PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

March 28, 2023

VIA ELECTRONIC FILING

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

Re: Advice 1383 / Advice 22-004—PacifiCorp's 2022 Demand Response Programs Report

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits the attached 2022 Demand Response Programs Report. On March 28, 2022, the Company filed Advice 22-004 to introduce a new broadly enabling Schedule 106 for Demand Response Programs, cancel the Irrigation Load Control Pilot Program, Schedule 105, and propose an expanded irrigation demand response program to replace the pilot program using the provisions of Schedule 106. Advice 22-004 was approved on May 5, 2022. On October 14, 2022, PacifiCorp filed Advice 22-011 to introduce a demand response program for commercial and industrial customers using the provisions of the Schedule 106. Advice 22-011 was approved on November 15, 2022.

PacifiCorp's 2022 Demand Response Programs Report provides an update on the following Oregon Demand Response Programs authorized under Schedule 106:

- Irrigation Load Control Program
- Commercial & Industrial Demand Response Program

PacifiCorp requests that all formal information requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

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

Informal inquiries may be directed to Cathie Allen at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosure

IRRIGATION LOAD CONTROL PROGRAM

2022 Irrigation Load Control Program in Oregon

Issued March 28, 2023

PACIFIC POWER
A DIVISION OF PACIFICORP

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Overview

On May 3, 2016, the Public Utility Commission of Oregon (Commission or OPUC) approved PacifiCorp d/b/a Pacific Power's (PacifiCorp or the Company) request to implement a pilot irrigation load control program for customers within the Oregon portion of the Klamath Basin. The Irrigation Load Control Pilot Program (Pilot Program) was filed to test the design characteristics of the Company's existing irrigation load control program for its Oregon customers.

In 2016, the Pilot Program focused on enrolling a small number of initial participants, testing and related logistics and one two-hour event was called during the season. In 2017, the focus was on maintaining engagement with enrolled growers, increasing the number and duration of events during the season and seeking updated market pricing for program delivery beyond the 2017 season. In 2018, the Company focused on transitioning the program to the new delivery provider, Connected Energy. During 2019, the Company proposed changes to expand and extend the program and filed them on July 22, 2019.[1] Additional customers, sites and pumps were enrolled and available capacity and impact per event increased compared to 2018. On February 14, 2020, changes to extend days and hours and add a shorter dispatch notification option were approved by the Commission. In 2021, the same small group of customers (five) from 2020 continued to participate. Six events were called through June, July and August 2021, each with a four-hour duration for a total of 24 event hours.

On March 28, 2022, the Company filed Advice 22-004 to introduce a new broadly enabling Schedule 106 for Demand Response Programs, cancel the Pilot Program, Schedule 105, and propose an expanded irrigation demand response program to replace the Pilot Program using the provisions of Schedule 106. The expanded program was approved on May 5, 2022.[2]

Since the expanded program builds on the Pilot Program, includes the legacy pilot customer, and utilizes the same implementation partners, this report summarizes 2022 Program activity (pilot and expanded aggregated together) and presents the key findings from the seventh season of providing demand response options for our Oregon irrigation customers. Reporting for the Program will continue to incorporate the same elements as the prior Pilot Program reports.

This report summarizes 2022 Program activity and presents the key findings from the seventh season. In its Pilot Program application, the Company identified key elements that would be provided annually, and the expanded program outlined the plan to continue to utilize the same reporting format. The following table describes where each of these elements is addressed in this report:

[1] Advice 19-008.
[2] See Oregon Public Utility Commission Advice No. 22-004. Available online: https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf

Element	Start Page	Section
1. Review of annual enrollment		
a. Total program enrollment	15	Enrolled Customers
b. Sites added and removed	15	Enrolled Customers
c. Customer outreach	10	2022 Activities to Address Key Challenges
d. Crop(s)	17	Customer Crop/ Operations and Pumping Equipment
e. Weather data from local weather station(s)	17-19	Weather and Drought Impact
f. Available information on water restrictions	17	Impact of Irrigation Technology and Water Availability
2. Customer satisfaction a. Customer requests for retirement b. Site reassignment management	5	Participant Behavior *There were no customer requests for retirement or reassignments in 2022
3. Incentive payments	15 27	Customer Payment Structure Appendix B: Customer Payments
4. Review of annual program performance		
a. Weekly available load reduction	20-21	Available Load Reduction
b. Load control events	22 -24	Load Control Events
c. Availability and load reduction comparison	8	Availability
5. Key observations	5	Key Findings

In 2022, the same small group of customers (five) from 2021 continued to participate. Three events were called: two in July and one in August, each with a four-hour duration for a total of 12 event hours. Key findings from 2022 focus on participant behavior, especially the interest and ability to participate with a) hour-ahead notice and 22.5-minute notice and b) reduced water availability.

Key Findings

Participant behavior

Grower interest and engagement was maintained amongst prior participants (five customers, 9 sites and 17 pumps), even with reduced water availability. With the program expansion approved on May 5, 2022, outreach efforts were increased resulting in two new customers, four new sites and five new pumps were enrolled for the 2022 season. The total of seven customers, 13 sites and 22 pumps participated in the 2022 season.

In addition to the expanded 2022 season participants, an additional eight customers, nine sites and 18 pumps were enrolled after the season ended. At the end of 2022, 15 customers, 22 sites and 40 pumps were enrolled. The 2022 program year included three events, all called with one-hour ahead notification. Events were called on consecutive days in July. The 2022 event schedule reinforces prior season observations around the propensity for growers to participate in events even if those events occur on days that are near each other.

Logistics

The 2022 events were all four hours and occurred near each other; Monday and Tuesday in July and Monday in August. This further supports the learning from prior years indicating the kilowatts (kW) available for load control events can be utilized in rapid succession during the season when an experienced delivery provider works with an engaged set of customers.

Event notification worked as designed and customers participated when called (i.e., did not opt out of events after they were called). Water availability and resultant operational challenges did cause one customer to opt out two pumps for the entire season. This occurred at the beginning of the season**.** The same customer made the same decision in 2021. Event information including baseline, load curtailed and post event load was successfully captured by program devices and the network operations center. Data on connected load for these sites during the irrigation season were also transmitted from the devices and archived at the network operations center. Timely access to the 15-minute Advanced Metering Infrastructure (AMI) information for the medium voltage pumps was improved. Converting the 15-minute AMI data to five-minute intervals continues to require an extra step.

Delivery Costs

2022 was the was the first year of a new delivery contract with Connected Energy for delivery of the expanded program. Delivery costs increased in 2022 reflecting installation of additional switches, increased data management and marketing. Fixed, ongoing administrative costs are comparable to costs to deliver the pilot. Incentive costs increased compared to 2021 which reflects the higher available kW during the season and grower willingness to participate with less notice (which earns them a higher incentive).

Assessing Costs and Benefits

Appendix 2 provides a discussion of potential benefits utilizing demand response cost-effectiveness protocols from California.

Background

The pilot, filed as Advice 16-04, was approved by the Commission on May 3, 2016, and has operated for three growing seasons. Activities in the prior four seasons were outlined in the annual reports filed on March 31, 2017, March 30, 2018, March 29, 2019, and March 27,2020. On July 22, 2019, the Company filed Advice 19-008 to extend and expand the program consistent with the recommendation provided in the year three report. The changes were approved on February 14, 2020. On March 28, 2022, the Company filed Advice 22-004 to expand the program to all Oregon irrigation customers and add an incentive option of curtailing loads with shorter notice.

The 2022 timeline of key program activities is outlined below.

2022 Timeline

April/May	Pre-season communication to existing participants
Week of May 23	Website updated to include 2022 season specific messages
July 26	Hour-ahead notification to participating customers for July 26 event
July 26	Four-hour event conducted between 4pm-8pm, Pacific time
July 27	Hour-ahead notification to participating customers for July 27 event
July 27	Four-hour event conducted between 4pm-8pm, Pacific time
August 16	Hour-ahead notification to participating customers for August 16 event
August 16	Four-hour event conducted between 4pm-8pm, Pacific time
September 18	End of season
December 2022	Incentives paid to participating customers

Anticipated Pilot Size

The Company's 2015 IRP helped inform the original 3-megawatt (MW) size of the Pilot Program. An increase, up to 5 MW was forecast in the information provided in Advice 19-008 but was directly impacted during the 2021 season by COVID-19, drought conditions in the Klamath Basin and competing customer priorities. The program expansion filing provided a forecast for an expanded program available statewide and noted 2022 performance of 18.97 (MW at site) depended on timing and customer uptake.[3]

Anticipated Duration

PacifiCorp originally proposed a five-year pilot period to provide sufficient time to test a variety of parameters and align with grower input favoring a multi-year program. In February 2020, the Commission approved Advice 19-008, including the extension of the pilot for an additional three years, through the 2023 season with the requirement that a third-party evaluation inform an "expand or cancel" recommendation after the 2021 season. Changes requested in Advice 22-004 reflect the "expand" recommendation and include treating the program as ongoing with no end date.

Program Parameters /Design

Participation in the Program requires irrigators to allow their pumps to be interrupted under conditions summarized in "Table 1 – Dispatch Parameters and Incentives" of the content managed on the website.[4] See Table 1. Changes approved in Advice 22-004 were applicable to the 2022 season.

[3] Advice 22-004, note on Table 2, page 6.

[4] Document available online: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/savings-energy-choices/wattsmart-business/OR_incentives_definitions.pdf

Table 1. Irrigation Load Control Program Parameters in place during 2022

Program Parameters	Description
Eligible Customers	Irrigation Customers on Schedules 41 or 48 in and around targeted areas posted on the Company web site.
Program Period	Week including June 1 through week including September 15.
Program Hours	All days 12:00 p.m. to 10:00 p.m. Pacific Time.
Dispatch Limitations	52 hours per year, 20 events per year, up to 4 hours per event or 12 hours per week.
Dispatch notification	Day ahead, hour ahead and 22.5 minute ahead
Incentive Rate	Day ahead at $18/kW per year. Hour ahead at $30/kW per year. 22.5 minute ahead at $45/kW per year
Opt-Outs	Participants may opt out of dispatches. Opting out will lower participation payments proportionally.
Incentive Payments	The incentive payment is calculated at the end of the irrigation season and paid to each participant after the season ends. Participant incentives will be determined by multiplying the average load (kW) a customer can reliably shut-off during program hours by the incentive rate, adjusted for event participation (opt-outs).

Additional information about 2022 customers, dispatch events, incentive rates and payments, and event opt-outs is provided in Appendix One.

2022 Performance

Availability
Program availability in 2022 increased and was related to water availability. Of all the participating pumps, 69% were willing to participate with one hour notice, 31% were willing to participate with 22.5-minute notice.

A total of three events were called through July and August. Each event was four hours. The average kW available from all events was 578 kW, an increase compared to 2021. Except for the one customer who opted out two pumps for the entire season for operational reasons related to water availability, there was 100 percent customer participation in all events and all customers opted for the hour-ahead dispatch notification (and higher incentive). Load control equipment performed as expected. Access to 15-minute AMI data improved, but conversion to 5-minute data still required additional time.

Table 2. Oregon Irrigation Load Control – 2016–2022 Performance

	Year 1 (2016)	Year 2 (2017)	Year 3 (2018)	Year 4 (2019)	Year 5 (2020)	Year 6 (2021)	Year 7 (2022)
Estimated kW	0 - 2,000	3,000	3,000	3,000	3,000	5,000	18,968
Proxy/Available kW	565	546	563	945	969	730	787
kW (average all events)	281	432	258	554	574	360	578

Notes for Table 2

- kW values are at customer site
- 2022 estimated kW is from Advice 22-004
- 2021 estimated kW is from Advice 19-008.
- For 2022 the five-minute interval data from the Connected Energy devices and 15/5-minute AMI data was available for the entire season from all customers. The available kW value represents the highest value during all program hours.
- For 2021 the five-minute interval data from the Connected Energy devices and 15/5-minute AMI data was available for the entire season from all customers. The available kW value represents the highest value during all program hours.
- For 2020 the five-minute interval data from the Connected Energy devices and 15/5-minute AMI data was available for the entire season from all customers. The available kW value represents the highest value during all program hours when the switches were installed.
- For 2019, the five-minute interval data from the Connected Energy devices was available for the entire season from legacy customers. A combination of device data and AMI data for the new customers was available from their connect dates of July 20 and July 25 to the end of the season. The available kW value represents the highest value during all program hours when the switches were installed.
- For 2018, the five-minute interval data from the Connected Energy replacement devices was available from July 26 to the end of the season. The available kW value represents the highest value during program hours when the switches were installed.
- For 2017, five-minute interval data was available for all enabled customers for the entire season. Available kW represents the highest five-minute interval demand reading during all program hours for the season.
- For 2016 only, average available load was set at customers; peak demand from June 2015 as a proxy for available load given the event occurred at the end of the season and a lack of five-minute interval load data until customers were enabled with site specific hardware.

Program Costs

Program costs in 2022 shown in Table 3 were associated with the Connected Energy delivery contract and included equipment costs, customer incentives and customer engagement expenses. Delivery costs increased with additional marketing, data ingestion and device installations for new customers.

Table 3. Irrigation Load Control – 2016–2022 Costs

	Year 1 (2016)	Year 2 (2017)	Year 3 (2018)	Year 4 (2019)	Year 5 (2020)	Year 6 (2021)	Year 7 (2022)
Estimated Program Costs (Calendar Year)	$150,000	$225,000	$225,000	$225,000	$225,000	$325,000	$2,027,125
Actual Program Costs (including corrections for prior years)	$150,000	$125,000	~~$179,634~~ $180,819	~~$157,082~~ $181,631	$175,704	$174,804	$312,056

Notes for Table 3

- 2022 estimated costs are from Advice 22-004
- 2021 estimated program costs are from Advice 19-008
- During preparation of the 2020 report, some minor cost corrections to prior years were identified. These corrections align prior reports with final accounting information and are displayed in red font.
- For 2018, accounting data reflects $169,985 in costs but does not include $10,834 for 2018 incentives which are reflected in 2019 accounting data. Program cost for 2018 should be $180,819. The difference of $1,185 and explanations for the difference was identified by the Company in their November 8, 2019, response to OPUC Request 11 in Advice 19-008. Removing $185 labor charges remains an open item and will be completed in 2022.
- The 2019 costs were prepared with preliminary accounting data which did not fully capture all costs and the impacts of accruals and their reversals. In addition, there were $76.50 in labor charges that should not be included. Labor charges will be removed in 2021. Final delivery and incentive costs total $181,631.

2022 Activities to Address Key Challenges

Through Advice 22-004, the Pilot Program and underlying Schedule 105 was replaced with an expanded program available to all irrigation customers in Oregon and higher incentives for curtailing load with shorter notice (22.5 minutes) using the provisions of the new broadly enabling demand response Schedule 106.

Increased marketing and outreach expanded the program from the five customers, nine sites and 17 pumps in the 2021 season to 15 customers, 22 sites and 40 pumps at the end of 2022.

Oregon irrigation resources were included in the Demand Responses Request for Proposals (RFP) released in February 2021. Information from this RFP informed the post 2021 season recommendation to either expand or cancel the Pilot Program. The recommendation prepared by AEG was included as an addition to the 2021 report.

Appendix 1: 2022 Connected Energy Pacific Power Irrigation Load Control Program Report

In support of Pacific Power's regulatory activities related to the Irrigation Load Control Program in Oregon, Connected Energy prepares an annual report on program activities including total program enrollment, sites added, customer outreach, crops, weather data, and any available information on water restrictions, incentive payments, load control events and key observations. Connected Energy's report is provided as Appendix 1 to this report.

2022 Pacific Power Irrigation
Load Control Program Report

Connected Energy
651 Holiday Drive
Foster Plaza 5, Suite 400
Pittsburgh, PA 15220
www.connectedenergy.com

Pacific Power
825 NE Multnomah
Portland, OR 97232
www.pacificorp.com

Date: February 24, 2023

Contents

Overview of the 2022 Irrigation Load Control Program

This report provides an overview of the Irrigation Load Control (ILC) Pilot Program for Pacific Power in the state of Oregon. The program was initially focused on the Klamath Falls, Oregon region of the Pacific Power service area, but has been expanded to include the entire state of Oregon. The program was implemented and administered by Connected Energy for the 2022 irrigation season. Connected Energy has been the program implementer since 2018. This report is intended to document program results, accomplishments, and challenges, including lessons learned that will be leveraged to enhance the program going forward.

Regulatory approval for the Irrigation Load Control (ILC) pilot program in Oregon was initially granted by the Oregon Public Utility Commission (OPUC) on May 4, 2016. The ILC pilot program was transitioned to Connected Energy in 2018 and was made available to irrigation loads in the Klamath Falls, Oregon region of the Pacific Power service area for customers that were not already participating in the time of use program. On February 14, 2020, the pilot program was approved to expand to areas beyond Klamath Falls and to provide for dispatch load control events with shorter notification.

On May 5, 2022 the ILC program was approved by the OPUC to transition from a pilot to a fully operational load control program across the entire Oregon service area of Pacific Power.[5] All customers that have participated in the program since its inception in 2016 have remained in the program through 2022.

In 2022, the program delivered an average load reduction across the three called events of 578 kW, an increase of 61% from the 2021 average of 360 kW, and just slightly above the 2020 average of 574 kW. This reason for the reduction in 2021 and minimal growth in 2022 when compared to 2020 was primarily due to significant water restrictions that created two noted operating scenarios. First, some program participants had reduced pumping loads due to the simple lack of available water. Second, one participant opted to continue operating pumps through all curtailments due to the need to keep water flowing to prevent fields from flooding. These two scenarios resulted in a lower overall program load as well as the inability to curtail all the controlled during the called events. In discussions with irrigators, as water restrictions are reduced, and more water is available to pump loads will increase resulting in more available load to curtail during peak events.

By the end of the 2022, the program had grown to include 36 pumps with load control devices

[5] OPUC. Staff Report. Public Meeting Date: May 5, 2022. Docket No. ADV 1382 / Advice No. 22-004. Available online: https://edocs.puc.state.or.us/efdocs/UBF/adv1383ubf10320.pdf

(and 4 large medium voltage pumps with annual control) across 22 different irrigator sites. Maximum load available for curtailment was 787 kW, occurring on August 24, 2022, between 6:00 PM and 7:00 PM. Participating sites were compensated for shutting off irrigation load for specific time periods determined by Pacific Power and were provided either day ahead, hour ahead, or 22.5-minute notice of load control events, based on participants option selection. For 2022, customers with 69% of the pumps selected hour ahead notification, customers with 31% of the pumps selected 22.5-minute notification, while no customers selected day ahead notification. Participants had the opportunity to opt-out of (i.e., choose not to have their pumps curtailed) events as necessary to suit their day-to-day business operations. Only one participant chose to opt out, opting out 2 pumps for all events as noted above, due to the need to continuously pump water to keep fields from flooding.

Participant incentives in the ILC program are based on the site level average available load during load control program hours adjusted for the number of opt outs or non-participation in load control events. For 2022, the program hours were maintained as 12:00 PM to 10:00 PM Pacific Daylight Time (PDT) for all days (weekends and holidays included) from May 30, 2022, through and including September 18, 2022.

Pacific Power initiated three load control events during the 2022 load control season on the following dates and times:

- July 26, 2022, between hours of 4:00PM - 8:00PM
- July 27, 2022, between hours of 4:00PM - 8:00PM
- August 16, 2022, between hours of 4:00PM - 8:00PM

Load reductions for the events are calculated using five-minute interval metering data from Connected Energy’s direct load control devices and from Pacific Power billing data for the one large customer with medium voltage (2300V) pumps.

Review of 2022 Customer Enrollment and Enablement

Customer Payment Structure

Participants get compensated by the program for their voluntary participation in load curtailment events. The participant payment is based on the amount of load able to be curtailed as well as the notice period that the participant agrees to in advance. In 2022, the program added a 22.5-minute notice option, while maintaining the previous incentive levels from 2021, with a day ahead notice option that provided an incentive of $18/kW per year and an hour ahead notice option that provided an incentive of $30/kW per year. The newly added 22.5-minute notice option provided an incentive of $45/kW per year.

For the 2022 irrigation season, none of the participants selected the day ahead option, 69% selected the hour ahead notice option, and 31% selected the 22.5-minute notice option. The incentive payment provided to participants was based on the measured available load for curtailment throughout the program season adjusted for any opt outs or non-performance in load control events. This payment structure is designed to provide fair and consistent treatment for all sites. The three events called by Pacific Power in 2022 were all initiated with an hour ahead notice, which allowed all program participants to be included in all events.

Enrolled Customers

In 2022, Connected Energy enrolled 19 new customer pumps into the program. Connected Energy conducted marketing activities early in the program year and similar to 2021 learned that continued water restrictions in and around the Klamath Basin would limit the ability for many interested participants from enrolling in the program. These interested participants did, however, continue to voice a strong desire to be in the program in the future as water restrictions continue to be reduced.

All previously installed customers remained active in the program in 2022. Previous participants, along with new installations resulted in a total of 36 pumps with devices (and 4 large medium voltage pumps with manual control) , across 22 different customer sites during the 2022 calendar year.

Data Quality

Connected Energy's load control devices are designed with an integrated metering chip that provides near real-time interval metering data during both Irrigation Load Control events and normal operation of the customer participating loads. This metered data is used to validate when the pump is running and when the pump has been successfully curtailed. Thus, there is no need to create a statistical methodology or tool to validate participation of enrolled loads in the program. In cases where participants power down pumps when they are not being used, Connected Energy will see no metering data coming into the platform and will treat that load as being powered off. When the load is powered up again, we will then either see positive load data (load is running) or zero load data (load is not running).

Connected Energy's load control devices utilize 4G (LTE) cellular communications which provides added benefits as the minimum projected network life for 4G (LTE) is currently year end 2028.

Review of 2022 Program Participants and Performance

Customer Crop/Operations and Pumping Equipment

For the 2022 Irrigation Load Control season, customer crop types/operations included alfalfa, potatoes, and grass fields for cattle and livestock grazing as well as pumping into reservoirs. Pump sizes at these locations ranged from 40 HP to 750 HP.

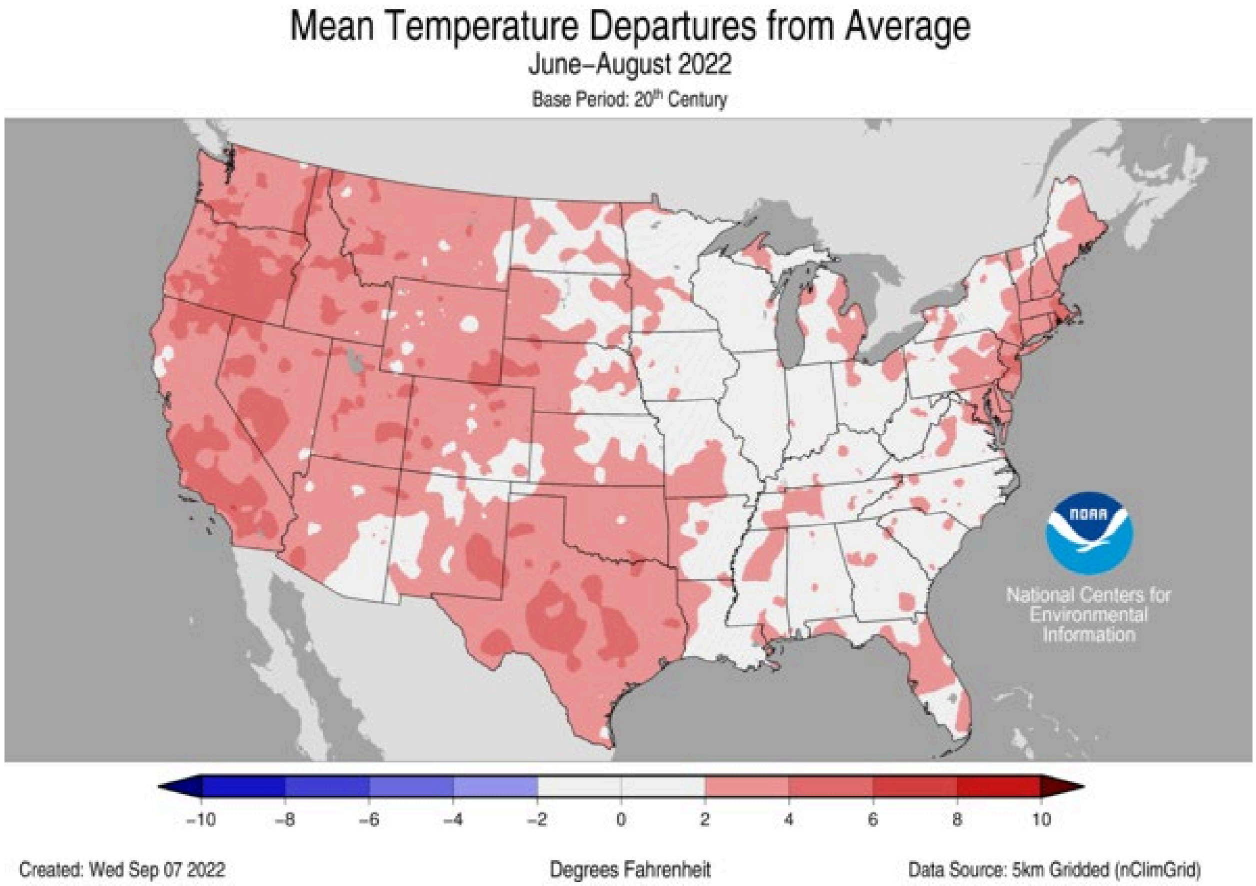
Impact of Irrigation Technology and Water Availability

While pump size is a clear determinant of total load availability in the Irrigation Load Control program, irrigation technology and water availability also impact irrigation pump run-time and thus can affect customer success in the Irrigation Load Control program. Pivot irrigation systems are operationally easier to manage for load control events than a wheel line or hand line irrigation system. During the 2022 season, Participants continued to have significant concerns related to major water restrictions throughout the Klamath Basin. These water restrictions resulted in several participants experiencing reduced pumping loads due to the lack of water to pump. In one other case, the participant found it operationally necessary to opt two pumps out of all events as there was a need to continuously move water to prevent fields from flooding.

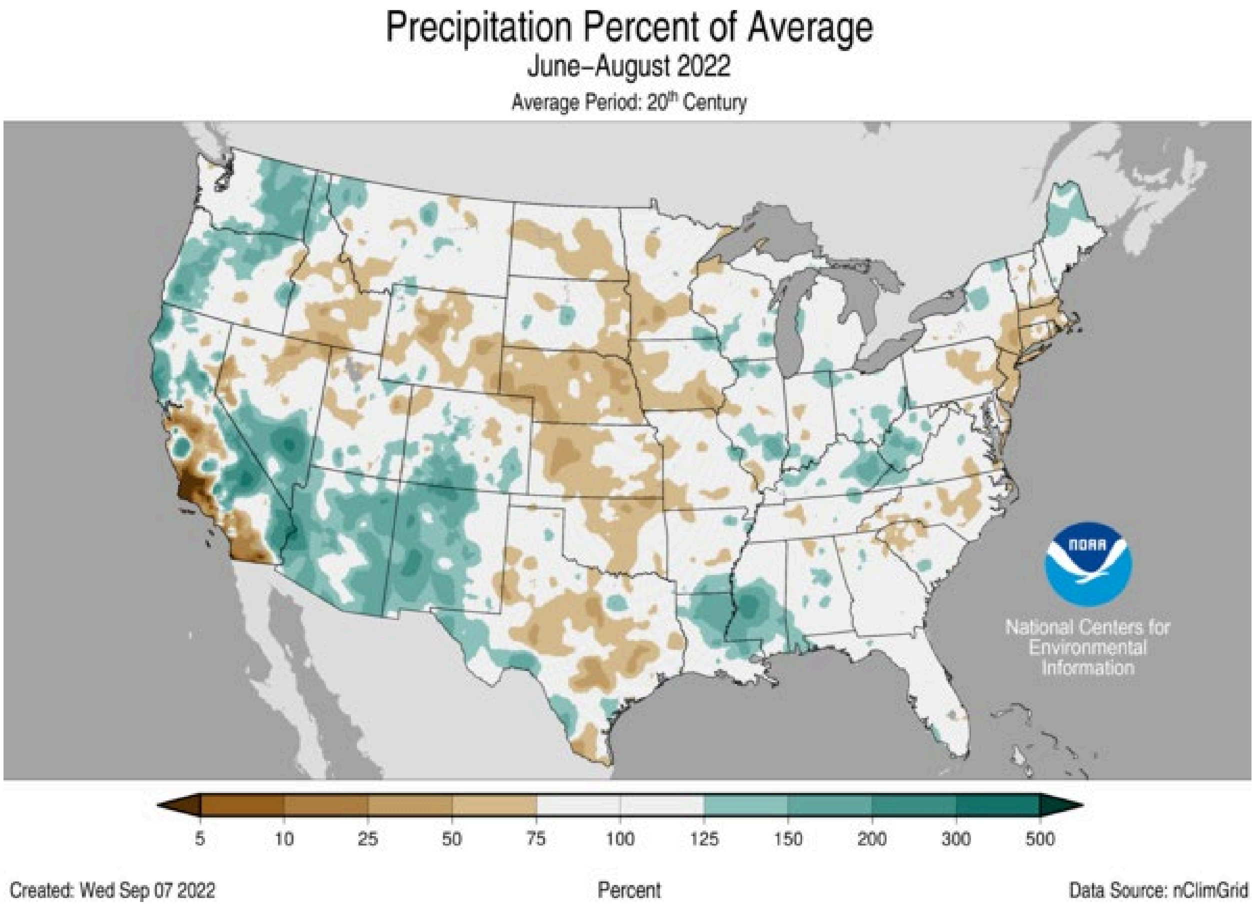
Weather & Drought Impact

Similar to the previous four years, 2022 was warmer than normal in the Irrigation Load Control geographical area, leading to greater irrigation needs. Unlike the previous four years, precipitation levels were average to slightly above average in the Irrigation Load Control geographical area. Even with slightly above average levels of precipitation, water restrictions remained in place and resulted in lower pump loads versus historical averages.

The two images below highlight the above average temperatures and average to slightly above average precipitation across much of the western part of the country including the ILC program region during the 2022 program season.



Mean Temperature Departures from Average
June–August 2022
Base Period: 20th Century
National Centers for Environmental Information
−10
−8
−6
−4
−2
0
2
4
6
8
10
Created: Wed Sep 07 2022
Degrees Fahrenheit
Data Source: 5km Gridded (nClimGrid)



Source: NOAA Mean Temperature Departures from Average (June-August) and Precipitation Percent of Average (June-August), available online: https://www.ncdc.noaa.gov/sotc/national/202008#season-precip

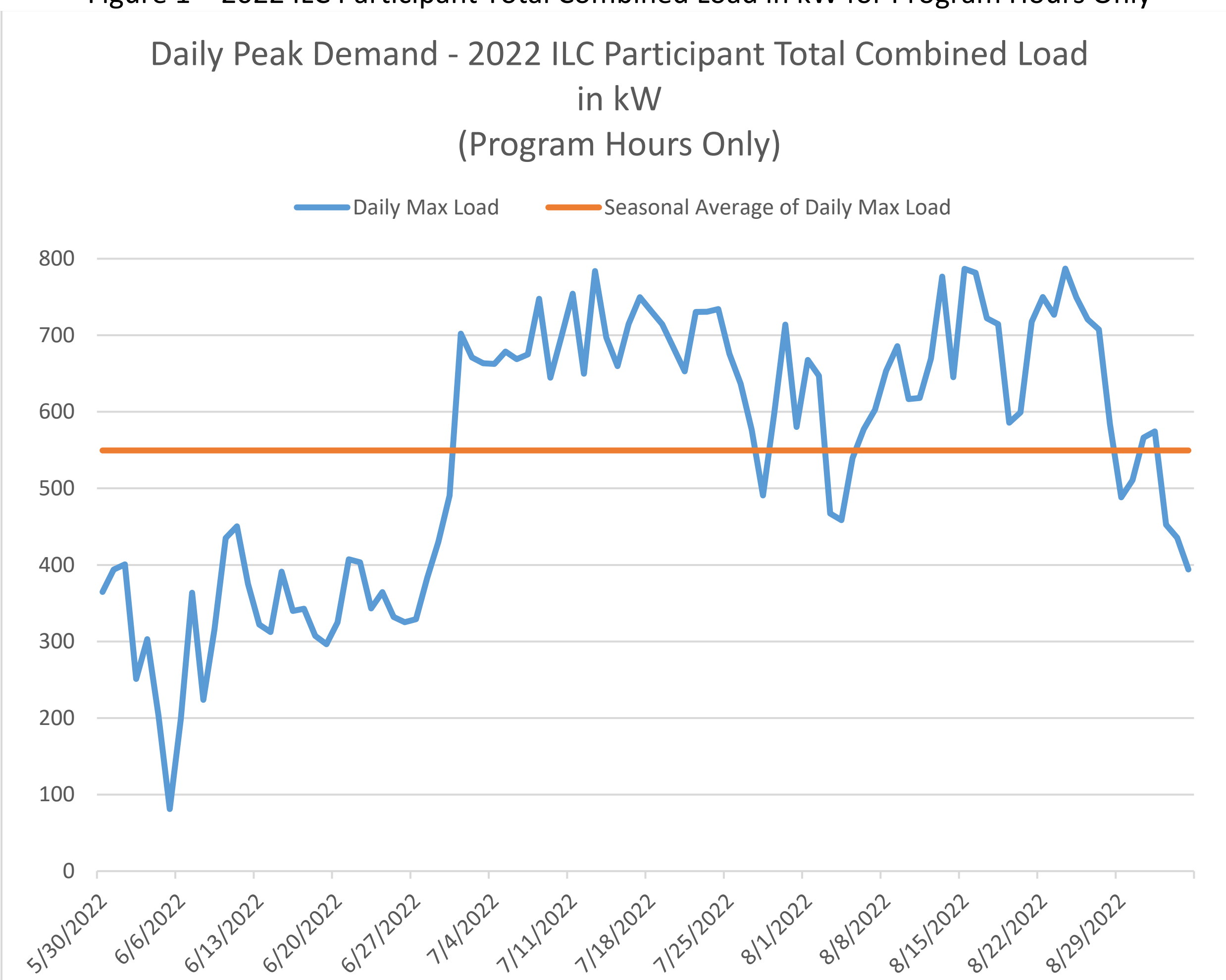
Available Load Reduction

The Oregon Irrigation Load Control program is evaluated based upon average available load reduction (kW) during the 2022 program year, which ran from May 30, 2022, through September 18, 2022.

The two charts below are provided for comparative purposes between the 2022 and 2021 program years.

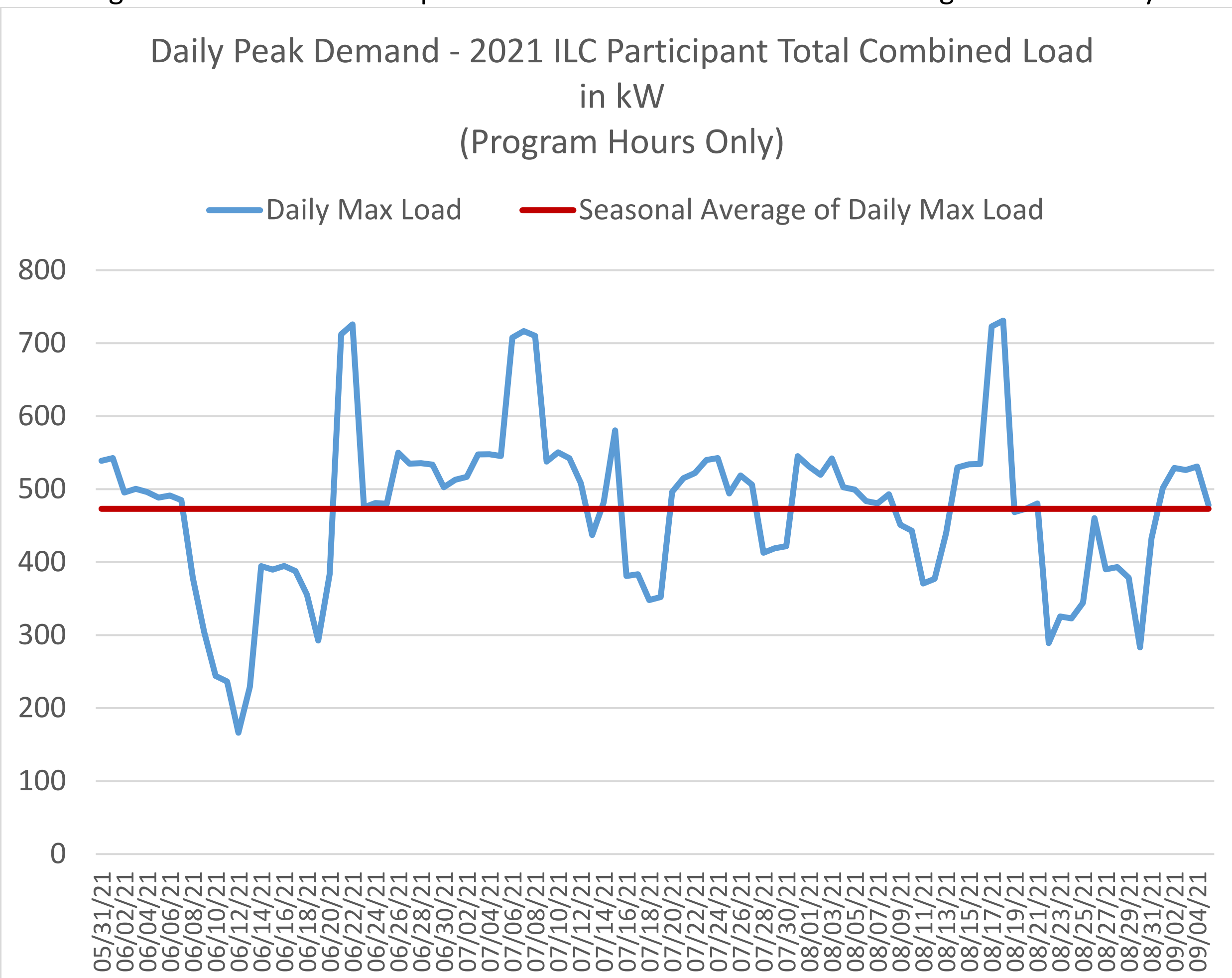
For the 2022 program year the portfolio average available load reduction for the operating season was 550 kW (see Figure 1 below) with a maximum of 787 kW occurring on August 24, 2022. The chart below shows daily available demand during active program hours (12:00 PM – 10:00 PM, all days) and active program months in 2022.

Figure 1 – 2022 ILC Participant Total Combined Load in kW for Program Hours Only



By comparison, for the 2021 program year, the portfolio average available load reduction was 473kW (see Figure 2 below), nearly 20% lower than 2020. As noted earlier in this report, this is due primarily to reduced pumping because of reduced water availability from the upper Klamath Lake.

Figure 2 – 2021 ILC Participant Total Combined Load in kW for Program Hours Only



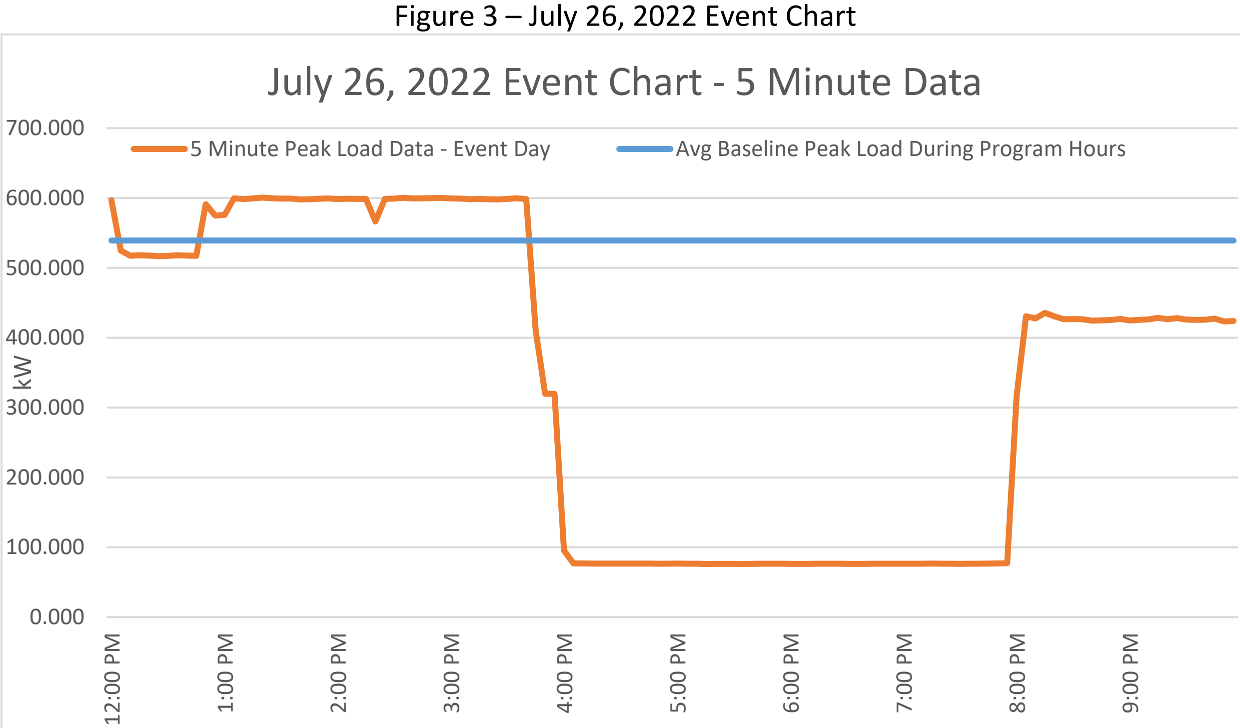
Load Control Events

Pacific Power activated the Irrigation Load Control program for three irrigation load control events in 2022. Load reduction was measured as the difference between actual demand remaining on the system during the event and baseline demand. Baseline demand is the average demand during program hours (12pm to 10pm) on the most recent non-event, program day. Detailed Baseline Charts are provided in Appendix C for each event. Actual Load Reduction (kW), Baseline Demand (kW) and Load Reduction Performance Factor as reported here correspond to 5-minute interval energy usage measurements from Connected Energy's field installed equipment at customers' sites and 5-minute Pacific Power data for the one customer with medium voltage equipment.

The 2022 portfolio delivered an average of 578 kW across the 3 called load control events. Load Reduction Performance Factor (LRPF), the measure of actual load reduction compared to baseline demand, was 88.3% for the portfolio in 2022. The LRPF was lower than 100% since one participant opted two pumps out of all events due to the need to continuously move ground water to prevent fields from flooding.

Figures 3 through 5 below are graphs showing the Event Peak Load data for each of the 3 event days. The red line on each graph shows the 5-minute Peak Load Data on the day of the event and the blue line shows the Average Peak Load During Program Hours for the baseline day.[6] The difference between the lines shows the amount of curtailed load achieved by the event.

Figure 3 – July 26, 2022 Event Chart



[6] Note that the baseline period is the same day (July 25, 2022) for both the July 26th and July 27th events.

Figure 4 – July 27, 2022 Event Chart

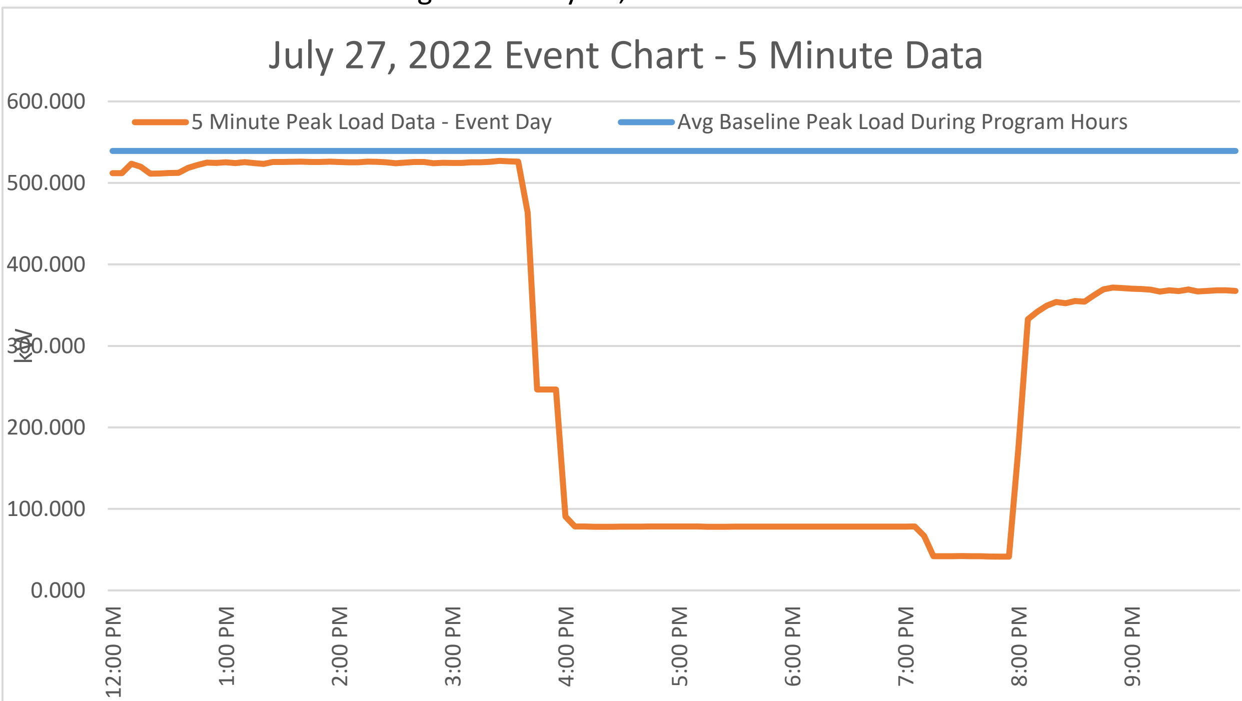
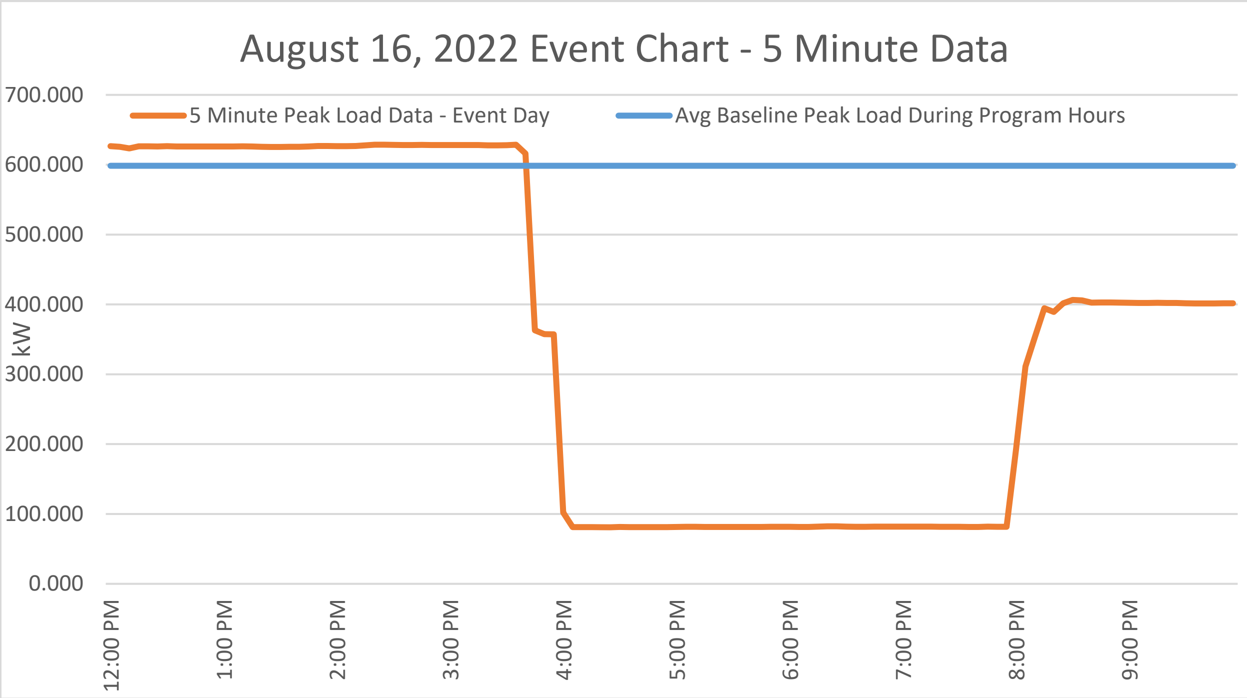


Figure 5 – August 16, 2022 Event Chart



Load Control Results

Table 1 below shows the summary detail for each of the three called events. Included is the actual load reduction (defined as Baseline Demand minus the amount of load remaining on the system), baseline demand, and performance factor (Actual Load Reduction / Baseline Demand) for each of the three called events.

Table 1: Actual Load Reduction, Baseline Demand, and Performance Factor, by Event and Region

Date	Region	Actual Load Reduction (kW)*	Baseline Demand (kW)*	Load Reduction Perf Factor (%)*
July 26 2022	Oregon	534.02	610.94	87.41%
July 27 2022	Oregon	539.50	610.94	88.31%
August 16 2022	Oregon	660.05	742.41	88.91%
Avg of 3 Events	Oregon	577.86	654.76	88.26%

* Actual Load Reduction (kW), Baseline Demand (kW) and Load Reduction Performance Factor as reported here correspond to 5-minute interval energy usage measurements from Connected Energy's equipment at customers' sites and 5-minute data from the Pacific Power system, for the one customer with medium voltage equipment. These measurements may or may not correspond to realized load reduction on Pacific Power's system.

One note regarding Load Reduction Performance Factor being lower in 2022 and 2021 than in previous years. As stated in the report, one participant opted two pumps out of all events due to the need to continue pumping water to prevent fields from flooding. This resulted in approximately 75 kW not being curtailed. This amount of load represents nearly all the difference between the Actual Load Reduction and the Baseline Demand.

Key Lessons Learned from 2022

- The addition of the 22.5-minute notice option was well received by both existing and new participants, with customers with 31% of the pumps selecting the notice option.
- As noted earlier in this report and similar to 2021, the overall program results were impacted by the severe water restrictions imposed on both existing and potential program participants.
- Of the three called events in 2022, all events were initiated with a one-hour notice which has continued to be received positively by all program participants.
- Other than a single participant who opted out 2 pumps for operational reasons, there was 100% participation from all remaining participants.
- Continued program marketing efforts are key to gaining program exposure and increased participation.

APPENDIX A: Customer-Facing Irrigation Load Control Activity

Listed below are the major activities involving program participants that occurred in 2022.

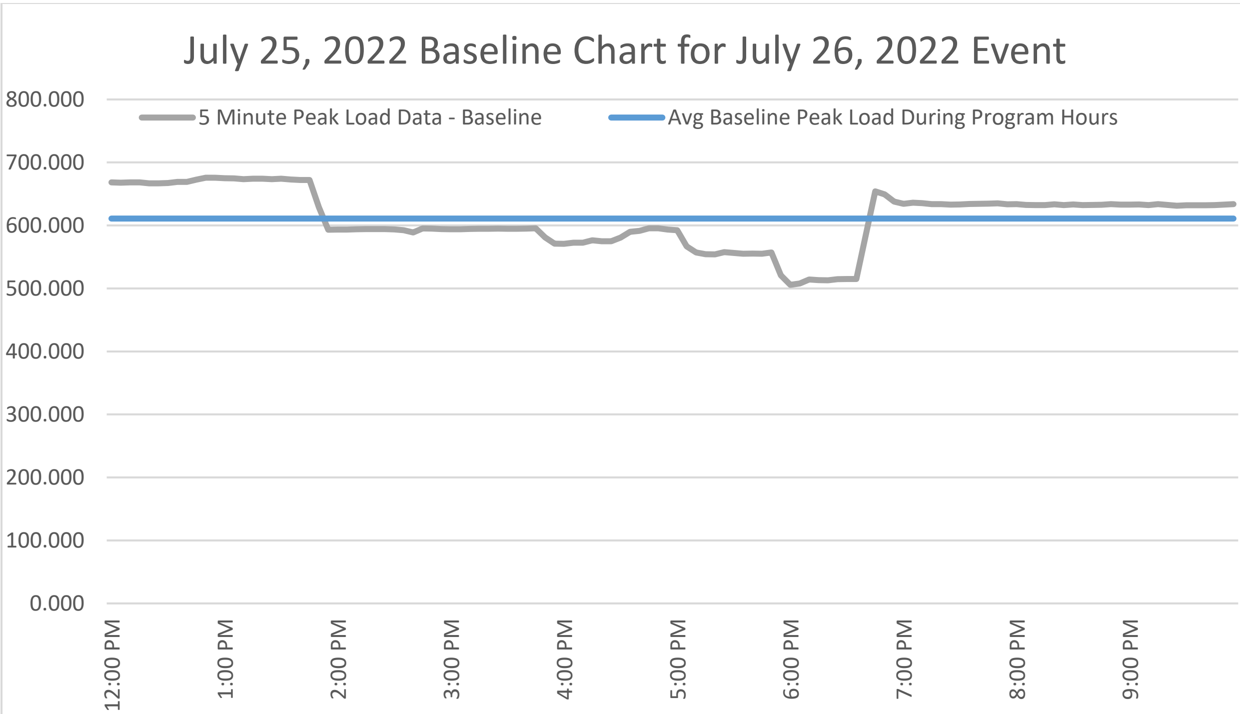
See Table 1 above for dates and detail related to the called Irrigation Load Control events.

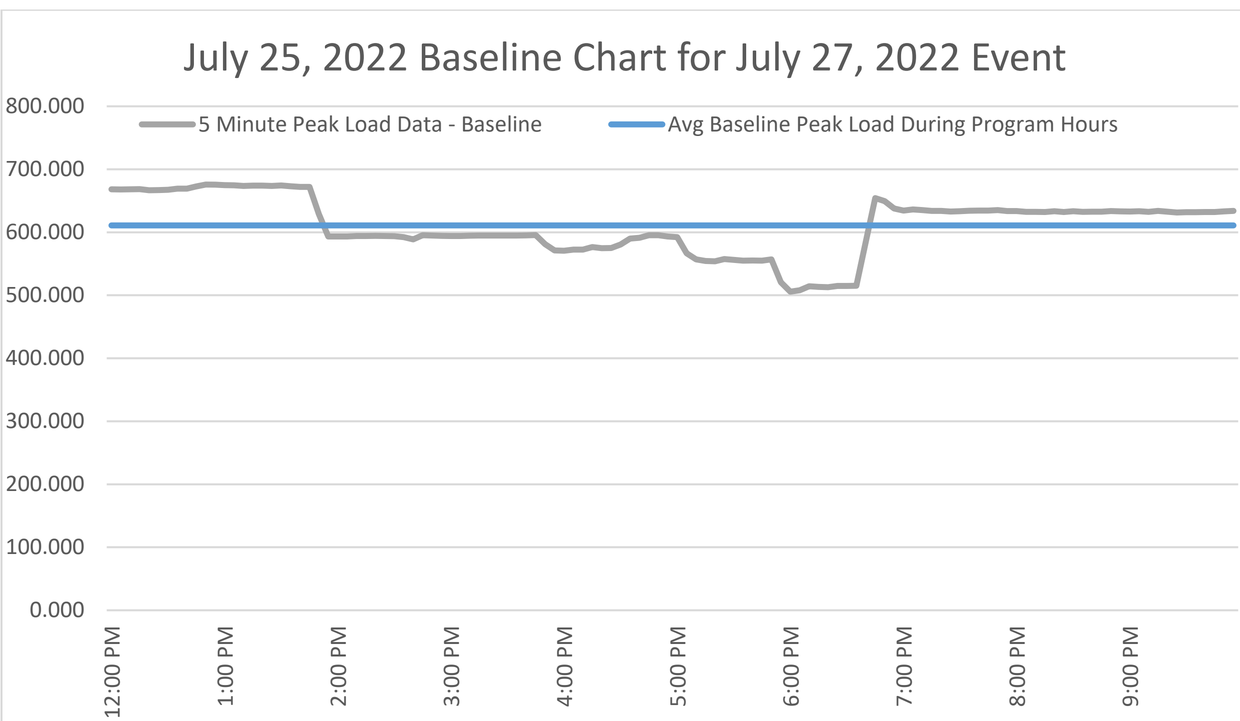
	Activity	Date	Description
1	**Welcome calls placed to previous year participants**	During months of April/May 2022	Connected Energy contacted all the 2021 participants to notify them of the 2022 program year start as well as the continuation of the program enhancements (addition of 22.5-minute notification). All participants were pleased that the program was continuing.
3	**Courtesy calls to customers in advance of events**	Prior to each event	Connected Energy placed Dispatch Notification phone calls to each participant in advance of an event (in addition to electronic notifications) to ensure they were aware of scheduled events.
4	**Incentive payments to participants**	Completed in December 2022	Incentives have been calculated based on program rules and participation. Similar to previous years, earned incentive payments were sent by check.

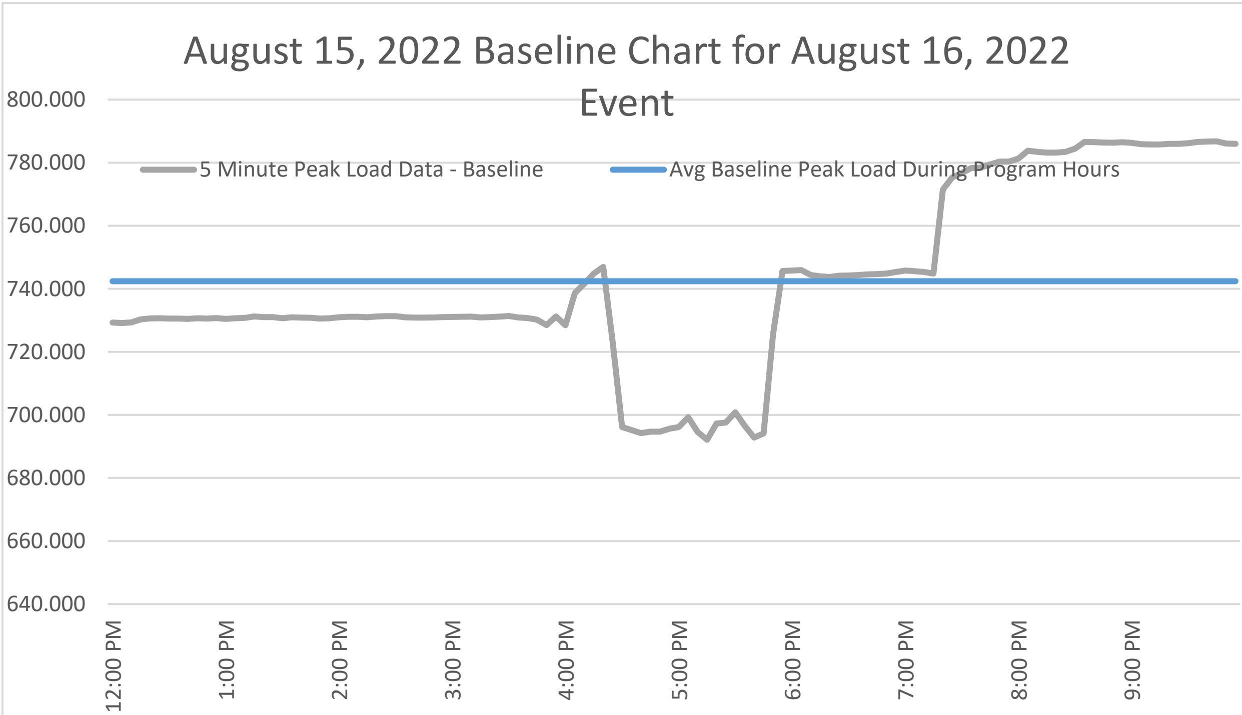
APPENDIX B: Customer Payments

Three customers received incentive payments for their participation in the 2022 ILC program season. Incentive payments totaled $14,586.19 and were based on available load that could participate in events multiplied by the participation factor less any load remaining on the load control device during a curtailment. Two of the three customer incentive payments were calculated utilizing the hour ahead incentive rate ($30/kW) with the third was calculated utilizing the 22.5-minute incentive rate ($45/kW).

APPENDIX C: Detailed Baseline Charts






August 15, 2022 Baseline Chart for August 16, 2022 Event
5 Minute Peak Load Data - Baseline
Avg Baseline Peak Load During Program Hours
800.000
780.000
760.000
740.000
720.000
700.000
680.000
660.000
640.000
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM

Appendix 2: Oregon Program Year Seven - Benefits and Costs Discussion

The Oregon Program is intended to test designs, provide market feedback, and generate information about delivery logistics and costs. PacifiCorp will monitor the costs and of the program after expanding it beyond the pilot stage in Oregon.

This Appendix provides discussion of the costs and benefits of the 2022 program developed in response to Recommendation No. 3 in the April 26, 2016 Commission Staff Report in Advice No. 16-04 to utilize the California Public Utilities Commission Distributed Energy Resource Avoided Cost Framework ("Framework") as a guide when conducting the post-season assessment.

Appendix A of the Framework, 2015 Demand Response Cost Effectiveness Protocols (Protocols) is dated November 2015.[7] It is important to note that these protocols are not directly applicable to pilots: "These protocols are not designed to measure 'pilot' programs, which are done for experimental or research purposes, technical assistance, educational or marketing and outreach activities which promote DR or other energy-saving activities in general..."[8]

Summary of Avoided Cost Results

	Short-Term Avoided Costs (Market)		Long-Term Avoided Costs (High)		Long-Term Avoided Costs (Expected)	
Value (2022$)	**$**	**$/kW-yr**	**$**	**$/kW-yr**	**$**	**$/kW-yr**
Energy	$1,375	$2.79	$1,375	$2.79	$1,375	$2.79
Losses	$110	$0.22	$110	$0.22	$110	$0.22
DA Energy+Losses	$1,028	$2.09	n/a	n/a	$242	$0.49
HA Energy+Losses	$4,922	$9.99	n/a	n/a	$1,161	$2.36
Generation Capacity	n/a	n/a	$23,861	$48.42	$16,185	$32.84
Transmission Capacity	n/a	n/a	$34	$0.07	$9	$0.02
Distribution Capacity	n/a	n/a	$212	$0.43	$45	$0.09
Total	**$7,434**	**$15.08**	**$25,591**	**$51.93**	**$19,127**	**$38.81**

1. *Avoided Generation Capacity Costs*
   In the near term, the Company's recent IRP's have assumed marginal capacity requirements would be met with Front Office Transactions (i.e. market purchases), which typically have a minimum increment of 25 MW. While this resource was too small to avoid an entire market transaction, the avoided energy costs below are calculated assuming that market transactions are avoided on a kW for kW basis. Because the Company has the option to call events, it can

[7] *2015 Demand Response Cost Effectiveness Protocols,* California Public Utilities Commission. 2015.
[8] *Id*, page 7.

avoid day-ahead market purchases, which often trade at a premium to real-time energy costs, especially when they cover a long block of hours. Based on the day-ahead product cost on the actual event days, this premium is estimated at $2.09/kW for the 2022 season. Note that some of the benefits within this value are actually attributable to the hour-ahead notice provision, as all of the events were initiated on an hour-ahead basis. If events had required day-ahead notice, different or fewer days might have been identified for events. With hour-ahead notice, the Company is better able to target events to conditions, and that targeting is reflected in this result.

The hour-ahead or less notification options selected by all participants in 2022 create additional value, as the Company can avoid day-ahead market purchases, with demand response option intended as a backstop, and does not have to actually initiate an event unless conditions warrant it. This value is estimated at $9.99/kW for the 2022 season, based on potential avoided market transactions during weeks when no events were called, but could have been if conditions had warranted it. This value does not include the additional benefits of hour-ahead notice embedded within the actual event days.

Over the longer term, the Company will need to acquire additional physical resources, at a higher cost than market transactions. This analysis uses the expected net cost of a simple cycle combustion turbine (SCCT) as a proxy. The timing of this resource need is uncertain, so the analysis considers high, medium, and low cases, with the SCCT need starting in year 1 for the high case and in year 10 for the low case, and a 20-year nominal levelized value is reported for each case. The medium case reflects the next SCCT starting in year 6, which corresponds to the 2026 resource in the 2019 IRP preferred portfolio. While the timing for an SCCT is uncertain, the expected value reflects the average of the medium and high cases, or a SCCT in roughly year 4. This assumption reflects the fact that the first resource additions were made prior to 2026 in the 2019 IRP, and that the 2021 IRP has adopted a lower market capacity limit in light of the evidence that regional resource sufficiency is declining. The generation capacity contribution for the high case was set at 66 percent, the expected contribution of 4-hour demand response resource in the summer. This assumption is slightly lower than the 76 percent contribution for a four-hour battery that is available every day during the summer. The value was reduced for the low case, based on the coincidence of event days with actual peaks on the system over the period.

In the expected case, a blend of near-term market and long-term SCCT net costs produces a generation capacity value of $32.84/kW. In the high case, SCCT net costs starting in year 1 result in a generation capacity value of $48.42/kW. Because a SCCT would provide much the same optionality ascribed to the avoided market capacity costs, the day-ahead and hour-ahead benefits are not included for those years in which capacity costs are based on an SCCT.

2. *Avoided Energy Costs*

A review of the loads preceding and following each event indicate a mixture of load shedding (loads not fully restored after events) or load shifting (loads returning following the event) or a hybrid (some but not all load returning after events) This review provides additional information to that gathered in the last six seasons and continues to suggest a mixture of shedding and shifting but provides no definitive conclusion about load shifting or shedding as the primary impact. For the purposes of this report, energy value is reported based on the amounts shed, relative to the prior day baseline, without any adjustments related to shifting. For the 2022 valuation, the value of avoided energy is based on the avoided energy during event hours, with day-ahead, hour-ahead, and 20-minute-ahead option value being reflected in the market capacity estimate.

Avoided energy during event hours is based on Energy Imbalance Market 15-minute market prices for PacifiCorp West, PacifiCorp East, and Malin, blended using the same ratios applied to qualifying facilities and adopted in the Resource Value of Solar proceeding. The value of energy during 2022 curtailment events averaged approximately $210/megawatt-hour (MWh).

Because energy volumes reflect metered loads, it is appropriate to account for the value of avoided line losses that would otherwise have been incurred to serve those loads. Avoided line losses are based on the secondary voltage service level for energy, for irrigation customers on Oregon Schedule 41, as applied in the 2018 Line Loss Study for the Oregon General Rate Case (GRC). Avoided losses represent a roughly 7.97 percent increase in energy savings, and resulted in effective energy savings of approximately $227/MWh when grossed up for losses.

3. *Avoided Transmission and Distribution Costs*

Assigning transmission and/or distribution deferral value(s) to load management is consistent with the 2019 IRP, the Northwest Power Planning and Conservation Council's 7th Power Plan[9] and Oregon's Resource Value of Solar (UM 1910). Deferral values and their application in this analysis are derived from analysis presented in Table 6.8 and in Appendix Q in the 2019 IRP. Available information indicates enabled load control equipment is connected to four separate distribution substations. In 2019, none of these substations were identified as needing import capacity upgrades and no transmission deferral value was assigned. In 2019, one device controlling approximately 15 kW (site) of irrigation load was connected to a distribution substation identified for an upgrade if block load additions materialize in the future.

For 2022, the transmission and distribution (T&D) deferral portion of the analysis was updated to more generically estimate value based on a full-size program, rather than the specific attributes of the existing load control locations. High, Average, and Low transmission and distribution deferral values were identified. Many locations have more than adequate T&D capacity, so the Low value is zero. In 2022$ and before capacity contribution is accounted for, Average values are $4.54/kw-yr. for transmission capacity and $10.05/kw-yr for distribution capacity, while High values roughly twice as the average at $8.68/kw-yr for transmission capacity and $23.56/kw-yr. for distribution capacity. While it is possible a

[9] 7th Power Plan applies transmission deferral value only.

single location could have T&D values that were both high, it is not expected to be common. Much more common would be locations where T&D values were both zero.

Because the program has restrictions on the number of events, the number of days per week, and the total number of hours per year, the ability to respond to both system requirements (for generation capacity) and local requirements (for transmission and distribution capacity) may be limited. In particular, the net load peak that drives generation capacity requirements tends to occur later in the day as the sun is setting, whereas transmission and distribution peaks tend to occur in mid-to-late afternoon. The four-hour daily event duration does not allow events to cover both of these periods. These limitations are reflected in the capacity contribution, which is estimated at 1 percent for transmission and 1 percent for distribution after grossing up for losses. These values are based on the kW of non-event load during Program hours, which was 493 kW during 2022.

The transmission capacity deferral credit for "High" cost locations is estimated at $0.07/kW-yr., while the comparable value for the distribution capacity deferral credit is estimated at $0.43/kW-yr. The expected values for the program as a whole are based on averaging the medium and low deferral credit values, and result in a transmission capacity deferral value of $0.02/kw-yr. and a distribution capacity deferral value of $0.09/kw-yr. These values are dependent each year on the program's ability to call events that coincide with actual peak load. In 2022, although the load the hour ahead of each event (when the event was called) was 95% or greater of the maximum load for any hour that month at the Oregon, Pacific Power, or PacifiCorp system level, the events coincided with few days that were ranked in the top ten highest load days.

4. *Avoided Environmental Costs for Greenhouse Gases (GHG)*
   There are no published costs for GHG that are applicable to this analysis. There are no Oregon explicit avoided environmental costs associated with GHG reductions in this historical period.

5. *Line Losses*
   For valuation purposes, the hourly line loss factor methodology developed for the Oregon GRC was used, based on a 2018 study. The value of avoided line losses is included in avoided energy and capacity costs.

6. *Weighted Average Cost of Capital (WACC)*
   Not applicable for contemporaneous recovery of these pilot costs.

The Load Serving Entity (LSE) will specify the following quantitative information relevant to the evaluation of each program, following the procedures outlined in these protocols:

1. *Load Impacts, in MW*
   The average MW reduction across the three 2022 events was 0.546 MW at site. Applying the estimated line loss, the load impacts at the generator are 0.589 MW.

2. *Expected call hours of the program (used to determine energy savings)*
   Program was called for 12 hours in 2022. This is 23 percent of 52 maximum annual dispatch hours.

3. *Administrative Costs*
   Administrative (non-incentive) costs paid in 2022 to Connected Energy include program delivery costs for the seventh year of the program.

4. *Participant Costs (for only those programs which are not using a percentage of incentives as a proxy measurement)*
   Participants do not incur capital costs to participate. Participant costs representing the transactions costs and the value of service lost were estimated to be 75 percent of incentives or $10,940. This assumes that the maximum possible value of the transaction costs and value of service lost can be approximated as a proportion of the value of all incentives otherwise a customer would not elect to participate in the program.

5. *Capital Costs and Amortization Period, both to the LSE and to the Participant (should be specified for each investment)*
   There are no unamortized capital costs to recover over an amortization period. The 2022 program expenses were paid through 2022 and are being positioned for recovery through Schedule 291.

6. *Revenues from participation in CAISO Markets (such as ancillary services or proxy demand resource)*
   - *CAISO Markets Entered*
   - *Average megawatts (MWs) and hours bid into those*
   - *Average market price received*
     This resource was not large enough to change any portion of the Company's participation in the California Independent System Operator (CAISO) markets.

7. *Bill reductions and increases*
   Pilot: The bills for the 2022 participants were not analyzed for changes since it was unlikely the 12 event hours combined with a mixture of load shedding and load shifting around those events would have had an impact on total bills for the season.

8. *Incentives paid*
   The 2022 incentive payments were $14,586.19.

9. *Increased supply costs*
   The resource is too small to change supply costs.

10. *Revenue gain/loss from changes in sales (usually assumed to be the same as bill reductions and increases)*
    See No. 7 above.

11. Adjustment Factors (if not required to use default values).

- *Data need to calculate Availability (A Factor)*
  The portion of the capacity value that can be captured by the program based on availability (daily, monthly), frequency and duration of calls permitted. While this program is likely to be coincident with generation capacity constraints in the summer, it is not necessarily available during all hours (or days before June 1 or after September 15) that a generation constraint could occur.

- *Notification Time (B Factor)*
  In 2022, program required no less than 22-minute- and no more than one day-ahead notification.

- *Trigger (C Factor)*
  Events can be called at the discretion of utility (within the specified months, weeks, days, hours). Other than that, there are no restrictions. The 2022 events were triggered by a forecast for higher than typical power prices for the super peak period. In addition, hot weather was forecast for the period.

- *Distribution (D Factor)*
  The D Factor can be summarized as "right time", "right place", "right certainty" and "right reliability." The pilot was not designed to avoid specific local investments.

- *Energy Price (E Factor)*
  See 2 for discussion of components utilized in 2022 avoided energy analysis.

- *Flexibility (F Factor)*
  The pilot is too small for the Company to assess possible F Factor value.

- *Geographical/local avoided generation capacity (G Factor)*
  Not applicable.

The LSE may also add the following optional inputs:

1. *Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.*
   Not applicable.

2. *Utility non-energy benefits, such as fewer customer calls and improved customer relations.*
   Not applicable.

3. *Participant non-energy benefits, such as improved ability to manage energy use and "feeling green."*
   Not applicable

4. *Market benefits, such as market power mitigation and market transformation benefits*
Not applicable.

Overall comparison of benefits and costs for the 2022 season*

	Benefits	Costs	b/c ratios
Avoided generation capacity	$16,185		
Avoided energy + market	$2,888		
Avoided transmission	$9		
Avoided distribution	$45		
Total	$19,127		
Incentives		$14,586	
Delivery		$297,470	
Total		$312,056	
Incentives			1.31
Delivery			0.06
Total			0.06
***T**he 2023 IRP values and the capacity valuation procedures outlined in the recently completed capacity investigation UM 2011 will lead to a change in methodology and valuation moving forward. The updated methodology will more fully capture the value of flexibility in response to both load and price volatility.			

COMMERICAL & INDUSTRIAL
DEMAND RESPONSE PROGRAM

2022 Commercial & Industrial Demand Response Program in Oregon

Issued March 28, 2023

PACIFIC POWER
A DIVISION OF PACIFICORP

Overview

On October 14, 2022, PacifiCorp filed Advice 22-011 to introduce a demand response program for commercial and industrial customers using the provisions of the recently approved Schedule 106. The advice filing was approved with an effective date of November 16, 2022.[1]

Program Parameters/Design

The commercial and industrial demand response program includes 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.[2]

2022 Activities

PacifiCorp selected Enel X to deliver the program and they are responsible for the customer outreach and marketing, installation, operation and maintenance of the load control devices, dispatch of the devices as directed by the Company and issuance of customer incentives. In late summer, ahead of the advice filing, Enel X conducted preliminary outreach to customers. Discussions with customers ahead of an effective date necessarily included the caveat that the program was subject to OPUC approval.

PacifiCorp's regional business managers introduced Enel X to 43 customers in 2022. Additionally, in 2022, Enel X hosted 30 meetings with customers and contracted with one. PacifiCorp met with Energy Trust of Oregon three times after filing the program in 2022: November 1, December 2, and December 16 to discuss ways to collaborate and cross-promote offers.

2022 Performance

No customers signed agreements, no events were called and no load was curtailed during the approximately month and a half of 2022 the program was approved.

2022 Program Costs

There were no customer incentive payments or delivery payments to Enel X during 2022. The only program costs were allocated utility labor expenses of $4,628.

Annual Reporting

The annual report for 2022 is abbreviated given the days in the year during which an approved program was available and is intended to capture the ramp up activities. It is anticipated the 2023 annual report will contain significant additional information and more closely resemble other company demand response annual reports such as the irrigation load control program.

[1] With a November 16, 2022 effective date, there were 46 days in 2022 (13% of the year) for the approved program to operate.

[2] For further program information, see PacifiCorp website: https://www.pacificpower.net/savings-energy-choices/business/wattsmart-efficiency-incentives-oregon/CIDR.html