Portland General Electric Company
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February 5, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: Advice No. 19-02, PGE's Offering of a New Load Direct Access (NLDA) Program

Summary:

Electricity is an essential service that is vital to the health and well-being of our customers and communities. Accordingly, we must continue to ensure that electric service remains reliable, safe, and affordable; and it must also be increasingly clean and green with fair and equitable outcomes for all. It is with these foundational imperatives in mind that PGE is introducing new tariff schedules and modifying existing schedules to implement its New Load Direct Access program.

- *In addition to standard program requirements, PGE is proposing two key mechanisms intended to help assure continued system reliability, with benefits, costs, and risks fairly shared by all customers; both cost-of-service and those that choose an alternate supplier under NLDA.*
- *Assuring reliable service and fair outcomes necessitates comprehensive resource adequacy requirements for all electric load. Development of such requirements should occur through robust and transparent system planning and resource procurement with strong oversight from the Commission. Finally, the regulatory framework must ensure that all customers receive the benefits of, and fairly contribute to the costs of implementing system reliability.*

Discussion:

PGE is filing this New Load Direct Access (NLDA) program to respond to the Commission's Order No. 18-341 in Docket No. AR 614. The NLDA program creates another option within the framework of the existing long-term direct access program[1]; the

[1] The existing long-term direct access program, created by the Commission following the passage of SB 1149 in 1999, allows up to 300 MWa of large nonresidential customer load to seek an alternative supplier. However, this program with a fixed term of transition adjustment applicability is not a requirement of SB 1149.

option is for very large customer loads—in excess of 10 MWa (akin to an industrial manufacturer or large hospital complex)—to seek an electricity supplier other than PGE.

In accordance with OPUC rules, PGE continues to be the reliability provider or provider of last resort ("Provider") with ultimate responsibility for ensuring system reliability for everyone in its service area without regard to whether a given customer has chosen PGE or an alternative supplier for energy service.

In establishing PGE's program for allowing New Large Load customers to opt out of cost-of-service based pricing, PGE is introducing new tariff schedules and modifying existing schedules.

In addition to the standard program requirements set forth in PUC rules, PGE is proposing two new mechanisms and charges in the NLDA tariff to address resource adequacy planning and procurement, and the fair allocation of the associated costs of assuring system reliability: one related to real-time balancing of customer loads to match the alternative energy supplier's scheduling of energy (called the Resource Intermittency Charge--RIC), and the other fee related to the cost PGE would incur if it were to plan for and secure the capacity necessary to effectuate the reliability provider responsibility (called the Resource Adequacy Charge--RAD). To implement the proposed RAD, the Commission would first have to reverse its earlier guidance regarding utility planning for long-term direct access load.

As noted, the RAD relates to PGE's system reliability provider role and the costs and risks placed on cost-of-service customers as a result of large loads choosing to be served by an alternative supplier for energy service. The Commission has interpreted this Provider responsibility to mean that, while PGE does not plan for the long-term direct access loads, if-- for any reason-- the market supplier to these large customers' loads fails to plan and procure the necessary resources, then PGE must immediately step in and provide service on an equal basis. A construct where PGE retains reliability responsibility for all customers but lacks the ability to plan and implement what is necessary to achieve such reliability, places the integrity of the electric system unnecessarily at risk. Such a scenario also creates inequity as cost-of-service customers bear the reliability risk of either insufficient or inconsistent planning and capacity procurement for direct access customers.

Unlike the general reliability planning PGE undertakes for its customers, a historical Commission order directed PGE <u>not</u> to plan for long-term direct access customer loads.[2] This order was issued before the new load direct access option was created and PGE's long-term direct access program had significant customer participation.[3]

[2] IRP Guideline #9; https://apps.puc.state.or.us/orders/2007ords/07-002.pdf. An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

[3] The IRP guideline that instructed electric utilities not to plan for LTDA loads, was adopted in 2007 in a docket that commenced in 2002. The Commission cited ICNU's testimony that in 2005, 11.3% of eligible loads took service from ESSs. As of 2018, roughly 41% of eligible load has opted out of PGE's cost of service supply.

Given that the loads have not been planned for, there are no guarantees of adequate supply should large new loads elect direct access and, for whatever reason, call on PGE as the Provider. Under such a situation, PGE cannot, by Commission directive, treat its cost-of-service supply customers and these returning customers differently. The proposed RAD addresses this concern.

When the Commission directed that electric companies not plan for the long-term direct access loads, the result was an approach that charged returning customers a premium energy price for default service. It addressed energy but not capacity. In this filing, PGE proposes to plan for the capacity needs of new load direct access, secure the necessary capacity, and then allocate a proportional share of the cost via the RAD. PGE's proposal is proactive, like charging a risk premium to prevent a lack of capacity. Importantly, our approach recognizes that costs and risks of NLDA are currently borne by customers not choosing the long-term direct access option and seeks to price the service fairly and equitably in terms of all customers' paying their fair share.

Given the importance of electricity and reliability in our daily lives, as a fundamental building block of our society-- to warm our homes, fuel our enterprises, and drive our economy (and, increasingly, to power our cars) – PGE encourages the Commission to reverse its decision on planning for long-term direct access loads. Times have changed since the earlier decision and greater amounts of load can and have chosen alternative suppliers. This then creates an increased reliability and cost shift risk to PGE's supply customers. Thus, PGE should plan for these loads, procure resources to meet the need, and charge for this reliability service. Such planning should be undertaken in an open, transparent and robust regulatory process with principles of equity and fair play at the forefront. Our Schedule 689 jumpstarts this conversation with the Commission, and proposes a charge for such service.

Required Filing Information

Portland General Electric Company (PGE) submits this filing pursuant to Oregon Revised Statutes (ORS) 757.205 and 757.210 and Oregon Administrative Rule (OAR) 860-022-0025 for filing proposed tariff sheets associated with Tariff P.U.C. No. 18, with a requested effective date of **April 1, 2019**:

Twentieth Revision of Sheet No. 1-1
Twenty Second Revision of Sheet No. 1-2
Thirtieth Revision of Sheet No. 1-3
Thirteenth Revision of Sheet No. 1-4
Third Revision of Sheet No. 26-7
Fourth Revision of Sheet No. 54-1
Ninth Revision of Sheet no 81-1
First Revision of Sheet No. 81-2
Fourth Revision of Sheet No. 88-1
Thirty Fourth Revision of Sheet No. 100-1
Eighteenth Revision of Sheet No. 105-3
Thirteenth Revision of Sheet No. 109-3

Sixth Revision of Sheet No. 110-4
First Revision of Sheet No. 112-2
Fifteenth Revision of Sheet No. 122-1
Fourteenth Revision of Sheet No. 123-5
Fourth Revision of Sheet No. 123-6
Eleventh Revision of Sheet No. 126-1
Tenth Revision of Sheet No. 126-3
Tenth Revision of Sheet No. 126-5
First Revision of Sheet No. 126-6
First Revision of Sheet No. 132-1
Ninth Revision of Sheet No. 135-1
Fourth Revision of Sheet No. 137-1
Original Sheet No. 139-1
Original Sheet No. 139-2
Sixth Revision of Sheet No. 143-3
Twelfth Revision of Sheet No. 145-1
Second Revision of Sheet No. 146-1
First Revision of Sheet No. 149-5
Original Sheet No. 689-1
Original Sheet No. 689-2
Original Sheet No. 689-3
Original Sheet No. 689-4
Original Sheet No. 689-5
Original Sheet No. 689-6
Original Sheet No. 689-7
Original Sheet No. 689-8
Original Sheet No. 689-9
Fifth Revision of Sheet No. 750-3
Second Revision of Sheet No. G-1

New Proposed Schedule 689, NLDA Program Requirements

Schedule 689, New Large Load Cost-of-Service Opt-Out, is the specific rate schedule under which Customers participating in this program will be provided service. Schedule 689 provides the rates, terms and conditions associated with PGE's NLDA program in accordance with PUC Rule 860-038-0710(1). For service under Schedule 689, the customer must sign a service agreement with the Company prior to service. The agreement represents written and binding notification to the Company that the Customer will pursue NLDA and will be presented by the Company to the Customer.

Eligibility

The following sets forth eligibility requirements under Schedule 689:

- Demonstration of an average hourly load of 10 MW over a period of 12 consecutive months within the first 36 months of receiving service.
- Loads must be separately metered or measured in a way that is mutually agreed upon with comparable accuracy between the customer and the Company. After 36 months of service, if the actual load of the facility does not meet the minimum load requirements for service under Schedule 689, the Company may de-enroll the Customer from the program.
- A new large load that exceeds the current program cap, or exceeds the load remaining under the enrollment cap will not be accepted into NLDA. Eligibility and determination of room under the cap will be determined on an average load basis. Customer applications with projected load beyond the program cap will require separate application and approval by the Commission.

De-enrollment and options

If de-enrolled, the Customer will be enrolled in the applicable cost-of-service rate schedule and will be eligible to opt-out of cost-of-service in a subsequent election window in accordance with the Company's tariff. Customers that opt out of cost-of-service in a subsequent election window will be subject to the transition adjustments of that election window. The Company will provide at least 90 days' prior written notice to the Customer before moving the Customer to a new rate schedule. The Customer will have 60 days to provide a written response to the Company to show cause of load reduction.

Rates and charges

Schedule 689 includes an ongoing administrative fee intended to recover the incremental charges outside of approved prices administering this program. Prices of $0.00 are being filed as the Company has not yet incurred incremental costs of administering this program. This charge will be updated upon commencement of the program once costs can be evaluated.

Basic, Distribution and System Usage rates under Schedule 689 match those specified in Schedule 489, the large customer long term direct access schedule. Additionally, all supplemental schedules applicable to Schedule 489 apply to Schedule 689.

Schedule 689 will provide the following options for energy supply:

Daily Market Energy Option

The Customer will receive energy supply from PGE. This will be priced on the Mid-Columbia daily index with a margin, a separate wheeling and ancillary services charge as specified, and additional costs to meet Oregon's Renewable Portfolio Standard (RPS), and other applicable legislative requirements.

Long-Term Market Energy Option

This option is PGE's standard offer service for NLDA. The Customer will receive energy from PGE. This will be based on a contract with a margin and other charges (e.g. wheeling and ancillary services) applicable to the contract(s) secured between the company and energy suppliers. This service will comply with Oregon's RPS and other applicable legislative requirements. Prices will be agreed upon in contract between the Customer and the Company.

Direct Access Service

The Customer will receive energy from an ESS. The Customer will also pay for transmission and required ancillary services through their energy supplier.

Customers receiving service under Schedule 689 will agree by affidavit to only purchase energy from a resource mix consistent with the specifications of OAR 860-038-0730(1), which does not include coal-fired generation. This provision will be included as an attachment to the signed agreement between the Customer and the Company and submitted to the Commission. Customers found in violation of the provision that no coal will be delivered by wire after January 1, 2030 will be enrolled in the general cost-of-service opt-out program in the next direct access enrollment window, subject to the then applicable transition adjustment for the entire period of time it applies.

Capacity Charges

As noted earlier in this letter, PGE is proposing two different capacity charges in Schedule 689: one that relates to PGE's Provider service (RAD) and the other (RIC) for real time balancing to match ESS supply scheduling and their customers' capacities. These capacity charges are applicable to all energy supply options, for all years of service on Schedule 689.

(1) Resource Adequacy Capacity Charge (RAD)

Under circumstances when an ESS fails to provide adequate service to its Customers in PGE's balancing authority area, the Company acts as Provider to ensure reliable electric service for affected new load direct access Customers. The RAD protects PGE cost-of-service Customers from compromised reliability by ensuring that PGE can secure capacity to adequately serve all load, protecting electric reliability for our system as a whole.

Resource adequacy and planning standards should apply to all load. PGE suggests that the RAD be the mechanism in place until system-wide capacity resource planning/resource adequacy is examined by the Commission.

The charge is currently set at $0.00 and, if approved, will be applied per kW of the Customer's on-peak demand. PGE plans to assign a cost for the RAD charge following approval from the Commission to plan to meet the capacity needs of these customers as the Provider. Through a subsequent general rate case, PGE will allocate capacity costs to NLDA customers. Based on PGE's proposed methodology and the proxy cost of a capacity resource, PGE estimates the cost of the RAD would amount to approximately $9.00 per kW of on-peak demand. This estimate and proposed methodology are provided for illustration purposes.

The charge would be applied during all years of service on Schedule 689. During the first 60 months, the Customer pays transition adjustments that include 20% of the fixed generation cost of energy supply, and a RAD charge less the amount of the transition adjustment. The RAD charge also applies during Emergency Default Service. This charge applies when the Customer is on the Company Supplied Daily Market Option or elects the Company Supplied Long-Term Market Energy Option.

(2) <u>Resource Intermittence Capacity Charge (RIC)</u>

When alternative energy suppliers deliver the power their customers require to PGE's balancing authority area, they schedule the amount to be delivered. The scheduling is for all customers' loads—an aggregate amount. Theoretically, the scheduled amount should closely match the actual loads of the customers on an hourly basis. When there are deviations between the ESS's scheduled supply and the customers actual loads, PGE maintains system balance by providing intra-hour capacity to meet these under-scheduling events. Currently, PGE secures this energy and capacity by using its own generating resources.

The provision of intra-hour capacity is not to be confused with OATT service. Currently in PGE's Open Access Transmission Tariff (OATT), PGE recovers the costs associated with securing energy to balance Direct Access load in PGE's balancing authority area through Schedule 4R. This schedule recovers only energy costs, based on a market index, and does not account for the capacity that PGE must have available to serve load. The purpose of the RIC is to pay for PGE's providing intra-hour capacity to meet the mismatch between scheduling and actual customer loads.

The RIC will be applied during billing periods when the Electricity Schedules for all of the Customers for which the Electricity Service Suppliers (ESSs) schedule is different from the actual amount of energy delivered by the Company to meet the load requirements of the Customers the ESSs serve. This charge is applied when the Company supplies capacity to support the Electricity Schedule of ESSs any time during the billing period. The charge is set at $0.58 per kW of on-peak demand. At this time, PGE's proposal does not distinguish the cost by ESS and this charge is applied regardless of the scheduling practices of a Customer's specific ESS. This charge applies to all energy supply options for NLDA service, including ESS provided service and PGE's company supplied options. The cost of supplying energy is not included in this charge as that is collected via Schedule 4R of PGE's OATT. If there are no deviations in scheduled energy to actual energy during the monthly billing period, this charge will not be applied.

Existing Load Shortage Transition Adjustment - OAR 860-038-0740(4)

This charge was directed in PUC rule to prevent gaming by a customer who shifts load among sites to game the eligibility rules such that load is deliberately increased at a location participating in NLDA from a location that is not eligible. The transition adjustment charge for the NLDA Customer for Existing Load Shortages is set in accordance with An Existing Load Shortage and is the larger of zero or a consumer's average historic cost-of-service load plus Incremental Demand Side Management less the average cost of service eligible load during the previous 60 months. Average Historical Cost-of-Service Load is the average monthly Cost-of-Service Eligible Load during the preceding 60 months prior to signing of the service agreement between the Customer and the Company for service on this rate schedule. Incremental Demand Side Management is the effective net impact of energy efficiency measures after the Customer has entered a written and binding agreement with the Company.

Energy Supply Return Charge - OAR 860-038-0720(3)

The PUC rules allow a charge when a Customer returning to PGE's cost of service supply based rates results in a significant rate increase to existing customers. PGE's Schedule 689 contains a place-holder for such a charge. If the Customer elects to return to the Company's Daily Market Energy Option or cost-of-service based pricing, resulting in a rate increase for existing cost-of-service customers by more than 0.5%, the Customer making the election will be subject to the Cost-of-Service Return Charge for three years. The Company will update this charge annually prior to the September enrollment window when Schedule 129 prices are updated. Prices for the Energy Supply return charge are currently set at $0.00 /kW.

Other PGE Tariff Schedule Changes and Additions to Effectuate NLDA Program

Schedule 81

Emergency Default Service has been modified to include the RAD Charge for Schedule 689 Customers.

Schedule 139

This Schedule sets the transition adjustment charge for the New Large Load Customer applicable to Schedules 689 in accordance with OAR 860-038-0740(3). As prescribed in PUC rule, this charge is based on 20% of the Company's current fixed generation costs. Updates to Schedule 139 will occur concurrently with updates to Schedule 129, the Long-Term Transition Adjustment. These charges will apply for the first 60 months of service on Schedule 689.

Schedule 100

The Company will add Schedule 139 to the matrix contained in Schedule 100 as an adjustment schedule and will identify which adjustments are applicable to Schedule 689.

Other Tariff Sheet Changes

Additional tariff sheets that specify direct access rates have been changed to include Schedule 689. OAR 860-022-0025 requires that PGE submit a statement of the tariff schedule change, the number of Customers affected, the change in revenue, and the grounds supporting the change. Schedule 689 is for new Customers or new load electing to leave PGE's cost-of-service. It is unknown how many customers will make this election and the revenue change cannot be forecasted.

In closing, with the introduction of new tariff schedules to implement Oregon's New Load Direct Access program, PGE seeks also to catalyze a conversation around what is needed to preserve system reliability in a safe and equitable manner. A construct where PGE retains reliability responsibility for all customers but lacks the ability to plan and implement what is necessary to achieve such reliability, risks compromising the integrity of the electric system, to the potential detriment of all customers and the communities they live in. Such a construct also creates inequity whereby cost-of-service customers unfairly bear the reliability risk of either insufficient or inconsistent planning and capacity procurement for direct access customers. Because it would be equally unfair for the utility to conduct the resource planning and procurement needed to assure system reliability without direct access customers adequately contributing to the costs of those measures, PGE has introduced two capacity charges with this filing.

Please direct any questions regarding this filing to Andrew Speer at (503) 464-7486.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel

Karla Wenzel
Manager, Pricing and Tariffs

Enclosures

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SCHEDULE 26 (Continued)

SPECIAL CONDITIONS

1. Customers cannot use on-site diesel, pipeline natural gas or propane or other carbon emitting generation equipment for load reductions to meet load reduction commitments under this tariff.

2. Customers that choose to take service under Schedules 86, 485, 489, 490, 532, 538, 549, 575, 583, 585, 589, 590, or 689 will be withdrawn from this program. (C)

3. Firm Load Reduction by Schedule 75 Customers will not exceed the Customer's Baseline Demand as specified in the written service agreement between the Customer and the Company. Customer cannot use purchases under Schedule 76 to meet load reduction commitments under this tariff. In the case of Customers participating on Schedule 76R – Partial Requirements Economic Replacement Power Rider – at the time of the event, the energy imbalance will not apply during event hours and for the event energy amount.

4. The Company is not responsible for any consequences to the participating Customer that results from the Firm Load Reduction Event or the Customer's effort to reduce Energy in response to a Firm Load Reduction Event.

5. This tariff is not applicable when the Company requests or initiates Load Reduction affecting a Customer SPID under system emergency conditions described in Rule N or Rule C(2)(B).

6. The Company will not cancel or shorten the duration of a Firm Reduction Event once notification has been provided.

7. Participating Customers are required to have interval metering and meter communication in place prior to initiation of service under this schedule. The Company will provide and install necessary equipment which allows the Company and the Customer to monitor the Customer's energy usage.

8. If the Customer experiences operational changes or a service disconnection that impairs the ability of the customer to provide the Firm Load Reduction as requested under this schedule, the agreement will be terminated.

9. If the Company is not allowed to recover any costs of this program by the Commission, the Company may at its option terminate service under this agreement with 30-day notice.

SCHEDULE 54
LARGE NONRESIDENTIAL
RENEWABLE ENERGY CERTIFICATES RIDER

PURPOSE

This rider is an optional supplemental service that supports the development of New Renewable Energy Resources as defined in ORS 757.600. Under this Schedule, a Large Nonresidential Customer may purchase Renewable Energy Certificates (RECs) based on a percentage of the Customer's load, subject to a minimum purchase.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all Customers taking service under any of the following PGE schedules: 38, 49, 83, 85, 89, 90, 91, 95, 485, 489, 490, 491, 495, 583, 585, 589, 590, 591, 595, and 689. Additionally, this Schedule is available to all competitive REC providers. (C)

PRODUCT OFFERINGS

I. PGE Clean Wind (Commercial & Industrial)

This product allows a customer to purchase RECs based on a percentage of load, subject to minimum purchase. The product is Green-e certified, and as a result all RECs purchased on behalf of Clean Wind Customers will conform to Green-e Energy National Standards and are either registered with Western Renewable Energy Generation Information System (WREGIS) or provided via third party audited Green-e attestation.

II. Specified Resource

This product allows a customer to purchase RECs from a specified facility, based on a percentage of load, subject to minimum purchase. Specified Resource provides the participating customer with RECs obtained from specified resources and derived from the following fuels:

1. Wind;
2. Solar;
3. Certified low-impact hydroelectric;
4. Pipeline or irrigation hydroelectric systems;
5. Wave or tidal action;
6. Low emissions biomass (from digester methane from landfills, sewage or waste treatment plants, forest or field residues).
7. Hydrogen derived from photovoltaic electrolysis or non-hydrocarbon derivation process

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 0.306¢ per kWh (R) 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

RESOURCE ADEQUACY CAPACITY CHARGE (N)

Customers that receive Emergency Default Service from the Company while on Schedule 689 will be subject to the Resource Adequacy Capacity Charge specified in Schedule 689 in addition to the Energy Charge Daily Rate above. (N)

(M)

SCHEDULE 81 (Concluded)

REACTIVE DEMAND CHARGE (M)

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. (M)

ADJUSTMENTS

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

TERM

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

SCHEDULE 88
LOAD REDUCTION PROGRAM

PURPOSE

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

AVAILABLE

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

APPLICABLE

To an individual or a group of Large Nonresidential Customers receiving Electricity Service under Schedules 83, 85, 89, 90, 485, 489, 490, 583, 585, 589, 590 and/or 689 from one or more **(C)** Service Point(s) (SPs) but from the same dedicated primary circuit and able to reduce Baseline Usage from the primary circuit by a minimum of 15%. Customers applying as a group must be represented by a Lead Customer. A group may consist of multiple SPs under one Customer name that are all located on the same primary circuit. Participation is dependent upon satisfaction of all conditions contained in this schedule.

BASELINE USAGE

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

LOAD REDUCTION DETERMINATION

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

SCHEDULE 100
SUMMARY OF APPLICABLE ADJUSTMENTS

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

Schs.	102 (1)	105	106 (1)	108 (3)	109 (1)	110 (1)	112	115	122	123 (1)	125 (1)	126	128 (4)	129 (1)	132	134	135	137	139	142	143	145	146	149	(N)
7	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x	
15	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x	
32	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
38	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
47	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x	
49	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x	
75	x$^{(2)}$	x$^{(2)}$	x	x	x$^{(2)}$	x$^{(2)}$	x	x	x$^{(2)}$	x	x$^{(2)}$	x$^{(2)}$	x		x	x	x	x		x	x	x	x	x	
76	x		x	x			x	x							x	x				x				x	
83	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
85	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
89	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
90	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x	
91		x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
92		x	x	x	x	x	x	x	x	x	x	x			x	x	x	x		x	x	x	x	x	
95		x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x		x	x	x	x	x	
485	x	x	x	x	x	x	x	x		x		x$^{(5)}$		x	x	x				x	x			x	
489	x	x	x	x	x	x	x	x		x		x$^{(5)}$		x	x	x				x	x			x	
490	x	x	x	x	x	x	x	x		x		x		x	x	x				x	x			x	
491		x	x	x	x	x	x	x		x		x		x	x	x				x	x			x	
492		x	x	x	x	x	x	x		x		x		x	x	x				x	x			x	
495		x	x	x	x	x	x	x		x		x		x	x	x				x	x			x	
515	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
532	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
538	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
549	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
575	x$^{(2)}$	x$^{(2)}$	x	x	x	x	x	x		x		x$^{(2)}$	x		x	x	x	x		x	x	x	x	x	
576	x		x	x			x	x							x	x				x				x	
583	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
585	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
589	x	x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
590	x	x	x	x	x	x	x	x		x		x	x		x	x	x	x		x	x	x	x	x	
591		x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
592		x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
595		x	x	x	x	x	x	x		x		x$^{(5)}$	x		x	x	x	x		x	x	x	x	x	
689	x	x	x	x	x	x	x	x		x		x$^{(5)}$			x	x			x	x	x			x	(N)

(1) Where applicable.
(2) These adjustments are applicable only to the Baseline and Scheduled Maintenance Energy.
(3) Schedule 108 applies to the sum of all charges less taxes, Schedule 109 and 115 charges and one-time charges such as deposits.
(4) Applicable to Nonresidential Customer who receive service at Daily pricing (other than Cost of Service) or Direct Access (excluding service on Schedules 485, 489, 490, 491, 492, 495, and 689).
(5) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 105 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
515	0.010	0.000	0.010	¢ per kWh
532	0.012	0.000	0.012	¢ per kWh
538	0.011	0.000	0.011	¢ per kWh
549	0.014	0.000	0.014	¢ per kWh
575				
Secondary	0.011	0.000	0.011	¢ per kWh(1)
Primary	0.011	0.000	0.011	¢ per kWh(1)
Subtransmission	0.011	0.000	0.011	¢ per kWh(1)
583	0.012	0.000	0.012	¢ per kWh
585				
Secondary	0.011	0.000	0.011	¢ per kWh
Primary	0.011	0.000	0.011	¢ per kWh
589				
Secondary	0.011	0.000	0.011	¢ per kWh
Primary	0.011	0.000	0.011	¢ per kWh
Subtransmission	0.011	0.000	0.011	¢ per kWh
590	0.010	0.000	0.010	¢ per kWh
591	0.010	0.000	0.010	¢ per kWh
592	0.010	0.000	0.010	¢ per kWh
595	0.010	0.000	0.010	¢ per kWh
689	0.000	0.000	0.000	¢ per kWh (N)
Secondary	0.000	0.000	0.000	¢ per kWh
Primary	0.000	0.000	0.000	¢ per kWh
Subtransmission	0.000	0.000	0.000	¢ per kWh (N)

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

SCHEDULE 109 (Concluded)

ENERGY EFFICIENCY ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
490	0.146 ¢ per kWh	
491	0.686 ¢ per kWh	
492	0.257 ¢ per kWh	
495	0.686 ¢ per kWh	
515	0.680 ¢ per kWh	
532	0.361 ¢ per kWh	
538	0.409 ¢ per kWh	
549	0.450 ¢ per kWh	
575		
Secondary	0.146 ¢ per kWh	
Primary	0.146 ¢ per kWh	
Subtransmission	0.146 ¢ per kWh	
583	0.283 ¢ per kWh	
585		
Secondary	0.242 ¢ per kWh	
Primary	0.242 ¢ per kWh	
589		
Secondary	0.146 ¢ per kWh	
Primary	0.146 ¢ per kWh	
Subtransmission	0.146 ¢ per kWh	
590	0.146 ¢ per kWh	
591	0.686 ¢ per kWh	
592	0.257 ¢ per kWh	
595	0.686 ¢ per kWh	
689		(N)
Secondary	0.146 ¢ per kWh	
Primary	0.146 ¢ per kWh	
Subtransmission	0.146 ¢ per kWh	(N)

SCHEDULE 110 (Concluded)

ENERGY EFFICIENCY CUSTOMER SERVICE ADJUSTMENT (Continued)

Schedule		Adjustment Rate	
585			
	Secondary	0.005 ¢ per kWh	
	Primary	0.005 ¢ per kWh	
589			
	Secondary	0.004 ¢ per kWh	
	Primary	0.004 ¢ per kWh	
	Subtransmission	0.004 ¢ per kWh	
590		0.004 ¢ per kWh	
591		0.011 ¢ per kWh	
592		0.004 ¢ per kWh	
595		0.011 ¢ per kWh	
689			(N)
	Secondary	0.004 ¢ per kWh	
	Primary	0.004 ¢ per kWh	
	Subtransmission	0.004 ¢ per kWh	(N)

SCHEDULE 112 (Concluded)

ADJUSTMENT RATE (Concluded)

(C)

Schedule	Adjustment Rate	
89/489/589/689		
Secondary	0.001	¢ per kWh
Primary	0.001	¢ per kWh
Subtransmission	0.001	¢ per kWh
90/490/590	0.001	¢ per kWh
91/491/591	0.025	¢ per kWh
92/492/592	0.023	¢ per kWh
95/495/595	0.025	¢ per kWh

ACCOUNTING

The Company will maintain an account to track the stipulated CET expenses and the actual Schedule 112 revenues. The account will accrue interest at the Commission-authorized rate for deferred accounts.

TERM

This schedule will terminate on December 31, 2022.

SCHEDULE 122
RENEWABLE RESOURCES AUTOMATIC ADJUSTMENT CLAUSE

PURPOSE

This Schedule recovers the revenue requirements of qualifying Company-owned or contracted new renewable energy resource and energy storage projects associated with renewable energy resources (including associated transmission) not otherwise included in rates. Additional new renewable and energy storage projects associated with renewable energy resources may be incorporated into this schedule as they are placed in service. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210 and Section 13 of the Oregon Renewable Energy Act (OREA).

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76, 485, 489, 490, 491, 492, 495, 576 and 689. This schedule is not applicable to direct access customers after December 31, 2010. (C) (C)

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule			
7		0.000	¢ per kWh
15		0.000	¢ per kWh
32		0.000	¢ per kWh
38		0.000	¢ per kWh
47		0.000	¢ per kWh
49		0.000	¢ per kWh
75			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh
	Subtransmission	0.000	¢ per kWh
83		0.000	¢ per kWh
85			
	Secondary	0.000	¢ per kWh
	Primary	0.000	¢ per kWh

SCHEDULE 123 (Continued)

DECOUPLING ADJUSTMENT (Continued)

Schedule	Adjustment Rate	
575		
Secondary	0.021 ¢ per kWh	
Primary	0.021 ¢ per kWh	
Subtransmission	0.021 ¢ per kWh	
583	0.021 ¢ per kWh	
585		
Secondary	0.021 ¢ per kWh	
Primary	0.021 ¢ per kWh	
589		
Secondary	0.021 ¢ per kWh	
Primary	0.021 ¢ per kWh	
Subtransmission	0.021 ¢ per kWh	
590	0.021 ¢ per kWh	
591	0.021 ¢ per kWh	
592	0.021 ¢ per kWh	
595	0.021 ¢ per kWh	
689		(N)
Secondary	0.004 ¢ per kWh	
Primary	0.004 ¢ per kWh	
Subtransmission	0.004 ¢ per kWh	(N)

TIME AND MANNER OF FILING

Commencing in 2014, the Company will submit to the Commission the following information by November 1 of each year:

1. The proposed price changes to this Schedule to be effective on January 1st of the subsequent year based on a) the amounts in the SNA Balancing Accounts and b) the amount in the LRRA Balancing Account.

2. Revisions to this Schedule which reflect the new proposed prices and supporting work papers detailing the calculation of the new proposed prices and the SNA weather-normalizing adjustments.

SCHEDULE 123 (Concluded)

SPECIAL CONDITIONS

1. The Fixed Charge Energy Rate, Monthly Fixed Charge per Customer and the Lost Revenue Rate will be updated concurrently with a change in the applicable base revenues used to determine the rates.

2. Weather-normalized energy usage by applicable rate schedule will be determined in a manner equivalent to that used for determining the forecasted loads used to establish base rates.

3. No revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than 2% to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. Rate revisions resulting in a rate decrease are not subject to the 2% limit.

4. The LRRA prices for Customers served under the provisions of Schedules 485, 489, 490, 491, 492, 495, and 689 will be calculated to apply to distribution services only. **(C)**

5. The SNA and LRRA mechanisms will terminate on December 31, 2022 if not extended by the Commission.

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, 592 595 and 689, or served (C) 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 1.0320 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, 495, and 689 as an offset to NVPC. (C)
- 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.
- Include actual State and Federal Production Tax Credits.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0320 to account for franchise fees, uncollectables, and OPUC fees.

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 126 (Continued)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate
90	0.000 ¢ per kWh
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
95	0.000 ¢ per kWh
485	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
489	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
Subtransmission	0.000 ¢ per kWh(2)
490	0.000 ¢ per kWh
491	0.000 ¢ per kWh
492	0.000 ¢ per kWh
495	0.000 ¢ per kWh
515	0.000 ¢ per kWh(2)
532	0.000 ¢ per kWh(2)
538	0.000 ¢ per kWh(2)
549	0.000 ¢ per kWh(2)
575	
Secondary	0.000 ¢ per kWh(1)
Primary	0.000 ¢ per kWh(1)
Subtransmission	0.000 ¢ per kWh(1)
583	0.000 ¢ per kWh(2)
585	0.000 ¢ per kWh(2)
Seconday	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
589	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
Subtransmission	0.000 ¢ per kWh(2)

(M)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 126 (Concluded)

POWER COST VARIANCE RATES (Continued) (N)

Schedule	Adjustment Rate	
590	0.000 ¢ per kWh	(M)
591	0.000 ¢ per kWh(2)	
592	0.000 ¢ per kWh(2)	
595	0.000 ¢ per kWh(2)	(M)
689		(N)
Secondary	0.000 ¢ per kWh(2)	
Primary	0.000 ¢ per kWh(2)	
Subtransmission	0.000 ¢ per kWh(2)	

(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued. (N)

TERM

Effective for service on and after January 17, 2007 and continuing until terminated by the Commission.

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

SCHEDULE 132
FEDERAL TAX REFORM CREDIT

PURPOSE

This schedule amortizes the Commission-approved deferred 2018 net benefits associated with the tax rules and provisions implemented through the U.S. Tax Cut and Jobs Act of 2017.

APPLICABLE

To all bills for Electricity Service.

ADJUSTMENT RATES

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

Schedule	Adjustment Rate		
7	(0.162)	¢ per kWh	
15/515	(0.316)	¢ per kWh	
32/532	(0.146)	¢ per kWh	
38/538	(0.179)	¢ per kWh	
47	(0.272)	¢ per kWh	
49/549	(0.191)	¢ per kWh	
75/575/76R/576R			
Secondary	(0.076)	¢ per kWh	
Primary	(0.075)	¢ per kWh	
Subtransmission	(0.090)	¢ per kWh	
83/583	(0.112)	¢ per kWh	
85/585			
Secondary	(0.096)	¢ per kWh	
Primary	(0.089)	¢ per kWh	
89/589/689			(C)
Secondary	(0.076)	¢ per kWh	
Primary	(0.075)	¢ per kWh	
Subtransmission	(0.090)	¢ per kWh	

SCHEDULE 135
DEMAND RESPONSE COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the expenses associated with demand response pilots not otherwise included in rates. This adjustment schedule is implemented as an automatic adjustment clause as provided for under ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689. (C)

ADJUSTMENT RATE

The Adjustment Rate, applicable for service on and after the effective date of this schedule are:

Schedule	Adjustment Rate	
7	0.044	¢ per kWh
15/515	0.033	¢ per kWh
32/532	0.040	¢ per kWh
38/538	0.037	¢ per kWh
47	0.048	¢ per kWh
49/549	0.048	¢ per kWh
75/575		
Secondary	0.036	¢ per kWh(1)
Primary	0.035	¢ per kWh(1)
Subtransmission	0.035	¢ per kWh(1)
83/583	0.040	¢ per kWh
85/585		
Secondary	0.038	¢ per kWh
Primary	0.038	¢ per kWh

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

SCHEDULE 137
CUSTOMER-OWNED SOLAR PAYMENT OPTION
COST RECOVERY MECHANISM

PURPOSE

This Schedule recovers the costs associated with the Solar Payment Option pilot not otherwise included in rates. This adjustment schedule is implemented as an "automatic adjustment clause" as provided for under ORS 469A.120, and defined in Renewable Portfolio Standards, ORS 757.210.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R, and 689. (C)

ADJUSTMENT RATES

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

Schedule		Adjustment Rate	
7		0.047	¢ per kWh
15		0.037	¢ per kWh
32		0.044	¢ per kWh
38		0.044	¢ per kWh
47		0.053	¢ per kWh
49		0.051	¢ per kWh
75			
	Secondary	0.040	¢ per kWh(1)
	Primary	0.039	¢ per kWh(1)
	Subtransmission	0.039	¢ per kWh(1)
83		0.043	¢ per kWh
85			
	Secondary	0.042	¢ per kWh
	Primary	0.041	¢ per kWh

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

SCHEDULE 139
NEW LARGE LOAD TRANSITION COST ADJUSTMENT

AVAILABLE

In all territory served by the Company.

APPLICABLE

Applicable to Large Nonresidential Customers that have selected New Large Load Cost-of-Service Opt-Out service under Schedule 689. This transition adjustment will be paid when the Customer begins service under Schedule 689. This transition adjustment represents 20 percent of the Company's fixed generation costs and is subject to change annually during the Customer's five-years enrolled in Schedule 689. At the end of the Customer's five-year payment term of these transition adjustments, the Customer will no longer be subject to the charges in this rate schedule. The Customer will not be subject to the charges in this rate schedule with at least three years of notification to the Company of a return to cost-of-service pricing.

TRANSITION COST ADJUSTMENT

Minimum Five Year Opt-Out

For Period 1 (2019), the Transition Cost Adjustment will be:

Period	Sch. 689 Secondary Voltage ¢ per kWh	Sch. 689 Primary Voltage ¢ per kWh	Sch. 689 Subtransmission Voltage ¢ per kWh
2019	0.679	0.667	0.658
2020	0.679	0.667	0.658
2021	0.679	0.667	0.658
2022	0.679	0.667	0.658
2023	0.679	0.667	0.658
After 2024	0.679	0.667	0.658

SCHEDULE 139 (Concluded)

SPECIAL CONDITIONS

1. Annually, the total amount collected in Schedule 139 New Large Load Transition Cost Adjustments will be incorporated into all rate schedules, through either System Usage Charges or Distribution Charges. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year.

2. Annually, changes in fixed generation revenues resulting from either return to or departure from Cost of Service pricing by Schedules 689 Customers relative to the Company's most recent general rate case will be incorporated into the System Usage Charges or Distribution Charges of all rate schedules. Such adjustment to the System Usage or Distribution Charges will be made at the time the Company files final rates for Schedule 125, and will be effective on January 1st of the following calendar year. The adjustment to the System Usage or Distribution Charges resulting from changes in fixed generation revenues shall not result in an overall rate increase or decrease of more than 2 percent except as noted below. For those Enrollment Periods in which the first-year Schedule 139 Transition Adjustments are expected to be positive charges to participants, the projected first-year revenues from Schedule 139 will be netted against the changes in fixed generation costs for purposes of calculating the proposed overall rate increase or decrease. Should the rate increase or decrease exceed 2 percent, the amounts exceeding 2 percent will be deferred for future recovery through a balancing account. This balancing account will be considered an "Automatic Adjustment Clause" as defined in ORS 757.210. For purposes of calculating the percent change in rates, Schedule 125 prices with and without the increased/decreased participating load will be determined.

TERM

The term of applicability under this schedule will correspond to a Customer's term of service under Schedules 689 but will not exceed 60 months.

SCHEDULE 143 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule	Part A	Part B	Adjustment Rate	
515	(0.013)	0.000	(0.013)	¢ per kWh
532	(0.015)	0.000	(0.015)	¢ per kWh
538	(0.014)	0.000	(0.014)	¢ per kWh
549	(0.018)	0.000	(0.018)	¢ per kWh
575				
Secondary	(0.014)	0.000	(0.014)	¢ per kWh
Primary	(0.013)	0.000	(0.013)	¢ per kWh
Subtransmission	(0.013)	0.000	(0.013)	¢ per kWh
583	(0.015)	0.000	(0.015)	¢ per kWh
585				
Secondary	(0.015)	0.000	(0.015)	¢ per kWh
Primary	(0.014)	0.000	(0.014)	¢ per kWh
589				
Secondary	(0.014)	0.000	(0.014)	¢ per kWh
Primary	(0.013)	0.000	(0.013)	¢ per kWh
Subtransmission	(0.013)	0.000	(0.013)	¢ per kWh
590	(0.013)	0.000	(0.013)	¢ per kWh
591	(0.013)	0.000	(0.013)	¢ per kWh
592	(0.013)	0.000	(0.013)	¢ per kWh
595	(0.013)	0.000	(0.013)	¢ per kWh
689				
Secondary	(0.014)	0.000	(0.014)	¢ per kWh (N)
Primary	(0.013)	0.000	(0.013)	¢ per kWh
Subtransmission	(0.013)	0.000	(0.013)	¢ per kWh (N)

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

BALANCING ACCOUNT

The Company will maintain balancing accounts to track the difference between the Trojan Nuclear Decommissioning Trust Fund refund, ongoing refunds, and the ISFSI payments and the actual Schedule 143 revenues. This difference will accrue interest at the Commission-authorized rate for deferred accounts.

SCHEDULE 145
BOARDMAN POWER PLANT
DECOMMISSIONING ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the revenue requirement effect of the decommissioning expenses related to the Boardman power plant. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689. (C)

ADJUSTMENT RATES

Schedule 145 Adjustment Rates will be set based an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate
7	0.026 ¢ per kWh
15	0.020 ¢ per kWh
32	0.024 ¢ per kWh
38	0.022 ¢ per kWh
47	0.029 ¢ per kWh
49	0.029 ¢ per kWh
75	
Secondary	0.021 ¢ per kWh
Primary	0.021 ¢ per kWh
Subtransmission	0.021 ¢ per kWh
83	0.024 ¢ per kWh
85	
Secondary	0.023 ¢ per kWh
Primary	0.023 ¢ per kWh

SCHEDULE 146
COLSTRIP POWER PLANT
OPERATING LIFE ADJUSTMENT

PURPOSE

This schedule establishes the mechanism to implement in rates the Company's share of the revenue requirement effect of the change in the Colstrip Power Plant Units 3 and 4 and associated common facilities currently assumed end of depreciable life year from 2042 to 2030 as specified in 2016 Oregon Laws, Chapter 28 (SB 1547), Section 1. This schedule is implemented as an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all bills for Electricity Service except Schedules 76R, 485, 489, 490, 491, 492, 495, 576R and 689. (C)

ADJUSTMENT RATES

Schedule 146 Adjustment Rates will be set based on an equal percent of Energy Charge revenues applicable at the time of any filing that revises rates pursuant to this schedule.

Schedule	Adjustment Rate	
7	0.000	¢ per kWh
15/515	0.000	¢ per kWh
32/532	0.000	¢ per kWh
38/538	0.000	¢ per kWh
47	0.000	¢ per kWh
49/549	0.000	¢ per kWh
75/575		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh
83/583	0.000	¢ per kWh
85/585		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
89/589		
Secondary	0.000	¢ per kWh
Primary	0.000	¢ per kWh
Subtransmission	0.000	¢ per kWh

SCHEDULE 149 (Continued)

ADJUSTMENT RATES

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15/515	0.000 ¢ per kWh
32/532	0.000 ¢ per kWh
38/538	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49/549	0.000 ¢ per kWh
75/575	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
76R/576R	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
83/583	0.000 ¢ per kWh
85/485/585	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
89/489/589/689	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh
90/490/590	0.000 ¢ per kWh
91/491/591	0.000 ¢ per kWh
92/492/592	0.000 ¢ per kWh
95/495/595	0.000 ¢ per kWh

(C)

SCHEDULE 689
NEW LARGE LOAD
COST-OF-SERVICE OPT-OUT
(>10 MWa)

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer that meets the requirements for New Large Load and has elected to opt out of the Company's cost-of-service based pricing. Participation in this program means Customer is giving up the right granted under state law to receive Electricity from the Company at a rate based on the cost of electric generating resources owned in whole or in part by the Company.

New Large Load must be separately metered from an existing facility or measured separately with comparable accuracy in a mutually agreed upon form between the Customer and the Company as specified within the service agreement for this program. The New Large Load Customer must meet a minimum load of 10 MWa over a consecutive 12-month period within the first 36 months of receiving service.

Per Oregon Administrative Rule 860-038-0710, New Large Load consists of any load associated with a new facility, an existing facility, or an expansion of an existing facility which (1) has never been contracted for or committed to receiving electric service in writing with the Company and (2) Is expected to result in a 10 MWa or more increase in the Customer's power requirements during the first three years after operations begin.

Service under this rate schedule begins at the time that the new meter is energized, or at a mutually agreed upon date between the Customer and the Company. The Company and Customer will identify the meter(s) that qualifies for service under this rate schedule within the enrollment contract between the Customer and the Company. A Customer is required to have interval metering and meter communications in place prior to initiation of service under this schedule. Construction meters and energy supplied during construction will not apply to this rate schedule.

Service under this schedule is limited to the first 119 MWa that applies to Schedule 689, or at an amount subject to the long-term transmission planning constraints of the Company. Load served under Schedule 689 will not apply to the Long Term Direct Access cap that applies to Schedules 485, 489, 490, 491, 492 and 495. The expected load of the Customer, as stated in the service agreement between the Customer and the Company will be the amount of load that applies toward the New Load Direct Access cap. The expected load for each Customer will apply toward the cap limit for the first 60 months of service. Following 60 months of service on Schedule 689, the actual load of the customer will apply toward the New Large Load Cost-of-Service opt-out limit and the total amount of load under the limit will be adjusted.

SCHEDULE 689 (Continued)

MONTHLY RATE

The Monthly Rate will be the sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$3,340.00	$1,890.00	$3,970.00
Distribution Charges**			
The sum of the following:			
per kW of Facility Capacity			
First 4,000 kW	$1.53	$1.49	$1.49
Over 4,000 kW	$1.22	$1.18	$1.18
per kW of monthly On-Peak Demand	$2.61	$2.53	$1.27
System Usage Charge			
per kWh	(0.014) ¢	(0.015) ¢	(0.015) ¢
Administrative Fee	$0.00	$0.00	$0.00

* 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 SP.

SCHEDULE 689 (Continued)

ADDITIONAL APPLICABLE RATES

Resource Intermittence Capacity Charge (RIC)

This rate is applicable to Schedule 689 Customers when the Electricity Schedule of the Customers for which the Electricity Service Supplier (ESS) has scheduling responsibility is different from the actual amount of energy delivered by the Company to meet the actual aggregated hourly load requirements of the Customers for which the ESS serves. This charge is applied when the Company supplies energy to support the Electricity Schedule of the ESS any time during the Customer's billing period. This charge applies for the Customer's entire term of service on Schedule 689.

	Secondary	Primary	Subtransmission
per kW of monthly On-Peak Demand	$0.58	$0.58	$0.58

Resource Adequacy Capacity Charge (RAD)

This rate is applicable to Schedule 689 Customers during all months of service on this schedule, except for customers taking service under the Standard Offer. This charge represents the operational costs of securing a Customer's capacity should they return to Company energy supply. This charge will be applied net of Schedule 139 transition adjustments when Schedule 139 is applicable.

	Secondary	Primary	Subtransmission
per kW of monthly On-Peak Demand	$0.00	$0.00	$0.00

SCHEDULE 689 (Continued)

ENERGY SUPPLY

The Customer may elect to purchase Energy from an ESS (Direct Access Service) or from the Company (Company Supplied Energy or Standard Offer). Election of energy supply from an ESS or from the Company applies toward the cap of this program. If the Customer submits an Electricity Schedule to the Company, the Customer must be certified by the Oregon Public Utilities Commission as a registered ESS and is subject to the requirements relating to ESSs specified in Rule K of this Tariff.

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. The Customer may only receive energy from ESSs that are registered to supply energy to PGE's balancing authority area. The RIC and the RAD apply during all months of service on this supply option.

Company Supplied Energy

The Company Daily Market 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.
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.

If a Customer taking service under this option has completed 60 months of payment for cost-of-service opt out transition adjustments, additional charges to meet the state of Oregon's Renewable Portfolio Standard may apply. If additional charges are required, the Customer and the Company will agree to a minimum term of service for this option in a separate service agreement between the Customer and the Company. The RIC and the RAD apply during all months of service on this supply option.

Wheeling Charge
The Wheeling Charge will be $1.793 per kW of monthly Demand.

SCHEDULE 689 (Continued)

Standard Offer

The Company Long Term Market Energy Option (Standard Offer) is based on energy and capacity supply procured and managed by the Company on behalf of Customer(s). Prices for this option will be specified in a negotiated contract between the Customer(s) and the Company. The cost of the energy, capacity, and other attributes specified in the contract will be contingent upon Customer desired supply characteristics and will capture the State of Oregon's renewable portfolio standard requirements. The RIC and the RAD apply during all months of service on this supply option.

RETURN TO COST OF SERVICE PRICING

Customers must provide not less than three years notice to terminate service under this Schedule, or return to Company Supplied Energy. If a Customer's return to Company Supplied Energy or cost-of-service based service increases rates for existing cost-of-service Customers by more than 0.5%, the Customer returning to company supplied energy will be subject to the forward looking rate adder below for three years beginning from the date of notice to return to Company Supplied Energy.

Energy Supply Return Charge
$0.00 per kWh

TRANSMISSION CHARGE

Transmission and Ancillary Service charges as specified in the Company's OATT, as specified and approved by the Federal Energy Regulatory Commission, will apply.

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 689 (Continued)

ON AND OFF PEAK HOURS

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

LOSSES

The following adjustment factors will be used where losses are to be included in the Energy Charges:

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

REACTIVE DEMAND CHARGE

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

ADJUSTMENTS

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

EXISTING LOAD SHORTAGE TRANSITION ADJUSTMENT

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Customer and to the Existing Load Shortage of the Customer's Affiliated Customers. An Affiliated Customer is a controlling interest which is held by another Customer, engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage is the larger of zero or a Customer's average historic cost-of-service load plus Incremental Demand Side Management less the average cost-of-service eligible load during the previous 60 months. Average Historical Cost-of-Service Load is the average monthly Cost-of-Service Eligible Load during the preceding 60 months prior to signing of the service agreement between the Customer and the Company for service on this rate schedule. Incremental Demand Side Management is the effective net impact of energy efficiency measures after the Customer has entered a written and binding agreement with the Company through the service agreement between the Customer and the Company.

SCHEDULE 689 (Continued)

The Existing Load Shortage Transition Adjustment for the first 60 months is equal to 75 percent of fixed generation costs plus net variable power cost transition adjustments during the first 60 months after enrollment in this rate schedule. The Existing Load Shortage Transition Adjustment after 60 months of service on this rate schedule is equal to 100 percent of fixed generation costs plus net variable power cost transition adjustments.

The Customer may be exempted from the Existing Load Transition Adjustment if the Customer can demonstrate that the change in load in question is not due to load shifting activity described in OAR 860-038-0740. The Company will provide written notification to the Customer at least 30 days prior to charging the Existing Load Shortage Transition Adjustment. The Customer must demonstrate the change in load by providing a written request for exemption that includes explanation for the change in load and support from available documentation. The Company will approve or deny the request of the Customer within 90 days and will not charge the Existing Load Transition Adjustment within this time period.

ENROLLMENT

The Customer must notify the Company of its intent to enroll in this Schedule and opt out of cost-of-service rates at the earlier of one year prior to the expected energization date of the new meter or upon entering a written and binding service agreement for distribution service with the Company. The date of energization date will be agreed upon between the Customer and the Company within a written and binding agreement for service under this Schedule provided by the Company to the Customer. The Customer warrants that the person signing the service agreement has full authority to bind the Customer to such agreement. Customer enrollment may be contingent upon additional agreements between the Company and the Customer, including but not limited to Minimum Load Agreements. The Company will not accept applications for service that exceed to the current program cap, or load remaining under the enrolled cap. Customer applications with expectations of load to grow beyond the program cap will require separate application and approval by the Commission.

If a Customer elects Direct Access Service, acceptance of an Enrollment Direct Access Service Request (DASR) is required by the Company. The Company will notify the ESS when to send the enrollment DASR. Prerequisites and notification requirements are as contained in Rule K.

Enrollments that do not meet the conditions above, or that are found in breach of the service agreement between the Customer and the Company are not eligible for enrollment in this rate schedule. If the Customer or the Customer's selected ESS cannot demonstrate creditworthiness, the Customer will not be eligible for service under this Rate Schedule and will be enrolled in an applicable cost-of-service based rate.

SCHEDULE 689 (Continued)

Prior to receiving service, the Customer will agree to only purchase energy from a resource mix consistent with the specifications of OAR 860-038-0730(1), which does not include coal-fired generation. This provision will be included in the signed agreement between the Customer and the Company. Customers found in violation of the provision that no coal will be delivered by wire after January 1, 2030 will be enrolled in an applicable cost of service rate.

DE-ENROLLMENT

After 36 months of service, if the actual load of the facility does not meet the minimum load requirements for service under this rate schedule, the Company may de-enroll the Customer from this rate schedule. The Company will provide the Customer and the Commission with written notification of its proposal to move the Customer to the applicable cost-of-service rate schedule. The Customer is subject to all notice requirements and provisions of the cost-of-service rate schedule. The Customer may elect to opt-out of cost-of-service in a subsequent direct access window, and in accordance with the Company's tariff requirements. Customers that opt out of cost of service in the September direct access window will be subject to Schedule 129 transition adjustment schedule charges. A Customer that is de-enrolled will be dropped from their ESS and served by the Company at an applicable cost-of-service rate.

The Customer must provide written notification within 60 days of notification of de-enrollment to the Company and the Commission to demonstrate that its reduction in load to less than 10 MWa was the result of equipment failure, incremental demand side management, load curtailment or load control, or other causes outside the control of the Customer. The Customer must provide documentation to demonstrate this.

The Company will not transition a Customer to a new rate schedule before 90 days has passed since notification from the Company.

TERM

Service under this rate schedule will be for the minimum of 36 months to determine if the minimum load required for service under this rate schedule, 10 MWa for 12 consecutive months, is met. Upon completion of this term, if 10 MWa for 12 consecutive months is met, service will continue under this schedule. If the minimum load requirement is not met, the Customer will be de-enrolled and transitioned to the applicable cost-of-service rate and subject to all notice requirements and provisions of the schedule.

SCHEDULE 689 (Concluded)

SPECIAL CONDITIONS

1. The rate the Customer pays for Electricity may be higher or lower than the rates charged by the Company to similar Customers not taking service under this schedule, including competitors to the Customer.

2. Neither the Company, its employees and agents, the Commission nor any other agency of the State of Oregon has made any representation to the Customer regarding future Electricity prices that will result from the Customer's election of service under this schedule.

3. The Customer is selecting this schedule based solely upon its own analysis of the benefits of this schedule. The Customer has available to it energy experts that assisted in making this decision.

4. If the Customer is served at either primary or subtransmission voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and in addition, the necessary wiring on both sides of the transformers. All transformers, equipment, and wiring will be of types and characteristics approved by the Company, and arrangement and operation of such equipment will be subject to the approval of the Company.

5. Customers selecting service under this Schedule will be limited to a Company/ESS Split Bill.

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	0.403 ¢ per kWh	Distribution Charge	
532	0.137 ¢ per kWh	Distribution Charge	
538	0.189 ¢ per kWh	Distribution Charge	
549	0.179 ¢ per kWh	Distribution Charge	
575			
Secondary	0.046 ¢ per kWh	System Usage Charge	
Primary	0.046 ¢ per kWh	System Usage Charge	
Subtransmission	0.046 ¢ per kWh	System Usage Charge	
583	0.075 ¢ per kWh	System Usage Charge	
585			
Secondary	0.069 ¢ per kWh	System Usage Charge	
Primary	0.068 ¢ per kWh	System Usage Charge	
589			
Secondary	0.046 ¢ per kWh	System Usage Charge	
Primary	0.046 ¢ per kWh	System Usage Charge	
Subtransmission	0.046 ¢ per kWh	System Usage Charge	
590	0.014 ¢ per kWh	System Usage Charge	
591	0.427 ¢ per kWh	Distribution Charge	
592	0.073 ¢ per kWh	Distribution Charge	
595	0.427 ¢ per kWh	Distribution Charge	
689			(N)
Secondary	0.046 ¢ per kWh	System Usage Charge	
Primary	0.046 ¢ per kWh	System Usage Charge	
Subtransmission	0.046 ¢ per kWh	System Usage Charge	(N)

RULE G
DIRECT ACCESS SERVICE AND BILLING

1. Direct Access Service

All Customers, except Residential, may elect to receive Direct Access Service from an ESS under the terms of the parallel Direct Access schedule (500 series). Direct Access Service is also an option for eligible Nonresidential Customers served on Schedules 485, 489 and 689. (C)

A. **Enrollment**

Direct Access Service is only available upon acceptance of an Enrollment DASR by the Company. Prerequisites and notification requirements are as contained in each service schedule and Rule K.

B. **Emergency Default Service**

The Company will provide Emergency Default Service under Schedule 81 when an ESS or the Customer informs the Company that the ESS is no longer providing service or when the Company becomes aware that the Customer is no longer receiving service from the ESS and the Company has not received the 10 business day notice required for Standard Service under the appropriate schedule.

2. Special Requirements for Direct Access Billings

A. **Generally**

A Customer purchasing Electricity from an ESS may choose from two billing options: the ESS bills for all services (ESS Consolidated Bill) or the Company and the ESS each bill for their respective services (Company/ESS Split Bill).

1) **Company/ESS Split Bill**

When the Customer is receiving a Company/ESS Split Bill, the Company may disconnect Electricity Service for nonpayment of Direct Access Service under the guidelines set forth in Rule H.

2) **ESS Consolidated Bill**

When the Customer receives an ESS Consolidated Bill, failure of the Customer to pay the ESS for Direct Access Service does not relieve the ESS of the responsibility to pay the Company for Direct Access Services and any other Company charges.