BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

General Rate Case Filing
For Prices Effective January 1, 2016

PORTLAND GENERAL ELECTRIC COMPANY

Executive Summary

February 12, 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

In the Matter of	)	
	)	**EXECUTIVE SUMMARY OF**
PORTLAND GENERAL ELECTRIC COMPANY	)	**PORTLAND GENERAL**
	)	**ELECTRIC COMPANY**
	)	
Request for a General Rate Revision	)	

I. INTRODUCTION

Portland General Electric Company ("PGE") is an electric company and public utility pursuant to ORS 757.005. The Public Utility Commission of Oregon has jurisdiction over the price and terms of service for PGE's customers. PGE is filing this request to revise its tariff schedules pursuant to ORS 757.205 and ORS 757.220. This executive summary is submitted to meet the requirements of OAR 860-022-0019.

As with PGE's previous rate case, this case is largely driven by the addition of new generating plant. The major addition in this case the Carty Generating Station ("Carty"), a 441 MW (with duct firing) combined cycle combustion turbine, located near Boardman, Oregon. The need for this generating plant was identified in PGE's 2009 Integrated Resource Plan ("IRP") and the action plan implementation resulting from that IRP. The 2011 and 2012 Updates to the 2009 IRP continued to show a need for the plant. Carty was chosen through a robust Request for Proposals process in accordance with the Commission's rules and guidelines. It was identified as the least cost/least risk resource to fill the need. Carty is being constructed under an engineering, construction and procurement contract with Abeinsa EPC LLC and related companies, on a site owned by PGE. Carty is expected to begin service to customers in the second quarter of 2016. In accordance with past Commission practice, PGE requests that Carty be incorporated into customer prices when it begins service to customers. The annualized revenue requirement for the Carty project is $83.6 million.

PGE's request in this case is comprised of a modest increase related to base business, and the costs of the new Carty generating plant. In summary, the request is as follows for cost of service and direct access customers:

	Revenue Change	Percent Change
Base Business	$38.8 million	2.1%
Changes in Supplemental Schedules	($56.2) million	(3.1%)
Base Business with Changes in Supplemental Schedules	($17.5) million	(1.0%)
Carty Generating Station	$83.6 million	4.7%
Overall: Base Business, Changes in Supplemental Schedules and Carty	$66.0 million	3.7%

(Totals may not foot due to rounding)

PGE has taken a number of steps to reduce the requested price increase in this case. PGE's benchmarking and continuous improvement cycle implemented in the past few years has yielded savings and decreased upward pressure on costs. Past and planned future efforts in this area are discussed in the testimony. PGE also reduced its request in this docket by: 1) removing some incentive compensation costs, 2) removing 50% of the costs of certain layers of directors and officer insurance, and 3) requesting a return on equity at the low end of the range supported by its expert witness. The result is a base business (without Carty or the impact of changes in supplemental schedules) increase request of $38.8 million, or 2.1% effective January 1, 2016.

PGE has also included in its request a proposal to mitigate the requested price increase by accelerating the tariff Schedule 143, Spent Fuel Adjustment credit. In PGE's last rate case the Commission approved refunding $50 million from the Trojan Nuclear Decommissioning Trust over three years beginning in 2015. To help mitigate the increase in this case, PGE requests that the refund of these excess funds be accelerated, with the amount currently scheduled to be refunded in 2017 instead be refunded during 2016. If approved, this will reduce the 2016 price change impact on customers by almost 1%.

PGE also anticipates an increase in the Regional Power Act Exchange Credit from the Bonneville Power Administration beginning in October 2015. PGE proposes to implement this increase in credits through Schedule 102 effective January 1, 2016. This increase in credits will reduce residential and applicable farm customers' costs by approximately $15 million. This increased credit, along with changes in a number of supplemental tariff schedules that will go into effect on January 1, 2016, will reduce projected revenues by a combined $56.2 million. Including these changes in supplemental schedules, PGE's requested price change (without the effects of Carty) beginning January 1, 2016, is an overall decrease in projected revenues of $17.5 million, or 1.0% relative to current approved prices.

The overall request, including the costs related to the Carty generating plant after it begins service to customers, and the changes in supplemental schedules, is an increase in revenues of about $66.0 million, or 3.7% relative to currently approved prices. The timing of these changes in supplemental schedules reduces the price increase request in this docket by about 3.1% overall. The size of the requested increase also reflects a successful, diligent effort by PGE to keep costs down while bringing into service a substantial generating asset.

II. SUMMARY OF THIS CASE

As described below, fourteen pieces of testimony discuss the basis for our request in this case. The witnesses are all, with the exception of the witness on the appropriate return on equity, PGE officers and employees. The testimony discusses the cost drivers in each area and the projected 2016 costs incorporated into this case.

This case is based on a normalized future test period of calendar year 2016, except that for rate base we use the balance as of December 31, 2015. PGE seeks a schedule in this docket that will allow for a Commission order by mid-December and revised tariff schedules implemented on January 1, 2016, with an additional price change implemented when Carty begins service to customers. The dollar amounts of the changes were discussed above.

PGE requests an authorized return on equity (ROE) of 9.9% with a forecasted actual capital structure of 50% equity and 50% debt. The projected test year results show that inclusive of the new generating plant and without a price increase, PGE will earn an ROE of approximately 6.7%. That is significantly below PGE's currently authorized ROE, and below the level needed to maintain PGE's credit and attract capital.

As set forth in the testimony in this docket, this case is predominantly about the addition of the Carty generating resource needed to meet our customers' needs for safe, reliable service. Prices need to be set to allow PGE the opportunity to earn a return on invested capital that is commensurate with similar companies, allowing it to maintain its credit and attract capital on terms that will ultimately be beneficial to customers.

PGE's request with respect to the price change when Carty comes on-line is consistent with past Commission practice. As has been done in previous dockets, when the plant is on-line, PGE will provide an attestation of a PGE officer verifying that it is in operation and available for service to customers. PGE requests that after the filing of such an attestation, prices including the costs of the plant become effective.

Net Variable Power Costs. Each year under Schedule 125, PGE's prices are adjusted to reflect projected net variable power costs ("NVPC") for the coming year, and transition charges or credits for those customers opting for an alternate electricity supplier are calculated. Schedule 125 requires PGE to file estimates of the adjustments on or before April 1. In addition to the NVPC forecast and Minimum Filing Requirements ("MFRs") with this filing, PGE intends to file an update, with additional MFR documentation, by April 1. PGE requests a schedule that will allow for a Commission decision of NVPC issues by mid-October consistent with the requirements of PGE's Tariff Schedules 125 and 128, and the November 2015 direct access window.

Compliance with OAR 860-022-0019. Attached as Exhibit 1 is the information required by OAR 860-022-0019. That exhibit shows the impact of the proposed price change without Carty on each customer class. The impact on residential customers of the requested base business price change, prior to the inclusion of Carty, is an increase of 2.6%. Including the impacts of the increased BPA Residential Exchange Credit, and the effect of supplemental tariff schedule changes, an average residential customer using 840kWh per month will see a decrease of approximately 1.5% prior to inclusion of Carty. Attached as Exhibit 2 is the OAR 860-022-0019 information reflecting the costs of Carty, and the changes in supplemental schedules. With Carty, the BPA credit and supplemental schedule changes, the requested price change for residential customers is 3.1%, and the increase for an average residential customer using 840 kWh per month is $2.84.

III. TESTIMONY

PGE's testimony and exhibits demonstrate that the Commission should approve this Application. The rates and tariffs proposed result in prices that are just and reasonable. PGE is introducing fourteen pieces of testimony sponsored by the following witnesses:

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	Jim Piro and Jim Lobdell
200	Revenue Requirement	Alex Tooman and Rebecca Brown
300	Carty Generating Station	Maria Pope and Jim Lobdell
400	Net Variable Power Costs	Mike Niman, Terri Peschka and Patrick Hager
500	Total Compensation	Arleen Barnett and Jardon Jaramillo

600	Corporate Support/A&G and Information Technology	Jim Lobdell, Cam Henderson and Alex Tooman
700	Production O&M	Steve Quennoz and Aaron Rodehorst
800	Transmission and Distribution	Bill Nicholson and Larry Bekkedahl
900	Customer Service	Kristin Stathis and Carol Dillin
1000	Cost of Capital	Patrick Hager and Brett Greene
1100	Return on Equity	Bente Villadsen
1200	Load Forecast	Sarah Dammen and Amber Riter
1300	Marginal Cost of Service	Robert Macfarlane and Bruce Werner
1400	Pricing	Marc Cody

IV. SUMMARY OF TESTIMONY

Exhibit 100. Jim Piro, CEO and Jim Lobdell, CFO, present the opening testimony. They explain the business context for this filing including the addition of the Carty Generating Station, and identify other key proposals. They continue describing the efficiency efforts PGE has successfully implemented, and credits proposed to mitigate the price increase requested in this docket. As the CEO and CFO, Messrs. Piro and Lobdell explain the policy drivers behind PGE's requests in this case, and why they are in the interests of customers. Messrs. Piro and Lobdell also introduce the other testimony in this docket.

Exhibit 200. Project Manager Alex Tooman and Senior Analyst Rebecca Brown summarize the overall 2016 test year revenue requirement and compare the request with 2014 actual costs and the results of PGE's recently concluded rate case, UE 283. Mr. Tooman and Ms. Brown address the costs associated with the new Carty generating plant, and how PGE

proposes to include these costs in customer prices when the plant begins providing service to customers.

Exhibit 300. Maria Pope, Senior Vice President of Power Supply and Operations and Resource Strategy and Jim Lobdell describe the new Carty Generating Station. These witnesses review the extensive planning and oversight that led to the selection of this project. The testimony addresses the costs of this resource, and the efforts to date to bring the project into service for customers on time and on budget.

Exhibit 400. PGE Managers Mike Niman, Terri Peschka and Patrick Hager present PGE's Net Variable Power Costs. The initial NVPC forecast for 2016, exclusive of Carty, is $556.9 million. This is a decrease of about $5.4 million from the 2015 NVPC determined in PGE's recent Annual Update Tariff proceeding, Docket UE 286. The additional effect of Carty further reduces NVPC by an estimated annualized $1.6 million, but the actual reduction is dependent upon the on-line date of the plant.

As stated above, PGE requests that a schedule be implemented in this docket to allow for a Commission decision of NVPC issues by mid-October consistent with the requirements of PGE's Tariff Schedules 125 and 128, and the November 2015 direct access window.

Exhibit 500. Arleen Barnett, Vice President of Administration, and Jardon Jaramillo, Director of Compensation and Benefits, testify on compensation and human resource issues. These witnesses describe compensation costs for 2016, gains through efficiencies, changes to PGE compensation policies and plans, and proposed pension cost recovery and pension investment strategy.

Exhibit 600. Jim Lobdell, Cam Henderson, Vice President of Information Technology, and Alex Tooman explain the costs and drivers associated with PGE's corporate support

operations such as insurance, environmental services, business continuity and emergency management, and Information Technology.

Exhibit 700. PGE's long-term power supply resources and associated costs are presented by Steve Quennoz, Vice President of Power Supply, and Aaron Rodehorst, Senior Analyst. These witnesses discuss plant performance and ongoing efforts to improve plant performance, reliability and safety. These witnesses provide support for 2016 power supply resource costs, and the proposed major maintenance accrual for Carty.

Exhibit 800. Bill Nicholson, Senior Vice President of Customer Service, Transmission and Distribution, and Larry Bekkedahl, Vice President of Transmission and Distribution, testify regarding PGE's transmission and distribution ("T&D") system. These witnesses explain the test-year costs necessary to provide service and the status of work on implementing new systems.

Exhibit 900. Kristin Stathis, Vice President of Customer Service Operations, and Carol Dillin, Vice President of Customer Strategies and Business Development, address PGE's Customer Service functions and costs for 2016. The areas covered in the customer service testimony account for most interactions with retail customers. The testimony discusses the major drivers of cost changes in this area including an update on the Customer Engagement Transformation project discussed in the last two rate cases. These witnesses also discuss implementation of the fee-free bank card program, and address improvement initiatives in the customer service area.

Exhibit 1000. Patrick Hager, Manager of Regulatory Affairs and Brett Greene, Assistant Treasurer and Director of Treasury and Tax, present PGE's testimony on cost of capital and capital structure for 2016. On behalf of PGE, these witnesses request a 7.667% cost of capital for PGE. This includes an ROE of 9.9% and long-term debt cost of 5.433%. The witnesses

address the impact of the Commission's decision regarding ROE on PGE's credit quality and the future cost of raising capital.

These witnesses also address PGE's current and proposed test-year capital structure. In this docket PGE proposes the same capital structure for ratemaking as was used in immediately previous rate cases, 50% equity and 50% debt. Finally, the witnesses address some of the specific risks PGE encounters that are relevant to PGE's cost of capital and to the appropriate ROE to be used in this docket.

Exhibit 1100. Bente Villadsen, economist and principal at The Brattle Group, addresses PGE's equity costs. Dr. Villadsen concludes that PGE's required return on equity falls in a range of 9.8% to 11.2%, with a recommendation that PGE's authorized ROE be no less than 9.9%.

Exhibit 1200. Economists Sarah Dammen and Amber Riter, present PGE's load forecast for 2016 and explain the method in forecasting 2016 load. As has been done in previous cases, PGE will update the load forecast during this case as updated economic and customer data become available.

Exhibit 1300. Robert Macfarlane, Senior Analyst and Bruce Werner, Pricing and Tariff Analyst, present PGE's marginal cost studies for distribution, customer service and generation. Those studies are then used in determining rate spread, rate design, and proposed prices in this docket, as explained in Exhibit 1400.

Exhibit 1400. Marc Cody, Senior Pricing Analyst, testifies on pricing. Mr. Cody discusses how he develops prices for the rate schedules, PGE's proposal to mitigate the price impacts to certain rate schedules, a proposed one dollar change to the residential basic charge, and the changes to various supplemental schedules. Mr. Cody also discusses PGE's proposal for pricing irrigation customers, and proposed language changes to Schedules 75 and 575.

V. COMMUNICATIONS

PGE requests that communications regarding this filing be addressed to:

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VI. REQUEST FOR APPROVALS

PGE requests that the Commission issue an order:

(1) Approving the requested rate changes;

(2) Approving the proposed tariffs; and

Approving the requested ratemaking mechanisms identified in the testimony including implementing a major maintenance accrual for the Carty plant and continuing the deferral of costs associated with PGE's Customer Engagement Transformation initiative.

Dated: this 12th day of February, 2015.

Respectfully submitted,

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Exhibit 1

Case Summary
Before Carty and Supplemental Schedules
($000)

Total Revenue Requirement	$1,837,762
Change in Revenues Requested	
Total Change in Revenues Requested	$38,752
Total Change net of RPA	$24,072
Percent Change in Base Revenues Requested	2.4%
Percent Change net of RPA	1.6%
Test Period	2016
Requested Rate of Return on Capital (Rate Base)	7.7%
Requested Rate of Return on Common Equity	9.9%
Proposed Rate Base	
Results of Operation	
A. Before Price Change	
Utility Operating Income	$283,049
Average Rate Base	$3,986,163
Rate of Return on Capital	7.1%
Rate of Return on Common Equity	8.8%
B. After Price Change	
Utility Operating Income	$305,644
Average Rate Base	$3,986,749
Rate of Return on Capital	7.7%
Rate of Return on Common Equity	9.9%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	2.6%
B. Small Non-residential Customers	3.8%
C. Large Non-residential Customers	1.8%
D. Lighting & Signal Customers	(3.5%)
Note: Percent Changes are on a cycle basis for Cost of Service Customers	

Exhibit 2

Case Summary
Including Carty and Supplemental Schedules
($000)

Total Requested Revenues (with supplementals)	$1,860,830
Change in Revenues Requested	$66,010
Percent Change in Revenues Requested	3.7%
Test Period	2016
Requested Rate of Return on Capital (Rate Base)	7.7%
Requested Rate of Return on Common Equity	9.9%
Proposed Rate Base	
Results of Operation	
A. Before Price Change	
Utility Operating Income	$271,400
Average Rate Base	$4,468,633
Rate of Return on Capital	6.1%
Rate of Return on Common Equity	6.7%
B. After Price Change	
Utility Operating Income	$342,730
Average Rate Base	$4,470,484
Rate of Return on Capital	7.7%
Rate of Return on Common Equity	9.9%
Base Rate Effect of Proposed Price Change	
A. Residential Customers	3.1%
B. Small Non-residential Customers	5.9%
C. Large Non-residential Customers	4.8%
D. Lighting & Signal Customers	(2.6%)
E. Cost of Service & Direct Access	3.7%
Note: Revenues and Percent Changes are on a cycle basis for Cost of Service Customers unless otherwise noted	

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **ADVICE NO. 15-02 PORTLAND GENERAL ELECTRIC GENERAL RATE REVISION UE 294** to be served by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 283.

DATED at Portland, Oregon, this 12th day of February 2015.

Jay Tinker

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 294

General Rate Case Filing
For Prices Effective January 1, 2016

PORTLAND GENERAL ELECTRIC COMPANY

ACRONYMS

February 12, 2015

UE 294 PGE ACRONYMS

401k – Portland General Electrtic 401(k) Plan
4-CP or 4-Coincident Peak – The monthly peak hours contained in the months of January, July, August, and December
A&G – Administrative and General
A/P – Accounts Payable
ACC – Arizona Corporation Commission
ACH – Automated Clearing House
ACI – Annual Cash Incentive
AFDC/AFUDC – Allowance for Funds Used during Construction
AGC – Automatic Generation Control
AMI – Advance Metering Infrastructure
AOP – Annual Operating Plan
ARM – Asset and Resource Manager
ASC – Accounting Standards Codification
AUT – Annual Update Tariff
B – Base
BA – Balancing Authority
BAA – Balancing Authority Area
BAL – Bank of America Leasing LLC
BCEM – Business Continuity and Emergency Management
Bcf – Billion Cubic Feet
BETC – Business Energy Tax Credits
BI – Business Intelligence Reporting Tool
BPA – Bonneville Power Administration
BVPS – Book Value per Share
CAISO – California Independent System Operator
CCCT – Combined Cycle Combustion Turbine
CE – Cost Element
CEI – Critical Energy Infrastructure
CEO – Chief Executive Officer
CET – Customer Engagement Transformation
CFA – Chartered Financial Analyst
CFO – Chief Financial Officer
CIAC – Contributions in Aid of Construction
CIP – Critical Infrastructure Protection
CIS – Customer Information System
CMC – Customer Marginal Costs
CME – Chicago Mercantile Exchange
CMS – Centers for Medicare and Medicaid Services
COS – Cost of Service
CPP – Critical Peak Pricing
CRPC – Columbia River Power Constructors
CRRA – Certified Rate of Return Analyst
CS&BD – Customer Strategies and Business Development
CSI – Centralization, Standardization and Integration

CSO – Customer Service Operations
CTG – Combustion Turbine Generator
CVR – Conversation Voltage Reduction
CWIP – Construction Work in Progress
D&O – Directors and Officers
DCF – Discounted Cash Flow
DDP – Dynamic Dispatch Program
DEQ – Department of Environmental Quality
DOE – Department of Energy
DNV-GL – Garrad Hassan America, Inc.
DP – Dynamic Programming
DPS – Dividends per Share
DR – Demand Response
DR – Data Request
DRA – Division of Ratepayer Advocates
DSG – Dispatchable Standby Generation
DSI – Dry Sorbent Injection
DTH – Decatherm
E – Post Price-Effect
EBITDA – Earnings Before Interest, Taxes, Depreciation and Amortization
EDD – Employment Development Department
EDI – Electronic Data Interchange
EE – Energy Efficiency
EFSC – Energy Facility Siting Council
EIA – Energy Information Administration
EIM – Energy Imbalance Market
ELS – Environmental Licensing Services
EOH – Equivalent Operating Hours
EPA – Environmental Protection Agency
EPRI – Electric Power Research Institute
EPS – Earnings per Share
ERISA – Employee Retirement Income Security Act
ERPs – Equity Risk Premiums
ES – Environmental Service
ES – Energy Storage
ESS – Energy Service Supplier
ETO – Energy Trust of Oregon
EV – Electric Vehicle
F&A – Finance and Accounting
FAS – Financial Accounting Standards
FASB – Financial Accounting Standards Board
Fed – Federal Reserve
FERC – Federal Energy Regulatory Commission
FICA – Federal Insurance Contributions Act
FITNES – Facility Inspections and Treatment to the National Electric Safety Code
FMBs – First Mortgage Bonds

FS – Feasibility Study
FSEC – Financial Systems Effectiveness Committee
FSRP – Financial Systems Replacement Project
FTE – Full Time Equivalent
GAAP – Generally Accepted Accounting Principles
GAC – G-Class Air Cooled
GAWE – Guaranteed Availability and Warranty Extension
GDP – Gross Domestic Product
GECC – General Electric Credit Corporation
GF – General Foreman
GIS – Geospatial Information System
GRC – General Rate Case
GTN – Gas Transmission Northwest, LLC
GWD – Graphic Work Design
HDHP – High Deductible Health Plan
HP/IP – High Pressure and Intermediate Pressure turbine
HPS – High pressure sodium
HR – Human Resources
HRA – Health Reimbursement Account
HRSG – Heat Recovery Steam Generator
I&C – Instrument and Control
IBEW – International Brotherhood of Electrical Workers
IC – Industrial Composite
ICE – IntercontinentalExchange
IE – Independent Evaluator
IPC – Idaho Power Company
IRP – Integrated Resource Plan
ISFSI – Independent Spent Fuel Storage Installation
ISO – Independent System Operator
IT – Information Technology
ITC – Investment Tax Credits
IVR – Interactive Voice Response
kW - Kilowatt
kWh – Kilowatt hours
kV – Kilovolt
kvar – Kilovolt ampere reactive
LEA – Line Extension Allowance
LED – Light-emitting diode
LGIA – Large Generator Interconnection Agreement
LRRA – Lost Revenue Recovery Adjustment
LSR – Lower Snake River
LTSA – Long-term Service Agreement
MAIFI – Momentary Average Interruption Frequency Index
MAP-21 – Moving Ahead for Progress in the 21st Century Act
MBA – Masters of Business Intelligence
MDCP – Managers Deferred Compensation Plan

MDMS – Meter Data Management System
MFRs – Minimum Filing Requirements
MH – Metal Halide
MHPSA – Mitsubishi Hitachi Power Systems America
Mid-C – Mid-Columbia
MMS – Maximo, Mobile and Scheduling
MONET – Multi-area Optimization Network Energy Transaction model
MPPS – Market Price per Share
MSI – Market Strategies International
MT – Magnetic Particle Testing
MV – Mercury Vapor
MWa – Megawatt average
MWh – Megawatt hours
NAICS – North America Industry Classification System
NCP – Non-coincident peak
NDE – Non-Destructive Examination
NDT – Nuclear Decommissioning Trust
NEPA – National Environmental Policy Act
NERC – North American Electric Reliability Corporation
NGTL – NOVA Gas Transmission, Ltd (TransCanada)
NIST – National Institute of Standards and Technology
NNMREC – Northwest National Marine Renewable Energy Center
NRC – Nuclear Regulatory Commission
NRSS – Non-running Station Service
NVPC – Net Variable Power Cost
NWN – Northwest Natural
NWPP MC – Northwest Power Pool Members Market Assessment and Coordination Committee
O&M – Operations and Maintenance
OATT – Open Access Transmission Tariff
OBI – Oracle Business Intelligence
ODEQ – Oregon Department of Environmental Quality
OE – Operational Efficiency
OEA – Office of Economic Analysis
OMS – Outage Management System
OMSI – Oregon Museum of Science and Industry
OOA – Ownership and Operation Agreement
OPIS – Oil Price Information Service
OPUC – Oregon Public Utility Commission
OSHA – Occupational Safety and Health Administration
OTC – Over-the-Counter
P – Price-Effect
PAC – PacificCorp
PAS – Publicly Available Specification
PBO – Pension Benefit Obligation
PCAM – Power Cost Adjustment Mechanism
PCB – Polychlorinated

PDL – Polynomial Distributed Lag
PG&E – Pacific Gas and Electric
PGE – Portland General Electric
PIC – Performance Incentive Compensation
PNCA – Pacific Northwest Coordination Agreement
PPA – Pension Protection Act
PPA – Prepaid Pension Asset
PPA – Power Purchase Agreement
PPC – Public Purpose Charges
PRB – Pelton and Round Butte plants
PRC – Power Resources Cooperative
PRPs – Potentially Responsible Parties
PSC – Portland Service Center
PSE – Puget Sound Energy
PSES – Power Supply Engineering Services
PSU – Portland State University
PT – Liquid penetrant method
PTCs – Production Tax Credits
PTP – Point-to-Point
PTSA – Precedent Transmission Service Agreement
PUD – Public Utility District
PwC – Price Waterhouse Coopers
PW1 – Port Westward 1
PW2 – Port Westward 2
R&D – Research and Development
R&ME – Reliability and Maintenance Excellence
RAP – Remedial Action Report
RC – Responsibility Center
RCA – Root Cause Analysis
RCM – Reliability Centered Maintenance
RE – Regional Entity
RES – Renewable Energy Standard
RFP – Request for Proposals
RI – Remedial Investigation
RLCOE – Real Levelized Cost of Energy
ROE – Return on Equity
ROM – Resource Optimization Model
RROE – Required Return on Equity
RP – Risk Premium
RP – Renewable Power
RPS – Renewable Portfolio Standard
RRMP – Recreation Resources Management Plan
RSP – Retirement Savings Plan
RTDT – Real Time Dispatch Tool
RTO – Regional Transmission Organization
S&P – Standard & Poor's

SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index
SB – Senate Bill
SCADA – Supervisory Control and Data Acquisition
SCCT – Simple Cycle Combustion Turbine
SCD – Scheduling Control and Dispatch
SCED – Security Constrained Economic Dispatch
SEC – Securities Exchange Commission
SEDC – Safe and Efficient Design Construction
SEI – Siemens Energy
SEM – Scanning Electron Microscope
SERP – Supplemental Executive Retirement Plan
SFAS – Statement of Financial Accounting Standards
SG – Smart Grid
SHARP – Safety and Health Achievement Recognition Program
SIP – Strategic Investment Program
SITF – Supervisor in the Field
SMA – Service and Maintenance Agreement
SME – Soy Methyl Ester
SNA – Sales Normalization Adjustment
SQM – Service Quality Measure
SR – System Reliability
SSPC – Salem Smart Power Center
STD – Short-term Disability
SY – System Resiliency
T&D – Transmission and Distribution
TCC – Tualatin Contact Center
TID – Turlock Irrigation District
TIV – Total Insured Value
TOU – Time-of-Use
TQS – TQS Research, Inc.
TSRs – Transmission Service Requests
UAM – Utility Asset Management
UG – Underground
USWC – US West Communications
UT – Ultrasonic testing
VER – Variable Energy Resource
VERBS – Variable Energy Resource Balancing Service
VIE – Variable Interest Entities
VoIP – Voice over Internet Protocol
VPP – Voluntary Protection Program
W&S – Wages and Salaries
WECC – Western Energy Coordinating Council
WIES – Western Interconnected Electric Systems
WMS – Work Management System
WNA – Wärtsilä North America

WSATA – Western States Association of Tax Administrators
WSPWE – Warm Spring Power and Water Enterprises
WTG – Wind Turbine Generators

Portland General Electric Company
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PortlandGeneral.com

February 12, 2015

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
P.O. Box 1088
Salem, OR 97308-1088

RE: **Advice No. 15-02, Portland General Electric General Rate Revision UE 294**

PGE hereby submits for filing revised tariff sheets implementing a general rate revision. A list of the revised Tariff sheets is attached.

Enclosed are 30 copies of Direct Testimony, Exhibits and an Executive Summary, that conform to the requirements in OAR 860-022-0019 for a general rate revision. Three copies of the non-confidential portion of work papers are provided on the enclosed CDs showing the source and calculation of rates. Confidential work papers accompany our filing pursuant to Protective Order 15-036. By April 1st, we will file the remaining power cost updates.

The tariff changes are filed with an effective date of March 16, 2015, subject to suspension for investigation. We request that a prehearing conference be held expeditiously to establish a schedule that will allow a Commission Order by mid-December and revised prices effective January 1, 2016.

<u>All Data Request Responses</u>

Pursuant to the Oregon Public Utility Commission's recent decision to use Huddle as a shared workspace for posting data responses, PGE will not be hosting a Huddle site. Instead PGE will post to the OPUC site: https://oregonPUC.huddle.com. Contemporaneous with this filing, PGE will upload the Standard Data Responses that have been completed. *As Intervenors are approved the OPUC will send an invitation to access the posted responses.*

Please direct your communications related to this filing to the following email address: pge.opuc.filings@pgn.com

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Sincerely,

Jay Tinker

Jay Tinker
Director, Regulatory Policy & Affairs

Enclosures
cc: Service List – UE 283 (Electronic only)

Advice No. 15-02
Portland General Electric General Rate Revision
Revised Tariff Sheets filed February 12, 2015

Eighth Revision of Sheet No. 7-1
Sixth Revision of Sheet No. 15-1
Seventh Revision of Sheet No. 15-2
Seventh Revision of Sheet No. 15-3
Seventh Revision of Sheet No. 15-4
Fifth Revision of Sheet No. 15-5
Third Revision of Sheet No. 15-6
Seventh Revision of Sheet No. 32-1
Seventh Revision of Sheet No. 32-4
Seventh Revision of Sheet No. 38-1
Ninth Revision of Sheet No. 38-3
Seventh Revision of Sheet No. 47-1
Eighth Revision of Sheet No. 49-1
Tenth Revision of Sheet No. 75-1
Sixth Revision of Sheet No. 75-5
First Revision of Sheet No. 75-8
Tenth Revision of Sheet No. 76R-1
Sixth Revision of Sheet No. 76R-3
Sixth Revision of Sheet No. 76R-4
Sixth Revision of Sheet No. 76R-5
Seventh Revision of Sheet No. 81-1
Ninth Revision of Sheet No. 83-1
Tenth Revision of Sheet No. 83-2
Sixth Revision of Sheet No. 85-1
Sixth Revision of Sheet No. 85-2
Tenth Revision of Sheet No. 89-1
Tenth Revision of Sheet No. 89-2
Second Revision of Sheet No. 90-1
Second Revision of Sheet No. 90-2
Tenth Revision of Sheet No. 91-7
Eighth Revision of Sheet No. 91-9
Seventh Revision of Sheet No. 91-10
Seventh Revision of Sheet No. 91-11
Sixth Revision of Sheet No. 91-12
Sixth Revision of Sheet No. 91-13
Sixth Revision of Sheet No. 91-14
Sixth Revision of Sheet No. 91-15
Ninth Revision of Sheet No. 92-1
Fourth Revision of Sheet No. 95-3
Seventh Revision of Sheet No. 95-5
Seventh Revision of Sheet No. 123-1
Sixth Revision of Sheet No. 123-2
Eleventh Revision of Sheet No. 125-2
Eighth Revision of Sheet No. 126-1
Sixth Revision of Sheet No. 126-3
Seventeenth Revision of Sheet No. 128-1
Sixteenth Revision of Sheet No. 128-2
Twentieth Revision of Sheet No. 129-3
Seventh Revision of Sheet No. 485-3
Fourth Revision of Sheet No. 485-4
Eleventh Revision of Sheet No. 489-3
Sixth Revision of Sheet No. 489-4
Second Revision of Sheet No. 490-2
Second Revision of Sheet No. 490-3
Second Revision of Sheet No. 491-6
Second Revision of Sheet No. 491-7
Third Revision of Sheet No. 491-8
Second Revision of Sheet No. 491-9
Second Revision of Sheet No. 491-10
Second Revision of Sheet No. 491-11
Second Revision of Sheet No. 491-12
Second Revision of Sheet No. 491-13
Second Revision of Sheet No. 491-14
Second Revision of Sheet No. 492-1
Second Revision of Sheet No. 492-2
Second Revision of Sheet No. 495-3
Second Revision of Sheet No. 495-4
Third Revision of Sheet No. 495-5
Third Revision of Sheet No. 495-8
Seventh Revision of Sheet No. 515-1
Seventh Revision of Sheet No. 515-2
Sixth Revision of Sheet No. 515-3
Fifth Revision of Sheet No. 515-4
Second Revision of Sheet No. 515-5
Sixth Revision of Sheet No. 532-1
Seventh Revision of Sheet No. 538-1
Seventh Revision of Sheet No. 549-1
Tenth Revision of Sheet No. 575-1
First Revision of Sheet No. 575-6
Tenth Revision of Sheet No. 576R-1
Eighth Revision of Sheet No. 583-1
Fifth Revision of Sheet No. 585-1
Tenth Revision of Sheet No. 589-1
Second Revision of Sheet No. 590-1
Twelfth Revision of Sheet No. 591-6
Thirteenth Revision of Sheet No. 591-7
Eighth Revision of Sheet No. 591-8
Seventh Revision of Sheet No. 591-9
Seventh Revision of Sheet No. 591-10
Fifth Revision of Sheet No. 591-11
Fifth Revision of Sheet No. 591-12
Sixth Revision of Sheet No. 591-13
Seventh Revision of Sheet No. 592-1
Fifth Revision of Sheet No. 595-3
Fourth Revision of Sheet No. 595-6
Second Revision of Sheet No. 750-1
Second Revision of Sheet No. 750-2
Second Revision of Sheet No. 750-3

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	$11.00		(I) (C)
Transmission and Related Services Charge	0.243	¢ per kWh	(R)
Distribution Charge	4.100	¢ per kWh	(I)
Energy Charge Options			
Standard Service			
First 1,000 kWh	6.524	¢ per kWh	
Over 1,000 kWh	7.246	¢ per kWh	
or			
Time-of-Use (TOU) Portfolio (Whole Premises or Electric Vehicle (EV) TOU) (Enrollment is necessary)			
On-Peak Period	12.626	¢ per kWh	
Mid-Peak Period	7.246	¢ per kWh	
Off-Peak Period	4.210	¢ per kWh	(I)
First 1,000 kWh block adjustment**	(0.722)	¢ per kWh	

* See Schedule 100 for applicable adjustments.
** Not applicable to separately metered Electric Vehicle (EV) TOU option.

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	0.122	¢ per kWh	(R)
Distribution Charge	5.252	¢ per kWh	(I)
Cost of Service Energy Charge	5.366	¢ per kWh	(I)

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	66	$ 12.67 [(2)]	(R)
	400	21,000	147	21.80 [(2)]	(I)
	1,000	55,000	374	46.58 [(2)]	(I)
HPS	70	6,300	30	8.87 [(2)]	(R)
	100	9,500	43	10.24	(R)
	150	16,000	62	12.38	(I)
	200	22,000	79	14.47	
	250	29,000	102	16.89	
	310	37,000	124	19.66 [(2)]	
	400	50,000	163	23.60	(I)
Flood, HPS	100	9,500	43	10.11 [(2)]	(R)
	200	22,000	79	14.88 [(2)]	
	250	29,000	102	17.31	(R)
	400	50,000	163	23.87	(I)
Shoebox, HPS (bronze color, flat lens or drop lens, multi-volt)	70	6,300	30	10.30	(R)
	100	9,500	43	11.40	
	150	16,500	62	13.64	
Special Acorn Type, HPS	100	9,500	43	13.81	
HADCO Victorian, HPS	150	16,500	62	15.89	
	200	22,000	79	18.47	
	250	29,000	102	20.94	
Early American Post-Top, HPS Black	100	9,500	43	10.66	(R)

(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					
Cobrahead, Metal Halide	150	10,000	60	$ 12.66	(R)
	175	12,000	71	13.89	
Flood, Metal Halide	350	30,000	139	21.54	(R)
	400	40,000	156	23.29	(I)
Flood, HPS	750	105,000	285	40.34	(I)
HADCO Independence, HPS	100	9,500	43	14.62	(R)
	150	16,000	62	15.66	
HADCO Capitol Acorn, HPS	100	9,500	43	17.12	
	150	16,000	62	18.46	
	200	22,000	79	21.81	
	250	29,000	102	22.75	(R)
HADCO Techtra, HPS	100	9,500	43	23.37	(I)
	150	16,000	62	24.80	
	250	29,000	102	29.02	(I)
HADCO Westbrooke, HPS	70	6,300	30	15.25	(R)
	100	9,500	43	16.07	
	150	16,000	62	18.12	
	200	22,000	79	20.13	
	250	29,000	102	22.79	
KIM Archetype, HPS	250	29,000	102	24.15	(R)
	400	50,000	163	28.20	(I)
Holophane Mongoose, HPS	150	16,000	62	16.23	(R)
	250	29,000	102	19.91	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)
Rates for LED Area Lighting

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate Per Luminaire[(1)]	
Acorn					
LED	60	5,488	21	$ 14.27	(R)
	70	4,332	24	16.40	
Cobrahead Equivalent					
LED	37	2,530	13	4.68	
	50	3,162	17	5.11	
	52	3,757	18	5.55	
	67	5,050	23	6.32	
	106	7,444	36	8.42	
Westbrooke LED (Non-Flare)	53	5,079	18	18.16	
	69	6,661	24	18.22	
	85	8,153	29	18.96	
	136	12,687	46	23.87	
	206	18,159	70	26.37	
Westbrooke LED (Flare)	53	5,079	18	20.31	
	69	6,661	24	20.96	
	85	8,153	29	20.42	
	136	12,687	46	24.96	
	206	18,159	70	27.54	
CREE XSP LED	25	2,529	9	3.50	
	42	3,819	14	4.12	
	48	4,373	16	4.78	
	56	5,863	19	5.57	
	91	8,747	31	6.86	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole	Pole Length (feet)	Monthly Rate Per Pole	
Rates for Area Light Poles(1)			
Wood, Standard	35 or less	$ 5.59	(R)
	40 to 55	7.31	
Wood, Painted for Underground	35 or less	5.59 (2)	
Wood, Curved Laminated	30 or less	6.93 (2)	
Aluminum, Regular	16	6.67	
	25	11.07	
	30	11.96	
	35	14.30	
Aluminum, Fluted Ornamental	14	9.76	
Aluminum Davit	25	10.23	
	30	10.99	
	35	12.02	
	40	16.30	
Aluminum Double Davit	30	16.22	
Aluminum, HADCO, Fluted Ornamental	16	9.98	
Aluminum, HADCO, Non-fluted Techtra Ornamental	18	19.21	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	
Aluminum, HADCO, Non-Fluted Westbrooke	18	20.41	
Concrete Ameron Post-Top	25	19.16	(R)

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

SCHEDULE 15 (Continued)

MONTHLY RATE (Continued)

Type of Pole Rates for Area Light Poles[1]	Pole Length (feet)	Monthly Rate Per Pole	
Fiberglass Fluted Ornamental; Black	14	$ 11.81	(R)
Fiberglass, Regular			
Black	20	4.91	
Gray or Bronze	30	8.35	
Other Colors (as available)	35	7.19	
Fiberglass, Anchor Base Gray	35	13.11	
Fiberglass, Direct Bury with Shroud	18	7.92	(R)

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.

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

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	$16.00		(I)
Three Phase Service	$22.00		(I)
Transmission and Related Services Charge	0.210	¢ per kWh	(R)
Distribution Charge			
First 5,000 kWh	4.049	¢ per kWh	(I)
Over 5,000 kWh	0.999	¢ per kWh	(R)
Energy Charge Options			
Standard Service	6.230	¢ per kWh	(I)
or			
Time-of-Use (TOU) Portfolio (enrollment is necessary)			
On-Peak Period	10.962	¢ per kWh	(I)
Mid-Peak Period	6.230	¢ per kWh	(I)
Off-Peak Period	3.656	¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

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 charge of this schedule until the term requirement of Schedule 532 is met.

The Daily Price will consist of:

- the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index)
- plus 0.305 ¢ per kWh for wheeling (I)
- times a loss adjustment factor of 1.0685

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.

PLUG-IN ELECTRIC VEHICLE (EV) TOU OPTION

A small Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service (Standard service or TOU service) or as a separately metered service billed under the TOU option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule. Renewable Portfolio Options are also available under this EV option.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

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

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, 2015.

MONTHLY RATE

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

Basic Charge	$25.00		(C)
Transmission and Related Services Charge	0.210	¢ per kWh	(I)
Distribution Charge	7.526	¢ per kWh	
Energy Charge*			
On-Peak Period	7.183	¢ per kWh	
Off-Peak Period	6.183	¢ per kWh	(I)

* 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 (Continued)

DIRECT ACCESS DEFAULT SERVICE

A Customer returning to Schedule 38 service before completing the term of service specified in Schedule 538, must be billed at the Daily Price for the remainder of the term. This provision does not eliminate the requirement to receive service on Schedule 81 when notice is insufficient. The Daily Price under this schedule is as follows:

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ 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 or for eligible Customers, the close of a Balance-of-Year Election Window. (I)

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

Secondary Delivery Voltage	1.0685

PLUG-IN ELECTRIC VEHICLE (EV) TIME OF DAY OPTION

A large Nonresidential Customer wishing to charge EV's may do so either as part of an integrated service or as a separately metered service billed under the TOU Option. In such cases, the applicable Basic, Transmission and Related Services, and Distribution charges will apply to the separately metered service as will all other adjustments applied to this schedule.

If the Customer chooses separately metered service for EV charging, the service shall be used for the sole and exclusive purpose of all EV charging. The Customer, at its expense, will install all necessary and required equipment to accommodate the second metered service at the premises. Such service must be metered with a network meter as defined in Rule B (30) for the purpose of load research, and to collect and analyze data to characterize electric vehicle use in diverse geographic dynamics and evaluate the effectiveness of the charging station infrastructure.

ADJUSTMENTS

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

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. 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			
Summer Months**	$44.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.210	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	7.976	¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.976	¢ per kWh	(I)
Energy Charge	6.230	¢ per kWh	(R)

* 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 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. A Large Nonresidential Customer is defined as having a monthly Demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service having exceeding 30 kW once.

MONTHLY RATE

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

Basic Charge			
Summer Months**	$50.00		(I)
Winter Months**	No Charge		
Transmission and Related Services Charge	0.210	¢ per kWh	(R)
Distribution Charge			
First 50 kWh per kW of Demand***	7.132	¢ per kWh	(I)
Over 50 kWh per kW of Demand	6.132	¢ per kWh	(I)
Energy Charge	6.731	¢ per kWh	(R)

* 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 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

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

MONTHLY RATE

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

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Basic Charge	$2,670.00	$1,620.00	$3,090.00	(R)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.79	$0.77	$0.76	(R)
Distribution Charges				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand	$2.38	$2.32	$1.21	(I)
Generation Contingency Reserves Charges				
Spinning Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
Supplemental Reserves				
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234	
System Usage Charge				
per kWh	0.083 ¢	0.080 ¢	0.077 ¢	(I)
Energy Charge				
per kWh	See Energy Charge Below			

* See Schedule 100 for applicable adjustments.

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 Powerdex Mid-Columbia Hourly Firm Electricity Price Index (Powerdex-Mid-C Hourly Firm Index) plus 0.305¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, **(I)**
plus losses.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

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

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

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

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

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

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

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

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

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

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:*

	Delivery Voltage			
	Secondary	Primary	Subtransmission	
Transmission and Related Services Charge per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.031	$0.030	$0.030	
Daily ERP Demand Charge per kW of Daily ERP Demand during On-Peak hours per day**	$0.093	$0.090	$0.047	(I)
Transaction Fee per Energy Needs Forecast (ENF)	$50.00	$50.00	$50.00	
Energy Charge* per kWh of ERP	See below for ERP Pricing			

* See Schedule 100 for applicable adjustments.

** Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ 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. (I)

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place. (I)

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.305¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. (I)

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing (Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

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

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

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.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 0.305¢ per kWh for wheeling, plus losses. **(I)**
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index plus 0.305¢ per kWh for wheeling, plus losses. **(I)**

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Powerdex Mid-Columbia Hourly Price Index (Powerdex-Mid-C Hourly Index), plus 10%, plus 0.305¢ per kWh for wheeling, plus losses. (I)

For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the Powerdex-Mid-C Hourly Index, less 10%, plus 0.305¢ per kWh for wheeling, (I) plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

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 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 N Curtailment Plan and Rule C (Section 2).

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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Firm Electricity Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh (I) 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	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

REACTIVE DEMAND CHARGE

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

SCHEDULE 83
LARGE NONRESIDENTIAL
STANDARD SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. Service under this Schedule is available for Secondary Delivery Voltage only.

MONTHLY RATE

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

Basic Charge		
Single Phase Service	$30.00	
Three Phase Service	$40.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.79	(R)
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.85	(I)
Over 30 kW	$2.75	
per kW of monthly On-Peak Demand	$2.38	(I)
Energy Charge (per kWh)		(T)
On-Peak Period***	6.666 ¢	(R)
Off-Peak Period***	5.166 ¢	(R)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.874 ¢	(I)

* 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 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. 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 OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus (I) 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 receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

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

Secondary Delivery Voltage	1.0685

Non-Cost of Service Option is 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.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 83 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 85
LARGE NONRESIDENTIAL STANDARD SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Secondary Delivery Voltage Large Nonresidential Customer whose Demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW. To each Primary Delivery Voltage Large Nonresidential Customer whose Demand has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 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	$430.00	$460.00	(I)
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.79	$0.77	(R)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.01	$2.94	(I)
Over 200 kW	$2.11	$2.04	|
per kW of monthly On-Peak Demand	$2.38	$2.32	(I)
Energy Charge (per kWh)			(T)
On-Peak Period***	6.497 ¢	6.387 ¢	(R)
Off-Peak Period***	4.997 ¢	4.887 ¢	(R)
See below for Daily Pricing Option description.			
System Usage Charge			
per kWh	0.120 ¢	0.116 ¢	(I)

* 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 85 (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, that Customer may not receive service under the Cost of Service Option until the next service year and with timely notice.

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 85 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

NON COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ 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 receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. (I)

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

Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

Non-Cost of Service Option is 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 89
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 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	$2,670.00	$1,620.00	$3,090.00	(R)
Transmission and Related Services Charge				
per kW of monthly On-Peak Demand	$0.79	$0.77	$0.76	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand	$2.38	$2.32	$1.21	(I)
Energy Charge (per kWh)				(T)
On-Peak Period***	6.409 ¢	6.304 ¢	6.225 ¢	(I)
Off-Peak Period***	4.909 ¢	4.804 ¢	4.725 ¢	(I)
See below for Daily Pricing Option description.				
System Usage Charge				
per kWh	0.083 ¢	0.080 ¢	0.077 ¢	(I)

* 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 OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ 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 receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window. **(I)**

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

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 89 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 90
LARGE NONRESIDENTIAL
STANDARD SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account.

MONTHLY RATE

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

Basic Charge	$25,000.00	
Transmission and Related Services Charge		
per kW of monthly On-Peak Demand	$0.77	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.97	(R)
Over 4,000 kW	$0.97	(R)
per kW of monthly On-Peak Demand	$2.32	(I)
Energy Charge (per kWh)		(T)
On-Peak Period***	6.027 ¢	(I)
Off-Peak Period***	4.527 ¢	(I)
See below for Daily Pricing Option description.		
System Usage Charge		
per kWh	0.067 ¢	

* 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 90 (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 OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ per kWh for wheeling, plus **(I)** 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 receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

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

Subtransmission Delivery Voltage	1.0356
Primary Delivery Voltage	1.0496
Secondary Delivery Voltage	1.0685

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 90 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate Schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

SCHEDULE 91 (Continued)

MONTHLY RATE

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

Transmission and Related Services Charge	0.122 ¢ per kWh	(R)
Distribution Charge	5.252 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.366 ¢ per kWh	(I)

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ 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. (I)

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, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily price 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 applicable daily Energy price by 1.0685.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

Enrollment for Service

To begin service under the Daily Price 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.

SCHEDULE 91 (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	
Cobrahead Power Doors **	70	6,300	30	*	$ 1.33	(I)
	100	9,500	43	*	1.32	(R)
	150	16,000	62	*	1.33	
	200	22,000	79	*	1.37	
	250	29,000	102	*	1.35	
	400	50,000	163	*	1.39	(R)
Cobrahead	70	6,300	30	$ 4.70	1.57	(R)(I)
	100	9,500	43	4.68	1.55	
	150	16,000	62	4.78	1.57	(I)
	200	22,000	79	5.41	1.62	(R)
	250	29,000	102	5.35	1.61	
	400	50,000	163	5.51	1.62	
Flood	250	29,000	102	5.78	1.66	
	400	50,000	163	5.78	1.66	
Early American Post-Top	100	9,500	43	5.10	1.61	(R)
Shoebox (bronze color, flat lens, or drop lens, multi-volt)	70	6,300	30	6.14	1.76	(I)
	100	9,500	43	5.84	1.71	(R)
	150	16,000	62	6.04	1.74	(R)(R)

* Not offered.
** Service is only available to Customers with total power door 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	$ 4.91	$ 0.15	(R)(I)
Fiberglass, Bronze	30	7.74	0.23	
Fiberglass, Gray	30	8.35	0.25	
Wood, Standard	30 to 35	5.59	0.17	
Wood, Standard	40 to 55	7.31	0.22	(R)(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	
Special Acorn-Types						
HPS	100	9,500	43	$ 8.61	$ 2.05	(R)(R)
HADCO Victorian, HPS	150	16,000	62	8.65	2.06	
	200	22,000	79	9.41	2.17	
	250	29,000	102	9.41	2.17	
HADCO Capitol Acorn, HPS	100	9,500	43	11.92	2.49	
	150	16,000	62	11.22	2.41	(R)
	200	22,000	79	12.75	2.62	(I)
	250	29,000	102	11.22	2.41	(R)
Special Architectural Types						
HADCO Independence, HPS	100	9,500	43	9.42	2.14	(I)
	150	16,000	62	8.42	2.01	(R)(R)
HADCO Techtra, HPS	100	9,500	43	18.17	3.32	(I) (I)
	150	16,000	62	17.56	3.24	(R)
	250	29,000	102	17.49	3.24	(I)
HADCO Westbrooke, HPS	70	6,300	30	11.45	2.43	(R) (I)
	100	9,500	43	10.87	2.34	(R)
	150	16,000	62	10.88	2.35	
	200	22,000	79	11.07	2.38	
	250	29,000	102	11.26	2.41	(R)(R)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Special Types						
Cobrahead, Metal Halide	150	10,000	60	$ 5.28	$ 1.87	(R)(R)
Flood, Metal Halide	350	30,000	139	6.03	1.94	(R)
Flood, HPS	750	105,000	285	9.14	2.88	(I)
Holophane Mongoose, HPS	150	16,000	62	8.98	2.10	(R)
	250	29,000	102	8.38	2.01	(R)(R)
Option C Only **						
Ornamental Acorn Twin	85	9,600	64	*	*	
Ornamental Acorn	55	2,800	21	*	*	
Ornamental Acorn Twin	55	5,600	42	*	*	
Composite, Twin	140	6,815	54	*	*	
	175	9,815	66	*	*	

* Not offered.
** Rates are based on current kWh energy charges.

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 6.67	$ 0.20	(R)(I)
	25	11.07	0.33	
	30	11.96	0.36	
	35	14.30	0.43	
Aluminum Davit	25	11.05	0.33	
	30	10.99	0.33	
	35	12.02	0.36	
	40	16.30	0.49	
Aluminum Double Davit	30	16.22	0.48	(R)(I)

SCHEDULE 91 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Fluted Victorian Ornamental	14	$ 9.76	$ 0.29	(R)(I)
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	19.21	0.57	
Aluminum, HADCO, Fluted Ornamental	16	9.98	0.30	
Aluminum, HADCO, Non-Fluted Ornamental	16	20.41	0.61	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	0.57	
Aluminum, HADCO, Non-Fluted Westbrooke	18	20.41	0.61	
Aluminum, Painted Ornamental	35	32.80	0.98	
Concrete. Decorative Ameron	20	19.16	0.57	
Concrete, Ameron Post-Top	25	19.16	0.57	
Fiberglass, HADCO, Fluted Ornamental Black	14	11.81	0.35	
Fiberglass, Smooth	18	4.90	0.15	
Fiberglass, Regular				
color may vary	22	4.38	0.13	
	35	7.19	0.21	
Fiberglass, Anchor Base, Gray	35	13.11	0.39	
Fiberglass, Direct Bury with Shroud	18	7.92	0.24	(R)(I)

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	Monthly Rates Option B	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	
	175	7,000	66	$ 4.64	$ 1.51	(R)(I)
	250	10,000	94	*	*	
	400	21,000	147	5.43	1.64	(I)
	1,000	55,000	374	5.83	1.94	
Special Box Similar to GE "Space-Glo"						
HPS	70	6,300	30	5.78	1.65	
Mercury Vapor	175	7,000	66	5.74	1.61	(R)(I)

* 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 - Twin	70	6,300	60	*	*	
HPS	70	6,300	30	*	*	
	100	9,500	43	*	$ 1.99	
	150	16,000	62	*	2.01	
	250	29,000	102	*	*	
	400	50,000	163	*	*	
Metal Halide	250	20,500	99	*	1.26	
	400	40,000	156	*	1.26	(I)
Cobrahead, Metal Halide	175	12,000	71	$ 5.32	1.72	(R)
Flood, Metal Halide	400	40,000	156	5.96	1.88	(R)
Cobrahead, Dual Wattage, HPS						
70/100 Watt Ballast	100	9,500	43	*	1.57	
100/150 Watt Ballast	100	9,500	43	*	1.57	
100/150 Watt Ballast	150	16,000	62	*	1.59	(I)
Special Architectural Types Including Philips QL Induction Lamp Systems						
HADCO Victorian, QL	85	6,000	32	*	0.73	(R)
	165	12,000	60	*	0.88	
HADCO Techtra, QL	165	12,000	60	18.94	1.16	(R)
Special Architectural Types						
KIM SBC Shoebox, HPS	150	16,000	62	*	2.53	
KIM Archetype, HPS	250	29,000	102	*	2.58	(R)
	400	50,000	163	*	2.24	(I)
Special Acorn-Type, HPS	70	6,300	30	8.63	2.07	(R)
Special GardCo Bronze Alloy						
HPS	70	5,000	30	*	*	
Mercury Vapor	175	7,000	66	*	*	
Special Acrylic Sphere						
Mercury Vapor	400	21,000	147	*	*	

* Not offered.

SCHEDULE 91 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	
Early American Post-Top, HPS						
Black	70	6,300	30	$ 5.03	$ 1.54	(R)(I)
Rectangle Type	200	22,000	79	*	*	
Incandescent	92	1,000	31	*	*	
	182	2,500	62	*	*	
Town and Country Post-Top						
Mercury Vapor	175	7,000	66	5.04	1.55	(R)(I)
Flood, HPS	70	6,300	30	4.58	1.45	
	100	9,500	43	4.54	1.56	
	200	22,000	79	5.82	1.70	(I)
Cobrahead, HPS						
Power Door	310	37,000	124	5.75	2.01	(R)(R)
Special Types Customer-Owned & Maintained						
Ornamental, HPS	100	9,500	43	*	*	
Twin Ornamental, HPS	Twin 100	9,500	86	*	*	
Compact Fluorescent	28	N/A	12	*	*	

* Not offered.

SCHEDULE 91 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.67	*	(R)
Bronze Alloy GardCo	12	*	$ 0.18	(I)
Concrete, Ornamental	35 or less	11.07	0.33	(R)
Steel, Painted Regular **	25	11.07	0.33	
Steel, Painted Regular **	30	11.96	0.36	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.33	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.33	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.36	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.36	
Wood, Laminated without Mast Arm	20	4.91	0.15	(R)(I)
Wood, Laminated Street Light Only	20	4.91	*	
Wood, Curved Laminated	30	7.74	0.23	(I)
Wood, Painted Underground	35	5.59	0.17	(I)
Wood, Painted Street Light Only	35	5.59	*	(R)

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

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.
- 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 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	0.161	¢ per kWh	(R)
Distribution Charge	2.342	¢ per kWh	(I)
Energy Charge	5.484	¢ per kWh	(R)

* See Schedule 100 for applicable adjustments.

ELECTION WINDOW

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

SCHEDULE 95 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

See Schedule 91 for Streetlight poles service options.

MONTHLY RATE

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

Transmission and Related Services Charge	0.122 ¢ per kWh	(R)
Distribution Charge	5.252 ¢ per kWh	(I)
Energy Charge		
Cost of Service Option	5.366 ¢ per kWh	(I)

NON-COST OF SERVICE OPTION

Daily Price Option – Available only to Customers with an average load of five MW or greater on Schedules 91 and 95 and those customers that met the five MW or greater threshold prior to converting to lights from Schedule 91 to Schedule 95. This selection of this option applies to all luminaires served under Schedules 91 and 95. This option gives eligible Customers an option between a daily Energy price and a Cost of Service option for the Energy charge. 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 Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.305¢ 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. (I)

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, using Sunrise Sunset Tables with adjustments for typical photocell operation and 4,100 annual burning hours.

For Customers billed on the Daily Price 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 applicable daily Energy price by 1.0685.

The Daily Price Option is subject to Schedule 128, Short Term Transition Adjustment.

SCHEDULE 95 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rate	Straight Time	Overtime [1]
	$133.00 per hour	$188.00 per hour

[1] Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Cobrahead Equivalent	37	2,530	13	$ 2.95	(R)
Cobrahead Equivalent	50	3,162	17	2.95	
Cobrahead Equivalent	52	3,757	18	3.28	
Cobrahead Equivalent	67	5,050	23	3.66	
Cobrahead Equivalent	106	7,444	36	4.36	(R)

RATES FOR DECORATIVE LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 11.43	(R)
	70	4,332	24	13.24	
Westbrooke (Non-Flared)	53	5,079	18	15.65	
LED	69	6,661	24	15.06	
	85	8,153	29	15.27	
	136	12,687	46	18.34	
	206	18,159	70	18.27	
Westbrooke (Flared)	53	5,079	18	17.79	
LED	69	6,661	24	17.79	
	85	8,153	29	16.73	
	136	12,687	46	19.43	
	206	18,159	70	19.43	(R)

SCHEDULE 123
DECOUPLING ADJUSTMENT

PURPOSE

This Schedule establishes balancing accounts and rate adjustment mechanisms to track and mitigate a portion of the transmission, distribution and fixed generation revenue variations caused by variations in applicable Customer Energy usage.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory except those Nonresidential Customers whose load exceeded one aMW at a Point of Delivery during the prior calendar year or those Nonresidential Customers qualifying as a Self-Directing Customer. Customers so exempted will not be charged the prices contained in this schedule.

DEFINITIONS

For the purposes of this tariff, the following definition will apply:

Energy Efficiency Measures (EEMs) – Actions that enable customers to reduce energy use. EEMs can be behavioral or equipment-related.

Self-Directing Customer (SDC) - Pursuant to OAR 860-038-0480, to qualify to be a SDC, the Large Nonresidential Customer must have a load that exceeds one aMW at a Site as defined in Rule B and receive certification from the Oregon Department of Energy as an SDC.

SALES NORMALIZATION ADJUSTMENT (SNA)

The SNA reconciles on a monthly basis, for Customers served under Schedules 7, 32 and 532, differences between a) the monthly revenues resulting from applying distribution, transmission and fixed generation charges (Fixed Charge Energy Rate) of 7.368 cents/kWh for Schedule 7 (I)
and 6.727 cents/kWh for Schedules 32 and 532 to weather-normalized kWh Energy sales, and (I)
b) the Fixed Charge Revenues that would be collected by applying the Monthly Fixed Charge per Customer of $62.52 per month for Schedule 7 and $99.23 per month for Schedules 32 and (I)
532 to the numbers of active Schedule 7 and Schedule 32 and 532 Customers, respectively, for each month. For Schedule 7, a Secondary Fixed Charge equal to 70% of the Monthly Fixed (C)
Charge will be used to calculate Fixed Charge Revenues for actual customer counts that exceed the projected customer counts used to establish base rates in a general rate review. The Schedule 7 Secondary Fixed Charge is $43.76. (R)

SCHEDULE 123 (Continued)

SALES NORMALIZATION ADJUSTMENT (SNA) (Continued)

The SNA will calculate monthly as the Fixed Charge Revenue less actual weather-adjusted revenues and will accrue to the SNA Balancing Account. The monthly amount accrued may be positive (an under-collection) or negative (an over-collection). The SNA is divided into sub-accounts so that net accruals for Schedule 7 will track separately from the net accruals for Schedules 32 and 532.

NONRESIDENTIAL LOST REVENUE RECOVERY ADJUSTMENT (LRRA)

The Nonresidential Lost Revenue Recovery Adjustment is applicable to all customers except those served under Schedules 7, 32 and 532 or as otherwise exempted above. Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM program kWh savings incorporated into the test year load forecast used to determine base rates. Also included are differences in actual energy savings from a test year forecast associated with the conversion to LED streetlighting in Schedule 95 reported by the Company. When base rates are adjusted in the future as a result of a general rate review, the test year load forecast used to determine new base rates will reflect all energy efficiency kWh savings that have been previously achieved. The cumulative kWh savings are eligible for Lost Revenue Recovery until new base rates are established as a result of a general rate review; the kWh base is then reset to equal the amount of kWh savings that accrue from EEMs following an adjustment in base rates.

The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are less than those estimated in setting base rates. A positive Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the Energy Trust of Oregon, plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, are greater than those estimated for the test year in setting base rates. The LRRA for each year subsequent to the test year will incorporate incremental kWh savings reported by the Energy Trust of Oregon for that year.

For the purposes of this Schedule, the Lost Revenue Recovery Adjustment is the product of: (1) the reduction in kWh sales resulting from ETO-reported EEMs plus the energy savings associated with the conversion to LED streetlighting in Schedule 95, and (2) the weighted average of applicable retail base rates (the Lost Revenue Rate). Applicable base rates for Nonresidential Customers are defined as the schedule-weighted average of transmission, distribution, and fixed generation charges; including those contained in Schedule122 and other applicable schedules. System usage or distribution charges will be adjusted to include only the recovery of Trojan Decommissioning expenses and the Customer Impact Offset. Franchise fee recovery is not included in the Lost Revenue Rate. The applicable Lost Revenue Rate is 5.125 **(I)**
cents per kWh.

SCHEDULE 125 (Continued)

CHANGES IN NET VARIABLE POWER COSTS

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

FILING AND EFFECTIVE DATE

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

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

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

RATE ADJUSTMENT

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

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those who were served on Schedule 76R and 576R, 485, 489, 490, 491, 492, 495, 515, 532, 538, 549, 583, 585, 589, 591, 592 and 595, or served under Schedules 83, 85, 89 or 90 Daily Price Option for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 585, 589, 590, 591, 592 and 595 who received the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. This account will accrue interest at the Commission-authorized rate for deferred accounts. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest calculated at the Commission-authorized rate. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0337 (I)
to account for franchise fees, uncollectibles, and OPUC fees.

EARNINGS TEST

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 Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical 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, 38, 83, 85, 89, 90, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 485, 489, 490, 491, 492, and 495 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.
- Actual NVPC will be increased to include the value of the energy associated with those Customers that received the Schedule 128 Balance of Year Transition Adjustment for the period during the year that the Customers received the Schedule 128 adjustment.
- Include reciprocating engine lubrication oil expenses.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0337 to account for franchise fees, uncollectables, and OPUC fees. (I)

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

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.

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 pricing (other than Cost of Service) on Schedules 32, 38, 75, 83, 85, 89, 90, 91 or 95 or Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595. This Schedule is not applicable to Customers served on Schedules 485, 489, 490, 491, 492 and 495.

SHORT-TERM TRANSITION ADJUSTMENT

The Short-Term 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.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE

For Customers who have made a service election other than Cost of Service in 2015, the Annual Short-Term Transition Adjustment Rate will be applied to their bills for service effective on and after January 1, 2016: **(C)** **(C)**

Schedule		Annual ¢ per kWh [1]	
32		2.647	**(I)**
38		3.079	
75	Secondary	2.260 [2]	
	Primary	2.219 [2]	
	Subtransmission	2.220 [2]	**(I)**
83		2.529	**(R)**
85	Secondary	2.390	
	Primary	2.319	**(R)**

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 128 (Continued)

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT RATE (Continued)

Schedule		Annual ¢ per kWh (1)	
89	Secondary	2.260	(I)
	Primary	2.219	|
	Subtransmission	2.220	(I)
90		1.921	(R)
91		2.011	(I)
95		2.011	|
515		2.011	|
532		2.647	|
538		3.079	(I)
549		3.185	(R)
575	Secondary	2.260 (2)	(I)
	Primary	2.219 (2)	|
	Subtransmission	2.220 (2)	(I)
583		2.529	(R)
585	Secondary	2.390	|
	Primary	2.319	(R)
589	Secondary	2.260	(I)
	Primary	2.219	|
	Subtransmission	2.220	|
590		1.921	|
591		2.011	(I)
592		1.961	(R)
595		2.011	(I)

(1) Not applicable to Customers served on Cost of Service.
(2) Applicable only to the Baseline and Scheduled Maintenance Energy.

ANNUAL SHORT-TERM TRANSITION ADJUSTMENT REVISIONS

The Annual Short-Term 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 Annual Short-Term Transition Adjustment and Cost-of-Service Energy Prices will be posted by the Company by September 1 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.

SCHEDULE 129 (Continued)

TRANSITION COST ADJUSTMENT (Continued)
Minimum Five Year Opt-Out

For Enrollment Period L (2013), the Transition Cost Adjustment will be:

Period	Sch. 485 Secondary Voltage ¢ per kWh	Sch. 485 Primary Voltage ¢ per kWh	Sch. 489 Secondary Voltage ¢ per kWh	Sch. 489 Primary Voltage ¢ per kWh	Sch. 489 Subtransmission Voltage ¢ per kWh
2014	1.992	1.956	1.398	1.728	1.709
2015	1.718	1.695	1.113	1.466	1.450
2016	1.482	1.466	0.860	1.239	1.226
2017	1.228	1.223	0.589	0.997	0.987
2018	1.154	1.147	0.483	0.921	0.914
After 2018	0.000	0.000	0.000	0.000	0.000

For Enrollment Period M (2014), the Transition Cost Adjustment will be:

Period	Sch. 485 Sec. Vol. ¢ per kWh	Sch. 485 Pri. Vol. ¢ per kWh	Sch. 489 Sec. Vol. ¢ per kWh	Sch. 489 Pri. Vol. ¢ per kWh	Sch. 489 Sub. Vol. ¢ per kWh	Sch. 490 Pri. Vol. ¢ per kWh	Schs. 491/492/495 ¢ per kWh	
2015	1.712	1.704	1.443	1.415	1.383	1.381	1.311	(I)
2016	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
2017	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
2018	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
2019	1.788	1.778	1.524	1.495	1.462	1.453	1.423	
After 2019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(I)

Three Year Opt-Out

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

For Enrollment Period C (2004), No Longer Applicable

For Enrollment Period D (2005), No Longer Applicable

For Enrollment Period E (2006), No Longer Applicable

SCHEDULE 485 (Continued)

CHANGE IN APPLICABILITY

If a Customer's usage changes such that their facility capacity falls below 201 kW, they will have their service terminated under this schedule and will be moved 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	$430.00	$460.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.01	$2.94	(I)
Over 200 kW	$2.11	$2.04	|
per kW of monthly On-Peak Demand	$2.38	$2.32	(I)
System Usage Charge			
per kWh	(0.026) ¢	(0.027) ¢	(I)

* 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.

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.

SCHEDULE 485 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this 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.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

Wheeling Charge

The Wheeling Charge will be $1.796 per kW of monthly Demand. **(I)**

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 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 monthly On-Peak Demand (in kW) will be 100 kW for primary voltage service.

SCHEDULE 489 (Continued)

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	$2,670.00	$1,620.00	$3,090.00	**(R)**
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	**(R)**
Over 4,000 kW	$0.99	$0.96	$0.96	**(R)**
per kW of monthly On-Peak Demand	$2.38	$2.32	$1.21	**(I)**
System Usage Charge				
per kWh	(0.058) ¢	(0.058) ¢	(0.059) ¢	**(R)**

* 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.

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.

SCHEDULE 489 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this 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.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

Wheeling Charge

The Wheeling Charge will be $1.796 per kW of monthly Demand. (I)

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 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

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 490 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges per Point of Delivery (POD)*:

Basic Charge	$25,000.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.97	(R)
Over 4,000 kW	$0.97	(R)
per kW of monthly On-Peak Demand	$2.32	(I)
System Usage Charge		
per kWh	(0.077) ¢	(R)

* 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.

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.

SCHEDULE 490 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this 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.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

Wheeling Charge

The Wheeling Charge will be $1.796 per kW of monthly Demand. (I)

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 200 kW and 4,000 kW for primary voltage and subtransmission voltage service respectively.

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 491 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.109 ¢ per kWh **(I)**

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.

SCHEDULE 491 (Continued)

MARKET BASED PRICING OPTION (Continued)

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

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this 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.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

Wheeling Charge

The Wheeling Charge will be $1.796 per kW of monthly Demand. **(I)**

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.

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:

Secondary Delivery Voltage	1.0685

SCHEDULE 491 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [1]
	$133.00 per hour	$188.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

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 **							
	70	6,300	30	*	$ 2.86	$ 1.53	(I)
	100	9,500	43	*	3.52	2.20	
	150	16,000	62	*	4.50	3.17	
	200	22,000	79	*	5.41	4.04	
	250	29,000	102	*	6.56	5.21	
	400	50,000	163	*	9.72	8.33	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.23	3.10	1.53	(R)
	100	9,500	43	6.88	3.75	2.20	(R)
	150	16,000	62	7.95	4.74	3.17	(I)
	200	22,000	79	9.45	5.66	4.04	
	250	29,000	102	10.56	6.82	5.21	
	400	50,000	163	13.84	9.95	8.33	
Flood	250	29,000	102	10.99	6.87	5.21	
	400	50,000	163	14.11	9.99	8.33	(I)
Early American Post-Top	100	9,500	43	7.30	3.81	2.20	(R)
Shoebox (Bronze color, flat	70	6,300	30	7.67	3.29	1.53	
Lens, or drop lens, multi-volt)	100	9,500	43	8.04	3.91	2.20	(R)
	150	16,000	62	9.21	4.91	3.17	(R)(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 491 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Fiberglass, Black	20	$ 4.91	$ 0.15	(R)(I)
Fiberglass, Bronze	30	7.74	0.23	
Fiberglass, Gray	30	8.35	0.25	
Wood, Standard	30 to 35	5.59	0.17	
Wood, Standard	40 to 55	7.31	0.22	(R)(I)

RATES FOR CUSTOM LIGHTING

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Monthly Rates Option B	Monthly Rates Option C	
Special Acorn-Types							
HPS	100	9,500	43	$ 10.81	$ 4.25	$ 2.20	(R)(I)
HADCO Victorian, HPS	150	16,000	62	11.82	5.23	3.17	
	200	22,000	79	13.45	6.21	4.04	
	250	29,000	102	14.62	7.38	5.21	
HADCO Capitol Acorn, HPS	100	9,500	43	14.12	4.69	2.20	
	150	16,000	62	14.39	5.58	3.17	
	200	22,000	79	16.79	6.66	4.04	
	250	29,000	102	16.43	7.62	5.21	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.62	4.34	2.20	
	150	16,000	62	11.59	5.18	3.17	(R)
HADCO Techtra, HPS	100	9,500	43	20.37	5.52	2.20	(I)
	150	16,000	62	20.73	6.41	3.17	
	250	29,000	102	22.70	8.45	5.21	(I)
HADCO Westbrooke, HPS	70	6,300	30	12.98	3.96	1.53	(R)
	100	9,500	43	13.07	4.54	2.20	
	150	16,000	62	14.05	5.52	3.17	
	200	22,000	79	15.11	6.42	4.04	
	250	29,000	102	16.47	7.62	5.21	(R)(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Types							
Cobrahead, Metal Halide	150	10,000	60	$ 8.35	$ 4.94	$ 3.07	(I)
Flood, Metal Halide	350	30,000	139	13.13	9.04	7.10	(R)
Flood, HPS	750	105,000	285	23.70	17.44	14.56	(I)
Holophane Mongoose, HPS	150	16,000	62	12.15	5.27	3.17	(R)
	250	29,000	102	13.59	7.22	5.21	(R)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	3.27	
Ornamental Acorn	55	2,800	21	*	*	1.07	
Ornamental Acorn Twin	55	5,600	42	*	*	2.15	
Composite, Twin	140	6,815	54	*	*	2.76	
	175	9,815	66	*	*	3.37	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 6.67	$ 0.20	(R)(I)
	25	11.07	0.33	
	30	11.96	0.36	
	35	14.30	0.43	
Aluminum Davit	25	11.05	0.33	
	30	10.99	0.33	
	35	12.02	0.36	
	40	16.30	0.49	
Aluminum Double Davit	30	16.22	0.48	
Aluminum, HADCO, Fluted Victorian Ornamental	14	9.76	0.29	(R)(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 491 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	$ 19.21	$ 0.57	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	9.98	0.30	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	20.41	0.61	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	0.57	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	20.41	0.61	
Aluminum, Painted Ornamental	35	32.80	0.98	
Concrete, Decorative Ameron	20	19.16	0.57	
Concrete, Ameron Post-Top	25	19.16	0.57	
Fiberglass, HADCO, Fluted Ornamental Black	14	11.81	0.35	
Fiberglass, Smooth	18	4.90	0.15	
Fiberglass, Regular,				
color may vary	22	4.38	0.13	
color may vary	35	7.19	0.21	
Fiberglass, Anchor Base, Gray	35	13.11	0.39	
Fiberglass, Direct Bury with Shroud	18	7.92	0.24	(R)(I)

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	Monthly Rates Option B	Monthly Rates Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.99	(I)
	175	7,000	66	$ 8.01	$ 4.88	3.37	
	250	10,000	94	*	*	4.80	
	400	21,000	147	12.94	9.15	7.51	
	1,000	55,000	374	24.94	21.05	19.11	(I)

* Not offered.

SCHEDULE 491 (Continued)

SERVICE RATE FOR OBSOLETE LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 7.31	$ 3.18	$ 1.53	(R)(I)
Mercury Vapor	175	7,000	66	9.11	4.98	3.37	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.07	
	70	6,300	30	*	*	1.53	
	100	9,500	43	*	4.19	2.20	
	150	16,000	62	*	5.18	3.17	
	250	29,000	102	*	*	5.21	
	400	50,000	163	*	*	8.33	
Metal Halide	250	20,500	99	*	6.32	5.06	
	400	40,000	156	*	9.23	7.97	
Cobrahead, Metal Halide	175	12,000	71	8.95	5.35	3.63	(R)
Flood, Metal Halide	400	40,000	156	13.93	9.85	7.97	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	150	16,000	62	*	4.76	3.17	
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.70	3.17	
KIM Archetype, HPS	250	29,000	102	*	7.79	5.21	
	400	50,000	163	*	10.57	8.33	(I)

* Not offered

SCHEDULE 491 (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	30	$ 10.16	$ 3.60	$ 1.53	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	6,300	30	*	*	1.53	
Mercury Vapor	175	7,000	66	*	*	3.37	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	7.51	
Early American Post-Top, HPS							
Black	70	6,300	30	6.56	3.07	1.53	(R)
Rectangle Type	200	22,000	79	*	*	4.04	
Incandescent	92	1,000	31	*	*	1.58	
	182	2,500	62	*	*	3.17	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.41	4.92	3.37	(R)
Flood, HPS	70	6,300	30	6.11	2.98	1.53	
	100	9,500	43	6.74	3.76	2.20	
	200	22,000	79	9.86	5.74	4.04	(R)
Cobrahead, HPS							
Power Door	310	37,000	124	12.09	8.35	6.34	(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.20	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.39	
Compact Fluorescent	28	N/A	12	*	*	0.61	(I)

* Not offered.

SCHEDULE 491 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.67	*	(R)
Bronze Alloy GardCo	12	*	$ 0.18	(I)
Concrete, Ornamental	35 or less	11.07	0.33	(R)
Steel, Painted Regular **	25	11.07	0.33	
Steel, Painted Regular **	30	11.96	0.36	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.33	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.33	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.36	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.36	
Wood, Laminated without Mast Arm	20	4.91	0.15	(R)
Wood, Laminated Street Light Only	20	4.91	*	
Wood, Curved Laminated	30	7.74	0.23	
Wood, Painted Underground	35	5.59	0.17	(I)
Wood, Painted Street Light Only	35	5.59	*	(R)

* 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	Monthly Rates Option B	Monthly Rates Option C	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.36	$ 1.63	(I)
	165	12,000	60	*	3.95	3.07	
	165	12,000	60	$ 22.01	4.23	3.07	(R)(I)

SCHEDULE 492
TRAFFIC SIGNALS
COST OF SERVICE OPT-OUT

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 500 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. Service under this schedule is limited to the first 300 MWa that applies to Schedules 485, 489, 490, 491, 492, and 495

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

MONTHLY RATE

The charge per Point of Delivery (POD)* is:

Distribution Charge	2.195 ¢ per kWh	(I)

* See Schedule 100 for applicable adjustments.

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.

SCHEDULE 492 (Continued)

MARKET BASED PRICING OPTION (Continued)

Company Supplied Energy

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this 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.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

Wheeling Charge

The Wheeling Charge will be $1.796 per kW of monthly Demand. (I)

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.

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:

Secondary Delivery Voltage	1.0685

ADJUSTMENTS

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

SCHEDULE 495 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/491/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.109 ¢ per kWh (I)

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

Upon not less than five business days notice, the Customer may choose the Company Supplied Energy Charge option. The election of this 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.

The Company Supplied Energy Option is the Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-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.

SCHEDULE 495 (Continued)

MARKET BASED PRICING OPTION (Continued)

Wheeling Charge

The Wheeling Charge will be $1.796 per kW of monthly Demand. (I)

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.

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:

Secondary Delivery Voltage	1.0685

SCHEDULE 495 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates [1]	Straight Time	Overtime
	$133.00 per hour	$188.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$ 3.61	(R)
LED	50	3,162	17	3.82	
LED	52	3,757	18	4.20	
LED	67	5,050	23	4.84	
LED	106	7,444	36	6.20	(R)

SCHEDULE 495 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 12.50	(R)
	70	4,332	24	14.47	
Westbrooke (Non-Flared)	53	5,079	18	16.57	
LED	69	6,661	24	16.29	
	85	8,153	29	16.75	
	136	12,687	46	20.69	
	206	18,159	70	21.85	
Westbrooke (Flared)	53	5,079	18	18.71	
LED	69	6,661	24	19.02	
	85	8,153	29	18.21	
	136	12,687	46	21.78	
	206	18,159	70	23.01	(R)

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.
- 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.

ADJUSTMENTS

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

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	66	$ 8.95 [2]	(R)
	400	21,000	147	13.52 [2]	(I)
	1,000	55,000	374	25.52 [2]	(I)
HPS	70	6,300	30	7.18 [2]	(R)
	100	9,500	43	7.82	(R)
	150	16,000	62	8.89	(I)
	200	22,000	79	10.03	|
	250	29,000	102	11.15	|
	310	37,000	124	12.68 [2]	|
	400	50,000	163	14.42	(I)
Flood , HPS	100	9,500	43	7.69 [2]	(R)
	200	22,000	79	10.44 [2]	|
	250	29,000	102	11.57	(R)
	400	50,000	163	14.69	(I)
Shoebox, HPS (bronze color, flat lens,	70	6,300	30	8.61	(R)
or drop lens, multi-volt)	100	9,500	43	8.98	|
	150	16,500	62	10.15	(R)

(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	
Special Acorn Type, HPS	100	9,500	43	$ 11.39	(R)
HADCO Victorian, HPS	150	16,500	62	12.40	
	200	22,000	79	14.03	
	250	29,000	102	15.20	
Early American Post-Top, HPS, Black	100	9,500	43	8.24	
Special Types					
Cobrahead, Metal Halide	150	10,000	60	9.29	
Cobrahead, Metal Halide	175	12,000	71	9.89	
Flood, Metal Halide	350	30,000	139	13.71	(R)
Flood, Metal Halide	400	40,000	156	14.51	(I)
Flood, HPS	750	105,000	285	24.29	(I)
HADCO Independence, HPS	100	9,500	43	12.20	(R)
	150	16,000	62	12.17	
HADCO Capitol Acorn, HPS	100	9,500	43	14.70	
	150	16,000	62	14.97	
	200	22,000	79	17.37	
	250	29,000	102	17.01	(R)
HADCO Techtra, HPS	100	9,500	43	20.95	(I)
	150	16,000	62	21.31	
	250	29,000	102	23.28	(I)
HADCO Westbrooke, HPS	70	6,300	30	13.56	(R)
	100	9,500	43	13.65	
	150	16,000	62	14.63	
	200	22,000	79	15.69	
	250	29,000	102	17.05	
KIM Archetype, HPS	250	29,000	102	18.41	(R)
	400	50,000	163	19.02	(I)
Holophane Mongoose, HPS	150	16,000	62	12.74	(R)
	250	29,000	102	14.17	(R)

(1) See Schedule 100 for applicable adjustments.

SCHEDULE 515 (Continued)

MONTHLY RATE (Continued)

Rates for Area Lighting (Continued)

Type of Light	Watts	Lumens	Monthly kWh	Monthly Rate[(1)] Per Luminaire	
Acorn					
LED	60	5,488	21	$ 13.08	(R)
	70	4,332	24	15.05	
Cobrahead					
LED	37	2,530	13	3.94	
	50	3,162	17	4.15	
	52	3,757	18	4.54	
	67	5,050	23	5.03	
	106	7,444	36	6.39	
Westbrooke LED (Non-Flare)	53	5,079	18	17.15	
	69	6,661	24	16.87	
	85	8,153	29	17.33	
	136	12,687	46	21.28	
	206	18,159	70	22.43	
Westbrooke LED (Flare)	53	5,079	18	19.30	
	69	6,661	24	19.61	
	85	8,153	29	18.79	
	136	12,687	46	22.37	
	206	18,159	70	23.60	
CREE XSP LED	25	2,529	9	2.99	
	42	3,819	14	3.34	
	48	4,373	16	3.88	
	56	5,863	19	4.50	
	91	8,747	31	5.11	(R)

(1) See Schedule 100 for applicable adjustments.

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	$ 5.59	(R)
	40 to 55	7.31	
Wood, Painted Underground	35 or less	5.59 [2]	
Wood, Curved laminated	30 or less	6.93 [2]	
Aluminum, Regular	16	6.67	
	25	11.07	
	30	11.96	
	35	14.30	
Aluminum, Fluted Ornamental	14	9.76	
Aluminum Davit	25	10.23	
	30	10.99	
	35	12.02	
	40	16.30	
Aluminum Double Davit	30	16.22	
Aluminum, HADCO, Fluted Ornamental	16	9.98	
Aluminum, HADCO, Non-fluted	18	19.21	(R)
Aluminum, HADCO, Fluted Westbrooke	18	19.26	(N)
Aluminum, HADCO, Non-Fluted Westbrooke	18	20.41	(N)
Concrete, Ameron Post-Top	25	19.16	(R)
Fiberglass Fluted Ornamental; Black	14	11.81	
Fiberglass, Regular			
Black,	20	4.91	
Gray or Bronze;	30	8.35	
Other Colors (as available)	35	7.19	
Fiberglass, Anchor Base Gray	35	13.11	
Fiberglass, Direct Bury with Shroud	18	7.92	(R)

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

(M)

SCHEDULE 515 (Concluded)

INSTALLATION CHARGE (M)

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

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 Company-owned area lighting 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. This condition applies if a Customer's selection of service under this Schedule requires the removal of Company-owned area lighting equipment or poles.

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	$16.00	(I)
Three Phase	$22.00	(I)
Distribution Charge		
First 5,000 kWh	3.882 ¢ per kWh	(I)
Over 5,000 kWh	0.832 ¢ per kWh	(R)

* 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 538
LARGE NONRESIDENTIAL OPTIONAL TIME-OF-DAY DIRECT ACCESS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

This optional schedule is applicable to Large Nonresidential Customers who have chosen to receive service from an Electricity Service Supplier (ESS), and: 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, 2015.

MONTHLY RATE

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

Basic Charge	$25.00		(C)
Distribution Charge	7.369	¢ per kWh	(I)

* 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.

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.

ADJUSTMENTS

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

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**	$50.00	(I)
Winter Months**	No Charge	
Distribution Charge		
First 50 kWh per kW of Demand	6.937 ¢ per kWh	(I)
Over 50 kWh per kW of Demand	5.937 ¢ per kWh	(I)

* 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 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 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

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	$2,670.00	$1,620.00	$3,090.00	(R)
Distribution Charge				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly On-Peak Demand**	$2.38	$2.32	$1.21	(I)
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	(0.058) ¢	(0.058) ¢	(0.059) ¢	(R)

* 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)

SPECIAL CONDITIONS (Continued)

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

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

8. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Customer provides the following notice:

   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Customer may make one such request per calendar year and will provide at least 6 months written notice;

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

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:*

	Secondary	Primary	Subtransmission	
Daily Economic Replacement Power (ERP) Demand Charge				
per kW of Daily ERP Demand during On-Peak hours per day**	$0.093	$0.090	$0.047	(I)
Transaction Fee				
per Energy Needs Forecast (ENF) submission or revision	$50.00	$50.00	$50.00	

* 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.

SCHEDULE 583
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(31 – 200 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has 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)*:

Basic Charge		
Single Phase Service	$30.00	
Three Phase Service	$40.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 30 kW	$2.85	(I)
Over 30 kW	$2.75	
per kW of monthly On-Peak Demand	$2.38	
System Usage Charge		
per kWh	0.710 ¢	(I)

* 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 585
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(201 – 4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customers whose Demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW and who has 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	$430.00	$460.00	(I)
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 200 kW	$3.01	$2.94	(I)
Over 200 kW	$2.11	$2.04	
per kW of monthly On-Peak Demand	$2.38	$2.32	
System Usage Charge			
per kWh	(0.026) ¢	(0.027) ¢	(I)

* 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
LARGE NONRESIDENTIAL DIRECT ACCESS SERVICE
(>4,000 kW)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 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	$2,670.00	$1,620.00	$3,090.00	(R)
Distribution Charges**				
The sum of the following:				
per kW of Facility Capacity				
First 4,000 kW	$0.99	$0.96	$0.96	(R)
Over 4,000 kW	$0.99	$0.96	$0.96	(R)
per kW of monthly on-peak Demand	$2.38	$2.32	$1.21	(I)
System Usage Charge				
per kWh	(0.058) ¢	(0.058) ¢	(0.059) ¢	(R)

* 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 590
LARGE NONRESIDENTIAL
DIRECT ACCESS SERVICE
(>4,000 kW and Aggregate to >100 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer who meet the following conditions: 1) Individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the Large Nonresidential Customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) 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 per Point of Delivery (POD)*:

Basic Charge	$25,000.00	
Distribution Charges**		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$0.97	(R)
Over 4,000 kW	$0.97	(R)
per kW of monthly on-peak Demand	$2.32	(I)
System Usage Charge		
per kWh	(0.077) ¢	(R)

* 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 591 (Continued)

STREETLIGHT POLES SERVICE OPTIONS (Continued)
Option B – Pole maintenance (Continued)

Emergency Pole Replacement and Repair

The Company will repair or replace damaged streetlight poles that have been damaged due to the acts of vandalism, damage claim incidences and storm related events that cause a pole to become structurally unsound at no additional cost to the customer.

Without notice to the Customer, individual poles that are damaged or destroyed by unexpected events will be replaced on determination that the pole is unfit for further use as soon as reasonably possible. Replacement is subject to the Company's operating schedules and requirements.

Special Provisions for Option B - Poles

1. If damage occurs to any streetlighting pole more than two times in any 12-month period measured from the first incidence of damage that requires replacement, the Customer will be responsible to pay for future installations or mutually agree with the Company and pay to have the pole either completely removed or relocated.

2. Non-Standard or Custom poles are provided at the Company's discretion to allow greater flexibility in the choice of equipment. The Company will not maintain an inventory of this equipment and thus delays in maintenance may occur. The Company will order and replace the equipment subject to availability since non-standard and custom equipment is subject to obsolescence. The Customer will pay for any additional cost to the Company for ordering non-standard equipment.

MONTHLY RATE

The service rates for Option A and B lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.109 ¢ per kWh (I)

Energy Charge Provided by Energy Service Supplier

NOVEMBER ELECTION WINDOW

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

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st. Customers may notify the Company of a choice to change service options using the Company's website, PortlandGeneral.com/business

SCHEDULE 591 (Continued)

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [(1)]
	$133.00 per hour	$188.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

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 **							
	70	6,300	30	*	$ 2.86	$ 1.53	(I)
	100	9,500	43	*	3.52	2.20	
	150	16,000	62	*	4.50	3.17	
	200	22,000	79	*	5.41	4.04	
	250	29,000	102	*	6.56	5.21	
	400	50,000	163	*	9.72	8.33	
Cobrahead, Non-Power Door	70	6.300	30	$ 6.23	3.10	1.53	(R)
	100	9,500	43	6.88	3.75	2.20	(R)
	150	16,000	62	7.95	4.74	3.17	(I)
	200	22,000	79	9.45	5.66	4.04	
	250	29,000	102	10.56	6.82	5.21	
	400	50,000	163	13.84	9.95	8.33	(I)
Flood	250	29,000	102	10.99	6.87	5.21	(R)
	400	50,000	163	14.11	9.99	8.33	(I)
Early American Post-Top	100	9,500	43	7.30	3.81	2.20	(R)
Shoebox (Bronze color, flat	70	6,300	30	7.67	3.29	1.53	
Lens, or drop lens, multi-volt)	100	9,500	43	8.04	3.91	2.20	(R)
	150	16,000	62	9.21	4.91	3.17	(R)(I)

* Not offered.
** Service is only available to customers with total power doors luminaires in excess of 2,500.

SCHEDULE 591 (Continued)

RATES FOR STANDARD POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Fiberglass, Black	20	$ 4.91	$ 0.15	(R)(I)
Fiberglass, Bronze	30	7.74	0.23	
Fiberglass, Gray	30	8.35	0.25	
Wood, Standard	30 to 35	5.59	0.17	
Wood, Standard	40 to 55	7.31	0.22	(R)(I)

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	$ 10.81	$ 4.25	$ 2.20	(R)(I)
HADCO Victorian, HPS	150	16,000	62	11.82	5.23	3.17	
	200	22,000	79	13.45	6.21	4.04	
	250	29,000	102	14.62	7.38	5.21	
HADCO Capitol Acorn, HPS	100	9,500	43	14.12	4.69	2.20	
	150	16,000	62	14.39	5.58	3.17	
	200	22,000	79	16.79	6.66	4.04	
	250	29,000	102	16.43	7.62	5.21	
Special Architectural Types							
HADCO Independence, HPS	100	9,500	43	11.62	4.34	2.20	
	150	16,000	62	11.59	5.18	3.17	(R)
HADCO Techtra, HPS	100	9,500	43	20.37	5.52	2.20	(I)
	150	16,000	62	20.73	6.41	3.17	
	250	29,000	102	22.70	8.45	5.21	(I)
HADCO Westbrooke, HPS	70	6,300	30	12.98	3.96	1.53	(R)
	100	9,500	43	13.07	4.54	2.20	
	150	16,000	62	14.05	5.52	3.17	
	200	22,000	79	15.11	6.42	4.04	
	250	29,000	102	16.47	7.62	5.21	(R)(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM LIGHTING (Continued)

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rates Option A	Option B	Option C	
Special Types							
Cobrahead, Metal Halide	150	10,000	60	$ 8.35	$ 4.94	$ 3.07	(I)
Flood, Metal Halide	350	30,000	139	13.13	9.04	7.10	(R)
Flood, HPS	750	105,000	285	23.70	17.44	14.56	(I)
Holophane Mongoose, HPS	150	16,000	62	12.15	5.27	3.17	(R)
	250	29,000	102	13.59	7.22	5.21	(R)
Option C Only **							
Ornamental Acorn Twin	85	9,600	64	*	*	3.27	
Ornamental Acorn	55	2,800	21	*	*	1.07	
Ornamental Acorn Twin	55	5,600	42	*	*	2.15	
Composite, Twin	140	6,815	54	*	*	2.76	
	175	9,815	66	*	*	3.37	(I)

RATES FOR CUSTOM POLES

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, Regular	16	$ 6.67	$ 0.20	(R)(I)
	25	11.07	0.33	
	30	11.96	0.36	
	35	14.30	0.43	
Aluminum Davit	25	11.05	0.33	
	30	10.99	0.33	
	35	12.02	0.36	
	40	16.30	0.49	
Aluminum Double Davit	30	16.22	0.48	
Aluminum, HADCO, Fluted Victorian Ornamental	14	9.76	0.29	(R)(I)

* Not offered.
** Rates are based on current kWh energy charges.

SCHEDULE 591 (Continued)

RATES FOR CUSTOM POLES (Continued)

Type of Pole	Pole Length (feet)	Monthly Rates Option A	Option B	
Aluminum, HADCO, Non-Fluted Techtra Ornamental	18	$ 19.21	$ 0.57	(R)(I)
Aluminum, HADCO, Fluted Ornamental	16	9.98	0.30	
Aluminum, HADCO, Non-Fluted Ornamental Westbrooke	16	20.41	0.61	
Aluminum, HADCO, Fluted Westbrooke	18	19.26	0.57	
Aluminum, HADCO, Non-Fluted, Westbrooke	18	20.41	0.61	
Aluminum, Painted Ornamental	35	32.80	0.98	
Concrete, Decorative Ameron	20	19.16	0.57	
Concrete, Ameron Post-Top	25	19.16	0.57	
Fiberglass, HADCO, Fluted Ornamental Black	14	11.81	0.35	
Fiberglass, Smooth	18	4.90	0.15	
Fiberglass, Regular,				
color may vary	22	4.38	0.13	
color may vary	35	7.19	0.21	
Fiberglass, Anchor Base, Gray	35	13.11	0.39	
Fiberglass, Direct Bury with Shroud	18	7.92	0.24	(R)(I)

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	Option C	
Cobrahead, Mercury Vapor	100	4,000	39	*	*	$ 1.99	(I)
	175	7,000	66	$ 8.01	$ 4.88	3.37	
	250	10,000	94	*	*	4.80	
	400	21,000	147	12.94	9.15	7.51	
	1,000	55,000	374	24.94	21.05	19.11	(I)

* 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 Box Similar to GE "Space-Glo"							
HPS	70	6,300	30	$ 7.31	$ 3.18	$ 1.53	(R)(I)
Mercury Vapor	175	7,000	66	9.11	4.98	3.37	(R)
Special box, Anodized Aluminum							
Similar to GardCo Hub							
HPS	Twin 70	6,300	60	*	*	3.07	
	70	6,300	30	*	*	1.53	
	100	9,500	43	*	4.19	2.20	
	150	16,000	62	*	5.18	3.17	
	250	29,000	102	*	*	5.21	
	400	50,000	163	*	*	8.33	
Metal Halide	250	20,500	99	*	6.32	5.06	
	400	40,000	156	*	9.23	7.97	
Cobrahead, Metal Halide	175	12,000	71	8.95	5.35	3.63	(R)
Flood, Metal Halide	400	40,000	156	13.93	9.85	7.97	(I)
Cobrahead, Dual Wattage HPS							
70/100 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	100	9,500	43	*	3.77	2.20	
100/150 Watt Ballast	150	16,000	62	*	4.76	3.17	
Special Architectural Types Including Philips QL Induction Lamp Systems							
HADCO Victorian, QL	85	6,000	32	*	$ 2.36	$ 1.63	
	165	12,000	60	*	3.95	3.07	
	165	12,000	60	$ 22.01	4.23	3.07	(R)
Special Architectural Types							
KIM SBC Shoebox, HPS	150	16,000	62	*	5.70	3.17	
KIM Archetype, HPS	250	29,000	102	*	7.79	5.21	
	400	50,000	163	*	10.57	8.33	(I)

* 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	30	$ 10.16	$ 3.60	$ 1.53	(R)(I)
Special GardCo Bronze Alloy							
HPS	70	5,000	30	*	*	1.53	
Mercury Vapor	175	7,000	66	*	*	3.37	
Special Acrylic Sphere							
Mercury Vapor	400	21,000	147	*	*	7.51	
Early American Post-Top, HPS							
Black	70	6,300	30	6.56	3.07	1.53	(R)
Rectangle Type	200	22,000	79	*	*	4.04	
Incandescent	92	1,000	31	*	*	1.58	
	182	2,500	62	*	*	3.17	
Town and Country Post-Top							
Mercury Vapor	175	7,000	66	8.41	4.92	3.37	
Flood, HPS	70	6,300	30	6.11	2.98	1.53	(R)
	100	9,500	43	6.74	3.76	2.20	
	200	22,000	79	9.86	5.74	4.04	(R)
Cobrahead, HPS							
Power Door	310	37,000	124	12.09	8.35	6.34	(I)
Special Types Customer-Owned & Maintained							
Ornamental, HPS	100	9,500	43	*	*	2.20	
Twin ornamental, HPS	Twin 100	9,500	86	*	*	4.39	
Compact Fluorescent	28	N/A	12	*	*	0.61	(I)

* Not offered.

SCHEDULE 591 (Continued)

RATES FOR OBSOLETE LIGHTING POLES

Type of Pole	Poles Length (feet)	Monthly Rates Option A	Monthly Rates Option B	
Aluminum Post	30	$ 6.67	*	(R)
Bronze Alloy GardCo	12	*	$ 0.18	(I)
Concrete, Ornamental	35 or less	11.07	0.33	(R)
Steel, Painted Regular **	25	11.07	0.33	
Steel, Painted Regular **	30	11.96	0.36	(R)
Steel, Unpainted 6-foot Mast Arm **	30	*	0.33	
Steel, Unpainted 6-foot Davit Arm **	30	*	0.33	
Steel, Unpainted 8-foot Mast Arm **	35	*	0.36	
Steel, Unpainted 8-foot Davit Arm **	35	*	0.36	
Wood, Laminated without Mast Arm	20	4.91	0.15	(R)(I)
Wood, Laminated Street Light Only	20	4.91	*	
Wood, Curved Laminated	30	7.74	0.23	(I)
Wood, Painted Underground	35	5.59	0.17	(I)
Wood, Painted Street Light Only	35	5.59	*	(R)

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

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 charge per Point of Delivery (POD)* is:

Distribution Charge	2.195 ¢ per kWh	(I)

* 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 595 (Continued)

STREETLIGHT POLES SERVICE OPTIONS

Option A – Poles

See Schedule 91/591 for Streetlight poles service options.

MONTHLY RATE

The service rates for Option A lights include the following charges for each installed luminaire based on the Monthly kWhs applicable to each luminaire.

Distribution Charge 5.109 ¢ per kWh (I)

Energy Charge Provided by Energy Service Supplier

REPLACEMENT OF NON-REPAIRABLE LUMINAIRES INSTALLATION LABOR RATES

Labor Rates	Straight Time	Overtime [1]
	$133.00 per hour	$188.00 per hour

(1) Per Article 20.2 of the Collective Bargaining Agreement Union No. 125 Contract, overtime is paid at the Overtime Rate for a minimum of one hour.

RATES FOR STANDARD LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

LED lighting is new to the Company and pricing is changing rapidly. The Company may adjust rates under this schedule based on actual frequency of maintenance occurrences and changes in material prices.

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
LED	37	2,530	13	$ 3.61	(R)
LED	50	3,162	17	3.82	
LED	52	3,757	18	4.20	
LED	67	5,050	23	4.84	
LED	106	7,444	36	6.20	(R)

SCHEDULE 595 (Continued)

RATES FOR DECORATIVE LIGHTING

Light-Emitting Diode (LED) Only – Option A Service Rates

Type of Light	Watts	Nominal Lumens	Monthly kWh	Monthly Rate Option A	
Acorn LED	60	5,488	21	$ 12.50	(R)
	70	4,332	24	14.47	
Westbrooke (Non-Flared)	53	5,079	18	16.57	
LED	69	6,661	24	16.29	
	85	8,153	29	16.75	
	136	12,687	46	20.69	
	206	18,159	70	21.85	
Westbrooke (Flared)	53	5,079	18	18.71	
LED	69	6,661	24	19.02	
	85	8,153	29	18.21	
	136	12,687	46	21.78	
	206	18,159	70	23.01	(R)

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.
- 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.

SCHEDULE 750
INFORMATIONAL ONLY: FRANCHISE FEE RATE RECOVERY

PURPOSE

To inform customers regarding the level of franchise fee rate recovery contained in each schedule's system usage or distribution charges.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Residential and Nonresidential Customers located within the Company's service territory.

FRANCHISE FEE RATE RECOVERY

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate		Included in:	
7	0.312	¢ per kWh	Distribution Charge	(I)
15	0.561	¢ per kWh	Distribution Charge	(R)
32	0.285	¢ per kWh	Distribution Charge	(I)
38	0.360	¢ per kWh	Distribution Charge	
47	0.673	¢ per kWh	Distribution Charge	(I)
49	0.579	¢ per kWh	Distribution Charge	(R)
75				
Secondary	0.174	¢ per kWh	System Usage Charge	(I)
Primary	0.171	¢ per kWh	System Usage Charge	
Subtransmission	0.168	¢ per kWh	System Usage Charge	(I)

DO NOT BILL

SCHEDULE 750 (Continued)

FRANCHISE FEE RATE RECOVERY (Continued)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
83	0.228 ¢ per kWh	System Usage Charge	(I)
85			
Secondary	0.201 ¢ per kWh	System Usage Charge	
Primary	0.197 ¢ per kWh	System Usage Charge	
89			
Secondary	0.174 ¢ per kWh	System Usage Charge	
Primary	0.171 ¢ per kWh	System Usage Charge	
Subtransmission	0.168 ¢ per kWh	System Usage Charge	
90	0.159 ¢ per kWh	System Usage Charge	(I)
91	0.457 ¢ per kWh	Distribution Charge	(R)
92	0.203 ¢ per kWh	Distribution Charge	(I)
95	0.457 ¢ per kWh	Distribution Charge	(R)
485			
Secondary	0.055 ¢ per kWh	System Usage Charge	
Primary	0.055 ¢ per kWh	System Usage Charge	
489			
Secondary	0.033 ¢ per kWh	System Usage Charge	
Primary	0.033 ¢ per kWh	System Usage Charge	
Subtransmission	0.033 ¢ per kWh	System Usage Charge	
490	0.014 ¢ per kWh	System Usage Charge	
491	0.315 ¢ per kWh	Distribution Charge	(R)
492	0.056 ¢ per kWh	Distribution Charge	(I)
495	0.315 ¢ per kWh	Distribution Charge	(R)

SCHEDULE 750 (Concluded)

FRANCHISE FEE RATE RECOVERY (Concluded)

The Rates, included in the applicable system usage and distribution charges are:

Schedule	Franchise Fee Rate	Included in:	
515	0.418 ¢ per kWh	Distribution Charge	**(R)**
532	0.118 ¢ per kWh	Distribution Charge	**(I)**
538	0.203 ¢ per kWh	Distribution Charge	**(I)**
549	0.383 ¢ per kWh	Distribution Charge	**(R)**
575			
Secondary	0.033 ¢ per kWh	System Usage Charge	
Primary	0.033 ¢ per kWh	System Usage Charge	
Subtransmission	0.033 ¢ per kWh	System Usage Charge	**(R)**
583	0.064 ¢ per kWh	System Usage Charge	**(I)**
585			
Secondary	0.055 ¢ per kWh	System Usage Charge	**(R)**
Primary	0.055 ¢ per kWh	System Usage Charge	
590	0.014 ¢ per kWh	System Usage Charge	
591	0.315 ¢ per kWh	Distribution Charge	**(R)**
592	0.056 ¢ per kWh	Distribution Charge	**(I)**
595	0.315 ¢ per kWh	Distribution Charge	**(R)**

DO NOT BILL