Portland General Electric Company
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Douglas C. Tingey
Assistant General Counsel

October 4, 2006

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: UE 180, UE 181 AND UE 184

Attention Filing Center:

Enclosed for filing in the above captioned dockets are an original and five copies of:

- **Stipulation Regarding Rate Spread and Rate Design Issues; and**
- **Joint Explanatory Brief in Support of Stipulation Regarding Rate Spread and Rate Design Issues**

This document is also being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:mmd
Enclosures
cc: Service List – UE 180, UE 181, and UE 184

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/ UE 181/ UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	STIPULATION REGARDING RATE SPREAD AND RATE DESIGN ISSUES
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE") Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and Fred Meyer Stores, (collectively, the "Stipulating Parties").

I. INTRODUCTION

On March 15, 2006, PGE filed Advice No. 06-8 for a general rate revision to increase its retail rates by about $98 million. The filing was based on a projected test year of 2007 and was docketed as UE 180. The advice filing was suspended by the Commission, and on April 4, 2006, the Administrative Law Judge held a Prehearing Conference and established a procedural schedule. On April 24, 2006, PGE filed Advice No. 06-10, to reflect in rates the Port Westward generation plant when it comes into service for customers, currently anticipated to be about March 1, 2007. That filing was docketed as UE 184, and was also suspended by the Commission. Dockets UE 180, UE 184 and UE 181 (PGE's 2007 RVM filing), have all been consolidated.

Settlement conferences regarding rate spread and rate design issues were held on August 25, 2006 and September 5, 2006. As a result of those settlement discussions, the Stipulating Parties have agreed to the terms of this Stipulation, and request that the Commission adopt orders in this docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation is entered to settle all rate spread and rate design issues among the Parties except issues regarding Schedule 76R, Economic Replacement Power raised by ICNU.

2. The Stipulating Parties support the rate spread/rate design proposal filed by PGE in this docket with the following changes:

   a. The parties agree that the pricing for Schedule 102 Regional Power Act Exchange Credit will be on an equal cents per kWh basis for all Schedules except Schedule 7. The Schedule 102 pricing for Schedule 7 will be on an inverted block basis. The first block will remain at the current level of 250 kWh with the second block consisting of all kWh greater than 250. A price differential of at least 1.75 cents per kWh will be maintained between the two blocks.

b. Regarding the Schedule 83/583 primary voltage facilities charge, the costs associated with single-phase service will be removed from the calculated prices in a manner similar to that proposed in PGE Response to Fred Meyer data request No. 002. Additionally, the distribution demand charge for Schedule 83/583-P will not be blocked, but rather implemented as a flat demand charge for this Schedule. The distribution demand charge for Schedule 83/583-S will continue to be blocked in order to provide a smooth transition for customers who migrate between Schedules 32 and 83-S.

c. In order to mitigate the rate change differential between Schedule 83/583-S and Schedule 83/583-P, the parties agree to an additional CIO credit of 0.50 mills/kWh applied to Schedule 83/583-P, recovered from Schedule 83/583-S. PGE estimates that this will result in an additional 0.03 mills/kWh charge for Schedule 83/583-S.

d. PGE agrees to seek implementation of transmission demand charges based on on-peak demand for Schedule 83 should the appropriate metering be installed for all Schedule 83 customers prior to PGE's next general rate case.

e. Schedule 75, Partial Requirements Service, will be modified as shown in Attachment "A" to this Stipulation.

f. The parties agree that the calculation of the Customer Impact Offset (CIO) will be made such that for all Schedules the rate increase will be limited to 2.0 times the overall increase when compared to 2006 prices, except that the maximum CIO credit is 3.5 cents/kWh. Furthermore, no Schedule that otherwise would receive a rate increase of less than 5% will receive a CIO credit.

3. The Stipulating Parties request and recommend that the Commission approve all tariff revisions necessary to implement the terms of this Stipulation.

4. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. The Stipulating Parties agree that they will not cite this Stipulation as precedent in any other proceeding other than a proceeding to enforce the terms of this Stipulation.

5. The Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable.

6. 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 Stipulating Parties 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 Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

7. 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 that rejects this Stipulation or adds such material condition.

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating 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. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no Party shall be deemed 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. Except as provided in 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 signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 4th day of October, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating 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. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no Party shall be deemed 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. Except as provided in 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 signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this day of September, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OR OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

FRED MEYER STORES

CITIZENS' UTILITY BOARD OR OREGON

INDUSTRIAL CUSTOMERS OF
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CITIZENS' UTILITY BOARD OR OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

FRED MEYER STORES

Attachment A , Rate Spread / Rate Design Stipulation
SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.66	$0.66	$0.66
Distribution Charges			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
Generation Contingency Reserves Charges			
Spinning Reserves			
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢
Energy Charge			
per kWh	See Energy Charge Below		

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5 percent of the Reserved Capacity.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)
Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan shall be terminated.

The duration of the Penalty Period shall not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned. Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.236¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

Losses will be included by multiplying the applicable Energy Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 75 (Continued)

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement shall be one calendar year (except that the term of the first service agreement shall be the remainder of the year when signed plus the next calendar year) and shall renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

3. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by the Company and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer will not use Electricity sold by the Company to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely.

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Customer provides the following notice:
   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, Customer must provide at least 13 months written notice to the Company with such change effective on January 1 of the applicable year. Any subsequent notice by the Customer under this special condition must be made consistent with these notice requirements.

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/ UE 181/ UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180), In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181), In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	)	JOINT EXPLANATORY BRIEF IN SUPPORT OF STIPULATION REGARDING RATE SPREAD AND RATE DESIGN ISSUES

This brief ("Explanatory Brief") explains the Stipulation ("Stipulation") dated October 4, 2006, among Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Industrial Customers of Northwest Utilities ("ICNU"), and the Citizens' Utility Board of Oregon ("CUB"), and Fred Meyer Stores ("Fred Meyer") (collectively, the "Parties"). The Parties submit this brief pursuant to OAR 860-014-0085(4). Capitalized terms used in this Explanatory Brief have the meanings ascribed to them in this joint

Explanatory Brief or in the Stipulation.

Introduction

This Stipulation resolves all issues among the Parties related to rate spread, rate design and partial requirements issues, with one exception noted below. Stipulation ¶ 1. The Stipulation describes specific changes PGE will make to the development of rates and tariff schedule provisions as filed in UE 180. The Parties agree that the Stipulation is in the public interest and will produce rates that are fair, just and reasonable. Stipulation ¶ 5. The Stipulation also contains a number of provisions typically contained in stipulations filed with the Commission. Stipulation ¶¶ 4-10.

The City of Portland, the City of Gresham and the League of Oregon Cities ("the Cities") are not a party to this Stipulation. However, the Parties believe that this Stipulation resolves the issues raised by the Cities regarding Schedule 75. The settlement does not resolve issues raised by the Cities related to streetlighting service. The settlement also does not resolve issues raised by ICNU regarding Schedule 76R, Economic Replacement Power.

An explanation of the specific settlement components is presented below. The settlement includes four changes that affect the methodology used to set and design the specific rate schedule prices, a commitment to move to on-peak demand charges for Large Nonresidential customers and a revised Schedule 75, Partial Requirements Service.

Discussion

Each item of the Rate spread/Rate Design Stipulation is stated and explained below.

1. Related to Schedule 102, Regional Power Act Exchange Credit, the settlement states:

The parties agree that the pricing for Schedule 102 Regional Power Act Exchange Credit will be on an equal cents per kWh basis for all Schedules except Schedule 7. The

Schedule 102 pricing for Schedule 7 in this rate case will be on an inverted block basis. The first block will remain at the current level of 250 kWh with the second block consisting of all kWh greater than 250. A price differential of at least 1.75 cents per kWh will be maintained between the two blocks.

Explanation:

This provision describes the rate design that will be applied to supplemental adjustment Schedule 102, Regional Power Act Exchange Credit, for residential customers (that is, customers receiving service under Schedule 7). Specifically, when establishing the Schedule 102 rate applicable to residential customers, the Company will design an inverted blocked rate such that the differential between the credit in the first block and the second pricing block is at least 1.75 cents per kWh. The rate blocking for residential (Schedule 7) customers consists of an initial block of zero to 250 kWh per month, and the second block is all usage greater than 250 kWh.

The rate design described above settles concerns of CUB regarding the inverted rate differential applied to residential customers. The design will maintain a block differential that CUB finds reasonable. In addition, Staff supports the concept of a residential inverted block design.

2. Related to Schedule 83 (and Schedule 583) Facilities Charge rate design, the settlement states:

Regarding the Schedule 83/583 primary voltage facilities charge, the costs associated with single-phase service will be removed from the calculated prices in a manner similar to that proposed in PGE Response to Fred Meyer data request No. 002. Additionally, the distribution demand charge for Schedule 83/583-P will not be blocked, but rather implemented as a flat demand charge for this Schedule. The distribution demand charge for Schedule 83/583-S will continue to be blocked in order to provide a smooth transition for customers who migrate between Schedules 32 and 83-S.

Explanation:

Fred Meyer Stores identified a cost allocation issue in the PGE proposed Schedule 83 cost study that affects the Facility Capacity Charge differential between secondary and primary delivery voltage service. Fred Meyer Stores recommends and PGE agrees that because there are no single-phase, primary voltage customers, costs should be allocated such that the primary service Facility Capacity Charge reflect only three-phase service cost and not reflect those costs associated with single-phase service. PGE estimates that this change will reduce the proposed Facility Capacity Charge for primary service by $0.13 per kW-month and increase slightly the charge for Schedules 83 secondary service by $0.01 per kW-month.

The design of the distribution Demand Charge for secondary and primary delivery service proposed by PGE incorporated a blocked design, $2.07 per kW for the first 30 kW and $2.64 for above 30 kW. The basis for the design is to facilitate the transition between Schedule 32 and 83 rates in order to mitigate adverse customer bill impacts. Fred Meyer Stores pointed out that there are no Schedule 32 primary delivery service customers and therefore the blocking for primary service is neither necessary nor appropriate. PGE agrees with the conclusion and will design primary delivery service Demand Charge as a single flat block. Blocking is appropriate for Schedule 83 secondary delivery service to manage the transition with Schedule 32.

3. Related to Schedule 83 (and Schedule 583) rate impact differential between secondary and primary delivery voltage, the settlement states:

> *In order to mitigate the rate change differential between Schedule 83/583-S and Schedule 83/583-P, the parties agree to an additional CIO credit of 0.50 mills/kWh applied to Schedule 83/583-P, recovered from Schedule 83/583-S. PGE estimates that this will result in an additional 0.03 mills/kWh charge for Schedule 83/583-S.*

Explanation:

Fred Meyer Stores raised an issue regarding the estimated rate impact difference between Schedule 83 secondary and primary voltage delivery service where the primary voltage service customer increase was substantially greater than the secondary class impact. PGE agreed that an intra-class mitigation that would not have detrimental effects on other classes or schedules was appropriate.

4. Related to on-peak Demand Charges for Schedule 83, the settlement states:

PGE agrees to seek implementation of transmission demand charges based on on-peak demand for Schedule 83 should the appropriate metering be installed for all Schedule 83 customers prior to PGE's next general rate case.

Explanation:

Staff raised in testimony a concern that the Schedule 83 transmission demand charges were set to apply to a customer's peak demand regardless of when that peak occurs. A customer with a maximum demand that occurs during off-peak could see a charge at a time when there is no impact on the costs of sizing the transmission system. PGE has proposed to implement on-peak transmission demand charges for the proposed Schedule 89. With this settlement PGE agrees to implement on-peak demand transmission charges for Schedule 83 when the appropriate metering (which can supply interval-data) is installed. When implemented, the resulting on-demand charge will likely be slightly higher than the otherwise applicable non-time differentiated Schedule 83 transmission demand charge.

5. Related to Schedule 75, Partial Requirements Service, the settlement states:

Schedule 75, Partial Requirements Service will be modified as shown in Attachment "A" to this Stipulation.

Explanation:

Staff and ICNU identified several issues with the Company's proposed Schedule 75: the determination of Baseline Demand and the basis to make changes to Baseline Demand, notice requirements for changes to Baseline Demand, availability of a Supplemental Reserves Load Reduction Plan option, and certain other clarifying changes. The Cities raised the issue of treatment of small on-site generators with intermittent generation. ICNU submitted a proposed Schedule 75 in their testimony. Staff described their issues in testimony. During settlement discussions, specific provisions and tariff language were developed and are reflected in the proposed Schedule 75 included with the Stipulation. The settlement on Schedule 75 addresses certain terms and conditions; the specific prices and price related items are subject to final determination of the revenue requirement level used to set all prices, including Schedule 75.

The following describes the settlement provisions:

a. Baseline Demand: The Baseline Demand section of the rate schedule incorporates changes to clarify how Baseline Demand is established and generally modified over time to reflect the customer's planned load and generator operations. Baseline Demand establishes the amount of Electricity that the Company will supply to the customer under Schedule 89. Baseline Demand is the Demand normally supplied by the Company when the customer's generator is operating as planned. Baseline Demand is initially based on the customer's historical loads prior to the installation of generation. The Baseline Demand section clarifies that customers can include the planned sales of power to the Company or third parties in setting Baseline Demand. Baseline Demand changes are made consistent with the notice requirements discussed below.

b. The Supplemental Reserves Load Reduction Option. This addition to the schedule describes in detail the components of the optional Supplemental Reserves Load Reduction Plan option set in the Supplemental Reserves section. ICNU proposed this addition in order to allow customers an option to avoid reserves charges otherwise applied due to the provision by the Company of Supplemental Reserves. The customer is required to provide a load reduction plan which PGE must approve. Further, the language sets out specific requirements for compliance with the requirement that the customer accepts to supply reserves on request of PGE.

c. Baseline Demand Notice Requirements. Proposals to address notice requirements for changes to Baseline Demand were made by ICNU and Staff. Settlement discussions resulted in a tiered notice requirement related to the level of Baseline Demand changes associated with changes in generation operations or capacity, as well as clarifications of Baseline Demand changes associated with load-related changes.

Special Condition 8 of Schedule 75 is revised to add specification for Baseline Demand changes related to planned long-term or permanent changes in load. The purpose of these changes is to clarify that partial requirements customers are treated in a manner similar to other customers that do not have on-site generation serving load with respect to any requirements to notify PGE of changes in load requirements. Permanent removal of the customer's generation equipment is also recognized as a reason for change in Baseline Demand.

The customer's notice requirements to PGE for Baseline Demand generation-related changes are described in Special Condition 9 and provide a 6 month notice for a change of 5 MW or less within a one calendar year period. This allows customers to make a limited change to the Baseline Demand within a relatively short period of time. In addition, the notice provides PGE with advance information about changes in the power supply requirements in the near future. For changes greater than 5 MW, the notice requirement is 13 months with the change effective on January 1st of the applicable year. Again, the notice requirement is sufficient to allow the Company to adjust the planned power supply requirements to accommodate the change in the Customer's planned Electricity requirements. PGE will plan to serve the customer's load up to the Baseline Demand level at a Cost of Service Energy Charge as provided under Schedule 89 or other

Schedule 89 energy pricing option.

PGE originally proposed a notice requirement of at least two calendar years in order to accommodate changes in load requirements. The settlement substantially reduces the Baseline Demand notice requirements PGE proposed in this proceeding, but establishes a threshold of 5 MW for short-term notice which should assist both PGE and customers in working together to maintain accurate Baseline Demand levels.

d. Schedule 75 Applicability. To accommodate the Cities' concern regarding small generators relying on intermittent resources, Parties agreed to change the threshold applicability of Schedule 75 to 2 MW of customer generation from the currently established 1 MW threshold. This change effectively removes from partial requirements service customers with generation less than 2 MW. Such a customer would continue to receive service under the applicable standard rate schedule. Relatively small generation that is intermittent in operation, due to reliance on such resources as wind, hydro or biogas from wastewater treatment facilities, is benefited by this change.

6. Related to the Customer Impact Offset ("CIO") calculation, the settlement states:

The parties agree that the calculation of the Customer Impact Offset (CIO) will be made such that for all Schedules the rate increase will be limited to 2.0 times the overall increase when compared to 2006 prices, except that the maximum CIO credit is 3.5 cents/kWh. Furthermore, no Schedule that otherwise would receive a rate increase of less than 5% will receive a CIO credit.

Explanation:

The CIO is a rate design mechanism which limits the rate impacts resulting from rate changes on rate schedules that would otherwise experience significantly greater percentage rate changes relative to the overall rate change percentage. Staff testimony identified issues with the PGE proposed CIO, primarily related to the longer term objective of moving pricing toward

appropriate cost of service levels while in the process mitigating the impact of specific rate changes. The settlement retains a rate impact limit of 2.0 times the overall average rate increase percentage to all schedules. The settlement further limits the impact such that no rate schedule receives a CIO credit (which mitigates the rate impact) that exceeds 3.5 cents/kWh. For rate schedules with a rate increase less than 5%, a CIO credit will not be applied. In this manner, the goal of moving toward cost of service is maintained while mitigating impacts.

Conclusion

The Stipulation resolves the rate spread and rate design issues raised by Staff, CUB, ICNU, and Fred Meyer in this docket. Each of the Parties, representing their respective interests, agree that the settlement contained in the Stipulation results in fair, just and reasonable rates in this rate case proceeding. For the reasons set forth above the Parties request that the Commission approve the Stipulation.

DATED this 4th day of October, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

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CITIZENS' UTILITY BOARD OF OREGON

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STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

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INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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FRED MEYER STORES

Michael L. Kurtz by DCT
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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing **JOINT EXPLANATORY BRIEF IN SUPPORT OF STIPULATION REGARDING RATE SPREAD AND RATE DESIGN ISSUES and STIPULATION REGARDING RATE SPREAD AND RATE DESIGN ISSUES OF PORTLAND GENERAL ELECTRIC COMPANY** to be served by First Class US Mail, postage prepaid and properly addressed, and by electronic mail, upon each party on the attached service list from OPUC Docket UE 180, UE 181, and UE 184.

Dated at Portland, Oregon, this 4th day of October 2006.

DOUGLAS C. TINGEY

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