PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah
Portland, Oregon 97232

October 14, 2022

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

RE: Advice No. 22-011
PacifiCorp New Demand Response Program for Commercial and Industrial Customers Using the Provisions of Schedule 106 and Canceling Schedule 218

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp, d/b/a Pacific Power (PacifiCorp or the Company), submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. As described further below, this filing proposes a new demand response program for commercial and industrial customers using the provisions of Schedule 106 and cancels tariff Schedule 218. The Company requests an effective date of November 16, 2022.

Sheet No.	Tariff	Title
Twenty-Ninth Revision of Sheet No. INDEX-3		Table of Contents - SCHEDULES
CANCELLED Sheet No. 218-1	Schedule 218	Interruptible Service Pilot
CANCELLED Sheet No. 218-2	Schedule 218	Interruptible Service Pilot

Purpose

The filing requests authorization to expand the demand response offerings available to Oregon customers. With this filing, the Company proposes the following changes:

- Introduce a demand response program for commercial and industrial customers using the provisions of the recently approved Schedule 106.
- Position commercial and industrial costs for recovery through Schedule 291.
- Cancel Schedule 218

Demand Response Background

This filing is part of the continuing implementation of the conditions attached to Action Item No. 4 in Order No. 20-186 in docket LC 70 by the Public Utility Commission of Oregon (Commission) which requires, in part, that:

> *PacifiCorp pursue demand response acquisition with a demand response RFP. PacifiCorp should work with non-bidding stakeholders from Oregon and other interested states to determine whether PacifiCorp should move forward with cost-effective demand response bids, or with a demand response pilot, or both.*

The demand response request for proposals (RFP) was issued on February 8, 2021 (2021 Demand Response RFP). The Company emphasized in its request that bidders include programs in Oregon or Washington service areas and products that achieve at a minimum 3 megawatts (MW) in three years, scalable to 25 MW over five to 10 years.

The Company received bids from 18 firms covering multiple programs for multiple sectors.

RFP bids were scored based on cost, volume, and equity criteria and the top bid for each program category was selected for inclusion into the 2021 Integrated Resource Plan (IRP) model.

Each program category represents a discrete set of customer end uses, e.g., irrigation or residential water heating. Modeling in the IRP reflects the top bid because all bids within a program category rely on the same pool of customers. Costs were characterized via RFP bids and the Conservation Potential Assessment (CPA) and compared against supply side resources.

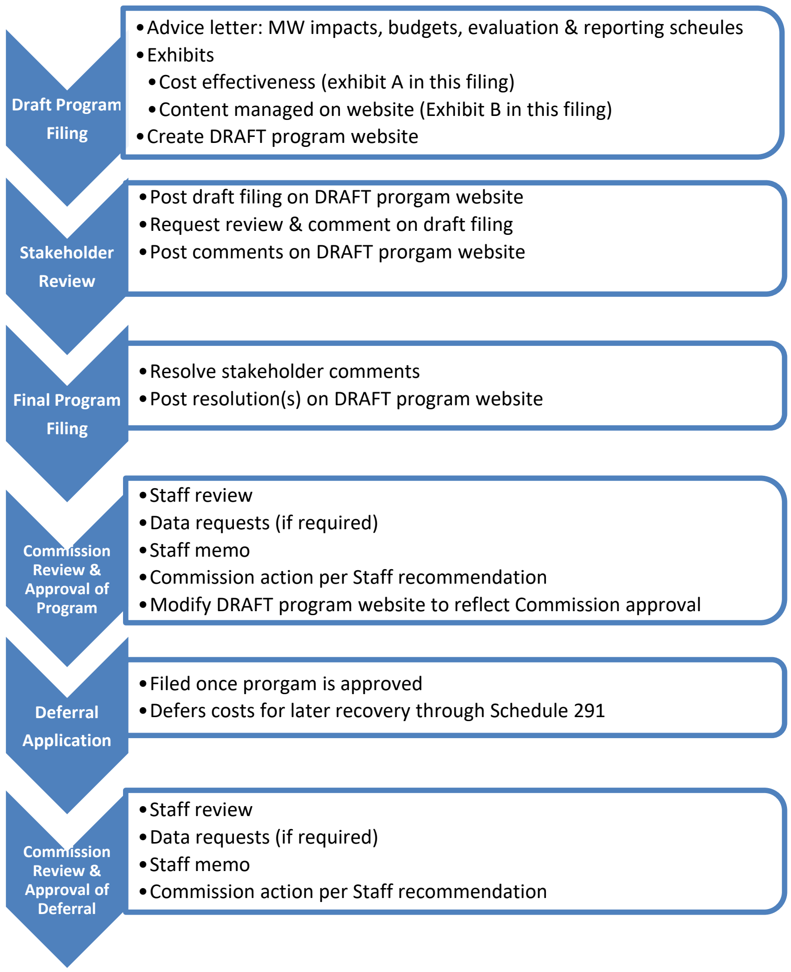
The modeling identified a need for demand response not just in the short term but throughout the planning horizon (2021–2040). The 2021 IRP preferred portfolio included the addition of 33 MW of cost-effective demand response in Oregon for 2022 with additional MWs being brought on in subsequent years. Since the selected resources cover multiple customer types and programs, the Company requested and received approval for a broad demand response tariff, Schedule 106 to support multiple programs. PacifiCorp has already utilized Schedule 106 to expand the offer for irrigation customers.[1] This is the second demand response program to utilize the provisions of Schedule 106.

<u>Using the provisions of Schedule 106 to add a demand response program</u>

As outlined in Advice 22-004, Schedule 106 is designed to enable multiple demand response programs. Each new demand response program is filed with the Commission and include the information found on the website, deferral request (filed after program approval), cost effectiveness, evaluation and reporting schedule and other details that may be required to support an approval request. Figure 1 outlines how the Schedule 106 process is used to add a new demand response program. The information for the new demand response program proposed in this filing is included as Confidential Exhibit A and Exhibit B.

[1] Advice 22-004 filed March 28, 2022, and approved May 5, 2022.

Figure 1 – Schedule 106 Process for Adding Demand Response Programs



As outlined in Advice 22-004, the Company plans to review this program annually for performance and the need for any changes. The Company will generally consider changes to its programs annually, though a program that is performing well may not require annual changes. Conversely, the Company may propose changes more frequently than annually if there is compelling market data. To initiate a program change, the Company will follow the process provided in Advice 22-004.[2]

Based on stakeholder conversations during the review and approval of the irrigation filing referenced above, the Company will not use the proposed program change process to make changes to Schedule 106, remove or add pilots/programs to Schedule 106, or propose an increase of expenditures greater than 130 percent of total estimated annual budgets for programs under Schedule 106. Changes to Schedule 106, additional or removal of pilots/programs, and budget

[2] Exhibit E.

increases of more than 130 percent will be made using the typical regulatory tariff revision process.

Table 1 - Oregon commercial and industrial selections in the 2021 IRP

	2022	2023	2024	2025	2026
Incremental MW (gen)	16.1	16.1	0	0	0
Cumulative MW (gen)	16.1	32.2	32.2	32.2	32.2

Delivery of the commercial and industrial program

PacifiCorp has selected Enel X to deliver the program. They were the successful bidder in the 2021 Demand Response RFP to deliver these services for PacifiCorp's customers in Oregon and Washington. They are also delivering demand response services for the same customer group in PacifiCorp's Rocky Mountain Power service territory.

Enel X is responsible for the installation, operation and maintenance of the load control devices, dispatch of the devices as directed by the Company, customer participation, customer service, and issuance of customer incentives. Enel X also provides a software application to all participating customer sites. The customer application allows participating customers to benchmark, manage, and optimize their energy consumption both during demand response events and during normal business operations. The Company, Enel X, and the Energy Trust of Oregon team will collaborate, so customers have cohesive messaging around energy efficiency and demand response opportunities at their facilities.

The commercial demand response program is part of an overall equity approach by the Company to make demand response programs available to all customer classes. The program will be focused on finding the highest connected end use loads available during the dispatch period(s). Enel X is a strong supporter of diverse businesses and has experience utilizing diverse subcontractors, including those installing and maintaining hardware at customer sites. The Enel X team delivering or supporting this program includes a diverse work force.

Commercial and industrial Program Period, Size and Grid Services Provided

The Company is proposing an on-going commercial and industrial demand response program without an end date to align with on-going capacity needs in the 2021 IRP period (2021–2040). The four product categories; hour-ahead, 20 minute-ahead, seven minute-ahead, and real time (no notice) options provide curtailment, regulation reserve, contingency reserve and frequency response grid services to the Company and are included in the impacts included in Table 2. Estimated impacts by product category as percentage of the totals in Table 2 is provided in Table 3.

Table 2 – Total commercial and industrial program impacts and participation estimates

	2022-2023	2024	2025	2026
Incremental MW[3] (gen)	42.78	10.7	0	0
Cumulative MW (gen)	42.78	53.48	53.48	53.48
Participants (inc. sites)	80	20	0	0

Table 3 – Estimated impacts by product category

Product Category	Percentage of total impacts in Table 2
Hour-ahead	33
20 minute-ahead	33
Seven minute-ahead	17
Real time (no notice)	17

Cancel Schedule 218

The Interruptible Service Pilot, Schedule 218, was approved in the Company's 2021 general rate case, docket UE 374, as an option for large customers to provide the Company with more flexible loads in return for reductions to their bills. By design the pilot had aggregate limits on loads that could participate, minimum requirements for the interruptible load at each customer and included administrative fees to offset Company costs of manual billing. The pilot became effective on January 1, 2021,[4] after approval of Advice No. 20-17 and the Schedule 218 preliminary report was filed on June 15, 2022. The report indicated no customers were participating in the pilot.

Based on pilot uptake and a need to manage co-participation in programs with the same intended outcomes, the Company is proposing to cancel this pilot and instead secure more flexible loads with the proposed demand response program for commercial and industrial customers. The proposed program is available to a broader range of customers and, as described above, offers multiple products with different incentives. The combination of more eligible customers and participation options is designed to secure the flexible loads originally sought in the Schedule 218 pilot.

Commercial and Industrial Program Costs

Estimated costs for the program are provided in Table 4 and include vendor costs, customer incentives, customer outreach/advertising, evaluation, measurement and verification, and utility staffing costs directly attributable to managing the program. Costs include the impacts of customers participating in the product categories that align with the percentage estimates provided in Table 3.

[3] MW volumes represent maximum capacity available during a given year.
[4] UE 374 Compliance filing Advice 20-017.

Table 4 – Commercial and Industrial Program Costs

	2022*	2023	2024	2025	2026
Total Program Costs[5]	$3,293,417	$3,906,166	$3,891,633	$3,891,633	$3,875,663

*Participation in 2022 will vary depending on when the program is approved. Customers can enroll in the approved program anytime during the year. At this point in the year, any 2022 costs should be considered as incurred in either 2022 or 2023 (and additive to the 2023 costs in Table 2).

Cost Recovery

PacifiCorp proposes to recover the approved commercial and industrial demand response program costs through Schedule 291 but is not proposing a change to Schedule 291 as part of this filing. Once the commercial and industrial demand response program is approved, the Company will file an application to defer the costs incurred through this program for later recovery through Schedule 291.

Annual Reporting and Evaluations

PacifiCorp will provide an annual report for the commercial and industrial program by March 31 of the following year with information on participating customer and load types, aggregate impacts by product type, opt outs, incentive and non-incentive expenditures, enrollment changes, customer service/satisfaction and cost effectiveness. The first evaluation will be completed after 2023, the first full year of program operation. Subsequent evaluations will occur no less frequently than every two years.

Cost Effectiveness

As discussed at the December 6, 2021, Demand Response Workshop, the Company proposes to continue the use of the 2016 California Demand Response Protocol. Cost-effectiveness from a Total Resource Cost (TRC) and Utility Cost Test (UCT) perspective will be provided prospectively when seeking Commission approval for a new demand response program and retrospectively as part of the annual reporting. The cost effectiveness prospective provided will be similar to information on energy efficiency in Oregon.

Cost effectiveness for each of the four product categories in the commercial and industrial demand response program is provided in Confidential Exhibit A. All product categories are cost effective from the utility cost and total resource cost perspectives when 10 years of benefits and costs are compared. The 20-minute and seven-minute product results are sensitive to the utility need for and utility value of reserves in 2025 and beyond. The forecast from the 2021 IRP for increased utility-scale battery installations diminish the reserve value in outer years.

In response to initial comments from Commission Staff, the Company re-ran the cost effectiveness model using longer-persisting reserve values. The average reserve values across the first five years was assumed through the final five years of the study period. As a result, the

[5] Additional detailed cost breakouts can be found in Confidential Exhibit A.

20-minute product's UCT increased from 1.5 to 1.6 and the seven-minute product's UCT increased from 1.2 to 1.4. For the TRC test, the results went from 1.8 to 2.0 for the 20-minute product and 1.5 to 1.8 for the seven-minute product. This sensitivity analysis illustrated that extending the current reserve values longer into the future had an impact of about 0.1 to 0.3 on the cost-effectiveness ratio, an increase of approximately 12-17 percent. Only the 20 and seven-minute products are impacted. For the frequency (real-time) product, the deferred resource used to establish value in the cost effectiveness model is not directly influenced by the rate of utility-scale battery installations added to the system. During this analysis, the Company also made the following updates: a) added costs for meter upgrades for participating customers, b) updated dispatch hours to align with final product design. The values in Table 5 reflect these updates. The values in Table 5 do not reflect the use of longer persisting reserve values described above.

Updated information on utility battery prices provided as part of 2023 IRP process[6] indicate they will be appreciably higher than those included in the 2021 IRP and therefore results for these products are relatively conservative. The Company did not conduct any sensitivity analysis around lower battery prices in light of the information provided in the 2023 IRP process.

In addition to reserve and capacity benefits, the real-time product also provides frequency response services[7] for the Company. Frequency events are unpredictable and difficult to model on a prospective basis, therefore a deferred utility resource is used to approximate the value of solving issues related to frequency events using a utility supply side resource. A summary of cost-effectiveness results over a 10-year horizon are summarized below in Table 5.

Table 5 – Commercial and Industrial Product Category Cost-Effectiveness Results

Product Category	UCT	TRC
Hour-ahead	1.3	1.6
20-minute	1.5	1.8
Seven-minute	1.2	1.5
Real-time (no notice)	1.0	1.2

Stakeholder Involvement – Action Item No. 4 in Order 20-186 in Docket LC-70

Stakeholder engagement was an integral part of pursuing demand response acquisitions with a demand response RFP. Key activities tied to the demand response are provided in summary form and are in addition to commercial and industrial activities described later.

[6] PacifiCorp. 2023 IRP Public-Input Meeting. Oct 13, 2022. Available online: www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_Oct_13_2022.pdf. See slide 5.

[7] Additional information regarding frequency response service and needs can be found in Appendix F – Flexible Reserve Study of the Company's 2021 IRP. Available online at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf

On January 21, 2020, PacifiCorp held a CPA workshop meeting in the 2021 IRP public input process. Highlights included reviewing prior IRP/CPA comments, proposed CPA methodologies for demand response, interactions between demand response, and pricing/rates options.

On February 18, 2020, PacifiCorp held a technical workshop in the 2021 IRP public input process. Highlights included further defining the grid services a demand response resource can provide and IRP credits for demand response.

On April 14, 2020, PacifiCorp held a stakeholder meeting interested in demand response. Highlights included background information on existing demand response programs, review of demand response in 2019 IRP, review of demand response potential in the conservation potential assessment, discuss pilot concepts and gather input on how to structure or focus a demand response RFP.

On April 16, 2020, at its regular IRP public input meeting, PacifiCorp shared information on the demand response stakeholder meeting with the broader IRP audience.

In June 2020, the Company and Energy Trust of Oregon met to have an intentional conversation around how to run energy efficiency/demand response programs most effectively for Oregon customers. The discussion was intended to gain insight into the Energy Trust of Oregon's interactions with Portland General Electric Company's demand response programs in advance of developing the RFP.

On June 18 & 19, 2020, PacifiCorp held an IRP public input meeting, which included 2019 IRP Action Item 4 acknowledgement with demand response conditions and draft RFP schedule shared with broader IRP audience.

On August 28, 2020, PacifiCorp held an IRP CPA Technical Workshop. Highlights included an assessment of demand response resources, assessment methodology, transition to grid services view of demand response, development of demand response costs, draft potential results (short and long duration, winter, and summer) and a demand response RFP update.

On October 22, 2020, PacifiCorp held an IRP public input meeting. Highlights included demand response ramp rates, battery storage assumptions, types of demand response costs used in the levelized calculation, demand response cost bundles.

On October 14, 2020, Johnson Consulting Group was hired to: research demand response technical vendor requirements, summarize demand response RFPs that have been issued by other energy organizations, assist in developing a simple Request for Qualifications (RFQ) template to identify potential vendors, assist in the distribution of the RFQ to ensure it is widely circulated to encourage a robust response rate, conduct in-depth interviews with up to 15 potential demand response vendors to identify market barriers, opportunities, and critical elements that should be addressed in a forthcoming demand response RFP, and summarize key elements and essential components that should be considered in developing a demand response RFP and a demand response RFQ.

On October 22, 2020, PacifiCorp held an IRP Public input meeting. Highlights included demand response ramp rates, battery storage assumptions, types of demand response costs used in the levelized calculation, demand response cost bundles.

On November 2, 2020, PacifiCorp posted the RFQ for bidders to the following website: https://www.pacificorp.com/suppliers/rfps/demand-response-rfp-2021.html. RFQ responses were due on or before November 23, 2020, and were intended to build the bidders list for the RFP and help to expand our outreach to a range of suppliers. The RFQ also asked respondents to provide some brief descriptions of potential programs and also asked for Oregon pilot ideas, response to stakeholder interests. The RFQ was also posted to Peak Load Management Alliance, Association of Energy Service Professionals, International Energy Program Evaluation Conference, Energy Central, and ESource in order to reach a broad audience.

On February 8, 2021, PacifiCorp released the RFP to 26 bidders registered in the Company's on-line procurement system.

On February 9, 2021, PacifiCorp filed the RFP with the Washington Utilities and Transportation Commission under Docket UE - 210088.

On March 15, 2021, the Company received RFP responses from 18 different organizations.

On April 23, 2021, PacifiCorp held an IRP public input meeting. Highlights included updates on the All Source 2020 and the 2021 Demand Response RFPs.

On June 25, 2021, PacifiCorp held an IRP public input meeting. Highlights included update on demand response selected by the System Optimizer model selections from the 2021 Demand Response RFP.

On July 14, 2021, the Company provided Commission Staff an update of the RFP process including, modeling selections in the five categories (smart thermostats, commercial and industrial curtailment, residential batteries, irrigation and water heating), costs and process steps.

On August 16, 2021, PacifiCorp filed a written update on its demand response efforts in Oregon in compliance with the directive provided by the Commission in Order No. 20-186. Staff provided a summary of the update at the August 24, 2021, regular public meeting.

On August 27, 2021, PacifiCorp held an IRP public input meeting highlighting the 2021 preferred portfolio action plan with demand side management actions.

On December 6, 2021, the Company held a demand response workshop with invitations sent to 17 organizations. Topics included Potential programs and design elements, targeted customers and eligibility, event parameters, measurement and verification structures, recruitment and managing the customer relationship, cost-effectiveness, evaluation, reporting, cost recovery, process and next steps.

Stakeholder Involvement – commercial and industrial demand response program

Beginning in November 2020, PacifiCorp began working with a large commercial customer, the Port of Portland, to identify demand response opportunities and strategies at the Portland International Airport. The assessment team included a third-party engineering firm and the Port of Portland's control contractor. An initial draft list of recommendations was compiled and refined to eliminate those that raised comfort or operational disruption concerns. On September 24, 2021, a two-hour test event was conducted to demonstrate viability of demand response and achieved approximately 700-kilowatt reduction (approx. 10 percent of total projected demand). Reductions were primarily from curtailed chillers and air handlers at the central utility plant and occurred without any comfort complaints or disruptions to normal operations. The Port of Portland has expressed an interest in participating in the demand response program when it is approved.

On January 7, 2022, Company representatives met with Energy Trust of Oregon staff to share the Company's plan for demand response in Oregon and explore opportunities for future coordination. Furthermore, during the last two years, integrating demand response with energy efficiency programs in general, and specifically joint opportunities for business (in addition to irrigation) customers has been a standing topic during the regular coordination meetings between the Energy Trust or Oregon and the Company.

On August 31, 2022, the Company provided a draft copy of the filing to Commission Staff and requested comments by September 9, 2022. Comments from Staff were incorporated into the draft filing provided to the demand response workshop invited parties.

On September 23, 2022, the Company provided a revised draft filing to the invited parties in the December 2021 demand response workshop and requested comments by October 7, 2022.

On October 7 & 11, 2022, in response to comments from the Energy Trust of Oregon, Company and Energy Trust of Oregon representatives met to identify practices and tactics for collaboratively identifying energy efficiency and demand response opportunities at customers facilities.

The Energy Trust of Oregon was the only stakeholder to provide comments on the Company's draft filing. As noted in Figure 1 above, the Company will post stakeholder comments on the "draft" program website before approval. The Company is in the process of finalizing the website and will post the Energy Trust of Oregon's comments along with the Company's responses to the "draft" program website by October 17, 2022.

It is respectfully requested that all formal data requests regarding this matter be addressed to:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Please direct any informal questions about this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosures

Confidential Exhibit A – Cost Effectiveness for commercial and industrial demand response program (four files[8])
Exhibit B – Content managed on web site (commercial and industrial demand response program)
Exhibit C – Cancel 218.1 and 218.2

[8] Note that the compilation of the four products can be found within the seven-minute product's workbook.

Confidential Exhibit A

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND HAS BEEN PROVIDED IN EXCEL FORMAT ONLY

Exhibit B

OREGON COMMERCIAL AND INDUSTRIAL DEMAND RESPONSE

This document includes the following sections:

- Definitions
- Program Description
- Participation Requirements and Procedures
- Dispatch Parameters and Incentives
- Additional Conditions

DEFINITIONS

Available Dispatch Hours: Daily timeframe within which Pacific Power may dispatch its demand response control system.

Co-Participation: Electrical loads at a Participating Customer's location that agree to participate in one of the following Dispatch Notifications, (60 minute or 20 minute or 7 minute) AND Real Time Dispatch Notification. *

Criteria: Additional requirements for participation beyond being an Eligible Customer. Criteria are set forth in Table 1 below.

Data Pulse Equipment: A single pulse initiator providing a Form C contact closure (KYZ) and any equipment or appurtenances, including a load profile card, a KYZ pulse initiator, junction boxes, fuses and terminal strips. *

Dispatch Days: The days upon which Pacific Power may or may not dispatch its demand response control system.

Dispatch Duration: The duration of time that demand response events may be dispatched.

Dispatch Event: The period during which Participating Customers' electrical loads are shut off or controlled to minimize electrical consumption.

Dispatch Parameters: The criteria within which Pacific Power may dispatch its load control system.

Dispatch Notification: The approximate time between a Participating Customer receiving a notice from the Program Administrator or Pacific Power and the beginning of the Dispatch Event. Participating Customers shall receive no less than this amount of notification (in minutes) for Dispatch Events. "Hour ahead" shall mean 60 minutes. "Real Time" shall mean no time between notice and beginning of event. *

Dispatch Period: The calendar year timeframe within which Pacific Power may dispatch its demand response control system.

Eligible Customer: Any party who has applied for, been accepted, and receives electric service at the real property, or is the electricity user at the real property.

Holiday: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. *

Incentive: Payments of money or bill credits made by Program Administrator or Company to a Participating Customer for participation in a demand response offer. Incentives are specific to Dispatch Notification the Participating Customer elects for the season.

Maximum Dispatch Hours: The maximum amount of time Pacific Power may dispatch its demand response control system annually.

Maximum Dispatch Events: The maximum number of events Pacific Power may utilize in dispatching its demand response control system annually.

Opt-Out: The process whereby a Participating Customer notifies the Program Administrator and/or the Company they don't want to be included in an upcoming event. Opt-Out notification must be received prior to the beginning of the event.

Participating Customers: Eligible Customers who meet the Criteria and agree to participate in the Commercial and Industrial Demand Response Program.

Program Administrator: A third-party entity selected by Pacific Power to engage with Eligible Customers about the commercial and industrial demand response program, contract with Participating Customers on behalf of Pacific Power and provide the systems to control Participating Customers loads during certain times.

Targeted Area: One or more geographic area within Pacific Power's Oregon service territory that may have additional demand response requirements and/or value. Targeted Areas may be used by the Program Administrator do one or more of the following: focus marketing and differentiate program elements such as participation requirements and/or Incentives.

Targeted Customers: Eligible Customers with electrical equipment or energy use patterns that make them a preferred Participating Customer. These customers may be the focus of targeted enrollment or marketing efforts. *

* Definition is unique to this program. All other definitions are the same as the definitions used in the Oregon Irrigation Load Control program.

PROGRAM DESCRIPTION

The Commercial and Industrial Demand Response Program is a program offered by Pacific Power that provides Incentives to Participating Customers in exchange for granting Pacific Power the right to curtail Participating Customers' loads at certain times within the Dispatch Parameters and during the Dispatch Period. Pacific Power contracts with the Program Administrator to deliver the Commercial and Industrial Demand Response Program; the Program Administrator will oversee the enrollment of Participating Customers, deliver Dispatch Notifications, and call Dispatch Events on behalf of Pacific Power. The ability to curtail these loads provides Pacific Power with curtailment, regulation reserve, contingency reserve and frequency response grid services.

1) Participation

Eligible Customer and relevant Criteria are included in the table in this document. Eligible Customers who meet the Criteria and agree to participate are Participating Customers. Participating Customers will be required to sign a standard agreement with the Program Administrator to initiate participation. The agreement is perpetual (unless terminated by either party) and does not need to be re-signed at the start of each year.

Participating customers may enroll specific electric loads in one of the following Dispatch Notifications, (60 minute or 20 minute or 7 minute) AND Real Time Dispatch Notification. In the case where there are Dispatch Events occurring at the same time, the loads must be curtailed at the beginning of the first Dispatch Event and remain curtailed through the end of the last Dispatch Event. Loads that are enrolled in more than one Dispatch Option and perform during Dispatch Events will receive an incentive for each Dispatch Option.

2) Incentives

Incentives are available on a $/kilowatt (kW) per year basis and vary by Dispatch Notification. The $/kW per year is further allocated by one or more of the following: months, time of day, annual hours. Using data from the Program Administrator installed equipment, loads available for curtailment (kW) during the hours, days and months of the Dispatch Period are averaged to arrive at an average available load which will be multiplied by the Incentive rate depending on the notification option selected. Loads opted out are removed from the connected load calculations and reduce the Incentive payment to the Participating Customer. Incentives are paid by check, electronic funds transfer, or if requested, a bill credit. For the 60 minute Dispatch Option, the incentive is paid after the seasons ends. For the other Dispatch Options, incentives are paid after each calendar quarter. Participating Customers receive Incentives based on the availability of load reduction, regardless of whether Pacific Power calls upon a load reduction during a Dispatch Event.

3) Dispatch Notification and Events

Participating Customers may select from four different Dispatch Notification options; 60 minute-ahead, 20 minute-ahead, 7 minute-ahead, Real Time (or None) which define the time between when the customer is notified of an event and when the event starts. Participating Customers notify the Program Administrator with their preferred notification channel(s) for Dispatch Events and may select more than one notification channel, i.e., text and a phone call. Dispatch Events called with 60 minute-ahead notice are focused on providing the utility with curtailment. Dispatch Events called with 20 minute-ahead notice are focused primarily on providing regulation reserve for the utility. Dispatch Events called with 7 minute-ahead notice are focused primarily on providing a contingency reserve tool for the utility. Dispatch Events called in Real Time with no notice provide frequency response grid services for the utility. The value of the curtailed load to the utility system depends on the time between the notification and the start of the event. Available Incentives reflect the variability in the utility value.

4) Equipment Operation

Event communication and control occurs through a Program Administrator-provided two-way communications device (communicating via cellular signals) installed at the customer site. Individual devices communicate with the software platform provided by the Program Administrator which also provides secure access to Pacific Power to initiate Dispatch Events. Unless activated during an event, the devices do not affect normal control of equipment, but they do convey information about the connected load back to the Program Administrator and Pacific Power. To enable the Program Administrator's event communication and control device, Pacific Power, at their expense may install data pulse equipment onto the utility meter after execution of an agreement between customer and Pacific Power.

5) Opt Outs

To provide Participating Customers with some operational certainty around the impacts of the demand response program on their operations, there are limits on hours in a day, the total number of events, and total hours when the loads may be curtailed. Recognizing that unforeseen operational issue may arise, Participating Customers in any Dispatch Notification may opt out of all Dispatch Events for specified times by contacting the program administrator. Participating Customers in 60 minute or 20 minute Dispatch Notification may Opt-Out of individual Dispatch Events dispatches by notifying the program administrator after Dispatch Notification is received and prior to the beginning of the Dispatch Event. Opting out will lower Incentive payments proportionally. In order maximize the load available for control and minimize program costs, loads that are available for control are strongly preferred. Loads that are opted out or unavailable on a regular basis may be removed from the program at the sole discretion of the Program Administrator.

6) Quality Assurance, Change Process and Reporting

Quality assurance review and techniques may be utilized during the delivery of the program. Periodic program impact and process evaluations will be conducted by a third party working for Pacific Power. Pacific Power will regularly review program performance, quality assurance and evaluation findings, and cost effectiveness results in combination with current Company resource planning results to evaluate potential program changes. Program changes may include changes to information in this document and will follow the process outlined in current version of Oregon Schedule 106.

Reports on program performance are provided to the Public Utility Commission of Oregon annually.

PARTICIPATION REQUIREMENTS AND PROCEDURES

Table 1 – Dispatch Parameters and Incentives

Dispatch Parameters and Incentives	**Description**
Eligible Customer	• All commercial and industrial customers on Delivery Service Schedules 23, 28, 30, 47 and 48.
Criteria	Interval meter installed
Targeted Customer	• More than 200 kW of curtailable load
Dispatch Period	60 minute: • May 1 through September 30 20 minute: • January 1 through Dec 31 7 minute: • January 1 through Dec 31

	Real Time: • January 1 through Dec 31
Targeted Areas	All areas within Company's Oregon territory
Dispatch Days	60 minute: • Weekdays, non-Holidays during Dispatch Period 20 minute: • Weekdays, non-Holidays during Dispatch Period 7 minute: • Monday through Sunday during Dispatch Period Real Time: • Monday through Sunday during Dispatch Period
Available Dispatch Hours	60 minute: • 3:00 p.m. to 9:00 p.m. Pacific Time on all Dispatch Days 20 minute: • 8:00 am to 9:00 p.m. Pacific Time on all Dispatch Days 7 minute: • 24 hours/day on all Dispatch Days Real Time: • 24 hours/day on all Dispatch Days
Maximum Dispatch Hours	60 minute: • 40 hours per year 20 minute: • 60 hours per year 7 minute: • 60 hours per year Real Time: • 5 hours per year
Maximum Dispatch Events	60 minute: • 1 event per day 20 minute: • 1 event per day 7 minute: • 25 events per year Real Time: • 50 events per year
Dispatch Duration	60 minute: • Up to 3 hours 20 minute: • Up to 4 hours 7 minute: • Up to 4 hours Real Time: • Up to 15 minutes
Dispatch Notification	60 minute, 20 minute, 7 minute, Real Time (or None)

Incentive	• 60 minute Dispatch Notification is paid at $30/kW per year allocated equally into the five Dispatch Period Months.
	• 20 minute Dispatch Notification is paid at $55/kW per year using an allocation (% of total $/kW per year) by month.
	  ○ 10% - January
	  ○ 8% - February
	  ○ 5% - March
	  ○ 5% - April
	  ○ 5% - May
	  ○ 8% - June
	  ○ 15% - July
	  ○ 15% - August
	  ○ 10% - September
	  ○ 5% - October
	  ○ 5% - November
	  ○ 10% - December
	• 7 minute Dispatch Notification is paid at $75/kW per year using all allocation (% of total $/kW per year) by month.
	  ○ 10% - January
	  ○ 8% - February
	  ○ 5% - March
	  ○ 5% - April
	  ○ 5% - May
	  ○ 8% - June
	  ○ 15% - July
	  ○ 15% - August
	  ○ 10% - September
	  ○ 5% - October
	  ○ 5% - November
	  ○ 10% - December
	  ○ The monthly incentive is further allocated by time of day.
	    ▪ 9 AM to 9 PM – 75%
	    ▪ 9 PM to 9 AM – 25%
	
	• Real Time Dispatch Notification is paid at $85/kW per year by allocating the $/kW per year incentive equally into each hour of the year.
	
	For 60 minute Dispatch Notification, the available Incentive is calculated at the end of the season and paid to each participant by check, electronic funds transfer, or (if requested) a bill credit. For 20 minute, 7 minute and Real Time Dispatch Notification, the available incentive is calculated at the end of each calendar quarter and paid by check, electronic funds transfer or bill credit. Incentives will be determined by multiplying the average load (kW) a

	customer can reliably shut-off during Available Dispatch Hours on the Dispatch Days in the Dispatch Period by the Incentive rate (including the application of any allocations) and adjusted for Opt-Outs.
Opt-Out	Participating Customers in any Dispatch Notification may opt out of all Dispatch Events for specified times by contacting the program administrator. Participating Customers in 60 minute or 20 minute Dispatch Notification may Opt-Out of individual Dispatch Events dispatches by notifying the program administrator after Dispatch Notification is received and prior to the beginning of the Dispatch Event. Opting out will lower Incentive payments proportionally. Repeated opt outs may result in removal of the site from the program.

ADDITIONAL CONDITIONS

System Emergency Dispatch: In the event of a system emergency, Pacific Power may, at its discretion, expand the Dispatch Parameters beyond the parameters listed. Emergency events may be used to satisfy requirements of the North American Electric Reliability Corporation standard BAL-002-WECC-2 for Contingency Reserve Obligation and may be deployed when the utility is experiencing a qualifying event as defined by the Western Power Pool.

Exhibit C

+Schedule No.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Nonresidential Consumers receiving Delivery Service under Schedule 48, in conjunction with Supply Service Schedule 201. Participation will be limited to the first twenty-five (25) megawatts of load on a first come, first served basis.

Monthly Billing

The Monthly Billing shall be the Interruptible Demand Credit, Interruptible Energy Credit, and Administrative Fee. The Monthly Billing is in addition to all other charges contained in Delivery Service Schedule 48, Base Supply Service Schedule 200 and Supply Service Schedule 201.

Interruptible Demand Credit	
Per kW of On-Peak Interruptible Demand	-$1.00
Interruptible Energy Credit	
Per kWh of Interrupted Energy	-20.000¢
Administrative Fee	
Per month	$90.00

Interruption Events

The Company may call up to 100 hours of Interruption Events each calendar year. One Interruption Event may be called each day and may not exceed 3 consecutive hours. Each Interruption Event called by the Company shall be set for a period of at least 15 minutes in duration. Interruption Events may be called on any day or at any time during the year. During Interruption Events, a participant's usage shall not exceed their Baseline Non-Interruptible Load.

Interruption Notification

At least 30 minutes prior to an Interruption Event, the Company shall notify participants.

Interrupted Energy

Interruptible Energy during each Interruption Event shall be measured as the difference between the average load in kW for the 2 hours preceding the Interruption Event and the Baseline Non-Interruptible Load multiplied by the duration of the Interruption Load in hours.

Interruptible Demand

Interruptible Demand shall be measured as the kW shown by or computed from the readings of the Company's demand meter for the highest 15-minute period during On-Peak as defined by Delivery Service Schedule 48 during the month, determined to the nearest kW, less the Baseline Non-Interruptible Load.

Baseline Non-Interruptible Load

Once per calendar year, participants may nominate a Baseline Non-Interruptible Load in kW which shall not be subject to Interruption Events.

(continued)

Interruptible Service Term

Unless otherwise removed from this schedule by the Company, participants shall agree to remain on Interruptible Service for a period of no less than 12 months. After terminating service under this schedule, a Consumer may not re-enroll for a 12 month period.

Special Conditions

1. If a participant does not interrupt its load by reducing its usage down to its Baseline Non-Interruptible Load or less during an Interruption Event, the participant shall be subject to the following penalties:
    a. For the first failure in a rolling 12 month period, the participant shall forfeit its Interruptible Demand Credit and Interruptible Energy Credit for the month in which it failed to interrupt.
    b. For the second failure in a rolling 12 month period, the participant shall forfeit its Interruptible Demand Credit and Interruptible Energy Credit for the month in which it failed to interrupt and for the prior six months.
    c. For the third failure in a rolling 12 month period, the participant shall be removed service on this schedule.
2. Participants removed from the schedule may not return to Interruptible Service for a period of 12 months.
3. Participants on this schedule may not also take service on Schedule 219 – Real-Time Day Ahead Pricing Pilot.
4. As a condition of receiving service on this schedule, the Company may elect to upgrade and/or update the Consumer's metering to record five minute interval data and otherwise be capable of being a participating resource in the Energy Imbalance Market. Any metering upgrade and/or update shall be at the Consumer's expense. The Company shall provide an estimate of the metering upgrade and/or update to the Consumer prior to incurring any expense.
5. Participants must nominate a Baseline Non-Interruptible Load that results in at least 1,000 kW of Interruptible Load.
6. At its sole discretion, the Company may elect to not provide service under this schedule or remove from participation Consumers with seasonal loads that do not correspond to the times of the year when anticipated Interruption Events may occur.
7. A Consumer may not enroll in this schedule for more than 10 MW of service.
8. A Consumer may not at the same time participate in this schedule and Schedule 219 or any other demand response program.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.