ITEM NO. CA4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: February 9, 2016

REGULAR ____ **CONSENT** _X_ **EFFECTIVE DATE** **February 15, 2016**

DATE: February 1, 2016

TO: Public Utility Commission

FROM: Michael Breish MB

THROUGH: Jason Eisdorfer and Aster Adams JE MH for AA

SUBJECT: IDAHO POWER COMPANY: (Docket No. ADV 193/Advice No. 15-14) Requests Modifications to Schedule 23 – Irrigation Peak Rewards Program.

STAFF RECOMMENDATION:

Staff recommends the Commission allow Idaho Power Company's (Company or Idaho Power) Advice No. 15-14 to go into effect February 15, 2016.

Introduction and summary

On December 30, 2015, Idaho Power filed Advice No. 15-14 to modify the Company's Schedule 23, Irrigation Peak Rewards Program (the Program), to consolidate the current program participation options available to customers as well as alter the qualifying criteria for the manual participation option. Staff reviewed Advice No. 15-14 to determine whether: (1) it complies with the 2013 Commission order regarding Idaho Power's demand response programs in Oregon, (2) is cost-effective, (3) the changes to the program do not hinder the programs intended purpose, and (4) it does not adversely affect ratepayers.

Staff concludes that the filing satisfies the criteria listed above.

Applicable Statutes, Rules, and Commission Orders

Criteria 1, compliance with Stipulation: In 2013, the Commission issued Order No. 13-482 approving a stipulation executed by Staff, the Citizen's Utility Board of Oregon, EnerNOC and the Oregon Irrigation Pumpers Association regarding Idaho Power's demand response portfolio in Oregon (the Stipulation). Under the Stipulation and Order No. 13-482, Idaho Power is required to offer demand response programs to its three customer classes (residential, commercial and industrial, and irrigation), even in years when Idaho Power does not anticipate peak-hour capacity deficits.[1] The Stipulation and Order specify some design requirements for the programs and a methodology for determining the programs' annual value.

Criteria 2, cost effectiveness: In 2013, in connection with its analysis of Portland General Electric Company's (PGE) request to amortize costs of a demand response program offered to industrial customers, Staff reviewed the cost effectiveness of the program by comparing the annual cost of the program per KW to the levelized cost of a deferred least-cost supply resource.[2] Staff concluded the program was cost-effective and the Commission approved Staff's recommendation to allow PGE to amortize costs of the program into rates.

Staff conducted similar analyses in 2009 and 2010 regarding requests by Idaho Power and PGE to implement demand response programs. In both cases, Staff concluded the programs were cost effective and the Commission authorized the companies to implement the programs.[3]

Criteria 3 and 4, designed to achieve intended purpose and adverse effect on ratepayers: In Order No. 12-159, the Commission adopted a set of factors that the Commission would use to examine utility requests to implement time-varying rates. The Commission did not intend the factors to be rigidly applied.[4] Instead, the importance of individual factors in any particular case is dependent on the circumstances of the proposal under consideration.[5] And, although the Commission stated that it did not explicitly adopt the factors for evaluation of demand response programs it noted parties could use them to analyze such programs.[6]

Staff did not apply several of the factors in Order No. 12-159 given that the Company is required to offer a demand response program to irrigation customers under Order No. 13-482. However, Staff did evaluate Factors 2, 3, and 6, which are "the extent to which an optional rate or alternative program can achieve these demand-side resource and system benefits;" "the impacts on customers of the proposed rate and the ability of customers to respond to these impacts;" and "the ability to explain and communicate the rate to customers."[7]

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[1] Commission Order No. 13-482, Docket No. UM 1653, December 19, 2013.
[2] Commission Order No. 13-172, Docket No. UE 272, May 7, 2013.
[3] Commission Order No. 10-206, Docket No. UM 1473, June 4, 2010; Commission Order No. 09-254, Docket No. UE 205, July 6, 2009.
[4] Commission Order No. 12-159, at pages 3-4, Docket No. UM 1415, May 8, 2012.
[5] Ibid.
[6] Ibid, at page 3.
[7] Ibid., Appendix A, at page 1.

Background

Idaho Power has offered the Program to Idaho and Oregon irrigation customers since 2004 when it was first deployed as a pilot project. The Company has modified the program several times throughout its existence, most notably in 2009 when a remote dispatch option was incorporated. Concurrently, Idaho Power was beginning to install its advanced metering infrastructure (AMI). Idaho Power utilized cellular-based communication infrastructure to initiate remote load-control events for some customers until the deployment of AMI was sufficient enough to have customers utilize that communications protocol instead.

The Program is intended to eliminate the need for additional supply-side resources by reducing energy demands during summer peaking periods. Participating customers are offered fixed and variable financial incentives in order to shut off designated irrigation pumps during load control events. Operational from June 15 to August 15, the Program currently permits customers to participate through automatic or manual interruption options. The former is accomplished with load control devices installed on irrigation pumps specified by the customer. Idaho Power remotely disables those pumps during a load control event by means of the AMI or cellular-based technology. Customers participating in the manual option, which is called "option 3," receive a communication from Idaho Power in advance of the load control event and then have the opportunity to disable pumps of their choosing. Customers must have service locations that feature 1,000 horsepower or more in order to qualify for option 3.

Under the current automatic dispatch options, customers can choose from one-way load control devices or two-way load control devices. The latter, also known as "option 2," enables customers to monitor and have remote control over the selected pumps through cellular-based communication devices.[8] According to Idaho Power, the monitoring and customer-enabled control of pumps afforded by the cellular-based technology are superfluous to the purpose and function of the Program.

Staff review

Advice No. 15-14 modifies Schedule 23 in two distinct ways. First, it eliminates option 2 by consolidating the two automated dispatch programs into one option called "Automatic Dispatch Option." Customers who are currently subscribed under option 2 would not immediately see any changes. Rather, when their cellular-communication devices fail or when the cost effectiveness changes, Idaho Power would replace these devices with AMI-compatible devices for the selected irrigation pumps. Idaho Power claims that option 2's two-way feature "has higher costs associated with replacement installations,

[8] The one-way dispatch option through customers' AMI is designated "option 1."

annual service fees, and ongoing maintenance expenses."[9] Transitioning these customers to AMI-enabled dispatch would generate cost savings as well as reduce the failure rate of the cellular-based dispatch devices. Because of device failure, the average percent of load that was not curtailed during the 2014 season was 7.1 percent.[10] Had these device failures not occurred, the average realization rate for the 2014 season would have been 74.4 percent.[11]

Second, requirements for option 3, which would be renamed "Manual Dispatch Option," would be modified to include language that permits the Company to allow customers who "may be limited by load control device communication technology or installation configuration" to participate in the Program.[12] The 1,000 horsepower criterion remains unchanged, but allows existing customers with less than 1,000 cumulative horsepower and specialized communications technology to participate in the manual option.

Idaho Power provided data in the advice filing that supports the recommended Schedule 23 changes. Only three percent of all Program participating locations are currently enrolled in option 2; this equates to one percent of all participating customers. Two percent of participating locations are enrolled under option 3, leaving 95 percent of the remaining participating locations enrolled in option 1. Therefore, very few customers, and subsequently few program megawatts (MW), would be impacted by this proposed change while still saving the Company program expenses.

From a review of the Program, Idaho Power also noted that of "2775 total eligible service locations, 12 percent do not have AMI technology available to them."[13] Of that 12 percent, only 14 service locations participate in option 3. Idaho Power indicates that if the qualifying criteria for option 3 are updated as requested, customers who rely on specialized communication technology, but do not currently meet the 1,000 horsepower threshold, could still participate in the Program if option 2 were to be eliminated by allowing them to participate in the Manual Dispatch Option. For example, 13 locations currently rely on costly satellite phone technology because they do not have AMI and have an aggregate horsepower of less than 1,000. These customers could eliminate the technology, saving them money while also still participating in the Program. Idaho Power estimates that, if the requested modifications are permitted, the portion of service locations participating in the Manual Dispatch Option would increase by one percent.

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[9] Idaho Power's cover letter for modifications to Schedule 23, at page 2, Advice No. 15-14, December 30, 2015.
[10] PECI's 2014 Impact Evaluation of the Irrigation Peak Rewards Program, at page iii, Idaho Power's 2014 Annual Demand Side Management Report, Supplement 2, October, 2014.
[11] Ibid. The calculated average realization rate for 2014 was 67.3 percent.
[12] Idaho Power's cover letter for modifications to Schedule 23, at page 3, Advice No. 15-14, December 30, 2015.
[13] Ibid., at page 2.

Staff had several concerns and questions regarding Idaho Power's provided information. On January 20, 2016, Idaho Power held a call with Staff to respond. Staff first wanted to know how each option contributes to the Program's approximate 300 MW overall demand reduction potential because of possible detrimental impacts to the program's performance. Idaho Power stated that approximately 3.7 MW are from option 2 and about 60 MW are from option 3, leaving approximately 236 MW, or approximately 79 percent to option 1. Staff also asked if Idaho Power anticipated any demand reduction performance changes if the requested modifications were to be permitted. In response, the Company doesn't anticipate any material changes in the annual delivered demand reduction. These responses assuaged Staff's concerns regarding potential impacts to the Program.

Staff also asked how Idaho Power determined the one percent increase in the Manual Dispatch Option. Idaho Power calculated this change based on the 13 participating service locations that do not have AMI and utilize satellite-based technology. Idaho Power anticipates that customers who have similar circumstances and are enrolled in option 2 would switch. Staff found this determination satisfactory, especially given the relatively minute amount of customers in reference.

In the conversation with Idaho Power, Staff asked if the Company could provide a delineation of what percentage of the realized load reduction each option contributes. Idaho Power was receptive to the idea and Staff recommends the Commission require Idaho Power to report such a breakdown in future *Annual Demand Side Management Reports.*

Staff concludes the Program modifications proposed by the Company are reasonable and result in a demand response program that fulfills the criteria mentioned earlier in this report. Staff recommends the Commission approve the Company's proposed changes.

PROPOSED COMMISSION MOTION:

Idaho Power's Advice No. 15-14 be allowed to go into effect on February 15, 2016, and that Idaho Power provide dispatch specific load reduction data in future *Annual Demand Side Management Reports.*