Portland General Electric Company
121 SW Salmon Street • 1WTC1703 • Portland, Oregon 97204
office (503) 464-7353 • facsimile (503) 464-7050

Pamela Grace Lesh
Vice President
Regulatory Affairs & Strategic Planning

March 15, 2006

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol Street, N.E., Suite 215
Salem, OR 97301-2551

RE: **Advice No. 06-8, PGE General Rate Case**

Enclosed for filing, with a requested effective date of **April 15, 2006**, are an original and four conformed copies of a revised Tariff, designated as E-18. All sheets are originals.

Also enclosed are 23 copies of Direct Testimony, Exhibits and a Pretrial Brief that conforms to the requirements in OAR 860-013-0075. Five copies of work papers showing the source and calculation of rates are also enclosed.

While we request an effective date of April 15, 2006, we expect this filing to be suspended for investigation. We request that a prehearing conference be held expeditiously to establish a schedule that will allow revised prices to become effective January 1, 2007.

In approximately mid-April, we will file an errata for corrections identified in the material herein presented.

To ensure a timely response, please direct your communications related to this filing to the following email address: pge.opuc.filings@pgn.com

Please mail hardcopies to:

Rates and Regulatory Affairs
121 SW Salmon St, 1WTC0702
Portland, Oregon 97204
(503) 464-7857

Doug Tingey
121 SW Salmon St, 1WTC1301
Portland, Oregon 97204
(503) 464-8926

Sincerely,

Pamela G. Lesh

Pamela G. Lesh
Vice President, Regulatory Affairs & Strategic Planning

Enclosure

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

Schedule	Description
	Table of Contents, Rate Schedules
	Table of Contents, Rules and Regulations
	Standard Service Schedules
7	Residential Service
10	GenerLink™ (No New Service)
15	Outdoor Area Lighting Standard Service (Cost of Service)
32	Small Nonresidential Standard Service
38	Large Nonresidential Optional Time-of-Day Standard Service (Cost of Service)
47	Small Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)
49	Large Nonresidential Irrigation and Drainage Pumping Standard Service (Cost of Service)
54	Large Nonresidential Tradable Renewable Credits Rider
75	Partial Requirements Service
76R	Partial Requirements Economic Replacement Power Rider
81	Nonresidential Emergency Default Service
83	Large Nonresidential Standard Service
84	Large Nonresidential Large Load Split Service Rider Option
86	Nonresidential Demand Buy Back Rider
87	Large Nonresidential (>1,000 kW) Experimental Real Time Pricing (RTP) Service
88	Load Reduction Program

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

Schedule	Description
89	Large Nonresidential (>1,000 kW) Standard Service
91	Street and Highway Lighting Standard Service (Cost of Service)
92	Traffic Signals (No New Service) Standard Service (Cost of Service)
93	Recreational Field Lighting, Primary Voltage Standard Service (Cost of Service)
99	Special Contracts
	Adjustment Schedules
100	Summary of Applicable Adjustments
102	Regional Power Act Exchange Credit
105	Regulatory Adjustments
108	Public Purpose Charge
115	Low Income Assistance
125	Annual Power Cost Update
126	Power Cost Variance Mechanism
128	Short-Term Transition Adjustment
129	Long-Term Transition Cost Adjustment
	Small Power Production
200	Dispatchable Standby Generation
201	Qualifying Facility Power Purchase Information
203	Net Metering Service

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

Schedule	Description
	Schedules Summarizing Other Charges
300	Charges as defined by the Rules and Regulations and Miscellaneous Charges
310	Deposits for Residential Service
320	Meter Information Services
	Promotional Concessions
402	Promotional Concessions Residential Products and Services
403	Heat Pump Promotional Concession
	Transmission Access Service
483	Large Nonresidential (<1,000 kW) Cost-of-Service Opt-Out
489	Large Nonresidential (>1,000 kW) Cost of Service Opt-Out
	Direct Access Schedules
515	Outdoor Area Lighting Direct Access Service
532	Small Nonresidential Direct Access Service
549	Large Nonresidential Irrigation and Drainage Pumping Direct Access Service
575	Partial Requirements Service Direct Access Service
576R	Economic Replacement Power Rider Direct Access Service
583	Large Nonresidential Direct Access Service
589	Large Nonresidential (>1,000 kW) Direct Access Service
591	Street and Highway Lighting Direct Access Service
592	Traffic Signals Direct Access Service
600	Energy Service Supplier Charges

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
RATE SCHEDULES

Schedule	Description
	Non-Utility Services
710	Utility Asset Management (UAM)
715	Electrical Equipment Services
720	Efficiency Services
725	E-Manager
730	Power Quality Products and Services

TABLE OF CONTENTS
RATE SCHEDULES (Concluded)

SCHEDULE 7
RESIDENTIAL SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Residential Customers.

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$10.00	
Three Phase Service	$13.00	
Transmission and Related Services Charge	0.198	¢ per kWh
Distribution Charge	3.123	¢ per kWh
Energy Charge		
Standard Service	5.675	¢ per kWh
or		
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)		
On-Peak Period	9.777	¢ per kWh
Mid-Peak Period	5.675	¢ per kWh
Off-Peak Period	3.259	¢ per kWh
Nonstandard Metering Charge (applicable to TOU)		
Single Phase meter	$1.00	
Three Phase meter	$4.25	

* See Schedule 100 for applicable adjustments.

SCHEDULE 7 (Continued)

MONTHLY RATE (Continued)

Renewable Portfolio Options
(available upon enrollment in either Energy Charge option)

Renewable Usage	0.800	¢ per kWh in addition to Energy Charge
Fixed Renewable	$3.50	per month per block
Habitat	$2.50	per month and
	0.800	¢ per kWh in addition to Energy Charge

RENEWABLE PORTFOLIO OPTIONS

The Customer will be charged for the Renewable Portfolio Option in addition to all other charges under this schedule for the term of enrollment in the Renewable Portfolio Option.

Habitat Option

The Company will distribute $2.50 per month as received from each Customer enrolled in the Habitat Option to a nonprofit agency chosen by the Company who will use the funds for habitat restoration. The 0.800¢ per kWh will purchase Tradable Renewable Credits (TRCs) and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

Fixed Renewable Option

The Company will purchase 200 kWhs of TRCs and/or renewable energy per block enrolled in the Fixed Renewable Option. All TRCs purchased under this option will come from new renewable resources.

The Company will also place $2.50 of the amount received from Customers enrolled in the Fixed Renewable Option in a new renewable resources development and demonstration fund. Amounts in the fund will be disbursed by the Company to public renewable resource demonstration projects or projects which commit to supply energy according to a contractually established timetable. The Company will report to the Commission annually by April 1st for the preceding calendar year on collections and disbursements. The fund will accrue interest at the Company's authorized rate of return.

Renewable Usage Option

All amounts received from the Customer under the Renewable Usage Option will acquire TRCs and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

SCHEDULE 7 (Continued)

RENEWABLE PORTFOLIO OPTIONS (Continued)
Renewable Usage Option (Continued)

Energy or TRCs supporting the Renewable Portfolio Options will be acquired by the Company such that within two years of a Customer's purchase of renewable energy, the Company will have received sufficient TRCs or renewable energy to meet the purchases by Customers. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

For purposes of these options, renewable resources include wind generation, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. New TRCs or new renewable resources will mean those qualifying resources placed in service after July 23, 1999, as defined in OAR 860-038-0005.

TIME OF USE PORTFOLIO OPTION

Time Periods

On- and Off-Peak Hours

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

** Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a TOU holiday. If a holiday falls on Sunday, the following Monday is designated a TOU holiday.

SCHEDULE 7 (Continued)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks notice prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having a time payment agreement that has not been kept current from month to month, b) having received two or more final disconnect notices in the past 12 months; or c) having been involuntarily disconnected in the past 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

Pertaining to the TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received two weeks notice prior to the meter read date. Absent the two week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater.

SCHEDULE 7 (Concluded)

SPECIAL CONDITIONS (Continued)
Pertaining to the TOU Option (Continued)

4. The Customer must have a meter provided by the Company which is capable of recording interval usage. Because of the special metering requirements of this option, the Company anticipates that a delay may occur from the time a Customer requests service under this option until the Company can provide it. In the interim, Customers will continue to receive service under Standard Service.

5. The Customer must provide the Company access to the meter on a monthly basis.

6. After a Customer's initial 12 months of service on the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. The Nonstandard Metering Charge will be excluded from the bill comparisons. No refund will be issued for Customers not meeting the 12 month requirement.

7. The Company will recover lost revenue from the TOU Option through Schedule 105.

8. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date.

9. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

SCHEDULE 10
GENERLINK™
(NO NEW SERVICE)

PURPOSE

Provision of generator connection to facilitate Customer use of a generator during power outages and protection for Company employees from back feed caused when a Customer improperly connects a generator.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Single Phase Residential and Small Nonresidential Customers receiving service on Schedule 7 or 32. This schedule is available only to those Single Phase Residential and Small Nonresidential Customers receiving service under Schedule 10 as of April 20, 2005.

SERVICE DESCRIPTION

GenerLink™ automatically disconnects a Customer from the Company's Electricity Service whenever the Customer's generator is operating.

BILLING RATES

Installation Charge	$65.00

The Installation Charge may be paid in 4 monthly installments of $16.25

Monthly Lease Fee	$9.50

SPECIAL CONDITIONS

1. The GenerLink™ capacity is 30 amps.

2. Generators are not provided by the Company.

3. Customers will be provided with an operator's manual that describes how the GenerLink™ unit works and how to operate it safely.

4. GenerLink™ installation requires the written authorization of the homeowner or Small Nonresidential Customer. Where the residence or business is a rental, the landlord must sign the application prior to installation.

SCHEDULE 10 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The Company will retain ownership of the GenerLink™ unit at all times.

6. Only Company approved personnel may install and remove the GenerLink™ unit.

7. The Customer assumes all responsibility for safely operating and maintaining the GenerLink™ unit.

8. GenerLink™ installation assumes Customer agreement not to connect a generator to their home's electrical system without using GenerLink™.

9. The Company will be responsible to replace GenerLink™ units that fail during normal use. If the Customer's activities have damage the GenerLink™ unit, the Customer is responsible to pay for the costs of replacing or repairing the unit.

10. Customers who move within the Company's service territory and would like the GenerLink™ unit transferred to their new residence, will be charged the installation fee.

11. Service under this schedule will be terminated and the GenerLink™ unit will be removed if the Customer fails to pay the charges for a period of 90 days.

12. The Company reserves the right to offer incentives including but not limited to rebates.

TERM

Customers receiving service under this rate schedule will sign an initial two year service agreement. After the completion of the initial agreement, service will be provided on a month to month basis.

After the initial two year term, Customers must give 30 days notice in order to terminate service under this schedule.

SCHEDULE 15
OUTDOOR AREA LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Customers for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer notifies the Company of the burn-out.

MONTHLY RATE

Included in the service rates for each installed luminaire are the following pricing components:

Transmission and Related Services Charge	0.097	¢ per kWh
Distribution Charge	3.476	¢ per kWh
Cost of Service Energy Charge	5.366	¢ per kWh

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate [1] Per Luminaire
Cobrahead				
Mercury Vapor	175	7,000	67	$12.30[2]
	400	21,000	149	19.78[2]
	1,000	55,000	379	41.25[2]
HPS	70	6,300	31	8.89[2]
	100	9,500	43	10.06
	150	16,000	63	11.88
	200	22,000	80	13.88
	250	29,000	103	15.99
	310	37,000	125	18.77[2]
	400	50,000	165	21.56
Flood, HPS	100	9,500	43	10.47
	200	22,000	80	13.95[2]
	250	29,000	103	16.29
	400	50,000	165	21.86
Shoebox (bronze color; HPS flat lens or drop lens, multi-volt)	100	9,500	43	11.00
	150	16,500	63	13.10
Special Acorn Type HPS	100	9,500	43	13.94
	150	16,500	63	15.42
	200	22,000	80	16.94
	250	29,000	103	19.15
Early American Post-Top HPS				
Black	100	9,500	43	10.99
Special Types				
Cobrahead, Metal Halide	175	12,000	72	12.86
Flood, Metal Halide	400	40,000	158	21.17
Flood, HPS	750	105,000	289	35.61

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[(1)]
Special Types (Continued)				
HADCO Independence	100	9,500	43	$13.03
Early American	150	16,000	63	14.84
HADCO Techtra HPS	100	9,500	43	20.68
	150	16,000	63	22.49
	250	29,000	103	33.12
KIM Archetype HPS	250	29,000	103	20.65
	400	50,000	165	26.01
Holophane Mongoose, HPS	150	16,000	63	14.27
	250	29,000	103	17.94
	400	50,000	165	23.53

Rates for Area Light Poles [(2)]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$ 6.30
	55 or less	7.91
Wood, Painted for Underground	35 or less	7.37[(3)]
Wood, Curved Laminated	30 or less	9.15[(3)]
Aluminum, Regular	16	7.79
	25	12.68
	30	13.71
	35	15.10
Aluminum, Fluted Ornamental	14	14.82

(1) See Schedule 100 for applicable adjustments.
(2) No pole charge for luminaires placed on existing Company-owned distribution poles.
(3) No new service.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lights Poles[1] (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Aluminum Davit	25	$13.09
	30	13.96
	35	15.43
	40	18.84
Aluminum Double Davit	30	16.80
Aluminum, HADCO, Fluted Ornamental	16	14.18
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	26.49
Concrete Ameron Post-Top	25	31.32
Fiberglass Fluted Ornamental; Black	14	8.65
Fiberglass, Regular		
Black	20	5.48
Gray or Bronze	30	7.34
Other Colors (as available)	35	9.98
Fiberglass, Anchor Base Gray	35	15.98
Fiberglass, Direct Bury with Shroud	18	8.30

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 15 (Concluded)

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installations or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. Electricity delivered to the Customer under this schedule may not be resold by the Customer.

4. If the Customer requests removal of Lighting Service equipment within five years of its installation, the Customer will be responsible for the costs of removal.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 32
SMALL NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers. A Small Nonresidential Customer is a Customer that has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$12.00	
Three Phase Service	$16.00	
Transmission and Related Services Charge	0.214	¢ per kWh
Distribution Charge		
First 5,000 kWh	3.073	¢ per kWh
Over 5,000 kWh	0.565	¢ per kWh
Energy Charge		
Standard Service	5.605	¢ per kWh
or		
Time-of-Use (TOU) Portfolio Option (enrollment is necessary)		
On-Peak Period	9.537	¢ per kWh
Mid-Peak Period	5.605	¢ per kWh
Off-Peak Period	3.178	¢ per kWh
Nonstandard Metering Charge (applicable to TOU)		
Single Phase meter	$2.35	
Three Phase meter	$4.25	

* See Schedule 100 for applicable adjustments.

SCHEDULE 32 (Continued)

MONTHLY RATE (Continued)

Renewable Portfolio Options (available upon enrollment in either Energy Charge Option)

Renewable Usage	0.800	¢ per kWh in addition to Energy Charge
Fixed Renewable	$3.50	per month per block
Habitat	$2.50	per month and
	0.800	¢ per kWh in addition to Energy Charge

RENEWABLE PORTFOLIO OPTIONS

The Customer will be charged for Renewable Portfolio Option in addition to all other charges under this schedule for the term of enrollment in the Renewable Portfolio Option.

Habitat Option

The Company will distribute $2.50 per month as received from each Customer enrolled in the Habitat Option to a nonprofit agency chosen by the Company who will use the funds for habitat restoration. The 0.800¢ per kWh will purchase Tradable Renewable Credits (TRCs) and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

Fixed Renewable Option

The Company will purchase 200 kWhs of TRCs and/or renewable energy per block enrolled in the Fixed Renewable Option. All TRCs purchased under this option will come from new renewable resources.

The Company will also place $2.50 of the amount received from Customers enrolled in the Fixed Renewable Option in a new renewable resources development and demonstration fund. Amounts in the fund will be disbursed by the Company to public renewable resource demonstration projects or projects which commit to supply energy according to a contractually established timetable. The Company will report to the Commission annually by April 1st for the preceding calendar year on collections and disbursements. The fund will accrue interest at the Company's authorized rate of return.

Renewable Usage Option

All amounts received from the Customer under the Renewable Usage Option will acquire TRCs and/or renewable energy consisting of at least 20% of new renewable resources and the remainder from other qualifying resources.

SCHEDULE 32 (Continued)

RENEWABLE PORTFOLIO OPTIONS (Continued)
Renewable Usage Option (Continued)

Energy or TRCs supporting the Renewable Portfolio Options will be acquired by the Company such that within two years of a Customer's purchase of renewable energy, the Company will have received sufficient TRCs or renewable energy to meet the purchases by Customers. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

For purposes of these options, renewable resources include wind generation, solar, biomass, low impact hydro (as certified by the Low Impact Hydro Institute) and geothermal energy sources used to produce electric power. New TRCs or new renewable resources will mean those qualifying resources placed in service after July 23, 1999, as defined in OAR 860-038-0005.

TIME-OF-USE (TOU) OPTION

Time Periods

Summer Months (begins May 1st of each year)

On-Peak	3:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	6:00 a.m. to 3:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday; 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

Winter Months (begins November 1st of each year)

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m. Monday-Friday
Mid-Peak	10:00 a.m. to 5:00 p.m. and 8:00 p.m. to 10:00 p.m. Monday-Friday 6:00 a.m. to 10:00 p.m. Saturday
Off-Peak	10:00 p.m. to 6:00 a.m. all days; 6:00 a.m. to 10:00 p.m. Sunday and Holidays**

** Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25). If a holiday falls on Saturday, Friday is designated a TOU holiday. If a holiday falls on Sunday, the following Monday is designated a TOU holiday.

SCHEDULE 32 (Continued)

DAILY PRICE

The Daily Price, applicable with Direct Access Service, is available to those Customers who were served under Schedule 532 and subsequently returned to this schedule before meeting the minimum term requirement of Schedule 532. The Customer will be charged the Daily Price and Nonstandard Metering charges of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index)
- plus 0.236¢ per kWh for wheeling
- times a loss adjustment factor of 1.0834

If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as “survey-based” will be considered reported.

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

Customers must enroll to receive service under any portfolio option. Customers may initially enroll or make one portfolio change per year without incurring the Portfolio Enrollment Charge as specified in Schedule 300.

Pertaining to Renewable Portfolio Options

1. Service will become effective with the next regularly scheduled meter reading date provided the Customer has selected the option at least five days prior to their next scheduled meter read date. Absent the five-day notice, the change will become effective on the subsequent meter read date. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

SCHEDULE 32 (Continued)

SPECIAL CONDITIONS (Continued)

Pertaining to Renewable Portfolio Options (Continued)

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having a time payment agreement that has not been kept current from month to month, b) having received two or more final disconnect notices in the past 12 months; or c) having been involuntarily disconnected in the past 12 months.

3. The Company will use reasonable efforts to acquire renewable energy, but does not guarantee the availability of renewable energy sources to serve Renewable Portfolio Options. The Company makes no representations as to the impact on the development of renewable resources or habitat restoration projects of Customer participation.

Pertaining to the TOU Option

1. Service may be terminated at the next regularly scheduled meter reading provided the Company has received notice two weeks prior to the meter read date. Absent the two-week notice, the termination will occur with the next subsequent meter reading date.

2. Participation requires a one year commitment by the Customer. Generally, if a Customer requests removal from the TOU Option, the Customer will be required to wait 12 months before re-enrolling. However, a Customer may request to reinstate service within 90 days of termination, in which case the Portfolio Enrollment Charge will be waived.

3. The Customer must take service at 120/240 volts or greater. Single phase 2-wire grounded service is not eligible because of special metering requirements.

4. The Customer must have a meter provided by the Company which is capable of recording interval usage. Because of the special metering requirements of this option, the Company anticipates that a delay may occur from the time a Customer requests service under this option until the Company can provide it. In the interim, Customers will continue to receive service under the Standard Cost of Service Option.

5. The Customer must provide the Company access to the meter on a monthly basis.

SCHEDULE 32 (Concluded)

SPECIAL CONDITIONs (Continued)

Pertaining to the TOU Option (Continued)

6. At the end of the Customer's first 12 months of service under the TOU Option, the Company will calculate what the Customer would have paid under Standard Service and compare billings. If the Customer's Energy Charge billings (including all applicable supplemental adjustments) under the TOU Option exceeded the Standard Service Energy Charge (including all applicable supplemental adjustments) by more than 10%, the Company will issue the Customer a refund for the amount in excess of 10% either as a bill credit or refund check. The Nonstandard Metering Charge will be excluded from the bill comparisons. No refund will be issued for Customers not meeting the 12-month requirement.

7. The Company will recover lost revenue from the TOU Option through Schedule 105.

8. Billing will begin for any Customer on the next regularly scheduled meter reading date following the initialization meter reading made on a regularly scheduled meter reading date.

9. The Company may choose to offer promotional incentives, including but not limited to rebates or coupons.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 38
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY STANDARD SERVICE (COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers: 1) served at Secondary voltage with a monthly Demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 as of December 31, 2006.

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$20.00	
Three Phase Service	$25.00	
Transmission and Related Services Charge	0.086	¢ per kWh
Distribution Charge	3.405	¢ per kWh
Energy Charge**		
On-Peak Period	6.091	¢ per kWh
Off-Peak Period	5.193	¢ per kWh

* See Schedule 100 for applicable adjustments.

** On-peak Period is Monday-Friday, 7:00 a.m. to 8:00 p.m. off-peak Period is Monday-Friday, 8:00 p.m. to 7:00 a.m.; and all day Saturday and Sunday.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In Addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

REACTIVE DEMAND

In addition to 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 38 (Concluded)

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. Service under this schedule will begin on the first day of the Customer's regularly scheduled Billing Period.

2. In no case will the Company refund a Customer by retroactively adjusting the rate at which service was billed prior to the date the Customer begins service on this schedule.

2. Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 49% on-peak and 51% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 47
SMALL NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

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

Basic Charge		
Summer Months**	$25.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.181	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand	3.714	¢ per kWh
Over 50 kWh per kW of Demand	1.714	¢ per kWh
Energy Charge***	5.096	¢ per kWh

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 10 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 47 (Concluded)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 49
LARGE NONRESIDENTIAL
IRRIGATION AND DRAINAGE PUMPING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

MONTHLY RATE

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

Basic Charge		
Summer Months**	$30.00	
Winter Months**	No Charge	
Transmission and Related Services Charge	0.180	¢ per kWh
Distribution Charge		
First 50 kWh per kW of Demand	3.000	¢ per kWh
Over 50 kWh per kW of Demand	1.000	¢ per kWh
Energy Charge***	5.064	¢ per kWh

* See Schedule 100 for applicable adjustments.
** Summer Months and Winter Months commence with meter readings as defined in Rule B.
*** For billing purposes, the Demand will not be less than 30 kW.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge if necessary, to justify the Company's investment in service facilities.

SCHEDULE 49 (Concluded)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 54
LARGE NONRESIDENTIAL
TRADABLE RENEWABLE CREDITS RIDER

PURPOSE

This rider is an optional supplemental service that supports the development of New Renewable Energy Resources as defined in ORS 757.600. Under this Schedule a Large Nonresidential Customer may purchase Tradable Renewable Credits (TRCs) based on a percentage of the Customer's load, subject to a minimum purchase. The purchase guarantees an equivalent amount of generation from qualified renewable resources will be transmitted within the Western Electricity Coordinating Council.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Large Nonresidential Customers.

RATE

A Customer may purchase TRCs at:

1.7¢ per kWh

A minimum TRC purchase of 1,000 kWh times 1.7¢ ($17.00) per month is required. For larger purchases, volume discounts may be available, subject to negotiation, pursuant to the execution of a written contract.

SPECIAL CONDITIONS

1. The Customer may enroll to purchase TRCs on a month to month basis or sign an annual contract to pay annually or monthly. Service will become effective upon execution of a signed agreement.

2. The Company will not accept enrollments from accounts with poor credit history. For the purposes of this rate schedule, poor credit history is defined as: a) having received two or more final disconnect notices in the past 12 months; or b) having been involuntarily disconnected in the past 12 months.

3. The Company makes no representations as to the impact on the development of renewable resources from Customer participation.

SCHEDULE 54 (Concluded)

SPECIAL CONDITIONS (Continued)

5. The Company is not required to own renewables or to acquire energy from renewable resources simultaneously with Customer usage.

6. A TRC purchase by the Company sufficient to meet the total of all Customer purchases of TRCs will occur, at least, on an annual basis.

6. All incremental costs and revenues associated with the provision of services under this schedule will be appropriately charged or credited to nonutility accounts.

7. Upon Customer written or verbal permission, the Company may use Customer proprietary information gathered for the provision of Electricity Services as long as it provides the same information under the same terms and conditions to alternative TRC providers.

8. The Company will communicate to its Customers or potential Customers, both in its verbal conversations and in its written materials that: the Customer may buy TRCs from other providers; and Customers are not required to buy TRCs from the Company in order to continue to receive the Company's safe and reliable Electricity Service.

9. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other TRC providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Large Nonresidential TRC program.

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 1 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 > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 1,000 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. The Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for generator operations, will be used to calculate the Baseline Demand. 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.

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

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 1,000 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.

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. 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. 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.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

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.

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.

SCHEDULE 75 (Continued)

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written 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. 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.

6. The Customer will not use Scheduled Maintenance Energy, Unscheduled Energy or Reserved Capacity 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.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

8. The Customer's Baseline Demand may be modified as requested by the Customer upon the addition of permanent energy efficiency measures, load shedding, or the removal of equipment. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation.

9. A change in Baseline Demand related to modifications in generating capacity or generation operations may be made provided the Customer provides not less than two calendar years prior notice to the Company of such change. Any subsequent notice by the Customer under this special condition must be made no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand.

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.

TERM

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

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:

Transmission and Related Services Charge
per kW of Daily Economic Replacement Power (ERP)
On-Peak Demand per day $0.026

Daily ERP Demand Charge

	Delivery Voltage	
	Secondary and Primary	Subtransmission
per kW of Daily ERP Demand during On-Peak hours per day*	$0.095	$0.050

System Usage Charge
per kWh of ERP 0.178 ¢

Transaction Fee
per Energy Needs Forecast (ENF) $50.00

Energy Charge**
per kWh of ERP See below for ERP Pricing

* 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.

** See Schedule 100 for applicable adjustments.

SCHEDULE 76R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 75). The Customer must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that ERP is requested.

Each ENF will be based on the Customer's expected Energy requirements and the Customer will use best efforts to conform actual Energy usage to the ENF and utilize Energy imbalances to the minimum extent reasonably possible.

The ENF will specify the expected ERP needed by hour. The Customer will deliver the ENF to the Company in accordance with Company procedures. The Company will inform the Customer as to the availability of ERP at the time of the ENF request. The Company can choose to provide all or a portion of the ENF and will inform the Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

<u>Economic Replacement Power Pricing</u>

Energy will be priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.236¢ per kWh for wheeling, plus losses. 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.

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

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

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

SCHEDULE 76R (Continued)

IMBALANCE CHARGES

Imbalance Amount = The absolute value of (ENF minus ERP)

Imbalance Amount	Adjustment Amount
Less than 7.5% of Energy Needs Forecast	zero
Greater than 7.5% of Energy Energy Needs Forecast	10% of Hourly Price applied to Imbalance Amount greater than 7.5% of Energy Needs Forecast

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 76R (Concluded)

SPECIAL CONDITIONS (Continued)

3. All charges and requirements of Schedule 75 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to transmission constraints.

6. The Customer must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than five MW that are expected to last one hour or longer. The Company may require the Customer to change its forecast if the Company believes the forecast does not adequately represent the expected load.

7. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 75 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

8. The Company is not responsible for providing market information to Customer.

9. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

10. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

SCHEDULE 81
NONRESIDENTIAL
EMERGENCY DEFAULT SERVICE

AVAILABLE

In all territory served by the Company. The Company may restrict Customer loads returning to this schedule in accordance with Rule K Curtailment Plan and Rule C Emergency Curtailment.

APPLICABLE

To existing Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule.

MONTHLY RATE

All charges for Emergency Default Service except the energy charge will be billed at the Customer's applicable Standard Service rate schedule for five business days after the Customer's initial purchase of Emergency Default Service.

ENERGY CHARGE DAILY RATE

The Energy Charge Daily Rate will be 125% of the Dow Jones Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (DJ-Mid-C Firm Index) plus 0.236 ¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on-peak and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

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.

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

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

ANCILLARY SERVICES

Customers receiving this service are required to pay for Ancillary Services at the rates determined by the Company's Open Access Transmission Tariff (OATT), Original Volume 8 (PGE-8) Transmission Services.

SCHEDULE 81 (Concluded)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service under this schedule will terminate five business days from initial purchase.

RULES AND REGULATIONS

Service and rates under this schedule are subject to all applicable General Rules and Regulations contained in the Tariff of which this schedule is a part.

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 1,000 kW more than once in the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW.

MONTHLY RATE

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

	Delivery Voltage	
	Secondary	Primary
Basic Charge		
Single Phase Service	$20.00	
Three Phase Service	$25.00	$90.00
Transmission and Related Services Charge		
per kW of monthly Demand	$0.66	$0.66
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity	$2.29	$2.11
per kW of monthly Demand		
First 30 kW of Demand	$2.07	$2.07
Over 30 kW of Demand	$2.64	$2.64
Energy Charge		
Cost of Service Option per kWh	5.544 ¢	5.344 ¢
See below for Daily or Monthly Pricing Option descriptions.		
System Usage Charge		
per kWh	0.216 ¢	0.205 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

SCHEDULE 83 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option 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 below and must complete the specified term of their current option except as provided below under the Monthly Direct Access Election Enrollment Window. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.236¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window.

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

Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment.

Interval metering and meter communications should be in place prior to initiation of service under this schedule. Where interval metering has not been installed, the Customer's Electricity usage will be billed as 65% on-peak and 35% off-peak. Upon installation of an interval meter, the Company will bill the Customer according to actual metered usage.

SCHEDULE 83 (Continued)

NOVEMBER ELECTION WINDOW

A Customer may change Energy Charge options by notifying the Company of his/her choice during the November Election Window.

The November Election Window begins at 2:00 p.m. on November 15th (or the following work day if the 15th falls on a weekend or holiday) and continues until 5:00 p.m. at the close of the fifth consecutive business day.

A Customer who elects an Energy Charge Option during the November Election Window must complete the specified term of their current option.

MONTHLY DIRECT ACCESS ELECTION ENROLLMENT WINDOW

For the remaining 11 months, the Monthly Direct Access Election Enrollment Window is applicable to Customers who have a historical usage or have demonstrated that projected usage in the current calendar year is at least 8,760,000 (1MWa) from one or more PODs. Each POD must have a Facility Capacity of at least 250 kW.

A Monthly Direct Access Election Enrollment Window will open at 12:00 p.m. PPT on the 15th of each month and remain open until 5:00 p.m. the next business day. If the 15th falls on a weekend or holiday, the window will be begin on the next business day. Customers may make a service election during a Monthly Direct Access Election Enrollment Window through the Company website (www.PortlandGeneral.Biz).

By 12:00 p.m. on the day of each Monthly Direct Access Enrollment Window, the Company will make available and post on its website (www.PortlandGeneral.Biz) the Schedule 128, Transition Adjustment applicable to those Customers electing discontinuation of Cost of Service.

During the Monthly Direct Access Election Enrollment Window, Cost of Service Customers may choose at this time discontinuation of Cost of Service. The elected service option will become effective the first calendar day of the month, approximately 45 days from the date of the Direct Access Election Enrollment Window. A Customer making a monthly election under this option may not return to the Cost of Service Option until the following calendar year, subject to the requirements of making an annual Cost of Service election.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW for primary voltage service.

SCHEDULE 83 (Concluded)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

A Customer served under the Daily or Monthly Option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 84
LARGE NONRESIDENTIAL
LARGE LOAD SPLIT SERVICE RIDER OPTION

PURPOSE

The Large Load Split Service Rider Option allows a Customer to receive Direct Access Service for a percentage of its usage, while the remainder is served on the Cost of Service option.

APPLICABILITY

To Large Nonresidential Customers served on Schedule 83 or 89 that demonstrate the following:

1) Usage in the most recent 12 months or, projected annual usage or where 12 months of usage history is not available, of at least 87,600,000 kWh (10 MWa) from one or more participating Points of Delivery (PODs);
2) An election to maintain at least 10 MWa usage on this option;
3) A Facility Capacity of at least 250 kW at each participating POD; and
4) An average non-coincident monthly load factor for the aggregated PODs participating of at least 60%, determined by the Company based the historical usage information.

DESCRIPTION OF SERVICE OPTION

A Customer receiving service under this rider must elect 10% to 50% of eligible load to be served on Direct Access Service. All remaining load will be served by the Company.

DIRECT ACCESS BLOCK

The Direct Access Block is a fixed kWh served on Direct Access Service.

The Customer will choose the percentage of load to be served on Direct Access Service. The Company will determine the Direct Access Block by multiplying that percentage by the Customer's annual historical kWh usage for all participating PODs with the result divided by 8,760 hours, subject to the following limits:

- A Direct Access Block will not result in more than 50% of the annual historical usage.
- A POD may not have more than five consecutive days (or 120 hours) where the Direct Access Block is greater than the historical usage. When this occurs, the percentage that determines the Direct Access Block will be reduced for all of the Customer's PODs.

The Direct Access Block will remain unchanged for the calendar year [which may be less than 12 months if an Electricity Service Supplier (ESS) does not make a timely submittal of the required Direct Access Service Requests (DASRs)].

SCHEDULE 84 (Continued)

COMPANY SERVED LOAD

The Company Served Load is the difference between the Direct Access Block and the metered interval load data for each POD by hour. If actual usage in an hour is less than the Direct Access Block, the Company supplied Energy is deemed to be zero for the hour.

DIRECT ACCESS SERVICE

The Customer must arrange for an ESS to provide Direct Access Service for the Direct Access Block. The ESS is responsible for enrolling each participating POD in Direct Access Service and meeting all requirements defined in Rule K for timely DASR submittals. Beginning on January 1st, all participating POD(s) will be billed at the Daily Price until Direct Access Service commences for the participating PODs.

MONTHLY RATE

The Monthly Rate is the sum of the following charges:

Energy Charge

For the Company Served Load, the Cost of Service Monthly Energy Charge from the applicable Schedule 83 or 89 rates (for the appropriate Delivery Voltage) will apply.

The Customer's ESS will bill separately for Energy provided for the Direct Access Block.

Other Charges

The following charges will be applied to the Customer's total usage for each POD: The applicable Schedule 83 or 89 Basic Charge, Transmission and Related Services Charge, Distribution Charge, System Usage Charge, Reactive and other applicable charges except the Energy Charge and including supplemental adjustments applied to each POD's total Energy, Demand, Facility Capacity and Reactive Demand.

Schedule 128, Short-Term Transition Adjustment, will apply only to the Energy provided for the Direct Access Block.

A credit will be applied to the Direct Access Block billing for Transmission and Related Services. The credit will be equal to the Schedule 83 or 89 Transmission and Related Services Charge applied to the Direct Access Block Demand.

SCHEDULE 84 (Concluded)

ENROLLMENT

The Company will provide a list of eligible PODs to Customers by September 15th of each calendar year (or the following business day if the 15th falls on a weekend or holiday).

By 5:00 p.m. on September 29th (or 10 business days from the date of Notification), the Customer must provide written notification to the Company verifying the following:

1) The Customer's intent to elect the service under this Rider.
2) A list of the PODs the Customer intends to enroll under this service option during the November Election Window (as defined in Schedules 83 and 89).
3) The proposed percentage of load to be served on Direct Access Service. This designation will be used by the Company to determine the Direct Access Block.

By October 15th (or the following business day if the 15th falls on a weekend or holiday), the Company will confirm receipt of the election and the PODs the Customer intends to enroll. In order to receive service under this rider, the Customer must confirm enrollment during the November Election Window. After the Customer selection is confirmed during the November Election Window, the Company will provide the Customer with POD identification (PODID) numbers to be used by an ESS to enroll the Direct Access Block PODs in Direct Access. The Customer is responsible for furnishing this information to its selected ESS.

SET UP FEE

Customers notifying the Company of their intent to receive service under this rider will be charged a one-time non-refundable fee of $70 per each designated POD. This fee will be due with the Customer's written notification in September for a service election in November and service the following January.

TERM

All of the Customer's enrolled PODs will remain on this option for the entire calendar year.

SCHEDULE 86
NONRESIDENTIAL
DEMAND BUY BACK RIDER

PURPOSE

This rider is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce their Electricity usage in return for a payment, at times and at prices determined by the Company. The Company will notify participating Customers of the opportunity to reduce Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To qualifying Customers served under Schedules 38, 83, 84 and 89 who satisfy the conditions contained in this rider. Customers must execute a Demand Buy Back Agreement prior to receiving service and have the capability to reduce not less than 250 kW at each metered location for each hour during a Buy Back Event. At the Company's discretion, new Customers that can establish a Baseline Usage and reduce a minimum of 250 kW per hour may take service under this rider.

BUY BACK CREDIT DETERMINATION

Energy Price

The Energy Price will be a price or prices quoted by the Company for a specified Buy Back Event, subject to requirements and other conditions described in Special Conditions.

Hourly Credit Rate

		Customer's Rate Schedule		
Energy Price	**less**	Energy Price	=	Hourly Credit Rate (¢/kWh)

The Hourly Credit Rate will be determined by subtracting the Energy Charge the Customer would pay on their otherwise applicable rate schedule from the Energy Price. This calculation is performed for each hour during the Buy Back Event. In circumstances when the Company cancels all or a portion of a Buy Back Event, the Hourly Credit Rate will be determined as described in Buy Back Event Cancellation.

Hourly Credit

Buy Back Amount (kWh) **X** Hourly Credit Rate = Hourly Credit

SCHEDULE 86 (Continued)

BUY BACK CREDIT DETERMINATION (Continued)
Hourly Credit (Continued)

The Hourly Credit is the amount owed to the Customer for each hour of the Buy Back Event. The Hourly Credit is determined by multiplying the Buy Back Amount by the Hourly Credit Rate. The Hourly Credit will not be less than zero.

Buy Back Credit

The Buy Back Credit is the amount paid to the Customer for its Electricity reduction during a Buy Back Event and is the sum of each Hourly Credit during such event (minus any amounts owed as a result of failure to comply during an Extended Buy Back Event).

PAYMENTS

The Company will pay the Buy Back Credit to the Customer within 60 days of the Buy Back Event.

BUY BACK AMOUNT

The Buy Back Amount will be the difference between the Customer's Baseline Usage and the Customer's measured hourly load during the term of the Buy Back Event. The Customer will participate by operating below its Baseline Usage for the length of the requested Buy Back Event. A participating Customer's measured load for purposes of determining a Buy Back Amount must be zero kW or greater.

BASELINE USAGE

The Customer's Baseline Usage is dynamic and is defined as the average Energy usage for each hour for a minimum of approximately 14 typical operational days prior to the Buy Back Event. Typical operational days exclude days that a Customer has participated in a Buy Back Event. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Usage when the Customer's Energy usage is highly variable.

BUY BACK PLEDGE

The Buy Back Pledge is the amount of Energy the Customer commits to curtail when it agrees to participate in a Buy Back Event. The Buy Back Pledge must be greater than a 250 kW reduction and can vary by hour. The Customer must submit to the Company the amount of the Buy Back Pledge prior to the Buy Back Event through the specified notification method. The Customer will receive an acceptance confirmation for its pledge prior to the start of the event. A Buy Back Pledge cannot exceed Baseline Usage and is the expected Buy Back Amount for the Buy Back Event. The Company reserves the right to reject a Buy Back Pledge.

SCHEDULE 86 (Continued)

RATE SCHEDULE ENERGY PRICE

The Rate Schedule Energy Price is the Energy Charge contained in the rate schedule under which the Customer is served. For rate schedules that contain on- and off-peak charges, the on-peak Energy price will be the Rate Schedule Energy Price during on-peak hours of a Buy Back Event and the off-peak Energy price will be the Rate Schedule Energy Price during off-peak hours of a Buy Back Event. No supplemental adjustments will be applied to the Energy Charge when determining the Rate Schedule Energy Price.

NOTIFICATIONS

The Company will utilize a secured Internet web site as the primary method to notify participants of Buy Back Events and to receive Customer notification of participation in a Buy Back Event. The Company's notification will include a time and date by which the participating Customers must submit a Buy Back Pledge. The Company will provide the Customer with access codes to the secured Internet web site. Other methods of notification such as, facsimile, telephone and electronic mail, may be utilized at the discretion of the Company.

BUY BACK EVENT

The Company is not obligated to call a Buy Back Event and the Customer is not obligated to reduce Energy upon being advised of a Buy Back Event. The Company will not be liable for failure to advise a Customer of a Buy Back Event.

Buy Back Event Cancellation

The Company reserves the right to cancel all or a portion of a Buy Back Event upon notification to participating Customers (i.e., those that have a Buy Back Pledge accepted by the Company), except that an Extended Buy Back Event will be cancelled only upon mutual agreement of the Customers participating in the particular Extended Buy Back Event and the Company. Upon notification of a cancellation, the Customer may resume its normal operations or continue with load reductions consistent with the requirements of its Buy Back Pledge. A Customer that elects to resume its normal operations will not receive a Buy Back Credit. A Customer that continues with load reductions will receive a Buy Back Credit for the amount of Energy reduced during the cancelled hours of the event. Such credit will be based on an Hourly Credit Rate determined by the amount of advance notice the Company provides the Customer prior to the start of the cancellation as written below. In no circumstance will the Company notify the Customer less than two hours prior to the start of a cancellation.

SCHEDULE 86 (Continued)

BUY BACK EVENT (Continued)
Buy Back Event Cancellation (Continued)

For a Customer that provides load reductions during non-cancelled hours of a partially cancelled Buy Back Event, the Company will pay the Customer for such load reductions at the Hourly Credit Rate quoted by the Company for the event.

For an announced cancellation to become effective:

1) In two hours, the Hourly Credit Rate is 7.0 ¢ per kWh; or

2) Between two hours and four hours, the Hourly Credit Rate is 5.0 ¢ per kWh; or

3) Between four hours and six hours, the Hourly Credit Rate is 3.5 ¢ per kWh; or

4) If more than six hours, no Hourly Credit is provided.

FAILURE TO COMPLY WITH BUY BACK PLEDGE

Single Day Buy Back Event

If a Customer's Buy Back Amount for any hour is less than 90% of the Customer's Buy Back Pledge, the Company may refuse to accept future pledges from the Customer until the capability to meet their pledge is demonstrated in a manner acceptable to the Company. After the third occurrence of nonperformance, the Company may refuse to allow the Customer to participate in future Buy Back Events.

Extended Buy Back Event

If a Customer's actual Buy Back Amount for any hour of an Extended Buy Back Event (as defined below in Special Condition 3 below) is less than the Buy Back Pledge, the Customer will pay to the Company an amount equal to the applicable Dow Jones Mid-Columbia Daily Electricity Firm On-Peak Price Index, plus 5%, multiplied by the difference between the Buy Back Pledge and the actual hourly Buy Back Amount for all of the hours during the Extended Buy Back Event that the pledge is not met. The Company may for any Extended Buy Back Event explicitly establish other lesser consequences for noncompliance.

SCHEDULE 86 (Continued)

DEMAND BUY BACK AGREEMENT

The Customer and Company must execute a written Demand Buy Back Agreement.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The portion of the Customer's load that is billed according to a Daily Price Option is not eligible to participate in a Buy Back Event.

2. Metering and Communications Equipment. The Customer may not participate in this rider until the Company has installed metering that records usage in 15 minute intervals. The Customer will provide communication service to the meter if requested by the Company. Service under this rider is subject to meter availability.

3. Buy Back Event. A Buy Back Event specifies the dates, times and duration of a Company requested load reduction and will be for one or more consecutive hours. A Buy Back Event with a duration of more than 24 consecutive hours is an Extended Buy Back Event. An Extended Buy Back Event may include requirements for a single, continuous Buy Back Pledge to which the participant must comply for the duration of the event. More than one Buy Back Event may occur in one day and more than one Buy Back Event may be in effect simultaneously.

4. Notification. The Company is not responsible for any load reduction that has not been confirmed and accepted by the Company.

5. Liability. The Company is not responsible for any consequences to the participating Customer that result from a Buy Back Event or the Customer's effort to reduce Energy in response to a Buy Back Event.

6. System Emergencies. Where the Company requests load interruptions for a system emergency, this rider is not applicable.

7. Third Party Management. The Company may utilize a third party to provide program management support for this rider. The Company has the right to provide the Customer's Energy consumption data to a third party for the purpose of providing service under this rider. Such information will be provided to a third party subject to confidentiality requirements.

SCHEDULE 86 (Concluded)

SPECIAL CONDITIONS (Continued)

8. Load Shifting. The Company may quote a separate Energy Price for Customers that shift load in conjunction with a Buy Back Event. Load shifting is the change in a Customer's Energy usage during non-Buy Back Event hours to compensate for reduced Energy usage during the Buy Back Event. For purposes of this rider, load shifting occurs when the Customer's Energy usage during the 24 hours preceding or following a Buy Back Event (or any day of an extended Buy Back Event) increases from the applicable hourly Baseline Usage by more than 50% of the Buy Back Amount.

9. Testing. The Company and the Customer will test the Customer's ability to reduce Energy usage prior to the Customer's participation in a Buy Back Event.

10. Eligibility for Other Schedules. If a Customer takes service under a Direct Access Service schedule (when available), it is no longer eligible to participate in this rider.

11. Billing Errors. Should an error occur in the calculation of the Buy Back Credit or any of the underlying components, the Company will provide written notice to the Customer detailing the circumstances and amount of adjustment. The Customer will return the overpayment to the Company or the Company will pay the underpayment to the Customer, as applicable, within a period of time agreed to by the Customer and the Company after notice has been given.

TERM

Service under this schedule will not be for less than one year term.

SCHEDULE 87
LARGE NONRESIDENTIAL
(> 1000 MW DEMAND)
EXPERIMENTAL REAL TIME PRICING (RTP) SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To the first six Large Nonresidential Customers with Facility Capacity greater than 1,000 kW Demand that apply and are accepted by the Company. Customers applying for service under this schedule must be able to demonstrate their ability to respond to market price signals. The Company will create a unique consumption baseline for each participating Customer. Each Customer will have different capabilities to respond to the hourly prices and thus will be considered a separate Customer class under this schedule. Customers participating in Schedules 84, 86, 88 or 200 are not eligible for service under this schedule.

MONTHLY BILL

The Monthly Bill consists of a Standard Bill, Administrative and Reactive Demand Charges, Adjustments, and a charge or credit based on the difference between a Customer's actual usage and their Customer Baseline Load (CBL) in each hour and the hourly Energy prices provided during the Billing Period. The Monthly Bill is calculated using the following formula:

$$\text{Bill}_{\text{Mo.}} = \text{Standard Bill}_{\text{Mo}} + \sum \text{Price}_{\text{Hr}} \times [\text{Load}_{\text{Hr.}} - \text{CBL}_{\text{Hr.}}] + \text{Administrative Charge} + \text{Reactive Demand Charge} + \text{Adjustments}$$

Where:

$\text{Bill}_{\text{Mo.}}$ = Customer's Monthly Bill for service under this schedule

Standard $\text{Bill}_{\text{Mo.}}$ = Customer's bill based on usage as defined by the CBL and billed under the Annual Cost of Service under Schedule 83 or 89

$\sum$ = Sum over all hours of the monthly Billing Period

$\text{Price}_{\text{Hr.}}$ = Hourly price based on marginal Energy costs

$\text{Load}_{\text{Hr.}}$ = Customer's actual load in an hour

$\text{CBL}_{\text{Hr.}}$ = Customer's baseline load shape on an hourly basis

SCHEDULE 87 (Continued)

STANDARD BILL

The Standard Bill is calculated by applying the Annual Cost of Service Option under Schedule 83 or 89 to a CBL for each month of the year, excluding the Reactive Demand Charge and Adjustments identified in Schedule 100. If prices are revised, those changes will be reflected in the Customer's Standard Bill based on the CBL for a given month. Hourly Energy prices are applied only to kWh usage changes from the CBL in each hour.

CUSTOMER BASELINE LOAD (CBL)

The CBL is the Customer's hourly load for a 12-month period at typical levels of operation. It is developed based on the Customer's specific hourly load data or monthly billing data allocated to hours based on the consumption pattern agreed to by the Customer and the Company as typical of the Customer's operation.

Agreement to a CBL is a precondition for service under this schedule. The CBL is proprietary and will not be released to any other entity without the approval of the Customer and the Company. In order that the CBL reflect the Customer's Energy and Demand as accurately as possible, the Customer may request adjustments to the CBL for the following reasons:

1. The installation of permanent energy efficiency measures either as a participant in Energy Trust of Oregon programs or other verifiable conservation or technology improvement measures.
2. The addition or removal of equipment that results in a permanent change in the Customer's expected electricity consumption.

If the Customer leaves the program, he/she may not be allowed to return for a minimum of 12 months. A new CBL will be calculated in such cases based on the most recent usage. At a minimum, the CBL will be reviewed every three years and may be adjusted.

HOURLY ENERGY PRICE

Hourly Energy Prices are determined each day for the following day using Mid-Columbia Day Ahead Prices for on- and off-peak periods shaped to hourly prices based on the reported hourly Mid-Columbia prices from preceding days. The following charges will be added to the shaped hourly prices, 0.236 ¢ per kWh for wheeling, plus losses and the System Usage Charge as specified in Schedule 83 or 89. If prices are not reported for a particular day or days, the Company will estimate and shape prices from its hourly Energy price projections.

In addition to the above charges, consumption of Energy above the CBL will be billed a 0.300¢ per kWh recovery factor. For consumption of Energy below the CBL, a 0.300¢ per kWh recovery factor will be subtracted from the Hourly Energy Price.

SCHEDULE 87 (Continued)

REVENUE NEUTRALITY

The Customer's bill under Schedule 87 will equal the Customer's bill under the Annual Cost of Service Option under Schedules 83 or 89 assuming the Customer uses Electricity according to the CBL plus the Administrative Charge.

ADMINISTRATIVE CHARGE

The Customer will pay an Administrative Charge of $155 per month to cover additional billing, administrative and communication costs associated with this service schedule.

REACTIVE DEMAND CHARGE

The Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand in the Billing Period.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100. Applicable adjustments are applied only to actual usage. When the adjustment is based on factors other than usage, such as Schedule 108, the adjustment will be applied to the monthly bill, after including all other applicable adjustments.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. Customers who request service under this schedule will be selected to participate in this experiment in accordance with this schedule. In addition to the previously specified qualifying criteria, Customers that have intermittent or highly seasonal loads, cannot demonstrate price response capability, or intend to undertake load (capacity) reductions under another Company schedule or through a Company contract pursuant to a solicitation for Demand response may not participate in this experiment.

3. The Company will make hourly Energy prices available to customers by 4:00 p.m. for the following day, via a method specified by the Company. Except during unusual circumstances, the Company will make available prices for Saturday through Monday on the previous Friday. More than day-ahead pricing may also be available for holiday periods. Holidays are New Year's Day (January 1), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Thanksgiving Day (fourth Thursday in November), and Christmas Day (December 25).

SCHEDULE 87 (Concluded)

SPECIAL CONDITIONS (Continued)

4. The Company is not responsible for a Customer's failure to receive and act upon hourly prices. If a Customer does not receive these prices, it is the Customer's responsibility to inform the Company of any failure to receive the hourly prices by 5:00 p.m. the day before they become effective so the prices may be supplied.

5. The Customer will notify the Company's Merchant Power Operations at a phone number specified as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer.

6. If the Company is required to install new distribution facilities based upon an increase in the Customer's load, the Company may require an update of the CBL.

7. Customers must be on Schedule 83 or Schedule 89, Annual Cost of Service Option to be eligible for this schedule.

TERM

Service under this schedule will be for a minimum of one year with annual renewal rights.

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

The Load Reduction Program is an optional, supplemental service that allows participating Customers an opportunity to voluntarily reduce Electricity usage to a Company-determined level during an Emergency Curtailment as described in Rule C(2)(B) in exchange for partial exemption from Emergency Curtailments.

AVAILABLE

In all territory served by the Company but total pledges will not exceed 5% of Company primary voltage circuits.

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 89, 583 and/or 589 from one or more Point(s) of Delivery (PODs)but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple PODs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule.

BASELINE USAGE

The Baseline Usage is defined as the average usage for each hour for a minimum of 14 typical operational days prior to the Emergency Curtailment. Typical operational days exclude days that a Customer has participated in either an Emergency Curtailment or a Demand Buy Back Event (Schedule 86). Holidays and weekends will be excluded when determining the Baseline Usage except when the Emergency Curtailment includes weekends or holidays. The Customer may request that specific days be excluded from the 14-day baseline calculation upon demonstrating to the Company's satisfaction that the specific days are not similar days. The Company and Customer may mutually agree to use an alternate method to determine Baseline Usage when the Customer's usage is highly variable.

LOAD REDUCTION DETERMINATION

During an Emergency Curtailment, the individual Customer or group of Customers will be required to reduce Baseline Usage to a Company-determined Maximum Circuit Load (MCL). The MCL is the Customer's or group of Customer's Baseline Usage minus the necessary load reduction of 5, 10 or 15%.

Schedule 88 (Continued)

LOAD REDUCTION DETERMINATION (Continued)

The Company may choose at any time during an Emergency Curtailment to increase the load reduction percentage. Upon notification of an MCL change, the Customer/Lead Customer has one-half hour (30 minutes) to meet the new MCL. The Company may only make one notification of an increased increment of reduction per hour.

If the Customer is participating in Demand Buy Back Rider (Schedule 86), Baseline Usage will be determined after subtracting the Buy Back amount stipulated under that schedule. State mandated curtailments as defined under Rule N will also be subtracted before determining Baseline Usage.

LOAD REDUCTION PLAN

Participation depends upon the Company approval of a single submitted Load Reduction Plan. A renewed plan is due annually on March 15th.

A Lead Customer will submit one Load Reduction Plan for the group of Customers served on the same dedicated primary circuit and jointly participating. The Lead Customer assumes responsibility for submitting the group's Load Reduction Plan, managing the load reduction and paying all noncompliance charges.

The Load Reduction Plan must include the following:

1) Customer or Lead Customer's name;
2) A list of all other participating Customers, their account numbers, service and mailing addresses, and contact information;
3) The Customer or Lead Customer's alphanumeric pager and facsimile numbers to be used for notification of an Emergency Curtailment;
4) A Company and Customer mutually agreed upon Baseline Usage;
5) An estimated MCL for the 5, 10 and 15% load reduction levels. The MCL for the 5% load reduction is equal to the Baseline Usage times 0.95; 10% load reduction is Baseline Usage times 0.90; 15% reduction is Baseline Usage times 0.85; and
6) Specific quantifiable measures to be utilized by the Customer to reduce load to or below each MCL.

NOTIFICATION

The Company will notify the Customer/Lead Customer as to the percent of load reduction needed by alphanumeric pager and/or facsimile. The Customer/Lead Customer is responsible for keeping the pager and facsimile functioning and able to receive notification.

Schedule 88 (Continued)

NOTIFICATION (Continued)

Upon notification, the Lead Customer will be responsible for contacting all other Customers participating under that plan. Upon notification, the Customer/Lead Customer will have 30 minutes to establish the determined MCL.

METERING EQUIPMENT

Customers on a dedicated circuit with one POD will have load reduction compliance audited by an interval meter with remote access capacity. The Company will install metering that records usage in 15-minute intervals. The Customer will provide communication service to the meter if requested by the Company. Participation under this schedule is subject to meter availability.

Customers on a dedicated circuit with more than one POD will have compliance monitored from individual meters or electronic recording equipment located at Company substations. Where the circuit does not have electronic recording equipment to monitor its load, the Company will install such equipment subject to availability. The Customer/Lead Customer will provide communication service when requested by the Company.

A Customer/Lead Customer will not be allowed to participate in any Load Reduction Programs until the proper monitoring equipment is installed and operational.

FAILURE TO COMPLY

Failure to meet the required MCL, to maintain the MCL for the duration of the Emergency Curtailment or to meet the required MCL within the required 30 minutes after notification will result in a noncompliance penalty. The penalty is equal to two times the baseline circuit load (BCL) on the applicable circuit, less the required MCL by hour, times the market price (MP) for power during the Emergency Curtailment as determined by an appropriate index such as the Dow Jones Mid-Columbia Daily Electricity Firm Price Index:

$$\text{Penalty} = 2[MP(BCL - MCL)]$$

Such penalties will be in addition to all other Company charges for Electricity Service.

After two noncompliance penalties, the Customer/Lead Customer will be removed from the program. Failure to pay noncompliance penalties may result in the termination of the Customer's/Lead Customer's Electricity Service.

Schedule 88 (Concluded)

ADJUSTMENTS

Supplemental adjustment schedules are applicable to the Customer's underlying rate schedule and not applicable to this schedule unless approved by the Commission.

SPECIAL CONDITIONS

1. The Company may not be able to supply advance notice of an Emergency Curtailment. Participation in this program does not guarantee that the Customer or group of Customers will not be subject to outages related to maintenance, storms or system emergencies caused by natural catastrophes.

2. The Company is not liable for any damage to Customer's property resulting from participation in this program.

TERM

Service under this schedule will be for a term of one year. Service thereafter may be extended after Company review of Customer's/Lead Customer's annually updated Load Reduction Plan. Customer/Lead Customer's decision to leave the program at any time may limit its eligibility to participate in the program in the future.

SCHEDULE 89
LARGE NONRESIDENTIAL (>1,000kW)
STANDARD SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 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
Energy Charge			
On-Peak Period***	5.868 ¢	5.658 ¢	5.581 ¢
Off-Peak Period***	4.973 ¢	4.791 ¢	4.718 ¢
See below for Daily or Monthly Pricing Option descriptions.			
System Usage Charge			
Per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable POD.

*** 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.

SCHEDULE 89 (Continued)

MONTHLY RATE (Continued)

Energy Charge Options:

Any Energy Charge option 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 below 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. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTIONS

Daily Price Option - The Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.236 ¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer will notify the Company by the close of the November Election Window.

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

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

Monthly Fixed Price Option - A monthly fixed price per kWh quoted by the Company, differentiated by on- and off-peak hours for the next calendar month. The quote will be made on the 15th of the preceding month (or the following working day if the 15th is a weekend or holiday) by a posting on the Company's website (www.PortlandGeneral.biz) and will be based on the expected market price for power delivered to the Company's service territory plus losses. The Customer will notify the Company by 5:00 p.m. PPT on the business day following such posting of its choice of this option.

Non-Cost of Service Options are subject to Schedule 128, Short Term Transition Adjustment

SCHEDULE 89 (Continued)

NOVEMBER ELECTION WINDOW

A Customer may change Energy Charge options by notifying the Company of his/her choice during the November Election Window.

The November Election Window begins at 2:00 p.m. on November 15th (or the following work day if the 15th falls on a weekend or holiday) and continues until 5:00 p.m. at the close of the fifth consecutive business day.

A Customer who elects an Energy Charge Option during the November Election Window must complete the specified term of their current option.

MONTHLY DIRECT ACCESS ELECTION ENROLLMENT WINDOW

The Monthly Direct Access Election Enrollment Window is applicable to Customers who have a historical usage or have demonstrated that projected usage in the current calendar year is at least 8,760,000 (1MWa) from one or more POD. Each POD must have a Facility Capacity of at least 250 kW.

A Monthly Direct Access Election Enrollment Window will open at 12:00 p.m. PPT on the 15th of each month and remain open until 5:00 p.m. the next business day. If the 15th falls on a weekend or holiday, the window will be begin on the next business day. Customers may make a service election during a Monthly Direct Access Election Enrollment Window through the Company website (www.PortlandGeneral.Biz).

By 12:00 p.m. on the day of each Monthly Direct Access Enrollment Window, the Company will make available and post on its website (www.PortlandGeneral.Biz) the Schedule 128, Short-Term Transition Adjustment.

During the Monthly Direct Access Election Enrollment Window, Cost of Service Customers may choose at this time discontinuation of Cost of Service. The elected service option will become effective the first calendar day of the month, approximately 45 days from the date of the Direct Access Election Enrollment Window. A Customer making a monthly election under this option may not return to the Cost of Service Option until the following calendar year and subject to the requirements of making an annual Cost of Service election.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Distribution and Transmission Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in service facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively.

SCHEDULE 89 (Concluded)

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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

A Customer served under the Daily or Monthly Option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 91
STREET AND HIGHWAY LIGHTING
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity generally are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control or time switch to be mutually agreeable to the Customer and Company for an average of 4,150 hours annually.

SERVICE OPTIONS

The Company has the following service options available for lighting:

Option A is for luminaires owned, maintained and supplied with Electricity by the Company.

Option B is for maintenance and Electricity supplied to Customer-owned equipment.

Option C is a grandfathered option, available only where Option C service was initiated prior to December 31, 2006. Option C is the provision of Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles.

MAINTENANCE

Maintenance of Option A luminaries includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance also includes repair of an inoperable luminaire. This means that any failed part (e.g., lamp, photoelectric controller, starter, ballast, refractor, power door) will be replaced, or the entire failed luminaire will be replaced with in-kind equipment, if it is more practical to do so.

SCHEDULE 91 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Transmission and Related Services Charge	0.109 ¢ per kWh
Distribution Charge	2.803 ¢ per kWh
Energy Charge	
Cost of Service Option	5.380 ¢ per kWh

Daily Price Option – Available only to Customers with an average load of five MW or greater. In addition to the daily Energy price, the Customer will pay a Basic Charge of $75 per month to help offset the costs of billing this option. The daily Energy price for all kWh will be the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Firm Index) plus 0.236¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period.

SCHEDULE 91 (Continued)

MONTHLY RATE (Continued)

Prices reported with no transaction volume or as "survey-based" will be considered reported. For the purposes of calculating the daily on- and off-peak usage, actual kWhs will be determined for each month. The on- and off-peak usage will be calculated using Sunrise Sunset Tables with adjustments of 15 minutes before Sunrise and 15 minutes after Sunset.

For Customers billed on the Daily Energy Rate Option, an average of the daily rates will be used to bill installations and removals that occur during the month. Any additional analysis of billing options and price comparisons beyond the monthly bill will be billed at a rate of $100 per manhour.

Losses will be included by multiplying the above applicable Daily Price by 1.0834.

To begin service under this option on January 1st, the Customer will notify the Company by 5:00 p.m. PPT on November 15th (or the following working day if the 15th falls on a weekend or holiday) of the year prior to the service year of its choice of this option. Customers selecting this option must commit to this option for an entire service year. The Customer will continue to be billed on this option until timely notice is received to return to the Cost of Service Option.

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Cobrahead Power Doors **	100	9,500	43	*	$3.23
	150	16,000	63	*	3.25
	200	22,000	80	*	3.30
	250	29,000	103	*	3.28
	400	50,000	165	*	3.29
Cobrahead	100	9,500	43	$6.09	3.31
	150	16,000	63	6.12	3.33
	200	22,000	80	6.58	3.37
	250	29,000	103	6.63	3.37
	400	50,000	165	6.66	3.39
Flood	250	29,000	103	6.92	3.39
	400	50,000	165	6.95	3.42

* Not offered.
** Service is only available to Customers with total power door luminaries in excess of 2,500.

SCHEDULE 91 (Continued)

RATES FOR STANDARD LIGHTING (Continued)
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Early American Post-Top	100	9,500	43	$6.55	$3.31
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	100	9,500	43	6.99	3.38
	150	16,000	63	7.29	3.42

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.38	$0.15
Fiberglass, Bronze	30	5.85	0.20
Fiberglass, Gray	30	5.86	0.20
Wood, Standard	30 to 35	5.04	0.16
Wood, Standard	40 to 55	6.32	0.21

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Special Acorn-Types					
HPS	100	9,500	43	$9.81	$3.62
HADCO Independence HPS	100	9,500	43	8.93	3.41
	150	16,000	63	8.95	3.43
Special Architectural Types					
HADCO Victorian HPS	150	16,000	63	9.51	3.61
	200	22,000	80	9.51	3.57
	250	29,000	103	9.66	3.63

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
HADCO Techtra HPS	100	9,500	43	$16.27	$4.00
	150	16,000	63	16.29	4.02
	250	29,000	103	23.06	4.71
KIM Archetype HPS	250	29,000	103	*	3.73
	400	50,000	165	*	3.74
Special Types					
Cobrahead, Metal Halide	175	12,000	72	6.28	3.41
Flood, Metal Halide	400	40,000	158	6.89	3.49
Flood, HPS	750	105,000	289	9.55	4.60
Holophane Mongoose, HPS	150	16,000	63	8.42	3.61
	250	29,000	103	8.50	3.62
	400	50,000	165	8.56	3.65

* Not offered.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	16	$ 6.23	$0.21
	25	10.13	0.34
	30	10.96	0.37
	35	12.06	0.40
Aluminum Davit	25	10.46	0.35
	30	11.15	0.37
	35	12.32	0.41
	40	15.05	0.50
Aluminum Double Davit	30	13.42	0.45

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, HADCO, Fluted Victorian Ornamental	14	$12.26	$0.28
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	21.53	0.50
Aluminum, HADCO, Fluted Ornamental	16	12.81	0.30
Aluminum, Painted Ornamental	35	33.55	0.78
Concrete, Ameron Post-Top	25	24.80	0.57
Fiberglass, HADCO, Fluted Ornamental Black	14	9.65	0.22
Fiberglass, Regular			
color may vary	22	5.89	0.14
color may vary	35	11.36	0.26
Fiberglass, Anchor Base, Gray	35	12.22	0.28
Fiberglass, Direct Bury with Shroud	18	7.15	0.17

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing Mercury Vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B
Cobrahead, Mercury Vapor	100	4,000	40	*	*
	175	7,000	67	$ 6.18	$3.17
	250	10,000	95	7.22	3.44
	400	21,000	149	6.32	3.32
	1,000	55,000	379	7.21	3.67
Special Box Similar to GE "Space-Glo"					
Sodium Vapor	70	6,300	31	9.91	3.31
Mercury Vapor	175	7,000	67	10.17	3.31

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Special Box, Anodized Aluminum Similar to GardCo Hub					
HPS	70	6,300	31	*	*
	100	9,500	43	*	$3.59
	150	16,000	63	*	3.61
	250	29,000	103	*	*
	400	50,000	165	*	*
Metal Halide	250	20,500	101	*	3.74
	400	40,000	158	*	4.19
Cobrahead, Dual Wattage HPS					
70/100 Watt Ballast	100	9,500	43	*	3.31
100/150 Watt Ballast	100	9,500	43	*	3.31
100/150 Watt Ballast	150	16,000	63	*	3.33
Special Architectural Types					
KIM SBC Shoebox HPS	150	16,000	63	*	3.95
Special Acorn-Type HPS	70	6,300	31	$9.66	3.31
Special GardCo Bronze Alloy					
HPS	70	5,000	31	*	*
Mercury Vapor	175	7,000	67	*	*
Special Acrylic Sphere					
Mercury Vapor	400	21,000	149	*	*
Early American Post-Top HPS					
Black	70	6,300	31	5.97	3.32
Rectangle Type	200	22,000	80	*	*
Incandescent	92	1,000	32	*	*
	182	2,500	63	*	*
Town and Country Post-Top					
Mercury Vapor	175	7,000	67	6.31	3.19

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Flood, HPS	70	6,300	31	$6.61	$3.36
	100	9,500	43	6.49	3.34
	200	22,000	80	6.92	3.39
Cobrahead, HPS					
Non-Power Door	70	6,300	31	5.99	3.31
Power Door	310	37,000	125	7.44	3.77
Special Types Customer Owned & Maintained					
Ornamental, HPS		9,500	43	*	*
Twin Ornamental, HPS	200	22,000	80	*	*
Compact Flourescent	28	N/A	12	*	*

* Not offered.

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Aluminum Post	30	$ 6.24	*
Bronze Alloy GardCo	12	*	$0.25
Concrete, Ornamental	35 or less	10.13	0.34
Steel, Painted Regular **	25	10.13	0.34
Steel, Painted Regular **	30	10.96	0.37
Steel, Unpainted 6-foot Mast Arm **	30	*	0.37
Steel, Unpainted 6-foot Davit Arm **	30	*	0.37
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41
Wood, Laminated without Mast Arm	20	5.67	0.15
Wood, Laminated Street Light Only	20	4.38	*

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES (Continued)

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B
Wood, Curved Laminated	30	7.31	0.27
Wood, Painted Underground	35	5.04	0.21
Wood, Painted Street Light Only	35	5.04	*

* Not offered.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B
Special Architectural Types Including Philips QI Induction Lamp Systems					
HADCO Victorian QL	85	6,000	35	$12.00	$2.41
	165	12,000	61	13.87	2.46
HADCO Techtra QL	85	6,000	35	15.77	2.53
	165	12,000	61	16.60	2.61

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's agreement, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Design services for Customer-owned streetlight equipment.
- Painting or staining of wood and steel streetlight poles.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 91 (Concluded)

SPECIAL CONDITIONS

1. The Company may offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one-year at which time the lighting service equipment will either be removed at Customer expense or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment.

5. If Customer-owned (Option B) streetlighting equipment or poles are removed or relocated at the Customer's request, the Customer is responsible for the costs associated with the change.

6. If circuits or poles are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

7. For Option C lights: When the Company provides the circuit, the Customer will incur a circuit charge of $1.52 per luminaire per month.

8. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaries owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

TERM

A Customer served under the Daily or Monthly Pricing option may not choose service under another rate schedule until the end of the calendar year in which the pricing choice was made.

SCHEDULE 92
TRAFFIC SIGNALS
(NO NEW SERVICE)
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments where funds for payment of Electricity are provided through taxation or property assessment for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

MONTHLY RATE

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

Transmission and Related Services Charge	0.130	¢ per kWh
Distribution Charge	1.803	¢ per kWh
Energy Charge	5.480	¢ per kWh

* See Schedule 100 for applicable adjustments.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Customer will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

SCHEDULE 92 (Concluded)

SPECIAL CONDITIONS (Continued)

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule, using sampling techniques to determine whether in the Company's opinion the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Electricity use as it may deem to be satisfactory or discontinue service to the Customer under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 93
RECREATIONAL FIELD LIGHTING, PRIMARY VOLTAGE
STANDARD SERVICE
(COST OF SERVICE)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers for recreational field lighting and related incidental lighting.

MONTHLY RATE

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

Basic Charge	$30.00	
Transmission and Related Services Charge	0.220	¢ per kWh
Distribution Charge	8.596	¢ per kWh
Energy Charge	5.332	¢ per kWh

* See Schedule 100 for applicable adjustments.

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying a higher Minimum Charge, if necessary, to justify the Company's investment in service facilities.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITION

The Customer's electrical equipment and its installation must be approved by the Company. All service under this schedule at any one location will be supplied through one meter.

TERM

Service under this schedule will not be for less than a one year.

SCHEDULE 99
SPECIAL CONTRACTS

PURPOSE

This schedule describes contracts between the Company and Customers at rates other than those contained in standard schedules. These descriptions do not include all terms and conditions in the contracts and are intended only as summaries. If there are any conflicts between these summaries and provisions in the contracts, the contracts will be controlling. The Company maintains for public inspection copies of special contracts at offices where the Tariff is available.

APPLICABLE

To those Customers that can meet the eligibility criteria established in Commission Order 87-402 and ORS 757.230, as well as the eligibility criteria listed below.

CONTRACTS

Port of Portland/Cascade General, Inc. (Portland)

Effective Date

February 21, 1996.

Term

Effective as long as Customer purchases Electricity Service from the Company under mutually agreed to Tariff.

Rate

Schedule 89 - General Service, Primary Voltage.

Special Conditions

Customer to supply Electricity for resale to his/her "Customers" at his/her Repair Facility. Customer will be allowed to reflect charges over and above the Company's price for electricity in order to recover the costs of the Customer's electrical distribution system as outlined in the Portland Ship Repair Yard Price Schedule. As a result, bills received by his/her "Customers" may show a kWh charge above that which is charged by the Company.

Eligibility Criteria

1. Customer engaged in sales for resale prior to November 5, 1973.

2. Customer has significant investment in distribution facilities requiring additional cost recovery from its "Customers".

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules.

APPLICABLE ADJUSTMENT SCHEDULES

Schedules	102	105	108	115	125	126	128	129
	(1)		(5)	(6)	(1)		(7)	(1)
7	x	x	x	x	x	x		
15	x	x	x	x	x	x		
32	x	x	x	x	x	x	x	
38	x	x	x	x	x	x		
47	x	x	x	x	x	x		
49	x	x	x	x	x	x		
75[2]	x[4]	x[4]	x	x	x[4]	x[4]	x	
76R[2]	x	x	x	x		x		
83	x	x	x	x	x	x	x	
89	x	x	x	x	x	x	x	
87[2]	x[4]	x[4]	x	x		x[4]		
91		x	x	x	x	x	x	
92		x	x	x	x	x		
93		x	x	x	x	x		
483	x	x	x	x				x
489	x	x	x	x				x
515	x	x	x	x		x	x	
532	x	x	x	x		x	x	
549	x	x	x	x		x	x	
575[3]	x[4]	x[4]	x	x		x[4]	x	
576R[3]	x	x	x	x		x		
583	x	x	x	x		x	x	
589	x	x	x	x		x	x	
591		x	x	x		x	x	
592		x	x	x		x	x	

(1) Where applicable.
(2) The applicable adjustment rate for Schedules 75, 76R and 87 will be as listed for Schedule 83 or 89 on each adjustment schedule.
(3) The applicable adjustment rate for Schedules 575 and 576R will be as listed for Schedule 583 or 589 on each adjustment schedule.
(4) These adjustments are applicable only to the Customer Baseline and Scheduled Maintenance Energy. Scheduled Maintenance Energy is optional under Schedule 75.
(5) Schedule 108 applies to the sum of all charges less taxes, Schedule 115 charges and one-time charges such as deposits.
(6) Except for Schedule 7 which receives a set monthly charge for Schedule 115, Schedule 115 is applicable to the lesser of the total kWh, or the first 1,515,152 kWh used per PODID or Site (where applicable).
(7) Applicable to Nonresidential Customer who receive service at Daily or Monthly pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 483 and 489).

SCHEDULE 102
REGIONAL POWER ACT EXCHANGE* CREDIT

PURPOSE

Each Customer's bill rendered under schedules providing Residential Service, Farm Service and Nonresidential Farm Irrigation and Drainage Pumping Service will include the Regional Power Act Exchange Credit applied to each kWh sold when the Customer qualifies for the adjustment according to the definitions and limitations set forth in this schedule. Where Customers are served by Electricity Service Suppliers (ESSs), the ESS will agree to pass through the credit to the Customer.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Direct Access Service, Emergency Default Service, Standard Service and Residential Service where the Customer meets the definition of Residential Service, Farm Service or Farm Irrigation and Drainage Pumping Service as specified in this schedule.

REGIONAL POWER ACT EXHANGE CREDIT

The credit will be the value of power and other benefits provided in accordance with the terms of the Settlement Agreement between the Company and the BPA.

The credit, inclusive of an adjustment of (0.014) ¢ per kWh for interest is:

Schedule 7

First 250 kWh	2.294	¢ per kWh
Over 250 kWh	0.763	¢ per kWh
All other schedules	1.176	¢ per kWh

RESIDENTIAL SERVICE

Residential Service means Electricity Service provided for residential purposes including service to master-metered apartments, apartment utility rooms, common areas, and other residential uses.

* Short title for "Pacific Northwest Electric Power Planning and Conservation Act".

SCHEDULE 102 (Concluded)

FARM IRRIGATION AND DRAINAGE PUMPING SERVICE

Farm Irrigation and Drainage Pumping Service means Electricity Service to a parcel of land used for the raising of crops, livestock, or pasturage and includes service to irrigation pumps.

FARM SERVICE

Farm Service means Electricity Service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting and selling crops; or by the feeding, breeding, management and sale of, or the produce of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and his/her disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

SPECIAL CONDITIONS

1. The Credit will be applied to residential and farm usage; however, irrigation for farm use is limited to the first 400 horsepower per farm. The 400-horsepower limitation will be converted to maximum monthly kWh usage according to the following formula:

   400 hp x .746 x (24 hrs x days in Billing Period) = maximum kWh but not to exceed 222,000 kWh in any month

2. The credit is no longer applicable upon determination that the service no longer constitutes residential or farm usage. The Customer or ESS will notify the Company of any change of the type of service on the Customer's Premises. The credit and eligibility for the adjustment are subject to review and approval by the BPA and the Commission.

SCHEDULE 105
REGULATORY ADJUSTMENTS

PURPOSE

The purpose of this schedule is to reflect the effects of regulatory adjustments such as net gains from nonrecurring property transactions, true-ups to UE 115 CIS/IT capital costs, and costs associated with the implementation of SB 1149.

APPLICABLE

To all bills for Electricity Service calculated under all schedules and contracts, except those Customers explicitly exempted.

PART A – MISCELLANEOUS ADJUSTMENTS

Part A is a compilation of nonrecurring regulatory adjustments including a credit for information technology (IT) and gains on property sales. Part A will be adjusted annually.

PART B – SB 1149 COSTS

Part B consists of costs incurred with SB 1149 implementation. Part B is based on a projected five year collection period.

PART C – GRID WEST COSTS

Part C consists of prior loan amounts and projected 2006 and 2007 amounts incurred as the Company's share of the research and development performed by Grid West, the Regional Transmission Organization (RTO) and its predecessor, RTO West.

ADJUSTMENT RATES

The Adjustment Rates, applicable for service on and after the effective date of this schedule, will be:

Schedule	Part A	Part B	Part C	Adjustment Rate	
7	(0.046)	0.027	0.009	(0.010)	¢ per kWh
15	(0.086)	0.036	0.009	(0.041)	¢ per kWh
32	(0.043)	0.039	0.009	0.005	¢ per kWh
38	(0.043)	0.039	0.009	0.005	¢ per kWh
47	(0.043)	0.039	0.009	0.005	¢ per kWh
49	(0.032)	0.039	0.009	0.016	¢ per kWh
83					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Part C	Adjustment Rate	
89					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
Subtransmission	(0.026)	0.039	0.009	0.022	¢ per kWh
91	(0.076)	0.039	0.009	(0.028)	¢ per kWh
92	(0.033)	0.039	0.009	0.015	¢ per kWh
93	(0.072)	0.039	0.009	(0.024)	¢ per kWh
483					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
489					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
Subtransmission	(0.026)	0.039	0.009	0.022	¢ per kWh
515	(0.086)	0.036	0.009	(0.041)	¢ per kWh
532	(0.043)	0.039	0.009	0.005	¢ per kWh
549	(0.032)	0.039	0.009	0.016	¢ per kWh
583					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
589					
Secondary	(0.033)	0.039	0.009	0.015	¢ per kWh
Primary	(0.029)	0.039	0.009	0.019	¢ per kWh
Subtransmission	(0.026)	0.039	0.009	0.022	¢ per kWh
591	(0.076)	0.039	0.009	(0.028)	¢ per kWh
592	(0.033)	0.039	0.009	0.015	¢ per kWh

SCHEDULE 108
PUBLIC PURPOSE CHARGE

PURPOSE

To collect funds associated with activities mandated for the benefit of the general public pursuant to OAR 860-038-0480. Activities include Energy conservation, new market transformation, new renewable energy resources and new low-income weatherization.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except Nonresidential Customers qualifying as a Self-Directing Customer may be partially exempt.

PUBLIC PURPOSE CHARGE

The Public Purpose Charge will be 3% of total revenue billed to the Customer "for electricity services, distribution, ancillary services, metering and billing, transition charges and other types of costs that were included in electric rates on July 23, 1999" as specified in OAR 860-038-0480 (2).

SELF-DIRECTING CUSTOMER (SDC)

Pursuant to OAR 860-038-0480, to qualify to be a Self-Directing Customer (SDC), the Large Nonresidential Customer must have a load that exceeds one aMW and receive certification from the Oregon Department of Energy (ODOE) as an SDC. Beginning November 30, 2004, the Company will include the credits due, as reported by the ODOE, to the applicable portions of the SDCs monthly Public Purpose Charge.

SPECIAL CONDITIONS

1. Electricity Service Suppliers (ESS) – Each ESS that provides Direct Access Service in the Company's service territory will collect a Public Purpose Charge from its Direct Access Customers. The ESS will remit monthly to the Company the Public Purpose Charges it collects from Customers.

SCHEDULE 108 (Concluded)

SPECIAL CONDITIONS (Continued)

2. Disbursement of Funds – The Company will distribute monthly, Public Purpose funds collected, minus reasonable administrative costs, as outlined in OAR 860-038-0480 and required by ORS 757.612:

   - The funds for conservation in schools to the education service districts located in the Company's service territory = 10.0%;
   - The funds for local and market transformation conservation will be allocated as directed by the Commission = 56.7%;
   - The funds for renewable energy resources will be allocated as directed by the Commission = 17.1%;
   - The funds for low-income weatherization will be allocated to the Housing and Community Services Department = 11.7%; and
   - The funds for low-income housing will be allocated to the Housing and Community Services Department Revolving Account = 4.5%.

TERM

This Schedule will terminate on February 29, 2012.

SCHEDULE 115
LOW-INCOME ASSISTANCE

PURPOSE

The purpose of this rate schedule is to implement the low-income bill payment assistance provisions in accordance with Section 3(7) of House Bill 3633.

APPLICABLE

To all bills for Electricity Service calculated under all rate schedules and contracts, except those Customers explicitly exempted. Based on House Bill 3633 provisions, this rate schedule is also applicable to Direct Service Industries (DSIs) located within the Company's service territory.

ADJUSTMENT RATES

The applicable Adjustment Rates are listed below. As specified in House Bill 3633, Customers will not be required to pay more than $500 per month per Site for low-income Electricity bill payment assistance.

Schedule	Adjustment Rate
7	33¢ per month
All other Schedules, including DSIs	0.033¢ per kWh for the first 1,515,152 kWh

SPECIAL CONDITION

On a monthly basis, on or before the last day of the month, the Company will forward an amount to the Oregon Housing and Community Services Department based on billings to Customers for the previous month less a reserve for uncollectable amounts.

SCHEDULE 125
ANNUAL POWER COST UPDATE

PURPOSE

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

APPLICABLE

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

NET VARIABLE POWER COSTS

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

RATES

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

ANNUAL UPDATES

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

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

CHANGES IN NET VARIABLE POWER COSTS

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

SCHEDULE 125 (Concluded)

FILING AND EFFECTIVE DATE

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

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

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

RATE ADJUSTMENT

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

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh [1]
7		0.000
15		0.000
32		0.000
38	Large Nonresidential	0.000
47		0.000
83	Secondary	0.000
	Primary	0.000
89	Secondary	0.000
	Primary	0.000
	Subtransmission	0.000
91		0.000
92		0.000
93		0.000

SCHEDULE 126
POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates differences in actual net variable power costs from those assumed in base energy rates adjusted pursuant to Schedule 125. This adjustment mechanism becomes effective with service on and after January 1, 2007. This Schedule is an "automatic adjustment clause" as defined in ORS 757.210, and is subject to review by the Commission at least once every two years.

APPLICABLE

To all bills for Electricity Service except those served under the provisions of Schedules 76R, 576R, 483 and 489.

NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) represent the power costs for Energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission / wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses 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 deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 83 and 89 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 483 and 489 as an offset to NVPC.

ACTUAL NVPC

Incurred cost of power based on the definition for NVPC described above.

ACTUAL LOADS

Actual loads are total annual retail loads adjusted as follows:

- Exclude loads from Schedule 483, Schedule 489, 76R, Schedule 83 and Schedule 89 options other than Cost of Service and any Direct Access 500 series schedules.

SCHEDULE 126 (Continued)

BASE UNIT NVPC

The Base Unit NVPC are defined as the NVPC used to develop existing rate schedules divided by the calendar basis retail loads used to develop existing rate schedules including Schedule 125. Each adjustment period will be for 12 months and correspond to the calendar year.

The Base Unit NVPC for 2007 is $XX.XX.

The NVPC used to calculate the Base Unit NVPC for the years 2007, 2008, 2009 and 2010 will be adjusted by PGE by an amount (increase or decrease) that removes the power supply cost impact resulting from the difference between the forecast and actual forced outage rates of PGE's owned thermal generating resources for the years 2002, 2003, 2004, 2005 and 2006.

POWER COST VARIANCE (PCV)

The Power Cost Variance (PCV) is calculated annually based on the following formula:

(Actual Unit NVPC - Base Unit NVPC) * Actual Loads

ADJUSTMENT AMOUNT

Adjustment Amount will be to 90% of the PCV times a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectables.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record overcollections and undercollections. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. Interest will accrue on the account at the Company's authorized rate of return. To account for the time value of money during the year, at the end of each year the Adjustment Amount for the calendar year will be multiplied by ½ year's worth of interest at the Company's authorized cost of capital and such amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission. Annually, the Company will recommend to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

SCHEDULE 126 (Continued)

EARNINGS REVIEW

The recovery from or refund to customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Adjusted Authorized ROE plus 100 basis points.

Should the Company's Actual ROE exceed its Adjusted Authorized ROE by more than 100 basis points, the Company will refund to Customers revenues representing 50% of the earnings exceeding the 100 basis point threshold.

Actual ROE will be based on the Company's ROE for utility operations adjusted for any expenses or rate base disallowed as inappropriate for utility operations by the Commission in the Company's last general rate case.

Adjusted Authorized ROE is the Authorized ROE determined by the Commission in the Company's most recent rate proceeding less the difference in the average of five-, seven-, and ten-year US Treasury debt used to determine authorized ROE and the actual average of five-, seven-, and ten-year US Treasury debt for the year that the power costs were incurred. The actual Treasury debt will be the annual rates reported by the Federal Reserve in their H15 Constant Maturity Statistical Releases.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

Included in this filing will be the following information:

1) A transmittal letter that summarizes the proposed changes.
2) Revised Power Cost adjustment rates.
3) Work papers supporting the calculation of the revised PCV rates.

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis applicable to all schedules except Schedules 76R, 576R, 483 and 489. The PCV Rates, applicable for service on and after the effective date of this schedule will be:

Schedule		Adjustment Rate
7		0.000 ¢ per kWh
15		0.000 ¢ per kWh
32		0.000 ¢ per kWh
38		0.000 ¢ per kWh
47		0.000 ¢ per kWh
49		0.000 ¢ per kWh
83	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
89	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
515		0.000 ¢ per kWh
532		0.000 ¢ per kWh
549		0.000 ¢ per kWh
583	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
589	Secondary	0.000 ¢ per kWh
	Primary	0.000 ¢ per kWh
	Subtransmission	0.000 ¢ per kWh
591		0.000 ¢ per kWh
592		0.000 ¢ per kWh

TERM

Effective for service on and after January 1, 2007 and continuing until terminated by the Commission.

SCHEDULE 128
SHORT-TERM TRANSITION ADJUSTMENT

PURPOSE

The purpose of this Schedule is to calculate the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Nonresidential Customers served who receive service at Daily or Monthly pricing (other than Cost of Service) on Schedules 32, 75, 83, 89, 91; or Direct Access service on Schedules 515, 532, 549, 575, 583, 589, 591 and 592. This Schedule is not applicable to Customers served on Schedules 483 and 489.

TRANSITION ADJUSTMENT

The Transition Adjustment will reflect the difference between the Energy Charge(s) under the Cost of Service Option including Schedule 125 and the market price of power for the period of the adjustment applied to the load shape of the applicable schedule.

2007 12-MONTH TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service for 2007, the 12-Month Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2007:

Schedule		Annual ¢ per kWh [1]
32		(1.341)
83	Secondary	(1.326)[2]
	Primary	(1.278)[2]
89	Secondary On-Peak	(1.402)
	Secondary Off-Peak	(1.192)
	Primary On-Peak	(1.353)
	Primary Off-Peak	(1.146)
	Subtransmission On-Peak	(1.334)
	Subtransmission Off-Peak	(1.129)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Customer's Baseline Load for Customers served on Schedule(s) 75, 76R, 87, 575 and, or 576R.

SCHEDULE 128 (Continued)

2007 12-MONTH TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh [1]
91		(1.287)
515		(1.283)
532		(1.341)
549		(1.212)
583	Secondary	(1.326) [2]
	Primary	(1.278) [2]
589	Secondary On-Peak	(1.402)
	Secondary Off-Peak	(1.192)
	Primary On-Peak	(1.353)
	Primary Off-Peak	(1.146)
	Subtransmission On-Peak	(1.334)
	Subtransmission Off-Peak	(1.129)
591		(1.287)
592		(1.310)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Customer's Baseline Load for Customers served on Schedule(s) 75, 76R, 87, 575 and, or 576R.

12-MONTH TRANSITION ADJUSTMENT REVISIONS

(November Election Window as defined in Schedules 83 and 89)
The 12-Month Transition Adjustment rate will 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. Indicative, non-binding estimates for the 12-Month Transition Adjustment will be posted by the Company two months and then again one week prior to the filing date. These prices will be for informational purposes only and are not to be considered the adjustment rates.

Monthly Transition Adjustment Election Window as defined in Schedules 83 and 89)
The Company will file and post the balance of year Transition Adjustments on its website (www.PortlandGeneral.biz) by 12:00 p.m. PPT on the first business day of the Monthly Direct Access Election Window.

SCHEDULE 128 (Concluded)

LARGE NONRESIDENTIAL LOAD SHIFT TRUE-UP

The Company may revise the 12-Month Transition Adjustment after the close of the November election window if the deviation in costs is greater than $240,000 based on the deviation between actual market prices experienced and market prices used to set the 12-Month Transition Adjustment associated with acquiring or disposing of power. The Transition Adjustment for all other monthly windows will be adjusted on the same basis as the November window, except the threshold amount will be $20,000 times the number of months to which the Transition Adjustment is applicable.

CHANGES TO TRANSITION ADJUSTMENT RATES

The 12-Month Transition Adjustment and Monthly Transition Adjustments are subject to modification to reflect any changes to the Energy Charge(s) of the Cost of Service Option that serve as the basis for the calculation of the Transition Adjustment. No change will be made, however, to the market price of power used to determine the applicable adjustment rate.

RESOURCE CHANGES

The Transition Adjustment Rate will be modified at any time to reflect changes in the Company's Schedule 125, Schedule 126, 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, the Transition Adjustment will be adjusted by replacing the variable costs of the resource with the cost of replacement power.

SCHEDULE 129
LONG-TERM TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected service under Schedule 483 and 489.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Enrollment Period A (2002), the Transition Cost Adjustment will be:

0.061 ¢ per kWh	January 1, 2003 through December 31, 2007
0.000 ¢ per kWh	after December 31, 2007

For Enrollment Period B (2003), the Transition Cost Adjustment will be:

(0.154) ¢ per kWh	January 1, 2004 through December 31, 2004
(0.136) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.062) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.046) ¢ per kWh	January 1, 2007 through December 31, 2007
(0.032) ¢ per kWh	January 1, 2008 through December 31, 2008
0.000 ¢ per kWh	after December 31, 2008

For Enrollment Period C (2004), the Transition Cost Adjustment will be:

(0.763) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.564) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.447) ¢ per kWh	January 1, 2007 through December 31, 2007
(0.398) ¢ per kWh	January 1, 2008 through December 31, 2008
(0.301) ¢ per kWh	January 1, 2009 through December 31, 2009
0.000 ¢ per kWh	after December 31, 2009

SCHEDULE 129 (Concluded)

TRANSITION COST ADJUSTMENT (Continued)
Three-Year Opt-Out Option

For Enrollment Period A (2002): Not available

For Enrollment Period B (2003): Not available

For Enrollment Period C (2004), the Transition Cost Adjustment will be:

(0.763) ¢ per kWh	January 1, 2005 through December 31, 2005
(0.564) ¢ per kWh	January 1, 2006 through December 31, 2006
(0.447) ¢ per kWh	January 1, 2007 through December 31, 2007

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedule 483 or 489.

SCHEDULE 200
DISPATCHABLE STANDBY GENERATION

PURPOSE

To provide the Company with additional generation capacity during times of peak demand and/or peak wholesale prices by contracting with Large Nonresidential Customers for the right to operate their standby or backup generator(s) for up to 400 hours annually.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers with 250 kW or greater of permanently installed standby or backup generation capacity in place or planned for installation within 24 months.

CUSTOMER RESPONSIBILITIES

The Customer will grant the Company access to its generation such that the Company can operate the generator(s) at the site or remotely operate the generator(s) in parallel with the Company's distribution system from the Company's dispatch center for up to 400 hours per year.

The Customer may operate the generator(s) at the site as needed for a limited number of hours per year, as specified in the service agreement.

COMPANY RESPONSIBILITIES

The Company will conduct an analysis of the Customer's generator project and develop a cost estimate. The Company will be responsible for providing engineering and funding based on the cost estimate not to exceed the Funding Level for the installation of the equipment necessary for participation in the program. The Company will pay for and own all communications and metering equipment.

In addition, the Company is responsible for routine maintenance of the generator(s) including overhauls over the term of the service agreement. The Company will also pay for all fuel used to operate the Customer's generator(s) throughout the term of the service agreement. The Company will perform monthly full-load testing of the Customer's generator(s) and control system and testing of the Company's dispatch control and interconnection facilities. The Company will provide power quality monitoring and data reporting of the Customer's facility and generator system.

The Company's design will be such that during outage situations, the Customer's generator(s) will automatically start and provide backup power to the Customer for as long as needed.

SCHEDULE 200 (Continued)

FUNDING LEVEL

The Company's Funding Level is based on the cost of Company owned equipment necessary for parallel operations, system protection, safety provisions and communications, related administrative costs and the generator and switchgear modifications, wiring and conduit necessary to permit Customer's generator(s) to run in parallel with the Company's system.

The Funding Level is set for each project. The Customer will be responsible for unique costs components that bring the total project costs above the Company's Funding Level. Due to the individual nature of each project, specifics on Company Funding and Customer payment responsibilities will be contained in the service agreement.

Upon termination of the agreement, the Company may remove its equipment.

SPECIAL CONDITIONS

1. The Customer's charges for Electricity Service under any of the Company's Standard Service or Direct Access Service schedules are not changed or affected in any way by service under this schedule and are due and payable as specified in those schedules.

2. Parallel operation of generators must satisfy Company interconnection requirements.

3. The Customer will ensure that the generator(s), communications equipment, switchgear and metering equipment are accessible to the Company at all times.

4. Prior to receiving service on this schedule, the Customer and the Company must enter into a written service agreement, signed by the Customer.

5. The Customer must obtain all required permits prior to service initiation to allow a minimum of 400 hours per year of parallel generator operation. The Company will reimburse the Customer for any DEQ and land-use compatibility permits specifically required for this service, including renewals during the term of the service agreement.

6. The Company may operate the generator(s) at any time and will notify the Customer by telephone, fax or e-mail a minimum of 24 hours before starting the generator(s) for the Company's purposes. Notice is deemed given when the Customer confirms notice either verbally or by e-mail.

7. Customers receiving service under this schedule will agree to an initial multi-year term for the service agreement, with options to renew. Should the Customer terminate the service agreement before the end of the initial term, the Customer will reimburse the Company for a portion of the capital investment plus a removal fee as specified in the service agreement.

SCHEDULE 200 (Concluded)

SPECIAL CONDITIONS (Continued)

8. The Company will have the right to refuse to fund projects for any reason; including, but not limited to projects deemed high-risk, not cost effective, of poor equipment quality, an excessive environmental risk, or unable to run 400 hours annually. Reasons for funding denial will be provided in writing to the Customer.

SCHEDULE 201
QUALIFYING FACILITY
POWER PURCHASE INFORMATION

PURPOSE

To provide information about Avoided Costs, Standard Contracts and negotiated Power Purchase Agreements, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Sellers of generation from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, the energy is delivered to the Company's system and made available for Company purchase, and the Seller meets all requirements herein described including establishing credit, providing proof of insurance, executing an interconnection agreement, a transmission agreement and a Power Purchase Agreement, where applicable.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard Contract Power Purchase Agreement (Standard Contract) as discussed below, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security as deemed sufficient by the Company as set out in the Standard Contract.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

SCHEDULE 201 (Continued)

POWER PURCHASE AGREEMENT

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a Power Purchase Agreement with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A Seller whose QF has a nameplate capacity rating of 10 mW or less may elect the Standard Contract option.

Any Seller may elect to negotiate a Power Purchase Agreement with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC) and the Commission. Negotiations for power purchase pricing will be based on the filed Avoided Costs in effect at that time. Filed Avoided Costs may be modified in negotiated Power Purchase Agreements by factors described in 18 CFR 292.304(e), *Factors Affecting Rates for Purchases,* which may be referenced through www.gpoaccess.gov/cfr/index.html.

STANDARD CONTRACT (Nameplate capacity of 10 mW or less)

A Seller choosing a Standard Contract will complete all informational and price option selection requirements in the agreement (Appendix 1) and submit the executed agreement to the Company prior to service under this schedule.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase rates are based on the Company's Avoided Costs. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

SCHEDULE 201 (Continued)

BASIS FOR POWER PURCHASE PRICE (Continued)
AVOIDED COST SUMMARY (Continued)

The Avoided Costs as listed in Tables 1 and 2 below include monthly On- and Off-Peak prices.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Avoided Costs are based on forward market price estimates through December 2008, the period of time during which the Company's Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the period 2009 through 2025, the Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

The CCCT Avoided Cost estimates beginning in 2009 include the avoidable power supply costs assumed to be represented by new generating capacity consistent with the Company's Integrated Resource Plan's Final Action Plan Acknowledged in Commission Order No. 04-375.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS

Pricing options represent the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard Contract up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option.

The Standard Contract pricing will be based on the Avoided Cost in effect at the time the agreement is executed.

Four pricing options are available for Standard Contracts. The pricing options include one Fixed Rate Option and three Market Based Options.

1) **Fixed Price Option**

The Fixed Price Option is based on Avoided Costs including forecasted natural gas prices.

This option is available for a maximum term of 15 years. Sellers with contracts exceeding 15 years will make a one time election at execution to select a Market-Based Option for all years up to five in excess of the initial 15. Under the Fixed Price Option, prices will be as established at the time the Standard Contract is executed and will be equal to the Avoided Costs in Tables 1 and 2 effective at execution for a term of up to 15 years.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
FIXED PRICE OPTION (Continued)

TABLE 1 Avoided Costs Fixed Price Option On-Peak Forecast ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	67.97	66.95	64.20	69.29	74.39
2006	77.96	74.39	69.29	59.10	49.42	50.44	69.04	75.92	72.40	69.04	71.08	74.13
2007	76.43	72.86	67.77	57.58	47.90	48.91	68.02	74.90	71.38	68.02	70.06	73.12
2008	74.90	71.33	66.23	56.04	46.36	47.38	66.49	73.37	69.85	66.49	68.53	71.58
2009	64.40	64.36	63.78	59.56	59.02	59.18	59.33	59.47	59.40	59.50	60.84	62.17
2010	60.39	60.33	59.78	56.25	55.77	55.90	56.03	56.14	56.10	56.19	57.41	58.58
2011	66.34	66.28	65.62	61.46	60.89	61.04	61.20	61.33	61.28	61.38	62.82	64.20
2012	69.28	69.21	68.51	64.09	63.48	63.65	63.81	63.95	63.90	64.01	65.54	67.01
2013	75.03	74.95	74.16	69.13	68.45	68.63	68.82	68.97	68.92	69.04	70.78	72.45
2014	80.36	80.28	79.40	73.82	73.06	73.26	73.47	73.64	73.59	73.72	75.65	77.50
2015	81.36	81.27	80.40	74.80	74.04	74.24	74.45	74.62	74.56	74.70	76.63	78.49
2016	73.15	73.08	72.37	67.88	67.27	67.43	67.60	67.74	67.69	67.80	69.35	70.85
2017	77.09	77.01	76.25	71.42	70.76	70.93	71.11	71.26	71.21	71.33	73.00	74.61
2018	84.84	84.75	83.86	78.17	77.40	77.61	77.81	77.99	77.93	78.07	80.04	81.92
2019	92.90	92.79	91.76	85.21	84.31	84.55	84.79	85.00	84.93	85.09	87.35	89.53
2020	98.17	98.06	96.94	89.85	88.88	89.14	89.40	89.62	89.55	89.72	92.17	94.53
2021	100.74	100.63	99.48	92.21	91.22	91.48	91.75	91.98	91.90	92.08	94.59	97.01
2022	103.25	103.14	101.97	94.51	93.49	93.77	94.04	94.27	94.20	94.38	96.95	99.43
2023	105.95	105.83	104.63	96.98	95.94	96.22	96.50	96.74	96.66	96.85	99.49	102.03
2024	108.35	108.23	106.99	99.16	98.09	98.38	98.67	98.91	98.83	99.02	101.73	104.33
2025	111.18	111.06	109.80	101.77	100.67	100.97	101.26	101.51	101.43	101.62	104.40	107.06

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
FIXED PRICE OPTION (Continued)

TABLE 2 Avoided Costs Fixed Price Option Off-Peak Forecast ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	56.76	55.74	54.01	58.59	64.45
2006	65.98	62.93	59.87	49.93	42.29	39.23	58.59	61.14	59.61	57.58	59.61	63.18
2007	63.43	60.38	57.32	47.90	40.25	37.20	57.83	60.38	58.85	56.81	58.85	62.42
2008	61.90	58.85	55.79	46.36	38.72	35.66	56.30	58.85	57.32	55.28	57.32	60.88
2009	38.83	38.79	38.21	33.98	33.44	33.61	33.75	33.90	33.83	33.92	35.27	36.59
2010	34.18	34.12	33.57	30.03	29.55	29.68	29.81	29.92	29.89	29.97	31.19	32.36
2011	39.47	39.41	38.75	34.59	34.02	34.17	34.33	34.46	34.41	34.51	35.95	37.34
2012	41.74	41.67	40.97	36.55	35.94	36.10	36.27	36.41	36.36	36.47	38.00	39.47
2013	46.80	46.72	45.93	40.90	40.22	40.40	40.59	40.74	40.69	40.81	42.55	44.22
2014	51.43	51.34	50.46	44.88	44.12	44.33	44.53	44.71	44.65	44.78	46.71	48.57
2015	51.70	51.62	50.74	45.14	44.38	44.58	44.79	44.96	44.91	45.04	46.97	48.83
2016	42.85	42.78	42.07	37.58	36.97	37.13	37.30	37.44	37.39	37.50	39.05	40.54
2017	45.83	45.75	44.99	40.16	39.50	39.67	39.85	40.00	39.95	40.07	41.74	43.35
2018	52.90	52.81	51.92	46.23	45.46	45.67	45.88	46.05	45.99	46.13	48.10	49.98
2019	60.16	60.06	59.03	52.47	51.58	51.82	52.06	52.26	52.19	52.35	54.62	56.79
2020	64.72	64.61	63.50	56.40	55.43	55.69	55.95	56.17	56.10	56.27	58.72	61.08
2021	66.34	66.23	65.09	57.81	56.82	57.09	57.35	57.58	57.51	57.68	60.20	62.61
2022	68.00	67.88	66.71	59.25	58.24	58.51	58.79	59.02	58.94	59.12	61.70	64.17
2023	69.70	69.58	68.38	60.73	59.69	59.97	60.25	60.49	60.41	60.60	63.24	65.77
2024	71.43	71.30	70.07	62.24	61.17	61.46	61.75	61.99	61.91	62.10	64.81	67.41
2025	73.22	73.09	71.83	63.80	62.71	63.00	63.30	63.55	63.46	63.66	66.43	69.10

Under the Fixed Price Option, the Company will pay Seller the Off-Peak Avoided Cost pursuant to Table 1 for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

MARKET BASED PRICE OPTIONS:

Market Based Price Options include Option 2, Deadband Index Gas Price; Option 3, Index Gas Price; and Option 4, Dow Jones Mid-Columbia Daily On- and Off-Peak Electricity Firm Price Index (DJ-Mid-C Firm Index). The price components for pricing Options 2 and 3 are defined as follows:

On Peak Price:	P_{Peak}
Off Peak Price:	P_{Off}
Variable Operating and Maintenance, Fixed Costs, and Gas Transportation (Table 6):	VFG
Capacity Value (Table 7):	C
Heat Rate:	HR = 6,776 BTU/kWh
Losses:	1.9%
Forecasted Gas Price (Table 5):	GP_F
First of Month* Northwest Pipeline Corp. Canadian Border Index as Reported in <u>Platts Inside FERC's Gas Market Report</u>	GP_{Sumas}
First of Month* one-month spot price averages for AECO/NIT transactions as Reported in <u>Canadian Gas Price Reporter Natural Gas Market Report</u> (in US dollars):	GP_{AECO}
Monthly Indexed Gas Price:	$GP_{MI} = (GP_{Sumas} + GP_{AECO})/2$
Deadband Gas Index:	GP_{DB}

Where:
If $GP_{MI} > GP_F$
GP_{DB} = Minimum of (GP_{MI} or $1.1*GP_F$)
Otherwise
GP_{DB} = Maximum of (GP_{MI} or $.9*GP_F$)

* "First of Month" means the first such monthly issuance.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Tables 3 and 4 below list applicable rates for Options 2 (Deadband Index Gas Price Option) and 3 (Index Gas Price Option) for the period through 2008. The monthly On- and Off-Peak prices will be applied for all Market Based Price Options.

TABLE 3
On-Peak Resource Sufficiency Rate ($/MWH)

	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	67.97	66.95	64.20	69.29	74.39
2006	77.96	74.39	69.29	59.10	49.42	50.44	69.04	75.92	72.40	69.04	71.08	74.13
2007	76.43	72.86	67.77	57.58	47.90	48.91	68.02	74.90	71.38	68.02	70.06	73.12
2008	74.90	71.33	66.23	56.04	46.36	47.38	66.49	73.37	69.85	66.49	68.53	71.58

TABLE 4
Off-Peak Resource Sufficiency Rate ($/MWH)

	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	56.76	55.74	54.01	58.59	64.45
2006	65.98	62.93	59.87	49.93	42.29	39.23	58.59	61.14	59.61	57.58	59.61	63.18
2007	63.43	60.38	57.32	47.90	40.25	37.20	57.83	60.38	58.85	56.81	58.85	62.42
2008	61.90	58.85	55.79	46.36	38.72	35.66	56.30	58.85	57.32	55.28	57.32	60.88

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

2) Deadband Index Gas Price Option

The Deadband Index Gas Price Option bases the fuel price component of the Energy rate on comparisons between the Forecast Gas Price (Table 5) and the simple average of the First of Month gas indices for Sumas and AECO trading hubs. The Northwest Pipeline Gas Index (Sumas) will be as reported in Platts Inside FERC's Gas Market Report. The AECO/NIT (AECO) Gas Index will be as reported in Canadian Gas Price Reporter Natural Gas Market Report (in US dollars). The fuel price component used will be bound between 90% and 110% of the natural gas price forecast but based on the then current gas price.

The price paid per MWh will be:

$$P_{Peak} = GP_{DB}*HR/1,000/(1\text{-}Losses) + VFG + C$$
$$P_{Off} = GP_{DB}*HR/1,000/(1\text{-}Losses) + VFG$$

Under the Deadband method, the Company will pay Seller the Off-Peak prices for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

3) **Index Gas Price Option**

The Index Gas Price Option is the simple average of the First of Month gas indices for Sumas and AECO trading hubs used in establishing the Avoided Costs. The Sumas Gas Index will be as reported in Platts Inside FERC's Gas Market Report. The AECO Gas Index will be as reported in the Canadian Gas Price Reporter Natural Gas Market Report (in US dollars).

The price paid per MWh will be:

$$P_{Peak} = GP_{MI}*HR/1{,}000/(1-Losses) + VFG + C$$
$$P_{Off} = GP_{MI}*HR/1{,}000/(1-Losses) + VFG$$

Under the Index Gas Price, the Company will pay Seller the Off-Peak Prices for: (a) for all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to the provisions of Section 4.3 of the Standard Contract; (d) for Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

4) **Mid C Index Price Option**

Under this option, prices paid per MWh will be based on the DJ-Mid-C Firm Index plus 0.204 ¢ per kWh for wholesale wheeling.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

The tables below contain the pricing components for Option 1 (Fixed Price Option) Option 2 (Deadband Index Gas Price Option) and Option 3 (Index Gas Price Option).

TABLE 5

Forecasted Gas Price - GP_F($/MMBTU)

	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	4.778	4.772	4.689	4.088	4.011	4.035	4.056	4.076	4.066	4.079	4.271	4.459
2010	4.097	4.089	4.011	3.508	3.440	3.458	3.476	3.492	3.487	3.499	3.673	3.840
2011	4.832	4.823	4.730	4.137	4.057	4.078	4.100	4.119	4.112	4.127	4.332	4.528
2012	5.136	5.126	5.027	4.398	4.312	4.335	4.358	4.378	4.371	4.386	4.604	4.813
2013	5.836	5.825	5.713	4.997	4.900	4.926	4.952	4.974	4.967	4.984	5.232	5.469
2014	6.475	6.462	6.337	5.543	5.435	5.464	5.494	5.518	5.510	5.529	5.804	6.067
2015	6.493	6.481	6.356	5.559	5.451	5.480	5.509	5.534	5.526	5.545	5.820	6.085
2016	5.213	5.203	5.103	4.463	4.376	4.400	4.423	4.443	4.436	4.452	4.673	4.885
2017	5.615	5.604	5.496	4.807	4.713	4.739	4.764	4.785	4.778	4.795	5.033	5.261
2018	6.599	6.586	6.459	5.650	5.540	5.569	5.599	5.624	5.616	5.635	5.915	6.184
2019	7.608	7.594	7.447	6.514	6.387	6.421	6.456	6.485	6.475	6.498	6.820	7.130
2020	8.236	8.220	8.061	7.051	6.914	6.951	6.988	7.019	7.009	7.033	7.382	7.717
2021	8.441	8.425	8.263	7.227	7.086	7.124	7.162	7.195	7.184	7.209	7.567	7.910
2022	8.653	8.636	8.469	7.408	7.264	7.302	7.341	7.375	7.364	7.389	7.756	8.108
2023	8.869	8.852	8.681	7.593	7.445	7.485	7.525	7.559	7.548	7.574	7.950	8.311
2024	9.091	9.073	8.898	7.783	7.631	7.672	7.713	7.748	7.736	7.763	8.148	8.519
2025	9.318	9.300	9.120	7.978	7.822	7.864	7.906	7.942	7.930	7.957	8.352	8.731

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 6 contains the Variable O&M and Fixed Costs that are derived from a natural gas-fired CCCT as identified in the Company's 2004 Integrated Resource Plan.

TABLE 6												
Variable O &M, Fixed Costs and Gas Transportation Forecast – VFG ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	5.83	5.83	5.82	5.75	5.74	5.74	5.74	5.74	5.74	5.74	5.77	5.79
2010	5.87	5.87	5.86	5.80	5.80	5.80	5.80	5.80	5.80	5.80	5.82	5.84
2011	6.09	6.09	6.08	6.01	6.00	6.00	6.01	6.01	6.01	6.01	6.03	6.06
2012	6.26	6.26	6.25	6.17	6.16	6.16	6.17	6.17	6.17	6.17	6.20	6.22
2013	6.49	6.49	6.47	6.39	6.38	6.38	6.38	6.38	6.38	6.39	6.42	6.44
2014	6.71	6.70	6.69	6.59	6.58	6.58	6.59	6.59	6.59	6.59	6.63	6.66
2015	6.85	6.85	6.84	6.74	6.73	6.73	6.73	6.74	6.74	6.74	6.77	6.80
2016	6.84	6.84	6.83	6.75	6.74	6.74	6.74	6.75	6.75	6.75	6.77	6.80
2017	7.05	7.05	7.03	6.95	6.94	6.94	6.95	6.95	6.95	6.95	6.98	7.01
2018	7.32	7.32	7.31	7.21	7.20	7.20	7.20	7.21	7.20	7.21	7.24	7.27
2019	7.61	7.60	7.59	7.47	7.46	7.46	7.47	7.47	7.47	7.47	7.51	7.55
2020	7.84	7.83	7.82	7.69	7.68	7.68	7.69	7.69	7.69	7.69	7.73	7.77
2021	8.04	8.04	8.02	7.89	7.87	7.88	7.88	7.89	7.89	7.89	7.93	7.97
2022	8.24	8.23	8.21	8.09	8.07	8.07	8.08	8.08	8.08	8.08	8.13	8.17
2023	8.44	8.44	8.42	8.28	8.27	8.27	8.28	8.28	8.28	8.28	8.33	8.37
2024	8.64	8.63	8.61	8.48	8.46	8.47	8.47	8.47	8.47	8.48	8.52	8.57
2025	8.86	8.86	8.83	8.70	8.68	8.68	8.69	8.69	8.69	8.69	8.74	8.79

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

Table 7 represents the variable C in the formulas for the Option 2 (Deadband Index Gas Price Option) and Option 3 (Index Gas Price Option).

TABLE 7												
Capacity Value - C ($/MWH)												
	Month											
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57	25.57
2010	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21	26.21
2011	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87	26.87
2012	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54	27.54
2013	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23	28.23
2014	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94	28.94
2015	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66	29.66
2016	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30	30.30
2017	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26
2018	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94	31.94
2019	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74	32.74
2020	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45	33.45
2021	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39	34.39
2022	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25	35.25
2023	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25	36.25
2024	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92	36.92
2025	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97	37.97

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard Contract:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on his/her own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for wheeling power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in an Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Concluded)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established in Rule C or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

The Seller may be required to execute a generation interconnection agreement.

SPECIAL CONDITIONS

1. Under negotiated agreements, Seller will execute a written Power Purchase Agreement with the Company. The contract will outline specific requirements including but not limited to the term of the agreement, nameplate capacity of the QF, the amount of power the QF agrees to sell, the Pricing Option chosen by the Seller, the default security requirements, the insurance requirements, and the means by which the QF owner established credit with the Company.

2. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

3. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

4. Contracts entered into pursuant to this schedule will not terminate prior to the Power Purchase Agreement's termination date if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

STANDARD CONTRACT POWER PURCHASE AGREEMENT

THIS AGREEMENT, entered into this _______ day, _____________ 200____, is between __________________________ ("Seller") and Portland General Electric Company ("PGE") (hereinafter each a "Party" or collectively, "Parties").

RECITALS

Seller intends to construct, own, operate and maintain a _____________ facility for the generation of electric power located in _______________ County, _____________ with a Nameplate Capacity Rating of ___________________ kilowatt ("kW"), as further described in Exhibit B ("Facility"); and

Seller intends to operate the Facility as a "Qualifying Facility," as such term is defined in Section 3.1.3, below.

Seller will sell and PGE will purchase the entire Net Output, as such term is defined in Section 1.14, below, from the Facility in accordance with the terms and conditions of this Agreement.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms will have the following meanings:

1.1. "As-built Supplement" means the supplement to Exhibit B provided by Seller in accordance with Section 4.4 following completion of construction of the Facility, describing the Facility as actually built.

1.2. "Billing Period" means a period between PGE's readings of its power purchase billing meter at the Facility in the normal course of PGE's business. Such periods typically vary and may not coincide with calendar months.

1.3. "Capacity Value" has the meaning provided for in the Tariff (as defined below).

1.4. "Commercial Operation Date" means the date that the Facility is deemed by PGE to be fully operational and reliable which will require, among other things, that all of the following events have occurred:

1.4.1. PGE has received a certificate addressed to PGE from a Licensed Professional Engineer ("LPE") acceptable to PGE in its reasonable judgment stating that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement (certifications required under this Section 1.4 can be provided by one or more LPEs);

1.4.2. Start-Up Testing of the Facility has been completed in accordance with Section 1.22;

1.4.3. After PGE has received notice of completion of Start-Up Testing, PGE has received a certificate addressed to PGE from an LPE stating that the Facility has operated for testing purposes under this Agreement uninterrupted for a Test Period at a rate in kW of at least 75 % of average annual Net Output divided by 8,760 based upon any sixty (60) minute period for the entire testing period. The Facility must provide ten (10) working days written notice to PGE prior to the start of the initial testing period. If the operation of the Facility is interrupted during this initial testing period or any subsequent testing period, the Facility will promptly start a new Test Period and provide PGE forty-eight (48) hours written notice prior to the start of such testing period;

1.4.4. PGE has received a certificate addressed to PGE from an LPE stating that, in accordance with the Generation Interconnection Agreement, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PGE's electric system;

1.4.5. PGE has received a certificate addressed to PGE from an LPE stating that Seller has obtained all Required Facility Documents and, if requested by PGE in writing, has provided copies of any or all such requested Required Facility Documents;

1.4.6. Notwithstanding the foregoing, Sellers with projects delivering Net Output to PGE prior to the Effective Date and with less than 100 Kw Nameplate Capacity will be deemed to have established a Commercial Operation date identical to the Effective Date.

1.5. "Contract Price" means the applicable price for Net Output as stated in Sections 5.1, 5.2, 5.3 and 5.4.

1.6. "Contract Year" means each twelve (12)- month period commencing at 00:00 hours on January 1 and ending on 24:00 hours on December 31 falling at least partially in the Term of this Agreement.

1.7. "Effective Date" has the meaning set forth in Section 2.1.

1.8. "Facility" has the meaning set forth in the Recitals.

1.9. “Generation Interconnection Agreement” means the generation interconnection agreement to be entered into separately between Seller and PGE, providing for the construction, operation, and maintenance of PGE’s interconnection facilities required to accommodate deliveries of Seller’s Net Output.

1.10. "Licensed Professional Engineer" or “LPE” means a person who is licensed to practice engineering in the state where the Facility is located, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer will be licensed in an appropriate engineering discipline for the required certification being made and be acceptable to PGE in its reasonable judgment.

1.11. “Lost Energy Value” means for a Contract Year: zero, unless the Net Output is less than Minimum Net Output and the mean Dow Jones Mid C Index Price is greater than the Contract Price, in which case Lost Energy Value equals: (Minimum Net Output - Net Output) X (Mean Dow Jones Mid C Index Price – Mean Contract Price). If PGE is in a Resource Sufficient Position as defined in the Tariff for a Contract Year, Lost Energy Value is deemed to be zero for that Contract Year.

1.12. “Nameplate Capacity Rating” means the maximum capacity of the Facility as stated by the manufacturer, expressed in kW, which will not exceed 10,000 kW.

1.13. “Net Dependable Capacity” means the maximum capacity the Facility can sustain over a specified period modified for seasonal limitations, if any, and reduced by the capacity required for station service or auxiliaries.

1.14. "Net Output" means all energy expressed in kWhs produced by the Facility, less station and other onsite use and less transformation and transmission losses and other adjustments, if any.

1.15. “Off-Peak Hours” has the meaning provided in the Tariff.

1.16. “On-Peak Hours” has the meaning provided in the Tariff.

1.17. "Point of Delivery" means the high side of the generation step-up transformer(s) located at the point of interconnection between the Facility and PGE’s distribution or transmission system, as specified in the Generation Interconnection Agreement.

1.18. “Prime Rate” means the publicly announced prime rate or reference rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate will be the announced prime rate or reference rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, N.Y., selected by the Party to whom interest based on the prime rate is being paid.

1.19. "Prudent Electrical Practices" means those practices, methods, standards and acts engaged in or approved by a significant portion of the electric power industry in the Western Electricity Coordinating Council that at the relevant time period, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by applicable equipment suppliers and manufacturers, operational limits, and all applicable laws and regulations. Prudent Electrical Practices are not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods and acts generally acceptable or approved by a significant portion of the electric power generation industry in the relevant region, during the relevant period, as described in the immediate preceding sentence.

1.20. “Recoupment Value” means, on a date during a Contract Year, the On-Peak Net Output generated and delivered from the Facility to the Point of Delivery during such Contract Year up to and including such date multiplied by the applicable Capacity Value.

1.21. "Required Facility Documents" means all licenses, permits, authorizations, and agreements necessary for construction, operation, and maintenance of the Facility including without limitation those set forth in Exhibit C.

1.22. "Start-Up Testing" means the completion of applicable required factory and start-up tests as set forth in Exhibit D.

1.23. “Tariff” will mean PGE rate Schedule 201 filed with the Oregon Public Utilites Commission in effect on the Effective Date of this Agreement and attached hereto as Exhibit E.

1.24. “Term” will mean the period beginning on the Effective Date and ending on the Termination Date.

1.25. “Test Period” will mean a period of 60 days or a commercially reasonable period determined by the Seller.

References to Recitals, Sections, and Exhibits are to be the recitals, sections and exhibits of this Agreement.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement will become effective upon execution by both Parties ("Effective Date").

2.2 Time is of the essence of this Agreement, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to complete all requirements to establish the Commercial Operation Date is critically important. Therefore,

2.2.1 By ________ [*date to be determined by the Seller*] Seller will begin initial deliveries of Net Output; and

2.2.2 By ________ [*date to be determined by the Seller*] Seller will have completed all requirements under Section 1.4 and will have established the Commercial Operation Date.

2.3 This Agreement will terminate on _________, ____ [*date to be chosen by Seller*], up to 20 years from the Effective Date, or the date the Agreement is terminated in accordance with Section 10 or 12.2, whichever is earlier ("Termination Date").

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 Seller represents, covenants, and warrants to PGE that:

3.1.1 Seller is a ___________ duly organized under the laws of ___________.

3.1.2 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.1.3 The Facility is and will for the Term of this Agreement continue to be a "Qualifying Facility" ("QF") as that term is defined in the version of 18 C.F.R. Part 292 in effect on the Effective Date. Seller has provided the appropriate QF certification, which may include a Federal Energy Regulatory Commission ("FERC") self-certification to PGE prior to PGE's execution of this Agreement. At any time during the Term of this Agreement, PGE may require Seller to provide PGE with evidence satisfactory to PGE in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements.

3.1.4 Seller has not within the past two (2) years been the debtor in any bankruptcy proceeding, and Seller is and will continue to be for the Term of this agreement current on all of its financial obligations.

3.1.5 During the Term of this Agreement, all of Seller's right, title and interest in and to the Facility will be free and clear of all liens and encumbrances other than liens and encumbrances arising from third-party financing of the Facility.

3.1.6 Seller will design and operate the Facility consistent with Prudent Electrical Practices.

3.1.7 The Facility has a Nameplate Capacity rating not greater than 10,000 kW.

3.1.8 Net Dependable Capacity of the Facility is ____________kW.

3.1.9 Seller estimates that the average annual Net Output to be delivered by the Facility to PGE is __________ kilowatt-hours ("kWh"), which amount PGE will include in its resource planning.

3.1.10 Seller will deliver from the Facility to PGE at the Point of Delivery Net Output not to exceed a maximum of _______kWh of Net Output during each Contract Year ("Maximum Net Output").

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Effective Date and continuing through the Term of this Agreement, Seller will sell to PGE the entire Net Output delivered from the Facility at the Point of Delivery.

4.2 Provided Seller has elected the Contract Price options in Section 5.1, 5.2, or 5.3, Seller will make available from the Facility either a) a minimum of seventy-five percent (75%) of its average annual Net Output or b) the Alternative Minimum Amount as defined in Exhibit A during each Contract Year (hereinafter "Minimum Net Output"), provided that such Minimum Net Output for the first or last Contract Year during which Commercial Operations begins will be reduced pro rata to reflect the Commercial Operation Date, and further provided that such Minimum Net Output will be reduced on a pro-rata basis for any periods during a Contract Year that the Facility was prevented from generating electricity for reasons of Force Majeure. All deliveries of Net Output are subject to the Contract Price.

4.3 Provided Seller has elected the Contract Price options in Section 5.1, 5.2, or 5.3, Seller agrees that if Seller does not deliver the Minimum Net Output each Contract Year, PGE will suffer losses equal to the Lost Energy Value. As damages for Seller's failure to deliver the Minimum Net Output (subject to adjustment for reasons of Force Majeure as provided in Section 4.2) in any Contract Year, notwithstanding any other provision of this Agreement the purchase price payable by PGE for all deliveries in the Contract Year following the year in which Seller failed to deliver such Minimum Net Output will be the Off-Peak Price of the applicable Contract Price option until Recoupment Value equals Lost Energy Value. If during such succeeding Contract Year Seller succeeds in delivering the Minimum Net Output for that Contract Year, then the purchase price payable by PGE for all deliveries in such Contract Year occurring after the Billing Period in which Seller first succeeds in delivering the Minimum Net Output for such Contract Year will be as set forth in Section 5.1, 5.2, or 5.3, as applicable.

4.4 Upon completion of construction of the Facility, Seller will provide PGE an As-built Supplement to specify the actual Facility as built. Seller will not increase the Nameplate Capacity Rating above that specified in Exhibit B or increase the ability of the Facility to deliver Net Output in quantities in excess of the Net Dependable Capacity, or the Maximum Net Output as described in Section 3.1.10 above, through any means including, but not limited to, replacement, modification, or addition of existing equipment, except with the written consent of PGE.

4.5 To the extent not otherwise provided in the Generation Interconnection Agreement, all costs associated with the modifications to PGE's interconnection facilities or electric system occasioned by or related to the interconnection of the Facility with PGE's system, or any increase in generating capability of the Facility, or any increase of delivery of Net Dependable Capacity from the Facility, will be borne by Seller.

SECTION 5: CONTRACT PRICE

PGE will pay Seller for the price options 5.1, 5.2, 5.3 or 5.4, as selected below, pursuant to the Tariff. Seller will indicate which price option it chooses by marking its choice below with an X. If Seller chooses the option in Section 5.1, it must mark below a single second option from Section 5.2, 5.3, or 5.4 for all Contract Years in excess of 15 until the remainder of the Term. Except as provided herein, Sellers selection is for the Term and will not be changed during the Term.

5.1 ______ Fixed Price.
5.2 ______ Deadband Index Gas Price.
5.3 ______ Index Gas Price.
5.4 ______ Mid-C Index Rate Price.

SECTION 6: OPERATION AND CONTROL

6.1 Seller will operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement, and Prudent Electrical Practices. PGE will have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and PGE's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's non-compliance with the Generation Interconnection Agreement. Seller is solely responsible for the operation and maintenance of the Facility. PGE will not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.2 Seller agrees to provide 60 days written advance written notice of any scheduled maintenance that would require shut down of the Facility for any period of time. If the Facility ceases operation for unscheduled maintenance, Seller immediately will notify PGE of the necessity of such unscheduled maintenance, the time when such shutdown has occurred or will occur and the anticipated duration of such shutdown. Seller will take all reasonable measures and exercise its best efforts to avoid unscheduled maintenance, to limit the duration of such unscheduled maintenance, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: CREDITWORTHINESS

In the event Seller: a) is unable to represent or warrant as required by Section 3 that it has not been a debtor in any bankruptcy proceeding within the past two (2) years; b) becomes such a debtor during the Term; or c) is not or will not be current on all its financial obligations, Seller will immediately notify PGE and will promptly (and in no less than 10 days after notifying PGE) provide default security in an amount reasonably acceptable to PGE in one of the following forms: senior lien, step in rights, a cash escrow or line of credit. The amount of such default security that will be acceptable to PGE will be equal to: (annual On Peak Hours) X (On Peak Price – Off Peak Price) X (Minimum Net Output / 8760).

SECTION 8: METERING

8.1 PGE will design, furnish, install, own, inspect, test, maintain and replace all metering equipment at Seller's cost and as required pursuant to the Generation Interconnection Agreement.

8.2 Metering will be performed at the location and in a manner consistent with this Agreement and as specified in the Generation Interconnection Agreement. All Net Output purchased hereunder will be adjusted to account for electrical losses, if any, between the point of metering and the Point of Delivery, so that the purchased amount reflects the net amount of power flowing into PGE's system at the Point of Delivery.

8.3 PGE will periodically inspect, test, repair and replace the metering equipment as provided in the Generation Interconnection Agreement. If any of the inspections or tests disclose an error exceeding two percent (2%) of the actual energy delivery, either fast or slow, proper correction, based upon the inaccuracy found, will be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction will be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) months, in the amount the metering equipment will have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records will be made in the next monthly billing or payment rendered. Such correction, when made, will constitute full adjustment of any claim between Seller and PGE arising out of such inaccuracy of metering equipment.

8.4 To the extent not otherwise provided in the Generation Interconnection Agreement, all PGE's costs relating to all metering equipment installed to accommodate Seller's Facility will be borne by Seller.

SECTION 9: BILLINGS, COMPUTATIONS AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PGE will send to Seller payment for Seller's deliveries of Net Output to PGE, together with computations supporting such payment. PGE may offset any such payment to reflect amounts owing from Seller to PGE pursuant to this Agreement, the Generation Interconnection Agreement, and any other agreement related to the Facility between the Parties or otherwise.

9.2 Any amounts owing after the due date thereof will bear interest at the Prime Rate plus two percent (2%) from the date due until paid; provided, however, that the interest rate will at no time exceed the maximum rate allowed by applicable law.

SECTION 10: DEFAULT, REMEDIES AND TERMINATION

10.1 In addition to any other event that may constitute a default under this Agreement, the following events will constitute defaults by Seller under this Agreement:

10.1.1 Seller's failure to meet the requirements as provided in Section 2.2.

10.1.2 Breach by Seller of a representation or warranty, except for Section 3.1.4, set forth in this Agreement.

10.1.3 Seller's failure to provide default security, if required by Section 7, prior to delivery of any Net Output to PGE or within 10 days of notice.

10.1.4 Seller's failure to deliver the Minimum Net Output for two consecutive Contract Years.

10.1.5 If Seller modifies the Facility such that the Nameplate Capacity Rating exceeds 10,000 kW.

10.1.6 If Seller is no longer a "Qualifying Facility".

10.2 In the event of a default hereunder, PGE may immediately terminate this Agreement at its sole discretion by delivering written notice to Seller and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement including damages related to the need to procure replacement power. Such termination will be effective upon the date of delivery of notice, as provided in Section 21.1. The rights provided in this Section 10 are cumulative such that the exercise of one or more rights will not constitute a waiver of any other rights.

10.3 If this Agreement is terminated by PGE as provided in this Section, PGE will make all payments, within 30 days, that, pursuant to the terms of this Agreement, are owed to Seller as of the time of Seller's receipt of notice of default. PGE will not be required to pay Seller for any Net Output delivered by Seller after such notice of default.

10.4 In the event PGE terminates this Agreement pursuant to this Section 10, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller will do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.

10.5 Sections 10.1, 10.3, 10.4, 11, and 20.2 will survive termination of this Agreement.

SECTION 11: INDEMNIFICATION AND LIABILITY

11.1 Seller agrees to defend, indemnify and hold harmless PGE, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with Seller's delivery of electric power to PGE or with the facilities at or prior to the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of PGE, its directors, officers, employees, agents or representatives.

11.2 PGE agrees to defend, indemnify and hold harmless Seller, its directors, officers, agents, and representatives against and from any and all loss, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with PGE's receipt of electric power from Seller or with the facilities at or after the Point of Delivery, or otherwise arising out of this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PGE, Seller or others, excepting to the extent such loss, claim, action or suit may be caused by the negligence of Seller, its directors, officers, employees, agents or representatives.

11.3 Nothing in this Agreement will be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement will constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PGE as an independent public utility corporation or Seller as an independent individual or entity.

11.4 NEITHER PARTY WILL BE LIABLE TO THE OTHER FOR SPECIAL, PUNITIVE, INDIRECT OR CONSEQUENTIAL DAMAGES, WHETHER ARISING FROM CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY OR OTHERWISE.

SECTION 12: INSURANCE

12.1 Prior to the connection of the Facility, provided such Facility has a design capacity of 200 kW or more, to PGE's electric system, Seller will secure and continuously carry for the Term hereof, with an insurance company or companies rated not lower than "A" by the A. M. Best Company, insurance policies for bodily injury and property damage liability. Such insurance will include provisions or endorsements naming PGE, it directors, officers and employees as additional insureds; provisions that such insurance is primary insurance with respect to the interest of PGE and that any insurance maintained by PGE is excess and not contributory insurance with the insurance required hereunder; a cross-liability or severability of insurance interest clause; and provisions that such policies will not be canceled or their limits of liability reduced without thirty (30) days' prior written notice to PGE. Initial limits of liability for all requirements under this section will be $1,000,000 million single limit, which limits may be required to be increased or decreased by PGE as PGE determines in its reasonable judgment economic conditions or claims experience may warrant.

12.2 Prior to the connection of the Facility to PGE's electric system, provided such facility has a design capacity of 200 kW or more, Seller will secure and continuously carry for the Term hereof, in an insurance company or companies rated not lower than "A" by the A. M. Best Company, insurance acceptable to PGE against property damage or destruction in an amount not less than the cost of replacement of the Facility. Seller promptly will notify PGE of any loss or damage to the Facility. Unless the Parties agree otherwise, Seller will repair or replace the damaged or destroyed Facility, or if the facility is destroyed or substantially destroyed, it may terminate this Agreement. Such termination will be effective upon receipt by PGE of written notice from Seller. Seller will waive its insurers' rights of subrogation against PGE regarding Facility property losses.

12.3 Prior to the connection of the Facility to PGE's electric system and at all other times such insurance policies are renewed or changed, Seller will provide PGE with a copy of each insurance policy required under this Section, certified as a true copy by an authorized representative of the issuing insurance company or, at the discretion of PGE, in lieu thereof, a certificate in a form satisfactory to PGE certifying the issuance of such insurance. If Seller fails to provide PGE with copies of such currently effective insurance policies or certificates of insurance, PGE at its sole discretion and without limitation of other remedies, may upon ten (10) days advance written notice by certified or registered mail to Seller either withhold payments due Seller until PGE has received such documents, or purchase the satisfactory insurance and offset the cost of obtaining such insurance from subsequent power purchase payments under this Agreement.

SECTION 13: FORCE MAJEURE

13.1 As used in this Agreement, "Force Majeure" or "an event of Force Majeure" means any cause beyond the reasonable control of the Seller or of PGE which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it will be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of resources to operate the Facility or changes in market conditions that affect the price of energy or transmission, and obligations for the payment of money when due. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party will be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the Force Majeure, after which such Party will re-commence performance of such obligation, provided that:

13.1.1 the non-performing Party, will, promptly, but in any case within one (1) week after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

13.1.2 the suspension of performance will be of no greater scope and of no longer duration than is required by the Force Majeure; and

13.1.3 the non-performing Party uses its best efforts to remedy its inability to perform its obligations under this Agreement.

13.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance will be excused as a result of the Force Majeure.

13.3 Neither Party will be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

SECTION 14: SEVERAL OBLIGATIONS

Nothing contained in this Agreement will ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party will be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 15: CHOICE OF LAW

This Agreement will be interpreted and enforced in accordance with the laws of the state of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 16: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement will remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties will enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 17: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver will not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 18: GOVERNMENTAL JURISDICTION AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller will at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and will provide upon request copies of the same to PGE.

SECTION 19: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof will be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party will become effective without the written consent of the other Party being first obtained and such consent will not be unreasonably withheld. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 20: ENTIRE AGREEMENT

20.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PGE's purchase of Net Output from the Facility. No modification of this Agreement will be effective unless it is in writing and signed by both Parties.

20.2 By executing this Agreement, Seller releases PGE from any claims related to the Facility, known or unknown, that may have arisen prior to the Effective Date.

SECTION 21: NOTICES

21.1 All notices except as otherwise provided in this Agreement will be in writing, will be directed as follows and will be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested:

To Seller: ______________________________
____
____
____

with a copy to: ______________________________
____
____
____

To PGE: Contracts Manager
QF Contracts, 3WTCBR06
PGE - 121 SW Salmon St.
Portland, Oregon 97204

21.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 21.

SECTION 22: SUBJECT TO OPUC INVESTIGATION

22.1 The seller and PGE acknowledge that the rates, terms and conditions specified in this agreement and the related tariffs are being investigated by the Oregon Public Utility Commission. Upon a decision by the Oregon Public Utility Commission in the investigation, PGE will notify the seller within ten calendar days. The seller will have thirty calendar days from the effective date of the revised standard contract and tariffs complying with the Commission's order to amend this agreement if the seller so chooses to adopt the revised standard contract and/or the revised rates, terms and conditions in the tariff approved by the Oregon Public Utility Commission as a result of the investigation.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the Effective Date.

PGE

By: ___________________________
Name: ________________________
Title: _________________________

___________________________.
(Name Seller)

By: ___________________________
Name: ________________________
Title: _________________________

EXHIBIT A
MINIMUM NET OUTPUT

Seller may designate an alternative Minimum Net Output to seventy-five (75%) percent of annual Net Output in this exhibit ("Alternative Minimum Amount"). Such Alternative Minimum Amount, if provided, will exceed zero, and will be established in accordance with Prudent Electrical Practices and documentation supporting such a determination will be provided to PGE upon execution of the Agreement. Such documentation will be commercially reasonable, and may include, but is not limited to, documents used in financing the project, and data on output of similar projects operated by seller, PGE or others.

EXHIBIT B

DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

EXHIBIT C

REQUIRED FACILITY DOCUMENTS

[Seller list all permits and authorizations required for this project]

EXHIBIT D

START-UP TESTING

[Seller identify appropriate tests]

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable):

1. Pressure tests of all steam system equipment;
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;
3. Operating tests of all valves, operators, motor starters and motor;
4. Alarms, signals, and fail-safe or system shutdown control tests;
5. Insulation resistance and point-to-point continuity tests;
6. Bench tests of all protective devices;
7. Tests required by manufacturer of equipment; and
8. Complete pre-parallel checks with PGE.

Required start-up test are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PGE's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;
3. Brake tests;
4. Energization of transformers;
5. Synchronizing tests (manual and auto);
6. Stator windings dielectric test;
7. Armature and field windings resistance tests;
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load;
9. Heat runs;
10. Tests required by manufacturer of equipment;
11. Excitation and voltage regulation operation tests;
12. Open circuit and short circuit; saturation tests;
13. Governor system steady state stability test;
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;
15. Auto stop/start sequence;
16. Level control system tests; and
17. Completion of all state and federal environmental testing requirements.

EXHIBIT E

TARIFF

[**Attach currently in-effect rate Schedule 201]**

SCHEDULE 203
NET METERING SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

Net Metering power production is generation made available to the Company from a Customer that owns and operates a generating facility using solar power, wind power, fuel cells, hydroelectric power, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis or low-emission, nontoxic biomass based on solid organic fuels from wood, forest or field residues with a generating-installed capacity of 25 kW or less. The facility must operate in parallel with the Company's existing Facilities and be primarily intended to offset part or all of the Customer's own electrical requirements. The Company will make this optional service available to Customers on a first-come, first-serve basis until the time that the total rated generating capacity equals 20,365 kilowatts. This schedule is offered in compliance with ORS 757.300, as amended by Senate Bill 84, May 2005.

DEFINITION

Net metering measures the difference between the Electricity supplied by the Company and the Electricity generated by a Customer-generator and fed back to the Company over the monthly Billing Period.

MONTHLY BILLING

Each Customer-generator will pay monthly charges as applicable in accordance with the Customer's service option selection.

Energy:

1. During a monthly Billing Period, should the Company supply a Customer-generator more energy than the Customer-generator feeds back to the Company, the Customer-generator will be charged for the net energy supplied in accordance with the Customer's service option selection.

2. During a monthly Billing Period, should a Customer-generator feed back more Energy than the Company supplies, the Customer will be billed the appropriate monthly charges (including Basic, Demand, Facilities, and Reactive Demand charges as applicable) and will be credited for the excess Energy at Schedule 201, Qualifying Facility Power Purchase Information, weighted rates.

SCHEDULE 203 (Concluded)

MONTHLY BILLING (Continued)

Energy: (Continued)

3. Where the Customer is a Direct Access Customer, the Electricity Service Supplier (ESS) will preschedule and deliver Energy into the Company's control area incorporating an individualized forecast applicable to the Customer selecting this service daily. Payments to the Customer will be based on an analysis of the forecast compared to the Customer's actual usage.

SPECIAL CONDITIONS

1. A Net Metering Facility will meet all applicable safety and performance standards established in the Oregon State Building Code. The standards will be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories or other similarly accredited laboratory. The Net Metering Facility must also be in compliance with the applicable provisions of Schedule 201, Qualifying Facility Power Purchase Information and Rule C, Conditions Governing Customer Attachment to Facilities.

2. Prior to interconnection, the owner of a Net Metering Facility intending to sell Electricity to the Company under this rate schedule will execute a written Net Metering Agreement with the Company.

3. The customer-generator is responsible for obtaining all necessary government approvals relating to its net metering facility.

4. The customer-generator is responsible for all costs associated with its facility and is also responsible for all costs related to any modifications to the facility that may be required by the Company for purposes of safety and reliability.

5. Company approved switching equipment capable of isolating the Net Metering Facility from the Company's system will be provided by the customer-generator and will be accessible to the Company at all times.

6. The Company maintains the right to approve the facilities for interconnection, and to inspect the facilities at any time and for any reason.

7. The Company maintains the right to disconnect, without liability, the customer-generator for issues relating to safety and reliability.

8. The Company will not be liable directly or indirectly for permitting or continuing to allow an attachment of a Net Metering Facility, or for the acts or omissions of the customer-generator that cause loss or injury, including death, to any third party.

SCHEDULE 300
CHARGES AS DEFINED BY THE RULES AND REGULATIONS AND MISCELLANEOUS CHARGES

PURPOSE

The purpose of this schedule is to list the charges referred to in the General Rules and Regulations.

AVAILABLE

In all territory served by the Company.

APPLICABLE

For all Customers utilizing the services of the Company as defined and described in the General Rules and Regulations.

INTEREST ACCRUED ON DEPOSITS (See Rules D and H)

2% per annum.

BILLING RATES (Rules C, E, H, I and J)

Trouble call, cause in Customer-owned equipment

Scheduled Crew Hours [(1)]	No charge
Other than Scheduled Crew Hours [(1)]	$170.00
Returned Payment Charge	$ 30.00
Special Meter Reading Charge	$ 35.00
Meter Test Charge	$ 75.00
Late Payment Charge	1.7% of delinquent balance
Field Service Collection Charge	$ 30.00
Bill History Information Service Charge (Not applicable when a billing dispute is filed with the Commission - see Rule E)	$ 32.00
Portfolio Enrollment Charge	$ 5.00
Customer Interval Data (12 months) to Customers	$100.00
Customer Interval Data (12 months, formatted and analyzed)	Mutually agreed price
Switching Fee	$20.00

(1) Scheduled Crew Hours - The Company's Scheduled Crew Hours for the above listed services are from 6:30 a.m. to 10:30 p.m., Monday through Friday, except for Company-recognized holidays. The Customer will be informed of and agree to the charges before Company personnel are dispatched.

SCHEDULE 300 (Continued)

CREDIT RELATED DISCONNECTION AND RECONNECTION RATES (Rule F)

Disconnects at Meter Base	
8:00 a.m. – 5:30 p.m. Monday through Friday (excluding holidays)(1)	No charge
All Other Hours	$240.00
Disconnects at Other Than Meter Base	
8:00 a.m. – 5:30 p.m. Monday through Friday (excluding holidays)(1)	No charge
All Other Hours	$450.00
Reconnects at Meter Base	
7:00 a.m. – 7:00 p.m. Monday through Friday (excluding holidays)(2)	$ 45.00
Weekends and Holidays	$240.00
Reconnects at Other Than Meter Base	
8:00 a.m. – 5:30 p.m. Monday through Friday (excluding holidays) (2)	$115.00
Weekends and Holidays	$450.00
Unauthorized Service Reconnect Charge	$ 75.00
(See Rule F for conditions under which these charges apply.)	
Reconnect Visit	$ 30.00
(See Rule F for conditions under which these charges apply.)	

(1) Scheduled Crew Hours for Credit Related Disconnection Rates.
(2) Scheduled Business Hours during which time Customers may call to provide proof of payment and request service reconnection. Upon receiving a valid request for service reconnection, the Company will make a reasonable attempt to reconnect service prior to the close of the next business day.

SCHEDULE 300 (Continued)

CUSTOMER REQUESTED DISCONNECTION AND RECONNECTION RATES (Rule F)[1]

Disconnects at Meter Base [2]	
7:00 a.m. - 3:30 p.m., Monday through Friday (excluding holidays) [3]	No charge
All Other Hours	$240.00
Disconnects at Other Than Meter Base [2]	
7:00 a.m. - 3:30 p.m., Monday through [3]	No charge
All Other Hours	$450.00
Reconnects at Meter Base [2]	
Safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	No charge
Non-safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	$ 45.00
All Other Hours	$240.00
Reconnects at Other Than Meter Base[2]	
Safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	No charge
Non-safety related, 7:00 a.m. - 3:30 p.m., [3] Monday through Friday (excluding holidays)	$115.00
All Other Hours	$450.00

---

(1) These rates apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In other cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.
(2) No charge for disconnects / reconnects completed to ensure safe working conditions that meet the guidelines in Rule F(6).
(3) Scheduled Crew Hours for Customer Requested Disconnection and Reconnection Rates.

SCHEDULE 300 (Continued)

METER INSTALLATION RATES (Rule I)

Meter Verification Charge	$ 33.00 per Unit
Pole Metering Rates(1)	
Single-phase meter per each installation - 120, 240, or 480 volts	$ 670.00
Three-phase meter per each installation 120, 240 or 480 3 or 4 wire	$ 740.00
Single-phase primary voltage service per each installation	$1,200.00
Three-phase primary voltage service per each installation	$1,990.00
Vault Metering Rates(1)	
Single-phase meter per each installation - 120, 240, or 480 volts	Estimated Actual Cost
Three-phase meter per each installation - 208, 240, or 480 volts	Estimated Actual Cost
Primary voltage service per each Meter installation	Estimated Actual Cost
Pad-Mounted Metering Rates(1)	
Primary voltage per each installation	$8,225.00 – 200 amp, single phase $9,030.00 – 200 amp, single phase
other sizes	Estimated Actual Cost

(1) Excludes costs of current transformers, potential transformers, and meters.

SCHEDULE 300 (Continued)

METER RENTAL RATES (Rule I)

Where the Company rents meters to Customers engaged in resale prior to November 5, 1973:

Self-contained watt-hour meter rated up to 200 amperes	$ 1.00 per month
Interval Meter Rates	
Meter Installation	$100.00
Monthly Charge	$ 6.00
Pulse Output Metering	
Meter Installation	$500.00

MISCELLANEOUS EQUIPMENT RENTAL (Rule C)

Rental of transformers, single-phase to three-phase inverters, capacitors, and other related equipment	1-2/3% per month of current replacement cost at time of installation

TRANSFORMERS (Rule G)

<u>Submersible Transformers</u>[1]

Subdivision - five dwelling units or more	$ 150.00 per lot $1,050.00 minimum
Mobile Home - five spaces or more	$ 150.00 per space $1,050.00 minimum
Multi-Family Units - nine units or more	$ 75.00 per family unit $1,050.00 minimum

(1) For all other applications, which include but are not limited to network service areas and densely populated urban areas, that require submersible transformers, the charge will be the calculated difference in cost between submersible and pad-mount transformer installations including the costs of future maintenance.

SCHEDULE 300 (Continued)

LINE EXTENSIONS (Rule G)

Line Extension Allowance (Section 2)

Residential Service	$1,514.00 / dwelling unit
Small Nonresidential Service (Schedules 15, 32 & 47)	$ 0.1129 /estimated annual kWh
Large Nonresidential Service Secondary Voltage Service (Schedules 38, 49, 83, 89 & 91)	$ 0.0524 /estimated annual kWh
Large Nonresidential Primary voltage service (Schedules 38, 49, 83 & 89)	$ 0.0295 /estimated annual kWh

Trenching or Boring (Section 3)

Trenching and backfilling associated with Service Installation except where General Rules and Regulations require actual cost.

In Residential Subdivisions:	
Short-side service connection up to 30 feet	$ 100.00
Otherwise:	
First 75 feet or less	$ 219.00
Greater than 75 feet	$ 3.80 /foot
Mainline trenching, boring and backfilling	Estimated Actual Cost

Lighting Underground Service Areas(1)

Installation of conduit on a wood pole for lighting purposes	$ 75.00 per pole

Additional Services (Section 3)
(applies solely to Residential Subdivisions in Underground Service Areas)

Service Guarantee	$ 100.00
Wasted Trip Charge	$ 100.00
Service Locate Charge	$ 30.00
Long-Side Service Connection	$ 120.00

(1) Applies only to 1-inch conduit without brackets.

SCHEDULE 300 (Concluded)

SERVICE OF LIMITED DURATION (Rule L)

Standard Temporary Service

Service Connection Required:

No permanent Customer obtained	$ 300.00
Permanent Customer obtained	$ 185.00
Existing service	$ 80.00

Enhanced Temporary Service

Fixed fee for 12-month period	$ 210.00

Temporary Area Lights	$ 400.00 (first luminaire)
	$ 345.00 (each additional luminaire)
	$ 450.00 (first pole)
	$ 400.00 (each additional pole)

SCHEDULE 310
DEPOSITS FOR RESIDENTIAL SERVICE

PURPOSE

The purpose of this schedule is to list the deposits for residential service referred to in Rule D of the General Rules and Regulations.

DEPOSIT AMOUNTS	Average Deposit
Single-Family Dwellings	
All electric (electric heat, hot water, range, and lights)	$229.00
Electric heat but not all electric	$177.00
Electric hot water, range, and lights	$160.00
Any other combination	$132.00
Multiple-Family Dwellings	
All electric	$129.00
Electric heat but not all electric	$108.00
Electric hot water, range, and lights	$108.00
Any other combination	$72.00
Mobile Homes	
All electric	$203.00
Any other combination	$130.00
Houseboats	
All electric	$122.00
Any other combination	$89.00

The deposit amounts represent one-sixth (1/6) of average annual bills for the various dwelling types. When one-sixth (1/6) of the actual annual bill for a particular dwelling is significantly greater or less than the average deposit listed, the Company may request a deposit amount that more accurately represents one-sixth (1/6) of the anticipated annual usage.

SCHEDULE 320
METER INFORMATION SERVICES

PURPOSE

This schedule describes Meter Information Services available to Large Nonresidential Customers.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Large Nonresidential Customers.

PROGRAM DESCRIPTION

Meter Information Services is the provision of electric, gas, water usage and other relevant data, such as weather conditions, through an on-line energy management system.

Large Nonresidential Customers requesting service under this schedule must have an ability to capture and transmit interval usage data. The Company will advise the Customer on equipment specifications and subsequent changes necessary to meet these service requirements.

Meter Information Services provides Large Nonresidential Customers with interval usage data depicted in charts and graphs. Meter Information Services enables Large Nonresidential Customers to compare their current usage with historic data, identify anomalies in their usage, track savings from energy efficiency projects and understand their energy usage.

Customers may choose between the basic service option or enhanced service:
1) Standard Package – Data is updated on a weekly basis.
2) Enhanced Service – Data is updated on a daily basis.

Customers may also choose Energy Worksite which is an optional feature that offers more automated tracking capability including the ability to track projects, manage preventative maintenance and track work orders and energy bills. The Energy Worksite offer is customized for each Customer.

BILLING RATES

Meter Information Services is billed monthly on the Customer's bill for Electricity Service. Customers may choose to be separately billed for Meter Information Services for an additional $8 per bill.

SCHEDULE 320 (Continued)

BILLING RATES (Continued)

Standard Package

Set Up Fee:	$250.00 for the first meter $50.00 for each additional meter
Monthly Fees per meter:	
1 to 5 meters	$50.00
6 to 10 meters	$45.00
11 to 15 meters	$40.00
16 to 20 meters	$35.00
21 or more meters	$30.00

Enhanced Service – These costs are in addition to cost for the Standard Package.

	Monthly Cost per meter	Start Up Fee per meter
Daily Information	$10.00	$100.00
Hourly Airport Weather Data	$25.00	$50.00

Additional Customer Support or Training $125.00 per hour

Customized data, including Energy Worksite, may be provided at a mutually agreed price.

SPECIAL CONDITIONS

1. Customers who request service both inside and outside of the service territory will have all Points of Delivery (POD) receiving service on Schedule 725 and on this Schedule, added together to determine the appropriate monthly rate per meter.

2. Service under this schedule requires interval metering and meter communications be in place prior to the initiation of Meter Information Services.

3. Because of the meter and/or software installation required for this service, the Company anticipates a delay may occur from the time a Customer requests service under this Schedule until the Company can provide it.

4. Meter Information Services requires that the Customer have certain minimum computer system requirements and an ability to capture and transmit interval usage data. Specifications will be provided upon request. The Customer will at its expense provide the necessary communications equipment.

SCHEDULE 320 (Concluded)

SPECIAL CONDITIONS (Continued)

5. Customers may request a submeter be installed for the purpose of receiving Meter Information Services from a specified location behind the Company meter. However, the ability to install a submeter will be at the discretion of the Company. Customers choosing submetering will incur charges for all associated labor and materials needed to install the meter. The Customer is responsible for ownership and maintenance of the submeter.

6. The Company will disclose to Customers in any written or electronic marketing communications of more than minor length that: a) the Customer is free to procure similar services from other providers; and b) the Customer is not required to purchase Meter Information Services in order to receive regulated electricity services from the Company.

SCHEDULE 402
PROMOTIONAL CONCESSIONS
RESIDENTIAL PRODUCTS AND SERVICES

PURPOSE

This schedule describes the Company's promotional concession program for enhancing the purchase of products and services.

APPLICABLE

To Residential Customers, qualified engineers, equipment vendors, installers, builders, contractors, and to commercial Customers for residential-type appliances, products, and services.

DESCRIPTION OF CONCESSION

From time to time, the Company will provide incentives to promote the purchase and installation of selected electrical appliances, products, and services. Incentives may include, but are not limited to, contests, discounts, rebates, gift certificates, free merchandise, etc.

In compliance with OAR 860-026-0025, the Company will submit a description of each concession to the Commission. In addition, the Company will furnish a copy of the description to any other energy utility providing service in any portion of the Company's service territory.

EXPIRATION / REVIEW DATE

This program will be offered as necessary to encourage installation of energy-efficient appliances and products, and support the introduction of new products and services.

ACCOUNTING TREATMENT

Project costs associated with selling and promoting Company products and services will be assigned to Account 416.0 (Costs and Expenses of Merchandising). Other costs will be assigned to Account 426.5 (Other Income Deductions).

SCHEDULE 403
HEAT PUMP PROMOTIONAL CONCESSION

PURPOSE

This schedule describes the Company's Heat Pump Promotional Concession that will provide Customers with information and incentives for the installation of qualifying heat pumps.

APPLICABLE

To Residential Customers who install qualifying heat pumps at a service address within the Company's service territory where the currently installed heat source is electric.

DESCRIPTION OF CONCESSION

The Company will provide a $200 cash rebate to qualifying Customers who install heat pumps that meet the 2006 Federal Standard for Heating Season Performance Factor (HSPF 7.7) and Seasonal Energy Efficiency Ratio (SEER 13).

The Company will maintain a list of approved contractors that must meet certain performance standards, will be subject to random installation inspections and will be eligible for cooperative advertising, when available.

SPECIAL CONDITION

The Company will annually report to the Commission the number of program inquiries received and rebates issued.

ACCOUNTING TREATMENT

Project costs associated with selling and promoting Company products and services will be charged to non-utility accounts.

SCHEDULE 483
LARGE NONRESIDENTIAL
(< 1,000 kW)
COST-OF-SERVICE OPT-OUT

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceed 1,000 kW more than once within the proceeding 13 months and who has chosen the Company's transition plan during one of the enrollment periods specified below. Customers must have historical usage or have a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1MWa) from one or more Points of Delivery (PODs). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 489. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option.

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: Applicable to any Customer who enrolled prior to November 8, 2002, with a minimum service period from January 1, 2003 through December 31, 2007.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Fixed Three-Year Option

This option was not available during Enrollment Periods A and B.

SCHEDULE 483 (Continued)

OPT-OUT SERVICE TERM OPTIONS

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage	
	Secondary	Primary
Basic Charge		
Single Phase	$20.00	
Three Phase	$25.00	$90.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity	$2.29	$2.11
per kW of monthly Demand		
First 30 kW	$2.07	$2.07
Over 30 kW	$2.64	$2.64
System Usage Charge		
per kWh	0.216 ¢	0.205 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 483 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

The Customer may choose the Company Supplied Energy Charge options of either Daily or Extended Fixed Pricing subject to the requirements for the options.

1) Daily Pricing

The Daily Pricing Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. The election will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

2) Extended Fixed Pricing

Upon Customer request during a November Election window, the Company will provide a fixed Energy Charge quote based on market conditions at the time of the quote for either a 3 or 5 year term effective January 1st. The price quote will be available to the Customer for acceptance through close of business on the day the Company issues the quote. The quote may specify monthly and on- and off-peak prices. The Customer must provide the Company with a monthly on- and off-peak usage forecast of at least 10 MWa usage prior to the Company providing a price quote.

The Customer must execute a Schedule 483 Fixed Price Service Agreement including but not limited to the specifications for all applicable Points of Delivery, the desired term (3 or 5 years), the accepted Energy Charge quote, the monthly on- and off-peak Energy forecast at the meter, the average daily minimum and maximum Energy Usage (equivalent to 10% above and below the Energy forecast, respectively), required credit standard representations, the early termination fee description and the means for load imbalance reconciliation.

SCHEDULE 483 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy (Continued)

Extended Fixed Pricing (Continued)

Energy usage greater than the maximum will be served at the Daily Price of this schedule. For Energy usage less than the minimum, Customer will pay an addition charge equal to 75% of the difference (only if positive) between the price quote and the Daily Price applied to the difference between minimum and actual usage.

Early termination of the Fixed Price Service Agreement will require a lump-sum payment by Customer if the price quote is greater than 90% of the then-current forward market curve, adjusted for delivery to the Customer. The difference will be applied the Customer's estimated monthly usage for each remaining month of the fixed Energy Charge quote. The Customer will then be served under the Daily Price Option.

Wheeling Charge

The Wheeling Charge will be $1.487 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW for primary voltage service.

ON AND OFF PEAK HOURS

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.

SCHEDULE 483 (Continued)

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

REACTIVE DEMAND CHARGE

In addition to 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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a written service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the minimum Five-Year Option must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

SCHEDULE 483 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either 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 in addition, 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 the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 489
COST-OF-SERVICE OPT-OUT
LARGE NONRESIDENTIAL (>1000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months and who has chosen the Company's transition plan during one of the enrollment periods specified below. Customers must have historical usage or have a demonstrated usage pattern such that projected usage for a full 12 months is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery (POD). Each POD must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies to this and Schedule 483. Beginning with the September 2004 Enrollment Period C, Customers have a minimum five-year option and a fixed three-year option.

ENROLLMENT PERIODS

Minimum Five-Year Option

Enrollment Period A: Applicable to any Customer who enrolled prior to November 8, 2002, with a minimum service period from January 1, 2003 through December 31, 2007.

Enrollment Period B: Applicable to any Customer who enrolled between September 1, 2003 and September 30, 2003 with a minimum service period from January 1, 2004 through December 31, 2008.

Enrollment Period C: Applicable to any Customer who enrolled between September 1, 2004 and September 30, 2004, with a minimum service period from January 1, 2005 through December 31, 2009.

Enrollment Period D: Applicable to any customer who enrolled between September 1, 2005 and September 30, 2005, with a minimum service period from January 1, 2006 through December 31, 2010.

Enrollment Period E: Applicable to any customer who enrolled between September 1, 2006 and September 30, 2006, with a minimum service period from January 1, 2007 through December 31, 2011.

Fixed Three-Year Option

This option was not available during Enrollment Periods A and B.

SCHEDULE 489 (Continued)

OPT-OUT SERVICE TERM OPTIONS

Fixed Three-Year Option (Continued)

Enrollment Period C: Applicable to any Customer who enrolled between September 1 and September 30, 2004, with a service period from January 1, 2005 through December 31, 2007.

Enrollment Period D: Applicable to any Customer who enrolled between September 1, 2005 and September 30, 2005, with a service period from January 1, 2006 through December 31, 2008.

Enrollment Period E: Applicable to any Customer who enrolled between September 1, 2006 and September 30, 2006, with a service period from January 1, 2007 through December 31, 2009.

CHANGE IN APPLICABILITY

If a Customer's usage changes such that they no longer qualify as a Large Nonresidential Customer, they will have their service terminated under this schedule and will move to an otherwise applicable schedule.

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per POD*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
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
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION

Energy Supply

The Customer may elect to purchase Energy from an Electricity Service Supplier (ESS) (Direct Access Service) or from the Company. Such election will be for all of the Customer's POD under this schedule.

Direct Access Service

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, Transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS.

Company Supplied Energy

Effective January 1, 2005, upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge options of either Daily or Fixed Pricing. The election of either option will be effective on the next regularly scheduled meter reading date, but with not less than a five business day notice to the Company prior to the scheduled meter read date.

1) Daily Pricing

The Company Supplied Energy Option is the Dow Jones Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (DJ-Mid-C Index) plus 2 mills per kWh plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported.

2) Extended Fixed Pricing

Upon Customer request during a November Election, the Company will provide a fixed Energy Charge quote based on market conditions at the time of the quote for either a 3 or 5 year term beginning with the calendar year. The price quote will be available to the Customer for acceptance through close of business on the day the Company issues the quote. The quote may specify monthly and on- and off-peak prices. The Customer must provide the Company with a monthly on- and off-peak usage forecast of at least 10 MWa usage prior to the Company providing a price quote.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy (Continued)

Extended Fixed Pricing (Continued)

The Customer must execute a Schedule 489 Fixed Price Service Agreement including but not limited to the following specifications for all applicable POD:

a) The desired term (3 or 5 years);
b) The accepted Energy Charge quote;
c) The monthly on- and off-peak Energy forecast at the meter;
d) The average daily Minimum Energy Usage (equivalent to 10% above the Energy forecast);
e) The average daily Maximum Energy Usage (equivalent to 10% below the Energy forecast);
f) Required credit standard representations;
g) The early termination fee description; and
h) The means for load imbalance reconciliation.

Energy usage greater than the Maximum Energy Usage will be served at the Daily Price of this schedule. For Energy usage less than the Minimum Energy Usage, Customer will pay an addition charge equal to 75% of the difference (only if positive) between the price quote and the Daily Price applied to the difference between minimum and actual usage.

Early termination of the Fixed Price Service Agreement will require a lump-sum payment by Customer if the difference between the price quote and 90% of the then current forward market curve, adjusted for delivery to the Customer, if the difference is a positive number. The difference will be applied the Customer's estimated monthly usage for each remaining month of the fixed Energy Charge quote.

Wheeling Charge

The Wheeling Charge will be $1.487 per kW of monthly Demand.

Transmission Charge

Transmission and Ancillary Service Charges will be as specified in the Company's Open Access Transmission Tariff (OATT) as filed and approved by the Federal Energy Regulatory Commission.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

SCHEDULE 489 (Continued)

ON AND OFF PEAK HOURS

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.

LOSSES

The following adjustment factors will be used where losses are to be included in the energy charges:

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

REACTIVE DEMAND CHARGE

In addition to 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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments applicable to this schedule are summarized in Schedule 100.

SPECIAL CONDITIONS

Customers selecting this schedule must enter into a service agreement. In addition, the Customer acknowledges that:

1. Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company. Customers enrolled for service under the Minimum Five-Year Option must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

2. At the time service terminates under this schedule, the Customer will be considered a new Customer for purposes of determining available service options. A Customer served under the Company Supplied Energy option must meet the terms of the service agreement associated with that service prior to termination of service under this schedule.

3. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar customers not taking service under this schedule, including competitors to the Customer.

SCHEDULE 489 (Concluded)

SPECIAL CONDITIONS (Continued)

4. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

5. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it Energy experts that assisted in making this decision.

6. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement.

7. Direct Access Service is available only on acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

8. If the Customer is served at either 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 in addition, 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 the arrangement and operation of such equipment will be subject to the approval of the Company.

9. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

TERM

Minimum Five-Year Option
The term of service will not be less than five years. Service will be year-to-year thereafter. Customers must give the Company not less than two years notice to terminate service under this schedule. Such notice will be binding.

Fixed Three-Year Option
The term of service will be three years. Upon completion of this three year term, the Customer will select service under any other applicable rate schedule, subject to all notice requirements and provisions of the schedule.

SCHEDULE 515
OUTDOOR AREA LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Nonresidential Customers purchasing Direct Access Service for outdoor area lighting.

CHARACTER OF SERVICE

Lighting services, which consist of the provision of Company-owned luminaires mounted on Company-owned poles, in accordance with Company specifications as to equipment, installation, maintenance and operation.

The Company will replace lamps on a scheduled basis. Subject to the Company's operating schedules and requirements, the Company will replace individual burned-out lamps as soon as reasonably possible after the Customer or Electricity Service Supplier (ESS) notifies the Company of the burn-out.

MONTHLY RATE

Rates for Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate(1) Per Luminaire
Cobrahead				
Mercury Vapor	175	7,000	67	$ 8.64(2)
	400	21,000	149	11.64(2)
	1,000	55,000	379	20.54(2)
HPS	70	6,300	31	7.20(2)
	100	9,500	43	7.71
	150	16,000	63	8.44
	200	22,000	80	9.51
	250	29,000	103	10.36
	310	37,000	125	11.95(2)
	400	50,000	165	12.55

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)
Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[1] Per Luminaire
Flood , HPS	100	9,500	43	8.12[2]
	200	22,000	80	9.58[2]
	250	29,000	103	10.66
	400	50,000	165	12.85
Shoebox (bronze color, flat lens, HPS	100	9,500	43	8.65
or drop lens, multi-volt)	150	16,500	63	9.66
Special Acorn Type HPS	100	9,500	43	11.59
	150	16,500	63	11.98
	200	22,000	80	12.57
	250	29,000	103	13.52
Early American Post Top, HPS, Black	100	9,500	43	8.64
Special Types				
Cobrahead, Metal Halide	175	12,000	72	8.92
Flood, Metal Halide HPS	400	40,000	158	12.54
Flood, HPS	750	105,000	289	19.83
HADCO Indepedence, Early American	100	9,500	43	10.68
	150	16,000	63	11.40
HADCO Techtra HPS	100	9,500	43	18.33
	150	16,000	63	19.05
	250	29,000	103	27.49
KIM Archetype HPS	250	29,000	103	15.02
	400	50,000	165	17.00
Holophane Mongoose HPS	150	16,000	63	10.83
	250	29,000	103	12.31
	400	40,000	165	14.52

(1) See Schedule 100 for applicable adjustments.
(2) No new service.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Light Poles[1]

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole
Wood, Standard	35 or less	$6.30
	55 or less	7.91
Wood, Painted Underground	35 or less	7.37 [2]
Wood, Curved laminated	30 or less	9.15 [2]
Aluminum, Regular	16	7.79
	25	12.68
	30	13.71
	35	15.10
Aluminum, Fluted Ornamental	14	14.82
Aluminum Davit	25	13.09
	30	13.96
	35	19.43
	40	18.84
Aluminum Double Davit	30	16.80
Aluminum, HADCO, Fluted Ornamental	16	14.18
Aluminum, HADCO, Non-fluted	18	26.49
Concrete, Ameron Post-Top	25	31.32
Fiberglass Fluted Ornamental; Black	14	8.65
Fiberglass, Regular		
Black,	20	5.48
Gray or Bronze;	30	7.34
Other Colors (as available)	35	9.98
Fiberglass, Anchor Base Gray	35	15.98
Fiberglass, Direct Bury with Shroud	18	8.30

(1) No pole charge for luminaires placed on existing Company-owned distribution poles.
(2) No new service.

SCHEDULE 515 (Concluded)

INSTALLATION CHARGE

See Schedule 300 regarding the installation of conduit on wood poles.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file to add the luminaire type to this rate schedule.

2. Maintenance of outdoor area lighting poles includes replacement of accidentally or deliberately damaged poles and luminaires. If damage occurs more than two times in any 12 month period measured from the first incidence of damage that requires replacement, the Customer will pay for future installation or may mutually agree with the Company and pay to have the pole either completely removed or relocated.

3. If the Customer requests removal of Lighting Service equipment within five years of its installation, the Customer will be responsible for the costs of removal.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 532
SMALL NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Small Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

Basic Charge	
Single Phase	$14.35
Three Phase	$20.25
Distribution Charge	
First 5,000 kWh	3.073 ¢ per kWh
Over 5,000 kWh	0.565 ¢ per kWh

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 532 (Concluded)

SPECIAL CONDITION

Unmetered service may be provided under this schedule to fixed loads with fixed periods of operation, including, but not limited to, telephone booths and television amplifiers, which are unmetered for the convenience and mutual benefit of the Customer and the Company. The average monthly usage to be used for billing will be determined by test or estimated from equipment ratings and will be mutually agreed upon by the Customer and the Company.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 549
IRRIGATION AND DRAINAGE PUMPING
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who have chosen to receive Electricity from an Electricity Service Supplier (ESS) for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

Basic Charge	
Summer Months**	$30.00
Winter Months**	No Charge
Distribution Charge	
First 50 kWh per kW of Demand	3.000 ¢ per kWh
Over 50 kWh per kW of Demand	1.000 ¢ per kWh

* See Schedule 100 for applicable adjustments.

** Summer Months and Winter Months commence with meter readings as defined in Rule B.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 549 (Concluded)

MINIMUM CHARGE

The Minimum Charge will be the Basic Charge. In addition, the Company may require the Customer to execute a written agreement specifying 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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITION

The Customer is also responsible for notification to the Company of any change in type of service provided to the Customer's premises.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 575
PARTIAL REQUIREMENTS SERVICE
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers who receive Electricity Service from an Electricity Service Supplier (ESS) and who supply 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 1 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.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

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			
Three Phase Service	$130.00	$230.00	$1,000.00
Distribution Charge			
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 > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.

** 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.

*** Not applicable when ESS is providing Energy Regulation and Imbalance services as described in Schedule 600.

SCHEDULE 575 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand of the Large Nonresidential Customer when the Customer's generator is operating. The Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for generator operations, will be used to calculate the Baseline Demand. 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. The Baseline Demand may be modified consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 576R, monthly Demand charges under Schedule 575 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 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 575 (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. Customers on Schedule 575 must have Spinning Reserves in all Billing Periods that their generator is expected to be operating either provided by their ESS or the Company. Spinning Reserves are not required for Customers with Reserved Capacity of 1,000 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 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.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission, and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SCHEDULE 575 (Continued)

MINIMUM CHARGE

The Minimum Charge will be the Basic, Ancillary Services, Distribution, and Contingency Generation Reserves Charges, where applicable. In addition, the Company may require the Customer to specify a higher Minimum Charge, if necessary to justify the Company's investment in service facilities.

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline 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 agreement specifying the terms and conditions of service, the Customer's Baseline Demand, 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. These terms and conditions will be consistent with this schedule.

2. 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.

3. Direct Access Service is available only upon acceptance of a Direct Access Service Request (DASR) by the Company. A Customer is required to 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.

SCHEDULE 575 (Concluded)

SPECIAL CONDITIONS (Continued)

5. If during a Billing Period, the Customer or its ESS is billed for Ancillary 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 Ancillary Services Charge under this schedule. The credit will be the actual OATT charges incurred but will not to exceed the Monthly Demand for the Schedule 575 monthly Ancillary Services Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Ancillary Services Charge incurred under this schedule. No credit will be provided against any Energy Imbalance Service charges.

6. Failure to inform the Company of use of on-site generation by a Customer will not relieve the Customer of responsibility for the charges and requirements under this schedule.

7. The Customer's Baseline Demand may be modified as requested by the Customer upon the addition of permanent energy efficiency measures, load shedding, or the removal of equipment. The Customer's Baseline Demand may be modified by the Company if the Company determines that the level does not reflect load adjusted for the actual Customer generation.

8. A change in Baseline Demand related to modifications in generating capacity or generation operations may be made provided the Customer provides not less than two calendar years prior written notice to the Company of such change. Any subsequent notice by the Customer under this special condition must be made no earlier than two years from the last notice that resulted in a change to the Customer's Baseline Demand.

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

10. If the Customer is receiving service under this schedule and Schedule 576R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 576R Special Conditions.

SCHEDULE 576R
ECONOMIC REPLACEMENT POWER RIDER
DIRECT ACCESS SERVICE

PURPOSE

To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 575.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 575:*

	Delivery Voltage	
Daily Economic Replacement Power (ERP) Demand Charge	Secondary and Primary	Subtransmission
per kW of Daily ERP Demand during On-Peak hours per day**	$0.095	$0.050
System Usage Charge		
per kWh of ERP		0.178 ¢
Transaction Fee		
per Energy Needs Forecast (ENF) submission or revision		$50.00

* See Schedule 100 for applicable adjustment.

** 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.

SCHEDULE 576R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 575). The Customer, or its agent, must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that ERP is requested.

Each ENF will be based on the Customer's expected energy requirements and the Customer will use best efforts to conform actual Energy usage to the ENF.

The ENF will specify the expected ERP needed by hour. The Customer, or its agent, will deliver the ENF to the Company in accordance with Company procedures. The Company can choose to allow delivery of all or a portion of the ENF and will inform Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 575 Baseline Energy.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Customer is taking ERP less the sum of the Customer's Schedule 575 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Customer is taking ERP.

If the sum of the Customer's Unscheduled and Schedule 575 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for any power cost adjustment for costs incurred while the Customer is taking Service under this schedule.

SCHEDULE 576R (Concluded)

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied to the Customer pursuant to this schedule and agreement. All other Energy delivered will be made under the terms of Schedule 575. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. Customer is required to maintain Schedule 575 service unless otherwise agreed to by the Company.

3. All charges and requirements of Schedule 575 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to Transmission constraints.

6. The Customer, or its agent, must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than 5 MW that are expected to last one hour or longer. The Company may require the Customer to change its forecast if the Company believes the forecast does not adequately represent the expected load.

7. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 575 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

8. The Company is not responsible for providing market information to Customer.

9. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

10. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has not exceeded 1,000 kW more than once in the proceeding 13 months and who have chosen to receive Electricity from an Electricity Service Supplier (ESS).

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

	Delivery Voltage	
	Secondary	Primary
Basic Charge		
Single Phase Service	$20.00	
Three Phase Service	$25.00	$90.00
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity	$2.29	$2.11
per kW of monthly Demand		
First 30 kW	$2.07	$2.07
Over 30 kW	$2.64	$2.64
System Usage Charge		
per kWh	0.216 ¢	0.205 ¢

* See Schedule 100 for applicable adjustments.

** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 583 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity shall be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW for primary voltage service.

REACTIVE DEMAND CHARGE

In addition to 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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

SCHEDULE 583 (Concluded)

SPECIAL CONDITIONS (Continued)

2. If the Customer is served at either 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 in addition, 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 the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 589
LARGE NONRESIDENTIAL
(>1000 kW)
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 1,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 1,000 kW, and who has chosen to receive Electricity from an ESS.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

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
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
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢

* See Schedule 100 for applicable adjustments.
** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the POD.

SCHEDULE 589 (Continued)

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving Electricity Service Supplier (ESS) for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

FACILITY CAPACITY

The Facility Capacity will be the average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the current Billing Period.

MINIMUM CHARGE

The minimum charge will be the Basic and Distribution Charges. In addition, the Company may require the Customer to execute a written agreement specifying a higher minimum charge or minimum Facility Capacity and/or Demand, if necessary, to justify the Company's investment in Facilities. The minimum Facility Capacity and Demand (in kW) will be 100 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

REACTIVE DEMAND CHARGE

In addition to 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.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SPECIAL CONDITIONS

1. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule.

SCHEDULE 589 (Concluded)

SPECIAL CONDITIONS (Continued)

2. If the Customer is served at either 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 in addition, 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 the arrangement and operation of such equipment will be subject to the approval of the Company.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 591
STREET AND HIGHWAY LIGHTING
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

CHARACTER OF SERVICE

From dusk to dawn daily, controlled by a photoelectric control or time switch to be mutually agreeable to the Customer and Company for an average of 4,150 hours annually.

SERVICE OPTIONS

The Company has the following service options available for lighting:

Option A is for luminaires owned, maintained and supplied with Electricity by the Company.

Option B is for maintenance and Electricity supplied to Customer-owned equipment.

Option C is a grandfathered option, available only where Option C service was initiated prior to December 31, 2006. Option C is the provision of Electricity to luminaires owned and maintained by the Customer and installed on Customer-owned poles.

MAINTENANCE

Maintenance of Option A luminaries includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance also includes repair of an inoperable luminaire. This means that any failed part (lamp, photoelectric controller, starter, ballast, refractor, power door, etc.) will be replaced, or the entire failed luminaire will be replaced with in-kind equipment, if it is more practical to do so.

SCHEDULE 591 (Continued)

MAINTENANCE (Continued)

Maintenance of Option B luminaires includes group lamp replacement and glassware cleaning on the Company's schedule. Individual lamps will be replaced on burnout as soon as reasonably possible after notification by the Customer and subject to the Company's operating schedules and requirements. Maintenance does not include replacement of a luminaire at end of life (when replacement of a part will not bring the unit into working condition and the unit is not inoperable due to damage from accident or vandalism). Option B Maintenance also does not include replacement of technologically obsolete luminaires still in working condition, or for which a simple part replacement (any combination of photocell, lamp, starter and refractor) will return obsolete lights to operable condition.

Non-Standard or Custom luminaires and poles are provided to allow greater flexibility in the choice of equipment. However, the Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. Also, this equipment is more subject to obsolescence. The Company will order and replace the equipment subject to availability.

If damage occurs to any lighting poles more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will then pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated. Pole maintenance does not include painting of fiberglass, or painting or staining wood poles. It does not include testing or treating of wood poles. Maintenance of Option B poles does not include replacement of rotted wood poles that are no longer structurally sound, or any other poles which by definition have reached a natural end of life.

MONTHLY RATE

In addition to the service rates for Option A and B lights, all Customers will pay the following charges for each luminaire based on the Monthly kWhs applicable to each installed luminaire.

Distribution Charge	2.803 ¢ per kWh
Energy Charge:	Provided by Energy Service Supplier

SCHEDULE 591 (Continued)

RATES FOR STANDARD LIGHTING
High-Pressure Sodium (HPS) Only – Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead Power Doors **	100	9,500	43	*	$4.44	$1.21
	150	16,000	63	*	5.02	1.77
	200	22,000	80	*	5.54	2.24
	250	29,000	103	*	6.17	2.89
	400	50,000	165	*	7.91	4.62
Cobrahead	100	9,500	43	$7.30	4.52	1.21
	150	16,000	63	7.89	5.10	1.77
	200	22,000	80	8.82	5.61	2.24
	250	29,000	103	9.52	6.26	2.89
	400	50,000	165	11.28	8.01	4.62
Flood	250	29,000	103	9.81	6.28	2.89
	400	50,000	165	11.57	8.04	4.62
Early American Post-Top	100	9,500	43	7.76	4.52	1.21
Shoebox (Bronze color, flat	100	9,500	43	8.20	4.59	1.21
Lens, or drop lens, multi-volt)	150	16,000	63	9.06	5.19	1.77

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Fiberglass, Black	20	$4.38	$0.15
Fiberglass, Bronze	30	5.85	0.20
Fiberglass, Gray	30	5.86	0.20
Wood, Standard	30 to 35	5.04	0.16
Wood, Standard	40 to 55	6.32	0.21

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Acorn-Types						
HPS	100	9,500	43	$11.02	$4.83	$1.21
HADCO Independence	100	9,500	43	10.14	4.62	1.21
	150	16,000	63	10.72	5.20	1.77
Special Architectural Types						
HADCO Victorian HPS	150	16,000	63	11.28	5.38	1.77
	200	22,000	80	11.75	5.81	2.24
	250	29,000	103	12.55	6.52	2.89
HADCO Techtra HPS	100	9,500	43	17.48	5.21	1.21
	150	16,000	63	18.06	5.79	1.77
	250	29,000	103	25.95	7.60	2.89
KIM Archetype HPS	250	29,000	103	*	6.62	2.89
	400	50,000	165	*	8.36	4.62
Special Types						
Cobrahead, Metal Halide	175	12,000	72	8.30	5.43	2.02
Flood, Metal Halide	400	40,000	158	11.32	7.92	4.43
Flood, HPS	750	105,000	289	17.65	12.70	8.10
Holophane Mongoose, HPS	150	16,000	63	10.19	5.38	1.77
	250	29,000	103	11.39	6.51	2.89
	400	50,000	165	13.18	8.27	4.62

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B
Aluminum, Regular	16	$6.23	$0.21
	25	10.13	0.34
	30	10.96	0.37
	35	12.06	0.40
Aluminum Davit	25	10.46	0.35
	30	11.15	0.37
	35	12.32	0.41
	40	15.05	0.50
Aluminum Double Davit	30	13.42	0.45
Aluminum, HADCO, Fluted Victorian Ornamental	14	11.84	0.40
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	21.16	0.71
Aluminum, HADCO, Fluted Ornamental	16	11.33	0.38
Aluminum, Painted Ornamental	35	29.22	0.98
Concrete, Ameron Post-Top	25	25.03	0.84
Fiberglass, HADCO, Fluted Ornamental Black	14	6.91	0.23
Fiberglass, Regular,			
color may vary	22	3.39	0.11
color may vary	35	7.98	0.27
Fiberglass, Anchor Base, Gray	35	12.77	0.43
Fiberglass, Direct Bury with Shroud	18	6.63	0.22

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING

The following equipment is not available for new installations under Options A and B. To the extent feasible, maintenance will be provided. Obsolete Lighting will be replaced with the Customer's choice of with Standard or Custom equipment. The Customer will then be billed at the appropriate Standard or Custom rate. If an existing mercury vapor luminaire requires the replacement of a ballast, the unit will be replaced with a corresponding HPS unit.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Cobrahead, Mercury Vapor	100	4,000	40	*	*	$1.12
	175	7,000	67	$8.06	$5.05	1.88
	250	10,000	95	9.88	6.10	2.66
	400	21,000	149	10.50	7.50	4.18
	1,000	55,000	379	17.83	14.29	10.62
Special Box Similar to GE "Space-Glo"						
Sodium Vapor	70	6,300	31	10.78	4.18	0.87
Mercury Vapor	175	7,000	67	12.05	5.19	1.88
Special box, Anodized Aluminum						
Similar to GardCo Hub						
HPS	70	6,300	31	*	*	0.87
	100	9,500	43	*	4.80	1.21
	150	16,000	63	*	5.38	1.77
	250	29,000	103	*	*	2.89
	400	50,000	165	*	*	4.62
Metal Halide	250	20,500	101	*	6.57	2.83
	400	40,000	158	*	8.62	4.43
Cobrahead, Dual Wattage HPS						
70/100 Watt Ballast	100	9,500	43	*	4.52	1.21
100/150 Watt Ballast	100	9,500	43	*	4.52	1.21
100/150 Watt Ballast	150	16,000	63	*	5.10	1.77
Special Architectural Types						
KIM SBC Shoebox HPS	150	16,000	63	*	5.72	1.77

* Not offered.

SCHEDULE 591 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Acorn-Type HPS	70	6,300	31	$10.53	$4.18	$0.87
Special GardCo Bronze Alloy						
HPS	70	5,000	31	*	*	0.87
Mercury Vapor	175	7,000	67	*	*	1.88
Special Acrylic Sphere						
Mercury Vapor	400	21,000	149	*	*	4.18
Early American Post-Top HPS						
Black	70	6,300	31	6.84	4.19	0.87
Rectangle Type	200	22,000	80	*	*	2.24
Incandescent	92	1,000	32	*	*	0.90
	182	2,500	63	*	*	1.77
Town and Country Post-Top						
Mercury Vapor	175	7,000	67	8.19	5.07	1.88
Flood, HPS	70	6,600	31	7.48	4.23	0.87
	100	9,500	43	7.70	4.55	1.21
	200	22,000	80	9.16	5.63	2.24
Cobrahead, HPS						
Non-Power Door	70	6,300	31	6.86	4.18	0.87
Power Door	310	37,000	125	10.94	7.27	3.50
Special Types Customer Owned & Maintained						
Ornamental	100	9,500	43	*	*	1.21
Twin ornamental	200	22,000	80	*	*	2.41
Compact Fluorescent	28	N/A	12	*	*	0.34

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Option B
Aluminum Post	30	$ 6.23	*
Bronze Alloy GardCo	12	*	$0.25
Concrete, Ornamental	35 or less	10.13	0.34
Steel, Painted Regular **	25	10.13	0.34
Steel, Painted Regular **	30	10.96	0.37
Steel, Unpainted 6-foot Mast Arm **	30	*	0.37
Steel, Unpainted 6-foot Davit Arm **	30	*	0.37
Steel, Unpainted 8-foot Mast Arm **	35	*	0.40
Steel, Unpainted 8-foot Davit Arm **	35	*	0.41
Wood, Laminated without Mast Arm	20	5.67	0.15
Wood, Laminated Street Light Only	20	4.38	*
Wood, Curved Laminated	30	7.31	0.27
Wood, Painted Underground	35	5.04	0.21
Wood, Painted Street Light Only	35	5.04	*

* Not offered.
** Maintenance does not include replacement of rusted steel poles.

SERVICE RATES FOR ALTERNATIVE LIGHTING

The purpose of this series of luminaires is to provide lighting utilizing the latest in technological advances in lighting equipment. The Company does not maintain an inventory of this equipment, and so delays with maintenance are likely. This equipment is more subject to obsolescence since it is experimental and yet to be determined reliable or cost effective. The Company will order and replace the equipment subject to availability.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C
Special Architectural Types Including Philips QI Induction Lamp Systems						
HADCO Victorian QL	85	6,000	35	$12.98	$3.39	$0.98
	165	12,000	61	15.58	4.17	1.71
HADCO Techtra QL	85	6,000	35	16.75	3.51	0.98
	165	12,000	61	18.31	4.32	1.71

SCHEDULE 591 (Continued)

SPECIALTY SERVICES OFFERED

Upon Customer request and subject to the Company's operating constraints, the Company will provide the following streetlighting services based on the Company's total costs including Company indirect charges:

- Trimming of trees adjacent to streetlight equipment and circuits.
- Arterial patrols to ensure correct operation of streetlights.
- Design services for Customer-owned streetlight equipment.
- Painting or staining of wood and steel streetlight poles.

ESS Charges

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

SPECIAL CONDITIONS

1. The Company may periodically offer temporary or experimental lighting equipment that is not otherwise listed in this rate schedule. Temporary or experimental lighting will be offered at a billing rate based on approved prices for near equivalent lighting service equipment. The use of temporary or experimental lighting will be for a limited duration not to exceed one year at which time the lighting service equipment will either be removed or the Company will file with the Commission to add the luminaire type to this rate schedule.

2. Customer is responsible for the cost associated with trenching, boring, conduit and restoration required for underground service to streetlighting.

3. Unless otherwise specifically provided, the location of Company-owned streetlighting equipment and poles may be changed at the Customer's request and upon payment by the Customer of the costs of removal and reinstallation.

4. If Company-owned streetlighting equipment or poles are removed at the Customer's request, a charge will be made consisting of the estimated original cost, less depreciation, less salvage value, plus removal cost. This provision does not pertain to the sale of Company-owned equipment.

5. If Customer-owned (Option B) streetlighting equipment or poles are removed or relocated at the Customer's request, the Customer is responsible for all costs associated with the change.

SCHEDULE 591 (Concluded)

SPECIAL CONDITIONS (Continued)

6. If circuits or poles are removed or relocated at the Customer's request, the Customer is responsible for all associated costs for labor and materials incurred when fulfilling this request.

7. For Option C lights: When the Company provides the circuit, the Customer will incur a circuit charge of $1.52 per luminaire per month.

8. For Option C lights in service prior to January 31, 2006: When the Company furnishes Electricity to luminaries owned and maintained by the Customer and installed on Customer-owned poles that are not included in the list of equipment in this schedule, usage for the luminaire will be estimated by the Company. When the Customer and the Company cannot agree, the Commission will determine the estimate usage.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 592
TRAFFIC SIGNALS
DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

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

Distribution Charge	1.803 ¢ per kWh

* See Schedule 100 for applicable adjustments.

ESS CHARGES

In addition to the above charges, the Customer is subject to charges from its serving ESS for Electricity, transmission and other services as well as any other charges specified in the service agreement between the Customer and the ESS. If the Customer chooses to receive an ESS Consolidated Bill, the Company's charges for Direct Access Service are not required to be separately stated on an ESS Consolidated Bill.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

SCHEDULE 592 (Concluded)

SPECIAL CONDITIONS

1. The Customer or ESS will furnish the Company with a complete list each month of all traffic-signal intersections and their respective estimated monthly kWh usage. The method of estimating usage will be established by the Company. The Customer will be responsible for updating the list of intersections and corresponding estimated usages each month as new installations are made, as existing installations are removed, or as wattages are increased or decreased.

2. The Customer will conduct an independent audit of all traffic-signal intersections once every three years and provide the Company with a copy of such audit. The audit must contain a listing of each light and its corresponding monthly kWh usage installed at all intersections.

3. The Company may, whenever it deems it to be advisable, conduct a field inventory of a Customer's electrical equipment being supplied under this schedule using sampling techniques to determine, whether in the Company's opinion, the Customer's list of estimated usages is being properly maintained. If the Customer's list is improperly maintained, or in the event the Customer does not furnish such a list, the Company may institute such other means of estimating the Customer's Energy use as it may deem to be satisfactory or remove the Customer from service under this schedule.

TERM

Service under this schedule will not be for less than one year.

SCHEDULE 600
ENERGY SERVICE SUPPLIER CHARGES

AVAILABLE

In all territory served by the Company.

APPLICABLE

To any Electric Service Supplier (ESS), including an applicant ESS, providing service to Customers. To receive service under this schedule, the ESS must sign an ESS Service Agreement and abide by all provisions of the Company's Tariff.

SERVICES

The following services are offered to an ESS providing Electricity to one or more Direct Access Service Customers.

Transmission Services (Applicable to Scheduling ESS only)

Transmission services are provided to an ESS pursuant to the Company's Open Access Transmission Tariff (OATT), Original Volume No. 8 (PGE-8). Transmission services include:

(a) Transmission as further described under Special Conditions;
(b) Scheduling, System Control and Dispatch Service;
(c) Reactive Supply and Voltage Control Service;
(d) Regulation and Frequency Response Service*;
(e) Energy Imbalance Service*;
(f) Operating Reserve - Spinning Reserve Service*; and
(g) Operating Reserve - Supplemental Reserve Service*.

* When provided by the Company.

ESS Provided Regulation and Imbalance Service

An ESS that self-provides Regulation and Frequency Response and Energy Imbalance Services must provide the Company with a real-time load and power factor signal via electronic metering from the Customer load to the location designated by the Company.

SCHEDULE 600 (Continued)

ESS SUPPORT SERVICES

The following charges are applicable to Scheduling and Non-Scheduling ESSs:

(1)	Application Processing Fee	$400.00 with Application
(2)	Registration Renewal Fee	$200.00
(3)	Electronic Data Interchange Testing	$100.00 per man-hour for all hours in excess of 16 hours annually
(4)	Change of Effective Date Request (Rule K)	$ 35.00
(5)	Switching Fee (Rule K) (Applicable for each Enrollment or Drop DASR, not applicable for Rescind or Change DASRs)	$ 20.00

ESS BILLING SERVICES

(1)	ESS Consolidated Bill Billing Credit	$ 0.63 per bill
(2)	Late Pay Charge	1.7 % of delinquent balances for products and services purchased under this Tariff, excluding products and services listed in the 700 series.

CUSTOMER INFORMATION

ESS Web Portal Historical Usage Download for Interval Data Charge	$ 20.00 per PODID

BILLING AND PAYMENT

Charges incurred for Schedule 600 services are the responsibility of the ESS for which service was provided and are due and payable as described in the Company's General Rules and Regulations.

SCHEDULE 600 (Concluded)

SPECIAL CONDITION

The ESS must purchase firm Transmission Service under the Company's OATT for not less than one-month duration and will be charged at the OATT monthly rate for firm transmission.

PGE SYSTEM LOSSES

The ESS will schedule sufficient Energy to provide for the following losses on the Company's system:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Losses:	6.28%	2.82%	1.31%

SCHEDULE 710
UTILITY ASSET MANAGEMENT (UAM)

PURPOSE

To assist utilities and other pole owners in recovering lost revenue, reducing regulatory penalties and increasing efficiency and effectiveness by managing poles, pole attachments and providing wireless service management.

AVAILABLE

To utilities and other pole owners in the State of Oregon.

CHARACTER OF SERVICE

Services available under this schedule include:

1. **Pole Management and Pole Maintenance Services** include processing pole attachment permits, field inspection, engineering, maintenance, construction, managing contracts, billing, GIS data and mapping, pole inspection and analysis, treatment and attachment auditing.

2. **Rental Services** include initiating contracts for pole owners prior to attachment installation, calculating pole attachment rates, managing the permit process, performing site inspections and load analysis and installing poles and lines in compliance with National Electric Safety Codes (NESC).

3. **Wireless Service Management** includes identifying clients for possible attachment sites, site identification design and load verification grounding analysis, zoning assistance and tower construction.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. All fully distributed costs and revenues associated with the provision of Utility Asset Management (UAM) will be charged or credited to non-utility accounts.

3. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other pole management providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's UAM program.

SCHEDULE 715
ELECTRICAL EQUIPMENT SERVICES

PURPOSE

To provide construction and maintenance to Customer or utility owned electrical equipment (other than equipment owned by the Company).

AVAILABLE

In the State of Oregon.

APPLICABLE

To all Nonresidential Customers and utilities.

CHARACTER OF SERVICE

The Company provides engineering, electrical design and construction, equipment maintenance and repair, preventative diagnostic and prevention maintenance, electrical oil containment and compliance with the Environmental Protection Agency's Spill Prevention Control and Countermeasure Oil Program (SPCC), equipment leasing, Energy recovery and revenue protection and electrical equipment refurbishing and disposal services.

BILLING RATES

Service will be contractually negotiated.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. All fully distributed costs and revenues associated with the provision of Electrical Equipment Services will be charged or credited to non-utility accounts.

3. Electrical Equipment Services will not use the Company's proprietary Customer information for the marketing of its products or services.

4. The Company's employees providing utility services will inform Customers about their choices to use other available service providers for these types of services.

5. There will be no tying of the provision of Electrical Equipment Services with the provision of Electricity Service.

6. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other electrical equipment services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Electrical Equipment Services.

SCHEDULE 720
EFFICIENCY SERVICES

PURPOSE

Provide cost-effective and innovative services to assist Customers, utilities, agencies, cities and other entities in managing energy and water consumption, improving indoor air quality and positively influencing the practices that impact the environment; and to offer ideas and solutions to meet goals for Energy savings and resource efficiency that emphasize cost-effective operations and long-term value, respectively.

AVAILABLE

To all Customers, utilities, agencies and cities in the State of Oregon.

SERVICES TO CUSTOMERS

Services from energy efficiency audits to large-scale mechanical systems retrofits, tailored services are provided to meet the needs of the recipient. These services include, but are not limited to:

1. Energy and facility audits to identify cost-effective opportunities for increased energy and water efficiency and enhanced working conditions, including: energy efficiency audits, facility management audits, and water efficiency studies.

2. Specification and/or project management for lighting, water and mechanical systems retrofits including facilitation and training, cash flow management and arrangement of financing.

3. Turnkey general contracting for lighting, water and mechanical systems retrofits in order to create a single-source high-performance building solution.

4. Consulting and technical services to support building certification under the Earth Advantage™ program or other third party guidelines.

SERVICES TO UTILITIES / AGENCIES / CITIES

Services are provided to respond to a variety of project sizes and scopes from specific consultations to turnkey operations, and are determined to best meet the utilities'/recipient's needs. Services include, but are not limited to:

1. Creation and management of comprehensive efficiency programs to meet the needs of the recipient's customers or constituency. Efficiency Services develops customized programs as well as full turnkey programs and operations including: lighting retrofits, industrial process, systems commissioning, water efficiency and new construction.

SCHEDULE 720 (Concluded)

SERVICES TO UTILITIES / AGENCIES / CITIES (Continued)

2. Earth Advantage™ new construction licensing program for commercial construction.

3. Technical services support existing programs or evaluate performance, including Energy audits for project identification, commissioning for quality control and project verification.

4. Training and consultations for internal teams or customer groups. Training is created to enhance the skills of program teams, design teams, contractors and facility managers, and is focused on understanding electricity, program management, sales training, lighting design, systems integration, motors and motor controls, green building and resource efficiency. Consulting services help develop and successfully manage customized efficiency programs and support program development, program management or program sales and marketing.

BILLING RATES

Services will be contractually negotiated.

SPECIAL CONDITIONS

All services provided under this schedule require a signed contract.

1. All fully distributed costs and revenues associated with the provision of Efficiency Services will be charged or credited to non-utility accounts.

2. Efficiency Services will not use the Company's proprietary Customer information for the marketing or provision of its products or services, with the exception of any proprietary Customer information made available to Efficiency Services in the event they are providing services to the Energy Trust of Oregon (ETO).

3. Marketing materials for efficiency products or services sold within the Company's service territory and not under contract with the ETO will contain the disclaimer statement, "You do not need to purchase this product to continue to receive safe and reliable power from PGE."

4. Efficiency Services will not tie the provision of its products or services with incentives or rebates to Electricity Services.

5. If the Company chooses to use bill inserts to market this schedule to Customers, it will allow other efficiency services providers access to place inserts in the Company's bills under the same prices, terms and conditions that apply to the Company's Efficiency Services program.

SCHEDULE 725
E-MANAGER

PURPOSE

Provide electric, gas, water usage and other relevant data, such as weather condition through an online energy maintenance system.

AVAILABLE

In all parts of Oregon except the territory served by the Company.

APPLICABLE

To Customers or utilities.

PROGRAM DESCRIPTION

E-Manager service provides Customers with interval usage data depicted in charts and graphs for the purpose of comparing current and historic load data, identifying anomalies in usage, tracking savings from energy efficiency projects, and understanding their energy usage.

Two service options are available:
1) Standard Package – Data is updated on a weekly basis.
2) Enhanced Service – Data is updated on a daily basis.

An optional feature called Energy Worksite that offers more automated tracking capability including the ability to track projects, manage preventative maintenance and track work orders and energy bills is also available.

BILLING RATES

Standard Package

Set Up Fee:	\$250.00 for the first meter \$ 50.00 for each additional meter

Monthly Fees per meter:

Standard Package

1 to 5 meters	\$ 50.00
6 to 10 meters	\$ 45.00
11 to 15 meters	\$ 40.00
16 to 20 meters	\$ 35.00
21 or more meters	\$ 30.00

SCHEDULE 725 (Concluded)

BILLING RATES (Continued)

Enhanced Service – These costs are in addition to cost for the Standard Package.

	Monthly Cost per meter	Start Up Fee per meter
Daily Information	$10.00	$100.00
Hourly Airport Weather Data	$25.00	$ 50.00

Additional Customer Support or Training $125.00 per hour

Customized data, including Energy Worksite, may be provided at a mutually agreed price.

SPECIAL CONDITIONS

1. All services provided under this schedule require a signed contract.

2. All fully distributed costs and revenues associated with the provision of E-Manager will be charged or credited to non-utility accounts.

3. If the Company chooses to use bill inserts to market this schedule, it will allow other Meter Information Service providers access to place inserts in the Company's bills under the same prices, and terms and conditions that apply to the Company's E-Manager program.

4. Service under this schedule requires interval metering and meter communications be in place prior to the initiation of E-Manager service.

5. Because of the meter and/or software installation required for this service, the Company anticipates a delay may occur from the time service under this schedule is requested until the Company can provide it.

6. E-Manager service requires certain minimum computer system requirements and an ability to capture and transmit interval usage data. Specifications will be provided upon request. The Customer must provide the necessary communications equipment as well.

7. If E-Manager services are requested from a specified location behind the meter, the Company will install a submeter at the discretion of the Customer or the utility serving the customer. All associated labor and materials to install the submeter as well as the cost of any future maintenance are the responsibility of the Customer or the utility.

8. Customers who request service both inside and outside the service territory will have all Points of Delivery (POD) receiving service on Schedule 320 and on this schedule added together to determine the appropriate monthly rate.

SCHEDULE 730
POWER QUALITY PRODUCTS AND SERVICES

PURPOSE

To provide Customers with products that protect their electronic equipment or their entire electrical system from potential power surges, spikes and outages.

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicability is dependent upon the specific product.

PROGRAM DESCRIPTION

Customers may choose any or all of the following products:

Meter Socket Adapter (MSA) Surge Suppressors are devices installed beneath the 200 amp, single phase Electricity meter that protect the Customer's electrical system from high voltage surges or spikes.

Home Surge Protection Center (HSPC) Surge Suppressors are devices installed near a 320 amp Electricity meter and provide electricity surge suppression, with the option to purchase telephone and/or cable surge protection.

Inside Outlet Surge Suppressors provide additional protection for sensitive electronic equipment, phone and cable television (CATV) protection. Features include surge protection that exceeds the Company's recommended standard, safety fusing for protection elements and a warranty on surge suppressor or product damage.

Uninterruptible Power Supply (UPS) provides Customers with a secondary power supply and surge protection which protects Customer equipment from damage caused by power outages or voltage instability. The following two devices are available:

UPS800 – This model is an automatic voltage regulator UPS that can support up to 800 VA and 480 watts of customer equipment for approximately 20 minutes.

UPS500 – This model provide standby UPS for 500 VA and 300 watts of customer equipment for approximately five minutes.

SCHEDULE 730 (Continued)

BILLING RATES

Meter Socket Adapter (MSA) Surge Suppressor

Installation Charge	$ 65.00

The Installation Charge is in addition to the cost to either Purchase or Lease the MSA Surge Suppressor.

Customers leasing the MSA may choose to pay the Installation Charge in four monthly installments of $16.25.

Purchase	$128.00
Lease	$ 5.95 per month

Home Surge Protection Center (HSPC) Surge Suppressor

HSPC device	$350.00
Shipping (Shipping charge applicable when a Customer chooses to hire a certified electrician to install the device rather than to have the Company install it.)	$ 7.00
Installation	$125.00
Phone Connection Installation	$ 30.00
Cable Television (CATV) installation	$ 30.00

Inside Outlet Surge Suppressor

Models available:

1)	eight outlet surge suppressor with phone jack	$ 30.00
2)	eight outlet surge suppressor with digital satellite, cable TV and phone protection	$ 39.00
3)	one outlet surge suppressor	$ 6.50
4)	one outlet surge suppressor with phone jack	$ 7.00
5)	one outlet surge suppressor with cable TV protection	$ 7.50

An additional $8 for shipping and handling will be added to the total cost of a Customer's order of Inside Outlet Surge Suppressors.

SCHEDULE 730 (Continued)

BILLING RATES (Continued)

Surge Protection Package[1]

Purchase

MSA and Outlet Devices	$196.00
Installation Fee (required)	$65.00
Shipping and handling	$8.00
TOTAL	$269.00

Lease

MSA Monthly Lease	$5.95 per month
Plus:	
Outlet Devices	$71.00
Installation Fee (required)	$65.00[2]
Shipping and handling	$8.00
TOTAL	$144.00

(1) Includes MSA Surge Suppressor and inside outlet surge suppressor model numbers 1, 2 and 5.
(2) Customers leasing the MSA may choose to pay the Installation Charge in four monthly installments of $16.25.

The Company will install Underwriter's Laboratories (UL) listed meter socket adapter surge suppressors other than those offered by the Company for an installation charge of $100.

UPS Devices

Purchase

UPS800 $150.00

An additional $17 for shipping and handling will be added to the total cost for each UPS800 purchase.

UPS500 $ 75.00

An additional $12 for shipping and handling will be added to the total cost for each UPS500 purchase.

Schedule 730 (Continued)

SPECIAL CONDITIONS

General

1. All fully distributed costs and revenues associated with the provision of products and services under this schedule will be charged or credited to non-utility accounts.

2. The Company will include in all of its written and verbal communications regarding its Power Quality products and services a statement that addresses the following two points: a) that the purchase of this service is not necessary for a Customer to continue to receive safe and reliable power from the Company; and b) that the Customer may buy similar products and services from other providers.

3. Any incentives or rebates offered will not be tied to the provision of Electricity Services.

4. If a Customer desires that any listed device be installed at a rented or leased dwelling, the landlord or property owner must agree in writing to the terms and conditions contained herein.

5. All products are warranted through the manufacturer. The Customer agrees that the Company will not be liable for any and all claims, costs, expenses, damages and liabilities, including reasonable attorney fees at trial and on appeal, resulting from, or alleged to be caused, directly or indirectly, by use, operation, or failure of any of the products or services offered under this schedule except when caused by sole negligence of the Company. The Customer will look solely to the manufacturer for any recovery of liability claims.

6. The Customer acknowledges and agrees that the Company makes no warranties of any kind, express or implied, regarding the condition or performance of the devices, including, but not limited to, any warranty of merchantability or fitness for a particular purpose.

MSA Surge Suppressor

1. Only Company employees may install, remove or otherwise work on the MSA Surge Suppressor device.

2. Customers will be responsible for checking the indicator lights periodically to ensure that the device is working properly.

SCHEDULE 730 (Concluded)

SPECIAL CONDITIONS (Continued)
MSA Surge Suppressor (Continued)

3. Customers leasing an MSA Surge Suppressor will be considered in default if any payment owed is not received within 90 days of the due date. Upon default the Company may repossess the device, and the Customer will remain responsible for all missed payments owed up to the date of repossession.

4. Customers leasing an MSA Surge Suppressor may terminate the service agreement for any reason within 30 days after installation but will owe the installation charge regardless of whether or not the service agreement has been terminated. After 30 days, the Customer is bound by the terms of the service agreement.

TERM

Customers who choose the lease option for the MSA Surge Suppressor must sign a two-year service agreement. At the completion of the two-year term, the lease agreement will remain in effect on a month by month basis until the Customer notifies the Company of their request to cancel service under this schedule.

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
GENERAL RULES AND REGULATIONS

RULE

A **Introduction**
1. General
2. Territory Served
3. Commission Rules, Regulations and Orders
4. Tariff Compliance
5. Relationship to Rate Schedules

B **Definitions**

C **Conditions Governing Customer Attachment to Facilities**
1. Acceptance of Electricity Service
2. Continuity of Electricity Service
3. Delivery Voltages
4. Conditions for Receiving Service
5. Interconnection of Customer-Generator Facilities
6. Transformers
7. Relocation or Removal of Facilities
8. Service Restoration

D **Application for Electricity Service**
1. Notification Requirement
2. Required Residential Identification Standards
3. Forms of Requests for Electricity Service
4. Effect of Application
5. Customer Service Agreements
6. Consequences of Accepting Electricity Service
7. Refusal of Electricity Service

E **Establishing Credit**
1. Residential Credit Standards
2. Nonresidential Credit Standards
3. Treatment of Residential and Nonresidential Deposits

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
GENERAL RULES AND REGULATIONS

RULE

F **Billings**
1. Basis for Billing
2. Customer to be Billed; Responsibility for Payment
3. Application for Site
4. Metering and Meter Reading
5. Presentation and Payment of Bills

G **Direct Access Service and Billing**
1. Direct Access Service
2. Special Requirements for Direct Access Billings
3. Customer Responsibility

H **Disconnection and Reconnection**
1. Grounds for Disconnection of Electricity Service
2. Procedures for Disconnection and Reconnection of Electricity Service
3. Disconnection and Reconnection Charges
4. Nonwaiver of Right to Disconnect Service
5. Other Remedies
6. Disconnection and Reconnection at the Customer's Request

I **Line Extensions**
1. Purpose
2. Applicant Cost Responsibilities
3. Special Conditions for Underground Line Extensions
4. Refunds
5. Special Conditions for Portland River District Undergrounding Project
6. Conversion from Overhead to Underground Service
7. Nonpermanent Line Extension
8. Excess Capacity
9. Rules Previously in Effect

J **Standard Service and Portfolio Options**
1. Standard Offer
2. Portfolio Options

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
GENERAL RULES AND REGULATIONS

RULE

K **Requirements Relating to ESSs**
1. Purpose
2. ESS Credit Requirements
3. Electronic Data Transfer Interchange (EDI)
4. Electricity Service Supplier Decertification
5. Pre-enrollment Information Provided to ESS
6. Customer Enrollment
7. ESS Service to Single Point of Delivery
8. Discontinuance of ESS Service
9. Company Billings to the ESS
10. Processing of Payments
11. ESS Scheduling Responsibilities
12. Company Scheduling Responsibilities
13. Settlement
14. Operational Order to Deliver Electricity
15. Preemption
16. Dispute Resolution

L **Special Types of Electricity Service**
1. Service of Limited Duration (Temporary Service)
2. Emergency Service
3. Intermittent Use Service
4. Alternate Service
5. Distribution Facilities Service

M **Metering**
1. Generally
2. Metering Requirements
3. Meter Location
4. Meter Rentals

PORTLAND GENERAL ELECTRIC COMPANY
TABLE OF CONTENTS
GENERAL RULES AND REGULATIONS

RULE

N **Curtailment Plan**

1. Purpose and Overview of the Curtailment Plan
2. Definitions
3. Curtailment Stages
4. Initiation of Load Curtailment
5. Administration of State-Initiated Curtailment
6. Base Year Data and Curtailment Targets
7. Auditing Customers for Compliance with State Orders for Mandatory Load Curtailment During Curtailment Stages 3-5
8. Penalties for Noncompliance
9. Exemptions and Adjustments
10. Measurement of the Amount of Curtailment Achieved and Determination of Compliance
11. Special Arrangements

RULE A
INTRODUCTION

1. **General**

These General Rules and Regulations provide the terms and conditions related to services offered by the Company under this Tariff.

2. **Territory Served**

The Company supplies Electricity Service in incorporated and unincorporated portions of Clackamas, Columbia, Hood River, Marion, Multnomah, Polk, Washington, and Yamhill counties, Oregon. The Company may also provide certain non-utility services in its 700 series schedules in other parts of Oregon.

3. **Commission Rules, Regulations and Orders**

Existing and future lawful rules, regulations, and orders of the Commission will be considered a part of this Tariff.

4. **Tariff Compliance**

Service and rates are subject to all applicable General Rules and Regulations contained in the Tariff of which each schedule is a part.

5. **Relationship to Rate Schedules**

If a rate schedule provision conflicts with a provision in these General Rules and Regulations, the rate schedule provision will apply.

RULE A (Concluded)

RULE B
DEFINITIONS

The terms listed below, which are used frequently in the Tariff, have the stated meanings:

1. **Ancillary Services**

   Services necessary or incidental to the transmission and delivery of Electricity from resources to retail Electricity Customers, including but not limited to scheduling, frequency regulation, load shaping, load following, spinning reserves, supplemental reserves, reactive power, voltage control and energy balancing services.

2. **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.

3. **Basic Charge**

   A monthly amount, specified in certain rate schedules, which is charged regardless of the amount of Energy consumed. The charge represents a part of the Company's fixed costs of making service available, such as meter reading and billing costs.

4. **Billing Period**

   A time interval, which may vary between 27 and 34 days, between successive billing dates.

5. **Commission**

   The Public Utility Commission of Oregon.

6. **Company**

   Portland General Electric Company.

7. **Customer**

   An individual, partnership, corporation, organization, government, governmental agency, political subdivision, municipality, or other entity who has applied for, been accepted, and is currently receiving Electricity Service at a Point of Delivery. A Customer who voluntarily terminates service and subsequently requests service with the Company at a new or existing location within 20 days after terminating service retains Customer status. For purposes of Schedule 201 and the Company's 700 series schedules, a Customer may not be receiving Electricity Services from the Company.

8. **Customer Service Agreement**

An Agreement with a Customer that specifies Utility Provided Service or Direct Access Service terms and conditions for service under this Tariff.

9. **Day of Flow**

The day in which Electricity deliveries are made; measured as the time period beginning immediately after midnight for the hour ending 0100 and ending at exactly the end of the 2400 hour Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

10. **Demand**

The maximum rate of delivery of Electricity metered for purposes of billing, measured in whole kilowatts (kW) registered over a nominal 30-minute interval.

11. **Demand Charge**

A charge for registered Demand normally assessed to Customers with Demands greater than 30 kW.

12. **Direct Access Service**

The delivery by the Company of Electricity and applicable Ancillary Services by the Company that a Nonresidential Customer has purchased from an ESS.

13. **Direct Access Service Request (DASR)**

Electronic notification provided by an ESS to the Company that a Customer has selected the notifying ESS as its supplier of Electricity Service. DASRs are also required for a Customer to terminate Direct Access Service and begin or resume receiving Electricity Service from the Company, rescind a previously submitted DASR, change the effective date of the enrollment DASR, or update the Customer's account information when the Customer is receiving Direct Access Service.

14. **Electricity**

Electric energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh); or electric capacity, measured in kilowatts (kW) or megawatts (MW), or both.

15. Electricity Schedule

A Scheduling ESS's projection of its hourly Electricity deliveries, measured in megawatt-hours (MWh), that are necessary to meet the aggregate hourly load of its Customers and the Customers of any Non-Scheduling ESS for which it provides scheduling service. The Electricity Schedule is for a Day of Flow and is provided to the Company in accordance with Western Electricity Coordinating Council (WECC) and National Energy Reliability Council (NERC) operating standards.

16. Electricity Service

The provision of Electricity to Customers by the Company or by an ESS using the Company's Facilities.

17. Electricity Service Supplier (ESS)

A provider of Electricity Service including a Large Nonresidential Customer that has obtained all necessary approvals to do business in the State of Oregon, is certified by the Commission if applicable, has met the Company's requirements for providing service and executed an ESS Service Agreement with the Company. The Company, when supplying Electricity to Nonresidential Customers in its own service territory, is not considered an ESS. The Company will classify ESSs as one of the following:

Scheduling ESS

An ESS that provides its own Electricity Schedule to the Company.

Non-Scheduling ESS

An ESS that does not provide the Company with a Schedule and relies on a Scheduling ESS for services related to scheduling and settlement.

18. Energy

Electric energy commonly measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

19. Energy Charge

A variable charge billed on the basis of a Customer's metered or estimated kilowatt-hours (kWh) usage.

20. **Emergency Default Service**

A service option provided by the Company to a Nonresidential Customer that requires Utility Provided Service with less than five business days' notice to the Company by the Customer or its ESS. This service is available to the Customer for a maximum of five consecutive days from initial purchase.

21. **ESS Service Agreement**

An agreement between the Company and an ESS specifying terms and conditions for service under this Tariff.

22. **Facilities**

Transmission and distribution plant and equipment owned and operated by the Company.

23. **Facility Capacity**

The Facility Capacity is the average of the two greatest non-zero monthly Demands established anytime during the 12-month period which includes and ends with the current Billing Period.

24. **Farm Service**

Nonresidential electric service furnished to Premises employed for the purpose of obtaining a profit in money by raising, harvesting, and selling crops; or by the feeding, breeding, management and sale of, or the producing of, livestock, poultry, fur-bearing animals, or honeybees; or for dairying and the sale of dairy products; or any other agricultural or horticultural use, animal husbandry, or any combination thereof. Farm Service includes the use of Energy to prepare and store the products raised on the Premises for human use and animal use and their disposal by marketing or otherwise. Farm Service does not include the use of Energy for commercial treatment, storage, or distribution of agricultural or horticultural products and does not include the use of land subject to the provisions of ORS Chapter 321 concerning commercial forestry.

25. **Kilovar (kVAr)** A unit of reactive power equal to 1,000 reactive volt amperes.

26. **Kilowatt (kW)** A unit of power equal to 1,000 watts.

27. **Kilowatt-Hour (kWh)** The amount of Energy delivered in one hour when power is delivered at a constant rate of 1 kW.

28. **Large Nonresidential Customer**

A Nonresidential Customer whose monthly Demand has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service whose Demand has exceeded 30 kW.

29. **Nonresidential Customer**

A Customer that does not meet the definition of a Residential Customer.

30. **Operational Order to Deliver Electricity**

An order issued by the Company to scheduling ESSs to deliver additional Electricity for purposes of maintaining the integrity of the Company's facilities.

31. **Point of Delivery (POD)**

Unless otherwise designated by agreement, the first point of connection of the Company's service drop, service lateral or bus to the Customer's service entrance conductors or equipment determined without regard to the location of the meter or metering equipment.

32. **Point of Delivery Identification (PODID)**

A code that identifies each unique Point of Delivery and associated Company meter location (if applicable).

33. **Portfolio**

A set of product and pricing options provided to Residential Customers and Small Nonresidential Customers.

34. **Premises**

Real and personal property owned and/or used by a Customer at a single location, which contains a Point of Delivery.

35. **Reactive Demand**

The maximum rate of delivery of kilovolt-amperes reactive (kVars) measured over a nominal 30-minute interval. Reactive Demand must be supplied to most types of magnetic equipment, such as motors. It is supplied by generators or by electrostatic equipment, such as capacitors, motors or transformers. It is recognized as a necessary Ancillary Service.

36. Reactive Demand Charge

A charge for Reactive Demand assessed to Customers with loads that are supplied Reactive Demand on the Company's system.

37. Residential Customer

A Customer that has applied for and been accepted to receive service at a dwelling primarily used for residential purposes, including, but not limited to, single family dwellings, separately metered apartment units, mobile homes, and houseboats, but excluding dwellings employed for Transient Occupancy, such as hotels, motels, camps, lodges, and clubs.

For purposes of this rule, a dwelling must contain permanent facilities for sleeping, bathing, and cooking.

Boarding houses with no more than four separate sleeping quarters for use by people who are not members of the Residential Customer's family and "adult foster homes" (defined in ORS 443.705 as a home or facility in which residential care is provided for five or fewer adults who are not related to the Residential Customer by blood or marriage) are residential dwellings.

When there is nonresidential use of Electricity at a dwelling used primarily for residential purposes, the Company will classify the Customer as residential if the Company determines that Electricity consumed in a typical month for residential use exceeds that consumed for nonresidential use, and if the nonresidential use is carried out primarily by the occupants of the dwelling.

Individual dwelling units in newly constructed multi-family residential buildings will be individually metered and billed as Residential Customers. Service through one meter to two dwelling units will be classified as one Residential Customer where an existing dwelling unit is or has been divided into two dwelling units, provided the ampacity of the service equipment is not increased. In the case where service is supplied through one meter to two or more new dwelling units, or to three or more existing dwelling units, service will be classified as nonresidential service.

Service through additional meters to other than dwellings on residential premises will be classified as nonresidential.

38. Scheduled Crew Hours

Those times that Company service crew personnel are working at their regular rate of pay. Scheduled Crew Hours may vary by location and type of work.

39. Site

A. Buildings and related structures that are interconnected by facilities owned by a single retail electricity Customer and that are served through a single electric meter; or

B. A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that

1) Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

2) Buildings and structures in the Site, and land containing and connecting buildings and structures in the Site, are owned by a single retail electricity Customer who is billed for electricity use at the buildings and structures; and

3) Land will be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as streetlighting, sewerage transmission, and roadway controls), will not be considered contiguous.

40. Small Nonresidential Customer

A Nonresidential Customer who does not meet the definition of a Large Nonresidential Customer, which means the Nonresidential Customer has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service had not exceeded 30 kW.

41. Standard Service

A service option provided by the Company to a Nonresidential Customer who elects to purchase Electricity from the Company rather than from an ESS.

42. Summer Months

Summer Months are the six regular Billing Periods from May through October. In 2007, the Summer Months will begin with regular meter readings on Month XX, 2007.

43. Tariff

This Tariff, including all schedules, rules and regulations as they may be modified or amended from time to time.

44. Theft of Service

Theft of Service occurs when an Applicant or Customer initiates or maintains Electricity Service through fraudulent means, including but not limited to providing false identification or false information to establish an account or credit, paying for Electricity Service with a stolen financial account, tampering with Company equipment including but not limited to the meter, or diverting service.

45. Tradable Renewable Credits

Tradable Renewable Credits (TRCs) consist of the non-power attributes resulting from the generation of Energy by a qualified renewable resource. Such attributes may be fuel, emissions, or other environmental characteristics deemed of value by a TRC purchaser.

Non-power attributes include, but are not limited to, any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and any other pollutant that is now or may in the future be regulated under the pollution control laws of the United States; and further include any avoided emissions of carbon dioxide (CO_2) and any other greenhouse gas (GHG) that contributes to the actual or potential threat of altering the Earth's climate. These non-power attributes are expressed in MWh.

Non-power attributes do not include any energy, reliability, scheduling, shaping or other power attributes.

46. Transient Occupancy

Tenancy at a Premise for a duration of less than 30 days.

47. **Utility Provided Service**

The provision of Electricity Service to a Customer by the Company.

48. **Winter Months**

Winter Months are the six regular Billing Periods from November through April. In 2007, the Winter Months will begin with regular meter readings on Month XX, 2007.

RULE B (Concluded)

RULE C
CONDITIONS GOVERNING CUSTOMER ATTACHMENT TO FACILITIES

1. **Acceptance of Electricity Service**

   By establishing or requesting a POD or by continuing an existing Point of Delivery (POD) to the Company's Facilities, an owner or tenant of the property agrees to the following:

   A. To be bound by the conditions of this Tariff including payment of costs for Electricity Service delivered at the rates and under the terms and conditions of this Tariff as in effect from time to time and all applicable Commission rules;

   B. To pay any costs incurred by the Company to provide Electricity Service if Electricity is taken and there is no Customer; and

   C. To have Electricity Service discontinued by the Company if there is no Customer.

2. **Continuity of Electricity Service**

   A. **Generally**

   Unless otherwise specified in a Customer Service Agreement, the Company intends to make Electricity Service available continuously at standard voltages on the Company's distribution system. The Company does not guarantee constant or uninterrupted delivery of Electricity, the constancy of its voltage or frequency, or against the loss or reversal of one or more phases in a three-phase service. The Company's obligation to provide or continue to provide Electricity Service is subject to the applicable provisions of this Tariff. During periods of imminent or actual system emergencies, the Company may curtail or interrupt service to the Customer in order to maintain system integrity.

B. **Emergency Curtailment**

During system emergencies, including but not limited to those caused by extremely cold weather, the temporary loss of a major generating plant or transmission facilities, or conditions that violate the Willamette Valley/Southwest Washington Area (WILSWA) or Western Electricity Coordinating Council (WECC) standards, the Company may find it 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 interconnected by initiating an Emergency Curtailment. The Company will contact the Commission prior to an Emergency Curtailment unless circumstances deem prior notice impractical. Upon the instigation of an Emergency Curtailment, the Company will begin complying with its Curtailment Operating Procedures in order to restore system stability.

The Company's Curtailment Operating Procedures include, but are not limited to, steps for implementing rotating outages. During rotating outages the Company would discontinue Electricity Service to a specific number of circuits for approximately one-hour periods. If after the first hour, system integrity were still in jeopardy, the circuits initially curtailed would have service restored while a second block of circuits would simultaneously have service discontinued. This cycle would continue until the Company determined that system emergency conditions no longer existed. Facilities deemed necessary to public health, safety and welfare are excluded from the rotating outage, as well as feeders serving Customers participating in the Schedule 88, Load Reduction Program.

During system emergencies, Customers having their own generation facilities or access to Electricity from non-utility power sources may choose to use energy from those other sources.

The Company will not initiate its Curtailment Operating Procedures to avoid the purchase of high priced power. The Curtailment Operating Procedures are periodically updated and submitted to the Commission.

C. **Limitation of Liability**

The Company is not liable to Customers, ESSs or any other person or entity for any interruption, suspension, curtailment or fluctuation in Electricity Service, or for any loss or damage caused thereby, resulting from:

1) Causes beyond the Company's reasonable control;

2) Repair, maintenance, improvement, renewal, or replacement of Facilities, or any discontinuance of service that the Company determines is necessary to permit repairs or changes to its Facilities or to eliminate the possibility of injuries to persons or damage to the Company's property or property of others. To the extent practical, such work will be done in a manner that will minimize inconvenience to the Customer, and whenever practical and applicable, the Customer will be given reasonable notice of such work, repairs, or changes;

3) An ESS's failure to abide by the terms of the ESS Service Agreement or the Tariff;

4) Automatic or manual actions taken by the Company, including but not limited to Emergency Curtailments, that in its opinion, are 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 interconnected; and

5) Actions taken by the Company to curtail Electricity use at times of anticipated resource deficiency in accordance with the applicable provisions of this Tariff.

D. **Company's Right to Remove Facilities**

The Company may remove its Facilities as specified in a Customer Service Agreement or when no longer used.

E. **No Customer**

The Company may refuse to maintain Facilities in place or to continue the availability of Electricity Service at any Premises for which the Company has No Customer.

3. Delivery Voltages

A. **Generally**

Electricity delivered under this Tariff is provided at alternating current, 60 hertz, single- or three-phase, at one of the following standard voltages:

B. **Secondary Voltages**

1) **Generally**

Single-phase, 120/240 volts, 3-wire, grounded
Single-phase, 240/480 volts, 3-wire, grounded
Three-phase, 208/120 volts, 4-wire, grounded wye
Three-phase, 240/120 volts, 4-wire, grounded delta
Three-phase, 480/277 volts, 4-wire, grounded wye
Three-phase, 480/240 volts, 4-wire, grounded delta

2) **In Some Locations**

Single-phase, 480 volts, 2-wire (no new service)
Single-phase, 120/208 volts, 3-wire
Three-phase, 240 volts, 3-wire (no new service)
Three-phase, 480 volts, 3-wire (no new service)

C. **Primary Voltages**

1) **Generally**

Three-phase, 12,470/7,200 volts, 4-wire, grounded

(2) **In Some Locations**

11,000/6,350 volts, 4-wire, grounded service

(New installations will not be supplied at 2,400 or 4,160/2,400 volts.)

D. **Subtransmission Voltage**

At 59.8-kV, voltage range is: 56.81-kV to 62.79-kV

At 115-kV, voltage range is: 109.25-kV to 120.75-kV

E. **Selection of Voltage Furnished**

The voltage to be furnished is at the Company's option and will depend upon the characteristics of the Company's distribution system near the POD, the applicable rate schedule and the Customer's service requirements.

4. Conditions for Receiving Service

A. **Generally**

This section describes the physical and technical requirements necessary to interconnect the Company's Facilities with the POD.

B. **Rights-of-Way and Access**

The Customer must provide, without cost to the Company, all rights-of-way and easements on the Premises to be served for the construction, maintenance, repair, replacement, or use of any or all Facilities necessary or convenient for the supply of Electricity. The Customer must grant the Company free and unrestricted access to the Premises at all reasonable times for purposes of reading meters, trimming trees, and inspecting, testing, repairing, removing or replacing any or all Facilities of the Company.

C. **Customer-Supplied Equipment**

1) **Customer's Responsibility**

The Customer will, at the Customer's risk and expense, furnish, install, inspect, and maintain in a safe condition all wiring, equipment, apparatus, protective devices, raceways, and enclosures which may be required beyond the POD for receiving and using Electricity. The Company may, at its option, install and maintain Facilities beyond the POD where deemed necessary to provide adequate Electricity Service.

2) **Conformance with Codes**

Before the Company will provide Electricity Service, the Customer's wiring and equipment must conform to applicable municipal, county and state requirements, and to accepted standards of the National Electrical Safety Code, the National Electric Code, the Company's published "Electric Service Requirements and Guidelines," and Company standards and practices. As required by law, the Customer or its agent must obtain a certificate of electrical inspection before the Company will provide Electricity Service.

3) **Company's Right to Inspect**

The Company has the right, but is not obligated, to inspect any Customer-owned installation, including all wiring, conduit, meter-bases or supporting equipment up to the electric meter and/or POD, at any reasonable time.

4) **Effect of Customer's Load**

The Customer must reasonably balance load between phases of a three-phase service or between ungrounded conductors of a single-phase, three-wire service. The Customer's equipment must not cause excessive voltage fluctuations on the Company's lines. The Company has the right to refuse, discontinue or to regulate hours of Electricity Service to loads that could, in the Company's opinion, impair Electricity Service to other Customers.

5) **Notice of Changes in Customer Load**

A Customer must give the Company prior written notice before making any material change in either the amount or character of the Customer's electrical appliances, apparatus or equipment, thereby allowing the Company to ascertain whether any changes are needed in its Facilities and to make such alterations in the charges for Electricity Service as may be required by this Tariff for the changed installation. If damage results to Facilities owned by the Company through failure of the Customer to notify the Company, the repair and, or replacement costs of such Facilities will be paid by the Customer.

6) **Trouble Calls**

When the Company, in responding to a report of an outage or other continuity of Electricity Service problem, determines the cause of the service problem to be solely in the Customer's equipment, the Company will bill the Customer for charges as listed under Schedule 300.

7) **Miscellaneous Equipment Rental**

When available, the Customer may elect to rent equipment from the Company including, but not limited to, transformers, single-phase to three-phase inverters, capacitors, and other related equipment in accordance with charges specified under Schedule 300 and the terms and conditions of the equipment rental agreement.

D. **Hazardous Substances**

1) **Evaluation of Job Sites**

The Company reserves the right, but is not obligated, to evaluate the job site of any new line extension request or of any required maintenance or repairs of existing Facilities for the purpose of identifying any hazardous wastes, hazardous substances or contaminants ("hazards") in soils or surface at the job site, as such hazards are defined under state or federal law.

2) **Information About Hazards**

Information about hazards may include the following:

a) The job site is within an area designated or listed as a hazardous site by a state or federal environmental agency; or

b) The Customer, Applicant or an employee of the Company or agent of the Company, Customer or Applicant reports unusual or inappropriate odor, color or material in, or adverse physical reaction to, soil or surfaces at the job site.

3) **Treatment of Information About Hazards**

If the Company receives information that hazards may exist at a job site, and such hazards may, in the Company's determination based upon applicable state, federal and industry standards, cause a risk to the health or safety of its employees or agents or the viability of equipment in the installation, maintenance, or repair of service, the Company will specify mandatory conditions for the protection of its employees, agents, or equipment. The Company also may require that the Customer or Applicant indemnify the Company against future claims related to the existence of the hazard. The cost of complying with the Company's conditions and with following state and federal regulations for the handling of the hazard, including, but not limited to, the cost of testing, handling, transporting and disposing of contaminated soil will be borne by the Customer or Applicant.

4) **Remediation of Hazardous Conditions**

The Company may require the Customer or Applicant to bear the cost of remediation or relocation of Company Facilities, if conditions cannot be prescribed which, in the Company's judgment, will adequately protect its employees or agents against hazards.

5) **Remediation Costs**

Nothing contained in this Tariff will be construed as obligating the Company to pay any remediation costs relating to hazards.

6) **Hazards in Public Right-of-Way**

This Tariff does not apply to hazards in a public right-of-way, either for purpose of recovery of extraordinary costs associated with installation, maintenance or repair, or for indemnification against future costs, except where the Customer's or Applicant's Premises are the source of the hazards in the right-of-way.

5. Interconnection of Customer-Generator Facilities

The following will apply to all interconnected Customers unless they are covered by an Interconnection Agreement entered into pursuant to the Company's Open Access Transmission Tariff (OATT) on file with the Federal Energy Regulatory Commission (FERC).

A. **Conformance with Regulations**

In order to ensure system safety and reliability of interconnected operations, the facility will be constructed, interconnected, and operated in accordance with all applicable federal, state, local laws and regulations, including the Company's Interconnection Guidelines, as may be amended from time to time.

B. **Control and Protective Devices**

The Customer will furnish, install, operate, and maintain in good order and repair without cost to the Company such switching equipment, relays, locks and seals, breakers, automatic synchronizers, and other control and protective apparatus as shown by the Company to be reasonably necessary for the operation of the facility in parallel with the Company's system. In all cases, the protective relaying design and equipment proposed for the interconnection of generator(s) must be approved by the Company.

C. **Cost Responsibilities**

The Customer is responsible for all costs of interconnection including any costs incurred by the Company. Additionally, the Customer is responsible for any modification to the Customer's facility that may be required by the Company for purposes of safety and reliability. The Customer will also reimburse the Company for administrative costs the Company incurs in this process.

D. **Conformance with Codes**

A facility will meet all applicable safety and performance standards established in the Oregon State Building Code. The standards will be consistent with the applicable standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and Underwriters Laboratories or other similarly accredited laboratory.

E. **Isolating Equipment**

A readily accessible, lockable and visible-break isolation device will be provided by the Customer at the point of interconnection for the Company's use and will be accessible to the Company at all times. At the Company's option, the Company may operate the isolating equipment if, in the sole opinion of the Company, continued operation of the qualifying facility in connection with the Company's system may create or contribute to a system emergency. At the Company's option, Customers installing small photovoltaic generators may customize their isolating equipment.

6. Transformers

A. **Generally**

Transformers furnished by the Company will be sized to the Customer's kVA requirement as determined by the Company. Transformers furnished by the Customer must be approved by the Company prior to connection.

B. **Restrictions on Transformer Types**

The Company will not furnish transformers with unusual specifications or connections, transformers with voltages not provided by the Company, or transformers insulated with gases or fluids other than oil. Dry-type transformers will be furnished only if:

1) A dry-type transformer installed by the Company prior to October 1, 1975, fails while in service.
2) A Company-owned, dry-type transformer requires replacement because of overload, provided no increase in the ampacity of the Customer's service entrance equipment has been made.
3) Multiple transformations are required to provide 120/240-volt single-phase service to load centers located throughout a residential building over five stories where the tenants are directly metered.

7. Relocation or Removal of Facilities

A. Generally

Any relocation of Facilities for a requesting party, including builders, developers, Customers or Customers' agents, that is for their convenience will be performed by the Company at the requesting party's expense. The Company may require payment in advance of a sum equal to the estimated original cost of installed Facilities to be removed, less estimated salvage and less depreciation, plus estimated removal cost, plus any operating expense associated with the removal or relocation.

B. Public Works Project

Under the following circumstances, the cost for relocation or removal of Facilities within the public right-of-way will be borne by the Company unless an ordinance, legislation or private agreement specifies other cost responsibilities:

1) The rearrangement can be identified to be for a Public Works Project. Examples of Public Works Projects include but are not limited to public transit or a road widening financed by public funds;
2) Reasonable notice is provided to the Company;
3) The overall project can generally be scheduled during normal work hours (excluding load transfers which may need to be performed outside of normal work hours); and
4) The Public Works Project does not require the Company to make temporary relocations.

C. Easement

Costs for permanently relocating Facilities on a private easement will be borne by the requesting party regardless of status as Public Works Project or otherwise.

D. Permit Job

Where it can be identified that the requesting party has received a permit through a city or county for work within the public right-of-way that is required for the requesting party's construction project, the requesting party is responsible for all of the costs associated with the necessary rearrangement of Facilities.

E. **Relocation of Overhead or Underground Facilities at Company Expense**

If the necessary work can be performed by Company crews in a single trip to the requesting party's Premises during Scheduled Crew Hours (7:00 a.m. to 3:30 p.m., Monday through Friday, except Company recognized holidays) relocation or removal of overhead or underground service distribution Facilities on or adjacent to the Premises will be performed at Company expense, under the circumstances listed below. For underground relocations, the requesting party is responsible for any necessary trenching, boring, backfilling, conduit, paving, vaults and pads.

1) Such Facilities are idle, meaning not receiving Electricity Service for more than six months, except in the case of conversion from overhead to underground service; or

2) The location of such Facilities in the street area deprive the requesting party of reasonable ingress to or egress from the Premises, provided such Facilities are not on a property line or a property line extended. Generally, one driveway is considered reasonable ingress or egress; or

3) Such Facilities occupy space on the requesting party's Premises that will be used for an expansion of the requesting party's building or plant. In these cases, the Line Extension Allowance will apply for the expansion. Costs exceeding the Line Extension Allowance must be borne by the Customer; or

(4) The purpose is to relocate a meter to a more accessible location approved by the Company; or

(5) Relocation of a service drop is the only work requested.

If more than one trip is required to accommodate the Customer, the Customer will be billed all costs plus loadings incurred for the additional trips.

F. **Temporary Relocations**

Where the Company is required to temporarily move its Facilities either because the Company cannot move its Facilities to the new permanent placement or the Facilities will be returned to their former location at a later point in time, the costs of the temporary relocation will be borne by the requesting party regardless of its status as a Public Works Project or otherwise. A temporary relocation is defined as any relocation where the Company must move its facilities two or more times within a three-year period.

8. Service Restoration

A. **Generally**

During a major outage due to events such as a major storm, the Company will follow priorities for service restoration as provided below. These restoration procedures are followed in order to restore service to the greatest number of Customers as quickly as possible with special consideration given to Customers that are critically essential to public welfare.

The Company maintains a list of critical Customers such as hospitals, airports, 911 dispatch centers, fire and police stations, water and sewage treatment plants, radio and television stations, newspapers and telephone exchanges. The Company will then repair other main distribution lines.

B. **Service Priority**

The priorities for service restoration are generally as follows:

1) **Protect Public Safety**

The Company will clear downed power lines and ensure that Facilities such as hospitals, fire and police departments, and utilities have power.

2) **Repair Transmission Lines to Substations**

The Company will first make the necessary repairs to the transmission system connecting generation facilities to substations in order to ensure system stability. The Company will then make the necessary repairs to transmission lines, substations, and distribution facilities that connect substations to critical Customers. Next, the Company will continue to repair remaining transmission lines and substations after service is restored to critical Customers' service addresses.

3) **Repair Substations**

The Company will repair substations making it possible to restore service to large numbers of Customers.

4) **Repair Distribution Lines**

The Company will repair distribution lines serving critical Customers as well as lines that may be blocking streets or highways.

5) **Repair of Tap Lines**

After the Company repairs distribution lines, it will repair tap lines that serve smaller groupings, such as Residential Customers.

6) **Repair of Individual Service Connections**

The Company will repair individual service connections last. If Customer-owned equipment has been damaged, such as the meter base, a licensed electrician must repair it before the Company can restore service. Such repairs are the responsibility of the Customer.

C. **Other**

The Company will not give priority restoration to any Customer, non-utility generator or ESS, but will employ the above process over the Company's entire territory served.

RULE C (Concluded)

RULE D
APPLICATION FOR ELECTRICITY SERVICE

1. **Notification Requirement**

An Applicant must provide the Company with five business days notice of intent to purchase Utility Provided Service.

2. **Required Residential Identification Standards**

In order to establish Electricity Service, an Applicant must provide identification as outlined below as well as meet the credit requirements as established in Rule E.

A. **Residential Applicants**

1) A Residential Applicant must provide the following information for the person(s) responsible for payment of the account:

a) Name(s);

b) Name to be used to identify the account, if different than the actual name(s) provided under (1)(a);

c) Date(s) of birth;

d) Social Security Number(s);

e) Current, valid Driver's License Number(s) or other current, valid state or United States Federal identification containing the name and photograph of the person(s) responsible for payment on the account;

f) Service address;

g) Preferred mailing address; and

h) Telephone number(s) where the Applicant may be reached.

2) In lieu of providing either a current, valid identification as required in Section (2)(A)(1)(e) or a Social Security Number as required in Section (2)(A)(1)(d), an Applicant will provide at least two of the following three:

a) Original or certified copy of the Applicant's birth certificate;

b) Current photo identification from school or employer; and

c) Name, address and telephone number of a professional person who can verify the Applicant's identity, such as a teacher, employer or caseworker.

d) Other information deemed sufficient by the Company to establish the Applicant's identification.

B. **Nonresidential Applicants**

Sole proprietors must provide the identification required under (2)(A) of this rule as well as meet the credit requirements as established in Rule E. All other Nonresidential Applicants must provide the following information for the person(s) responsible for payment of the account:

1) Company name and, if applicable, name used for Doing Business As (DBA);
2) Service address;
3) Preferred mailing address;
4) State of incorporation;
5) Name of an officer or other responsible employee; and
6) A current, valid telephone number(s) where the officer or other employee named for (5) may be reached.

3. Forms of Requests for Electricity Service

1) An Applicant may request Utility Provided Service from the Company by telephone, electronically or in person at one of the Company's offices. The Company has the discretion to require an Applicant to fill out and sign a written application form.
2) The Company may accept complete third party applications for residential Utility Provided Service. The Company may refuse to process such an application until it receives satisfactory evidence of the third party's authority to request such service.
3) When a Nonresidential Applicant selects Direct Access Service through an ESS, the ESS must submit a Direct Access Service Request (DASR) under the provisions of Rule K prior to initiation of Direct Access Service.

4. Effect of Application

An application does not bind the Company to provide service and does not bind the Applicant to remain a Customer for a period longer than the minimum term specified in the applicable rate schedule.

5. **Customer Service Agreements**

In most cases, the Company will not require a written Customer Service Agreement as a condition of providing Electricity Service. Certain rate schedules and Rule I of these General Rules and Regulations may require a written Customer Service Agreement.

6. **Consequences of Accepting Electricity Service**

Any person who occupies or is responsible for Premises where Electricity Service is supplied and/or delivered by the Company where the Company has no accepted current application for Electricity Service is liable for all charges for such Electricity Service, based on the applicable rate schedule. Such persons, however, do not have the rights and privileges accorded to Customers.

7. **Refusal of Electricity Service**

The Company may refuse an application for Electricity Service until it receives full payment of any past due amount or other obligation related to a Customer's/Applicant's prior account or as also set forth in OAR 860-021-0335.

RULE D (Concluded)

RULE E
ESTABLISHING CREDIT

1. Residential Credit Standards

A. Generally

Before the Company accepts an application for Electricity Service, it may require the Applicant to establish credit standing. OAR 860-021-0200 (hereinafter referred to as "Commission Credit Rules") determines the criteria for establishing credit.

The establishment or reestablishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. Establishing Credit

A Residential Applicant may establish credit standing for new or continuing service by providing one of the following:

1) An Applicant may submit an authorized letter from his/her previous electric utility, on the utility's letterhead, verifying all of the following:
   a) The dates the Applicant received service;
   b) That the Applicant was the responsible person on a service account where 12 months of continuous, equivalent Electricity Service was received within the prior 24 months;
   c) That the Applicant did not have service disconnected for Theft of Service; and
   d) That the Applicant did not have service disconnected for nonpayment during the final 12 months that service was received.
2) If the Applicant has previously received Electricity Service from the Company, then the Company may verify the Applicant's creditworthiness based on the same standards listed above;

3) A letter from the Applicant's employer, income provider or authorized representative verifying the Applicant's ability to pay. A letter from an employer must state that the Applicant is currently employed and has been employed the entire 12 months prior to the application, and must contain a telephone number for an authorized representative of the employer. The Company must be able to verify the Applicant's employment; or

4) Payment of a Deposit as detailed below in Section C.

C. **Two-Month Deposit Requirement**

In general, the Commission Credit Rules require that deposits be equal to two months' estimated billings (1/6 of the estimated annual usage) at the service address. When a deposit is required, the charges specified in Schedule 310 may apply. A deposit is required if any of the following is true about the Applicant or Customer:

1) Does not establish credit as set forth in Subsections (1) through (3) of Section B above;

2) Received equivalent Electricity Service from the Company or the same type of utility service from an Oregon-regulated utility within the preceding 24 months and, at the time service was terminated, the Customer owed an account balance that was not paid according to its terms. This does not apply to Customers who registered a dispute with the Commission within 60 days after service terminated and who promptly paid all undisputed or adjudicated amounts;

3) Was previously terminated for Theft of Service by the Company or any Oregon-regulated utility or was otherwise found to have tampered with the meter, other utility facilities or diverted utility service; or

4) Moves and the anticipated bill at the new residence will be at least 20% greater than that upon which any current deposit was based.

D. **Payment of Residential Deposit**

An Applicant or Customer who is required to pay a deposit or additional deposit may:

1) Pay the deposit in full prior to receiving service;

2) Enter into an agreement to pay the deposit in three installments, except where a deposit is required to reconnect service after disconnection for nonpayment (OAR 860-021-0335), in which case the whole deposit is due prior to reconnection; or

3) Provide a letter of guaranty.

If the Applicant or Customer chooses to enter into a deposit installment agreement they must do so within five business days from the date of notice from the Company that a deposit is required. Except for the last payment, installments must be the greater of $30 or 1/3 of the deposit. The Applicant or Customer must pay the first installment immediately. The remaining installments will be due 30 and 60 days after the first installment payment. If a Customer has an existing deposit on file with the Company, and an additional amount is being added to the deposit due, any additional installment payment(s) will be adjusted to include the additional deposit; however, two payments will not be required within the same 30 day period.

If a Customer fails to abide by the terms of a deposit installment agreement, the Company may disconnect service after making a good-faith effort to contact the Customer in person or by mailing a notice no less than six business days before disconnection. Should disconnection for nonpayment of a deposit occur, the Customer is required to pay: the full amount of the unpaid deposit balance, any applicable Reconnection charge, Late Payment Charge, and 1/2 of any past due amount before service is restored. The balance of the past due amount is to be paid within 30 days of the date service is restored. A Customer may continue with an existing time payment agreement by paying all past-due installments along with the full deposit and other applicable charges [OAR 860-21-0205(7)].

If an Applicant/Customer pays a deposit or an outstanding bill from a prior account by making a noncash payment which is subsequently returned for insufficient funds by the Applicant's/Customer's financial institution, the Applicant/Customer is subject to immediate disconnection and does not obtain/retain Customer status. The Company will make a good-faith attempt to notify the Applicant/Customer of the returned payment and that service will be disconnected without further notice if payment is not received within one business day following notification. Because the Applicant does not obtain Customer status, the Applicant does not have the right to a time payment agreement or a medical certificate.

E. **Letter of Guaranty**

In lieu of paying a deposit, a Customer or Applicant may provide the Company with a personal Letter of Guaranty from a responsible party to secure payment in an amount equal to two months' average billings as listed in Schedule 310. A responsible party is a Customer who has received continuous service for 12months from the Company with no late payment. For the purposes of this rule, a Customer has had a late payment if he/she has had one or more notices of pending disconnection generated for his/her account.

When the Customer who has established credit with a Letter of Guaranty has his/her Electricity Service disconnected for nonpayment, the responsible party is charged the two months average billing as listed in Schedule 310. The money paid by the responsible party will be applied to the Customer's balance owing. When the Customer requests reconnection of Electricity Service, any additional monies will be applied to the costs of the Customer's reconnection charges and other costs of establishing credit. When service reconnection is not requested, the responsible party who has paid the Letter of Guaranty amount is refunded any excess amount.

2. **Nonresidential Credit Standards**

A. **Generally**

Before an application for Electricity Service is accepted, the Nonresidential Applicant must establish credit as defined below in this rule. The establishment or reestablishment of credit under this rule does not relieve an Applicant or Customer from complying with all of the Company's rules and regulations on file with the Commission, making prompt payment of bills, and being subject to the discontinuance of Electricity Service for nonpayment.

B. **Establishing Credit**

A Nonresidential Applicant or Customer may establish credit for new or continuing service by:

1) Demonstrating that the Applicant or Customer has received 12 months continuous and equivalent Electricity Service from the Company or another electric utility during the preceding 12 months, and did not receive more than two late payment notices or two five-day disconnection notices within the 12-month period. If the service was provided by another electric utility, the Applicant must provide the Company acceptable written verification from the other electric utility;
2) Providing an irrevocable Letter of Credit in a form acceptable to the Company guaranteeing payment in an amount equal to the deposit that would otherwise be assessed;
3) Providing a surety bond or other form of guarantee acceptable to the Company in an amount equal to the deposit that would otherwise be assessed; or
4) Payment of a deposit.

The Company may verify the Customer's creditworthiness at any time. If the Customer is unable to maintain creditworthiness, the Customer may be required to provide a deposit as discussed in Section C below.

C. **Deposit Requirement**

Except for seasonal Applicants or Customers, a deposit equal to a maximum of two average month's billings for Company charges is required when the Applicant or Customer:

1) Does not satisfy the credit criteria as defined in Subsections (1) through (3) of Section (2)(B);
2) Was previously exempted from paying a deposit based upon false information given at the time of application;
3) Is involved in a liquidation, bulk transfer, or financial reorganization or if a receiver is appointed in a state court proceeding involving the Applicant or Customer; or
4) Has sought any form of relief under the federal bankruptcy laws, or is brought within the jurisdiction of the bankruptcy court for any reason in an involuntary manner; then deposit may be demanded as allowed by the Federal Bankruptcy Act of 1978 and, in particular, 11 USC § 366.

In the case of seasonal Applicants or Customers, the maximum deposit amount will be based on the two highest months of usage.

D. **New or Additional Deposits**

A Customer may be required to reestablish credit where conditions of Electricity Service or the basis upon which credit was originally established have materially changed. For the purposes of this rule, conditions are considered to have materially changed if any of the following exist:

1) The Customer's Electricity use is such that the Company does not have a deposit that equals 1/6 of the estimated annual usage where a deposit has been paid, or the Customer must establish credit at a different service address;
2) The expected billings to the Customer have changed as a result of the Customer's enrollment in Direct Access Service, Portfolio or other Electricity Service options; or
3) The Customer returns to Standard Service from Direct Access Service or Emergency Default Service.

F. **Payment of Deposit**

A Nonresidential Applicant who is required to pay a deposit must pay the deposit in full within five business days of the service request if the Applicant has an account balance from a prior service account that was not paid according to its terms. Absent an account balance from a prior service, if the service is connected at the requested service address, the deposit must be paid with the first bill for the new service regardless of whether or not the first month's billing is for a full Billing Period. If service is not connected at the service address, the deposit must be paid in full before the service will be turned on.

An existing Nonresidential Customer who has its Electricity Service disconnected for nonpayment of a deposit will be required to pay the full amount of the deposit, plus any applicable Reconnection Charge, Late Payment Charge, and past due amount before service is restored. Written notice of disconnection for nonpayment of deposit will be provided to Nonresidential Customers five days before service disconnection. The procedures in OAR 860-021-0505 will be used in issuing the notice of disconnection.

E. **Like Ownership**

If the Company, in its discretion, determines that principals of a corporation, partnership, or other commercial enterprise are substantially the same as another corporation, partnership, or commercial enterprise that either is receiving or has at one time received Electricity Service, they are deemed to be the same corporation, partnership, or commercial enterprise for the purposes of this rule.

3. Treatment of Residential and Nonresidential Deposits

A. **Generally**

The Company will furnish a receipt upon payment of deposit and will hold the deposit until credit is satisfactorily established or reestablished. For the purposes of this section of the rule, credit is considered to be established or reestablished if, at the end of 12 months after a deposit is paid in full:

1) The account is current;

2) The Customer has not been issued more than two five-day disconnection notices during the previous 12 months; and

3) The Customer was not disconnected for nonpayment during the previous 12 months.

In the event the Customer moves to a new address within the Company's Service Territory and the Company is holding a deposit in accordance with this rule, the deposit, plus accrued interest, will be transferred to the new account.

B. **Interest Accrual**

Deposits will accrue interest at a rate prescribed by order of the Commission and set forth in Schedule 300. If a deposit is held beyond 12 months, accrued interest will be paid by a credit to the Customer's account on the next bill for service following the anniversary of the accrual date. Interest will be prorated on deposits held by the Company for less than a full 12 months.

C. **Delinquent Accounts**

When service is terminated, the Company will refund a Customer deposit with interest accrued at the rate as listed in Schedule 300, except that such refund will first be applied to reduce or eliminate any unpaid balance on the Customer's account. The Company is under no obligation to draw on deposits to cure delinquency of an active Customer account.

RULE E (Concluded)

RULE F
BILLINGS

1. **Basis for Billing**

   A. **Generally**

   Unless specifically provided otherwise in a rate schedule or in a contract, the Company's rates are based upon the furnishing of continuous Electricity Service to the Customer's Premises at a single Point of Delivery (POD), and at a single voltage and phase. If the Company agrees to additional PODs, each POD is separately metered and billed and treated as a separate Line Extension under the provisions of Rule I.

   B. **Individual Metering**

   Each separately operated business activity and each separate building is individually metered and billed except:

   1) Where two or more buildings on one Premises are occupied and used by one Customer in the operation of a single and integrated business enterprise, the Company may furnish Electricity Service for the entire group of buildings through one service connection at one POD; and
   2) Where a site has service measured and billed from a single meter, a Customer will furnish Electricity to the tenants on its Premises, provided the cost to the tenant for such Electricity is included as a general cost in the rent and is not separately billed or paid.

   C. **Continuing Nature of Charges**

   Disconnect and reconnect transactions do not relieve a Customer from the obligation to pay Basic or Minimum Charges that accumulate during the periods where the Company makes Electricity Service available but such service is not used by the Customer.

   D. **Tax Adjustment**

   A separately stated tax adjustment is billed in any community or area where a governmental authority imposes a tax or assessment in excess of the limit established by the Commission in OAR 860-022-0040 and 0045.

E. **Restrictions on Resale**

Electricity Service will not be supplied for resale, except on Premises and through installations where a Customer engaged in resale to tenants prior to November 5, 1973. In such cases, the Customer will bill the tenants at the Company's applicable rates or, if approved by the Company, at the Customer's average rate per kWh (the Customer's total bill for Electricity including all charges, adjustments and taxes divided by the associated kWh). The Company will allow billing at the Customer's average rate when the Customer does not have adequate metering to bill tenants at applicable rates or the usage characteristics of the tenants do not lend themselves to standard billing.

2. Customer to be Billed; Responsibility for Payment

The Customer receiving Electricity Service is responsible for payment of all Company charges except when an ESS is providing consolidated billing as specified in Section (2) of Rule G. In such case, the ESS is responsible for payment of Direct Access Service and other Company charges.

Customers are responsible for checking their billings and verifying their accuracy.

When a change in occupancy occurs or the Customer otherwise chooses to close an account, the Customer must provide five business days' notice to the Company, before the change will go into effect. 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. The outgoing Customer (or serving ESS if it is providing a Consolidated Bill) is held responsible for all service supplied to the Premises until the account is closed.

3. Application for Site

In order for multiple accounts to be billed as a Site, the Customer must either obtain Site certification through the Oregon Department of Energy (ODOE) or request Company certification.

To request Company certification, the Customer must provide a list of all account numbers and maps or other supporting documentation to demonstrate that these accounts comprise a Site. The Customer will be required to sign and return a letter of understanding before any billing changes are effective.

As a Site, the Customer's primary account will be assessed the maximum $500 Schedule 115 charge. When the Customer's usage is seasonal, the Company will review the usage from all accounts comprising the Site and assess the maximum or less than the maximum charge as applicable. For nonseasonal Customers, if the combined usage from all accounts comprising the Site is such that the total Schedule 115 charge based on kWh would be less than $500 a month, the Customer is responsible to provide sufficient documentation to the Company in order to be refunded any overpayment. For purposes of Schedule 108, the Customer must be certified as a Site with ODOE and have completed a certified project. Once the project is certified, the Customer must notify and provide documentation to the Company before Schedule 108 billing changes will be made.

4. Meter Readings

A. **Generally**

The Company will keep a record of at least three years of meter readings. Meter readings are the basis for determining all bills rendered for metered service.

B. **Assessed Demand**

At the Company's option, Demand may be determined by test or assessment. The assessed Demand of each motor is the nameplate horsepower of the motor multiplied by 0.825 rounded to the nearest whole kW.

C. **Estimated or Prorated Meter Readings**

The amount of Electricity, Demand or Reactive Demand used by the Customer is estimated by the Company from the best available sources and evidence in the following circumstances:

1) Where a meter is inaccessible due to conditions on the Customer's Premises; or

2) When it is determined that the amount of Electricity, Demand, or Reactive Demand used was different from that recorded or billed; or

3) In preparing opening and closing bills. It is the normal practice of the Company, however, to make reasonable efforts to prepare opening and closing bills from actual meter readings.

D. **Incorrect Metering or Billing**

When Electricity Service has been unmetered or incorrectly metered or billed, regardless of cause, or when a meter is found to be more than 2% fast or slow, the Company will adjust its billings and notify the Customer and any serving ESS. Any such adjustment will be for a period not exceeding six months, unless it can be shown that the error was due to a specific cause, the date of which can be fixed, in which case the actual date will be used. In no event, however, will an overbilling or underbilling be for more than three years' usage.

E. **Special Meter Reading**

The Special Meter Reading Charge, as set forth under Schedule 300, is applied when a Customer has requested more than one Special Meter Reading during the preceding 12-month period to verify the accuracy of a previous meter reading. If the Special Meter Reading results in a billing correction, the Company will waive the Special Meter Reading Charge.

F. **Unmetered Loads**

Electricity Service to fixed loads with fixed periods of operation, such as streetlights, Schedule 92 traffic lights, television amplifiers and other similar installations, may be unmetered for the convenience and mutual benefit of the Customer and Company. Monthly usage is billed in accordance with the Customer's applicable rate schedule. Customers have the responsibility of notifying the Company of changes in connected load. Without such notice, the Company is not obligated to make retroactive adjustments to billings or continue to offer unmetered service to the fixed load.

G. **Special Demand**

All rate schedules are based upon loads for which standard Demand measurements reflect adequately the burden imposed on the Company's system. If a Customer has a load with large short-period fluctuations, the Company reserves the right to employ a Special Demand determination.

H. **Reactive Demand**

All rate schedules assume that the Customer takes a minimum of Reactive Demand. Charges in the rate schedules for Reactive Demand are separate from and in addition to charges under the monthly rate for Demand and Electricity or under any minimum charge. Where the Customer installs equipment to supply part or all of its Reactive Demand requirement, such equipment must be switched in a manner acceptable to the Company. Separate charges for Reactive Demand will not be made when the Customer's Reactive Demand is 30 kVar or less.

5. Presentation and Payment of Bills

A. **Generally**

The rate schedules in this Tariff set forth the rates for one Billing Period. However, the Company may read meters and render bills for a period shorter or longer than one Billing Period, in which case the charges based on one month of service (e.g. monthly Basic Charges, charges for Facility Capacity and other Demand related charges) and the number of kWh in each of the rate blocks of the rate schedules will be prorated by multiplying by the number of days in the period and dividing by 30. The number of days in the Billing Period must be less than 27 or more than 34 for a bill to be prorated.

B. **Prorating Initial and Closing Bills**

Initial and closing bills are prorated, unless the time between initial and final use of service is less than 27 days.

C. **Prorating for Tariff Changes**

Changes in Tariff charges or provisions which become effective with service rendered as of a particular date rather than upon the date of meter readings or billings are prorated based on the number of days during the Billing Period that service was provided under the former and revised rate schedules unless the Company is billing on a daily basis using daily readings.

D. **Payment of Bills**

All bills, except closing bills, are due and payable at the Company's offices or authorized pay stations within 15 days of the date of presentation, unless otherwise specified on the bill. Closing bills are due and payable upon presentation. The date of presentation is the date on which the Company mails the bill.

Non-cash payments remitted by Customers in payment of bills are accepted conditionally. A Returned Payment Charge, set forth under Schedule 300, is assessed when the Customer's financial institution refuses to pay as charged.

A Field Service Collection Charge, as specified in Schedule 300, is charged for each visit to a service address by a Company representative to disconnect service for nonpayment of past due amounts where such visit does not result in disconnection of service due to collection of payment from the Customer or representative regarding payment by the Customer.

If a Customer's non-cash payment is returned by the Customer's financial institution within the last 12 months, future payments must be made in cash, money order, verified credit card payment or cashier's check.

E. **Processing of Payments**

The Company will allocate payments from Customers in the following order:

1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

F. **Budget Pay Plans**

Budget Pay Plans are available to Residential Customers who have satisfactory credit and have no past due balance on their account. At the Company's option, Small Nonresidential Customers that are not receiving Direct Access Service may also be offered these plans. No additional charges will be made for rendering bills under a Budget Pay Plan. The Company may adjust a Customer's budget pay amount if changes in the Customer's usage patterns or other factors cause the budget pay amount to no longer accurately reflect the Customer's actual billings.

The Company may discontinue a Customer's Budget Pay Plan if the Customer fails to pay the monthly budget pay amount in full by the due date. Customers may discontinue participation in the Budget Pay Plan upon notification to the Company. If a Budget Pay Plan is discontinued, the Customer must pay any unpaid balance determined by subtracting the total amount paid under the Budget Pay Plan from the total amount the bills would have been, based on the actual kWh used. If a budget pay plan is voluntarily or involuntarily discontinued, the Company is not obligated to offer another Budget Pay Plan to that Customer for a period of 12 months from the time the plan was discontinued. Other monthly charges, such as financing contract and area light charges, will be added to the Customer's monthly bill but are not included when computing the monthly budget pay amount. The Company offers:

1) **Average Pay Plan**

Bills for service under this plan are rendered on a 12-month average basis. The average pay amount is calculated each month and is equal to the average consumption of the preceding 12-months (actual or estimated) or less (based on the number of months available), multiplied by the current rate, plus up to 1/10 of any then-outstanding debit or credit balance.

2) **Equal Pay Plan**

The monthly payment amount is based upon 1/12 of the anticipated annual bill, adjusted as necessary for Tariff changes. Annually, Customer accounts are reviewed to determine the equal pay amount for the subsequent 12 months. At the time of the annual review and at the Customer's request, a present account balance can be settled; otherwise, any remaining balance will be included in estimating the equal payment for the following year. Adjustments in the equal pay amount may be made by the Company at times other than annually if the Customer's actual bill would differ significantly from their previously calculated anticipated annual bill.

G. **Time Payment Agreements**

Residential Customers who are notified of pending disconnection may choose between two Time Payment Agreement options: a levelized payment plan and an arrearage plan as described in OAR 860-021-0415.

H. **Credit Balance**

Except where a Customer is on a Time Payment Agreement, an amount paid in excess of what is owed the Company for services rendered and other applicable charges will be carried as a credit balance on its account and applied to bills for future service unless the Customer requests a cash refund. When a customer on a Time Payment Agreement pays more than the billed amount, the excess payment will be applied to the principle due.

I. **Forced Shutdown of Customer's Operations**

If a Nonresidential Customer's productive operations are completely shut down for a continuous period of more than 15 days solely by reason of fire, flood, wind, action of the elements, acts of God, or other accident or casualty beyond the Customer's control, and the Customer so notifies the Company in writing immediately upon the Customer's knowledge of such event, any minimum charge provision of the applicable rate schedule will be waived during the time of such shutdown. During such time, bills will be computed on the basis of actual Demand and Electricity use and prorated to the number of days involved. The Customer will give notice to the Company prior to resumption of any productive operations.

J. **Late Payment Charge**

A Late Payment Charge may be assessed against any Residential Customer's account that has an unpaid balance carried forward for two consecutive monthly due dates. A Nonresidential Customer may be assessed a late payment charge against any account that is not paid in full each month. The charge will be computed on the delinquent balance at the time of preparing the subsequent month's bill at the rate specified as the Late Payment Charge in Schedule 300. Customers who participate in a Time Payment Agreement [Section (5)(G) of this rule and OAR 860-021-0415] or budget pay plans [Section (5)(F)] are exempted from the late payment charge as long as they are current with their scheduled payments; however, they are assessed a Late Payment Charge on any delinquent balances.

K. **Bill History Information Service Charge**

Advance payment of the Bill History Information Service Charge, as specified in Schedule 300, is required for each year of requested prior bill information beyond the most recent 12 months. No charge is assessed when the billing information is required to resolve billing disputes filed with the Commission. The Company will provide unformatted and unanalyzed interval usage data, if available, to a Customer who requests such data for the Customer Interval Data Charge specified in Schedule 300. In the case where a Customer requests formatted and analyzed interval data, the charge will be based on a mutually agreeable charge.

RULE F (Concluded)

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. **Direct Access Service**

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 483 and 489.

A. **Enrollment**

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. **Special Requirements for Direct Access Billings**

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

(1) **Company/ESS Split Bill**

When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.

(2) **ESS Consolidated Bill**

When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.

B. **ESS Billing Responsibilities**

An ESS is responsible for the following:

1) Confirming receipt of Customer usage data within 12 hours of transmittal from the Company;
2) Responding to Customer inquiries regarding ESS charges; and
3) Under the ESS Consolidated Bill option, issuing a timely corrected bill to the Customer when the Company provides revised billing information.

C. **Company Billing Responsibilities**

The Company will provide usage data to the ESS within two business days of the Customer's meter reading. When the ESS provides an ESS Consolidated Bill, the Company will provide bill-ready data within two business days of the Customer's meter reading. The Company is not responsible for computing or determining the accuracy of ESS charges.

D. **Information Included in Billing**

ESS billing for Customers will include the following information:

1) The beginning and ending dates of the Billing Period;
2) The number of units of service supplied;
3) The telephone number, identified as a Company number, to call for outage reporting and other local electrical utility matters;
4) The PODID(s) of the Customer;
5) The price and amount due for each service or product the Customer is purchasing;
6) Price, power source and environmental impact information in accordance with Oregon Administrative Rule 860-038-0300; and
7) The amount of the Public Purpose Charge, if any.
8) When the Customer receives an ESS Consolidated Bill, the bill will include the following additional information:
   a) Any tax adjustments;
   b) The amount of any transition charge or credit; and
   c) Mandated legal and safety notices in the format provided by the Company.

3. Customer Responsibility

Customers are responsible for checking their billings and verifying their accuracy. Questions regarding ESS charges must be directed to the ESS and questions regarding Company charges must be directed to the Company.

Rule G (Concluded)

RULE H
DISCONNECTION AND RECONNECTION

1. **Grounds for Disconnection of Electricity Service**

Electricity Service may be disconnected:

A. When a Customer/Applicant fails to pay a Company required deposit or make payments in accordance with the terms of a deposit payment arrangement with the Company (OAR 860-021-0205);

B. When service is being received after having obtained Customer status through the provision of false identification or verification of identity;

C. Where Customer facilities provided are unsafe or do not comply with state and municipal codes governing service or the rules and regulations of the Company (OAR 860-021-0335);

D. Where the Customer does not cooperate in providing access to the meter (OAR 860-021-0120);

E. When a Customer requests the Company to disconnect or close an Electricity Service account (OAR 860-021-0310);

F. When a joint account is closed and any remaining Customer(s) fails to reapply for Electricity Service within 20 days, so long as the Company has provided a notice of pending disconnection;

G. Where dangerous or emergency conditions exist at the Premises (OAR 860-021-0315);

H. For failure to pay Oregon Tariff charges due for Electricity Service rendered (OAR 860-021-0405; OAR 860-021-0505);

I. For meter tampering, diverting Electricity Service or other Theft of Service;

J. For failure to abide by the terms of a time payment agreement [OAR 860-021-0410(6); OAR 860-021-0415(5)]; or

K. When the Commission approves the disconnection of Electricity Service.

2. **Procedures for Disconnection and Reconnection of Electricity Service**

The Company will discontinue and reconnect Electricity Service in accordance with the rules of the Commission. These rules, copies of which may be obtained from the Company, are contained in OAR 860-021-0305 through 860-021-0505.

A Customer who has avoided disconnection, established credit, or gained reconnection of Electricity Service by making a non-cash payment that is subsequently returned by the Customer's financial institution is subject to disconnection of such service. Prior to disconnection the Company must make a good-faith attempt to notify the Customer 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 Customer shall make the payment in either cash, money order, cashier's check or verified credit card payment.

3. **Disconnection and Reconnection Charges**

A. The Company may impose a charge for reconnection of Electricity Service to an Applicant to whom prior Electricity Service has been disconnected involuntarily. These charges are set forth under Credit-Related Disconnection and Reconnection Rates in Schedule 300. The charge is assessed based on the time the Customer calls to request service reconnection.

The Company prioritizes credit-related reconnection by the time the Customer provides the Company with verification of sufficient payment for reconnection, and the service addresses' proximity to other service requests so as to assure efficient scheduling of field crews.

In cases where the disconnection is performed at the meter base, the Reconnects at Meter Base Charge as listed in Schedule 300 will be imposed in order to reconnect service.

Should it become necessary to disconnect the Electricity Service at other than the meter base, the Schedule 300 Reconnects at Other Than Meter Base Charge will be imposed in order to reconnect service. Should this require a second trip to the Premises to perform the disconnection, the Reconnects at Other than Meter Base Charge is in addition to the normal charge under Reconnects at Meter Base.

Should other than authorized Company personnel unlawfully attempt reconnection of the Electricity Service, the Customer shall additionally incur the Unauthorized Service Reconnect Charge set forth in Schedule 300.

B. No charge is imposed for a reconnection performed during scheduled business hours in order to provide Electricity Service to a new Applicant. If such a reconnection is performed outside of Scheduled Business Hours, a charge set forth under Disconnection and Reconnection Rates of Schedule 300 is imposed.

C. In the case where a building owner or manager requests reconnection of Electricity Service for cleaning, showing the unit, or any other purpose other than to provide Electricity Service to an occupant, a charge for reconnection as specified in Schedule 300 will be imposed.

D. In cases where the Company has been requested to reconnect Electricity Service after it has been disconnected at the meter and the visit has not resulted in a reconnection of service due to Customer action or inaction, a Field Visit Charge is assessed as specified in Schedule 300.

4. <u>Nonwaiver of Right to Disconnect Service</u>

The Company has the option, but is not obligated, to seek disconnection of Electricity Service if grounds exist. Delay or failure on the Company's part to exercise the option does not constitute a waiver of its right to do so at a later time.

5. <u>Other Remedies</u>

The Company reserves the right to pursue all other legal remedies available to it if grounds for disconnection of Electricity Service exist, whether or not it exercises its right to disconnect service.

6. **Disconnection and Reconnection at the Customer's Request**

At the Customer's request, the Company will disconnect and reconnect Electricity Service to ensure safe working conditions. The disconnection and reconnection will be done without charge if the work can be completed on the initial trip or on a second trip scheduled during Scheduled Crew Hours and at the Company's convenience. If, at the Customer's request, the disconnection and reconnection are performed during other than Scheduled Crew Hours or for reasons other than to ensure safe working conditions, Schedule 300 charges for disconnection and reconnection apply when a standard service crew (a two-person crew) can complete the work in less than 30 minutes and the work can be scheduled at Company convenience. In all cases, the Customer will be charged the actual loaded cost for the disconnection and reconnection.

RULE H (Concluded)

RULE I
LINE EXTENSIONS

1. **Purpose**

This rule establishes procedures and defines respective cost responsibilities to provide a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. **Generally**

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements.

When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension.

B. **Definitions**

1) **Applicant**

For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:

a) Serve new construction; or

b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.

2) **Distribution Facilities**

Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

3) **Line Extension**

A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company has determined has adequate capacity for the Applicant's planned Electricity needs to the Applicant's Point of Delivery (POD). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. However, any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension.

4) **Line Extension Allowance**

The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant.

5) **Line Extension Cost**

A Line Extension Cost is the Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension. Line Extension Costs include, but are not limited to, labor costs, the cost of transformers, primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs, of the existing transformer. Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule.

6) **Long Side Service Connection**

A service connection, which runs parallel to the street, rather than perpendicular to the street.

7) **Primary Voltage Project**

A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.

8) **Public Thoroughfare**

A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.

9) **Residential Subdivision**

A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

10) **Unity Service**

Unity Service is the simultaneous installation of Electricity and gas utilities.

C. <u>Company Requirements</u>

1) **Company to Determine Route**

The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.

2) **Company Ownership**

The Company will own and maintain all Facilities to the POD.

3) **Company Installation**

The Company will install all Facilities to the POD except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:

a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying;

b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;

c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and

d) Following receipt of the title, the Company will energize the Line Extension to make Electricity Service available to the Applicant.

e) If, within 24 months of the time the Company energized the Line Extension, it determines that the overhead Distribution Facilities are deficient in materials or workmanship, the Applicant must pay the cost to correct the deficiency to the Company's satisfaction.

4) **Unusual Distribution Facilities or Nonstandard Construction**

The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. If, at the Applicant's request, the Company installs Facilities which are in addition to, or in substitution of, the standard Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 6 of Rule C applies.

2. Applicant Cost Responsibilities

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension.

B. **Applicants for New Permanent Service**

1) **Individual Applicants**

Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

2) **Other than Individual Applicants**

The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300.

C. **Existing Customers**

1) **Nonresidential**

Where an Applicant is an existing Nonresidential Customer requesting an additional POD, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges.

2) **Residential**

Where an Applicant is a Residential Customer requesting additional capacity at the same POD, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

3. Special Conditions for Underground Line Extensions

A. **Applicability**

Underground Line Extensions will be made:

1) When required by a governmental authority having jurisdiction;
2) When required by the Company for reasons of safety or because the extension is from an existing underground system; or
3) When otherwise mutually agreed upon by the Company and the Applicant.

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.
2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors.

3) Where the Company provides trenching and backfilling for installation of applicable residential underground service laterals, the charges specified in Schedule 300 will apply. Where electricity and gas utilities are to be installed, Applicant can contact the Company for simultaneous installation through the Company's Unity Service. Estimated actual costs will apply where the Company provides trenching, and backfilling beyond the service lateral installation process. The Applicant will be responsible for all additional costs of excavating rock, furnishing and installing raceway, excavating to a depth in excess of Company standards, manual digging, and the repair of paved roads, walks, and driveways when such work must be performed.

4) Where no other restrictions apply and the Applicant is only considering submersible transformers for aesthetic reasons, the Applicant may request the installation of submersible transformers instead of standard pad-mounted transformers. In this event, the cost set forth under the Transformers Section of Schedule 300 will be paid by the Applicant.

5) Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 will be as follows:
   a) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;
   b) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and
   c) At the commencement of pathway construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company.

   The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (3)(B)(5) are not refundable.

C. **Additional Services**

1) **Service Locates**

Before installing Unity Service, the Company will locate underground water, sewer and water runoff services along the Applicant's proposed trench route on the Applicant's property if requested by the Applicant. The cost set forth in Schedule 300 will be paid by the Applicant.

2) **Service Guarantee/Wasted Trip Charge**

The Company will begin the installation of residential single family underground service laterals within seven working days following the date an Applicant requests such service, except during periods of major storms or other such conditions beyond the Company's control. If the Company does not meet this standard, the Company will pay the Applicant the Service Guarantee Charge in Schedule 300. If, however, Company resources are dispatched to install the residential single family service lateral within the seven-day period and the Applicant's site or other facilities are not ready for service, the Applicant will be assessed the Wasted Trip Charge in Schedule 300.

3) **Long-Side Service Connection Charge**

Where the Applicant requests that the Company provide trenching and conduit for a long-side service connection the charge in Schedule 300 will apply.

4) **Joint Trench Installation Charge (for other than Unity Service)**

Upon mutual agreement between the Company and the Applicant, the Company may install telephone and cable services during the installation of the underground service lateral. The parties involved will mutually agree to the price for such service.

4. Refunds

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:

1) The original Line Extension has been in service for less than five years when the additional connections are made;
2) The original Line Extension has been in service less than six years when the application for refund is made; and
3) The payment made by the original Applicant was $100 or more.

B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:

1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and
2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant.

5. Special Conditions for Portland River District Undergrounding Project

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A[1], the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $33,280.00[2] for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area.

---

(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2007. Beyond 2007, the charge will be escalated annually by the Company's then authorized cost of capital.

6. Conversion from Overhead to Underground Service

A. General

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

B. Payment for Service Changes

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. Special Conditions

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:
    a) All existing overhead communication equipment and Distribution Facilities in such district are removed;
    b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer's Premises in order to receive service from the Company's underground Facilities as soon as available; and
    c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.

2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.

3) When the local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.

4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an allocation or assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

7. Nonpermanent Line Extension

A. General

A Line Extension is nonpermanent when the Company believes service for its intended purpose by the Applicant will continue for less than five years. If the Company believes a requested Line Extension is nonpermanent, the Company will require a cash advance of the entire Line Extension Cost, plus payments to third parties for easements and those costs outlined under Section 3, plus the estimated cost of removing the Line Extension, less any salvage value. If service is used for the intended purpose by the Line Extension Applicant for a period of five years, that portion of the amount advanced by the Applicant which was in excess of the amount that would have been charged for a permanent Line Extension will be refunded to the Applicant with interest.

B. Greater than 1 MWa Nonresidential Nonpermanent Service

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\left[\frac{(5 - \text{Years Served})}{5} * \text{LEA}\right]$$

8. Excess Capacity

Excess Capacity will be determined to exist where:

A. The characteristics of the Customer's load require the Company to install Facilities larger than the kVA demand of the load for voltage regulation or other reasons;

B. The Customer requests additional capacity due to planned expansion needs that have not yet occurred; or

C. The Customer requests Facilities that are in excess of what the Company determines is required based on the Company's analysis of the Customer's planned load.

When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period.

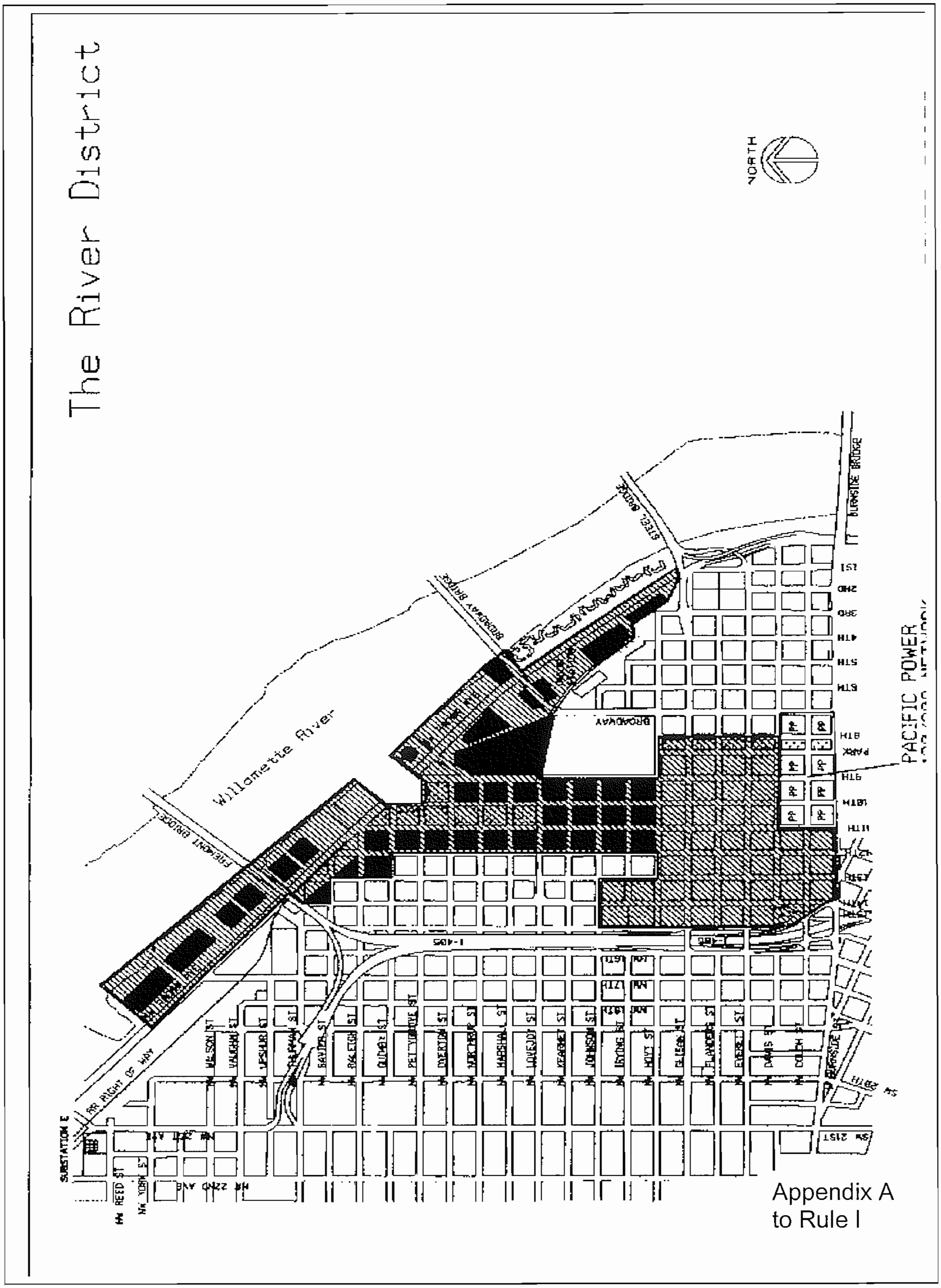
9. Rules Previously in Effect

Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract.

RULE I

APPENDIX A

RULE I (Concluded)



Appendix A
to Rule I

RULE J
STANDARD SERVICE AND PORTFOLIO OPTIONS

1. **Standard Service**

   A. **Eligibility**

   A Large Nonresidential Customer may select Standard Service.

   B. **Enrollment**

   Standard Service will automatically be provided to a Large Nonresidential Customer who has received Emergency Default Service for five business days and/or does not select Direct Access Service.

   A Large Nonresidential Customer that is receiving Direct Access Service may move to Standard Service upon 10 days' notice to the Company. The Customer will be charged a Switching Fee as specified in Schedule 300.

   C. **Term**

   A Large Nonresidential Customer must remain on Standard Service until he/she has met the notice and term requirements of the Standard Service option selected.

2. **Portfolio Options**

   A. **Eligibility**

   A Residential or Small Nonresidential Customer is eligible for service under one or more Portfolio Options in addition to the Standard Cost of Service as contained in the applicable rate schedule.

   B. **Enrollment**

   Residential and Small Nonresidential Customers may select a Portfolio Option via telephone, in person, over the Internet or by other Company-approved means. The Portfolio Enrollment Charge as specified in Schedule 300 will be incurred for any requested portfolio enrollment change other than the initial enrollment and the first requested change per year.

   A Small Nonresidential Customer will be charged a Switching Fee, as specified in Schedule 300, when moving between Direct Access Service and a Portfolio Option or Standard Cost of Service.

RULE J (Concluded)

RULE K
REQUIREMENTS RELATING TO ESSs

1. **Purpose**

A. **Generally**

Prior to providing Electricity Service to Customers, an Electric Service Supplier (ESS) must be certified by the Commission, if applicable, and meet the Company's requirements for providing service. The Company may provide information to the Commission certification process, if applicable, regarding the ESS's scheduling capabilities, electronic data transmission capabilities, insurance coverage and credit.

B. **Requirements for Providing Service**

To provide Electricity to a Customer an ESS must:

1) Be certified by the Commission, if applicable;
2) Complete the Company's business application form and submit an Application Processing Fee or Renewal Fee as listed in Schedule 600;
3) Establish creditworthiness as set forth in the ESS Credit Requirements provision of this rule;
4) Demonstrate the capability to meet the information exchange requirements of the Company. A Setup and Verification Fee may be charged to the ESS as listed in Schedule 600;
5) Name the Company as an additional insured in the amount of at least $10 million on the ESS's general liability policy;
6) Execute an ESS Service Agreement with the Company confirming the terms and conditions of the service(s) elected and agree to abide by the terms and conditions of the Company's Tariff and the Oregon Administrative Rules;
7) If a Scheduling ESS, execute a transmission service agreement under the Company's Open Access Transmission Tariff; and
8) If a Non-Scheduling ESS, provide the name of the Scheduling ESS.

2. ESS Credit Requirements

A. Credit Review/Applicability

An ESS's participation in Direct Access Service is contingent upon meeting and maintaining the credit requirements set forth in this Tariff and the applicable ESS Service Agreement. The Company will determine whether the ESS meets the Company's initial creditworthiness requirements as set forth below, and advise the Commission whether the ESS has been credit approved or not. The Company will enter into an ESS Service Agreement after ESS's credit has been established, collateral has been obtained and ESS certification by the Commission is complete. The Company will continue to monitor the ESS creditworthiness to determine continuing compliance under the minimum credit requirements.

B. Credit Exposure

An ESS must establish and maintain creditworthiness relative to the Company's credit exposure to the ESS. Credit exposure will include, but not be limited to, the expected liabilities of the ESS.

C. Establishment of Credit

An ESS must establish its creditworthiness as described below.

1) **Creditworthiness Requirements**

Each ESS, or guarantor, must meet the Company's creditworthiness requirements by satisfying all of the criteria below. An ESS who cannot meet the requirements below will provide a collateral deposit as described in item (4) below.

a) Credit Evaluation

An ESS seeking to enter into a new ESS Service Agreement with the Company must complete a credit application to provide the financial information necessary to conduct a credit evaluation and establish the ESS's initial credit profile. The Company may require an ESS to complete a new or revised credit application if the ESS's ESS Service Agreement has been terminated, was not renewed, or in any other manner was caused to lapse; if the ESS no longer meets the minimum credit criteria; or periodically based on the Company's standard commercial practice.

The credit evaluation will be conducted by the Company. This evaluation will be completed within 10 Business Days from the Company's receipt of a completed credit application and all relevant financial statements. All information required to evaluate credit will remain strictly confidential between the ESS and the Company, except as otherwise required by law. The Company will notify the Commission of its credit decision upon completion of the Company's credit review. All credit evaluations and associated collateral deposit calculations performed by the Company will be done in a non-discriminatory and consistent manner.

b) Required Credit Information

Each ESS and guarantor (if applicable) will be required to provide the following information: (1) completed credit application; (2) three years of annual, audited financial statements; and (3) the latest interim financial statements along with the same interim financial statements from the prior year.

c) Rating Agency

An ESS and guarantor (if applicable) must demonstrate a current and maintained long-term, senior unsecured debt rating of Baa3 or higher from Moody's Investor Service (Moody's) or BBB- or higher from Standard and Poors (S&P).

d) Tangible Net Worth

An ESS and guarantor (if applicable) must maintain a minimum Tangible Net Worth of $750 million dollars and demonstrate a minimum Tangible Net Worth of $750 million dollars for the prior two-year period. Tangible Net Worth is defined as net worth minus intangibles such as goodwill and rights to patents or royalties.

e) Credit History

An ESS and guarantor (if applicable) must not be currently in default under any of its agreements with the Company or under any of its other agreements, and must be current on all of its financial obligations. An ESS and guarantor (if applicable) must pay all past due amounts owed to the Company before credit is established.

2) **Unsecured Credit**

For an ESS and guarantor (if applicable) whose creditworthiness is established by satisfying the above requirements, a maximum unsecured credit limit will be established by the Company according to the following table. The S&P and Moody's rating is based on the ESS's long-term senior unsecured debt rating. If an ESS is split rated, the applicable credit limit will be based on the lower debt rating.

S&P / Moody's Ratings	Unsecured Credit Limit
> A+ / A1	$15MM
=A / A2	$10MM
=A- / A3	$7MM
=BBB+ / Baa1	$5MM
=BBB / Baa2	$4MM
=BBB- / Baa3	$3MM
<BBB- / Baa3	$0MM

The Company may increase the maximum unsecured credit limit on a case by case basis using accepted commercial credit standards and based on the following criteria: (1) financial performance; (2) credit payment history; and (3) business fundamentals, which includes review of (a) market position; (b) litigation and contingencies; (c) organization; and (d) strategic and financial support. The Company will monitor the established creditworthiness utilizing these factors on an on-going basis.

3) **Collateral Requirements**

The ESS will be required to post or increase collateral under any of the following conditions:

a) The ESS does not meet the minimum creditworthiness standards established above;

b) The ESS fails to provide the Company sufficient relevant credit and financial information on an ongoing basis as required in this Tariff and the ESS Service Agreement;

c) The ESS experiences a material adverse change. A material adverse change is defined as the occurrence of any of the following events: (1) the ESS's long-term senior, unsecured debt rating is downgraded by either S&P or Moody's below BBB- and Baa3, respectively, or (2) a change in condition (financial or otherwise), net worth, assets, or properties which can reasonably be anticipated to impair the ESS's ability to fulfill its payment and credit obligations; or

d) The Company's total credit exposure to the ESS exceeds the ESS's unsecured credit limit and/or any existing Collateral Deposit.

4) **Collateral Deposits**

If collateral is required, the ESS will submit and maintain a collateral deposit as described below.

a) Amount of Collateral Deposit

The amount of the collateral deposit required to establish credit will be the sum of the following amounts as applicable:

(i) For ESSs billing customers for services provided by the Company, three times the estimated maximum monthly customer charges owed by the ESS to the Company, where such estimate is based on the usage and Tariff prices expected to prevail over the next 12 months;

(ii) All other charges from the Company to an ESS as estimated over a 90 day period; and

(iii) All invoiced and non-invoiced receivables due from the ESS; or

(iv) Not less than $500,000.

b) Form of Collateral Deposit

Collateral deposits will be in the form of (1) cash deposits, (2) Letters of Credit, defined as irrevocable and renewable issued by a major financial institution acceptable to the Company, or (3) guarantees, with guarantors who have a long-term senior, unsecured debt rating of Baa3 or higher from Moody's or BBB- or higher from S&P, unless the Company determines that a material change in the guarantor's creditworthiness has occurred, or, in other cases, through the credit evaluation process described above.

c) Collateral Deposit Payment Timetable

ESSs are obligated to post collateral deposits with the Company prior to entering into an ESS Service Agreement. Collateral deposit increases and/or adjustments must be received within two calendar days of a request from the Company. Collateral deposits must be established, maintained or extended within five days of expiration of a collateral deposit.

d) Interest on Cash Deposit

The Company will pay interest on cash collateral deposits. Interest will be calculated according to the interest rate prescribed in Schedule 300.

5) **On-going Maintenance of Credit**

a) The Company may review the ESS's creditworthiness, credit limits and the Company's credit exposure on a daily basis. The Company may request an increase in the collateral deposit by providing notice to the ESS that an increase is required as the ESS enrolls additional Customers, the ESS no longer satisfies the minimum criteria commensurate with its unsecured credit line as described above, the Company draws on the collateral deposit or a portion of the collateral deposit pursuant to this Section or the ESS Service Agreement, and/or the Company's credit exposure to the ESS increases.

b) To assure continued validity of established unsecured credit, the ESS will promptly notify the Company if the ESS (i) experiences any material adverse change; (ii) has its long-term, senior unsecured debt rating downgraded by Moody's and/or S&P; (iii) experiences a change in control as a result of merger or consolidation; (iv) sells or transfers a material portion of its assets; or (v) proposes to change its designation from Non-Scheduling to Scheduling or vice versa.

c) The ESS will provide to the Company an updated credit application reflecting current financial and business information pursuant to the terms of this Section; upon the occurrence of any event listed in Section (2)(C)(3)(c); if the ESS has been suspended pursuant to the terms of the ESS Service Agreement; to support a request for an increased credit line; or as the Company may reasonably require on a quarterly basis.

d) The ESS will review and maintain its collateral and establish, extend or increase collateral when required pursuant to this Section.

e) All collateral amounts will be adjusted up or down to the nearest integral multiple of $25,000, but never less than the required initial collateral deposit at the time the ESS enters into and signs an ESS Service Agreement. The Company will notify the ESS of any needed adjustments.

6) **Re-establishment of Credit**

An ESS whose ESS Service Agreement has been suspended due to inadequate credit may re-establish its creditworthiness in the manner prescribed in item C above.

D. **Additional Documents**

The ESS will execute and deliver all documents and instruments (including, without limitation, security agreements and Company financing statements) reasonably required from time to time to implement the provisions set forth above and to perfect any security interest granted to the Company.

3. Electronic Data Transfer Interchange (EDI)

All electronic communications between the Company and the ESS must conform to industry standard electronic data interchange protocols. The ESS must demonstrate its ability to successfully exchange test data for all transactions before the first Direct Access Service Request (DASR) is processed. The ESS will also provide a point of contact to resolve daily electronic data interchange problems. If the ESS is certified, but does not have active enrollments within a six-month period, the Company will request that the ESS retest the interchange.

The ESS must notify the Company of plans to modify its electronic data interchange systems such as the installation of new software or upgrades to software as well as any plans to change system subcontractors when such plans may affect data transfers between the Company and the ESS. The Company may require retesting of data transfers under such circumstances. Where retesting is required, the ESS will be subject to the set-up and verification charge contained in Schedule 600.

When the Company makes any changes to its interchange systems or changes subcontractors, it will promptly notify all ESSs. If the changes require retesting of systems, the Company will not charge ESSs for this testing.

4. Electricity Service Supplier Decertification

A. **Notice to ESS**

The Company may recommend to the Commission decertification of an ESS that the Commission has certified at times other than the annual renewal date. The Company will notify the ESS that it is initiating such action, if applicable.

B. **Criteria for Recommending Decertification**

The Company may recommend decertification, if applicable, of an ESS to the Commission when the ESS fails to comply with the terms and conditions under this Tariff, or fails to perform obligations under the transmission service agreement or ESS Service Agreement. The following are examples of when the Company may recommend decertification of an ESS:

1) Failure to submit an Electricity Schedule that meets the requirements of Section 11;
2) Failure to deliver Electricity according to its Electricity Schedule;
3) Submission of a DASR not authorized by a Customer;
4) Failure to conform with industry electronic data interchange protocols;
5) Failure to comply with Federal Energy Regulatory Commission (FERC), North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) operating procedures;
6) Failure to pay for services rendered by the Company;
7) The ESS makes a general assignment or arrangement for the benefit of creditors;
8) The ESS becomes bankrupt, a debtor in a bankruptcy proceeding, insolvent, however evidenced, or is unable to pay its debts as they fall due;
9) The ESS files a petition or otherwise commences a proceeding under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it;
10) The ESS has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets;
11) Evidence that indicates the ESS has violated any state or federal customer protection laws or rules, including antitrust laws, during the past three years;
12) The ESS has materially failed to meet its obligations under terms of the ESS Service Agreement so as to constitute an event of default;

13) The ESS engages in unauthorized use of Electricity or a Customer of the ESS engages in unauthorized use of Electricity and the ESS knew about it;

14) Failure to provide a complete, accurate and truthful credit application;

15) Failure to maintain credit requirements; and

16) At the general discretion of the Company.

C. **Notice to Customers**

The Company, upon consultation with the Commission, may transfer the ESS's Customers to the applicable Utility Provided Service prior to ceasing to provide service to the ESS. The Company will notify the ESS's Customers of the transfer in writing as soon as possible. The ESS will be charged a Switching Fee for each Customer transferred as listed in Schedule 600.

D. **Decertification**

Upon decertification, the ESS may no longer serve Customers, and all amounts billed or owed by the ESS are immediately due. The Company will move all Customers served by the ESS to Emergency Default Service and the ESS will be charged the Switching Fee listed in Schedule 600 for each Point of Delivery that moves to Emergency Default Service.

5. Pre-enrollment Information Provided to ESS

With the Customer's authorization, the Company may provide account-specific information, including one year of monthly usage history but excluding credit information, to an ESS. The ESS will be charged the ESS Web Portal Data Access Fee as listed in Schedule 600 for such requests.

6. Customer Enrollment

A. **ESS/Company Relationship**

The ESS may not state or in any way imply that it has been given preferential status by the Company.

B. **ESS Liability**

The ESS will defend, indemnify and hold the Company harmless against all claims of loss made by any Customer arising from claims of inappropriate switching from the Company or another ESS in violation of the solicitation or verification provisions of the Commission, regardless of whether the person or entity doing the marketing or solicitation was an independent contractor of the ESS.

C. **Enrollment DASR**

The ESS must submit to the Company an Enrollment DASR which, at a minimum, includes the Customer's name, Company account number, service address, mailing address, type of service being purchased, name of the ESS, name of Scheduling ESS if different, proposed effective date, Customer's billing preference, and Point of Delivery Identification (PODID) for each Customer that elects service from the ESS.

1) Unless the Company deems otherwise, the Company will activate only one (1) Enrollment DASR per PODID per meter reading cycle. When multiple Enrollment DASRs for the same PODID are received during the same meter reading cycle, the Company will activate the first Enrollment DASR received. The Enrollment DASR must be submitted at least 13 business days prior to the effective date. The Company will notify the ESS of Enrollment DASR acceptance or rejection within three business days of its receipt. For Enrollment DASRs submitted during the annual enrollment window, the three business day notice period does not begin until the end of the enrollment period. The Company will notify the ESS as to the date the Customer will begin Direct Access Service once interval metering is verified.

2) The Company will charge the ESS the Switching Fee listed in Schedule 600 for each Enrollment DASR received whether accepted or rejected.

3) Upon acceptance of an Enrollment DASR the Company will provide notice within three business days to the Customer's current ESS, if any, of the pending change to a new ESS.

D. **Refusal of Enrollment DASR**

The Company may refuse to accept an Enrollment DASR when:

1) The Company has not received full payment from the Customer for past-due amounts or other obligations owed by it related to regulated charges from the Customer's prior Electricity Service account(s) unless such charges are part of a pending Customer dispute;
2) The Company has not received full payment or the Customer has not made an arrangement to pay the balance owed by the Customer on an existing Budget Payment Option or other agreements;
3) The Enrollment DASR is not accurate and/or complete;
4) The ESS has not complied with provisions of the ESS Service Agreement;
5) The Customer has not completed any term obligation under Standard Service; or
6) The ESS is not certified by the Commission.

E. **Change DASR**

A Change DASR must be submitted when the ESS is requesting a modification. The Change DASR requires up to 13 business days to process. The Change DASR may only be submitted after receipt of the assigned effective date of the information subject to modification and must be submitted at least 13 business days prior to the requested effective date of the Change DASR. There is no charge for submitting a Change DASR. However, when a Change DASR is submitted to change the assigned enrollment effective date to a date that is not a regular meter read date, a Change of Effective Date charge as listed in Schedule 600 will be imposed.

F. **Other DASRs**

The Other DASR forms are as follows:

1) **Rescind DASR**

A Rescind DASR is a request to withdraw an Enrollment DASR and it must be submitted prior to the issuance of an Direct Access effective date. No charge is assessed for a Rescind DASR. A Rescind DASR requires three business days to process. If the Company does not have three business days to process before the effective date is issued, a Cancel DASR is required.

2) **Cancel DASR**

A Cancel DASR is a request for cancellation of Direct Access Service that has been submitted after the Direct Access Service effective date has been issued. No charge is assessed for a Cancel DASR. A Cancel DASR requires three business days to process. Failure to provide adequate notice may require the Customer to take Direct Access Service and/or move to Emergency Default Service until processing is complete.

3) **Drop DASR**

A Drop DASR is a request to stop Direct Access Service and return to Standard Service or to close the service account. A Drop DASR must be submitted at least 13 business days before the requested effective date. Failure to provide adequate notice may require the Customer to continue Direct Access Service and/or move to Emergency Default Service until the Drop DASR process can be completed. The Customer or ESS, whichever initiates the Drop DSAR, is charged the Switching Fee as listed in Schedule 300 or Schedule 600.

The Company may submit a Rescind, Cancel, or Drop DASR on behalf of the Customer to nullify an Enrollment DASR submitted for a Customer without their consent. The Customer will not be charged the Schedule 300 Switching Fee and the Customer's service will not be switched regardless of the required processing timeframes described above.

G. **Customer Information**

The Customer consents to the release by the Company to its ESS monthly usage data when it agrees to take Direct Access Service. Upon acceptance of an Enrollment DASR, the Company may provide to the ESS account-specific information, including one year of monthly usage history, excluding credit information.

H. **Return of Customer Deposits**

Following acceptance of an Enrollment DASR, the Company will return any Customer deposit, net of any amounts owing when the ESS is providing Consolidated Billing. When the Company is continuing to bill the Customer or the Customer has requested split billings between the ESS and the Company, the Company will retain the portion of the deposit appropriate for two months of regulated Electricity Service billings from the Company and credit the excess deposit, if any, to the Customer's account.

I. **Customer Change of Location**

When a Customer moves to a new service location, the Customer's ESS must submit an Enrollment DASR for the new service location if the Customer elects to continue Direct Access Service.

7. **ESS Service to Single Point of Delivery**

Only one ESS may serve any single Point of Delivery. If the Customer is receiving products and services from more than one ESS, the ESS that submitted the accepted Enrollment DASR is responsible for the coordination of services including, but not limited to billing, payment, delivery and scheduling.

8. **Discontinuance of ESS Service**

Upon determination by an ESS that it will discontinue service to a Customer because of nonpayment of charges or other reasons provided for in the ESS/Customer Agreement, the ESS will provide the Company with ten business days' notice of such discontinuance. The Company will subsequently move the Customer to Standard Service in the absence of an accepted Enrollment DASR. The Switching Fee listed in Schedule 600 will be charged to the ESS in conjunction with moving the Customer to Standard Service.

9. **Company Billings to the ESS**

The ESS is responsible for payment of all charges assessed to it by the Company. All bills issued under this Tariff are due and payable through electronic payment within 15 days of presentation. Billings unpaid by the due date are subject to a late payment charge as described in Schedule 600. When the ESS disputes charges assessed to it by the Company, the ESS is still responsible to make payment of such charges within 15 days of presentation.

10. **Processing of Payments**

Unless otherwise specified, the Company will allocate payments from ESSs in the following order:

1) Past due deposits or installments;
2) Required deposits currently due;
3) Past due regulated charges for Electricity Services;
4) Current regulated charges for Electricity Services;
5) Past due charges for optional services by oldest date first; and
6) Current charges for optional services.

11. **ESS Scheduling Responsibilities**

At least one day prior to the Day of Flow, in accordance with the ESS Service Agreement and transmission service agreement, each Scheduling ESS will provide the Company with an Electricity Schedule of the expected aggregated hourly load requirements of the Customers for which it has scheduling responsibility subject to the following terms and conditions:

A. **Scheduling Period: Day of Flow**

Each daily scheduling period will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable, "PPT").

B. **Changes in Load**

The Company may require a Scheduling ESS to change its Electricity Schedule if the Company determines the Electricity Schedule does not adequately represent the expected ESS Customer load. If a Customer or Customers are served under an interruptible arrangement by the ESS, the ESS will notify the Company of any interruption coincident with its notification to those Customers and will adjust its Electricity Schedule accordingly.

C. **Failure to Schedule**

An ESS that fails to submit an Electricity Schedule is subject to applicable charges and immediate termination of the ESS Service Agreement. The Customers served by the ESS will be moved to Emergency Default Service.

D. **Confirmation**

The Company reserves the right to confirm with appropriate transmission service providers each Electricity Schedule provided by ESSs and to reject any Electricity Schedule that cannot be confirmed.

E. **Conformance with Regional Requirements**

The ESS will conform to FERC, NERC and WECC scheduling, operating and reporting requirements.

F. **ESS Control Information**

An ESS that chooses to self-provide ancillary services will provide the Company a real-time load and power factor signal via electronic means.

12. Company Scheduling Responsibilities

A. **Change in Load**

The Company will notify an ESS as soon as practical of a planned outage when such outage affects its Customer(s) with a load greater than one megawatt.

B. **Major Outage Procedures**

The Company will attempt to maintain system balance during a major outage using all appropriate methods available according to utility practices. 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. In such case, the Company will notify the ESS when it can resume normal scheduling. The Company will waive related imbalance penalty adjustment provisions during such event. The Company is responsible for responding to inquiries related to major outages. Customers who contact their ESS regarding major outages should be referred to the Company.

13. Settlement

The Company will reconcile total Electricity delivered by the ESS with the total Electricity consumed by the Customers for which the ESS has scheduling responsibility in accordance with Schedule 600 of this Tariff. Customer Electricity consumption will be measured accordingly:

A. **Interval-Metered Electricity**

Where the Customer has an interval-meter installed, Electricity consumed is equal to the metered quantity plus losses as specified in Schedule 600.

B. **Profiled Electricity**

Where interval-meter data is missing, hourly consumption will be estimated using load profiles and adjusted based on available metered data plus losses as specified in Schedule 600. For unmetered loads, consumption will be based on a test or estimated from equipment ratings, adjusted for losses, and allocated to each hour based on hours of usage and whether the equipment is operational during that hour.

14. Operational Order to Deliver Electricity

A. **General**

An "Operational Order to Deliver Electricity" may be issued by the Company upon one hour's notice for purposes of maintaining the integrity of its electrical distribution system.

B. **Action by the ESS**

Upon receiving an Operational Order to Deliver Electricity, the ESS will endeavor to deliver its full capability for all its Customers served by adjusting its Electricity Schedule.

C. **Compensation**

The Company will waive all energy imbalance service charges and penalty provisions for an ESS that demonstrates substantial compliance with an Operational Order to Deliver Electricity. Compensation for excess Electricity delivered in accordance with the Company's Operational Order to Deliver Electricity will be at a rate equal to the higher of:

1) The ESS's direct cost of such Electricity; or
2) The highest incremental cost of Electricity purchased by the Company during each hour of the Operational Order to Deliver Electricity.

15. Preemption

In addition to an Operational Order to Deliver Electricity, the Company may take automatic or manual actions that, in its opinion, are necessary or prudent to protect the performance, integrity, reliability or stability of its electrical system or any electrical system with which it is interconnected. During such period, delivery of Electricity to Customers may be curtailed or interrupted by the Company even though the ESS continues to supply Electricity to the Company. The payment for such Electricity will be made at a rate equal to the higher of:

A. The ESS's direct cost of such Electricity; or
B. The highest incremental cost of Electricity purchased by the Company during each hour of the preemption.

16. Dispute Resolution

A Dispute Resolution process is contained in the ESS Service Agreement.

RULE K (Concluded)

RULE L
SPECIAL TYPES OF ELECTRICITY SERVICE

1. **Service of Limited Duration (Temporary Service)**

   A. **Definition**

   "Service of Limited Duration" or "Temporary Service" means Electricity Service to a Customer who, in the Company's opinion, will not continue to receive service for the minimum of five years.

   B. **Availability**

   Service of Limited Duration includes installations requiring only an overhead service drop, a service lateral to existing underground Facilities, or service to Premises where Facilities are in place, whether or not a meter setting is required. Charges will be in accordance with Schedule 300. Where Facilities other than those specified above are needed to provide service, the provisions of Rule I, Line Extensions, will apply.

   1) The Company provides Standard Temporary Service as well as an optional Enhanced Temporary Service subject to the following conditions.

      a) Standard Temporary Service will be provided to Applicant-supplied service entrance equipment in accordance with applicable codes and regulations. Electricity Service will be metered and billed according to the applicable rate schedule until the account is closed or converted to permanent service.

      b) Nonresidential Customers may receive Standard Temporary Service from an ESS and are required to pay for the installation and removal of interval metering and meter communications (telephone or other method) necessary to deliver such service.

      c) Enhanced Temporary Service is provided on an optional basis for the construction of residential single-family and multi-family dwellings in underground service areas. Under Enhanced Temporary Service, the Company will provide and install an unmetered service pedestal for use until the permanent service is installed.

d) The fixed charges for Enhanced Temporary Service specified in Schedule 300 include Electricity usage for up to 12 months. After 12 months, a permanent connection is required.

C. In order to qualify for Enhanced Temporary Service, the Applicant must agree to the following:

1) Service will be used only for lights, tools, and equipment necessary for the construction of residential dwellings;

2) Service will not be used for the operation of permanently installed appliances or equipment or to heat or dry structures under construction;

3) For multi-family construction, the number of unmetered service pedestals can vary depending on the necessary service outlets per units/buildings under construction; and

4) Unless the trenching or boring work is provided by the Company under the terms of Schedule 300, the Applicant will provide a continuous underground conduit, suitable for Electricity Service, from the permanent meter base to the location of the Enhanced Temporary Service pedestal for the Company to use in later providing the permanent service.

In the event that Enhanced Temporary Service is used for purposes other than those specified, the Company will estimate the amount of Electricity used and bill according to the applicable rate schedule. The Company may restrict future availability of Enhanced Temporary Service in such cases.

2. Emergency Service

A. **Definition**

"Emergency Service" means Electricity Service supplied or made available to load devices which are operated only in emergency situations or in testing to respond to such situations. Electricity Service for freeze protection or similar applications likely to occur annually and/or only in the coldest time of the year is not an Emergency Service.

B. **Availability**

Emergency Service will be provided only to permanent Customers. Where the Company must furnish, install and maintain additional or specific facilities or capacity to provide Emergency Service, the Customer must pay the entire cost of the Line Extension and is ineligible for the Line Extension Allowance as described in Rule I. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Emergency Service including the maintenance charge will be refunded to the Customer.

3. **Intermittent Use Service**

A. **Definition**

"Intermittent Use Service" means continually available Electricity Service which a Customer uses intermittently for a short duration and at a high Demand level such that standard Energy or Demand measurement does not adequately reflect the burden imposed on the Company's equipment and facilities. Examples of Intermittent Use Service include service to test facilities, elevator or hoist motors, welding equipment, x-ray equipment and whole house instant or tankless hot water heaters with a Demand of 18 kW or greater.

B. **Availability**

Intermittent Use Service will be furnished only to permanent Customers. Where the Company must furnish, install, and maintain additional or specific facilities or capacity to provide Intermittent Use Service, the Customer must pay the entire cost of the portion of the Line Extension associated with such service and is ineligible for a Line Extension Allowance for that portion of the service. The Customer is also responsible for a maintenance charge equal to the present value of future maintenance of the facilities at the time the service is installed. Where the Customer modifies its usage and consistently uses the service at its transformer rating within a five year period, the portion of the Line Extension charges that resulted from the designation of Intermittent Use Service including the maintenance charge will be refunded to the Customer.

4. Alternate Service

A. Definition

"Alternate Service" means Electricity Service to a Customer from a second independent primary voltage circuit for which the Company provides a second path for supply of service in the event of the failure of the first electrically independent circuit. Alternate Service facilities include, but are not limited to, the substation and distribution line capacity reserved for the Customer's exclusive use, plus any additional metering or switching equipment required which is beyond the Company's normal responsibility.

B. Availability

The Company will provide Alternate Service at the request of a Customer who demonstrates a requirement for a higher than normal degree of service continuity. The Company will maintain Alternate Service to the best of its ability consistent with the need to operate and maintain its overall distribution system and will notify the Customer if the Alternate Service is to be discontinued for any extended period of time. Alternate Service will be provided only under a contract between the Company and a Customer.

C. Contract Provisions

Alternate Service contracts will provide generally as follows:

1) The Customer will specify its Alternate Service kVA Demand requirement and the period of time for which Alternate Service is required;
2) The design and arrangement of both the preferred and alternate circuits will be at the option of the Company. The Customer will install and maintain an automatic transfer switch. The characteristics, arrangement, and operation of such switch and the associated circuits will be subject to the Company's approval.
3) The Customer will pay the Company either a monthly charge or a lump sum payment to cover the Company's cost to provide the Alternate Service. The rate of the monthly charge, per kVA of alternate capacity required, will be the levelized future revenue requirements imposed on the Company by its investment in Alternate Service facilities and all future maintenance of those facilities. The lump sum amount will be the present worth of the items used to determine the monthly charge.

4) The kVA Demand on the Alternate Service will be measured by separate kW and kVAr Demand meters. Should the Customer impose a kVA Demand on the Alternate Service facilities that is in excess of the amount contracted for, the Customer will pay the Company an additional monthly charge per kVA of excess Demand for that month and the succeeding 11 months. The amount will be determined by multiplying the excess Demand by the monthly rate per kVA as determined in (4)(C)(3) above. In addition to this monthly charge, the Customer must either promptly modify plant operation to prevent future excess kVA Demand or execute a supplemental agreement with the Company for the additional amount of Alternate Service required. The facilities cost for Alternate Service will be based on the costs of the Company in effect at that time and will be calculated and billed as determined in (4)(C)(3). The Customer will be billed the actual cost of any damage to the Company's facilities caused by the Customer's Alternate Service Demand in excess of the contracted amount.

5) The Customer may terminate the agreement for Alternate Service upon 30 days' written notice to the Company. If the Customer is making monthly payments for the Alternate Service, it will, upon termination, pay to the Company the amount that the Company's present-day investment in such facilities exceeds the value to the Company at that time. A Customer who has made a lump sum prepayment to the Company will, upon termination, receive from the Company an amount equal to the current value to the Company for those facilities dedicated to the Alternate Service. Such amount will not exceed the amount of the initial prepayment.

D. **Existing Alternate Service Customers**

Unless otherwise specifically provided, a Customer receiving Alternate Service on or before August 1, 1975 will continue to receive Alternate Service without charge subject to the conditions listed below.

1) Should the nature of the Premises change, Alternate Service without charge will be discontinued after 30 days' written notice by the Company.

2) Should an additional investment be required of the Company to continue to furnish Alternate Service, the Customer will be so notified and given the option of limiting the kVA Demand of Alternate Service required to that which is available from the Company at no charge or executing an agreement with the Company for Alternate Service in accordance with this rule.

3) Should a Customer receiving Alternate Service without charge modify its facilities such that an increase in Alternate Service requirement occurs, the Customer must execute an agreement with the Company for Alternate Service in accordance with this rule.

5. Distribution Facilities Service

A. **Definitions**

"Distribution Facilities Service" means the installation, operation, maintenance and ownership by the Company of Distribution Facilities that are dedicated solely to service on a Customer's site for the Customer's exclusive use, and located on the Customer's side of the POD. "Distribution Facilities" includes primary and secondary cable, distribution transformers, and associated equipment terminating at Customer-owned service entrance or meter base for each building or structure.

B. **Availability**

The Company will provide Distribution Facilities Service on an optional basis to Customers with a minimum installed transformer capacity of 500 kVA as mutually agreed to by contract between the Company and Customer. Upon request of a Customer and agreement by the Company, Distribution Facilities Service will be provided to an existing Customer-owned distribution facilities installation subject to all conditions of this rule and subject to Company determination that the existing system meets Company Distribution Facilities requirements.

If the Customer's existing system does not meet the Company's current standards but is otherwise acceptable to the Company, with respect to safety and reliability, the Company may choose to offer Distribution Facilities Service to the Customer provided that a mutually agreeable plan to upgrade the system, as necessary, is developed and included in the Distribution Facilities Service Charge.

C. **Contract Provisions**

Distribution Facilities Service contracts will provide generally as follows:

1) **Distribution Facilities requirements**

The Distribution Facilities, on the Customer's side of the Point of Delivery (POD), will meet Company distribution system requirements in a manner consistent with Company practices, Company overhead and underground construction standards, applicable standards of the National Electric Safety Code (NESC), American National Standards Institute (ANSI) and the Oregon Electric Service Requirements.

2) **Facilities design and installation**

The design and arrangement of the Distribution Facilities will be as agreed to by the Customer and the Company. The Company will generally meter Electricity Service at the POD.

3) **Memorandum of Agreement**

A Memorandum of Agreement will be filed with the appropriate county in order to provide notice of the existence of the Distribution Facilities Service contract.

4) **Access**

The Customer will provide the Company access to the Distribution Facilities on the Customer's premises without restrictions or structural impediments for purposes of maintenance and repair of the Distribution Facilities.

5) **Distribution Facilities Service Charge**

The Customer must pay the Company a monthly charge to cover the Company's cost to provide the Distribution Facilities Service. The rate of the monthly charge will be the levelized revenue requirements imposed on the Company by its investment in Distribution Facilities and all future maintenance of those facilities. This charge is in addition to any charges for the furnishing or delivery of Electricity to the POD. No Line Extension Allowance as described in Rule I will be applied to Distribution Facilities.

6) **Load Requirements**

The Customer will promptly notify the Company of any changes in electrical load. The Customer will reimburse the Company for all costs of modification, replacement or repair of any transformers or other Distribution Facilities necessitated by increased electrical load.

7) **Maintenance and Repair**

The Company and Customer will be responsible for components of maintenance and repair as set out in the contract. All modifications or enhancements to the Distribution Facilities will be performed by the Company unless otherwise agreed to, in writing, by the Company.

8) **Termination**

The Customer may terminate the contract for Distribution Facilities Service upon purchase of the Distribution Facilities at a purchase price specified, and on terms set out, in the contract or as otherwise mutually agreed upon. Transfer of Distribution Facilities to Customer ownership may occur only after the Distribution Facilities have been approved by local authorities as meeting all applicable codes and requirements for such non-utility owned distribution facilities. Any costs to modify the facilities are the obligation of the Customer.

RULE L (Concluded)

RULE M
METERING

1. **Generally**

A. **Company Responsibility**

The Company will own/lease, install, test, read, remove, replace and maintain meters for each Customer receiving metered Electricity Service. The meters and any meter transformers installed remain the Company's property and may be removed by the Company upon discontinuance of service.

B. **Customer Responsibility**

The Customer will, at Customer's expense, furnish, install and maintain the meter socket and all raceways and enclosures necessary to accept the Company's meters and metering transformers. The Company will provide metering transformers when required for installation by the Customer. The Customer will exercise proper care to protect Company property installed on the Premises, will not break the Company's seal or seals, and will pay for all loss or damage to such property caused by the Customer's negligence or misuse.

C. **Meter Accuracy and Testing**

The Company will, at a Customer's or ESS's request, test the accuracy of the registration of a meter once per 12-month period. If a Customer or ESS requests such a test more than once in a 12-month period, the Company will impose a Meter Test Charge listed in Schedule 300. The Company will refund to the Customer or ESS the Meter Test Charge if the meter is found to be more than 2% fast or 2% slow.

D. **Meter Verification Charge**

Where multiple meters are installed at a location with multiple units, such as for residential multi-family units, it is the developer/owner's responsibility to ensure that each meter socket is correctly labeled for the associated service. The Company may check such meter installations to ensure they are correctly labeled. The Company will charge the Meter Verification Charge, as set forth in Schedule 300, to the developer/owner for each meter installation checked. If all meters at a building location are correctly labeled for each unit, the Company will waive the Meter Verification Charges for that building.

The Company will also impose the Meter Verification Charge at the time addresses are changed for multiple units when the change is a result of other than a government requirement. When locations with multiple units are sold and the new owner requests that service connections to each unit be verified, the Company may also impose the Meter Verification Charge on the new owner.

2. **Metering Requirements**

A. **Standard**

The Company will install at the Customer's Point of Delivery (POD) a meter capable of registering kWh usage. Meters capable of registering Demand, Reactive Demand, and time of use or interval usage will be installed when required due to the Customer's Electricity usage or rate schedule.

B. **Interval Metering**

The Company will meter Electricity usage in intervals of 30-minutes or less for Customers that purchase Electricity Service from an ESS, with the exception of unmetered loads. Where an interval meter does not exist at the time the Company receives a DASR, the Company has 30 days from the date the DASR is accepted to install such meter. Once installed, the Customer may begin purchasing Electricity from the ESS. A Customer who would not normally receive interval metering may, at its request, have an interval meter installed at the charge established in Schedule 300.

C. **Pulse Output Metering**

The Company will provide a connection to its metering facilities to supply kWh data pulses to Customer-owned load control equipment. The Company will also supply a Demand interval timing pulse, provided the Customer's load-control equipment is of the ideal curve or forecasting type. A Customer may have a pulse output metering installed for the charge established in Schedule 300.

D. **Nonstandard Metering**

The Company installs metering that corresponds to the Customer's Electricity usage and rate schedule requirements. If an ESS requests that the Company offer a specific meter capability, function or metering service not currently supported, the Company must approve or deny the request within 10 days. If the request is approved, the Company will file with the Commission to offer such meter or metering service within 30 days. If the request is denied, the ESS may appeal the decision to the Commission.

3. Meter Location

A. **Generally**

Meters are to be installed on the outside of buildings at a location which is easily and conveniently accessible by Company personnel and by the Company's distribution lines; however, with the Company's prior approval, meters for nonresidential buildings may be located indoors if accessible to Company personnel during Scheduled Crew Hours.

B. **Locating Meter on Company's Pole, Pad, or Vault**

If no satisfactory location for the meter is available on or in the Customer's building, the meter and related equipment may, at the Company's option, be installed on the Company's pole or in a Company vault or enclosure. In such event, the Customer will pay the charge specified under Meter Installation Rates of Schedule 300.

C. **Inaccessible Meters**

When in the Company's opinion a meter is inaccessible, the Company may:

(1) Permit the Customer to read the meter and supply meter readings to the Company, subject to actual verification by the Company, not less than once every four months; or

(2) Require the Customer, at the Customer's expense, to relocate the meter socket to an accessible location satisfactory to the Company.

D. **Metered on the Non-Service Side of Transformation**

If the Company installs or maintains the metering equipment on the primary voltage side of the meter and the Customer is receiving service at secondary voltage, billing will be based on meter registration less 1-1/2%. If the meter is located after the occurrence of transformation, and the Customer is receiving service at primary voltage, the billing will be based on meter reading plus 1-1/2%. These billing adjustments compensate for transformer losses or gains.

4. Meter Rentals

The Company will rent meters to Customers engaged in resale prior to November 5, 1973 at rates specified in Schedule 300.

RULE M (Concluded)

RULE N
CURTAILMENT PLAN

1. Purpose and Overview of the Curtailment Plan

This plan identifies the process by which the Company would initiate and implement load curtailment during a protracted regional Electricity shortage to ensure uniform treatment of all regional Customers. This plan would be activated only when declared necessary by State authorities.

The goal of this plan is to accomplish Curtailment while treating Customers fairly and equitably, minimizing adverse impacts from Curtailment, complying with existing State laws and regulations, and providing for smooth, efficient and effective Curtailment administration.

2. Definitions

The following definitions apply to terms used in this plan:

A. **Base Billing Period**

One of the Billing Periods that comprises the Base Year. Base Billing Period data are weather-normalized before being used to calculate the amount of Curtailment achieved.

B. **Base Year**

Normally, the 12-month period which immediately precedes imposition of State-initiated load curtailment.

C. **Critical Load Customer**

A Customer that supplies essential services relating to public health, public safety, welfare, or Electricity production.

D. **Curtailment**

Reduction in Electricity usage irrespective of the means by which that reduction is achieved.

E. **Curtailment Target**

The maximum amounts of Electricity that the Customer may use and still remain in compliance with State Action. The Curtailment Target is figured individually for each Customer by Base Billing Period.

F. **Excess Power Consumption**

The lower of the following two values for loads subject to penalty:

1) The difference between the Customer's actual (or metered) consumption level during a Billing Period and the Curtailment Target; or

2) The difference between the Customer's weather-normalized Electricity usage during a Billing Period and the Curtailment Target.

G. **General Use Customer**

Any Nonresidential Customer who purchased less than five average megawatts (43,800 MWh) during the Base Year.

H. **Major Use Customer**

A Customer who purchased more than five average annual megawatts (43,800 MWh) during the Base Year.

I. **Plan**

The Curtailment Plan.

J. **Region**

The states of Washington, Oregon, and Idaho, and those portions of Montana that are west of the Continental Divide and/or within the control area of the Montana Power Company.

K. **Regional Plan**

The Regional Electric Energy Curtailment Plan as adopted by the Commission.

L. **State**

The Public Utility Commission of Oregon.

M. **State-Initiated**

Actions taken by the State to implement individual load curtailment plans within its jurisdiction.

N. **Threshold Consumption Level**

The maximum amount of Electricity that a Customer can use during mandatory load curtailment without being subject to penalties under this Plan.

O. **Utility Coordinator**

The Director of the Northwest Power Pool.

P. **Utility Curtailment Reports**

Report(s) summarizing Curtailment data, such reports are to be submitted monthly to the Commission and the Utility Coordinator.

Q. **Weather-Normalization**

The procedure used to reflect the impact of weather on load levels. Sometimes referred to as weather-adjustment.

3. Curtailment Stages

State curtailment directives apply to all retail loads served within the State of Oregon. Under the Plan, Curtailment is requested or ordered as a percentage of historical, weather-normalized (Base Billing Period) Electricity consumption. The curtailment stages are associated with increasing Electricity deficits. The five stages of Curtailment are:

Stage	Nature	Curtailment Requirement	Curtailment Type
Stage 1	Voluntary	No Specified %	Uniform Among All Regional Customers
Stage 2	Voluntary	5% or Greater	Uniform Among All Regional Customers
Stage 3	Mandatory	5 to 15%	Uniform Among All Regional Customers
Stage 4	Mandatory	15% 15% or Greater 15% or Greater	Residential Customers General Use Customers Major Use Customers
Stage 5	Mandatory	% Associated with Stage 4 Plus Additional Curtailment	Continued Customer Curtailment Plus Utility Action, Including Plant Closures and Possible Blackouts

4. **Initiation of Load Curtailment**

Curtailment will be initiated when directed by State authorities. However, nothing precludes the Company from requesting voluntary load reduction at any time.

5. **Administration of State-Initiated Curtailment**

A. **Stage-By-Stage Utility Administrative Obligations**

Upon notice from the State to initiate load curtailment, the Company will immediately begin complying with the directives of this Plan. All requirements for lower-level stages continue to apply to higher-level stages. Throughout a period of Curtailment, the Company will provide Electricity Service Suppliers (ESSs), Customers and the general public with as much useful information as can reasonably be supplied. The requirements specified below represent the minimum actions to be taken.

1) **Stage 1**

The Company will begin, or continue if it has already begun, providing Curtailment information to ESSs, Customers and the general public. The Company will also assist the State, as appropriate, in briefing the media about the shortage.

2) **Stage 2**

In Stage 2, the Company will:

a) Notify ESSs, Customers and the general public of the percentage level of voluntary curtailment stemming from State Action;

b) Provide Curtailment tips to ESSs, Customers and the general public;

c) Answer Customer questions about Curtailment;

d) Provide Curtailment reports to the State and the Utility Coordinator; and

e) Provide more detailed information to the media than provided in Stage 1.

3) **Stage 3**

In Stage 3, the Company will:

a) Notify ESSs, Customers and the general public of the percentage level of State-ordered mandatory Curtailment;

b) Calculate weather-normalized Base Billing Period data and Curtailment Targets for all Customers who will be audited in the current billing period;

c) Provide Curtailment Targets to ESSs and all Customers who request such data for their own accounts;

d) Provide audited Customers with information about how to apply for exemption and adjustment of Base Year data;

e) Process requests for exemption and Base Year data adjustments from those Customers selected for audit who would otherwise be subject to penalties; and

f) Implement the penalties aspect of the Plan.

4) **Stage 4**

In Stage 4, the Company will notify ESSs, Customers and the general public of any applicable changes in State-initiated mandatory curtailment.

5) **Stage 5**

In Stage 5, the Company will collaborate with the State to develop and implement the most effective methods to secure the required Electricity Curtailment while minimizing, to the extent possible, any economic and human hardships of the last stage of load curtailment.

B. **Suggested Curtailment Actions**

Information will be disseminated to Customers regarding actions that they can take to reduce their Electricity consumption. The Company will work with the State to develop this material. The recommendations will be based on the actions described in Appendix C of the Regional Plan.

6. **Base Year Data and Curtailment Targets**

A. **Identification of the Base Year**

The Base Year for a shortage will be established by the State. Base Year and Base Billing Period data shall be weather-normalized.

B. **Estimating Base Billing Period Data for Customers for Whom No Base Billing Period Data Exists**

Base Billing Period data must be obtained or developed for any Customer who is audited under this Plan. Although the Company has the option of excluding residential and General Use Customers without actual Base Billing Period data from the random sample of audited Customers, Base Billing Period data will be estimated for any audited Customer for whom actual data does not exist or is found to be inaccurate.

C. **Communicating Curtailment Target Information to Customers**

During mandatory Curtailment, retrospective, current billing period, and forthcoming billing period Curtailment Target information will be provided to any Customer who requests such information. Retrospective Curtailment Target information will be provided to any audited Customer who will be issued a warning or penalty. At its option, the Company may provide Curtailment Target information to other Customers or Customer classes as well.

7. **Auditing Customers for Compliance With State Orders for Mandatory Load Curtailment During Curtailment Stages 3-5**

A. Each billing period, at least one percent of residential users, five percent of General Use Customers, and 100 percent of Major Use Customers (including those Major Use Customers with estimated Base Billing Period data) plus any Customers penalized in the previous billing period will be audited. The number of Customers exempted or excluded from audit will not affect the sample size.

B. New compliance samples shall be drawn each month. Customers penalized under this Plan shall continue to be audited until their Energy use falls below the Threshold Consumption Level. Once their Energy use falls below that level, they will be audited again only if selected by random sample.

C. Unless the Company is auditing 100 percent of its residential users and General Use Customers, all such Customers selected for audit shall be chosen on a random sample basis, except that the following Customers are to be excluded: (a) Customers granted an exemption under this Plan; and (b) Customers with an estimated power bill in the current billing period. At its option the Company may also choose to exclude Customers with estimated Base Billing Period data, if the State does not require their inclusion in the pool of Customers subject to audit.

8. Penalties for Noncompliance

A. **Nature of Penalties**

The following penalties will be assessed under this Plan to Excess Power Consumption as defined below:

Violation	Penalty
First Bimonthly Violation	10¢ per kWh of Excess Use
Second Bimonthly Violation	20¢ per kWh of Excess Use
Third Bimonthly Violation	40¢ per kWh of Excess Use
Fourth Bimonthly Violation	1 Day Disconnection Plus 40¢ per kWh of Excess Use
Fifth Bimonthly Violation	2 Days Disconnection Plus 40¢ per kWh of Excess Use
Sixth and all Subsequent Violations	Penalties are Determined by the State; Civil Penalties or Other Corrective Actions would be possibilities.

The penalty for violators who are billed every two months will escalate on every power bill in which they are subject to penalty. Customers billed on a monthly basis will be assessed the same penalty on two successive occasions before incurring the next higher level penalty. During any continuous period of curtailment, assessed penalties remain on the record for the purposes of administration of subsequent penalties, even if there has been an intervening period of compliance.

Standard disconnect criteria and procedures will be used whenever disconnecting Customers in accordance with this Plan. Health, safety, and welfare considerations will be taken into account, and Customers will be billed for normal disconnect and reconnect charges.

B. **Calculation of Financial Penalties**

Financial penalties will be calculated by multiplying the Customer's Excess Electricity Consumption each billing period by the appropriate penalty level identified above.

1) **Threshold Consumption Level**

The Threshold Consumption Level assigned to each Customer class is identified as:

a) Residential Customers,
10% Above Curtailment Target.

b) General Use Customers,
10% Above Curtailment Target.

c) Major Use Customers,
2% Above Curtailment Target.

These values may be changed by the State so as to effect better compliance with the curtailment order.

2) **Excess Power Consumption Calculation**

Penalties will not be assessed if a Customer's load (either actual load or weather-normalized load) is equal to, or less than, the Threshold Consumption Level. Excess Power Consumption is the lower of the following two values for each sampled load subject to penalty: (a) (Actual Load) minus (Curtailment Target) or (b) (Weather-Normalized Load) minus (Curtailment Target).

3) **Assessment of Penalties**

Penalties Vs Warnings. Customers will be assessed penalties only if they have Excess Electricity Consumption and if they are to be penalized based on the penalty assessment procedures described below. Any sampled Customer who is not penalized and whose use exceeds the Curtailment Target will receive a warning.

C. **Penalty Assessment Procedures**

Sample at the mandated minimum percentages for each section as specified in this Plan [1%-5%-100%] (or as otherwise specified by the State) and assess penalties on all Customers with Excess Power Consumption.

At its option, the Company may sample at higher percentages of Customers than the minimum required by Section 7 above and may choose among the following penalty assessment options:

1) **Option (1)**

Assess penalties on all sampled Customers with Excess Power Consumption (this methodology must be used for Major Use Customers even if the utility chooses Option (2), below, for its other Customer sectors); or

2) **Option (2)**

Develop a ratio of the minimum percentage sample size to the actual percentage sampled for the Residential and/or General Use Customer sectors. Multiply the resulting percentages by the total number of violators in each respective Customer sector to determine the minimum number of penalties that must be assessed in each sector. Calculate the percentage violation for each individual Customer that has been sampled (Excess Power Consumption divided by Curtailment Target) and apply penalties to the worst offenders in the overall sample based on their percentage Excess Power Consumption. Also penalize all Customers who were penalized in the previous billing period and who still have Excess Power Consumption.

D. **Billing Customers for Penalties**

The penalty on the power bill may be described as State-mandated and shall include any State-provided material describing the penalty aspect of the Plan as a bill stuffer in the bills of penalized Customers. If the Customer is receiving an ESS Consolidated Bill, the ESS will bill the Customer for any penalties incurred by that Customer. The bills shall include any Commission-provided material describing the penalty aspect of the Plan, such as a bill stuffer. When the Company is billing the Customer, the bills shall note that failure to pay penalties will result in service disconnection in accordance with standard disconnect criteria and procedures.

E. **Treatment of Penalties Pending Adjustment / Exemption Determinations**

A Customer that has applied for adjustment of Base Billing Period data and/or exemption from mandatory Curtailment may request a stay of enforcement of the penalty aspect of the Plan pending a final decision regarding its request. Any Customer who has been granted such a stay will be subject to retroactive penalties as applicable if the request is ultimately denied.

F. **Use of Funds Collected Under the Penalty Provisions of the Plan**

Funds collected under the State-ordered penalty provisions of this Plan shall be set aside in a separate account. The ultimate disposition of these funds will be determined by the Commission.

9. Exemptions and Adjustments

A. **Customer Application for Exemption/Adjustment**

Customers will be informed of how to apply for exemption from Plan requirements or adjustments of Base Billing Period data. At its option, the Company may elect to process exemptions and adjustments only for audited Customers. Customers seeking an exemption or adjustment shall apply first to the Company and then, if dissatisfied with that outcome, to the Commission.

At its option, the Company may provide for a credit against future curtailment for a Customer who has already accomplished a reduction in Demand for the utility's service by installing an alternative Energy device or by weatherization or other installed conservation measures equivalent to the proposed level of curtailment. Where the level of curtailment exceeds the Demand reduction produced by the conservation measures or installed alternative Energy device of the Customer, the Company may provide for credit against the level of curtailment ordered to the extent of the Demand reduction produced by the conservation measure or alternate Energy device.

B. **Granting Customer Requests for Exemption From Mandatory Curtailment**

No automatic Customer exemptions will be granted under mandatory State-initiated load curtailment. Exempted Customers should be informed that exemption may not protect them from Stage 5 blackouts.

1) Critical Load Customers

Critical Load Customers may be exempted once the Customers have demonstrated to the Company that they have eliminated all nonessential Energy use and are using any reliable, cost-effective backup Energy resources.

2) Other Customers

Exemptions for Customers not qualifying as Critical Load Customers under the Plan will be evaluated based on whether Curtailment would result in unreasonable exposure to health or safety hazards, seriously impair the welfare of the affected Customer, cause extreme economic hardship relative to the amount of Energy saved, or produce counterproductive results.

C. **Utility Record Keeping Relative to Customer Exemptions**

Records regarding exemption determinations will be made available to the Commission upon request.

10. Measurement of the Amount of Curtailment Achieved and Determination of Compliance

At all times during State-initiated regional load curtailment, the Commission and the Utility Coordinator will be provided with consumption and savings data on a monthly basis in the form specified in Appendix D of the Regional Plan. To the extent that circumstances at the time of actual load curtailment dictate the need for additional data or more frequent data submittal, a best effort to comply with the Commission request will be made.

11. Special Arrangements

A. **Use of Customer-Owned Generation Facilities**

Consistent with the need for safety and system protection, Customers having their own generation facilities or access to electricity from non-utility power sources may choose to use Energy from those other sources to supplement their curtailed power purchases from their electric utility under any protracted regional shortage situation.

B. **Curtailment Scheduling**

During periods of mandatory Curtailment, a Customer is obligated to provide the requisite amount of curtailment within each billing period. Within that period, and subject to equipment limitations and the Company's rules on load fluctuations, Customers are free to schedule their curtailment so as to minimize the economic cost, hardship or inconvenience they experience as a result of the mandatory curtailment requirement.

C. **Related Curtailment Information**

The Regional Electric Energy Curtailment Plan is included, by reference. That plan contains additional information on curtailment administration.

RULE N (Concluded)