearings and Presentations

In November and December 2000, the Commission held public comment hearings in Portland and Salem to give the general public an opportunity to comment on PGE's tariff filings. In addition, the Commission held special public meetings for opening and closing presentations by the parties. In March 2001, the Commission heard opening presentations from PGE, PacifiCorp, ICNU, CUB, City of Portland, Fred Meyer Stores, and Staff. In July 2001, the Commission heard closing oral argument from PGE, ICNU, CUB, Fred Meyer, OSM, OOE, and Staff.

Commission Orders

During the course of this proceeding, the Commission issued three orders relating to procedural matters. On December 4, 2000, the Commission issued Order No. 00-765, granting PGE additional protection for confidential information.

On March 21, 2001, the Commission issued Order No. 01-249, denying ICNU's request to allow a former Staff employee, John Thornton, to participate as an expert witness. The Commission, in explaining OAR 860-012-0010(2), set forth an analysis for determining when a former employee may testify for another party. In this case, the Commission determined that Mr. Thornton could not appear as an expert witness in this docket or in docket UE 116, the PacifiCorp restructuring and rate case.

On July 20, 2001, the Commission issued Order No. 01-592, which involved a question certified to the Commission by the presiding ALJs in dockets UE 115 and UE 116. In that order, PGE and PacifiCorp had challenged the agency's Internal Operating Guidelines that govern post-hearing procedures. They claimed that the policies were unlawful and sought the immediate adoption of more stringent procedures recommended in the Report to the Oregon Legislature from the HB 3615 Interim Task Force (Task Force).

The Commission determined that the Internal Operating Guidelines, which allow limited post-hearing communications between Commissioners and so-called "party Staff," were legal. The Commission, however, acknowledged the utilities' concerns about Staff's role in the decision-making process, and noted that the issue will be carefully examined during review of the Task Force Report. Therefore, the Commission concluded that, while the Task Force recommendations should not be fully implemented at this time, Staff witnesses who sponsored testimony or testified at hearing would not appear at decision meetings, and that only "non-party" Staff members would participate in deliberations on rate of return issues.

Evidentiary Hearings

On June 4 and 5, 2001, ALJ Grant held evidentiary hearings in Salem, Oregon. During those proceedings, the following appearances were entered: J. Jeffery Dudley, and Philip Van Der Weele, attorneys, appeared on behalf of PGE; David Hatton, Assistant Attorney General, appeared on behalf of Staff.

Based on the record in these proceedings, we make the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

Applicable Law

In this rate case, the Commission's function involves two primary steps. First, we must determine how much revenue PGE is entitled to receive. A utility's revenue requirement is determined on the basis of the utility's costs.[5] Second, we must allocate the revenue requirement among the utility's customer classes.

In the revenue requirement phase of a rate case, we must determine: (1) the gross utility revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base to establish the return to which the stockholders of the utility are reasonably entitled.[6] The purpose of answering these questions is to determine the utility's reasonable costs of providing service and expected revenues, so that the Commission can set utility rates at just and reasonable levels.

A question has arisen in this case regarding the application of the burden of proof. The phrase "burden of proof" has two meanings: one to refer to a party's burden of producing evidence; the other to a party's obligation to establish a given proposition in order to succeed.[7] To distinguish these two meanings, we refer to the burden of production and the burden of persuasion.[8] In Commission proceedings, ORS 757.210 provides that a "utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." This burden is borne by the utility throughout the proceeding and does not shift to any other party.

PGE acknowledges that the utility has the initial burden of production and persuasion to show that the proposed rates are just and reasonable. PGE contends, however, that once the utility presents its evidence, both burdens shift to parties opposing the rate increase.[9] It relies on the Commission's decision in docket UT 125, *In re U S WEST Communication, Inc.*, which provides, in pertinent part:

[5] *See, e.g., American Can Co. v. Lobdell*, 55 Or App 451, 454-55, *rev den* 293 Or 190 (1982).
[6] *See Pacific Northwest Bell Tel. Co. v. Sabin*, 21 Or App 200, 205 n. 4, *rev den* (1975).
[7] *See Hansen v. Oregon-Wash. R. & Nav. Co.*, 97 Or 190 (1920).
[8] *See, e.g.,* Oregon Evidence Code, Rule 305 and Rule 307.
[9] We note that PGE's claim is contrary to the argument traditionally raised by utilities when scheduling the filing of testimony and order of appearance at hearing. In rate cases, the utilities have always insisted on having the last word due to its burden to show that the proposed rates are just and reasonable.

> "[U S WEST] as the proponent of the rate increase must submit evidence showing that its proposed rates are just and reasonable. Once [U S WEST] has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claimed costs, must in turn show that the costs are not reasonable. Each time the burden of going forward shifts, the burden of persuasion shifts as well. That is, each party who has the burden of going forward must, in order to prevail, persuade us by competent evidence that its position with respect to that set of costs should prevail."[10]

PGE's reliance on the above-cited language is misplaced. First, PGE ignores the Commission's concluding paragraph to that section, where it clarified that:

> "The Commission's role is to weigh the evidence presented on each issue in the case and determine where the preponderance lies. We make that decision on the record as a whole. The basic decision we make with respect to each issue in this case is whether the utility has produced persuasive evidence that its revenue requirement is reasonable. A component of that decision is whether Staff has persuasively rebutted [U S WEST's] revenue requirement evidence. *We reject [U S WEST's] arguments that Staff has the 'burden of proof' with respect to disallowances and test year adjustments, because the arguments distort the way evidence is presented and decisions are made in a rate case.*"[11]

When the section is read in its entirety, it is clear that the Commission did not agree with U S WEST's arguments about shifting burdens. More importantly, however, the Commission later rescinded Order No. 97-171, and did not readopt the language relied upon by PGE in Order No. 00-191.[12] Thus, that section has been withdrawn and no longer has precedential value.

In our most recent rate case, docket UG 132, *In re Northwest Natural Gas Company*, we stated:

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[10] Order No. 97-171 at 8.

[11] *Id.* at 8. (Emphasis added.)

[12] We note that Order No. 00-191 contained a general reference to the burden of proof language relied upon by PGE. Specifically, the order states at page 15:

> "As we stated above, in the section called [U S WEST's] Burden of Proof Argument, [U S WEST] must show that its expenses are reasonable for us to allow them as part of the revenue requirement calculation."

Although Order No. 00-191 contains no section entitled "[U S WEST's] Burden of Proof Argument," PGE claims that the inclusion of this reference indicates that the Commission implicitly adopted the burden of proof language. PGE is mistaken. We simply made an error by placing a reference to a section in Order No. 00-191 that does not exist.

> "As the petitioner in this rate case, NW Natural has the burden of proof on all issues. Thus, NW Natural must submit evidence showing that its proposed rates are just and reasonable. Once the company has presented its evidence, the burden of going forward then shifts to the party or parties who oppose including the costs in the utility's revenue requirement. Staff or an intervenor, if it opposes the utility's claim costs, may in turn show that the costs are not reasonable."[13]

We adhere to that language and affirm that, under ORS 757.210, the burden of showing that the proposed rate is just and reasonable is borne by the utility throughout the proceeding. Thus, if PGE makes a proposed change that is disputed by another party, PGE still has the burden to show, by a preponderance of evidence, that the change is just and reasonable. If it fails to meet that burden, either because the opposing party presented compelling evidence in opposition to the proposal, or because PGE failed to present compelling information in the first place, then PGE does not prevail.

STIPULATED ISSUES

PGE entered into five stipulations designed to resolve many of the contested issues in this proceeding. On April 26, 2001, PGE, Staff and Fred Meyer filed a stipulation regarding changes to PGE's cost of service. The stipulation represents a settlement of all revenue requirement issues identified by Staff except the authorized return on equity portion of the cost of capital and net variable power costs. Several non-revenue requirement issues are also covered by the stipulation. The stipulation, which is attached as Appendix B, is supported by joint testimony of Jim Barnes and Sara Cardwell of PGE, and Ed Krantz of Staff.

On June 7, 2001, PGE, Portland, and League submitted a stipulation intended to resolve specific rate and tariff issues identified by Portland and League in their opening testimony. These issues include interconnection standards, restoration of utility services, utility relocation, allocation of ancillary service costs, and streetlights. The stipulation, which is attached as Appendix C, is supported by joint testimony of Sara Cardwell of PGE, David Tooze, Duane Sanger, and Bill Graham of Portland, and Andrea Fogue of League.

On July 27, 2001, PGE, Staff, ICNU, CUB, and Fred Meyer filed a stipulation designed to resolve all power cost issues. Most notably, the stipulation establishes a mechanism by which PGE will value its long-term and short-term resources for the purposes of establishing rates for energy services. It also establishes a mechanism by which PGE will account for variations between expected power costs included in base rates and actual power costs, and the method by which the company and its customers will share in the benefits and burdens of such variations. The stipulation, which is attached as Appendix D, is supported by joint testimony of Stefan Brown of Staff, Bob Jenks of CUB, Lincoln Wolverton of ICNU, Kevin Higgins of Fred Meyer, and Randy Dahlgren of PGE. To help further explain the stipulation, PGE and Staff submitted a letter from PGE counsel that clarifies the assumptions and inputs that the company will use in its final Monet power cost run. The letter, dated August 20, 2001, is included as an additional attachment to the stipulation set forth in Appendix D.

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[13] Order No. 99-697 at 3. (*Statutory language and citation omitted.*)

On August 6, 2001, PGE, Staff, and Fred Meyer filed a supplemental stipulation regarding franchise fees and steam sales. The stipulation adjusts PGE's revenue requirement to reflect the company's agreement to permit cities the ability to choose between the volumetric or revenue-based method of calculating franchise fees. The stipulation also adjusts steam sales to incorporate a recent contract to sell steam at PGE's Coyote Springs Generating Plant (Coyote Plant). The stipulation, attached as Appendix E, is supported by an explanatory brief.

Finally, on August 10, 2001, PGE and Staff filed a stipulation concerning residential rate design for Schedule 7. The stipulation is intended to resolve how the benefits and burdens of subscription power from the Bonneville Power Administration (BPA), as well as cash benefits, should be flowed through to eligible customers, and how the Resource Value Mechanism in PGE's Schedule 125 should be applied to residential and small farm classes of customers. The stipulation is attached as Appendix F and supported by an explanatory brief.

All five stipulations and supporting testimony were entered into the record of this proceeding as evidence pursuant to OAR 860-014-0085(1). We address each separately.

I. Revenue Requirement Stipulation

PGE, Fred Meyer, and Staff filed a stipulation that represents a settlement of most of the revenue requirement issues raised by Staff. The parties' settlement results in a $135.6 million reduction in rate base, a $40.6 million reduction in operating expenses, and an increase in other revenue of $1.7 million from PGE's original proposal. The stipulating parties believe that each of the adjustments discussed in the stipulation are reasonable and, overall, will yield fair and reasonable rates if adopted by the Commission.

CUB and ICNU are not parties to the stipulation and believe that PGE's non-power O&M costs are inflated. PGE initially sought $229.3 million in non-power O&M costs. The stipulation reduces PGE's request to $206.9 million. CUB and ICNU contend that this stipulated amount is excessive and should be further reduced. To demonstrate the significant increase in these costs, ICNU claims that PGE's regulatory adjusted average cost per customer averaged $219 during 1997-1999. Even with the adjustments contained in the stipulation, ICNU calculates that this figure increases to $275 per customer for 2002, a 25 percent increase.

Preliminarily, CUB and ICNU question whether PGE may have inflated its non-power O&M costs to account for the six-year rate freeze contained in the PGE/Sierra Pacific merger stipulation. This potential rate freeze, CUB and ICNU maintain, appears to have caused the company to inflate its costs in this docket to account for future increases in program costs occurring over the next six-year period.

CUB and ICNU are particularly troubled by the proposed increase in PGE's non-power O&M costs given the significant and largely unavoidable increases in power costs. The parties believe it is inappropriate for PGE to initiate, at this time, large and expensive increases in any portions of its regulated business. Before passing these additional expenses on to ratepayers, CUB and ICNU contend that the Commission should first consider the rate impact on customers and determine whether some non-power expenditures should be delayed or simply not made at this time. CUB notes that the Commission has previously ordered utilities to reduce discretionary costs to mitigate a significant rate increase.[14]

To offset the rising power costs, CUB and ICNU recommend that PGE's non-power O&M costs be limited to the rate of inflation. They each present similar, but slightly differing inflation-escalator models to forecast a reasonable level of expenditures. Adjusting the company's 1999 actual costs for inflation, CUB contends that PGE's 2002 test-year forecast for non-energy expenditures, as originally filed, should be reduced by $61.9 million. CUB proposes the Commission achieve this inflation-based target by accepting some elements of the stipulation and making additional reductions for customer service, labor, distribution O&M, technology, and other revenues. These adjustments, which are further addressed below, reduce PGE's non-power O&M costs by $55 million.

ICNU proposes an alternative test year forecast by taking PGE's 1999 actual non-power O&M expenses, applying the regulatory adjustments from docket UE 88, and escalating the results by anticipated customer growth and inflation. This methodology results in base 2002 test year non-power O&M costs of $175.6 million, a $31.3 million reduction from the stipulation. If the Commission does not adopt this alternative test year forecast, ICNU proposes the Commission make specific adjustments in addition to those contained in the stipulation. These adjustments are also addressed below.

In response, PGE contends that the non-power O&M costs contained in the stipulation are reasonable. It objects to CUB's and ICNU's speculation that the company inflated the 2002 test year forecast in anticipation of the potential six-year rate freeze resulting from the PGE-Sierra Pacific merger. PGE explains that it developed its forecasted revenue requirement using traditional ratemaking principles. It started with budget information and adjusted the numbers to remove abnormalities and to include recurring expenses and revenues that were reasonably certain to occur during the 2002 test year.

Next, PGE objects to CUB's and ICNU's inflation-escalator proposals to establish non-power O&M costs. PGE contends that the approach violates established ratemaking principles. Citing *American Can Co. v. Lobdell*, and *In re Pacific Northwest Bell Co.*, PGE argues that a utility's forecast for the test year must consider known and measurable changes that are expected to persist.[15] PGE points out that, under CUB's and ICNU's proposal, the Commission would ignore numerous factors that relate to the company's operating costs and expenditures. Moreover, PGE contends that CUB and ICNU are essentially asking for a

[14] *See In re Portland General Electric Company*, Order No. 95-322.

[15] *See* footnotes 5 and 6. In *American Can*, the Supreme Court explained that:

> "When an historic test year is used, adjustment to the test year data are made to remove abnormal events not expected to persist into the future. When a future test year is used, the data is drawn from budget figures and financial models of the utility. *Abnormal events of the past are therefore excluded and all know future changes are included.*" (Emphasis added.)

moratorium on all spending that exceeds inflation—without regard to the company's need to make appropriate up-front capital investments and properly maintain its plant. PGE believes that, in the long run, the adoption of a management-by-crisis approach would increase overall costs. Due to these limitations, PGE contends that the inflation-escalator approach cannot establish reasonable expenditures and should be rejected by the Commission.

Before turning to CUB's and ICNU's specific adjustments to PGE's non-power O&M costs, we first find no evidence that the six-year rate freeze adopted in the PGE-Sierra Pacific merger case influenced either PGE's 2002 test year or the revenue requirement stipulation between PGE, Staff, and Fred Meyer. Neither CUB nor ICNU provide any support for their allegation. Moreover, the record contradicts their claim. PGE had completed the underlying budget process before the parties developed the six-year rate freeze in the merger docket, and actually made its rate filing in this case before the Commission approved the merger agreement. In addition, PGE took specific steps to ensure that consideration of a six-year rate freeze did not affect the budget process. For these reasons, we conclude that PGE, Staff and Fred Meyer used a 2002 test year without considering the impact of the Sierra Pacific acquisition.

We also reject CUB's and ICNU's inflation-escalator proposals as independent methods to establish non-power O&M costs for PGE. Consistent with established Oregon ratemaking principles, PGE's test year should be based on actual or budgeted expenditures and adjusted to remove abnormalities and to include known and measurable changes that are expected to persist.[16] The parties' respective inflation benchmark proposals are not appropriate for evaluating PGE's expenditures, because the methodologies do not examine the reasonableness of historical operations, fail to consider abnormalities in the baseline year's results of operations, and do not take into account known and measurable changes between the baseline and test year, such as the passage of SB 1149.

We further conclude, however, that CUB's and ICNU's inflation-benchmark comparisons, as well as ICNU's cost per customer assessment, highlight the increases that PGE is seeking for its non-power O&M costs. While PGE disputes the accuracy of these comparisons and recommends numerous corrections, the fact remains that PGE's stipulated non-power O&M costs are significantly higher than the company's actual costs in 1999. We acknowledge that the implementation of SB 1149 drives many of these cost increases. Nonetheless, given the unavoidable increases in power costs and resulting impact on customer rates, it is imperative that we carefully review the company's internal operating costs and capital expenditures to ensure that proposed increases are reasonable and prudent. With this in mind, we turn to the specific non-power O&M adjustments proposed by CUB and ICNU. We address each parties' recommendations separately.

CUB Recommendations

CUB recommends that the Commission reduce PGE's non-power O&M costs, as originally filed, by $55 million. CUB proposes the Commission achieve this result by accepting

[16] *See, e.g., In re U S WEST Communications*, Order No. 00-191; *In re PacifiCorp*, Order No. 00-091; *In re Pacific Northwest Bell*, Order No. 87-406.

some elements of the stipulation[17] and making additional reductions for customer service, labor, distribution O&M, technology, and other revenues. The individual adjustments are summarized as follows:

1. Customer Service

CUB contends that PGE's proposed revenue requirement for customer service of $54.8 million is simply too great for customers to absorb, given the forecasted increase in power costs. CUB proposes an overall reduction in Customer Service of $13.86 million, which is broken down as follows:

- Reduce PGE's request for $39.2 million to deliver information and service by $11.05 million. CUB believes that the cost of the Web, responding to media requests and initiating channels of information should be split 50-50 between customers and shareholders. In addition, the cost of providing information to customers through telephone and personal contact should be reduced 25 percent.
- Eliminate the $1.2 million cost for PGE's proposed credit card payment option.
- Reduce by two-thirds the cost for Network Meter Reading/Automatic Meter Reading (NMR/AMR) system, as only one-third of the system is for customers located in test areas where the program is necessary to implement SB 1149.
- Eliminate the $750,000 allocation of distributed generation costs to customer service.
- Reduce the cost of customer surveys by $100,000 by increasing the amount allocated to non-regulated operations.
- Eliminate the $160,000 costs for WeatherWise.

In response, PGE contends that—with one minor exception—the record does not support the proposed reductions to customer costs. PGE first claims that CUB provides little

[17] CUB participated in settlement discussion and agrees with some adjustments set forth in the stipulation. Those adjustments, which reduce non-power O&M costs by $26.53 million, are as follows:

Issue #	Description	Adjustment	Issue #	Description	Adjustment
S-14	SERP	-$4.645 million	S-32	SERP O&M	-$1.250 million
S-15	Remove Trojan	-$16.584 million	S-33	Bonus/Incentive Pay	-$2.477 million
S-16	Remove NEIL	+$3.818 million	S-35	OPUC Wage Formula	-$1.717 million
S-28	Public Purpose Adj.	-$0.699 million	S-38	Y2K Amortization	-$1.977 million
S-31	A&G Accounts	-$1.00 million		Total	-$26.53 million

analysis for its proposed $11.05 million reduction for the delivery of information and services. PGE observes that the company already allocates 62 percent of Internet Web (Web) costs to non-regulated activities—well above the 50 percent CUB claims is reasonable. PGE adds that the company has justified the need for, and the benefit of, a credit card payment option for customers, and that the reduction of the scope of the NMR/AMR system will not save money due to the fixed costs of the system. In addition, PGE explains that a portion of distributed generation is properly allocated to customer service, as certain costs involve program development, testing, and analysis. Similarly, PGE maintains that customer surveys are properly allocated to regulated operations, since less than one percent of the cost, effort, and questions related to customer surveys concern non-regulated services. PGE does agree with CUB's proposed adjustment for WeatherWise, and acknowledges that approximately $160,000 should be removed from above-the-line expenditures for this program.

After our review, we share CUB's concerns about the significant increases to PGE's Customer Service costs. While some of these costs are related to PGE's efforts to meet the requirements of SB 1149, others are in response to PGE's belief that its customers want new services, more options, and better communication channels. To address these perceived needs, PGE is adding payment options, expanding communication choices, adding new customer services, and increasing the frequency of customer surveys. PGE admits that these changes cost more, but explains that they provide more value to PGE's customers.

PGE is correct that we should judge these services and the costs associated with them on the basis of the value they provide and the demand they meet. We must do so, however, in the context of PGE's overall request, which includes significant increases to its power costs. While we commend PGE for it efforts to enhance its services based on customer requests, we question whether its customers would enthusiastically support the addition of costly new programs when also faced with unprecedented power cost increases. Indeed, as CUB's counsel explained during oral argument:

> "[A]dvocates of PGE's customers are here to say that we're not nearly as concerned about more payment options right now as we are about how we're going to pay for the electricity we use. More than anything, customers want to be able to afford to use electricity to heat and light their homes, run appliances and, in short, live their lives. Business customers want to stay in business."[18]

We find that some of PGE's Customer Service expenses, such as the distributed generation, NMR/AMR system costs, and others related to SB 1149, should not be reduced or delayed at this time. PGE has showed that postponing these programs will not lead to decreased costs, and may actually increase costs over time. PGE has failed, however, to establish that it has made every reasonable effort to reduce other, discretionary Customer Service costs to help offset its spiraling power costs. We acknowledge that such reductions require difficult choices. Nonetheless, given the increasing wholesale power costs and PGE's reliance on that market to meet customer load, we believe that PGE must consider the rate impact on customers and critically examine whether some of these proposed expenditures should be delayed or simply not made at this time.

[18] Oral Argument, July 13, 2001, Transcript at 32, lines 13-19.

For these reasons, we agree that the stipulated Customer Service costs should be further reduced. As ICNU notes, customers want an economical power supply more than a new Internet Website or the ability to pay their bill with a credit card. However, we decline to adopt CUB's overall proposal to reduce Customer Service costs by $13.86 million. As noted above, some challenged costs should not be reduced or delayed at this time. Moreover, CUB has double-counted some costs, such as the credit card payment option, by targeting the same expense in two separate adjustments, and targeted other expenses that are already reduced by the revenue requirement stipulation. Adjusting CUB's proposal, we conclude that PGE's Customer Service costs forecast for the 2002 test year should be reduced by an additional $3.5 million above and beyond the adjustments contained in the stipulation. We decline to identify particular program areas that may be susceptible to reassessment or to impose specific cost reductions. These discretionary costs are best managed by the company.

2. Labor

CUB notes that, as with any large organization, PGE has staffing vacancies at any point in time. Due to these vacancies, CUB claims that PGE's actual employment costs were 5.3 percent below the budgeted employment level. In order to account for these unfilled positions for the 2002 test period, CUB proposes a reduction of 143.2 full-time equivalent (FTE) positions. This results in a reduction of operating expense of $6.4 million.

PGE questions CUB's methodology, but argues that a proper application of the analysis shows that the stipulated reduction of FTEs is reasonable. Using a longer time period (1995 through 2000), PGE calculates the percentage of unfilled positions to be 2.9 percent below budget. Applying this calculation to the 2002 forecast results in a proposed reduction of 78 FTEs, which is two less than the 80 FTEs eliminated by the stipulation.

We agree with PGE and adopt, as reasonable, the stipulated adjustment to the company's labor costs. PGE has demonstrated that CUB's analysis, when applied over the last six years, supports the stipulated reduction of 80 FTEs. Moreover, the 2002 test period, as stipulated, has a slightly lower FTE count than PGE's FTE total as of December 31, 2000. The stipulation, therefore, effectively caps the level of FTEs included in customer rates to the number of FTEs employed at the end of last year.

3. Distribution O&M

CUB contends that PGE's distribution O&M costs should be limited to 1999 actuals, adjusted for inflation. To accomplish this, CUB argues that these costs should be reduced by $3.9 million. PGE counters that CUB's suggestion to delay these expenditures, which are required to ensure safety, reliability, and regulatory compliance, is irresponsible.

We find no basis to adopt CUB's proposed adjustment to PGE's distribution O&M costs. As PGE notes, CUB has failed to question a single program as unnecessary or unreasonable, and does not allege that PGE's forecast of the cost of any program is inaccurate. We have previously rejected an inflation-escalator approach as an independent means for establishing PGE's revenue requirement. Accordingly, in the absence of any specific information challenging PGE's proposed expenditures for these critical services, we are unwilling to cap such costs with a simple inflation factor, as CUB recommends.

4. Technology

CUB believes that PGE's technology costs support non-regulated activities and should be adjusted accordingly. For example, CUB claims that the company's website provides information on a variety of non-regulated activities, such as wholesale power products and Earth Smart Homes. CUB also contends that its customer database has uses that go beyond the regulated system. For these reasons, CUB proposes a 30 percent, or $4.3 million, reduction in PGE's Information Technology (IT) budget.

PGE responds that CUB's proposed 30 percent reduction is unsupported. PGE explains that the challenged website program is just one of 16 different IT systems presented in PGE's case, and adds that it already allocates almost two-thirds of its web budget to non-regulated activities. Moreover, PGE clarifies that its Customer Information System (CIS) is not part of its IT budget, but rather is part of Customer Services and is specifically subject to the stipulation adjustment S-29.

We reject CUB's proposed reduction to PGE's technology costs. Adjustment S-31 of the stipulation, which CUB supports, already reduces the company's IT costs by $1 million. The stipulation also requires an audit of PGE's IT capital expenditures that will result in a refund to customers of capital costs that are not expended or found to be imprudent.[19] Moreover, PGE agrees that its website has non-regulated uses and has allocated almost two-thirds of its costs to non-regulated activities. For these reasons, we accept, as reasonable, the stipulated adjustments relating to PGE's IT costs.

5. Other Revenue

CUB believes that the company's filing underestimates the Other Revenue that it will receive in 2002. CUB claims that PGE's revenues should continue to increase, because of the company's on-going success in increasing revenues from pole attachments. After accepting some adjustments contained in PGE's rebuttal testimony, CUB proposes that Other Revenues be increased to $15.87 million, some $40,000 more than set forth in the stipulation.

PGE responds that CUB's forecast of Other Revenue is overly optimistic. The company believes that CUB's reliance on the growth in pole attachment revenues is misplaced, because the limited number of poles places a limit on any growth in this area. Additionally, PGE notes that many telecommunications companies have recently suspended build-outs of broadband access systems, and that much of the current growth in telecommunications occurs underground.

We reject CUB's proposal to increase PGE's Other Revenue by $40,000. Staff, PGE, and Fred Meyer have stipulated to pole-rental revenues of $5.8 million for 2002, a $100,000 increase from the company's actual revenues in 1999. Given the company's finite number of poles, the suspension of broadband access systems, and expanding use of

[19] We further address this issue in our analysis of ICNU's proposed adjustments to non-power O&M costs.

underground conduit, we conclude that the projection for Other Revenue contained in the stipulation is reasonable and adopt it.

ICNU Recommendations

Like CUB, ICNU also recommends that the Commission make specific adjustments in addition to those contained in the stipulation. Specifically, ICNU recommends that the Commission: (1) reduce PGE's non-power O&M costs by an additional $13.4 million; (2) adopt certain adjustments proposed by CUB; (3) exclude a portion of PGE's proposed IT costs; and (4) exclude SB 1149 implementation costs. We address each separately.

1. *Non-Power O&M Adjustments*

ICNU claims that PGE's costs for lobbying, governmental affairs, and strategic planning costs should be excluded from the company's revenue requirement. Citing *Re Cascade Natural Gas Co*, ICNU contends that lobbying and other "expenses for legislative activities should not be borne by ratepayers."[20] These costs include $650,923 for lobbying costs, $510,798 for state, local, and federal governmental affairs, and $1,030,267 for competitive strategic planning, for a total of $2.19 million.

ICNU also contends that PGE has failed to establish that the following new programs and costs increases are warranted and benefit ratepayers: (1) general business support costs ($368,421); (2) administration of compensation programs ($659,717); (3) employee training and development costs ($1,585,831); (4) management of Commission relationship costs ($354,000); and (5) customer service and IT costs ($6,588,577). ICNU states that the removal of these programs results in a total disallowance of approximately $9.5 million.

Finally, ICNU maintains that PGE has included in its test year cost increases related to rates and regulatory affairs that are not reasonably certain to occur in the future. ICNU explains that these costs are related to PGE's filings before state and federal agencies. ICNU does not believe that the year 2000 should be used to gauge a typical level of such activity, and proposes: (1) two adjustments to reduce rates and regulatory affairs costs by a total of $972,697; and (2) two adjustments to reduce legal costs by a total of $691,734. Together, these exclusions result in a $1.66 million reduction.

In response, PGE claims that ICNU has failed to support its specific recommended reductions. First, the company claims that, contrary to ICNU's assertion, the general support and governmental affair cost categories contain no expenses for lobbying. PGE explains that the company always charges lobbying costs below the line. PGE further argues that it has fully justified its costs for general business support, administration of compensation programs, and employee training and development. Moreover, according to the company, historic cost levels and increased regulatory requirements justify the increased expenses for legal services and regulatory affairs.

We agree with a portion of ICNU's proposed adjustments to PGE's non-power O&M costs. PGE adequately rebuts ICNU's allegations relating to governmental affairs and

[20] Order No. 74-898 at 10.

strategic planning, but fails to sufficiently describe or provide evidence detailing the costs in Ledger N42255, General Support-Manage External Relations. PGE's general assertion that the company "always charges lobbying costs below the line" is not, by itself, a sufficient justification for the expense. Accordingly, we adopt ICNU's proposed $650,923 reduction.

Second, we conclude that PGE has justified its programs and proposed cost increases related to general business support and administration of compensation programs. We agree with ICNU, however, that the company has failed to adequately explain why its proposed employee training and development costs increase from $1.6 million in 1999 to roughly $3.2 million in 2002. PGE explains the various training areas within its Human Resource Department, but offers no explanation as to why its test year training costs are twice those incurred in 1999. Similarly, while PGE identified that $1.3 million of its proposed $1.654 million increase for Commission relationship costs was related to SB 1149 project management, it provided no evidence to justify the remaining $354,000 increase in other, non-SB 1149 costs. Therefore, we adopt ICNU's $1,585,831 reduction in employee and development costs, and exclude $354,000 of PGE's costs associated with management of Commission relationships. We have already reduced PGE's Customer Service costs, pursuant to CUB's recommendations, and decline ICNU's additional request.

With regard to test year cost increases related to rates and regulatory affairs, we agree with ICNU that PGE's 2000 costs should not be considered reflective of typical department activity. As the parties are well aware, the year 2000 started a period of extensive regulatory activity at PGE, primarily due to the passage of SB 1149. Before this Commission alone, PGE initiated this rate case, filed a resource plan in docket UE 118, and actively participated in numerous rulemaking proceedings, such as dockets AR 380 and AR 390. The PGE/Sierra Pacific merger proceeding in docket UM 967 occurred that year. Moreover, the company sought an interim rate increase in docket UE 117, and a power cost adjustment mechanism in dockets UM 1008/1009. We do not believe that it is reasonable to assume that this abnormally high level of regulatory activity will continue to occur in all the future years in which PGE's rates will be in effect. We further agree with PGE, however, that 1999 was a relatively quiet year for the company's regulatory activities. The lack of major contested dockets that year, and the future efforts required for the implementation of SB 1149, confirm that the 2002 test year expenditures should be increased above the level of actual regulatory expenditures for 1999. Accordingly, we adopt half of ICNU's proposed $660,945 adjustment, and reduce PGE's 2002 test year expenditures for rates and regulatory affairs by $330,472. This adjustment allows for a considerable increase in PGE's rates and regulatory affairs budget, yet reflects a reasonable level of future regulatory activity.[21]

We make a similar adjustment to PGE's proposed legal costs in its 2002 test year. PGE has forecasted a $1.0 million increase from 1999 costs based on "the restructuring of PGE's business environment from regulated to competitive."[22] As ICNU notes, however, PGE fails to account for any cost decreases that may be associated with unbundling and the transfer of operational control of transmission assets to a Regional Transmission Organization. Moreover, like the company's regulatory activities, we do not believe that all costs associated with the

[21] ICNU also recommended an additional $311,752 reduction in rates and regulatory affairs costs, for a total reduction of $972,679. We do not adopt ICNU's additional adjustment, which would reduce expenditures for PGE's Environmental Affairs.
[22] *See* PGE/700, Stevens/7.

competitive transition will continue to occur in all future years. Accordingly, we adopt ICNU's recommendation and disallow half ($505,829) the proposed increase in legal fees. We do not adopt ICNU's additional $185,805 reduction relating to Ledger Account N44013, which includes the cost of Portland General Holdings (PGH) employees performing legal services for PGE.

2. Adopted CUB Adjustments

While the majority of the proposed adjustments by CUB do not impact industrial customers, ICNU accepts, as reasonable, $32.04 million of those adjustments and recommends the Commission adopt them.

We have previously addressed the relevant CUB adjustments above and need not repeat our analysis here.

3. IT Costs

In addition to the adjustments cited above, ICNU recommends the Commission exclude $49 million of PGE's proposed IT costs from the 2002 rate base. ICNU contends that PGE has failed to provide sufficient justification for the need and reasonableness of these costs. PGE responds that ICNU's proposed disallowance for IT costs is unsupported. We agree with PGE.

As clarified above, PGE has the burden of showing that any proposed expense is just and reasonable. Nonetheless, any intervenor opposing a claimed cost must provide competent evidence that such costs are not reasonable. ICNU's proposal, based solely on three lines of testimony, is not sufficient. In fact, ICNU presents no explanation as to whether it objects to the programs or the program's costs.

After a Staff review of the company's new IT systems and their associated capital costs, Staff determined that PGE's capital costs for the new IT systems were prudent and stipulated to full recovery, subject to audit. In this audit, Staff will examine PGE's actual capital expenditures for IT costs, and only those expenditures that are deemed reasonable and prudent will be authorized in rates. Expenditures that are not made or found to be imprudent will be refunded to customers. We conclude that this stipulated agreement on IT costs is reasonable, will ensure that customers will only pay for prudently incurred expenditures, and should be adopted.

4. SB 1149 Costs

ICNU agrees that PGE should be compensated for prudently incurred SB 1149 costs, but contends that PGE has failed to establish that these costs are reasonably certain to occur during the time period when UE 115 rates will be in effect. ICNU notes that PGE's assumption that the restructuring bill will take effect in October 2001 appears to be erroneous, given the recent passage of HB 3633. Moreover, regardless of the implementation date, ICNU believes that the SB 1149 costs are both extraordinary and nonrecurring and should not be included in revenue requirement. ICNU argues that implementation costs not already incurred to date should be recovered through deferred accounting.

In response, PGE first clarifies that HB 3633 delayed implementation of SB 1149 only until March 2002, so SB 1149 will be in effect during 2002. Second, PGE contends that these expenditures reflect new components of PGE's ongoing operations that are required by SB 1149. Thus, PGE argues they are not extraordinary, uncertain, and nonrecurring.

We agree with PGE. The five-month delay of SB 1149 will not materially affect PGE's activities to implement the restructuring. As PGE notes, SB 1149 will take effect in March 2002, and the company will be making expenditures in the first quarter of next year to prepare for the implementation. Contrary to ICNU's assertions, we conclude that the challenged expenditures reflect ordinary, certain, and recurring costs that should be included in PGE's revenue requirement.

Commission Resolution

We appreciate the efforts of PGE, Staff, and Fred Meyer in negotiating and stipulating to 54 separate revenue requirement issues. With the exception of the additional non-power O&M adjustments sought by CUB and ICNU, the stipulation was unopposed by any party. We have reviewed the unopposed portions of the stipulation, find the proposed adjustments contained therein to be reasonable, and conclude that the results should be adopted.

For the reasons cited above, we also find that the results contained in the disputed portions of the stipulation should be adopted, but conclude that additional reductions to PGE's non-power O&M costs are necessary to yield fair and reasonable rates. These adjustments include an additional $3.5 million reduction in Customer Service expenditures and a $3,427,055 reduction in management of Commission and external relationships, employee training and development, rates and regulatory affairs, and legal costs. Moreover, PGE has agreed to CUB's proposed $160,000 reduction for WeatherWise. Together, these additional adjustments total $7,087,055.

II. Portland and League Stipulation

This stipulation covers several issues raised by Portland and League regarding PGE's proposed tariffs, rules, and rates. Under the stipulation, PGE agrees that its interconnection standards will continue to reference applicable Institute of Electrical and Electronics Engineers (IEEE) criteria and that its interconnection standards will follow those IEEE criteria. If Portland or a member of the League opts to pursue interconnection with PGE's distribution or transmission system, PGE will work cooperatively with that municipality in applying these standards. Moreover, PGE agrees to revise Rule C relating to restoration of utility services to confirm that it will reconnect critical retail load consumers as soon as possible. PGE also agrees to continue to work cooperatively with municipalities and other public bodies to identify critical load customers. In addition, PGE agrees to further revise Rule C to clarify what constitutes a "public works project."

The stipulation also addresses disputed issues related to street lighting. The stipulation addresses four rate-related components: (1) circuit charges (marginal costs of service drops); (2) group relamping; (3) power door luminaries; and (4) emergency pole replacements. PGE, Portland, and League request that the Commission approve the various tariff adjustment described in the stipulation. No other party has filed any objection to the stipulation.

Commission Resolution

We have reviewed the Portland and League stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix C, is adopted.

III. Power Cost Stipulation

In this stipulation, PGE, ICNU, CUB, Fred Meyer, and Staff agree on matters related to power costs issues raised in this docket. The stipulation establishes methodologies or mechanisms by which PGE will: (1) establish its power costs; (2) value its long-term and short-term resources and credit that value to all consumers, including consumers selecting direct access; (3) pass all of the benefits of BPA subscription power to all residential and small farm customers; (4) reflect, in rates, the current adverse hydro conditions facing the company; and (5) share, with its customers, the benefits and burdens of variations between expected power costs included in base rates and actual power costs. The stipulation also includes a shopping credit for commercial customers and addresses charges to Boise Cascade.

Under the stipulation, charges for PGE's energy services are based on a combination of market prices and the value of PGE's resources. PGE will first determine the market price of power using its most recent forward price curves. The company will make that determination on September 12, 2001 for this upcoming year, and on November 15 for each calendar year thereafter.[23] In addition to this market price, PGE will credit or charge each customer with the positive or negative value of PGE's resources. This credit or charge will be calculated from the Resource Valuation Mechanism (RVM) set forth in Schedule 125.

The RVM compares, by customer class, the total cost of power from PGE's long-term and short-term resources to the market price of an equivalent amount of power. If total cost of power from either long-term or short-term resources is less (greater) than the market price of an equivalent amount of power, the difference will be provided as a credit (charge) to customers and spread among customers in the class on an equal cents per kWh basis. PGE will make a similar calculation for BPA subscription power to ensure that 100 percent of the benefits of subscription power will flow to eligible customers.[24]

For purposes of allocating total fixed and variable power costs among customer classes and calculating the RVM, PGE will allocate its long-term and short-term resources as follows:

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[23] The stipulation originally listed September 11, 2001 at the valuation date for the upcoming year. In post-stipulation settlement discussions, however, the parties agreed that September 12, 2001 will be the date for final pricing in this docket.

[24] To reflect the projected difference in net variable power costs between expected and normal hydro conditions, PGE will calculate a separate charge under Part C of Schedule 125. This charge is described in Paragraphs 1 and 2 of the Stipulation and is designed to account for the current adverse hydro conditions. The charge applies only until December 31, 2002. The charge is based on reduced hydro generation of 300,000 MWh over the period October 1, 2001 through December 31, 2002, spread to months based on Exhibit E to the stipulation.

(a) First, PGE will allocate its long-term resources among customer classes in proportion to their respective percentages of retail load for the 12 month period ended September 30, 2001;

(b) Second, BPA subscription power will be allocated to the residential and small-farm customers of PGE eligible to participate in BPA's residential exchange program;

(c) Third, PGE will allocate its short-term resources among all customer classes until each customer class has been allocated a sufficient amount of resources to cover the expected load of that class. If resources are insufficient to serve all expected customer load, PGE shall allocate the shortfall among the customer classes in proportion to their respective percentages of expected shortfall. Any shortfall of resources for any customer class shall be filled by market purchases;

(d) Any excess of short-term resources over expected load shall be allocated among all customer classes in proportion to their respective percentages of expected load; and

(e) If, after applying (a) and (b) above, the residential class has sufficient resources to meet expected load, short-term resources shall be allocated to the other classes on a pro rata basis until they reach the same relative position as the residential class. Any remaining short-term resources shall then be allocated in accordance with (d) above.

PGE will next allocate the net variable power costs produced by Monet, its power cost model, for the rate period for long-term resources, short-term resources and BPA subscription power among the customer classes in accordance with their relative percentages of each type of resource. PGE will then allocate and add the fixed costs of long-term resources among the customer classes in accordance with their relative percentages of long-term resources.

The stipulation also adopts a Power Cost Adjustment (PCA) to address the uncertainty in forecasting power costs. The PCA, set forth in Schedule 127, starts with net variable power costs as described above, adjusted for specific items.[25] The credits or charges produced by portions of the RVM are combined with net variable power costs to produce a base net variable power cost (NVPC). The power cost variance (PCV) is then calculated. The PCV is the difference between actual and base NVPC less the difference between actual and base energy revenues. Base energy revenues are the energy revenues forecast from existing tariffs and the load forecast used to develop the base NVPC.

The PCV is then compared to a table in Schedule 127 to determine an adjustment amount that will be charged or credited to customers in rates. The table includes a dead band of negative $28 million to positive $28 million in PCV before there is any adjustment amount. The

[25] Schedule 127 does not apply to BPA Subscription Power.

table also includes percentage sharing of the PCV between PGE and its customers in percentages ranging from 50 percent to 95 percent. This sharing is designed to motivate PGE to manage its power costs prudently, while recognizing the current volatile power markets.

The stipulation also includes a shopping incentive of 0.5 cents per kWh for large nonresidential customers with load less than 1 MWa. This incentive is limited to the first 10 percent of eligible customers that choose direct access, and its cost is recouped from the eligible class. Finally, the stipulation addresses charges to the Boise Cascade St. Helens Plant.

Commission Resolution

As noted above, this stipulation represents a settlement in compromise of the positions of most of the active parties to this docket concerning power costs. The executing parties recognize that PGE's power cost situation is unique, given PGE's exposure to the wholesale energy market and the current uncertainty and volatility of that market. The parties believe that the stipulation produces several benefits for customers that are consistent with the provisions of SB 1149. No party opposed the stipulation.

After our review, we conclude that the stipulation is reasonable. As the executing parties note, the stipulation establishes rates for PGE's energy services based on the market price of energy. This allows customers to know the actual price of energy by sending the appropriate pricing information to the retail market. In addition, the RVM passes the value of PGE's long-term and short-term resources to all of PGE's customers, including those electing direct access and portfolio service. This promotes competition and choice consistent with SB 1149.

The stipulation also provides the methodology to allocate PGE's resources among customer classes. This will more appropriately allocate, to each customer class, the actual cost to provide energy service and resource value to that class and reduce potential cross-subsidies among customer classes. Finally, the stipulation provides a means for PGE to mitigate the adverse impact of current hydro conditions, and implements a PCA that fairly distributes among the customers and PGE the potential benefits and costs resulting from changes in load, resources and the wholesale power market. Accordingly, the stipulation, set forth in Appendix D, the attached Schedules 125 and 127, and the August 20, 2001 letter explaining the assumptions and inputs that PGE will use in the final Monet run, are adopted.

IV. Supplemental Revenue Requirement Stipulation

PGE, Staff, and Fred Meyer filed this stipulation to resolve the treatment of franchise fees and steam sales. In its original filing, PGE believed that ORS 221.450, as modified by SB 1149, required franchise fees to be paid on a volumetric basis, rather than a revenue sensitive basis described in the previous version of the statute. After discussions with the League, however, PGE now agrees that cities will be able to choose the basis that is most advantageous to them pursuant to a specific set of procedures. Because the parties believe that cities will utilize the revenue basis for fees based on revenues collected in 2001, the stipulation permits PGE to revise its revenue requirements to: (1) reflect a $794,000 increase in franchise fees based on 2002 revenues at current rates, and (2) adjust revenue sensitive costs in the test year 2002 to reflect a 2.26 percent rate.

The steam sale adjustment is due to a recent contract to sell steam produced at PGE's Coyote Plant. Under this stipulation, PGE will decrease Other Revenue by $306,000 to remove imputed steam sales as originally filed. Other Revenue is increased by $1,143,000 to reflect PGE's total estimated steam sales revenue for 2002. Further, PGE will make certain adjustments to its Monet power cost model to reflect expected steam sales for each month. PGE, Staff, and Fred Meyer request the Commission to approve the stipulation. No party opposes it.

Commission Resolution

We have reviewed the supplemental revenue requirement stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix E, is adopted.

V. Rate Design Stipulation

Under the Northwest Regional Power Act, residential and small farm customers of PGE are entitled to share in the benefits of the low cost power sold by the BPA. Traditionally, the BPA provided those benefits in cash to PGE, which in turn has credited its customers under Schedule 102. Beginning in October 2001, however, the BPA will begin providing the benefits in the form of both power and cash. This stipulation is intended to resolve how PGE should pass the BPA power and financial benefits to PGE's residential and small farm customers.

Under the stipulation, PGE will value the BPA subscription power by comparing the cost and market value of that power. This value will flow through to customers under Schedule 102 as a credit or charge per kWh, which will be valued consistently with the way PGE prices energy and establishes the RVM under Schedule 125. This gives customers a credit or charge equal to the rate BPA charges PGE for subscription power, and ensures that all of the benefits and burdens of subscription power will flow through to eligible customers. PGE will also pass through the cash benefits in the form of a credit to all residential customers for all kWhs of use in excess of 225 kWh per month.

PGE and Staff designed the application of the BPA credit, BPA cash and the RVM credit or charge to produce an initial rate differential of between 10 and 25 mills per kWh for residential customers between the first 225 kWh of use per month and any kWh of use in excess of 225 kWh per month. Because changes in the forward price curves applied to PGE's final Monet run may produce a rate differential outside these parameters, the stipulation allows an adjustment to the rate differential so that there is an initial price differential that is neither too large nor too small.

In the stipulation, PGE and Staff also agree that the basic or customer charge shall be $10 per customer per month. Although PGE had originally requested a $7 per month charge, the company provided evidence that customer-related costs are in excess of $15 per month. According to the explanatory brief, Staff and PGE believe that the stipulated rate of $10 per month more accurately reflects the per-customer costs incurred by PGE. PGE and Staff request the Commission to approve the stipulation.

CUB and OOE are not parties to the stipulation, and object to certain portions of it. CUB does not oppose the content of the stipulation, but believes that the explanatory brief supporting the stipulation mischaracterizes the reason why the parties negotiated an increase in the basic or customer charge. While it does not support the proposed increase to $10 per month, it recognizes that the increase avoids the perverse result of having some low use customer rates go down, while overall rates go up. CUB claims that this is the basis for the stipulated increase, not the one contained in the explanatory brief. CUB believes that adoption of the stipulation based on the need to "more accurately reflect the per customer costs incurred by PGE" represents a significant change to Commission policy that is not supported by the record.

OOE also does not oppose PGE's and Staff's settlement on residential rate design. OOE contends, however, that the proposed stipulation does not provide adequate inversion to residential rates to move the rate for use over 1,000 kWh per month significantly closer to the long-run incremental costs for space heat use. Therefore, it recommends the Commission further modify the stipulation by adopting its rate design proposal. Like the stipulated rate design, OOE recommends an initial residential block set at the per-customer amount of BPA power and priced equal to what BPA charges PGE. OOE proposes a second block for use above the BPA block and below 1,000 kWh per month, and a third block, or tail block, for all use above 1,000 kWh.

To move energy charges for space heating closer to the high costs to serve these loads, OOE recommends that the calculation of the average rate for the first 1,000 kWh should equal the sum of the commodity charges, plus the $3.00 increase in the basic rate, divided by 1,000 kWh. It then recommends PGE decrease the net rates for the first 1,000 kWh and increase the net rate for the tail block to obtain a rate differential of 1.1 cents per kWh. OOE explains that this 1.1 cent differential would exist only until further adjustments are applied after October 1, 2001, and that the rate differential could be greater or less than 1.1 cents after that date. OOE claims that the higher tail block rate will begin to provide better price signals for residential customers when making home-heating decisions.

Commission Resolution

We have reviewed the rate design stipulation and find the proposals contained therein to be reasonable. Accordingly, the stipulation, set forth in Appendix F, is adopted. In making this decision, we clarify that we adopt the proposed increase in the basic or customer charge based on reasons cited by CUB. The increase will avoid a rate decrease to low use customers while overall rates are increasing.

We decline to adopt OOE's proposed modification. OOE provides little evidence or analysis of how its proposal would affect consumers or whether it will accomplish its apparent goal of reducing space heating. OOE's proposed rates could significantly affect a large number of customers that live in multi-family dwellings and, consequently, have no control over their heat source. Moreover, it is unclear how many customers that live in single-family dwellings would switch to gas heating under OOE's proposal. Only about 16 percent of PGE's residential customers heat with electricity. Many of these homes have no duct systems, which are necessary for the convenient installation of gas systems.

CONTESTED ISSUES

I. RATE OF RETURN

The United States Supreme Court established the standard for determining cost of capital allowance in utility rate-making proceedings:

> "[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital[.]"[26]

To determine a rate of return on rate base that is appropriate for PGE, we must first identify the costs and components of the company's capital structure. The cost of each capital component is estimated and weighted according to its percentage of total capitalization. These weighted costs of capital are combined to calculate PGE's overall cost of capital, which becomes the allowed rate of return on rate base.

During settlement discussions, PGE and Staff reached agreement on all rate of return issues except PGE's required return on equity (ROE or cost of equity). PGE estimates its required ROE to be 11.5 percent and seeks an authorized ROE at or above that level. PGE contends that this return is the appropriate rate, using a 2002 test year and considering the company's pricing and operation risks. The company's ROE recommendations are based on the joint testimony of Mr. Patrick Hager, PGE's Manager of Regulatory Affairs, and Mr. William Valach, PGE's Manager of Finance (collectively Hager-Valach). Hager-Valach present ROE estimates using a single-stage and multi-stage Discounted Cash Flow (DCF), the Risk Positioning Method, and a comparison of actual determinations of required equity returns in other jurisdictions.[27]

Staff contends that PGE's request is excessive and recommends the adoption of an ROE for the company of 9.0 percent.[28] Staff presents ROE estimates from two witnesses. Bryan Conway (Conway), Staff's Program Manager of Economic and Policy Analysis, presents cost of equity estimates using a single-stage DCF model, the Fisher-Kamin version of the Capital Asset Pricing Model (CAPM), and a qualitative analysis of the Commission's most recent contested ROE decision in docket UG 132.[29] James A. Rothschild (Rothschild), President of Rothschild Financial Consulting, quantifies his cost of equity recommendations using the single-stage and multi-stage DCF model and two versions of what he calls the risk premium/CAPM method.

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[26] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944). We note that the 2001 Legislative Assembly recently codified this standard in HB 3502, amending ORS 756.040(1).

[27] In rebuttal testimony, Hager-Valach update their original ROE recommendations based on information available through April 30, 2001, and make certain adjustments to their DCF analysis based on Staff's testimony. In this order, we address Hager-Valach's recommendations contained in their rebuttal testimony.

[28] Staff originally recommended an authorized ROE of 8.9 percent, but adjusted its recommendation in its opening brief to account for the increase in risk free rate. *See* footnote 35; *infra*.

[29] *In re Northwest Natural Gas Company*, Order No. 99-697.

Our discussion is divided by methodology. For each section, we begin with a review of the methodology, followed by a summary of the parties' recommendations. We then address and resolve the contested issues under each specific methodology. After addressing all five methodologies, we conclude our discussion by adopting an authorized ROE for PGE.

1. Discounted Cash Flow (DCF)

The DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation. The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.

In this case, the parties used two DCF models. The basic, or single-stage DCF formula assumes a constant growth rate in future dividends. It is generally expressed as:

$$k_e = \frac{D_1}{P_0} + g$$

Where:

k_e = cost of equity;
D_1 = dividends per share over the next 12 months;
P_0 = current stock price; and
g = annual growth rate in future dividends per share.

The multi-stage, or complex DCF formula assumes that growth rates may change over time. That formula is expressed as:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \ldots + \frac{D_n}{(1+k_e)^n}$$

Where:

$D_1 \ldots D_n$ = the expected stream of annual dividends per share.

DCF Estimates

Hager-Valach could not apply the DCF model directly to PGE, because the company is no longer publicly traded following the merger with Enron Corporation. Therefore, as a proxy for PGE, Hager-Valach use three sample groups of electric utility companies. The first group, which they had originally selected in their direct testimony, is comprised of 17 utilities listed in *Moody's* Electric Utility Index and *Standard & Poor's* Electric Utility Index. The second and third sample groups are ones used by Staff in its testimony. Although PGE does not agree with Staff's sample groups, Hager-Valach include them to demonstrate that the different samples did not significantly impact the DCF calculations. Hager-Valach use both the single-stage and multi-stage DCF models.

For their single-stage DCF analysis, Hager-Valach estimate the dividend yield (D_1/ P_0) as four times the most recent quarterly dividend payment divided by the stock price.[30] To calculate stock price, Hager-Valach use the month-high closing price, month-low closing price, and the month-end price for each month during the February through April 2001 period.

To determine future growth (g), Hager-Valach use the *br* + *vs* method, which allows for growth through stock issuance and through earnings growth. In this formula, *b* represents the percentage of earnings retained by the company, and *r* represents the rate of return investors expect to earn on the company's book value. For these inputs, Hager-Valach rely on *Value Line*[31] forecasts. For the *vs* component, *v* represents the portion of the proceeds from future stock expected to exceed book value, and *s* is the growth rate of the stock outstanding. For these inputs, Hager-Valach use historical data.

For their multi-stage DCF analysis, Hager-Valach separate dividend growth into three stages. For the first stage, they use *Value Line* forecasts for the indicated dividend for the next 12 months. These forecasts reflect implicit one-year growth rates. Hager-Valach estimate the second growth rate as the annual growth rate occurring between 2001 and 2004. The 2004 dividend is estimated as an average of estimated dividends for the years 2003-2005, as estimated by *Value Line*. For the final growth rate, Hager-Valach use the *br* + *vs* calculations they use in their single-stage DCF.

For the three electric utility sample groups, Hager-Valach's single-stage DCF cost of equity estimates range from 11.44 to 12.80 percent, while their complex DCF estimates range from 10.90 to 12.13 percent.

Staff presents a total of three DCF models: Conway's single-stage model and Rothschild's single-stage and multi-stage models. Conway applies his single-stage DCF analysis to a sample of 42 electric utility companies he believes are suitable for use as a proxy cost of equity estimate for PGE. He limits his sample to companies covered by the *Value Line* Investment Survey that are primarily engaged in retail sales of electricity, companies that have not omitted an annual dividend in the past five years and for whom *Value Line* is forecasting continued dividend payments, and those companies for whom he could calculate CAPM betas.

To compute his yield component, Conway uses reported stock prices for January 11, 2001, and *Value Line* forecasts of dividend per share for each company for the next 12 months. To estimate future growth, Conway uses past dividend growth as an indicator of the marginal investor's expectations of future growth. For his sample of electric companies, Conway examines both the arithmetic and geometric means across the sample of historical dividend growth. Conway's single-stage DCF analysis produces a cost of equity estimate between 7.75 and 8.0 percent.

Rothschild applies his single-stage DCF analysis to four sample groups. First, he examines the groups of electric companies selected by PGE in this proceeding and by PacifiCorp in docket UE 116. Next, to confirm the reasonability of his estimates, he performs a DCF

[30] Hager-Valach initially used a different methodology, but adopt this approach in response to Staff's testimony. Although Hager-Valach believe that this approach causes the cost of equity to be understated, Hager-Valach adopt it for purposes of this case.
[31] *Value Line* is a widely-circulated subscription service that provides independent analysis of stocks.

analysis on the group of gas distribution companies used by PacifiCorp in docket UE 116, as well as a group of water companies.

Rothschild considers dividend yield data at a recent point in time and over the last year. First, he calculates dividend yield by dividing the most current annualized dividend rate declared by each company by the spot stock price as of February 28, 2001 for each company. He also divides the most current annualized dividend rate declared by the average high and low stock price of each company over the year ended February 28, 2001. He increases the dividend yield result by adding one-half the future expected growth rate so that the yield is equal to an estimate of dividends over the next year.

To calculate a growth rate, Rothschild uses a $br + vs$ formula similar to that used by Hager-Valach, but with different data. He calculates b, the retention rate, based on a derived dividend yield on book value, and r, return on book equity. To determine r, Rothschild examines both analysts' forecasts and historical data for returns on book equity. Finally, he uses *Value Line* forecasts for his vs inputs.

Rothschild's simplified DCF results produce a cost of equity range of 9.17 to 9.24 percent for the PacifiCorp sample group, and a range of 9.47 to 9.71 percent for the PGE sample group. He places no weight, however, on the results for the PGE sample group, which he considers to be an upwardly biased example.

In his multi-stage DCF model, Rothschild separates dividend growth into two stages. His first stage of the model is based on *Value Line's* forecasts for earnings per share and dividends per share for 2000 through 2004. Because *Value Line* does not forecast a specific earnings and dividend projection for every year in that period, Rothschild projects those omitted years by extrapolating the available data.

Rothschild determines second stage earnings by multiplying the future book value per share by the future expected return on book equity used to calculate future growth, g, in his single-stage DCF model. Rothschild projects growth in his second stage for 40 years into the future. Rothschild's complex DCF results produce a cost of equity range of 9.71 to 9.81 percent for PacifiCorp's sample group of electric utility companies.

Disputed DCF Issues

Of the two DCF versions presented, the parties differ the most with regard to the single-stage DCF model. Specifically, the parties disagree significantly on the proper method to calculate the growth component. PGE criticizes Conway's single-stage DCF estimate, because he uses historical data to estimate the growth rate component. While Rothschild uses the same $br + vs$ formula used by Hager-Valach to calculate growth, PGE claims that Rothschild's estimates for retention ratios, b, and return on book equity, r, are highly subjective, downwardly biased, and flawed. Staff counters that Hager-Valach's use of *Value Line* forecasts for retention ratios, b, combined with an historic dividend rate in their calculations, seriously overstates the cost of equity. Staff contends that the mismatch in the time chosen to estimate these two inputs creates substantial and unnecessary error. These differences are so significant that Staff suggests that the Commission simply reject the use of the single-stage version of the DCF model in favor of the multi-stage formula.

Staff and PGE agree that the single-stage version of the DCF model can only be properly used if dividends, earnings, stock price and book value are expected to grow at the same rate. The difficulty arises, however, in selecting the values to use for these inputs. PGE and Staff disagree on whether the use of a forecasted retention ratio requires an adjustment to the current dividend to avoid double counting. Both parties provide a reasonable basis for their respective positions, but neither has sufficiently established why the opposing methodology should be rejected.

We have previously favored use of the multi-stage DCF analysis over the single-stage DCF formula. In docket UG 132, *In re Northwest Natural Gas Company*, we noted that the multi-stage DCF improves on the implicit assumption in the single-stage version that dividends grow indefinitely at the same rate.[32] This limitation of the single-stage DCF model is even more significant given the ongoing restructuring of the electric industry. For this reason, and in light of the parties' significant disagreements over the proper application of the single-stage DCF model, we adopt Staff's recommendation to reject the single-stage DCF analysis in favor of PGE's and Staff's multi-stage DCF results. We conclude that the parties' single-stage DCF analyses provide no information not already contained in their complex DCF analyses. Parties are free to use the single-stage version of the DCF method in future dockets, but they will be expected to show that the required industry stability is present.

Turning to the multi-stage DCF models presented, PGE identifies four primary errors in Rothschild's multi-stage DCF calculation, three of which relate to his second stage growth projections. First, PGE criticizes Rothschild's estimate for expected return on book equity, *r*. PGE notes that, while Rothschild claims to have relied, in part, on *Value Line* forecasts for the companies in PacifiCorp's sample group, he actually lowers that average by omitting the company with the highest expected return—DPL, Inc. (DPL). Rothschild retained DPL in his sample for the purpose of calculating market-to-book ratio (M/B).

Staff responds that Rothschild's exclusion of DPL is justified, because the *Value Line* forecast of a 23 percent return on equity for that company is not indicative of the return investors expect could be maintained into the future. Staff notes that the 23 percent forecast is more than three standard deviations above the mean for the forecasted returns for the sample group, and that only one company earned more than 20 percent on equity in any given year out of about 150 historic earned returns reported by *Value Line*.

Staff is correct that the *Value Line* forecast for DPL is high by historical standards. The issue presented, however, is not whether to include DPL in the DCF estimate, but rather if data for the company should be used selectively in the analysis. As discussed above, Rothschild excludes DPL to estimate return on book equity, but includes the company to calculate his average M/B for the PacifiCorp sample group. This selective use of data overlooks the interrelationship between the various components of the DCF model. Given the high forecasted return on book equity, it is likely that investors have bid up DPL's stock price, which is the numerator of the M/B calculation. Because a higher stock price produces a higher M/B, it is not surprising that DPL, the company with the highest forecasted return on book equity, also has the highest M/B. Thus, we agree with PGE that Rothschild has, in effect, decreased his cost

[32] Order No. 99-697 at 23.

of equity estimate by using DPL's relatively high stock price but excluding the company in his assessment of the expected returns that generated the higher stock price in the first place. Accordingly, we conclude that Rothschild's expected return on book equity for his second stage of his DCF calculation should be adjusted to 13.37 percent—the value Rothschild used for the last year (2004) of his first stage calculation.

Second, PGE claims that Rothschild erred in calculating the retention rate, *b*. PGE explains that, rather than relying on *Value Line* forecast, Rothschild reverts to a 2001 retention rate for his second stage growth projection. PGE observes that Rothschild's reversion to the 2001 retention rate creates a sharp discontinuity between the first and second stages in his model. PGE also contends that Rothschild provides no basis to disregard *Value Line* forecasts in his second stage. PGE notes, while he claims the current retention rate is "more consistent with investor expectations," Rothschild fails to provide any basis for that statement. PGE adds that he also failed to sufficiently explain why he used the current forecast in this docket, when he had used long-term forecasts in a prior Commission docket, UE 102.

In examining Rothschild's calculation of the retention rate, we are not persuaded that current data should be used instead of forecasted rates. To explain his switch in methodologies since docket UE 102, Rothschild refers to a large forecasted difference that existed in an intervening case, but fails to explain whether a similar difference existed in this case. He similarly fails to support his assertion that the current retention rate seems to better represent investor expectations. Indeed, Rothschild's adjustment causes a steep decline in retention ratios after 2004, reversing an upward trend forecasted by *Value Line*. We concur with PGE that the use of a forecasted retention rate should be used in this docket. We are not precluding the use of historical retention rate information in future dockets, but parties advocating such usage must justify the use of such data.

Third, PGE criticizes Rothschild's use of *Value Line* forecasts to estimate the sale of newly issued stock, the *s* term in *vs*. Although PGE admits that DCF inputs should, in general, be based on forecasts rather than historical rates, PGE contends that an exception is appropriate here, because *Value Line* does not forecast large but relatively infrequent public offerings.

Staff disagrees and believes it inappropriate for PGE to favor the use of historical data to estimate *s*, while strenuously arguing that forward-looking projections should be used for both *b* and *r*. We agree. Moreover, while we acknowledge the difficulty in predicting large offerings, PGE failed to establish that *Value Line* expressly excludes the possibility of such offerings in forecasting future sales of newly issued stock. Moreover, Staff demonstrated that the historic data is misleading, since new stock sales as a percentage of the amount of stock outstanding has been in a steep decline. Based on this record, we conclude that projections should be used to estimate the sale of newly issued stock in this docket.

PGE contends that the fourth flaw in Rothschild's multi-stage DCF model is his calculation of stock price using a mismatched M/B. PGE explains that, for each stock in the sample group, Rothschild calculated a M/B using a February 28, 2001 stock price but an estimated book value as of year-end 2000. He then used the sample average M/B rate of 1.78 to calculate a sample average 2000 stock price for his first value for market price—$38.47.[33] PGE claims that Rothschild should have used, for his first value for market price, the actual average stock price of $36.99.[34] By using the higher stock price, PGE contends that Rothschild drove down the cost of equity, because the higher the stock price, the lower the discount rate—which is the cost of equity in the multi-stage calculation—needed to equate future cash flows to the stock purchase price. PGE adds that the use of the correct, lower stock price, also requires reducing the M/B, since the stock price serves as the numerator in that calculation. Otherwise, PGE explains, the cost of equity will be overstated.

Further, PGE claims that Rothschild used the wrong denominator for his M/B. PGE observes that, for this figure, Rothschild used *Value Line's* estimated book value for the sample for year-end 2000, which ignores the growth in book value expected to occur by February 28, 2001. Thus, PGE contends that, in his analysis, Rothschild should have added to the year-end book value one-sixth of the expected growth in 2001. This, according to PGE, results in a book value of $21.70, and a M/B of 1.70. PGE adds that this lower M/B results in lower proceeds from the sale of stock and, all things being equal, reduces the cost of equity.

We agree with PGE's observations and conclude that Rothschild's multi-stage DCF estimates should be adjusted so that the average stock price on February 28, 2001 of $36.99 is used for the hypothetical stock purchase. There is no explanation why an investor would irrationally pay $38.47 for a stock that he or she can buy on the market for $36.99. Moreover, because of this adjustment, both the numerator and denominator of Rothschild's M/B calculation should also be modified. For the numerator, Rothschild should have used the average stock price of $36.99; for the denominator, Rothschild should have increased year-end 2000 book values by one-sixth of the increase in the estimated year-end 2001 book values.

2. Capital Asset Pricing Model (CAPM)

Another method of estimating cost of equity is the CAPM. The CAPM is a risk premium analysis that calculates the expected equity return by adding a risk premium to a "risk free" rate of return. Risk is represented by the term "beta," which measures the stock's volatility relative to the market as a whole. The beta for the market is equal to one. Therefore, a stock with a beta greater than one is more risky than the average stock, while a stock with a beta of less than one is less risky than the average stock. The risk premium is generally calculated by multiplying the company's beta by the difference between the expected market return and the risk free rate. The formula is generally stated as follows:

$$K_e = \text{Risk-free rate} + \text{beta (market risk premium)}$$

CAPM Estimates

Only Staff presents ROE estimates based on the CAPM. Conway's CAPM analysis relies on the traditional formula set forth above. Assuming that investors have intermediate-term investment horizons, Conway calculates a risk-free rate based on an average of intermediate-term U.S. Treasury notes. Averaging the yields-to-maturity of the 5-, 7-, and

[33] *See* Staff/702, Rothschild Schedule JAR 5, page 1, column 9.
[34] *See* Staff/701, Rothschild Schedule JAR 3, page 1, column 5.

10-year U.S. Treasury securities quoted in the March 21, 2001 edition of *The Wall Street Journal*, Conway calculates a risk free rate of 4.7 percent.[35]

Using Staff's traditional Fisher-Kamin method and a new GARCH approach,[36] Conway then calculates a beta for his sample group of electric utility companies of between 0.26 and 0.29. He estimates the sample companies beta by "regressing" their stock returns—minus a risk-free proxy rate—on the combined portfolio of NYSE/AMEX/NASDAQ stock returns—minus a risk-free rate proxy. Conway notes that his beta calculations may require some subjective adjustment, because they are significantly lower than historical beta estimates. Noting that 5-, 7-, and 10-year moving averages for beta estimates are 0.40, 0.42, and 0.44, respectively, Conway believes it is reasonable for the Commission to rely on the longer-term historical beta in this docket.

To estimate the expected market risk premium, Conway assumes that the average market risk premium over a large number of historical intermediate-term holding periods is a reasonable estimate of the expected intermediate-term market risk premium. He estimates the average historical intermediate term market risk premium by calculating the difference between expected compounded returns on the market portfolio and the compounded returns on the risk free asset over an intermediate period. The difference is then annualized.

To make his estimate, Conway uses monthly returns from 1926 to 1999 for all NYSE/AMEX/ NASDAQ stocks as a proxy for the theoretical market portfolio returns. He then estimates the risk-free rate over that period by using 1926 to 1999 data on intermediate-term U.S. Treasury securities. Next, he separates the 1926 to 1999 data into holding periods of five to ten years each, such that all the data were used just once. Finally, he calculates the average rate of return difference between holding the market portfolio and holding the risk-free rate over the intermediate-term.

Conway estimates a range of historical market-risk premia of 6.6 to 6.8 percent.[37] Inserting these figures into the CAPM formula with his beta range of 0.29 to 0.44 and a risk free rate of 4.7 percent, Conway estimates a range of cost of capital for his electric utility company sample of 6.6 to 7.7 percent.

Rothschild uses two different versions of what he calls the "CAPM/risk premium method."[38] His first version estimates the cost of equity by adding the historic inflation premium to investors' current expectation for inflation. In this calculation, Rothschild first estimates the expected rate of inflation to be 2.0 percent by comparing the yields on Treasury bonds with inflation-indexed Treasury bonds. He then adds this 2.0 percent factor to a 6.6 to 7.2 percent

[35] In its opening brief, Staff updates the risk-free rate to 4.8 percent, based on the arithmetic average of the three U.S. Treasury rates listed in the June 20, 2001 edition of *The Wall Street Journal*.
[36] Staff explains that the GARCH approach was developed by Dr. Curt Wells, Professor of Economics at the Lund University in Sweden.
[37] Conway also derives market risk premium calculations based on the recommendations of Dr. Pettit, who reviewed Staff's risk premium estimation procedures in 1999. Utilizing Dr. Pettit's recommended approach, Conway estimates the market risk premium to be 4.5 to 4.8 percent. Conway does not rely on these estimates in his CAPM recommendation, however.
[38] Although these can fairly be called risk premium methods, we do not consider them versions of CAPM.

historic return on common stocks net of inflation to get an inflation risk premium indicated cost of equity for an investment average risk of 8.6 to 9.2 percent.

Rothschild adjusts this return to account for the lower than average market-risk for the electric utility sample group. To accomplish this, he subtracts the 4.83 percent yield on 90-day U.S. Treasury bills from the historic return on common stocks. He then multiplies this figure by the average *Value Line* beta for the PacifiCorp sample group of 0.53 to derive a 0.94 to 1.26 risk adjusted equity premium. Finally, Rothschild adds this risk adjusted equity premium back to the 6.6 to 7.2 percent range of historic returns on common stocks to derive a 7.77 to 8.09 percent risk premium for the sample group.

In his second risk premium analysis, Rothschild estimates PGE's cost of equity based on an increment to the historic annual earned returns. He makes four separate calculations using various interest rates—ranging from 4.83 to 6.71 percent—as his risk-free rate, and various market risk premia—ranging from 3.51 to 5.33 percent. Rothschild takes the average of these four calculations using both an average risk beta of 1.0 and the *Value Line* beta of 0.53 for electric utilities. Under this methodology, he produces a cost of equity range of 7.60 to 9.55 percent.

To arrive at his final recommendation, Rothschild averages the high-end and low-end of his two methodologies to obtain a range of 7.69 to 8.82 percent, with a midpoint of 8.25 percent.

Disputed CAPM Issues

PGE begins its criticism of Staff's CAPM analysis by attacking the reliability of the model itself. PGE contends that there are several problems with the CAPM model in general, and with Staff's Fisher-Kamin version of CAPM, in particular. PGE contends that these problems are so significant that the Commission cannot rely on CAPM estimates to establish an ROE for the company.

PGE argues that the most persuasive evidence against the use of CAPM in this case is the unrealistically low results it is producing. PGE observes that both Rothschild and Conway made numerous *ad hoc* adjustments to artificially inflate their CAPM results. PGE claims that Rothschild and Conway's true CAPM results are uniformly below the company's cost of new, long-term debt, which is 8.17 percent.[39] PGE contends that such low results are not consistent with financial theory—that the return on a riskier asset, like common stock, should be higher that the return on a less risky asset, like long-term debt.

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[39] PGE contends that Rothschild's true CAPM/Inflation Risk Premium results yield a range of cost of equity of 6.83 to 8.58 percent, not 7.60 to 9.55 percent as reported in his testimony. PGE asserts that Rothschild inflated his results by using, without explanation, a beta of 1.0 to calculate one of his four findings. PGE also claims that, in his inflation-based analysis, Rothschild uses an unconventional method to calculate the company-specific risk premium that increased his estimate by 94 basis points.

Similarly, PGE contends that Conway's CAPM results would have been significantly lower had he followed Staff's traditional CAPM approach or adopted the recommendations made by Drs. Wells and Pettit for calculating betas and market risk premium. For example, PGE notes that, while Conway calculated the Fisher-Kamin beta to be 0.29, he actually used a beta of 0.44 derived from a 10-year historical average. PGE believes that this adjustment is contrary to Staff's traditional endorsement of the Fisher-Kamin methodology, namely that it allows betas to change over time.

Staff defends the CAPM model and disputes PGE's specific criticisms. Staff notes that the CAPM model is a commonly accepted method of determining cost of equity and contends that the CAPM estimates here provide important insights into PGE's cost of equity. Staff acknowledges that the CAPM may be currently understating the cost of equity due to present market conditions. Nonetheless, Staff adds that Conway and Rothschild took this fact into consideration and liberally rounded up the results in their analyses.

This Commission has relied on the CAPM as an appropriate method for estimating a utility's cost of common equity for over 20 years. Recently, however, many utilities have argued against its use for reasons similar to those presented by PGE in this proceeding. To date, this Commission has rejected those arguments, concluding that the CAPM remains a viable method for determining cost of equity.[40]

We acknowledge that Staff's CAPM methodology faces its biggest challenge yet. Staff cannot escape the fact that its CAPM analyses appear to be producing results below PGE's current cost of new, long-term debt. While Staff recognizes that the CAPM may be currently understating cost of equity, it is unable to fully explain the significant drop in the Fisher-Kamin betas used in its calculations.[41] It has also failed to convince us that its upward adjustments and rounding of results have accurately and fully compensated for the current CAPM deficiencies.

While the results in this case cast further doubt on the validity of Staff's CAPM methodology, we do not believe that CAPM should be rejected in its entirety. We continue to believe that, in certain cases, CAPM analyses may provide a useful and reliable addition to the DCF results for determining cost of equity. After our review of the results in this case, however, we further conclude that the CAPM does not provide supportable and reasonable results in this docket. Accordingly, we give no weight to the CAPM results in determining an appropriate cost of equity for PGE.[42]

3. Risk Positioning Method

The Risk Positioning Method is a risk premium model that estimates the cost of equity by adding a premium for risk to a current or expected interest rate. In this analysis, PGE contends that the non-stipulated ROE decisions by regulatory bodies provide, on average, unbiased estimates of the cost of equity for electric utilities. By measuring differences between the authorized returns on equity and the yields on electric utility corporate bonds and yields on U.S. Treasuries, PGE calculates ranges of estimates of the equity risk premium. The company then adds the equity risk premia estimates to the current bond and treasury yields to derive a range for cost of equity.

In their analysis, Hager-Valach rely on approximately 500 reported, non-stipulated ROE decisions dating back to January 1983. Using the Risk Positioning Method with corporate bonds, Hager-Valach estimate a risk premium of 3.44 percent. Adding that figure to the yield from PGE's most recent non-callable bond (8.19 percent) and the yield for A-rated

[40] *See, e.g.,* Order No. 99-697 at 19.
[41] Conway's 0.29 beta is based on data through the year 1999. Using data through the year 2000, PGE found that the Fisher-Kamin beta for companies in Conway's sample declined to 0.09—a risk figure close to that for U.S. Treasuries that are used as the "risk-free" rate in CAPM calculations.
[42] This conclusion also applies to Rothschild's "CAPM/Risk Premium" analyses.

bonds from the *S & P Bond Guide* (8.21 percent), Hager-Valach produce a range for PGE's cost of equity of 11.28 to 11.48 percent.

Hager-Valach calculate a risk premium range of 5.70 to 5.80 percent using the Risk Positioning Method with U.S. Treasury Bonds. Adding that range to the 7-year U.S. Treasury rate for 2002 using the WEFA forecast (5.39 percent), Hager-Valach calculated a range for PGE's cost of equity of 11.09 to 11.19 percent.

Staff contends that the Commission should place little weight on PGE's Risk Positioning Method for three primary reasons. At the outset, Staff notes that the proposed methodology is not a commonly accepted method for determining cost of equity. Second, Staff believes that PGE's proposed analysis is flawed, because it measures cost of equity without a review of whether the allowed return, relative to the interest rate, is more or less than the cost of equity actually demanded by investors.

Next, Staff contends that PGE's Risk Positioning Method suffers from omitted variable bias. Staff explains that, in conducting a regression analysis, it is critical to include all relevant variables to eliminate bias. While PGE admits that many factors influence commissions in setting the return on equity, such as business risk, interest rate risk, financial risk, and liquidity risk, Staff points out that the company's Risk Position Method fails to consider them, instead relying solely on lagged treasury rates. Because PGE fails to include all the relevant variables relied upon by the various commissions, Staff contends that PGE's regression equation suffers from omitted variable bias and should be rejected.

This Commission rejected a similar risk-positioning method proposed by another utility in a recent rate case.[43] We reach the same conclusion here. As Staff notes, PGE's proposed methodology using authorized ROEs and yields on treasuries and corporate bonds is unconventional and has not been accepted by other regulatory agencies as a reliable means for determining cost of equity. Because the methodology is not based on accepted regulatory principles, we decline to adopt it for use in this proceeding.

4. **ROEs Authorized by other Regulatory Commissions**

In addition to their DCF and Risk Positioning Method estimates, Hager-Valach rely on recent authorized ROE decisions by other regulatory commissions. Hager-Valach note that, during the last twelve months, electric utilities received an average authorized ROE of 11.6 percent, with a range of 11.0 to 12.9 percent. Because an investor will consider this type of information when making an investment, Hager-Valach believe that PGE should be awarded a common equity return within this range.

Staff objects and contends that PGE's proposal is circular in reasoning, because decisions would simply be based by looking at what other commissions allow. Staff adds that PGE's proposal would have the effect of improperly transferring to other jurisdictions the Commission's obligation of setting cost of equity for Oregon utilities. Finally, Staff notes that the Commission rejected a similar request made by NW Natural in docket UG 132:

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[43] *See, e.g.*, Order No. 99-697 at 19.

"NW Natural contends that the Commission should rely on recent common equity return decisions made in other jurisdictions. We disagree. As Staff and NWIGU point out, there is frequently a substantial lag between the time evidence is prepared in a rate case and when a decision is finally rendered. Because interest rates have been steadily declining during the past several years, the failure to account for the regulatory lag could result in an overstatement of cost of capital. Moreover, as noted above, the authorized ROE is just one component of setting rates and is often tied to other, unknown elements in a rate case. Therefore, while other ROE determinations may provide evidence to confirm a decision, we are reluctant to base an award for NW Natural on unknowable parameters from other cases, set in other jurisdictions and different capital market conditions."[44]

PGE believes that a review of other authorized ROEs is relevant to determine investor's expectations. Because an investor views a commission decision as the utility's best estimate of the cost of equity at the time of the decision, PGE maintains that the investor will go elsewhere if the authorized ROE is set too low for the risk of the investment. PGE adds that, contrary to its argument here, Staff has previously asked the Commission to consider ROE decisions from other jurisdictions. As an example, PGE notes that Staff referred the Commission to a decision by Nevada Commission to justify its ROE recommendation in docket UG 132.[45]

We adhere to our prior determination that, while other ROE determinations may provide confirmation of a decision, they should not be used as an independent method on which to base an award. Capital market conditions, not regulatory decisions, determine a utility's cost of equity. While we agree that regulatory agencies generally make every effort to capture those conditions, a review of past decisions cannot replace an independent analysis of current market conditions and how they affect the particular utility. Moreover, ROE determinations are made not just in traditional rate cases, but also in a range of other proceedings, such as industry restructuring plans, merger approval cases, or performance-based regulatory plans. Thus, the ROE awards may have been based, in part, on other unknown parameters relevant in that particular docket.

Accordingly, we will continue to review ROEs authorized in other jurisdictions to help gauge the reasonableness of the cost of equity estimates derived from independent methodologies. We will not, however, rely on such decisions to base an ROE award for a utility.

5. Qualitative Analysis

Staff's final cost of equity estimate is based on a qualitative analysis that updates the Commission's most recent contested ROE decision. Conway notes that, in docket UG 132, Order No. 99-697, the Commission set rates for NW Natural based on a return on equity of 10.25 percent. There, the Commission adopted a market risk premium of 8.5 percent, a risk-free rate of 6.3 percent, and a beta estimate of 0.46, to obtain a rounded CAPM estimate of

[44] Order No. 99-697 at 23.
[45] Order No. 99-697 at 24.

10.2 percent. The Commission averaged that estimate with a DCF estimate of 10.3 percent to obtain a 10.25 percent cost of equity.

Updating those figures with new information, Conway presents a range of estimates for PGE's cost of equity from 8.3 to 10.1 percent. Conway provides this range as an upper bound for ROE estimates.

While recognizing that Conway's qualitative analysis favors the company, PGE contends that it is misleading and unprincipled. PGE notes that Conway developed its upper cost of equity estimate of 10.1 percent using: (1) the Fisher-Kamin beta for NW Natural; (2) an updated 1999 estimate for the market risk premium plus 150 basis points; and (3) the 6.3 percent risk-free rate used in that prior docket. PGE questions how the 1999 beta for Northwest Natural is applicable to PGE in this case, and why Conway relies on an outdated risk-free rate even though he acknowledges that it is contrary to Commission policy. PGE believes that Conway's analysis is unprecedented and another example of the contortions through which that Staff is willing to go rather than admitting that the Fisher-Kamin CAPM is not producing realistic results.

Staff responds that PGE misrepresents its qualitative analysis. Staff explains that it provided the qualitative analysis to give an upper bound to the range of reasonable cost of equity, consistent with the Commission's internal operating guidelines.[46] Furthermore, Staff notes that its testimony made clear that the analysis illustrated various permutations and combinations of factors to update the Commission's decision in docket UG 132.

We acknowledge and commend Staff's efforts to provide additional analyses for our review of this issue. Nonetheless, we agree with PGE that the adjustments included in the qualitative analysis are not sufficiently linked to the company to provide a valid cost of equity estimate in this docket. Accordingly, we give it no weight.

Commission Resolution

We begin with the range of rates of return on common equity offered by each of the parties. For the reasons stated above, we reject the parties' single-stage DCF estimates, Staff's CAPM and risk premium calculations, PGE's Risk Positioning and Comparison to Authorized methods, and Staff's Qualitative Analysis. Focusing on PGE multi-stage DCF calculations, we adjust Hager-Valach's estimates by using *Value Line* forecasted information to calculate *s*, the growth rate of new stock. This produces a cost of equity range of 10.4 to 11.5 percent, with a mid-point of 10.95 percent.

Turning to Rothschild's multi-stage DCF analysis and using the PacifiCorp sample group and actual stock closing prices as of February 28, 2001, we first adjust his estimate by using the average forecasted retention rate, *b*, for 2004 (43.74 percent) throughout his second stage. This increases his overall cost of equity estimate to 9.89 percent. Next, we adjust Rothschild's second stage input for the expected return on book equity, *r*, by using the year 2004

[46] Those guidelines provide that Staff is "responsible for ensuring that the record includes a range of legally supportable positions so that the Commission has options when making a final decision." Order No. 01-253, App C at 1.

value of 13.37 percent. This adjustment further increased Rothschild's DCF estimate to 10.13 percent. Finally, we correct Rothschild's inputs for the stock purchase date and price set at February 28, 2001, and adjust his M/B accordingly. This produces a final adjusted DCF estimate of 10.53 percent.

Together, these two adjusted estimates produce a cost of equity range of 10.53 to 10.95 percent, with a mid-point of 10.74 percent. We round this number to 10.75 percent. We find that this average of 10.75 percent is an appropriate cost of equity for the comparable group of electric utilities. We conclude, however, that this figure should be adjusted for PGE, whose capital structure contains a substantially higher percentage of common equity than the average for the comparative group of electric utilities.

It is well understood by finance practitioners and theoreticians that the cost of equity drops as the percentage of common equity in the capital structure increases. Because the average amount of common equity in the capital structure of the comparable group of electric companies was 45.14 percent compared to 52.16 percent for PGE, it necessarily follows that PGE has a lower cost of equity. PGE's capital structure is therefore less risky, and its cost of common equity should be adjusted accordingly.

The question therefore becomes how much of an adjustment should be made. This record contains varying estimates that the cost of equity for regulated electric utilities decrease anywhere from 4 to 13.8 basis points for each one percent increase in the level of common equity in the capital structure. We find Rothschild's proposed 25 basis point reduction to be a reasonable adjustment to account for the above average percentage of common equity in PGE's capital structure. Contrary to PGE's arguments, this reduction does not constitute a "penalty." Rather, it is simply an adjustment to acknowledge PGE's reduced financial risk due to its increased level of common equity in its capital structure. Reliance on the stipulation in docket UM 814 is reasonable for the purpose of establishing a capital structure for PGE. The stipulation, however, cannot reasonably be used to argue for an ROE that does not correspond to the adopted capital structure.

Accordingly, we will adopt this adjusted average of 10.50 percent as an appropriate and reasonable cost of equity for PGE.[47] Evidence shows that this award will allow PGE to maintain a reasonable financial structure and attract capital at a reasonable cost. Using this figure in connection with other stipulated capital costs and the company's capital structure, which we find reasonable and adopt, yields a rate of return for PGE of 9.09 percent.

Capital Component	Ratio	Cost	Weighted Cost
Long-term Debt	46.32 %	7.508 %	3.48 %
Preferred Stock	1.53 %	8.432 %	0.13 %
Common Equity	52.16 %	10.50 %	5.48 %
Total	100.00 %		9.09 %

Finally, we close this subject with a short discussion on efforts expended in this docket to fix a reasonable ROE for PGE. ROE determinations have always been a fundamental

[47] Given this conclusion, we need not address PGE's argument that Staff's ROE recommendation, if adopted, would impair the company's bond ratings.

part of utility regulation and, despite a decline in the frequency of traditional utility rate cases, continue to play an important role in ratemaking. The task of determining a reasonable ROE, however, is often one of the most difficult and contentious aspects of a rate case proceeding. This docket was no different. PGE and Staff presented ROE testimony from seven witnesses and submitted over 600 pages of prefiled testimony and supporting documents. They required two full days of hearing on the ROE issue, at which they introduced approximately 30 new exhibits. After hearing, PGE and Staff produced over 100 pages of legal argument on the issue, and spent a majority of their time at oral argument addressing the issue to the Commission.

We recognize the inherent complexity of the issue, and that it may be impossible to devise a method to make the process of determining a reasonable ROE an agreeable one. Others with more time and expertise have tried to establish a consensus on the overall efficacy of ROE techniques and methodologies, but failed. It appears that contention over ROE is unavoidable. Nonetheless, while we recognize our inability to make the ROE process easy, we believe that the adoption of certain principles on this matter will make the process of setting a reasonable ROE easier. Based on our experience in this and in other dockets, we offer guidelines, set forth in Appendix A, for witnesses providing cost of equity recommendations.

II. PRICING

The parties to this docket largely agree with PGE's proposed pricing structure, tariff building blocks, rules and regulations, rate design and rate spread. ICNU, OSM, and OOE disagree with specific proposals, which we address below.

1. Customer Impact Offset

To help mitigate the rate impact on customers, PGE proposes to limit rate increases to not more than 150 percent of the overall average increase in base rates. Consequently, PGE proposes prices for Schedules 38, 48, 49, 93, and 97, that are less than the cost of service. To offset the revenue lost by this limitation and the effect of certain special contracts, PGE proposes to increase the energy charges of the remaining schedules.

While it acknowledges the need to mitigate large rate increases, ICNU contends that it is equally important to have an orderly transition to cost-based rates. Therefore, rather than embed a subsidy in base rates, ICNU recommends that PGE establish an adjustment schedule to phase out the customer impact offset over a two- to five-year period. ICNU explains that the adjustment schedule should be implemented such that, once a year, prices are increased for schedules whose prices are significantly below the long run incremental cost (LRIC) of service and reduced by a corresponding amount for the remaining schedules.

Commission Resolution

If adopted, ICNU's proposal would move all customers to LRIC in as little as two years, essentially eliminating the customer impact offset. Even under a full five-year period, the Commission would be required to determine how much certain rates should be increased, resulting in administrative difficulty and confusing price changes. In the past, this Commission has phased out the customer impact offset and similar offsets in conjunction with other general rate changes. We affirm that practice, which allows us the opportunity to consider the impact of rate changes on all customer classes at the time that general rates are being changed.

2. Non-Conforming Load Charge

PGE's proposed Schedule 83 and 583 includes a Nonconforming Load Charge of \$5.60 per kW/month.[48] PGE explains that this charge is needed to offset the costs required to maintain generating capacity for these highly variable loads.

OSM contends that PGE failed to establish that the charge is either necessary or that the amount is appropriate. Therefore, OSM asks the Commission to reject the proposed charge. In the alternative, OSM requests that, if the Commission determines a special charge is necessary to cover the cost of load following and load regulation for highly variable loads, the charge should be based on the actual costs associated with providing the service.

Commission Resolution

We conclude that PGE's proposed non-conforming load charge is premature. PGE admits that no customers will be subject to the charge until 2004. While PGE claims that the charge is proposed to recover the costs of regulating capacity, it is not known what those costs will be at that future date to serve these variable loads. Accordingly, we reject PGE's proposed non-conforming load charge. During the next three years, PGE will have the opportunity to observe industry developments and propose, at a more timely date, an appropriate charge for load following and load regulation for non-conforming loads.

III. OTHER ISSUES

1. Emergency Default Service

PGE's Schedule 82 is designed to provide back-up service for any direct-access customer that loses its Electricity Service Supplier (ESS) and has not provided PGE with the notice required to receive service under the applicable standard offer service rate. PGE proposes to provide Emergency Default Service under Schedule 82 on a restricted "as available" basis. Schedule 82, as proposed, provides in part:

> "In all territory served by the Company, Emergency Default Service shall be provided by the Company as available. The Company may restrict customer loads returning to this schedule if it experiences constraints in the availability of electricity."

PGE explains that the purpose of the "as available" language is to prevent a returning direct access customer from causing PGE to curtail service to other customers who did not go to direct access or who are already on Schedule 82. Without limiting the availability of emergency default service, PGE explains that these direct access customers—who do not pay to have backup resources in case their ESS fails—would have the ability to get firm service under

[48] PGE defines "nonconforming loads" as consumer loads grater than 10 MW that routinely cycle up and down during the course of the day at a rate of at least 10 MW per minute.

Schedule 82 for free. PGE contends that other customers should not be required to suffer rolling outages to provide emergency default service or to pay for standby resources for direct access customers.

Staff and ICNU contend that PGE's proposal is discriminatory and could act as a barrier to competition. Because PGE remains the provider of last resort within its service territory, Staff notes that the company is obligated to provide safe and adequate service to all customers within its service area regardless of whether the customer is returning to utility service or has remained as a PGE customer. Thus, Staff contends that PGE should not be permitted to treat customers who choose direct access and subsequently return to PGE's Schedule 82 differently than other customers within its territory.

ICNU adds that ORS 757.622 requires the Commission establish terms and conditions for emergency default service for direct access customers that "provide for viable competition among electricity service suppliers." It adds that any customer with critical reliability concerns or large costs associated with a disruption of service could be dissuaded from going to direct access under PGE's proposed Schedule 82.

Commission Resolution

We share ICNU and Staff's concerns. For the successful implementation of SB 1149, it is important that direct access customers be treated equally to those customers who remain with the utility. For that reason, we agree that customers who choose direct access should not be limited to default service on an "as available" basis. We are not persuaded by PGE's claims that the restriction is necessary to protect existing customers. As ICNU notes, PGE's argument focuses on extreme conditions when power is not available at any price and rolling blackouts are imminent. Under such conditions, PGE's ability to offer Schedule 82 on an "as available" basis would not guarantee service reliability for existing customers. Furthermore, contrary to PGE's claim, returning customers would not be receiving firm service under Schedule 82 for free. In its filing, PGE proposes to charge a 25 percent premium on the Dow Jones Mid-Columbia Daily on-peak and off-peak Firm Electricity Price Index for emergency default service under Schedule 82. While PGE claims in its brief that this premium covers only the administrative costs, its testimony explains that the premium is necessary to mitigate the risk associated with the supply of emergency default service and "to cover the unpredictable nature of service under this rate."[49]

PGE's Rule K Curtailment Plan specifies that the utility may initiate certain actions "when necessary or prudent to protect the performance, integrity, reliability, or stability of the Company's electrical system or any electrical system with which it is connected." We agree with ICNU that PGE should follow the Rule K procedures for Schedule 82 customers under short-term emergencies. Accordingly, we adopt ICNU's recommendation that PGE's Schedule 82 conditions be modified so that the "Available" section reads:

> "In all territory served by the Company. The Company may restrict Consumer load returning to this schedule in accordance

[49] *See* PGE/100, Fowler-Lesh at 12.

with Rule K, Curtailment Plan and Stage 5 Utility Actions under short-term emergency conditions."

2. **Refusal of DASR**

A Direct Access Service Request (DASR) is an electronic notification provided by an ESS to PGE that a customer has selected the notifying ESS as the customer's supplier of electricity service. As applicable here, PGE proposes that the company should have the authority to refuse a DASR when:

(1) The Company has not received full payment from the Consumer for past due amounts or other obligations related to regulated charges from a Consumer's prior Electricity Service account(s) unless such charges are part of a pending Consumer dispute; or

(2) The Company has not received full payment or the Consumer or ESS has not made an arrangement to pay the balance on an existing Budget Payment Option or other agreements.[50]

Staff objects to PGE's proposal and believes that, if the ESS has not paid PGE, the customer should not be held hostage and not be allowed to switch electricity suppliers. It contends that the consumer should be allowed to switch and that PGE should address non-payment issues through its disconnection policies. PGE responds that Staff's proposal simply creates a potential conflict between PGE, the customer and ESS. It contends that it would be simpler to allow the company to refuse the request until past due amounts are paid, rather than requiring it to make the switch and then subsequently disconnect the customer from its new service supplier for non-payment of past bills.

Commission Resolution

Both parties raise valid concerns. A customer should not be held hostage due to the misconduct of its ESS. At the same time, however, it would be confusing and administratively burdensome for the company to switch a customer to a new ESS, then disconnect the customer for unpaid charges from a prior account. We believe it is appropriate to focus on the party at fault. PGE's Rule H should be amended to allow the company the limited ability to refuse a request for direct access for a customer if that customer has not fully paid PGE for prior regulated services rendered. PGE should not be allowed to refuse a DASR where the ESS, not the end-user customer, has failed to make full payment.

3. **Offsetting Termination Payments**

PGE has proposed that its ESS service agreement allow any termination payment owed to the defaulting party to be offset against any amounts due or owed by the defaulting party

[50] *See* Advice No. 00-14, PUC Oregon No. E-17, Original Sheet No. H-15, as marked in copy attached to PGE's Opening Brief.

or any of its affiliates to the non-defaulting party. ICNU does not dispute the ability to offset, but contends that it is not industry practice for the offset to include the non-defaulting party's affiliate under any other agreements.

Commission Resolution

We disagree with ICNU's contention. As PGE explains, the language contained in the ESS service agreement was modeled after the Edison Electric Institute Master Purchase and Sale Agreement, which is becoming the model for power purchase and sales agreements throughout the country.

4. Portfolio Fees

PGE's proposed Rule J addresses eligibility requirements and enrollment terms and procedures for residential and small non-residential customers participating in the portfolio options and standard offer service. After an initial free enrollment period, PGE proposes to charge residential customers a $5.00 fee each time a portfolio selection is made or changed. PGE proposes a $20 switching fee for small non-residential customers moving between portfolio options or switching to or from direct access or the standard energy offer.

CUB and Portland believe that PGE's proposed switching fees will create economic disincentives for customers to exercise choice. Portland contends that PGE should recover any administrative costs by recovery through rates, not by separate fees to individual customers. Portland recommends that PGE recover the modest costs associated with option enrollment and switching through the basic charge. Portland maintains that a separate charge would be confusing and unnecessary, and impede access to new electricity options.

Commission Resolution

We first note that PGE's proposed fees are authorized by OAR 860-038-0220(9)(e), which provides that "an electric company may impose nonrecurring charges to recover the administrative costs of changing suppliers or rate options." CUB and Portland offer no evidence that the proposed fees are so high as to prevent a customer from switching services or providers. In fact, as PGE notes, many service providers might offer to pay any switching fees, as is common in the telecommunications industry. We find no reason why PGE should not be allowed to charge these fees to customers on a cost-causation basis under the SB 1149 rules.

5. Purchase of Transmission Services

In its Schedule 600, PGE proposes the requirement that an ESS must purchase firm transmission service on a monthly basis under PGE's Open Access Transmission Tariff. Portland contends that the minimum duration of purchase of transmission services by ESSs should be reduced from one month to one day. Portland notes that PGE's merchant function can purchase transmission services for as little as one day.

Commission Resolution

We are not persuaded by Portland's argument. As PGE notes, Portland attempts to compare transmission for merchant trading with transmission to serve retail load. PGE must secure transmission service for its retail service customers on a firm basis to ensure reliable service. ESSs should not be allowed to provide any less reliable transmission services. Indeed, OAR 860-038-0590(2) requires electric companies to coordinate the filings of tariffs "to ensure that all retail and direct access customers are offered comparable services at comparable prices." Moreover, if ESSs were to purchase non-firm transmission on a daily basis, they would run the risk that no transmission would be available on certain days because firm purchasers take priority over the short-term and non-firm purchasers. We believe that, like PGE, ESSs should be required to secure firm transmission on a long-term basis.

6. Merchant Trading Fee

Staff seeks to impose a one-half percent fee on the absolute value of all PGE's Merchant Trading Activity. Staff proposes the fee to compensate ratepayers for the use of expertise gained in PGE's regulated trading operations. It believes that PGE's unregulated Merchant Trading activity benefits from the knowledge and expertise its traders gain from conducting trades for the company's retail customers.

PGE objects to the proposed fee. It contends that the fee is prohibited by the stipulation approved by the Commission in the Enron-PGE merger, docket UM 814, in which PGE agreed to pay ratepayers $105 million for the expertise used or to be used in PGE's unregulated wholesale trading activities. It relies on Paragraph 20A of that stipulation, which provides, in relevant part:

> "Enron and PGE are obligated to provide PGE's customers $105 million upon merger completion, which represents full payment for any entitlement PGE's customers may have to value that relates to:
>
> > (1) use of PGE's name, reputation, business relationships, expertise, goodwill or other intangibles;
> >
> > (2) wholesale and non-franchise retail activities that PGE has undertaken that will not take place within PGE after the merger (this includes but is not limited to PGE's discontinued term wholesale trading and risk management activities), and wholesale and non-franchise retail activities that PGE might have undertaken had the merger with Enron not occurred; and,
> >
> > (3) added value of the merged entity that is achievable because of the combination or because of the association with PGE.

> This payment obligation also shall constitute full payment to PGE's customers for any entitlement to the revenues, value or other benefits arising from the business activities of the merged entity, other than the regulated business activities conducted by PGE. The term 'regulated business activities' shall mean the assets and services of PGE which are subject to economic regulation under Oregon or federal law."[51]

PGE contends that Staff's proposed fee violates: (1) the release relating to all future customer claims to PGE's expertise set forth in Condition 20(A)(1); (2) the release relating to wholesale and non-franchise retail sales the PGE might have undertaken had the merger not occurred, as stated in Condition 20(A)(2); and (3) the release as it relates to unregulated activities of the merged entity set forth in the final paragraph. Staff responds that the stipulation anticipated that PGE would discontinue wholesale trading after the merger with Enron. Thus, Staff contends, the stipulated $105 million payment applies only to wholesale trading activities that PGE had engaged in prior to, but not after the merger.

Commission Resolution

The wording of the stipulation is ambiguous, and our ability to determine the parties' intent in drafting the language is frustrated by the fact that, at the time of entering the stipulation, both PGE and Staff believed that PGE would permanently discontinue its Merchant Trading activities. We need not, however, resolve the issue of whether Staff's proposed fee is barred by the merger stipulation. Even assuming that the PGE-Enron merger does not control, we agree with PGE's alternative argument that Staff's Merchant Trading fee proposal lacks sufficient evidentiary support.[52]

Both Staff and PGE agree that benefits of trading expertise and information flow both ways between the company's Retail and Merchant Trading activities. The combination of functions give the Merchant Trading operations access to information about regulated utility operations that is generally not available to independent trading operations. At the same time, the company's Retail Trading operations gain greater access to price information as a result of the contacts made through Merchant Trading. The combination of functions also enables PGE to leverage better terms for purchases to meet retail load requirements.

There is nothing in this record, however, that sufficiently quantifies the value of this expertise and information. Consequently, we are unable to determine whether the flow of this information is, as Staff believes, so unbalanced as to require the imposition of a fee on PGE's Merchant Trading activity. Indeed, there is no empirical evidence to establish that the value of information and expertise that PGE's Merchant Trading operation receives is greater than the value of the information and expertise that it provides to the company's Retail Trading activities. Moreover, there has been no analysis on what effect Staff's proposal may have on retail rates, as the imposition of a trading fee would provide the company incentive to transfer the Merchant Trading activity to an unregulated affiliate.

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[51] Order No. 97-196 at Appendix A, page 6.
[52] In light of this conclusion, we also need not address PGE's motion to strike Staff's testimony relating to the proposed Merchant Trading Fee.

In short, we find that the synergies of joint trading operations flow both ways between PGE's retail and Merchant Trading operations. In the absence of any evidence that establishes that the flow of this expertise and information is unbalanced in favor of PGE's unregulated operations, we reject Staff's proposal to adopt a one-half percent fee on the absolute value of all PGE's Merchant Trading Activity.

CONCLUSIONS

1. PGE is a public utility subject to the Commission's jurisdiction.

2. The stipulations, attached as Appendix C, D, E, and F, should be adopted. The results contained in the revenue requirement stipulation, attached as Appendix B, should be adopted with the additional adjustments to non-power O&M costs described above.

3. Based on the record in this case, PGE's rates that result from the stipulations and the Commission's conclusions in the body of this order are just and reasonable. A results of operations spreadsheet is attached as Appendix G.

ORDER

IT IS ORDERED that:

1. Advice No. 00-14, filed by Portland General Electric Company on October 2, 2000, is permanently suspended.

2. The stipulations attached as Appendices C, D, E, and F are adopted in their entirety.

3. The results contained in the stipulation attached as Appendix B are adopted, with the additional adjustments to non-power O&M costs described above..

4. In its September 12, 2001 power cost filing, PGE shall submit a rate design table identifying, for each rate schedule, the specific percentage increase resulting from the updated power cost estimates and consistent with the terms of this order.

5. PGE may file revised tariffs consistent with findings of fact and conclusions of law contained in this order, to be effective no earlier than October 1, 2001.

Made, entered, and effective AUG 3 1 2001

Roy Hemmingway
Chairman

Roger Hamilton
Commissioner

Joan H. Smith
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

UE115F04

GUIDELINES FOR COST OF EQUITY WITNESSES

When providing cost of equity recommendation in Commission proceedings, witnesses should bear in mind the following guidelines:

- Clarity: All witnesses should clearly and fully explain the methodologies used and the theoretical support for using the methodologies. When advocating a new approach, or one previously rejected by the Commission, a witness should explain why the Commission should adopt the proposed methodology in the present docket.

- Candor: All witnesses should clearly explain the use of every subjective adjustment and explain the reasons for making them, whether they are based on academic literature, personal judgment, or other reasons. The witnesses should include any such explanations in the text of their testimony, rather than bury them in footnotes, work papers, or appendices.

- Reproducible Results: All witnesses should clearly explain every formula, calculation, and adjustment used in sufficient detail to allow other parties and the Commission the ability to easily reproduce and adjust their results. If necessary, the witnesses should include electronic spreadsheets and step-by-step instructions for use.

- Professionalism: When challenging the opinions offered by others, witnesses should exercise a high degree of professionalism. While the Commission must consider the credibility of witnesses, the emphasis in testimony and briefs should be on the evidence presented, not the integrity of opposing witnesses. Criticism of opposing testimonies should be clearly articulated and objectively supported. Before criticizing other positions, witnesses should ensure that their own opinions are properly supported and clear.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

RECEIVED

APR 26 2001

Public Utility Commission of Oregon
Administrative Hearings Division

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	)))	STIPULATION REGARDING CHANGES TO PGE'S REQUESTED COST OF SERVICE

This Stipulation is entered into for the purpose of resolving specified adjustments to Portland General Electric Company's (PGE) requested revenue requirements in this docket. This Stipulation presents a partial settlement of revenue requirement issues and does not resolve all issues in this docket.

I. INTRODUCTION

On October 2, 2000, PGE filed Advice No. 00-14 to produce a $324 million increase in its base prices to its customers. The filing was based on a projected test year of 2002. Advice No. 00-14 was suspended by the Commission at its October 20, 2000 Public Meeting, Order No. 00-669.

The Administrative Law Judge held a Prehearing Conference on October 24, 2000 to establish a procedural schedule in the case. Pursuant to that schedule, Staff and Intervenors published settlement proposals on January 12, 2001. Settlement Conferences commenced January 16 through 19 and were continued to January 23, January 26, January 30, and February 1. The Settlement Conferences were open to all parties.

As a result of the settlement conferences, the parties signing this Stipulation (Parties) have agreed to a reduction in PGE's requested revenue requirement with respect to specified adjustments. The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. TERMS OF STIPULATION

1. The Parties to this Stipulation agree that PGE will reduce its revenue requirement request to reflect the adjustments listed in Attachment A to this Stipulation. The parties agree to calculate the revenue requirement impact of the adjustments listed in Attachment A consistent with the final Commission approved Cost of Capital in this case.

2. The Parties recommend that the Commission approve the various tariff, rule, rate base, expense and other revenue adjustments described in Attachment A.

3. The Parties request the Commission allow PGE to place certain items in supplemental tariffs. Specifically, the Parties request that adjustments S-22 (Y2K Deferral), S-38 (1999 Y2K Amortization), S-39 (Neil Settlement), S-42 (Property Sale Gains), and S-46 (Non-recurring property sales) be placed in supplemental tariffs.

4. The parties agree to work in good faith to agree on the unbundling of the stipulated adjustments in Attachment A in accordance with OAR 860-038-0200. Absent agreement on unbundling the adjustments in Attachment A, such adjustments will be unbundled pursuant to the unbundling approved in the final order of the Commission.

5. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiations of this Stipulation shall not be admissible as evidence in this or any other proceeding.

6. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

7. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

8. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's order.

9. By entering into the Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principals, methods or theories employed by any other party in arriving at the terms of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

10. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each Party on the date entered below.

Dated this 7th day of March, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: _______________

PACIFICORP

By: _______________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

David B. Hatton

By: _______________

OTHER

By: _______________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: _______________

FRED MEYER STORES

By: _______________

CITIZENS' UTILITY BOARD

By: _______________

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This Stipulation is entered into by each Party on the date entered below.

Dated this 7th day of March, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ______________________

PACIFICORP

By: ______________________

FRED MEYER STORES

Michael L. Kurtz

By: [signature]

CITIZENS' UTILITY BOARD

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

OTHER

By: ______________________

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Attachment "A"

The Stipulated Adjustments are described below and summarized in Attachments A1 (Cost of Capital), A2 (Other Revenue, Operating Costs and Rate Base), A3 (Tariff Language Revisions), A4 (Schedule 48 & 105, Rules B-G, I, K and L) and A5 (Tariff Schedule Review). The adjustments below do not include the impact of revenue sensitive costs (e.g., taxes and bad debt expense). The revenue requirement impact of each of the adjustments (including revenue sensitive costs) will be determined once the Cost of Capital issue (S-0) is settled.

S-0 Cost of Capital: The parties agree on the capital structure, cost of preferred stock, and cost of long-term debt as provided in Attachment A-1. No stipulation on the cost of equity at this time.

S-1 FERC Wholesale Fee: Reduce A&G expenses by $372,000.

S-2 Montana Production Tax: Increase Taxes Other Than Income by $450,000.

S-3: Colstrip O&M: Increase Production O&M by $1,043,000 and increase Transmission O&M by $25,000.

S-4: Transmission O&M: All Transmission O&M issues are addressed under Staff issue S-30.

S-5: FERC Hydro Fee: Reduce Production O&M by $14,000 and increase A&G expense by $714,000.

S-6: Income Tax Apportionment: This adjustment is incorporated into Staff issue S-41.

S-7: Trojan Severance Program: Increase Amortization by $66,000 to reflect a three-year recovery of the unamortized balance at October 1, 2001.

S-8: Oregon Analytical Lab Sale: Reduce Production O&M by $83,000, Transmission O&M by $28,000, Distribution O&M by $223,000, and rate base by $439,000. Increase A&G expense by $108,000 and Amortization by $100,000.

S-9: PGH Billings: Reduce A&G expense by $436,000.

S-10: Retail Unbundling: Increase Customer Service expense by $435,000 and A&G expense by $303,000.

S-11: Beaver Turbine: Increase Depreciation by $182,000, Property Taxes by $14,000, and rate base by $2,789,000.

S-12: Other Revenue: This item is considered under Staff issue S-24.

S-13: State Tax Credit: This adjustment is incorporated into Staff issue S-41.

S-14: SERP Rate Base & MDCP expense: Decrease A&G Expense by $4,645,000 and rate base by $2,122,000.

S-15: Remove Trojan: Reduce Amortization expense by $16,584,000 and rate base by $102,904,000 to comply with the Commission Order No. 00-601 in Docket UM-989.

S-16: Remove NEIL: Increase Production O&M by $2,400,000 and A&G by $1,418,000 to comply with the Commission Order No. 00-601 in Docket UM-989.

S-17: Remove Other Debits & Credits: Decrease Other Revenue by $589,000 and Amortization by $959,000. Increase rate base by $181,000. This complies with the Commission Order in Order No. 00-601 in Docket UM-989.

S-18: Solar for Schools: Reduce Customer Service costs by $55,000 to reflect removal of the cost of this program as a regulated activity.

S-19: Salmon Spring Reclassification: Increase Other Revenue by $183,000.

S-20: Green Power Purchase: Reduce Purchased Power by $420,000.

S-21: Property Tax Unbundling Correction: Transfer $902,000 of property taxes from Transmission to Production.

S-22: Y2K Deferral: Incremental Y2K costs incurred in 2000 will not be recovered through base rates in UE-115. Accordingly, there will be no adjustment in item S-22. The parties further agree that PGE will collect the unamortized balance of these 2000 Y2K costs at 10-1-01 through a balancing account (approximately $363,000) and supplemental tariff. The balancing account will accrue interest at PGE's last approved cost of capital.

Recovery of the 2000 Y2k costs is subject to a prudence review by Staff. Staff will attempt to complete the review before June 1, 2001.

S-23: Two-Cities: Increase Wheeling expense by $129,000 and rate base by $96,000.

S-24: Misc. Electric Revenue: Increase Other Revenue by $998,000.

S-25: Variable Power Cost: No stipulation at this time.

S-26: Customer Acct. Non-Labor: Reduce Customer Service costs by $1,600,000.

S-27: Category A Advertising: The parties agree to include in base rates Category A advertising costs equal to 1/8 of one percent (.125 percent) of revenues in accordance with OAR 860-026-0022(3)(a). Based on PGE's filed revenue requirement, this results in a reduction of $2,405,000 in Customer Service costs. The parties agree that this calculation will be updated to reflect the final Commission approved revenue requirement in this case.

The Parties further agree that PGE may defer (for future amortization in rates) amounts spent in excess of the final approved amount for the twelve month period starting when UE-115 rates go into effect subject to Staff audit of all Category A advertising and related expenses. This is an annual deferral that continues until new base rates are established. Interest will accrue on deferred amounts at PGE's most recently approved cost of capital. The Parties agree that the mechanism described above is an automatic adjustment mechanism and no earnings test is required.

S-28: Public Purpose Adjustment: Reduce A&G expense by $149,000 to reflect removal of Lighting Lab costs. Remove $550,000 from Customer Service expense for DSM Evaluation and Verification (E&V) costs. The parties agree that the DSM E&V costs may be deferred and recovered through Schedule 101 subject to a review of prudence by the Staff. Deferral will continue until all energy efficiency programs receiving lost revenue recovery are closed out. The Parties agree that the mechanism described above is an automatic adjustment mechanism and no earnings test is required.

S-29: Marketing and Sales Expense: Reduce Customer Service expense by $800,000.

S-30: Transmission & Distribution O&M: Reduce Transmission O&M by $1,505,000 and Distribution O&M by $990,000. The Open Access Transmission Tariff (OATT) and intertie revenue will be revised based on the final transmission revenue requirement. This update cannot occur until the cost of capital (Issue S-0) is finalized.

S-31: A&G Accounts: Reduce A&G expense by $1,000,000.

S-32: SERP O&M: Reduce A&G by $1,250,000.

S-33: Bonus/Incentive Pay: Reduce A&G expense by $2,237,000, payroll taxes by $240,000, and rate base by $602,000.

S-34: Workforce Level: Reduce A&G expense by $4,821,000, payroll taxes by $518,000 and rate base by $1,046,000.

S-35: OPUC Wage Formula: Reduce A&G expense by $1,550,000, payroll taxes by $167,000, and rate base by $336,000.

S-36: Distribution Plant: Reduce net average plant by $2,000,000, Depreciation expense by $60,000, and Property Taxes by $30,000. Sales to Consumers is increased by $1,075,452.

S-37: Materials and Supplies: Reduce rate base by $3,681,000.

S-38: Y2K Amortization: The parties agree that PGE should recover the unamortized balance of 1999 incremental Y2K costs deferred through a supplemental tariff versus base rates as initially proposed by PGE. Accordingly, reduce Amortization expense by $1,977,000 and rate base by $4,942,000. The unamortized balance at 10-1-01 will be placed in a balancing account, accruing interest at PGE's last approved cost of capital, for future amortization in rates through a supplemental tariff.

S-39: NEIL Amortization: The parties agree that PGE should refund amounts due to customers resulting from the settlement of NEIL through a balancing account, accruing interest at PGE's last approved cost of capital, and supplemental tariff. Accordingly, there is no adjustment for issue S-39.

S-40: Acc. Deferred Taxes: Reduce rate base by $22,832,000.

S-41: Income Tax Adjustments: The parties agree that the composite state income tax rate for the UE-115 filing is 6.6547%, that PGE will incorporate $917,000 in expected state income tax credits into the final calculation of test year state income tax expense, and that the interest deduction for tax purposes will be calculated consistent with the weighted cost of debt, as provided in Attachment A1 to this Stipulation, and the final approved rate base total in this case. The S-41 adjustment will be calculated after all the component factors are finalized.

S-42: Property Sale Gains: Starting the later of 10-01-01 or the date UE-115 rates go into effect, PGE will assign actual gains and losses from the sale of utility property into a balancing account for later refund or collection from customers in a supplemental tariff. The balancing account will accrue interest at PGE's last approved cost of capital. Accordingly, increase Amortization expense by $477,000 to reflect the removal of forecast property sale gains/losses from the calculation of PGE's base rates.

S-43: Depreciation Study: Reduce Depreciation expense by $3,567,000 and increase rate base by $1,784,000 to reflect the stipulation in Docket UM-982, Order No. 01-123.

S-44: SB 1149 Implementation Costs: Increase A&G expense by $416,000, Customer Service expense by $376,000, and Rate Base by $459,000. Certain prudently incurred expenses only occur in 2002. Those one-time expenses are included in rates at 1/6'th of the 2002 amount and are also included in rate base, based on a six-year average. The adjustments listed previously incorporate the six year recovery of the one-time costs.

S-45: CIS/IT Capital Costs: PGE will place into base rates, 100% of the 2002 revenue requirement related to the 2000, 2001 and 2002 capital additions for the CIS/IT capital items listed below. The 2002 revenue requirement included in base rates will be trued-up to the actual revenue requirement for the CIS/IT capital costs. OPUC Staff will audit PGE's actual capital expenditures for the CIS/IT capital items below. Only those CIS/IT costs that are deemed reasonable and prudent will be authorized for inclusion in the "actual" revenue requirement calculation. Accordingly, relative to the CIS/IT costs included in UE-115 base rates, customers will receive a refund for any CIS/IT costs PGE does not expend or CIS/IT costs the OPUC rules imprudent. This ensures customers will only pay for prudently incurred CIS/IT costs.

UE-115 2000-2002 CIS/IT Capital Items

A) Customer Information System (CIS).
B) Enterprise Resource Planning (ERP) system.
C) Network Meter Reading (NMR) backbone and data store (excluding the meters).
D) Miscellaneous capitalized information technology costs.

The amount of the 2000-2002 gross capital additions included in the UE-115 filing for the CIS/IT capital items is $96.85 million.

Audit / Deferral Process
Prior to April 1, 2003, PGE will report to the Commission Staff its 2000-2002 capital expenditures for the CIS/IT capital items. Staff will audit PGE's information technology programs and expenditures at any time, but will complete their audit by June 1, 2003. If PGE disagrees with the results of Staff's audit, PGE may present their concerns to the Commission who will decide which CIS/IT costs are recoverable. Based on the "actual" CIS/IT costs approved by the Commission/Staff, PGE will calculate its "actual" revenue requirement. If the actual 2002 revenue requirement is less than the base rate 2002 revenue requirement, the difference will be deferred in a balancing account for future refund to customers. The balancing account will accrue interest at PGE's last approved cost of capital. The balancing account will presume the deferral was known and measurable as of January 1, 2003, and will accrue interest from that date forward. PGE agrees to waive an earnings review if one is required to implement the potential refund.

It is possible that some of the forecasted CIS/IT capital items will be delayed and not expended until 2003. If there are expenditures in 2003, the above audit process will be repeated in 2004 for the incremental 2003 expenditures. The actual revenue requirement for the 2003 expenditures will be added to the actual revenue requirement for 2002, this combined actual revenue requirement will be compared to the base rate 2002 revenue requirement. If the combined actual revenue requirement is less than the 2002 base revenue requirement, the difference will be deferred in the balancing account with an effective date of January 1, 2004. Each January 1st thereafter, an amount equal to the 2003 true-up will be deferred in the balancing account. The annual deferrals will terminate when new base rates are established.

To facilitate the audit process, Staff will receive and be an active participant in existing PGE processes for monthly or quarterly monitoring and/or progress reports for PGE's information technology projects. Staff's audit will focus on determining whether the information technology systems are providing reasonable performance and are used and useful.

S-46 Supplemental Amortization Tariff – Nonrecurring Property Sales: PGE will refund the items listed below (including any applicable interest) to customers through a supplemental tariff. The start date of the amortization will be established separate from this Stipulation.

- The $2,179,000 of property transactions listed in PGE Exhibit/209, Barnes 1.
- The $2,500,000 per the Trojan Offset Settlement, Order No. 00-601.
- The $10,468,236 gain from the sale of the Coyote II Common Facilities, Order No. 00-214. Subject to Staff verifying the gain calculation.

S-47 Rate Spread/Rate Design: No stipulation at this time.

S-48 Residential Customers CTM/PAA/PCA, etc: No stipulation at this time.

S-49 Proposed Tariff Language Revisions, Schedules 100, 101, 108 and 115: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A3.

S-50 Decoupling Adjustment, Schedule 123: No stipulation at this time.

S-51 Proposed Revisions to Schedule 48, 105, Rules B-G, I, K, and L: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A4.

S-52 Tariff Schedule Review: The parties agree to certain general tariff revisions and specific language changes as described in Attachment A5.

S-53 ESS Service Agreement: No stipulation at this time. The Parties are working together to develop an ESS Service Agreement.

S-54 Reclassification of Transmission Plant: The Parties agree to the re-classification of Transmission, Distribution and Generation plant (and related operating costs) proposed in PGE's UE-115 filing, Exhibit 1500, subject to certain conditions. A separate stipulation will be developed for this issue.

Attachment A1

Cost of Capital

Portland General Electric							
Composite Cost of Capital: Settlement (Excluding ROE)							
Test Year Based on 12 Months Ending 12/31/02							
($000)							
	Average Outstanding		Percent		Percent Cost		Weighted Average Cost
Long Term Debt	$887,900		46.32%		7.508%		3.48%
Preferred Stock	$29,250		1.53%		8.432%		0.13%
Common Equity	$999,781		52.16%				
Composite Cost of Capital	$1,916,931		100.00%				

Attachment A2

Other Revenue, Operating Costs, Rate Base

Financial Summary Reflecting Stipulated Positions				Attachment A-2						
Excluding Revenue Sensitive Costs										
	FERC Wholesale Fee	Montana Production Tax	Colstrip O & M	Transmission O & M	FERC Hydro Fee	Income Tax Apportion	Severance Program	OAL Sale	PGH Billings	Retail Unbundling Allocation
Revenue Requirement Category	(S-1)	(S-2)	(S-3)	(S-4)	(S-5)	(S-6)	(S-7)	(S-8)	(S-9)	(S-10)
Retail Revenues										
Other Revenue										
Production O&M			1,043		(14)			(83)		
Transmission O&M			25					(28)		
Distribution O&M								(223)		
Purchased Power										
Generation										
Wheeling										
A&G	(372)				714			108	(436)	303
Customer Service										435
Depr. & Amort.							66	100		
Other Taxes		450								
Rate Base (excluding working cash)								(439)		
	Beaver Turbine	Other Revenue	State Tax Credit	Remove SERP Rate Base & MDCP Expense	Remove Trojan	Remove Neil	Remove Other Debits & Credits	Solar For Schools	Salmon Springs Reclassification	Green Power Purchase
Revenue Requirement Category	(S-11)	(S-12)	(S-13)	(S-14)	(S-15)	(S-16)	(S-17)	(S-18)	(S-19)	(S-20)
Retail Revenues										
Other Revenue							(589)		183	
Production O&M						2,400				
Transmission O&M										
Distribution O&M										
Purchased Power										(420)
Generation										
Wheeling										
A&G				(4,645)		1,418				
Customer Service								(55)		
Depr. & Amort.	182				(16,584)		(959)			
Other Taxes	14									
Rate Base (excluding working cash)	2,789			(2,122)	(102,904)		181			

Financial Summary Reflecting Stipulated Positions — **Attachment A-2**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	CRM (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)	Public Purpose Adjustment (S-28)	Remove Marketing & Sales Expense (S-29)	T&D O&M (S-30)
Retail Revenues										
Other Revenue				998						
Production O&M										
Transmission O&M										(1,505)
Distribution O&M										(990)
Purchased Power										
Generation										
Wheeling			129							
A&G								(149)		
Customer Service						(1,600)	(2,405)	(550)	(800)	
Depr. & Amort.										
Other Taxes										
Rate Base (excluding working cash)			96							

Revenue Requirement Category	Reduce A & G Accounts N44173 & N44174 (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)	Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)
Retail Revenues						1,075				
Other Revenue										
Production O&M										
Transmission O&M										
Distribution O&M										
Purchased Power										
Generation										
Wheeling										
A&G	(1,000)	(1,250)	(2,237)	(2,411)	(1,550)					
Customer Service				(2,411)						
Depr. & Amort.						(60)		(1,977)		
Other Taxes			(240)	(518)	(167)	(30)				
Rate Base (excluding working cash)			(602)	(1,046)	(336)	(2,000)	(3,681)	(4,942)		(22,832)

ORDER NO. 01-777

APPENDIX B
PAGE 14 OF 32

Financial Summary Reflecting Stipulated Positions				Attachment A-2	
Excluding Revenue Sensitive Costs					
		Remove		SB 1149	CIS/IT
	Income Tax	Property	Depreciation	Implementation	Disallowance
	Adjustments	Sales Gains	Study Adj.	Costs	Adjustments
Revenue Requirement Category	(S-41)	(S-42)	(S-43)	(S-44)	(S-45)
Retail Revenues					
Other Revenue					
Production O&M					
Transmission O&M					
Distribution O&M					
Purchased Power					
Generation					
Wheeling					
A&G				416	
Customer Service				376	
Depr. & Amort.		477	(3,567)		
Other Taxes					
Rate Base (excluding working cash)			1,784	459	

G:\RATECASE\OPUC\DOCKETS\UE-115\Settlement\Staff Proposal\[Stip Exhibit A2 03-07-01.xls]Adjustments

ORDER NO. 01-777

APPENDIX B
PAGE 15 OF 35

Attachment A3

ISSUE S-49: Tariff Language Changes

Schedule 100 – The Attorney General's office will review Section 43 of SB1149 and provide a written summary on how to treat special contracts that may have a provision within the contract limiting the applicability of adjustment schedules. PGE will abide by the Attorney General's summary.

Schedule 101 – All of Staff's proposed changes listed in the January 12, 2001 Staff Settlement Proposal, with the exception of adding back in the Demand Side Management Refund, will be incorporated into Schedule 101.

Schedule 108 – All of Staff's proposed changes listed in the January 12, 2001 Staff Settlement Proposal will be incorporated into Schedule 108.

Schedule 115 - The Attorney General's office will review Section 43 of SB1149 and provide a written summary on how to treat special contracts that may have a provision within the contract limiting the applicability of adjustment schedules. PGE will abide by the Attorney General's summary.

Attachment A4

S-51: Revisions to Schedule 48 and 105, Rules B-G, I, K and L.

PGE TARIFF REVIEW
PGE Exhibit 1602
Oregon E-17
Issue S-51

OVERALL STAFF COMMENT
Throughout the tariff PGE has replaced "customer" with the term "consumer". The company has defined consumer as "a person who has applied for, been accepted, and is currently receiving service." This is the definition of a "customer" per OAR 21-0008(3).

In a few places, they also replaced "applicant" with consumer which does not mean exactly the same thing. Customers have specific rights which applicants do not have.

The tariffs need to be aligned with the meanings of customer and applicant in OAR Division 21.

Status Resolved.
Discussion PGE will review for consistency and submit edits if necessary towards the end of the ratecase process for Staff review.

Schedule 48 – Standard Offer Service
Irrigation and Drainage Pumping Small Nonresidential
Added a notice under minimum charge that "...the Company may require the Consumer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities". The tariff should specify the circumstances under which the charge is incurred.

Status Resolved.
Discussion No change required to language as filed.

Schedule 105 – Property Transactions Adjustment - Property is spelled "propery" in the title

Status Resolved.
Discussion Will be corrected.

Rule B – Definitions
Applicant – "A person or business applying to the Company for Electricity Service or reapplying for service at a new or existing location after service has been discontinued *for greater than 20 days.*" This tariff is not in compliance with OAR 21-0008(1). It mixes up a customer's right to retain customer status for twenty days after a voluntary disconnect with the definition of an applicant. A customer becomes an applicant automatically if service is involuntarily disconnected.

Status Resolved.
Discussion 'for greater than 20 days' - phrase will be stricken.

Rule B – Definitions
Customer Service Charge – deleted, should be included.

Status Resolved.
Discussion Customer Service Charge-This term is eliminated.
Basic Charge - Definition will be added.
Energy Charge - Definition will be added.
Demand Charge - Definition will be added.
Reactive Demand Charge- Definition will be added.

Rule B – Definitions
Premises – deleted the section regarding the circumstances under which various types of business properties are considered one premises. If there has been no change in intent, the deleted portion should be restored.

Status Resolved.
Discussion Definition of SITE added (as written in AR-390 Order 01-073 entered Jan 3, 2001).
PGE will review use of the term "premise" versus "site" towards end of the ratecase process for Staff review.

Rule B – Definitions
- Kilovar – deleted, should be included.
- Kilowatt – deleted, should be included
- Kilowatt Hour – deleted, should be included

Status Resolved.
Discussion All three definitions will be added back.

Rule B – Definitions
Irrigation Service – deleted, should be included

Status Resolved.
Discussion This will be left out as this statement is included in the individual schedules in E-17, and which irrigation customers qualify for the RPA credit is defined under Schedule 102 in E-17.

Rule B – Definitions
Residential Consumer – deleted the reference to 30-days for transient occupancy, deleted the description of a dwelling, and the caveat that a recreational vehicle is not a dwelling. Deleted the section regarding multi-family dwellings. Verbiage in the current tariff regarding the definition of a dwelling, recreational vehicles, and multi-family dwellings was the result of several different complaints handled by Consumer Services. It should be retained in order to maintain the clarity of the tariff.

Status Resolved.
Discussion
* Definition for "Residential Consumer" will be modified to include descriptions of the terms transient occupancy, dwelling, and multi-family.
* Definition of "Transient Occupancy" will be added to Rule B. (30 day limitation is included).
* Recreational Vehicles qualify for residential service as per SB1149.

Rule B – Definitions
Transient Occupancy – deleted. Transient occupancy is referred to in the definition of residential service, the definition should be included.

Status Resolved.
Discussion Definition returned.

Rule C – Conditions Governing Consumer Attachment to Facilities
C-8 Hazardous Substances – deleted term "applicant" throughout. Because "consumer" does not have the same meaning, applicant should be restored where applicable.

Status Resolved.
Discussion Restored where applicable.

Rule C – Conditions Governing Consumer Attachment to Facilities
C-14 Service Restoration is an entirely new section putting into the tariff the restoration priorities. It states "The Company will not give priority to any Consumer or ESS but will employ the above process over the Company's entire territory served." Is this a change from the policy that allowed identification of medically needy accounts for restoration purposes?

Status Resolved.
Discussion No editing required.

Rule D – Consumer Service Requirements
D-1 allows applications to be accepted from **third-parties** such as landlords. This is not within current accepted procedures. Only the person intending to be the customer of record can obligate themselves to paying for service.

Status Resolved.
Discussion PGE will revise wording so this option is available but the implication that this is a common situation for landlords will be removed.

Rule D – Consumer Service Requirements
D-4 leaves out the term "same type of utility service" (OAR 21-0200) under deposit requirements and letter of credit option. It should be restored to be in line with Division 21.

Status	Resolved.
Discussion	Wording added.

Rule D – Consumer Service Requirements
D-5 states a notice shall be mailed six business days before disconnection. "No less than" should be added to avoid a problem with disconnects occurring past six days.

Status	Resolved.
Discussion	Wording added.

Rule D – Consumer Service Requirements
D-5 deleted the part about customers on a Time Payment Agreement who default on deposit arrangements (OAR 21-0205(7). Needs to be added.

Status	Resolved..
Discussion	Added sentence and OAR reference.

Rule D – Consumer Service Requirements
D-6 adds a new section "Like Occupancy" – "When a Residential Applicant requests Electricity Service and the previous occupant(s) of the dwelling continues to reside at the dwelling, the Applicant will be considered a co-Consumer and may be required to pay a deposit." This does not comply with OAR 21-335 (Refusal of Service Rule) or 21-200 (Establishment of Service).

Status	Resolved.
Discussion	Deleted.

Rule D – Consumer Service Requirements
D-7 nonresidential deposit requirements added a consumer who "has had their Electricity Service discontinued by an ESS for nonpayment of charges." Consumer Services is concerned about basing deposits for regulated services on credit history with an unregulated company.

Status	Resolved.
Discussion	PGE will insert the following language instead: The Company reserves the right to check an applicant's credit and, based on the credit report, a deposit may be requested.

Rule D – Consumer Service Requirements
D-9 added that credit is established one year after a deposit or final deposit installment is paid. OAR 21-215 only uses the term "one year after a deposit is made. It doesn't mention installments. So this means that a customer who makes installment arrangements does not establish credit for fourteen months.

Status Resolved.
Discussion Language removed.

Rule E – Billings
E-1 Continuing Nature of Charges – "Disconnect and reconnect transactions do not relieve a Consumer from the obligation to pay charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Consumer." The charges in question need to be clearly identified.

Status Resolved.
Discussion PGE added the word 'Basic' so it now reads: "... do not relieve a Consumer from the obligation to pay Basic or Minimum Charges that accumulate....

Rule E – Billings
E-2 Responsibility for Payment deleted the option for closure of an account by a landlord. This could impact the ability of a new tenant to put service in their name if the outgoing tenant has not closed their account.

Status Resolved.
Discussion New language added: "The Company may accept a change of occupancy notification from a third party. The Company may refuse to process a change of occupancy until it receives satisfactory evidence of the third party's authority to request such a change."

Rule E – Billings
E-3 Assessed Demand deleted two sentences from the current tariff: "Demand will be billed to the nearest whole kilowatt, and Reactive Demand will be billed to the nearest whole kilovar. At the Company's option, Demand may be determined by test or assessment." The material deleted clarifies the tariff.

Status Resolved.
Discussion Word "whole" included in Rule B definitions.

Rule E – Billings
E-4 Special Meter Reading deleted the allowance for one special read in twelve months at no charge. The charge is now $24 for each special read that does not result in a billing correction.

Status	Resolved.
Discussion	Clarifying language added: "The first special read is free if the purpose is to verify a previous read but that if the special read is associated with movement to open access, the one free read does not apply."

Rule E – Billings
E-4 Unmetered Loads deleted the description of how estimated monthly usage is calculated (1/12 of the annual use determined by the Company by test or estimated from equipment ratings).

Status	Resolved.
Discussion	No change required. This change is okay based on the need to not use 1/12 for some consumers that may go direct access.

Rule E – Billings
E-5 Payment of bills changes the calculation for prorated bills from multiplying the number of days in the period and dividing by 30.4167 to 30 (except for Consumers billed by the legacy system).

Status	Resolved.
Discussion	No change required.

Rule F – Disconnection and Reconnection
F-1 Deletes all references to the OAR which were in the previous tariff.

Status	Resolved.
Discussion	OAR cites returned.

Rule F – Disconnection and Reconnection
F-1 Grounds for Disconnection leaves out "Oregon" in "For failure to pay Company Tariff charges..." (OAR 21-0305(5))

Status	Resolved.
Discussion	The word "Oregon" is returned.

Rule F – Disconnection and Reconnection
F-2 Adds section "A Consumer who has avoided disconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Consumer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a documented good faith attempt to notify the Consumer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day. When remitting for dishonored funds the Consumer shall make the payment in either cash, money order, cashier's check or verified credit card payment.

- Consumer Services suggests changing to "A Consumer who has avoided disconnection, *established credit, or gained reconnection* of Electricity Service..."
- Also, add a section under credit establishment to clarify that an Applicant who establishes credit or pays an outstanding bill from a prior account by making a non-cash payment which is returned does not obtain customer status. They would still come under the one-day notice but it would make it clear they are NOT customers with the right to a TPA or medical certificate option.

<u>Status</u> Resolved.
<u>Discussion</u> Language change will be reviewed with Staff.

Rule G – Line Extensions
G-1 Purpose does not include Applicant in the list of folks who may request a line extension.

<u>Status</u> Resolved.
<u>Discussion</u> Researching editing possibilities as Applicant has a different meaning in Rule G. Language changes will be reviewed with Staff.

Rule G – Line Extensions
G-1 Does not include Applicant as being represented by an agent.

<u>Status</u> Resolved.
<u>Discussion</u> Researching editing possibilities as Applicant has a different meaning in Rule G. Language changes will be reviewed with Staff.

Rule G – Line Extensions
G-2 Line extension cost omitted "labor" from the list of costs.

<u>Status</u> Resolved.
<u>Discussion</u> The word "labor" is returned.

Rule G – Line Extensions
G-9 Deleted the section on Unity installations

Status Resolved.
Discussion Unity is now described on Sheet G-4. No action required.

Rule G – Line Extensions
G-9 • Adds a section on "Service Locates" which states that there is a charge to locate underground utility services on private property along the Applicant's proposed trench route"
- Add the clarification this applies only to subdivision (per Schedule 300)
- How does this relate to One-Call?

Status Resolved.
Discussion PGE is researching clarifying language which will be reviewed with Staff.

Rule I – Metering
I-3 Nonstandard Metering deletes the option for customers to choose nonstandard metering, now limits the request to ESS.

Status Resolved.
Discussion No change required. Customers still have the right to other meters. It is discussed under Interval Metering on the same sheet.

Rule I – Metering
I-4 Inaccessible Meters states that the company may *in its sole discretion* permit the Consumer to read the meter. The tariff does not comply with OAR 21-120(3)(a) which states ..."the energy utility shall seek the customer's cooperation in obtaining monthly readings (for example, having the customer complete and return a meter reading form).

Status Resolved.
Discussion The words 'in its sole discretion' are removed.

Rule K – Curtailment Plan

K-2 Curtailment Target deleted the calculations.
K-5 Stage 3 Notification deleted "Who will be audited... and who request" from "Provide Curtailment Targets to ESSs and Consumer. It also deleted a paragraph about providing information regarding exemption and processing requests for exemption.
K-6 Identification of the Base Year deleted "weather-normalized".
K-6 Estimating Base Billing...Changed audited customers with an option to exclude residential and small use to "all Consumers".
K-7 Communicating Curtailment Target Information deleted reference to retroactive information for audited customers.
K-8 Threshold Consumption Level deleted reference to changes required by the state.
K-8 Excess Electricity Calculation deleted how the excess load is calculated.
K-9 Non-Financial Penalties deletes references to sampling and substantially changed the penalty options.
K-10 Application for Exemption deletes reference to audited customers.
K-10 Granting Requests for Exemption deletes a paragraph with options to provide credit against further curtailment and the statement advising customers exemptions may not protect them against stage 5 curtailment.

<u>Status</u> Resolved.
<u>Discussion</u> E-17 Rule K language changes have been replaced with existing E-16 Rule M Curtailment Plan language.

Rule K – Curtailment Plan

K-2 General Use Consumer shows 43,800 MWh. Previous tariff had 48,300. Major Use Consumer had 43,800 in old (and new). Verify which was in error.

<u>Status</u> Resolved.
<u>Discussion</u> Corrected. Proposed E-17 now reads 43,800.

Rule L – Special Types of Electricity Service

L-1 Availability changed Applicant to Consumer (they do not have the same meaning).

<u>Status</u> Resolved.
<u>Discussion</u> It now reads, "Where Facilities other than those specified above are needed to provide service, the provisions of Rule G, Line Extensions, will apply."

Attachment A5

S-52: Tariff Schedule Review

Tariff Language Changes to PGE Exhibit 1602 Oregon E-17 Issue S-52

The following review is broken into two parts, "A" and "B." Staff contacts for part A are Jack Breen. Deborah Garcia, and Rebecca Hathhorn. The staff contact for Part B is Stefan Brown.

Part A

RATE SCHEDULES

Schedule 7 – Residential Service
Portfolio Option Enrollment

- The language for portfolio option enrollment is subject to the decisions of the Advisory Committee as approved by the Commission.

STATUS RESOLVED.
DISCUSSION The language will be revised based upon Advisory Committee recommendation.

Schedule 82 – Emergency Default Service Nonresidential

- Availability

STATUS Not stipulated.

Direct Access Schedules – 500 series
ESS Charges

- The last sentence states, "...the Company's charge for Direct Access Service may not be separately stated on the bill." In Data response No. 171, PGE intends to use alternative wording "The Company charges for Direct Access Service are not required to be separately stated on an ESS consolidated bill."

STATUS RESOLVED.
DISCUSSION The alternative wording in Data Response #171 will be used.

Schedule 300 – Miscellaneous Charges
Interest accrued on Consumer Deposits
- The rate is now 6%. The tariff will need to be modified accordingly. Additionally, the title should delete "Consumer" to clarify that deposit interest applies to an ESS deposit, as well as a consumer deposit.

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Schedule 600 – Energy Service Supplier Charges
ESS Support Services
- Maintenance Fee

STATUS Not stipulated.

Schedules 7, 15, 32, 38, 48, 49, and 86
Term
- Staff questions the justification of the requirement of a one-year term for service under these schedules. In Data response No. 174, PGE states it will further consider the issue and may provide revised term provisions at a later date.

STATUS RESOLVED.
DISCUSSION Term requirements were removed from Schedule 7 (unless required by a Portfolio Option) and set at 1 year for 15, 32, 38, 48, 49, and 86.

Schedules 83, 91, 92, 93, and 97
Term
- Staff questions the justification of the requirement of a five-year term for service under these schedules. In Data response No. 175, PGE states it will further consider the issue and may provide revised term provisions at a later date.

STATUS RESOLVED.
DISCUSSION Term requirements were removed from Schedule 83 (unless required by a pricing option) and set at 1 year for 91, 92, 93, and 97.

RULES

Rule C – Conditions Governing Consumer Attachment to Facilities
Sheet C-3 C. Limitation on Damages

STATUS Not stipulated

Sheet C-14 Service Restoration

- A. PGE should add language similar to: "Restoration priority is independent of whether a consumer purchases supply services from the Company or its affiliates, or from an ESS."

STATUS RESOLVED.
DISCUSSION PGE agrees. The following language is located on last page of Rule C:
"The Company will not give priority restoration to any Consumer or ESS, but will employ the above process over the Company's entire territory served."

Rule D – Consumer Service Requirements
Sheet D-6 Deposit Requirement

- Staff believes the credit-screening criteria language of B.(2) should be modified to correspond to the establishment of credit language in Sheet D-9 Treatment of Deposits A.(2)

STATUS RESOLVED.
DISCUSSION The revision will be made on Sheet D-6 at 4B(2)

Sheet D-7 Nonresidential Credit Standards

- (6) Staff believes the nonresidential deposit requirement in (6) should be deleted. A consumer who has had their Electricity Service discontinued by an ESS for nonpayment of charges may have a legitimate dispute. and the consumer's nonpayment to the ESS should not be the sole basis for a deposit request. PGE may consider nonpayment to an ESS as it would any other nonpayment to a creditor within the context of a credit report. In Data Response 202, PGE reaffirmed that it intends to require a deposit from a consumer who had electricity disconnected by an ESS for nonpayment.

STATUS RESOLVED.
DISCUSSION The disputed language was deleted. The following was added to the credit screening requirements:

"The Company reserves the right to check an Applicant's credit and, based on the credit report, a deposit may be requested."

Rule E – Billings
Sheet E-11 ESS Billing Responsibilities

- 24-hour turnaround for ESS

STATUS Not stipulated.

Rule F – Disconnection and Reconnection
Sheet F-3 – Disconnection and Reconnection Charges

- A. In the last sentence, "reconnection" should be changed to "disconnection". "Should this require a second trip to the premises to perform the ~~reconnection~~ disconnection the charge for reconnects at Other Than the Meter Base...." In Data response No. 207, PGE agreed to correct the error.

STATUS RESOLVED.
DISCUSSION Error corrected.

Rule G – Line Extensions
Sheet G-5 (d)

- Delete "All costs incurred by the Company shall be included as Line Extension Costs."

STATUS RESOLVED.
DISCUSSION This sentence will be moved and modified such that it is clear that customers building their own lines will be charged based on estimated actuals. Wording may fit better on Sheet G-2.

Sheet G-6 Applicants for New Permanent Service

- The language in existing tariffs should be retained.

STATUS RESOLVED.
DISCUSSION Add wording under the "Other Than Individual Applicants" section that clarifies residential subdivision refunds are not based on expected load.

Sheet G-14 Nonpermanent Line Extension

- The section deletes the payment of interest on money paid for a nonpermanent extension that becomes permanent. Why?

STATUS RESOLVED.
DISCUSSION PGE will pay interest.

Rule H – Requirements Relating to ESSs
Sheet H-1 & H-2 Service Agreement

- See settlement package work papers for line S-53. Staff suggests a workshop be held to discuss the content of a service agreement.

STATUS Being considered under S-53.

Sheet H-2 Credit Requirements and Security

- Delete "or more" from the last sentence of the first paragraph.
- (2) Staff is concerned about PGE exercising discretion in the credit evaluation process. The criteria should be explicitly identified in the tariff or standard service agreement, rather than being applied on a case-by-case basis.
- 3 (b) PGE should add "equal to 90 days of business volume" to the first sentence after "A letter of credit ...."

STATUS Being considered under S-53.

Sheet H-3 Default of ESS Service Agreement

- Staff believes the customer must be notified as soon as possible of the switch to emergency default service. A provision for notification should be added.

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-3 Information and Credit Updates

- See Staff's discussion under H-2 Credit Requirements and Security.

STATUS Being considered under S-53.

Sheet H-5 Electronic Data Transfer

- Staff believes the first paragraph should be changed so that the ESS is required to notify the Company only if it plans to modify its electronic data interchange systems if it will affect the form or content of the information. In the last sentence, "may" should be changed to "will."

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-6 Criteria for Recommending Decertification

- **(12) "...or should have known..." should be stricken from the tariff.**

STATUS RESOLVED.
DISCUSSION Suggestion is adopted.

Sheet H-8 Refusal of DASR

- 1. Staff believes this should be deleted. Acceptance of a DASR does not necessarily mean that a consumer will receive service. For example, if the consumer does not pay regulated charges, service can be disconnected.

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 2. Staff believes this should be deleted. The Company cannot hold a customer responsible for ESS obligations.

STATUS Being considered under S-53

Sheet H-8 Refusal of DASR (continued)

- 4. Staff recommends this be deleted.

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 5. Standard offer term obligations are in question.

STATUS RESOLVED.
DISCUSSION Staff's changes adopted.

Sheet H-8 Refusal of DASR (continued)

- 6. Staff recommends this replacement: "The ESS is not certified by the Commission."

STATUS Being considered under S-53.

Sheet H-8 Refusal of DASR (continued)

- 7. This should be deleted. The issue of full payment from the ESS for charges assessed to the ESS should be addressed in disconnection of an ESS within the tariff or service agreement.

STATUS Being considered under S-53.

Sheet H-9 Return of Consumer Deposits

- Staff suggests that the last sentence be modified so that it is clear that the Company is holding a deposit for regulated services only.

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Sheet H-10 Company Billings to the ESS

- Remove requirement for electronic payment, unless there is a reciprocal agreement between the Company and the ESS. Change due and payable period from five to fifteen days in accordance with OAR 860-021-0125.

STATUS RESOLVED.
DISCUSSION Changed to 15 days.

Sheet H-12 Company Scheduling Responsibilities
B. Major Outage Procedures

- Should add statement that Company intends to negotiate reductions in energy scheduling in a nondiscriminatory fashion.

STATUS RESOLVED.
DISCUSSION Staff's alternate wording is adopted:

> "The Company may require an ESS to reduce its Electricity Schedule in the event of a major loss of load due to a major outage consistent with the Company's resources."

Sheet H-16 Dispute Resolution

- The dispute resolution process should be consistent for all ESSs, not a function of the individually negotiated terms and conditions of a service agreement.

STATUS Being considered under S-53.

Rule I – Metering

Sheet I-2 Meter Verification Fee

The last sentence should be changed to reflect the current tariff. "...the Company will waive the Meter Verification fees..." rather than "may."

STATUS RESOLVED.
DISCUSSION Staff changes adopted.

Sheet I-3 Interval Metering

- 45 days is too long for a meter installation. In addition, the customer is prohibited from purchasing electricity from the ESS for that period.

STATUS RESOLVED.
DISCUSSION 45 days changed to 30 days.

^^

Part B

Rule K – Curtailment Plan

The Company withdraws its proposed changes to Rule K (Rule M in current E-16 tariff) with the exception of the correction to the MWh number.

STATUS RESOLVED.
DISCUSSION PGE withdraws its proposed changes to Rule K (Rule M in current E-16 tariff) with the exception of the correction to the MWh number.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	))))	STIPULATION WITH CITY OF PORTLAND AND LEAGUE OF OREGON CITIES

This Stipulation is entered into for the purpose of resolving specific issues identified by the City of Portland (City) and the League of Oregon Cities (League) in their Opening Testimony filed March 12, 2001. This Stipulation presents a full settlement of the detailed issues.

I. INTRODUCTION

On October 2, 2000, Portland General Electric Company (PGE) filed Advice No. 00-14 proposing certain increases in its base prices to its customers. The filing was based on a projected test year of 2002 and included tariffs changing rates paid by the City and members of the League. Advice No. 00-14 was suspended by the Commission at its October 20, 2000 Public Meeting, Order No. 00-669.

The Administrative Law Judge issued a Ruling on March 12, 2001, requiring, among other things, that the City and the League enter into settlement talks with PGE. A Settlement Conference, which was open to all parties, was held on April 23, 2001.

As a result of that settlement conference, the parties signing this Stipulation (Parties) have agreed to specific adjustments in PGE's requested tariff and rate proposals. The Parties submit this Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. GENERAL TERMS OF STIPULATION

1. The Parties to this Stipulation agree that PGE will adjust its proposed tariffs and rate proposals to reflect the agreements detailed in this Stipulation.

2. The Parties recommend that the Commission approve the various tariff, rule, and other adjustments described in this Stipulation.

3. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiations of this Stipulation shall not be admissible as evidence in this or any other proceeding.

4. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained in it.

5. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks changes in PGE's tariffs that depart from the terms of this Stipulation, the Parties to this Stipulation reserve the right to cross-examine witnesses and introduce evidence to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Parties to this Stipulation agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

6. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's order.

7. By entering into the Stipulation, no Party shall be considered to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. No Party shall be considered to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

8. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

III. SPECIFICALLY STIPULATED ADJUSTMENTS

For issues raised by the City and the League regarding PGE's proposed tariffs, rules, and rates, the Parties agree as follows:

9. With regard to Interconnection Standards, PGE publishes interconnection standards as part of its avoided cost filing based on the most current version of IEEE published standards. These standards apply whether or not a generating unit qualifies as a QF under State and Federal law, and whether or not a particular generating technology is identified in such laws. An interconnection at transmission level or one that affects the transmission system is also subject to the interconnection provisions of PGE's Open Access Transmission Tariff. PGE agrees that its interconnection standards will continue to reference applicable IEEE criteria, and that implementation of such standards will follow such IEEE criteria. If the City or another member of the League opts to pursue this course, PGE will work cooperatively with that municipality as necessary if the municipality chooses to apply for Exempt Wholesale Generator (EWG) or similar status at the Federal Energy Regulatory Commission.

10. With regard to Restoration of Utility Services, PGE will propose to rewrite part of Rule

C. In addition to other clarifying changes, the language in the currently proposed Part (7)(B)(2) will be rewritten to read: "The Company will first make the necessary repairs to transmission lines, substations, and distribution facilities that connect substations to critical load Consumers. Then the Company will continue to repair remaining transmission lines and substations after critical load Consumers have been restored to service." In addition, PGE agrees that it will continue to work cooperatively with municipalities and other public bodies to identify such critical load Consumers or accounts.

11. With regard to the Definition of a Large Non-Residential Consumer, the City and the League understand that PGE's definition will result in automatic reclassifications if the Consumer's usage varies, as determined by the classification standards approved by the Commission and reflected in PGE's Tariff.

12. With regard to Utility Relocation, PGE will propose to rewrite Part 6(b)(1) of Rule C to read: "The rearrangement can be identified to be a public works project. Examples of public works projects include but are not limited to public transit and a road widening financed by public funds."

13. With regard to the Allocation of Ancillary Service Costs, the City and the League accept the proposal in PGE Exhibit 2402.

14. With regard to Streetlights, the City, the League, and PGE agree as follows:

a. With regard to Luminaire/Circuit charges, PGE will withdraw the proposed revisions identified in its October, 2000 filing. Specifically, PGE will eliminate that component of the distribution charge for Schedule 91 service that recovers the marginal cost of service drops (identified as $1.139 million in PGE's October 2000 filing, Exhibit 1603 at 12). The existing Luminaire/Circuit charges contained in the Streetlight Agreement between PGE and the City dated May 1, 1997, will remain in place without modification and will apply to all Schedule 91 accounts. These charges are as follows:

Option A lights will be charged $0.64/month/light.

Option B lights will be charged $0.64/month/light.

Option C lights will be exempt from the circuit charge.

Option C circuits will be charged $0.64/month/circuit consistent with the Streetlight Agreement between PGE and the City dated May 1, 1997, and current Schedule 91.

b. With regard to Group Relamping, PGE will charge for group relamping services at an effective rate of 19% per year, (or 95% over five years), while continuing to provide services at a level of relamping 20% of all streetlights per year (or 100% over a five year period).

c. With regard to Power Doors Luminaires, PGE will use a maintenance level of 175 per year for power door usage, which translates into a frequency of 0.47%.

d. With regard to Pole Replacement, PGE will use a replacement frequency of 0.25% for calculation of all rates and charges.

15. The City and the League agree that, except for the issues specifically noted below, all other issues addressed in their direct testimony will not be pursued in this docket but may be addressed in other proceedings:

a. Allocation of the CTM credit among customer classes;

b. Minimum duration of ESS purchase of transmission service;

c. Portfolio Enrollment and Switching Fees (Schedule 300); and,

d. Aggregation of accounts through metering (Rule E).

This Stipulation is entered into by each Party on the date entered below.

Dated this 6 day of June, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

CITY OF PORTLAND

By: Benjamin Walters

LEAGUE OF OREGON CITIES

By: ______________________

STAFF OF THE OREGON PUBLIC UTILITY COMMISSION

By: ______________________

RECEIVED
JUL 3 0 2001
Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	STIPULATION CONCERNING POWER COSTS

This Stipulation is among Portland General Electric Company (PGE), Staff of the Public Utility Commission of Oregon (Staff), Fred Meyer Stores, the Industrial Customers of Northwest Utilities (ICNU), the Citizens' Utility Board (CUB) and any other parties signing this Stipulation (collectively, the Parties).

The Parties have been active participants in this docket. As part of that participation, PGE has filed proposed tariffs, and PGE and other Parties have filed testimony and exhibits addressing PGE's proposals to establish power costs in this docket, PGE's proposal to value its Long-Term Resources, PGE's proposal to value its Short-Term Resources, PGE's proposal to adjust rates to account for changes in power costs and Energy Revenues from those used to establish base rates in this docket, and proposals made by other Parties. Capitalized terms used in this Stipulation have the meanings ascribed to them in this Stipulation or the attached tariff schedules.

The Parties held settlement conferences on these matters on May 24, May 25, June 1, June 12, June 28, July 11, and July 16, 2001. As a result of those settlement discussions, the Parties have negotiated this Stipulation to accomplish the following:

(a) To establish the mechanism by which PGE will value its Long-Term and Short-Term Resources for the purpose of establishing rates for energy services in this docket;

(b) To account for the current hydro and market conditions affecting PGE. The Parties intend to reflect in Part C of Schedule 125 the difference in PGE's projected NVPC between such costs under expected hydro and market conditions (Expected NVPC), and such

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DOCKETED

costs under the normal hydro conditions ordinarily used to established rates (Base NVPC). In general, this adjustment accounts for the current low reservoir levels and their effect on future power costs, but assumes normal weather on a going-forward basis;

(c) To establish the mechanism by which PGE will account for variations in its actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish PGE's energy prices in this docket, and the method by which PGE and its customers will share in the benefits and burdens of such variations;

(d) To establish the method and date upon which PGE's Expected NVPC, Base NVPC and Base Energy Revenues will be calculated; and

(e) To establish a Shopping Incentive for large non-residential customers who use less than 1000 kWa.

The Parties agree to and request that the Commission adopt orders in this docket as follows:

1. PGE's Long-Term Resources and Short-Term Resources shall be valued under the mechanism described in Schedule 125. The Commission shall adopt Schedule 125 (attached to this Stipulation as Exhibit A) in its entirety for purposes of this docket.

2. The effect of adverse hydro conditions on PGE's projected NVPC shall be taken into account under Part C of Schedule 125. The Part C costs and revenues shall be a part of actual NVPC and actual Energy Revenues under Schedule 127. The Parties recognize that Part C expires December 31, 2002. The Part C adjustment shall be based on reduced hydro generation from that available in the water year used to develop normalized power costs of 300,000 MWh over the period October 2001 through December 2002 which shall be allocated to months based on Exhibit E attached to this Stipulation.

3. Schedule 127 shall be used to calculate the variances in PGE's actual NVPC from Base NVPC and actual Energy Revenues from Base Energy Revenues used to establish rates in this docket for the period ending December 31, 2002, and for the purpose of sharing the benefits

and burdens of such variances between PGE and its customers. Schedule 127 shall not apply to Schedule 83 customers unless they elect the Annual Fixed Price Option. The Commission shall adopt Schedule 127 (attached to this Stipulation as Exhibit B) in its entirety for purposes of this docket. The Parties recognize that PGE will collect or refund through the Power Cost Adjustment Rate only the Adjustment Amount for the period October 2001 through December 2002.

4. The Parties agree that the mechanisms provided in Schedules 125 and 127 fairly balance the interests of customers and PGE with respect to variations in PGE's actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish rates in this proceeding and the effect that such variations will have upon the earnings of PGE for the period ending December 31, 2002. Accordingly, the Parties agree and request that:

(a) To the extent that a deferral of revenues or costs is necessary to implement the mechanism provided in Schedule 127, the Commission, at the request of PGE or any other Party, shall defer the variation in actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues used to establish rates in this docket. The Parties will not oppose any such deferral application and will support any such deferral consistent with this stipulation;

(b) The Parties shall request that the Commission allow PGE to amortize into rates, both before and after December 31, 2002, that portion of the variation in actual NVPC and actual Energy Revenues from the Base NVPC and Base Energy Revenues that is the Adjustment Amount produced by the application of Schedule 127, notwithstanding the results of any earnings review that the Commission may be required to conduct under ORS 757.259. In any such earnings review, the Parties shall support full recovery or refund of the Adjustment Amount without any adjustment, except those adjustments specifically allowed in this Stipulation.

(c) The Parties agree to support recovery or refund of the Adjustment Amount in any proceeding to amortize such Adjustment Amount into rates or to implement Schedule 127.

(d) Any balance in the Power Cost Adjustment Account under Schedule 127 will begin to accrue interest on and after January 1, 2003. In addition, there shall be added to the balance at January 1, 2003, an amount equal to the product obtained by multiplying one-half of the balance at December 31, 2002, by an interest rate equal to 15 months of PGE's last approved Cost of Capital.

5. (a) PGE will estimate the difference between what the Boise Cascade St. Helens Plant (Boise) is projected to pay under actual rates for the three-month period October 2001 through December 2001 and what Boise is projected to pay on standard rates. This difference will be credited to all customers with interest at PGE's cost of capital as a separate kWh credit over the 15-month period October 1, 2001, through December 31, 2002, under the Special Contract Adjustment Schedule 131 (attached to this Stipulation as Exhibit C). The Commission shall adopt Schedule 131 in its entirety for purposes of this docket. This credit will be included as an offset to actual Energy Revenues under Schedule 127.

(b) For purposes of determining Base Energy Revenues for Schedule 127, PGE will assume that Boise is on standard rates for the entire period of October 2001 through December 2002.

(c) For purposes of determining actual Energy Revenues for Schedule 127 for Boise for the October 2001 through December 2001 period, the following shall be summed:

- Energy Revenues as if Boise was billed under standard rates, and
- The difference between actual bills to Boise and bills calculated as if Boise was under standard rates.

6. PGE shall establish its Expected NVPC and Base NVPC for purposes of this docket by running its Monet Power Cost Model on or about September 11, 2001, or such later date as may be determined by the Commission.

7. PGE shall remove $100,000 in administrative and general costs from its revenue requirement used to set rates to reflect costs included in its revenue requirement related to its

demand exchange program. This adjustment reflects the uncertainty that demand exchanges will occur under Schedule 86, PGE's demand exchange tariff. For any month beginning October 2001 and ending December 2002 in which PGE and a customer participate in a demand exchange under Schedule 86, PGE shall add $8,333 to its actual NVPC for purposes of Schedule 127. This will allow PGE to recognize costs of the demand exchange when and if demand exchanges occur.

8. The Parties recognize that PGE's power cost situation is unique, given its exposure to the wholesale energy market in order to serve its retail customers and the current uncertainty and volatility in the wholesale energy market. Accordingly, this Stipulation represents a settlement in compromise of the positions of the Parties with respect to the matters contemplated by this Stipulation in light of the unique circumstances of PGE and the wholesale market energy market. This Stipulation may not be cited or used as precedent by any party or person in any proceeding except for those proceedings implementing the terms of this Stipulation.

9. For the purpose of allocating total fixed and variable power costs among PGE's customer classes and calculating Parts A and B of Schedule 125, the Parties agree that PGE shall allocate its Long-Term and Short-Term Resources and market purchases as follows:

(a) First, PGE shall allocate its Long-Term Resources (including a credit for any PGE provided ancillary services) among customer classes in proportion to their respective percentages of PGE's expected retail load (adjusted to remove the effects of any demand exchanges) for the 12 months ended September 30, 2001;

(b) Second, Subscription Power from the Bonneville Power Administration shall be allocated to the residential and small-farm customers of PGE eligible to participate in BPA's Residential Exchange Program;

(c) Third, PGE shall allocate its Short-Term Resources among all customer classes until each customer class has been allocated a sufficient amount of Long-Term

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Portland, Oregon 97204

Resources, BPA Subscription Power and Short-Term Resources to cover the expected load of that class; except that, to the extent that the resources available under paragraphs (a), (b) and this paragraph (c) are insufficient to serve all expected customer load, PGE shall allocate such shortfall among the customer classes in proportion to their respective percentages of expected shortfall. Any shortfall of resources for any customer class shall be filled by market purchases; and

(d) Any excess of Short-Term Resources over expected load shall be allocated among all customer classes in proportion to their respective percentages of expected load.

(e) If, after applying (a) and (b) above, the residential class has sufficient resources to meet expected load, Short-Term Resources shall be allocated to the other classes on a pro rata basis until they reach the same relative position as the residential class. Any remaining Short-Term Resources shall then be allocated in accordance with (d) above.

10. The Parties agree to support Schedule 130, Shopping Incentive for large non-residential customers below 1MWa described in Exhibit D attached to this Stipulation. The Commission shall adopt Schedule 130 in its entirety for purposes of this docket.

11. ICNU and Fred Meyer Stores will not argue in this docket that the residential and small farm customer classes should be assigned additional costs of load shaping and load following related to BPA Subscription Power allocated to the residential and small farm customer classes.

12. The Parties agree that, so long as PGE does not file a general rate case for rates to become effective prior to December 31, 2002, they will not advocate or support, for rates effective prior to January 1, 2003, an adjustment to PGE's estimated or projected NVPC similar to the adjustment which the Staff sought to introduce into evidence in the proposed surrebuttal testimony of Staff Witness Bill Wordley in this docket, which testimony was disallowed by the Administrative Law Judge. The Parties also agree that, except as otherwise provided in this Stipulation, they are not bound by the terms of this Stipulation in any future general rate

proceeding initiated by or against PGE.

13. The Parties agree and support the conclusion that Paragraphs 9 and 11 of this Stipulation and Schedule 125 are designed to ensure that 100% of any federal system benefits provided by BPA to PGE, on behalf of its residential and small farm consumers, will flow through to such consumers.

14. The Parties agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order rejecting this Stipulation or adding such material condition.

15. Upon written request, PGE shall make available to any Party to this Stipulation, within 10 business days, all data and workpapers that support the calculations required under the Schedules attached hereto.

16. The Parties shall file this Stipulation with the Commission.

17. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute only one agreement.

18. The parties to any dispute concerning this Stipulation agree to confer and make a good faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

19. The parties agree that the combination of PGE's Standard Offer tariff schedules and the Schedule 125 Resource Valuation Mechanism provides cost-of-service options to customers eligible to receive service under such schedules.

20. The parties acknowledge that legislation has delayed the date for direct access under SB 1149 and that Administrative Law Judge Grant has issued a Post-Hearing Conference

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this 27th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

FRED MEYER STORES

By: ______________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

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Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

- DATED this _____ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ____________________	By: ____________________
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: Michael L. Kurtz Michael L. Kurtz, Esq.	By: ____________________

ORDER NO. 01-777

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _______ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
By: ______________________	By: ______________________
FRED MEYER STORES	INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES
By: ______________________	By: ______________________

CITIZENS' UTILITY BOARD

By: Robert T. Jenks

Robert T. Jenks

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ORDER NO. 01-777

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this 27th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: David B. Hatton

FRED MEYER STORES

By: ______________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: ______________________

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503-221-1440

ORDER NO. 01-777

Memorandum on July 17, 2001. The parties acknowledge that certain dates in this Stipulation and accompanying tariff sheets may need to be changed as a result. In addition, the Revenue Valuation Mechanism will require modification to reflect a mid-period implementation of direct access. The parties agree to confer and make a good faith effort to accomplish these changes while retaining the spirit and intent of this Stipulation.

DATED this _____ day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

FRED MEYER STORES

By: ______________________

INDUSTRIAL CUSTOMERS OF THE NORTHWEST UTILITIES

By: S Bradley Van Cleve

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Portland, Oregon 97204

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SCHEDULE 125
RESOURCE VALUATION MECHANISM

PURPOSE

To recognize the difference between the market price and costs of power on an annual basis.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service calculated under all rate schedules specified herein, including contracts, except where explicitly exempted.

PART A – LONG-TERM RESOURCES

Part A shall reflect the difference between the projected total cost of power (including a credit for any Company provided Ancillary Services) from long-term resources owned or controlled by the Company including associated transmission by others and the market price of an equivalent amount of power. The market price shall be based on the forward price curve that the Company uses to set the Annual Fixed Price Option. Long-term resources are all generating plants and power purchases with an initial term longer than five years, except BPA Subscription Power.

PART B – SHORT-TERM RESOURCES

Part B shall reflect the difference between the projected cost of power from short-term resources including associated transmission by others and the market price of an equivalent amount of power. The market price shall be based on the forward price curve that the Company uses to set the Annual Fixed Price Option. Short-term resources are all resources that do not meet the definition of long-term resources except BPA Subscription Power.

EXHIBIT A
PAGE 1 OF 5

Portland General Electric Company
P.U.C. Oregon No. E-17 Original Sheet No. 125-2

SCHEDULE 125 (Continued)

PART B – SHORT-TERM RESOURCES (Continued)

A Large Nonresidential Consumer may provide Preliminary Direct Access Notice 12 months in advance of the next Part B adjustment informing the Company that it does not want the Company to plan to serve its load. In such case, the Consumer will be exempt from the Part B adjustment beginning with the next Part B adjustment and continuing until it gives 12-month notice to return to Part B eligible status. The first such notice shall be for the 12-month period beginning January 1, 2003.

PART C – ADVERSE HYDRO CONDITIONS

Part C shall reflect the projected difference in Net Variable Power Costs (as defined in Schedule 127) between expected and normal hydro conditions, on or about August 1, 2001, for the period of October 2001 through December 2002 of $xxxx.

ADJUSTMENT RATE

The Adjustment Rates, applicable for service on and after the effective date of this schedule, shall be:

		Adjustment Rate	
Schedule	Part A	Part B	Part C
7	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
15	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
32	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
38	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
48	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
49	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
82 Small Nonresidential	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Large Nonresidential			
Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh

EXHIBIT A
PAGE 2 OF 5

SCHEDULE 125 (Continued)

Adjustment Rate (continued)

Schedule		Adjustment Rate Part A	Part B	Part C
83	Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	-Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
91		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
92		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
93		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
97		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
99	(where applicable)	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
515		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
532		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
549		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
583	Secondary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Primary	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
	Subtransmission	_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
591		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh
592		_____¢ per kWh	_____¢ per kWh	_____¢ per kWh

ANNUAL ADJUSTMENT REVISIONS

The adjustment rates for Part A and Part B shall be filed on November 15th (or the next business day if the 15th is a weekend or holiday) to be effective for service on and after January 1st of the next year. For the first year of implementation, the service year will last 15 months, beginning on October 1, 2001 and ending on December 31, 2002, causing the filing to be made on or by August 15, 2001. Part C will be set to zero effective January 1, 2003.

EXHIBIT A
PAGE 3 OF 5

SCHEDULE 125 (Continued)

Part A shall be based on the Company's most recent rate order, adjusted for the service year. Part B shall be based on the Company's purchase obligations for the next calendar year entered into on or before September 15 of the filing year (August 1, 2001 for the October 2001 through December 2002 period). The Part A and Part B revisions shall reflect updates to the following:

- Applicable resources
- Company market power purchases
- Costs of fuel and transportation
- Hydro operating constraints imposed by governmental agencies
- Market power prices (including transmission to the Company)
- Transmission and ancillary services
- Retail load forecast

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

If the net difference of load between:

1. Consumers who provided Preliminary Direct Access Notice and subsequently selected the Annual Fixed Price Option of Schedule 83 (Category 1 Consumers) and

2. Consumers who did not provide Preliminary Direct Access Notice and did not select the Annual Fixed Price Option of Schedule 83 (Category 2 Consumers)

is greater than 25 aMW, the Company may adjust the Part A or Part B adjustment for large nonresidential consumers to account for such difference in load.

If the load of Category 1 Consumers exceeds that of Category 2 Consumers, the Company will adjust the Part A adjustment for large nonresidential consumers to reflect the deviation between the market prices used to set the Part A adjustment and actual market prices experienced in acquiring power to meet the difference in load.

If the load of Category 2 Consumers exceeds that of Category 1 Consumers, the Company will adjust the Part B adjustment for large nonresidential consumers to reflect the deviation between the market prices used to set the Part B adjustment and actual market prices experienced in disposing of power to meet the difference in load.

EXHIBIT A
PAGE 4 OF 1

SCHEDULE 125 (Concluded)

RESOURCE CHANGES

The Part A Adjustment Rates shall be modified at any time to reflect changes in the Company's resources resulting from the implementation of all or a portion of a Commission-approved Resource Plan, any other Commission-approved resource change, or the catastrophic failure of a resource. In the case of a catastrophic failure, Part A shall be adjusted by replacing the variable costs of the resource with the cost of replacement power.

EXHIBIT A
PAGE 5 OF 5

SCHEDULE 127
POWER COST ADJUSTMENT

PURPOSE

To recognize in rates differences in actual net power costs from those assumed in base energy rates.

APPLICABLE

To all bills for electric service calculated under Schedules 7, 15, 32, 38, 48, 49, 83 (Annual Fixed Price Option only), 91, 92, 93, 97, and contracts, except for BPA power delivered for service to residential consumers and also where explicitly exempted.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are defined as the total power cost 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. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude the Regional Power Act Exchange Credit, the cost of BPA Subscription Power, and payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude the results of any transaction arising from the Company's merchant trading business; that is, transactions relating to the acquisition and disposition of wholesale power, hedges, options and other financial instruments solely for the Company's own account and at its own risk.
- Include as a cost (or exclude from revenue) all losses (except those related to merchant trading) that the Company incurs, or is reasonably expected to incur, as a result of any non-retail customer failing to pay the Company for the sale of power during the period in which this schedule is in effect.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.

BASE NVPC

The Base NVPC are defined as the NVPC used to develop existing rate schedules including Parts A and B of Schedule 125. The current Base NVPC are:

$x,xxx October 2001 through December 2002

ENERGY REVENUES

Energy Revenues are defined as the total revenues from Energy Charges of tariff Schedules 7 through 99, plus all charges or credits under Schedule 125, Resource Valuation Mechanism and Schedule 131, Special Contract Adjustment. To the extent that the Energy Charges of a particular rate schedule contain elements not directly related to the cost of power (e.g. system usage charges), such elements shall be excluded from Energy Revenues.

BASE ENERGY REVENUES

The Base Energy Revenues are defined as the Energy Revenues, excluding Part C of Schedule 125 and Schedule 131, forecast from existing tariffs and the load forecast used to develop the Base NVPC. The current Base Energy Revenues are:$x,xxx October 2001 through December 2002

POWER COST VARIANCE

The Power Cost Variance (PCV) is the difference between actual and Base NVPC less the difference between actual and Base Energy Revenues for the period October 2001 through December 2002. The Adjustment Amount shall be determined according to the following based on the level of the PCV:

Power Cost Variance	Adjustment Amount
-$28.0 million to $28.0 million	zero
$28.0 million to $38.0 million	50% of PCV between $28.0 million and $38.0 million
$38.0 million to $100 million	$5.0 million plus 85% of PCV between $38.0 million and $100 million
$100 million to $200 million	$57.7 million plus 90% of PCV between $100 million and $200 million
over $200 million	$147.7 million plus 95% of PCV in excess of $200 million
-$28.0 million to -$38.0 million	50% of PCV between -$28.0 million and -$38.0 million
-$38.0 million to -$100 million	-$5.0 million plus 85% of PCV between -$38.0 million and -$100 million
-$100 million to -$200 million	-$57.7 million plus 90% of PCV between -$100 million and -$200 million
less than -$200 million	-$147.7 million plus 95% of PCV less than -$200 million

POWER COST ADJUSTMENT ACCOUNT

The Company will maintain a Power Cost Adjustment Account to record overcollections and undercollections. The Account will contain the difference between the actual Adjustment Amount and revenues collected/credited under this schedule. Interest will accrue on the account at the Company's authorized rate of return beginning January 1, 2003. In addition, there shall be an amount added to the balance on January 1, 2003 equal to the product obtained by multiplying ½ the balance on December 31, 2002 by an interest rate equal to 15 months of the Company's authorized rate of return.

POWER COST ADJUSTMENT RATE

The Power Cost Adjustment Rate shall be revised on a quarterly basis. It shall be determined as an amount per kilowatt-hour, carried to the nearest 0.001 cents per kilowatt-hour, necessary to bring the projected balance of the Power Cost Adjustment Account (including the projected Adjustment Amount for the period October 2001 through December 2002) to zero at the end of 2002. Each quarter the Company will forecast the PCV and resulting Adjustment Amount for the October 2001 through December 2002 period based on actual results to date and a forecast of the remaining months. This amount less collections to date under this schedule will be the projected balance of the Power Cost Adjustment Account. The new Power Cost Adjustment Rate will be equal to this projected balance divided by the load forecast minus the amount of power delivered by BPA to PGE residential consumers for the remaining period.

If this tariff is terminated for any reason prior to December 31, 2002, the Commission shall determine the Adjustment Amount on a prorated basis consistent with principles of this schedule. In such case, or when this tariff otherwise terminates, any balance in the Power Cost Adjustment Account shall be amortized to rates over a period to be determined by the Commission.

Each Consumer's billing shall state the dollar amount of this adjustment.

TIME AND MANNER OF FILING

Forty-five days prior to the effective date of the revised Power Cost Adjustment Rate, the Company shall submit to the Commission the following information:

(1) A letter of transmittal that summarizes the proposed changes under the schedule.
(2) A revised rate schedule page that reflects the new quarterly Power Cost Adjustment Rate.
(3) Working papers supporting the calculation of the revised Power Cost Adjustment Rate.

ADJUSTMENT RATE

The Power Cost Adjustment Rate, applicable for service on and after the effective date of this rate schedule shall be:

Schedule		Adjustment Rate
7		0.000 ¢ per kWh
15		0.000 ¢ per kWh
32		0.000 ¢ per kWh
38		0.000 ¢ per kWh
48		0.000 ¢ per kWh
49		0.000 ¢ per kWh
83*	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
	Subtransmission	0.000 ¢ per kWh
91		0.000 ¢ per kWh
92		0.000 ¢ per kWh
93		0.000 ¢ per kWh
97		0.000 ¢ per kWh
99	(where applicable)	0.000 ¢ per kWh

* **Annual Fixed Price Option only**

SCHEDULE 131
SPECIAL CONTRACT ADJUSTMENT

PURPOSE

To refund to Consumers $___ million of special contract collections.

APPLICABLE

To all bills for electric service.

ADJUSTMENT RATE

- ____ cents per kwh

TERM

This adjustment shall terminate on December 31, 2002.

EXHIBIT C
PAGE 1 OF 1

ORDER NO. 01-777

SCHEDULE 130
SHOPPING INCENTIVE RIDER

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Consumers using less than 1 MWa at a site in the prior calendar year (after adjusting to remove the effects of any demand exchanges).

SHOPPING INCENTIVE (PART A)

Consumers for whom this rider is applicable and who elect to receive service under Schedule 583 will receive a Shopping Incentive credit of 0.500¢ per kWh. The Shopping Incentive will be limited to the first ten percent (10%) of Qualifying Consumer Load, measured on a kWa basis that is served under Schedule 583, where Qualifying Consumer Load is equal to the estimated total load of Large Nonresidential Consumers using less than 1 MWa at a site in the prior calendar year (after adjusting to remove the effects of any demand exchanges). No Consumer, business, or group of affiliated businesses with common or similar ownership shall receive Shopping Incentives for single or multiple locations that represent more than 2.5% of Qualifying Consumer Load.

SHOPPING INCENTIVE RECOVERY ADJUSTMENT (PART B)

The Shopping Incentive Recovery Adjustment shall be applied to all applicable Large Nonresidential Consumers.

At least 30 days prior to January 1 of each year (October 1, 2001 for the period October 2001 through December 2002) the Company will file an adjustment rate to recover credits provided under this Schedule. The rate shall be set to recover the estimated credits to be given during the year plus any over- or under-collections during prior periods.

Effective October 1, 2001 the Shopping Incentive Recovery Adjustment shall be

_______ cents per kWh

EXHIBIT D
PAGE 1 OF 2

SCHEDULE 130
SHOPPING INCENTIVE RIDER (Concluded)

TERM

Shopping Incentive credits under this rider will expire three years after direct access is first available under the provisions of section 2, chapter 865, Oregon Laws 1999.

The Shopping Incentive Recovery Adjustment shall expire four years after direct access is first available under the provisions of section 2, chapter 865, Oregon Laws 1999.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the Tariff of which this schedule is a part.

EXHIBIT I
PAGE 20

Exhibit E

Allocation of Hydro Adjustment to Months

		Mwh Adjustment
Oct	2001	-65,780
Nov	2001	-42,465
Dec	2001	-44,999
Jan	2002	-97,437
Feb	2002	-102,967
Mar	2002	-83,851
Apr	2002	24,525
May	2002	33,976
Jun	2002	-11,485
Jul	2002	9,707
Aug	2002	-46,502
Sept	2002	24,819
Oct	2002	8,090
Nov	2002	32,132
Dec	2002	62,236
Total		-300,000

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MICHAEL M. MORGAN

(503) 802-2007
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mike@tonkon.com

RECEIVED AUG 2001 OPUC SALEM

August 20, 2001

Janice Fulker, Administrator
Regulatory and Technical Division
Oregon Public Utility Commission
550 Capitol St. NE, Suite 215
Salem, OR 97301-2551

Re: UE 115 Monet Run

Dear Ms. Fulker:

Pursuant to Judge Grant's Post-Hearing Conference Memorandum dated July 17, 2001, enclosed is PGE's "final draft" Monet Run. This was delayed due to settlement discussions among the Parties. Staff, ICNU, CUB and PGE held settlement discussions on August 13, 15, 16 and 17, 2001, concerning the June 1 and July 27, 2001, Monet Runs and the corrections and updates to the June 1 Monet Run that would be included in the "final draft" Monet Run and the final Monet Run used to establish final pricing in this docket in September 2001.

Attached to this letter is a list of 16 corrections and updates that were included in PGE's July 27, 2001, Monet Run that were not included in the June 1, 2001, Monet Run distributed to the parties. This list was attachment 3 to PGE's comments filed August 9, 2001, on the July 27, 2001, Monet Run. Staff and PGE have agreed that the "final draft" Monet Run and the September 2001 Monet Run will be based on the inputs to the June 1 Monet Run with the adjustments contained in items 2, 10-14 and 16 on the attached list of corrections and updates, and will not include the other items on the attached list. In addition, PGE will remove from these runs a merchant trading transaction that was inadvertently included in the June 1, 2001, Monet Run. CUB and ICNU will not oppose the use of the June 1, 2001, Monet Run with the inclusion of these corrections and updates. Staff and PGE have agreed that the September Monet Run will be based on the "final draft" Monet Run updating only the most recent gas and electric forward curves. CUB and ICNU will not oppose this agreement.

At the request of ICNU, the date for final pricing in this docket will be September 12, not September 11.

PGE withdraws its motion to reopen the record filed August 9, 2001.

Very truly yours,

Michael M. Morgan

MMM/pcs
Enclosure
cc: UE 115 Service List
Mr. Maury Galbraith

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Attachment 3 to
PGE's August 9 Comments

On Thursday, August 2nd, PGE met with Staff and discussed the following corrections and updates to the June 1st Monet model run that were incorporated into the July 27th Monet model run:

1. Updating the cost of coal for Boardman, including transportation, based on the most recent information available. This update was incorporated in the June 1, 2001 Monet run.
2. Updating Coyote fuel costs for the cost of gas to operate the auxiliary boiler to produce steam, consistent with the 2nd Stipulation with Staff on revenue requirement issues and Commission Order 01-489.
3. Updating the Wells Settlement contract output based on hydro output.
4. Update contract cost for the Portland Hydro Project based on most recent available information.
5. Utilize 48-month average for Thermal Availability and Thermal Maintenance based on historical data through 12/31/00 (the most recent data available).
6. Update firm Gas Transportation for most recent tariff information available.
7. Update variable Gas Transportation costs to include losses due to compressor usage.
8. Update cost of Ogden/Mt. Tabor contract based on most recent available information.
9. Update cost of Lake Oswego Street Lighting contract based on most recent available information.
10. Incorporate BPA subscription power at expected contract cost (28.3 mills) rather than forecast market.
11. Correct the load forecast for two months to match forecast provided in PGE's Rebuttal Testimony (STF01AE).
12. Utilize most recent forward curves for market gas/electricity.
13. Utilize most recent contracts for gas/electricity.
14. Incorporate Staff/PGE Stipulation on expected Hydro output.
15. Expected output of Vancycle Ridge contract updated to 10 aMW using most recent available information.
16. Correct capacity of Chelan Exchange In contract from 50 MW to 25 MW in October 2002.

ORDER NO. 01-777

RECEIVED

AUG 7 2001

Public Utility Commission of Oregon
Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of PGE's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149	))))	SUPPLEMENTAL REVENUE STIPULATION REGARDING FRANCHISE FEES AND STEAM SALES

This stipulation (Supplemental Revenue Stipulation) is entered into for the purpose of resolving Portland General Electric Company's (PGE) requested revenue requirements related to franchise fees and steam sales in this docket. Specifically, this Supplemental Revenue Stipulation represents a supplement to the stipulation entered into by PGE, the Staff of the Oregon Public Utility Commission (Staff), and Fred Meyer Stores on March 7, 2001.

I. INTRODUCTION

On October 2, 2000, PGE filed Advice No. 00-14 to produce a $324 million increase in its base prices to its customers. The filing was based on a projected test year of 2002.

Not addressed in the March 7, 2001 Stipulation were revenue requirements adjustments regarding the treatment of franchise fees to cities in PGE's service territory and steam sales at PGE's Coyote Springs generating plant. The parties signing this Supplemental Revenue Stipulation (Parties) agree to modify PGE's currently stipulated revenue requirement as stated below. The Parties submit this Supplemental Revenue Stipulation to the Commission and request that the Commission approve the settlement as presented.

II. TERMS OF STIPULATION

1. The Parties to this Supplemental Revenue Stipulation agree that PGE will adjust its revenue requirement request to reflect the adjustments listed in Attachment A to this Supplemental Revenue Stipulation. The parties agree to calculate the revenue requirement impact of the adjustments listed in Attachment A consistent with the final Commission approved Cost of Capital in this case.

2. The Parties recommend that the Commission approve the various rate base, expense, and other revenue adjustments described in Attachment A.

3. The Parties agree to adjust "Revenue Sensitive Costs" to incorporate a 2.26% Franchise Fee, and include a calculation for Franchise Fee Costs at 2.26% in "Franchise and Other Tax" in all revenue requirement calculations (see Attachment B). The Parties agree that

APPENDIX E
PAGE 1 OF 12

PGE will use the adjusted "Revenue Sensitive Costs" for calculating rate adjustments subsequent to this docket until the Commission issues an order changing the Franchise Fee rate.

4. The Parties agree that this Supplemental Revenue Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiations of this Stipulation shall not be admissible as evidence in this or any other proceeding.

5. This Supplemental Revenue Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-014-0085. The Parties agree to support this Supplemental Revenue Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Supplemental Revenue Stipulation at the hearing, if any, and recommend that the Commission issue an order adopting the settlements contained herein.

6. If this Supplemental Revenue Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Supplemental Revenue Stipulation, the Parties to this Supplemental Revenue Stipulation reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Supplemental Revenue Stipulation. Notwithstanding this reservation of rights, the Parties to this Supplemental Revenue Stipulation agree that they will continue to support the Commission's adoption of the terms of this Supplemental Revenue Stipulation.

7. The Parties have negotiated this Supplemental Revenue Stipulation as an integrated document. If the Commission rejects all or any material portion of this Supplemental Revenue Stipulation or imposes additional material conditions in approving this Supplemental Revenue Stipulation, any Party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's order.

8. By entering into this Supplemental Revenue Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principals, methods or theories employed by any other party in arriving at the terms of this Supplemental Revenue Stipulation. No Party shall be deemed to have agreed that any provision of this Supplemental Revenue Stipulation is appropriate for resolving issues in any other proceeding.

9. This Supplemental Revenue Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Supplemental Revenue Stipulation is entered into by each Party on the date entered below.

Dated this _____ day of ____________________, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

_______________________ 8/6/01
By: J. Jeffrey Dudley

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

____
By: _______________________

PACIFICORP

____
By: _______________________

FRED MEYER STORES

____
By: _______________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

____
By: _______________________

[OTHER]

____
By: _______________________

CITIZENS' UTILITY BOARD

____
By: _______________________

ORDER NO. 01-777

This Supplemental Revenue Stipulation is entered into by each Party on the date entered below.

Dated this 26th day of July, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ____________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ____________________

PACIFICORP

By: ____________________

FRED MEYER STORES

By: ____________________

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

David B. Hatton

By: David B. Hatton
Of Attorneys for Staff

[OTHER]

By: ____________________

CITIZENS' UTILITY BOARD

By: ____________________

APPENDIX E
PAGE 4 OF 12

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ORDER NO. 01-777

This Supplemental Revenue Stipulation is entered into by each Party on the date entered below.

Dated this _____ day of ___________________, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

By: ______________________

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

By: ______________________

PACIFICORP

By: ______________________

FRED MEYER STORES

Michael L. Kurtz
By: Michael L. Kurtz

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________

[OTHER]

By: ______________________

CITIZENS' UTILITY BOARD

By: ______________________

APPENDIX E
PAGE 5 OF 12

Attachment "A"

The Stipulated Adjustments are described below and summarized in Attachment A1. The revenue requirement impact of each of the adjustments (including revenue sensitive costs) will be determined once the Cost of Capital issue (S-0) is determined.

S-55 Franchise Fees: Increase Franchise and Other Tax by $794,000 to reflect a revenue-based calculation on 2002 sales to customers. Adjust "Revenue Sensitive Costs" to incorporate a 2.26% Franchise Fee, and include a calculation for Franchise Fee Costs at 2.26% in "Franchise and Other Tax" in all revenue requirement calculations.

S-56 Steam Sales: For the UE-115 test year, PGE will include all costs and revenues expected for steam sales. Decrease Other Revenue by $306,000 to remove imputed steam sales as originally filed in UE-115. Increase Other Revenue by $1,143,000 to reflect estimated steam sales revenue for 2002. Increase the heat rate in the "Monet" power cost model to reflect expected steam sales for each applicable month. If steam sales are expected to be supplied from the auxiliary boiler, increase energy output from Coyote Springs 1 and include cost of increased gas usage from the auxiliary boiler.

Attachment A1

Other Revenue, Operating Costs, Rate Base

Financial Summary Reflecting Stipulated Positions — **Attachment A1**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	FERC Wholesale Fee (S-1)	Montana Production Tax (S-2)	Colstrip O & M (S-3)	Transmission O & M (S-4)	FERC Hydro Fee (S-5)	Income Tax Apportion (S-6)	Severance Program (S-7)	OAL Sale (S-8)	PGH Billings (S-9)	Retail Unbundling Allocation (S-10)
Retail Revenues										
Other Revenue										
Production O&M			1,043		(14)			(83)		
Transmission O&M			25					(28)		
Distribution O&M								(223)		
Purchased Power										
Generation										
Wheeling										
A&G	(372)				714			108	(436)	303
Customer Service										435
Depr. & Amort.							66	100		
Other Taxes		450								
Rate Base (excluding working cash)								(439)		

Revenue Requirement Category	Beaver Turbine (S-11)	Other Revenue (S-12)	State Tax Credit (S-13)	Remove SERP Rate Base & MDCP Expense (S-14)	Remove Trojan (S-15)	Remove Nell (S-16)	Remove Other Debits & Credits (S-17)	Solar For Schools (S-18)	Salmon Springs Reclassification (S-19)	Green Power Purchase (S-20)
Retail Revenues										
Other Revenue							(589)		183	
Production O&M						2,400				
Transmission O&M										
Distribution O&M										
Purchased Power										(420)
Generation										
Wheeling										
A&G				(4,645)		1,418				
Customer Service								(55)		
Depr. & Amort.	182				(16,584)		(939)			
Other Taxes	14									
Rate Base (excluding working cash)	2,789			(2,122)	(102,904)		181			

ORDER NO. 01-777

APPENDIX E
PAGE 8 OF 11

07/19/2001 4:48 PM

Financial Summary Reflecting Stipulated Positions | **Attachment A1**

Excluding Revenue Sensitive Costs

Revenue Requirement Category	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	CRM (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)	Public Purpose Adjustment (S-28)	Remove Marketing & Sales Expense (S-29)	T&D O&M (S-30)
Retail Revenues										
Other Revenue				998						
Production O&M										
Transmission O&M										(1,505)
Distribution O&M										(990)
Purchased Power										
Generation										
Wheeling			129							
A&G								(149)		
Customer Service						(1,600)	(2,405)	(550)	(800)	
Depr. & Amort.										
Other Taxes										
Rate Base (excluding working cash)			96							

Revenue Requirement Category	Reduce A & G Accounts N44173 & N44174 (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)	Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)
Retail Revenues						1,075				
Other Revenue										
Production O&M										
Transmission O&M										
Distribution O&M										
Purchased Power										
Generation										
Wheeling										
A&G	(1,000)	(1,250)	(2,237)	(2,411)	(1,550)					
Customer Service				(2,411)						
Depr. & Amort.						(60)		(1,977)		
Other Taxes			(240)	(518)	(167)	(30)				
Rate Base (excluding working cash)			(602)	(1,046)	(336)	(2,000)	(3,681)	(4,942)		(22,832)

ORDER NO. 01-777

APPENDIX E
PAGE 9 OF 12

07/19/2001 4:48 PM

Financial Summary Reflecting Stipulated Positions			Attachment A1				
Excluding Revenue Sensitive Costs							
		Remove		SB 1149	CIS/IT		
	Income Tax Adjustments	Property Sales Gains	Depreciation Study Adj.	Implementation Costs	Disallowance Adjustments	Franchise Fee	Steam Sales Adjustment
Revenue Requirement Category	(S-41)	(S-42)	(S-43)	(S-44)	(S-45)	(S-55)	(S-56)
Retail Revenues							
Other Revenue							837
Production O&M							
Transmission O&M							
Distribution O&M							
Purchased Power							
Generation							
Wheeling							
A&G				416			
Customer Service				376			
Depr. & Amort.		477	(3,567)				
Other Taxes						794	
Rate Base (excluding working cash)			1,784	459			

ORDER NO. 01-777

Attachment B

Revenue Sensitive Costs

APPENDIX E
PAGE 11 OF 12

ORDER NO. 01-777

Revenue Sensitive Costs:	
Revenues	1.00000
Franchise Fees	0.02260
OPUC Fee	-
O&M Uncollectibles	0.00500
State Taxable Income	0.97240
State Tax @ 6.65%	0.06471
Federal Taxable Inc.	0.90769
Federal Tax @ 35%	0.31769
Total Income Taxes	0.38240
Total Rev. Sensitive Costs	0.41000
Utility Operating Income	0.59000
Net To Gross Factor	1.69492

ORDER NO. 01-777

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Administrative Hearings Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 115

In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149	STIPULATION CONCERNING RESIDENTIAL RATE DESIGN FOR SCHEDULE 7

This Stipulation is between Portland General Electric Company (PGE) and the Staff of the Public Utility Commission of Oregon (Staff). The parties have filed testimony on how the benefits and burdens of Subscription Power from the Bonneville Power Administration (BPA) should be flowed through to eligible customers, how the cash benefits BPA will pay to PGE under the Residential Exchange Settlement Agreement between them will be passed through to eligible customers, and how the Resource Valuation Mechanism in PGE's Schedule 125 should be applied to the residential and small farm classes of customers.

The parties held settlement conferences on June 26, 2001, July 10, 2001, July 18, 2001, July 23, 2001, and August 2, 2001. As a result of these settlement conferences, the parties have negotiated this Stipulation to resolve the matters described above. The parties agree to and request that the Commission adopt orders in this Docket as follows:

1. PGE shall value Subscription Power, for the 15 months beginning October 1, 2001 and ending December 31, 2002, and for each succeeding calendar year beginning with 2003, by comparing the cost of Subscription Power to the market value of that power. PGE will determine market value using the same market price on the same day that it establishes the market price for the residential energy charge. The difference between the value of the Subscription Power and the price of that power to PGE will be credited or charged to customers under Schedule 102. For

Tonkon Torp LLP
888 SW Fifth Avenue, Suite 1600
Portland, Oregon 97204
503-221-1440

APPENDIX F
PAGE 1 OF 4

DOCKETED

Residential customers, the credit or charge will apply only to the first 225 kWh of energy used each month. The credit or charge shall equal the difference in the market value of the Subscription Power and the price of the Subscription Power charged by BPA to PGE.

2. The cash BPA pays to PGE under the Residential Exchange Settlement Agreement will be credited to residential customers eligible to receive the cash on a per-kWh basis applied only to all kWh used by such customers in excess of 225 kWh per month.

3. PGE will apply the credit or charge produced by the Resource Valuation Mechanism in Schedule 125, including parts A, B and C of Schedule 125, on a per-kWh basis to all kWh of energy use of all of PGE's customers within each customer class.

4. If the credits and charges described above, and the market price for energy, produce proposed rates for residential customers under which the price differential between the first block of 225 kWh of energy use and the second block of energy use in excess of 225 kWh is less than 10 mills, then the charges and credits applied to each block shall be adjusted so that the price differential between the two blocks is 10 mills. If the proposed rates produce a price differential between the two blocks of more than 25 mills, then the charges and credits applied to each block shall be adjusted to produce a price differential between the two blocks of 25 mills. In each case, however, the benefits and burdens of Subscription Power shall be passed through fully and only to residential and small farm customers eligible to receive such Power.

5. If, subsequent to October 1, 2001, BPA modifies the amount of Subscription Power available to PGE, the size of the first rate block will be adjusted to reflect the approximate amount of Subscription Power available to each residential customer. If, subsequent to October 1, 2001, the rate for BPA Subscription Power is changed, PGE will file to adjust the rate for the first rate block to reflect the change in the BPA rate notwithstanding the provisions of paragraph 4 of this Stipulation.

6. If the average amount of Subscription Power available to each residential customer differs substantially from 225 kWh per customer per month, PGE will adjust the size of the first block of energy to approximate the amount of Subscription Power available to each residential customer.

7. PGE will maintain a balancing account to ensure that all of the benefits and burdens of Subscription Power and cash payments from BPA under the Residential Exchange Settlement Agreement are provided to or collected from eligible customers.

8. Schedule 7 shall include a customer or basic charge of $10 per customer per month.

9. This Stipulation represents a settlement in compromise of the positions of the parties with respect to the matters covered by this Stipulation. This Stipulation may not be cited or used as precedent in any proceeding except for those proceedings implementing the terms of this Stipulation.

10. The Parties agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order rejecting this Stipulation or adding such material condition.

11. The Parties shall file this Stipulation with the Commission.

12. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute only one agreement.

13. The parties to any dispute concerning this Stipulation agree to confer and make a good faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

Tonkon Torp LLP
888 SW Fifth Avenue, Suite 1600
Portland, Oregon 97204
503-221-1440

DATED this 10th day of August, 2001.

PORTLAND GENERAL ELECTRIC COMPANY

J. Jeffrey Dudley by DFW

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ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Issues Summary
UE 115 - Test Year Ending December 2002
($000)

Item	Issue	Revenue Requirement Effect 2002
	Revenue Requirement on the Company's Filed Results	$323,982
	Adjustments (Base Rates)	
S-0	Rate of Return (Long Term Debt and Preferred, see S-41 for interest effect)	($4,258)
S-00	Rate of Return (ROE @ 10.50%)	(16,476)
S-1	FERC Wholesale Fee	(374)
S-2	Montana Producers Tax	454
S-3	Colstrip O & M	1,078
S-4	Transmission O & M	0
S-5	FERC Hydro Fee	705
S-6	Income Tax Apportion	0
S-7	Trojan Severance Program	67
S-8	Oregon Analytical Lab Sale	(184)
S-9	PGH Billings	(439)
S-10	Retail Unbundling Corrections	745
S-11	Beaver Turbine	553
S-12	Other Revenues	0
S-13	State Tax Credit	0
S-14	Remove SERP Rate Base and MDCP O & M	(4,956)
S-15	Remove Trojan Assets	(33,742)
S-16	Remove NEIL	3,850
S-17	Remove Other Offsetting Liabilities	(354)
S-18	Solar for Schools	(55)
S-19	Salmon Springs Reclassification	(183)
S-20	Green Power Purchase	(424)
S-21	Property Tax Unbundling Correction	0
S-22	Y2K Deferral	0
S-23	Two Cities Wheeling Expense	142
S-24	Miscellaneous Electric Revenues	(1,001)
S-26	Remove Customer Accounts Non-Labor Expenses	(1,613)
S-27	Category "A" Advertising Reduction	(2,378)
S-28	Public Purpose Adjustment	(705)
S-29	Remove Marketing and Sales Expense	(807)
S-30	Transmission and Distribution Expense Reduction	(1,834)
S-31	Reduce A & G Information Technology Costs	(1,008)
S-32	Remove Supplemental Executive Retirement Plan	(1,261)
S-33	Bonus and Incentive Adjustment	(2,576)
S-34	Workforce Level Adjustment	(5,520)
S-35	OPUC Wage Formula Adjustment	(1,775)
S-36	Distribution Plant Reduction	(1,395)
S-37	Materials & Supplies Adjustment	(469)
S-38	Y2K Amortization	(2,624)
S-39	NEIL Amortization	0
S-40	Accumulated Deferred Taxes	(2,916)
S-41	Miscellaneous Income Tax Adjustments	797
S-42	Remove Property Sales Gains	481
S-43	Depreciation Study Adjustment	(3,371)
S-44	SB 1149 Implementation Costs	857
S-45	CIS/IT Disallowance Adjustments	0
S-55	Franchise Fee (Base)	800
S-56	Coyote Steam Sales Adjustment	(839)
	Franchise Fee on Revenue Change	8,904
	Demand Exchange	(100)
	Weather Wise	(161)
	Load Forecast Revenue Update	33,068
	Additional Non-Power O & M Reduction	(6,985)
	Variable Power Cost–Monet Update 8/29/01(Including S-25, Weather Option)	118,272
	Rounding	17
	Total Adjustments (Base Rates)	70,007
	Total Revenue Requirements Change (Base Rates)	393,989 **36.0%**

APPENDIX G
PAGE 1 OF 10

PORTLAND GENERAL ELECTRIC - UE 115
Results of Operations
Twelve Months Ended December 31, 2002
($000)

		2002 Results Per Company Filing (1)	Adjustments (2)	2002 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Sales to Consumers	$1,128,504	($32,842)	1,095,662	$393,989	$1,489,651
3	Sales for Resale	0	0	0	0	0
4	Other Operating Revenues	15,236	749	15,985	0	15,985
5	*Total Operating Revenues*	$1,143,740	($32,093)	$1,111,647	$393,989	$1,505,636
6	**Operation & Maintenace**					
7	Net Variable Power Cost	$627,942	$116,987	$744,929	$0	$744,929
8	Production O&M	63,410	946	64,356	0	64,356
9	Trojan O&M	3,702	2,400	6,102	0	6,102
10	Transmission O&M	7,781	(1,508)	6,273	0	6,273
11	Distribution O&M	58,181	(1,213)	56,968	0	56,968
12	Customer & MBC O&M	47,555	(10,623)	36,932	0	36,932
13	Uncollectible Expense	5,642	(164)	5,478	1,970	7,448
14	Administrative and General	108,517	(14,617)	93,900	0	93,900
15	Total Operation & Maintenance	$922,730	$92,208	$1,014,938	$1,970	$1,016,908
16	Depreciation	155,232	(3,465)	151,767	0	151,767
17	Amortization	45,682	(18,857)	26,825	0	26,825
18	Property & Payroll Tax	41,127	(941)	40,186	0	40,186
19	Franchise & Other Tax	25,191	502	25,693	8,904	34,597
20	Utility Income Tax	(35,763)	(39,948)	(75,711)	150,662	74,951
21	Total Operating Expenses & Taxes	$1,154,199	$29,498	$1,183,697	$161,536	$1,345,233
22	**Net Operating Revenues**	($10,459)	($61,591)	($72,050)	$232,453	$160,403
22	**Average Rate Base**					
23	Electric Plant In Service	$3,636,902	($784)	$3,636,118	$0	$3,636,118
24	Accumulated Depreciation & Amortization	(1,757,582)	1,446	(1,756,136)	0	(1,756,136)
25	Accumulated Deferred Income Taxes	(165,850)	7,557	(158,293)	0	(158,293)
26	Accumulated Deferred Inv. Tax Credit	(25,599)	4,288	(21,311)	0	(21,311)
27	Net Utility Plant	$1,687,871	$12,507	$1,700,378	$0	$1,700,378
28	Net Trojan Investment	137,738	(137,738)	0	0	0
29	Weatherization Investment	0	0	0	0	0
30	Working Cash	51,477	1,315	52,792	7,205	59,997
31	Fuel	11,368	0	11,368	0	11,368
32	Materials & Supplies	26,292	(3,681)	22,611	0	22,611
33	Other Deferred Debits	17,429	(7,611)	9,818	0	9,818
34	Deferred Gains on Sales	(21,996)	0	(21,996)	0	(21,996)
35	Other Deferred Credits	(22,078)	5,870	(16,208)	0	(16,208)
36	Y2K Deferral	4,942	(4,942)	0	0	0
37	Total Average Rate Base	$1,893,043	($134,281)	$1,758,763	$7,205	$1,765,968
38	Rate of Return	-0.55%		-4.10%		9.08%
		[illegible]		-14.77%		10.50%

ORDER NO. 01-777

APPENDIX 6
PAGE 2 OF

PORTLAND GENERAL ELECTRIC
Results of Operations
Twelve Months Ended December 31, 2002
($000)

30-Aug-01
08:14 AM

	Income Tax Calculations	2002 Per Company Filing (1)	Adjustments (2)	2002 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	Book Revenues	$1,143,740	($32,093)	$1,111,647	$393,989	$1,505,636
2	Book Expenses Other than Depreciation	1,034,729	72,911	1,107,640	10,874	1,118,514
3	State Tax Depreciation	155,232	(3,465)	151,767		151,767
4	Interest	68,353	(7,184)	61,169	251	61,420
5	Schedule M Differences	(67,382)	6,846	(60,536)		(60,536)
6	State Taxable Income	($47,192)	($101,201)	($148,393)	$382,864	$234,471
7	State Income Tax @ 6.6547%	($3,214)	($6,663)	($9,877)	$25,478	$15,601
8	Net State Income Tax	($3,214)	($7,580)	($9,877)	$25,478	$15,601
9	Additional Tax Depreciation	0	0	0	0	0
10	Other Schedule M Differences	0	0	0	0	0
11	Federal Taxable Income	($43,978)	($93,621)	($137,599)	$357,524	$219,925
12	Federal Tax @ 35%	($15,392)	($32,769)	($48,161)	$125,184	$77,023
13	Current Federal Tax	($15,392)	($32,769)	($48,161)	$125,184	$77,023
14	ITC Adjustment					
15	Deferral	$0	$0	$0	$-0	$0
16	Restoration	1,885	(362)	1,523		1,523
17	Total ITC Adjustment	($1,885)	$362	($1,523)	$-0	($1,523)
18	Provision for Deferred Taxes	($15,272)	$39	($15,233)	$0	($15,233)
19	Total Income Tax	($35,763)	($39,948)	($75,711)	$150,662	$74,951

APPENDIX G
PAGE 3 OF 10

ORDER NO. 01-777

30-Aug-01
08:58 AM

PORTLAND GENERAL ELECTRIC
Results of Operations
Twelve Months Ended December 31, 2002

INPUT ASSUMPTIONS

COST OF CAPITAL - 2002	Capital Structure	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	$887,900	46.32%	7.51%	3.478%
Preferred Stock	$29,250	1.53%	8.43%	0.129%
Common Equity	$999,781	52.16%	10.50%	5.476%
Total	$1,916,931	100.00%		9.083%

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00500
Taxes Other - Franchise	0.00000
- OPUC fee	0.00000
- Resource supplier	0.00000
State Taxable Income	0.99500
State Income Tax @ 6.6547%	0.06621
Federal Taxable Income	0.92879
Federal Income Tax @ 35%	0.32508
ITC	0.00000
Current FIT	0.32508
Other	0.00000
Total Excise Taxes	0.39129
Total Revenue Sensitive Costs	0.39629
Utility Operating Income	0.60371
Net-to-Gross Factor	1.65642

APPENDIX G
PAGE 4 OF 16

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
08:14 AM

Miscellaneous Corrections to Company Filing

		FERC Wholesale Fee (S-1)	Montana Production Tax (S-2)	Colstrip O & M (S-3)	Transmission O & M (S-4)	FERC Hydro Fee (S-5)	Income Tax Apportion (S-6)	Severance Program (S-7)	OAL Sale (S-8)	PGH Billings (S-9)
1	*Operating Revenues*									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	*Sales for Resale*									
4	Other Operating Revenues									
5	**Total Operating Revenues**	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operation & Maintenance									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M			$1,043		($14)			($83)	
9	Trojan O&M							$0		
10	Transmission O&M			$25	$0				($28)	
11	Distribution O&M				0				(223)	
12	Customer & MBC O&M									
13	Uncollectible Expense	0	0	0	0					
14	Administrative and General	(372)				714			108	(436)
15	**Total Operation & Maintenance**	($372)	$0	$1,068	$0	$700	$0	$0	($226)	($436)
16	Depreciation								(20)	
17	Amortization							$66	120	0
18	Property & Payroll Tax	0	0	0	0				0	
19	Franchise & Other Tax		450							
20	*Utility Income Tax*	147	(177)	(420)	0	(276)	0	(26)	55	172
21	**Total Operating Expenses & Taxes**	($225)	$273	$648	$0	$424	$0	$40	($71)	($264)
22	**Net Operating Revenues**	$225	($273)	($648)	($0)	($424)	$0	($40)	$71	$264
22	**Average Rate Base**									
23	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization								(60)	
25	Accumulated Deferred Income Taxes								(24)	
26	Accumulated Deferred Inv. Tax Credit									
27	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	$0	($84)	$0
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	(10)	12	29	0	19	0	2	(3)	(12)
31	Fuel									0
32	Materials & Supplies								0	
33	Other Deferred Debits								(355)	
34	Deferred Gains on Sales						0			
35	Other Deferred Credits									
36	Y2K Deferral									
37	**Total Average Rate Base**	($10)	$12	$29	$0	$19	$0	$2	($442)	($12)
	Revenue Requirement Effect	($374)	$454	$1,078	$0	$705	$0	$67	($184)	($439)

APPENDIX G
PAGE 5 OF 10

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
08:14 AM

		Miscellaneous Corrections to Company Filing								
		Retail Unbundling Allocation (S-10)	Beaver Turbine (S-11)	Other Revenue (S-12)	State Tax Credit (S-13)	Remove SERP Rate Base & MDCP Expense (S-14)	Remove Trojan (S-15)	Remove Neil (S-16)	Remove Other Debits & Credits (S-17)	Solar For Schools (S-18)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues			0				0	(589)	
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	($589)	$0
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M							$2,400		
10	Transmission O&M									
11	Distribution O&M									
12	Customer & MBC O&M	435								(55)
13	Uncollectible Expense									0
14	Administrative and General	303	0	0	0	(4,645)	0	$1,418		0
15	Total Operation & Maintenance	$738	$0	$0	$0	($4,645)	$0	$3,818	$0	($55)
16	Depreciation		182							
17	Amortization						(16,584)		(959)	0
18	Property & Payroll Tax		14							
19	Franchise & Other Tax									
20	Utility Income Tax	(290)	(116)	0	0	1,857	5,605	(1,603)	143	22
21	Total Operating Expenses & Taxes	$448	$80	$0	$0	($2,788)	($10,979)	$2,315	($816)	($33)
22	Net Operating Revenues	($448)	($80)	$0	$0	$2,788	$10,979	($2,315)	$227	$33
22	Average Rate Base									
23	Electric Plant In Service	$0	$3,200	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization		(278)							
25	Accumulated Deferred Income Taxes	0	0				30,413			
26	Accumulated Deferred Inv. Tax Credit		(133)				4,421			
27	Net Utility Plant	$0	$2,789	$0	$0	$0	$34,834	$0	$0	$0
28	Net Trojan Investment						(137,738)			
29	Weatherization Investment									
30	Working Cash	20	4	0	0	(124)	(490)	103	(36)	(1)
31	Fuel									
32	Materials & Supplies									
33	Other Deferred Debits								(7,811)	
34	Deferred Gains on Sales									
35	Other Deferred Credits					(2,122)			7,992	0
36	Y2K Deferral									
37	Total Average Rate Base	$20	$2,793	$0	$0	($2,246)	($103,394)	$103	$145	($1)
	Revenue Requirement Effect	$745	$553	$0	$0	($4,956)	($33,742)	$3,850	($354)	($55)

ORDER NO. 01-777

APPENDIX E

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
08:14 AM

		Miscellaneous Corrections to Company Filing								
		Salmon Springs Reclassification (S-19)	Green Power Purchase (S-20)	Property Tax Unbundling Correction (S-21)	Y2K Deferral (S-22)	Two Cities (S-23)	Miscellaneous Electric Revenues (S-24)	Remove Weather Option Cost (S-25)	Reduce Customer Acct. Non-Labor Exp. (S-26)	Category "A" Advertising Reduction (S-27)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues	183					998			
5	Total Operating Revenues	$183	$0	$0	$0	$0	$998	$0	$0	$0
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	($420)	$0	$0	$129	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M									
10	Transmission O&M									
11	Distribution O&M									
12	Customer & MBC O&M								(1,600)	(2,358)
13	Uncollectible Expense									
14	Administrative and General	0	0	0	0	0	0	0	0	0
15	Total Operation & Maintenance	$0	($420)	$0	$0	$129	$0	$0	($1,600)	($2,358)
16	Depreciation									
17	Amortization									
18	Property & Payroll Tax									
19	Franchise & Other Tax									
20	Utility Income Tax	72	165	0	0	(52)	392	0	630	928
21	Total Operating Expenses & Taxes	$72	($255)	$0	$0	$77	$392	$0	($970)	($1,430)
22	Net Operating Revenues	$111	$255	$0	$0	($77)	$606	$0	$970	$1,430
22	Average Rate Base									
23	Electric Plant in Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization								0	
25	Accumulated Deferred Income Taxes									
26	Accumulated Deferred Inv. Tax Credit									
27	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	3	(11)	0	0	3	17	0	(43)	(64)
31	Fuel									
32	Materials & Supplies									
33	Other Deferred Debits					96				
34	Deferred Gains on Sales									
35	Other Deferred Credits									
36	Y2K Deferral									
37	Total Average Rate Base	$3	($11)	$0	$0	$99	$17	$0	($43)	($64)
	Revenue Requirement Effect	($183)	($424)	$0	$0	$142	($1,001)	$0	($1,613)	($2,378)

ORDER NO. 01-777

APPENDIX G
PAGE 4 OF 10

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
08:14 AM

		Public Purpose Adjustment (S-28)	Reduce Marketing & Sales Expense (S-29)	Transmission & Distribution Exp. Reduction (S-30)	Reduce A & G Information Tech. Costs (S-31)	Remove Suppl. Executive Retirement Plan (S-32)	Bonus & Incentive Adjustment (S-33)	Workforce Level Adjustment (S-34)	OPUC Wage Formula Adjustment (S-35)	Distribution Plant Reduction (S-36)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$1,075
3	Sales for Resale									
4	Other Operating Revenues			(680)						0
5	Total Operating Revenues	$0	$0	($680)	$0	$0	$0	$0	$0	$1,075
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M									
10	Transmission O&M			(1,505)						
11	Distribution O&M	0		(990)						
12	Customer & MBC O&M	(550)	(800)					(2,411)		
13	Uncollectible Expense									5
14	Administrative and General	(149)			(1,000)	(1,250)	(2,237)	(2,411)	(1,550)	
15	Total Operation & Maintenance	($699)	($800)	($2,495)	($1,000)	($1,250)	($2,237)	($4,822)	($1,550)	$5
16	Depreciation			0						(60)
17	Amortization									
18	Property & Payroll Tax					0	(240)	(518)	(167)	(30)
19	Franchise & Other Tax									24
20	Utility Income Tax	275	315	715	394	492	983	2,118	680	473
21	Total Operating Expenses & Taxes	($424)	($485)	($1,780)	($606)	($758)	($1,494)	($3,224)	($1,037)	$413
22	Net Operating Revenues	$424	$485	$1,100	$606	$758	$1,494	$3,224	$1,037	$662
22	Average Rate Base									
23	Electric Plant in Service	$0	$0	$0	$0	$0	($602)	($1,046)	($336)	($2,000)
24	Accumulated Depreciation & Amortization				0	0				0
25	Accumulated Deferred Income Taxes				0					
26	Accumulated Deferred Inv. Tax Credit									
27	Net Utility Plant	$0	$0	$0	$0	$0	($602)	($1,046)	($336)	($2,000)
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	(19)	(22)	(79)	(27)	(34)	(67)	(144)	(46)	18
31	Fuel									
32	Materials & Supplies									
33	Other Deferred Debits									
34	Deferred Gains on Sales									
35	Other Deferred Credits								0	
36	Y2K Deferral									
37	Total Average Rate Base	($19)	($22)	($79)	($27)	($34)	($669)	($1,190)	($382)	($1,982)
	Revenue Requirement Effect	($705)	($807)	($1,834)	($1,008)	($1,261)	($2,576)	($5,520)	($1,775)	($1,395)

APPENDIX G

ORDER NO. 01-777

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
08:14 AM

		Materials & Supplies Adjustment (S-37)	Y2K Amortization (S-38)	NEIL Amortization (S-39)	Accumulated Deferred Taxes (S-40)	Income Tax Adjustments (S-41)	Remove Property Sales Gains (S-42)	Depreciation Study Adj. (S-43)	SB 1149 Implementation Costs (S-44)	CIS/IT Disallowance Adjustments (S-45)
1	Operating Revenues									
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for Resale									
4	Other Operating Revenues									0
5	Total Operating Revenues	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Operation & Maintenace									
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Production O&M									
9	Trojan O&M									
10	Transmission O&M									
11	Distribution O&M									
12	Customer & MBC O&M								376	
13	Uncollectible Expense									
14	Administrative and General								416	0
15	Total Operation & Maintenance	$0	$0	$0	$0	$0	$0	$0	$792	$0
16	Depreciation							(3,567)		0
17	Amortization		(1,977)	0		0	477		0	0
18	Property & Payroll Tax									0
19	Franchise & Other Tax									
20	Utility Income Tax	51	846	0	312	479	(188)	1,379	(318)	0
21	Total Operating Expenses & Taxes	$51	($1,131)	$0	$312	$479	$289	($2,188)	$474	$0
22	Net Operating Revenues	($51)	$1,131	$0	($312)	($479)	($289)	$2,188	($474)	$0
22	Average Rate Base									
23	Electric Plant In Service	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Accumulated Depreciation & Amortization					0		1,784	0	0
25	Accumulated Deferred Income Taxes				(22,832)	0				0
26	Accumulated Deferred Inv. Tax Credit									
27	Net Utility Plant	$0	$0	$0	($22,832)	$0	$0	$1,784	$0	$0
28	Net Trojan Investment									
29	Weatherization Investment									
30	Working Cash	2	(50)	0	14	21	13	(98)	21	0
31	Fuel									
32	Materials & Supplies	(3,681)		0						
33	Other Deferred Debits			0					459	
34	Deferred Gains on Sales									
35	Other Deferred Credits									
36	Y2K Deferral		(4,942)							
37	Total Average Rate Base	($3,679)	($4,992)	$0	($22,818)	$21	$13	$1,686	$480	$0
	Revenue Requirement Effect	($469)	($2,624)	$0	($2,916)	$797	$481	($3,371)	$857	$0

ORDER NO. 01-777

APPENDIX G
PAGE 9 OF 12

PORTLAND GENERAL ELECTRIC
Staff Adjustments to Oregon Results
UE 115 Test Year Ending December 2002
($000)

30-Aug-01
09:00 AM

		Franchise Fees (Base) (S-55)	Coyote Steam Sales (S-56)	Demand Exchange (PGE)	Weather Wise (PGE)	Load Forecast Revenue Update (PGE)	Additional Non-Power O & M Reduction (OPUC)	NVPC Forecast Additional (PGE)	Total Adjustments (Base Rates)
1	Operating Revenues								
2	Retail Sales	$0	$0	$0	$0	($33,917)	$0	$0	($32,842)
3	Sales for Resale								0
4	Other Operating Revenues	0	837	0	0	0	0	0	749
5	Total Operating Revenues	$0	$837	$0	$0	($33,917)	$0	$0	($32,093)
6	Operation & Maintenace								
7	Net Variable Power Cost	$0	$0	$0	$0	$0	$0	$117,278	$116,987
8	Production O&M								946
9	Trojan O&M								2,400
10	Transmission O&M								(1,508)
11	Distribution O&M								(1,213)
12	Customer & MBC O&M				(160)		(3,500)		(10,623)
13	Uncollectible Expense					(170)	0	0	(164)
14	Administrative and General	0	0	(100)	0	0	(3,426)	0	(14,617)
15	Total Operation & Maintenance	$0	$0	($100)	($160)	($170)	($6,926)	$117,278	$92,208
16	Depreciation	0	0	0	0	0	0	0	($3,465)
17	Amortization	0	0	0	0	0	0	0	(18,857)
18	Property & Payroll Tax	0	0	0	0	0	0	0	(941)
19	Franchise & Other Tax	794				(767)	0	0	502
20	Utility Income Tax	(313)	329	40	63	(12,961)	2,726	(46,164)	(39,948)
21	Total Operating Expenses & Taxes	$481	$329	($60)	($97)	($13,897)	($4,200)	$71,114	$29,498
22	Net Operating Revenues	($481)	$508	$60	$97	($20,020)	$4,200	($71,114)	($61,591)
22	Average Rate Base								
23	Electric Plant In Service	$0	$0	$0	$0	$0	$0	$0	($784)
24	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	1,446
25	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	7,557
26	Accumulated Deferred Inv. Tax Credit								4,288
27	Net Utility Plant	$0	$0	$0	$0	$0	$0	$0	$12,507
28	Net Trojan Investment								(137,738)
29	Weatherization Investment								0
30	Working Cash	21	15	(3)	(4)	(620)	(187)	3,172	1,315
31	Fuel								0
32	Materials & Supplies								(3,681)
33	Other Deferred Debits								(7,611)
34	Deferred Gains on Sales								0
35	Other Deferred Credits								5,870
36	Y2K Deferral								(4,942)
37	Total Average Rate Base	$21	$15	($3)	($4)	($620)	($187)	$3,172	($134,281)
	Revenue Requirement Effect	$800	($839)	($100)	($161)	$33,068	($6,985)	$118,272	$81,820

ORDER NO. 01-777