PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 28, 2018

VIA ELECTRONIC FILING

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

Attn: Filing Center

RE: Advice 16-04—Compliance Filing—2017 Report on Pacific Power's Irrigation Load Control Pilot Program

PacifiCorp d/b/a Pacific Power submits the attached 2017 Irrigation Load Control Pilot Program Report. The report is provided in compliance with the terms of PacifiCorp's Irrigation Load Control Pilot Program that was approved by the Public Utility Commission of Oregon on May 4, 2016.

Pacific Power 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, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to me at (503) 813-6583.

Sincerely,

Natasha Siores
Manager, Regulatory Affairs

Enclosure

2017 Irrigation Load Control Pilot Program in Oregon

Issued March 28, 2018

PACIFIC POWER
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Overview

PacifiCorp has operated an irrigation load control program in Idaho since 2003 and in Utah since 2007. These voluntary direct load reduction programs allow PacifiCorp to better manage summer peak loads by providing incentives to customers that allow the Company to interrupt their irrigation service under certain conditions.

On May 3, 2016, the Public Utility Commission of Oregon (OPUC) approved PacifiCorp d/b/a Pacific Power's 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.

This report summarizes 2017 pilot program activity and presents the key findings from the second year. In its pilot program application, the Company identified key elements that would be provided annually. The following table describes where each of these elements are addressed in this report.

Element	**Start Page**	**Section**
1. Review of annual enrollment		
a. Total program enrollment	14	Enrolled Customers
b. Sites added and removed	14	Enrolled Customers
c. Customer outreach	9	2017 Activities …Challenges From 2016
d. Crop(s)	14	Customer Crop/ Operations and Pumping Equipment
e. Weather data from local weather station(s)	16	Weather and Drought Impact
f. Available information on water restrictions	15	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 2017
3. Incentive payments	14 23	Customer Payment Structure Appendix B: Customer Payments
4. Review of annual program performance		
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5. Key observations	5	Key Findings

In 2017, the same small group of customers participated and on-going efforts were made to enroll the one customer with medium voltage equipment that was identified but not enabled during the 2016 season. Four events were called in July and August of 2017, each of which lasted for four hours. Key findings from 2017 focus on participant behavior, event logistics and efforts to refine and improve delivery costs.

Key Findings

Participant behavior

Grower interest and engagement was maintained between the first and second years of the pilot. The pilot was able to recruit a small number of initial participants in a short period of time. The 2017 program year included more events of longer duration than the first year. In addition, two events were called close to each other (separated by only one day), which provides additional insight into the propensity for growers to opt out of events. The growers participated in all events and fulfilled their commitment to curtail irrigation usage. Similar to the 2016 season, participants did not indicate concerns about water availability for the current season.

Logistics

The four 2017 events with longer duration and close proximity to one another (one day separation in one case) further support the learning from 2016 indicating the resource (kW available for load control events) can be ramped up quickly and is reliable with an experienced delivery provider and an engaged grower community.

Event notification was successful and customers participated when called (i.e., did not opt out of events). 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.

Delivery Costs

The company and its delivery provider agreed to continue the fixed fee delivery for 2017 to maintain grower engagement while updated market pricing was secured. This structure focused on making sure the previously enabled participants were available for the entire season, but did not include any resources for outreach or to increase the enrolled customer count.

Assessing Costs and Benefits

The pilot program is intended to test designs, provide market feedback, and generate information about delivery. The company will monitor the pilot costs and potential benefits to understand the feasibility of expansion or alternate delivery models in Oregon beyond this initial pilot phase. The second year results reflect a full season of operation and provide additional information in this regard. Appendix 2 provides a discussion of potential benefits and initial findings related to the pilot objectives, including a discussion of potential benefits utilizing demand response cost-effectiveness protocols from California.

Background

On March 19, 2015, PacifiCorp held a workshop for irrigation customers in the Klamath Basin to provide an update on energy efficiency programs and a time-of-use pilot that was underway.[1] At the workshop, the company outlined a potential irrigation load control pilot based on the company's Utah and Idaho program design. Growers indicated support for the load control pilot program and emphasized their interest in a multiple-year offer and the ability to opt out of individual events.

The company's 2015 Integrated Resource Plan (IRP), filed March 31, 2015, committed to pursue a west-side irrigation load control pilot beginning in 2016.

On August 4 and December 16, 2015, the company held informal discussions about the proposed program with OPUC staff, Oregon Department of Energy, Northwest Energy Coalition and Citizens' Utility Board of Oregon.

On March 4, 2016, the company filed Advice No. 16-04 requesting authorization to implement a pilot irrigation load control program for irrigation customers near the Oregon and California border, specifically in the Klamath Basin area. The pilot was intended to test program design and interest among irrigation customers in the region. The filing included the following pilot program attributes:

- A five year pilot program to allow sufficient time for participants to work through scheduling and water availability issues and to investigate changes to pumping operations.
- A minimum of four dispatch events per season allowing growers to experience and adjust to operational impacts.
- A year-end report that provides information on program participation, program costs, load control achieved and other benefits, provided within 90 days of the end of each calendar year prior to the end of the five year pilot.

On May 3, 2016, the OPUC approved Advice No. 16-04.

On March 31, 2017, the company filed the 2016 Irrigation Load Control Pilot Program report with the OPUC.

On April 4, the company filed the 2017 Integrated Resource Plan. The three MW irrigation load control pilot resource was included in Table 5.14 – Summer Peak – System Capacity Loads and Resources without Resource Additions.

2017 Timeline

May 15	Dispatch training for PacifiCorp's Energy Supply Management group
May 26	Enrollment communication & notification test with customers

[1] Oregon Schedule 215 – Irrigation Time-of-Use Pilot Supply Service.

May 26	Equipment/communication tests completed. Program goes “live” for 2017 season with enrolled participants.
May 30	Web site message updated to 2017 season offer
July 30	Event notification to participating customers for July 31 event
July 31	Four hour event conducted between 4pm-8pm, Pacific time
August 1	Event notification to participating customers for August 2 event
August 2	Four hour event conducted between 3pm-7pm, Pacific time
August 7	Event notification to participating customers for August 8 event
August 8	Four hour event conducted between 3pm-7pm, Pacific time
August 14	Event notification to participating customers for August 15 event
August 15	Four hour event conducted between 3pm-7pm, Pacific time
August 19	End of regular season (mandatory events)
September 30	End of season (including voluntary event window). Season end communication to participating customers
Mid-December	Incentives paid to participating customers

Anticipated Pilot Size

PacifiCorp’s 2015 IRP helped inform the 3 MW size of the pilot program. Year 2 availability (2017) was comparable to Year 1 which is consistent with having the same set of customers and equipment enrolled between the two years. The challenges of adding new customers for 2017 was outlined in the 2016 report.

Anticipated Duration

PacifiCorp 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.

Program Parameters /Design

Participation in the Pilot Program requires irrigators to allow their pumps to be interrupted under conditions specified in Schedule 105 and summarized in Table 1.

Table 1. Irrigation Load Control Pilot Program Parameters

Program Parameters	**Description**
Eligible Customers	Irrigation Customers on Schedules 41 or 48 in and around Klamath Falls.
Program Period	Week including June 1 through week including August 15[2].

[2] In addition, voluntary events may be dispatched separately through September 30.

Program Hours	Weekdays, 12 p.m. to 8 p.m. Pacific Time.
Dispatch Limitations	52 hours per year, 20 events per year, up to 4 hours per event or twelve hours per week.
Incentive Rate	Estimated at $23-$27/kw per year. The program vendor may adjust the incentive rate based upon the needs of the program.
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 in the Fall. 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 2017 customers, dispatch events, incentive rates and payments, and opt out is provided in Appendix 1.

2017 Performance

Availability

Program availability in 2017 was more closely aligned with initial estimates for Year 1 than with initial estimates for Year 2 shown in Table 2. Delivery contract and cost challenges identified in the 2016 report necessitated the enrolled customer count remain constant between the two years and the alignment between the two years is consistent with the actions proposed in the 2016 report and taken during the 2017 season.

Four events were called in July and August, each lasting for four hours. The average kW available from all events was 432 kW. There was 100% participation in all events. Load control equipment performed as expected.

Table 2. Oregon Irrigation Load Control Pilot — 2016–2017 Performance

	Year 1 (2016)	Year 2 (2017)	Year 3	Year 4	Year 5
Estimated kW	0 - 2,000	3,000	3,000	3,000	3,000
Proxy/Available kW	565	546			
kW (average all events)	281	432			

* kW values are at customer site

For the 2017 season, 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 the 2016 program season 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 2017 were bounded by the delivery contract challenges identified in the 2016 annual report. 2017 actuals shown in Table 3 include vendor costs, customer incentives and customer engagement expenses.

Table 3. Irrigation Load Control Pilot — 2016–2017 Costs

	Year 1 (2016)	Year 2 (2017)	Year 3	Year 4	Year 5
Estimated Program Costs (Calendar Year)	$150,000	$225,000	$225,000	$225,000	$225,000
Actual Program Costs	$150,000	$125,000			

2017 Activities to Address Key Challenges From 2016

At the end of 2016, the existing vendor reviewed the economics for future years of the pilot program in Oregon and identified thee was not a sustainable path for delivering the Oregon Pilot Program under the existing pricing structure.

During the 2017 season, there was a focus on maintaining grower engagement with existing participants and minimizing the expense of new customer recruitment and enablement until new pricing could be secured. As a result, no new customers were added to the program in 2017 and the fixed pricing model was again utilized.

In 2017, the company issued a Request for Proposals (RFP) for delivering this pilot as well as other demand responses resources specific to states/regions within the six-state service territory. This activity was consistent with the plan described in the 2016 report. Multiple proposals were received for delivering the Oregon irrigation pilot program and were fully evaluated. These proposals provide updated pricing and a contracting path to operate the program utilizing load control switches for 2018 and as a possible transition to alternate delivery technologies.

In considering delivery options for continuing this pilot program, the company also explored the possibility of using the company's developing Advanced Metering Infrastructure (AMI) equipment being deployed throughout Oregon. The overall AMI schedule is designed to maximize cost efficiencies throughout the state with area installations being managed within the larger project milestones. As of the data of this report, Klamath basin area installation are forecasted to begin in mid-May and be completed in mid-July 2018. Since the Klamath installations will be completed mid-way through the 2018 irrigation season and not available for the entire season, the company is considering the 2018 season as a bridge to full AMI capability in 2019.

Efforts to enable the one customer with medium voltage equipment enrolled in 2016 did not come to fruition during the 2017 season. Enabling this type of customer with different operational and ownership characteristics than growers would expand pilot learnings and increase the resource size. This equipment is owned by a federal entity and operated by a local irrigation district. The federal entity is responsible for equipment modifications (including the addition of upgraded utility metering and load control switches). The irrigation district is responsible for utility bills for this equipment and managing overall water movement for the benefit of their members. The irrigation district would be responsible for managing changes in water flow during load control events and unless other arrangement are made, receive the load control incentive payment. In this arrangement both entities need to be comfortable that program participation impacts are fully understood and shared responsibilities with their partners are delineated.

Discussions with the parties continued through 2017 and these efforts will be restarted in 2018, again with the goal of enabling a new type of owner and expanding the pilot size. In many ways, the 2016 and 2017 work reinforce the need for a multi-year pilot so these complex ownership and operational issues can be better understood and addressed, where possible. If so, then this equipment can serve as a resource in the basin. If the challenges are insurmountable, then the company has gained the knowledge that this equipment should not be considered an available load control resource in the basin.

Appendix 1
2017 EnerNOC Pacific Power Irrigation Load Control Program Report

As part of its delivery contract with the company for the pilot program in Oregon, EnerNOC 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. EnerNOC's report is provided as Appendix 1 to this report.

ENERNOC

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2017 Pacific Power Irrigation Load Control Program Report

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Date:
February 21, 2018

Contents

<u>Overview of the 2017 Irrigation Load Control Program</u>

This report provides an overview of the Irrigation Load Control (ILC) Program in the Klamath Falls, Oregon region of the Pacific Power service territory as implemented and administered by EnerNOC. This report is intended to document program results, accomplishments, and challenges, including lessons learned.

Regulatory approval for the ILC program in Oregon was granted by the Public Utility Commission of Oregon on May 4, 2016. The Irrigation Load Control program was available in both 2016 and 2017 to irrigation loads in the Klamath Falls, Oregon region of the Pacific Power service territory for customers that were not already participating in the time of use program.

Three customers with a total of five sites and ten pumps participated in the program in 2017, providing a total of 546 potential capacity (peak) kW during program hours in 2017. Participating sites were compensated for shutting off irrigation load for specific time periods determined by Pacific Power, and were provided day-ahead notice of load control events. Customers had the opportunity to opt-out of (i.e., choose not to have their pumps curtailed) for events as necessary to suit their day-to-day business operations.

Customer 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. The program hours are 12:00 PM to 8:00 PM Pacific Daylight Time (PDT), Monday through Friday, not including holidays.

Per Oregon Schedule 105, the load control season starts on the Monday of the week including June 1st and ends on the Friday of the week including August 15th. For the 2017 load control season, the first day of the program season was Tuesday, May 30th since Monday, May 29th was the Memorial Day holiday and, thus, not an eligible program day. The program season ended on Friday August 18th. During this period, capacity payments are earned by customers for making load available for curtailment and fulfilling that obligation when called upon by Pacific Power. Per Oregon Schedule 105, Pacific Power may call voluntary events from June 1st to September 30th each year. Voluntary events allow customers to earn payments for their real-time reductions during voluntary events, but their participation or lack of participation does not impact their regular season capacity payments. No voluntary events were called by Pacific Power in 2017.

Pacific Power initiated four load control events during the load control season. Load reductions for the events are calculated using five-minute interval data from EnerNOC's energy monitoring equipment. The performance factor for all events was 100%, which indicates that all 10 irrigation pumps across the three customers participated in each load control event with no opt-outs.

Review of 2017 Enrollment and Enablement

Customer Payment Structure

All participants are paid the same incentive based on measured available load for curtailment throughout the program season adjusted for any opt outs or non-performance in load control events. In 2017, participants were paid at the $23/kW rate. This payment structure is designed to provide fair and consistent treatment for all sites.

Enrolled Customers

EnerNOC had 3 of 4 customers participating again in the 2017 load control season. One customer with pumps taking medium voltage service that were enrolled in 2016 were not enabled in 2017 and did not participate. These pumps are unique with ownership and operational responsibilities shared between two public entities. Installing additional equipment (interval meters and pulse splitters) to enable operational participation in this program required both entities to consider impacts. Ahead of and at the beginning of season, Pacific Power and EnerNOC support team participated in phone calls and followed up with written information about logistics and benefits of participation. Both entities have many priorities and the despite these efforts, necessary approvals to install equipment were not forthcoming during the 2017 season.

Data Quality

EnerNOC's Data Operations team validates all five-minute interval data following Irrigation Load Control events and for the entire program season each year. Data quality tools developed by EnerNOC in recent years were used in 2017 to verify pump runtime. Wireless connectivity and on-site hardware issues can cause data stream gaps or poor quality data, and power is often cut to irrigation pumps when they are not in use, which can obfuscate the distinction between a powered-down device and a hardware problem. To improve verifications of power status, EnerNOC uses an M2 Power Log tool to transmit and record "last gasp" power messages from the M2 devices to the EnerNOC platform. The log messages indicate the last recorded status of the M2 as powered-on or powered-off. In this manner, EnerNOC has a list of devices that were deliberately powered down for the purpose of event participation and can differentiate from those devices with bad metering or communications problems. Pacific Power and EnerNOC have agreed that where the powered-off status is confirmed by this tool for an event, event participation will be credited.

In 2017, EnerNOC did not identify any pumps with persistent data quality issues during program hours or load control events.

Review of 2017 Program Participants and Performance

Customer Crop/Operations and Pumping Equipment

Customer crop types/operations included alfalfa, wheat and hay. Pump sizes ranged for 60 HP to 250 HP.

Impact of Crop Type

Experience in other programs shows that crop type can typically be a predictor of customer willingness and ability to successfully participate in the Irrigation Load Control program. Irrigators in Klamath Falls most commonly grow alfalfa, wheat, hay, corn and potatoes, or some combination thereof over the course of a multi-year planting schedule.

- **Alfalfa** is typically grown on a five to seven year planting cycle and is watered consistently across the season. Prices have been particularly high since 2013, and many irrigators are choosing to plant this crop. Typically alfalfa crops have the flexibility to participate in events due to a tolerance for shifts in watering schedules. However, the load profile of alfalfa is intermittent. Pumps watering alfalfa are typically shut off for two periods each summer for harvest. These harvest periods can last a week or more, resulting in significantly reduced availability.
- **Wheat** will typically require large amounts of water early in the program season, and then pumps will be shut off once for several weeks to allow the crop to dry out for harvesting. These are tolerant crops that can withstand a couple off-schedule days to participate in load control events. However, incentive payments will be affected by variable availability.
- **Potatoes** are a water-intensive crop that typically stays in the ground for one to three years, and is often rotated with wheat. Potatoes are significantly more sensitive to irrigation schedule interruptions than wheat or alfalfa. Irrigation Load Control participants with potato crops will have high availability but likely a reduced flexibility to participate in load control events. Potatoes will also be particularly sensitive in drought years, further impacting event participation.
- **Corn** and **fields watered for livestock pasture** have less consistent or predictable irrigation schedules, and are mostly found on dairy farms.

A pump that waters wheat in year one with high event participation and 50% availability due to harvesting downtimes may water potatoes in year two. This crop shift would likely result in a shift to lower participation but 95% availability, making it difficult to use single year performance as a predictor for program fit across the ten-year period.

Impact of Irrigation Technology and Water Availability

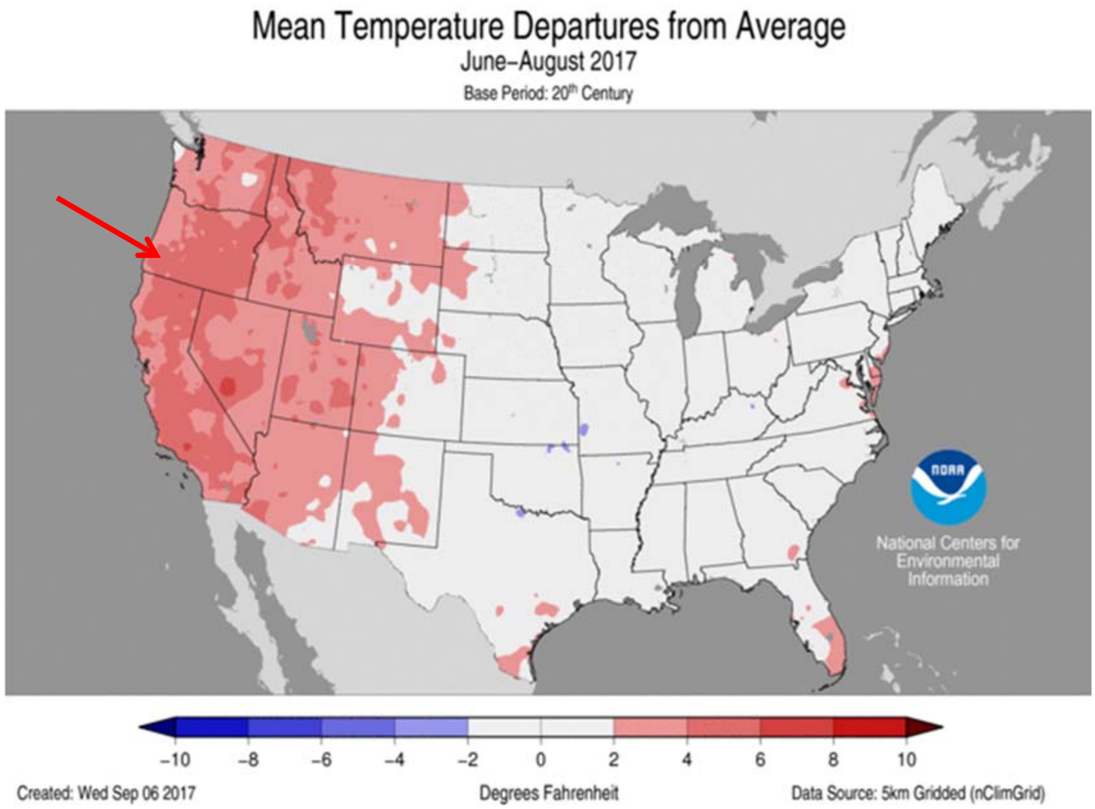
While pump size is a clear determinant of total availability in the Irrigation Load Control program, irrigation technology and water availability also impact irrigation pump run-time and thus can affect customer success in the Irrigation Load Control program. Pivot irrigation systems are operationally easier to manage for load control events than a wheel line or hand line irrigation system. During the 2017 season participants did not raise issues or questions about current or potential future water restrictions impacting their ability to participate in the program.

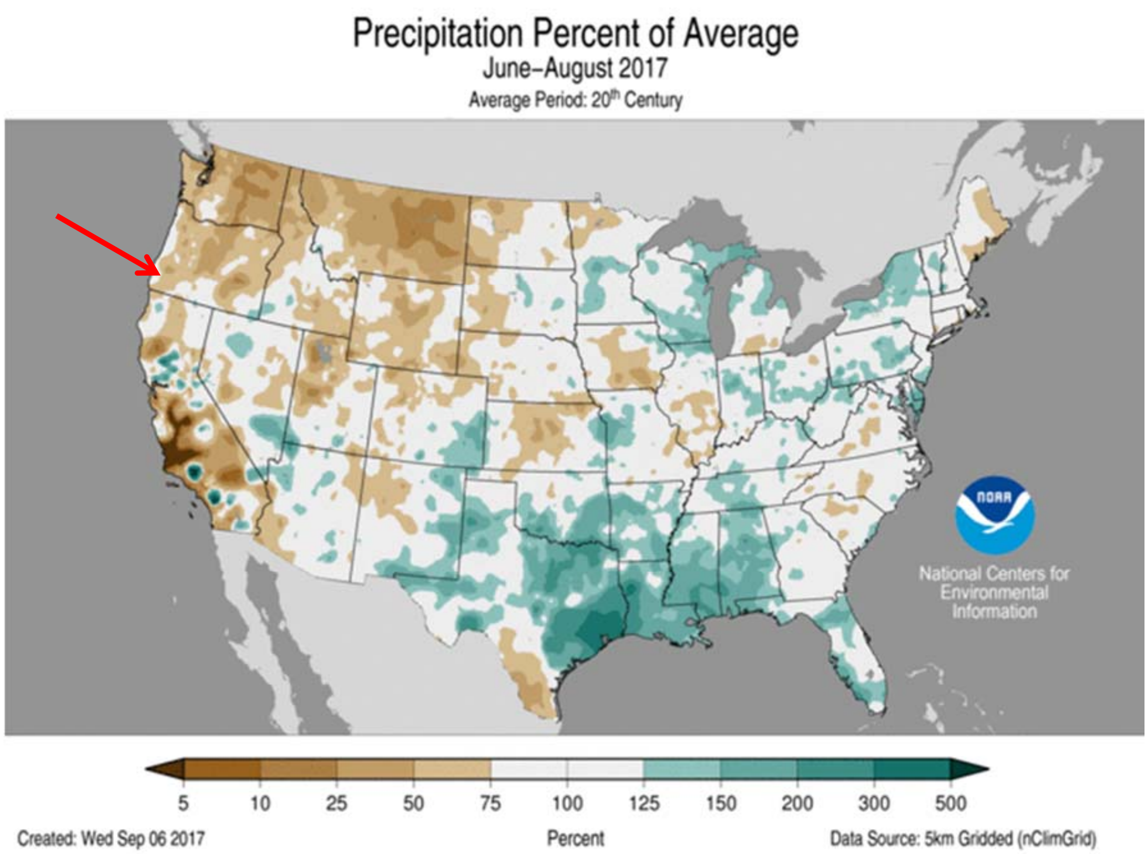
Weather & Drought Impact

2017 was warmer and dryer than normal, especially in July and August.[3] Warmer and dryer conditions, likely led to greater irrigation needs and higher available loads versus historical averages. However, since this is the first full season of interval data, definitive conclusions about higher average loads based on a comparison with historical interval data cannot be made.

The two images below highlight the above average temperatures and below average precipitation across much of the western part of the country including the ILC program region during the 2017 program season.

[3] 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/201708.

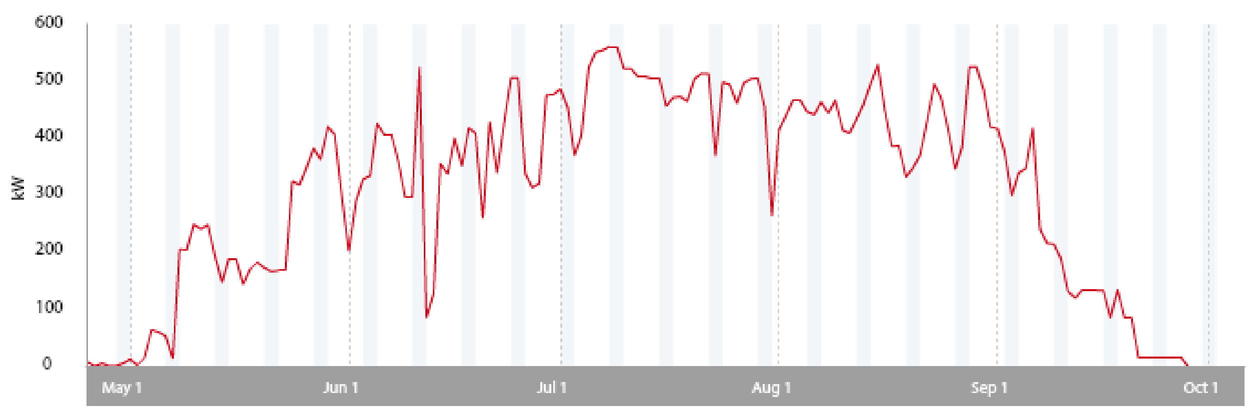

Mean Temperature Departures from Average
June–August 2017
Base Period: 20th Century
National Centers for Environmental Information
–10
–8
–6
–4
–2
0
2
4
6
8
10
Created: Wed Sep 06 2017
Degrees Fahrenheit
Data Source: 5km Gridded (nClimGrid)


Precipitation Percent of Average
June–August 2017
Average Period: 20th Century
National Centers for Environmental Information
5
10
25
50
75
100
125
150
200
300
500
Created: Wed Sep 06 2017
Percent
Data Source: 5km Gridded (nClimGrid)

Weekly Available Load Reduction

The Oregon Irrigation Load Control program is evaluated based upon average available load reduction (kW) between the nearest Monday on or before June 1st and the nearest Friday on or after August 15th during program hours from 12:00 PM to 8:00 PM Pacific Daylight Time, non-holidays. In 2017, the program was active between Tuesday, May 30th and Friday, August 18th and the portfolio average available load reduction was 425kW. [4]

The image below shows daily demand during active program months. Peak daily demand of just over 562 kW was set on Sunday July 9th, at noon. Peak Daily demand that occurred during program hours was set on Thursday July 6th at 12:15PM PST at 546 kW. Customers stopped their irrigation activities in line with the end of the growing season in late September with load dropping to 0kW on Sept 27th and remaining at ~0kW for the remainder of the year. The shape of the seasonal load curve is in keeping with expectations that the highest load should align with the active growing season and the warmest seasonal periods.



Load Control Events

Pacific Power activated the Irrigation Load Control program for fours control events in 2017. Actual load reduction was measured as the difference between actual demand during the event and baseline demand. Baseline demand is the average demand during program hours (12 to 8pm PT) on the most recent non-event, program day. Actual Load Reduction (kW), Baseline Demand (kW) and Load Reduction Performance Factor as reported here correspond to 5-minute interval energy usage measurements from EnerNOC's equipment at customers' sites. These measurements may not correspond to realized load reduction on Pacific Power's system.

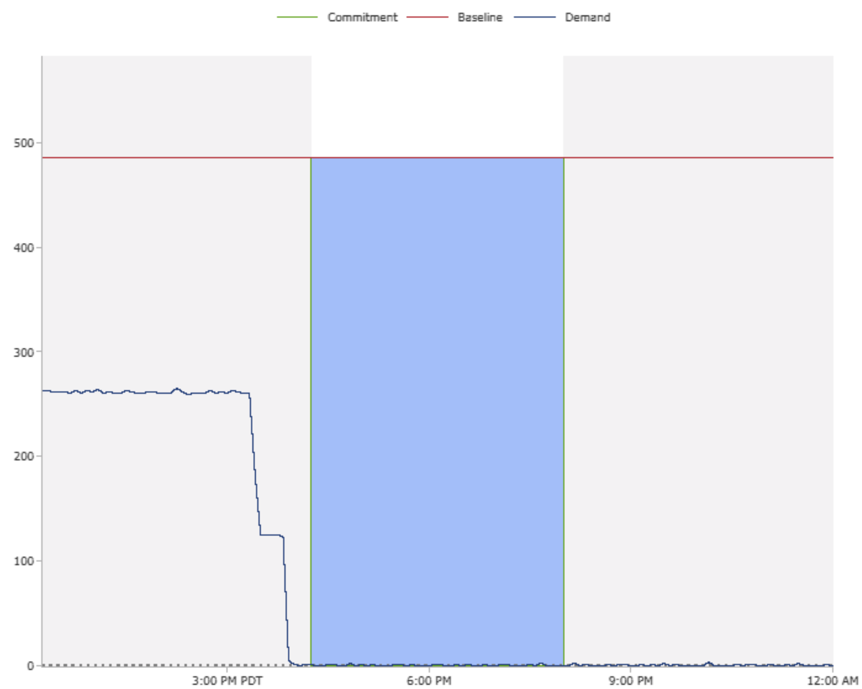
The 2017 portfolio delivered an average of 432 kW across the 4 load control events called during the 2017 program season. Load Reduction Performance Factor, the measure of actual load

[4] Monday, May 29th was the Memorial Day holiday, which moved the start of the program season to the next non-holiday weekday, which was Tuesday, May 30th.

reduction compared to baseline demand, was 100% for the portfolio. A customer participation factor is also calculated for each participating site and is designed to measure customers' choices to opt-out of participating in events. This customer participation factor is used to adjust availability payments in accordance with the pay-for-performance nature of the program. Performance factor should not be confused with any notion of performance against a capacity nomination. In the 2017 program season, load reduction performance factor and customer performance factor were both 100%.

Images below are visual representations of the 4 load control events showing the 5-minute interval demand relative to baseline:

Dispatch 1: 07/31/17



Dispatch 2: 08/02/17

Dispatch 3: 08/08/17

Dispatch 4: 08/15/17

Figure 2 details the actual load reduction, baseline demand, and performance factor.

Figure 3, below, provides details of the mandatory event in 2017. No events were called and then subsequently cancelled in 2017. Additionally, there were no voluntary events in 2017.

Figure 2: Actual Load Reduction, Baseline Demand, and Performance Factor, by Event and Region

Date	Region	Actual Load Reduction (kW)*	Baseline Demand (kW)*	Load Reduction Performance Factor (%)*
7/31/2017	Oregon	485	485	100%
8/2/2017	Oregon	335	335	100%
8/8/2017	Oregon	428	428	100%
8/15/2017	Oregon	482	482	100%

*Actual Load Reduction (kW), Baseline Demand (kW) and Load Reduction Performance Factor as reported here correspond to 5-minute interval energy usage measurements from EnerNOC's equipment at customers' sites. These measurements may not correspond to realized load reduction on Pacific Power's system.

Figure 3: List of 2017 Event Activity

Type	Start Time (PDT)	End Time (PDT)	Notes
Mandatory Event	7/31/17 4:00 PM	7/31/17 8:00 PM	• Total baseline demand was 485kW • Total load reduction was 484.98kW • Performance factor was 100%
Mandatory Event	8/2/17 3:00 PM	8/2/17 7:00 PM	• Total baseline demand was 335kW • Total load reduction was 334.77kW • Performance factor was 100%
Mandatory Event	8/8/17 3:00 PM	8/8/17 7:00 PM	• Total baseline demand was 428kW • Total load reduction was 428.69kW • Performance factor was 100%
Mandatory Event	8/15/17 3:00 PM	8/15/17 7:00 PM	• Total baseline demand was 482kW • Total load reduction was 481.74kW • Performance factor was 100%

*During an event, site loads are curtailed on a staggered basis over the first 15 minutes to reduce potential impact to the grid. During a four hour event, the total load reductions are fully enabled for 3.75 hours.

Key Lessons Learned from 2017

There were two key lessons learned in 2017:

1. With 100% participation in four events in 2017 from customers that participated in 2016, it indicates strong interest and willingness for irrigators in the Klamath region to continue to participate in an irrigation load control program.

2. Customers that require non-standard enablement pose a participation challenge. When a customer needs additional metering technology, such as an interval meter and pulse, it adds additional complexity and may reduce the likelihood of customer participation/enrollment.

APPENDIX A: Customer-Facing Irrigation Load Control Activity

The table below lists all activity involving program participants related to the Irrigation Load Control program that occurred in 2017, excluding Irrigation Load Control events. See figures 2 and 3 above for dates and detail related to those events.

Figure 4: Participant-Facing Irrigation Load Control Activity in 2017

	Activity	Date	Description
1	**Enrollment Communication and Notification Test**	Wednesday, 5/26/17	EnerNOC's Network Operations Center sent test notification messages via phone call, text, and/or email to all enrolled contacts in advance of the program going live on May 30th. Customers were asked to confirm receipt or call EnerNOC with contact changes.
2	**Season End Communication**	Friday, 9/30/17	EnerNOC's Network Operations Center sent reminders via text message to all enrolled contacts that Irrigation Load Control had ended for 2017 (mandatory & voluntary periods).
3	**Incentives Mailed to Participants**	Tuesday, 12/19/17	Incentive checks were mailed to enrolled customers for participation in the 2017 Load Control program.

APPENDIX B: Customer Payments

Three customers received incentive payments for their participation in the 2017 ILC program season. Incentives payments totaled $9,062 and were based on weekly available load that could participate in events multiplied by the participation factor. The participation factor was 100% for all customers and all customer incentives were calculated utilizing a $23/kW rate

Appendix 2
Oregon Pilot Program year two - benefits and costs discussion

The Oregon pilot program is intended to test designs, provide market feedback, and generate information about delivery logistics and costs. Pacific Power will monitor the costs and benefits to understand the feasibility of expanding the load control program beyond the pilot stage in Oregon.

This Appendix provides discussion of the 2017 program developed in response to Recommendation No. 3 in the April 26, 2016 OPUC staff memo 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.[5] 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...[6]" Although these Protocols are not directly applicable to pilots, they are being used here as an initial guide to help discuss the pilot program as it moves forward.

To utilize the Protocols as a guide, information from pages 11 and 12 of Appendix A is provided below, italicized; Protocol references to California utilities have been removed. 2017 program information is provided below each Protocol topic and labeled "Pilot" for the purposes of this discussion.

1. *Avoided Generation Capacity Costs*
   Pilot: For 2017, the Company's marginal capacity resource was Front Office Transactions (i.e. market purchases), which typically have a minimum increment of 25 MW. While this resource was too small to avoid a market transaction, the avoided energy costs below are calculated assuming that market transactions are avoided on a kW for kW basis.

2. *Avoided Energy Costs*
   Pilot: A review of the loads preceding and following each event indicate a mixture of load shedding (loads not restored following the July 31 event event) or load shifting (loads returning following the August 8 event) or a hybrid (some but not all load returning after the August 2 and 15 events). This review provides additional information to that gathered in the 2016 season and suggests a mixture of shedding and shifting but provides no definitive conclusion about load shifting or shedding as the primary impact.

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[5] *2015 Demand Response Cost Effectiveness Protocols,* California Public Utilities Commission. 2015.
[6] *Id*, page 7.

Because day-ahead notice is required for curtailment, for valuation purposes the pilot program was assumed to allow day-ahead on-peak market purchases to be avoided. However, day-ahead on-peak purchases typically span a standard 16 hour block, rather than the four-hour curtailment associated with the pilot program. As a result, an additional twelve hours of purchases may be necessary during the hours in which the irrigation loads are not being curtailed. The 2017 valuation is based on the highest cost day-ahead purchase transaction entered by the Company, net of costs in non-curtailment hours based on Energy Imbalance Market (EIM)[7] prices.

3. *Avoided Transmission and Distribution Costs*
   Pilot: Assigning transmission and/or distribution deferral value(s) to load management is consistent with the 2017 IRP, the Northwest Power Planning and Conservation Council's 7th Power Plan[8] and Oregon's Resource Value of Solar (UM-1910). Deferral values and their application in this analysis are from UM-1910 and are based on equipment requiring investments within the planning horizon. Available information indicates enabled load control equipment is connected to four separate distribution substations. In 2017, none of these substations were identified as needing import capacity upgrades and no transmission deferral value was assigned. In 2017, one device controlling approximately 15 kW of irrigation load was connected to a distribution substation identified for an upgrade if block load additions materialize in the future. While no future block loads were identified in 2017, for the purposes of this analysis, the distribution deferral value of $14.08 kw-year was utilized to estimate a potential distribution deferral benefit of $211.

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

5. *Line Losses*
   Pilot: For valuation purposes, the hourly line loss factor methodology developed for UM-1910 was used. Under that methodology, avoided line losses are highest during peak load periods, and as a result, the avoided line losses during the 2017 curtailment events is estimated at 10.13%. The value of avoided line losses is included in avoided energy costs.

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

The 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*
   Pilot: The average kW reduction across the four 2017 events was 432 kW at site. Applying the 10.13% estimated line loss, the load impacts at the generator are 476 kW.

[7] For more information on EIM, see www.westerneim.com/pages/default.aspx
[8] 7th Power Plan applies transmission deferral value only.

2. *Expected call hours of the program (used to determine energy savings)*
   Pilot: Program was called for 16 hours in 2017. This is approximately 30% of 52 maximum annual dispatch hours.

3. *Administrative Costs*
   Pilot: Administrative (non-incentive) costs paid in 2017 to EnerNOC included fixed delivery costs for the second year of the pilot.

4. *Participant Costs (for only those programs which are not using a percentage of incentives as a proxy measurement)*
   Pilot: Participants do not incur capital costs to participate.

5. *Capital Costs and Amortization Period, both to the LSE and to the Participant (should be specified for each investment)*
   Pilot: There are no unamortized capital costs to recover over an amortization period. 2017 program expenses were paid in November December 2017, and are being recovered contemporaneously through Schedule 95.

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*
     Pilot: This resource was not large enough to change any portion of the Company's participation in CAISO markets.

7. *Bill reductions and increases*
   Pilot: 2017 participant's bills were not analyzed for changes since it was unlikely the sixteen 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*
   Pilot: 2017 incentive payments were $9,062.

9. *Increased supply costs*
   Pilot: 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)*
    Pilot: See No. 7 above.

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

    - *Data need to calculate Availability (A Factor)*

Pilot: 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 (weekends, before June 1st that a generation constraint could occur.

- *Notification Time (B Factor)*
  Pilot: This program has day ahead notification.

- *Trigger (C Factor)*
  Pilot: Events can be called at the discretion of utility (within the specified months, weeks, days, hours). Other than that there are no restrictions. The 2017 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)*
  Pilot: 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)*
  Pilot: Valuation for the avoided energy during the four events was performed internally by same team involved in other Oregon work; solar and avoided costs. Events require day ahead notification, so they are assumed to avoid day-ahead on-peak market energy purchases (16 hour blocks). The cost of replacing the portion of the 16 hour block not covered by the 4 hour curtailment event is estimated based on EIM price results. The small size of the current program makes it unlikely to actually avoid a day-ahead market transaction (typically 25MW increments). Estimated value based on day-ahead PacifiCorp transactions and EIM prices during the four events in 2017 was $1,313.

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

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

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

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

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