ITEM NO. CA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: February 8, 2022

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ____**February 15, 2022**____

DATE: January 31, 2022

TO: Public Utility Commission

FROM: Nick Sayen and Kacia Brockman

THROUGH: Bryan Conway, JP Batmale, and Sarah Hall **SIGNED**

SUBJECT: IDAHO POWER COMPANY:
(Docket No. ADV 1355/Advice No. 21-12)
Revises demand response programs in Schedules 23, 74, and 76.

STAFF RECOMMENDATION:

Allow Idaho Power Company's (Idaho Power, IPC, or Company) Advice No. 21-12, revising demand response programs in Schedules 23, 74, and 76, effective with service rendered on and after February 15, 2022.

DISCUSSION:

Issue

Whether the Commission should allow Idaho Power to revise the valuation and timing of three demand response (DR) programs, along with other programmatic changes, and also update the Company's DR cost-effectiveness calculation.

Applicable Law

ORS 757.205 requires public utilities file to all rates, rules, and charges with the Commission.

ORS 757.210 establishes a hearing process to address utility filings and requires rates be fair, just, and reasonable.

ORS 757.220 provides that no change shall be made in any schedule, except upon 30 days' notice to the Commission prior to the time the changes are to take effect.

OAR 860-022-0025 requires that filings revising tariffs include statements showing the change in rates, the number of customers affected and resulting change in annual revenue, and the reasons for the tariff revision.

In Order No. 13-482, issued December 19, 2013, the Commission adopted a Stipulation establishing terms by which IPC would maintain, rather than suspend, its DR programs until the Company identifies a system need for DR resources, reports a change to DR program cost-effectiveness, or receives a Commission order. The Stipulation also sets forth the circumstances under which the term of the Stipulation may be amended.

Analysis

This filing describes how the Company began to use a new methodology to evaluate the capacity contribution of resources including DR, and proposes modifications to the Company's DR programs resulting from the new methodology. The filing also proposes changes to the DR cost-effectiveness calculation. In this memo, Staff provides background to the Company's proposed changes, and discusses changes to the Company's operational needs and the valuation of capacity. Staff summarizes the proposed changes to the DR programs, and reviews Staff's analysis of these changes. Staff describes the Company's proposed changes to the DR cost-effectiveness calculation, and finally discusses stakeholder outreach. The memo concludes with Staff's recommendation.

Background
Idaho Power offers the following three opt-in DR programs in which participating customers receive incentives for reducing their load when the Company calls peak load events during the summer.

- The Irrigation Peak Rewards program (Schedule 23) provides agricultural customers demand and energy credits for allowing IPC to turn off, or for manually turning off, their irrigation pumps during called events. The program was first offered to Oregon customers in 2006.
- The Residential Air Conditioner (A/C) Cycling program (Schedule 74) is marketed as "A/C Cool Credit" and provides residential customers a monthly participation incentive for allowing the Company to cycle their A/C units during called events. The program was first offered to Oregon customers in 2008.
- The Flex Peak program (Schedule 76) provides commercial and industrial customers capacity and energy payments for manually reducing their demand a committed amount during called events. The program was first offered to Oregon

customers in 2010 and was delivered through a third-party contractor.[1] Idaho Power assumed program delivery in 2015.

In 2013, IPC determined that these DR programs were no longer needed in the near term because the Company's 2013 Integrated Resource Plan (IRP) identified no peak-hour capacity deficit until 2016. As a result, IPC received Commission approval to temporarily suspend the Irrigation Peak Rewards and A/C Cool Credit programs for the 2013 summer season,[2] and informed the Commission of contract changes that would significantly scale back the Flex Peak program.[3]

Idaho Power and stakeholders then participated in workshops to discuss treatment of the DR programs in 2014 and beyond. These workshops resulted in a Stipulation that was adopted by the Commission in Order No. 13-482. The Stipulation requires IPC to maintain the DR programs, even during periods when the Company does not anticipate peak-hour capacity deficits, in order to have viable DR programs in the long term. The Stipulation provides for how the DR programs would be operated during periods of peak-load sufficiency, the cost-effectiveness methodology, and valuation of the DR resource. The Stipulation remains in effect until: a) the Company identifies a change to its operational needs or to the cost-effectiveness of the DR measures that warrants a change; b) the Commission on its own determines that an investigation should be conducted into IPC's DR programs; or c) intervenors request the Commission conduct an investigation of the DR programs subject to the Stipulation. With this filing, the Company has identified a change to its operational needs and the cost-effectiveness of DR measures, triggering review of the Stipulation.

Changes to Idaho Power's Operational Needs and Valuation of Capacity
In its filing, IPC explains that, historically, the capacity value of the DR resource portfolio was based on the portfolio's ability to be utilized during the top 100 system gross load hours. Gross load looks only at the demand side and not the supply side. In this filing, the Company discusses that net load (demand minus supply) is a more relevant metric than gross load to identify hours of need. In the 2021 IRP planning process, the Company began using the risk-based Effective Load Carrying Capability (ELCC) methodology to evaluate the capacity contribution of DR and other existing and new resources, including variable supply resources. Staff believes IPC's use of the ELCC method best captures the Company's future resource adequacy risk. Staff has also recommended the ELCC method for valuing capacity in current Docket No. UM 2011. The ELCC methodology identified that the primary hours of need for additional resources, or the highest-risk Loss-of-Load Probability (LOLP) hours, are no longer

[1] Order No. 10-206, granting IPC authorization to expand its Flex Peak program offering to its Oregon service area.
[2] IPC Advice No. 13-04, filed February 15, 2013.
[3] IPC's letter filing dated July 9, 2013 in Docket No. UM 1473.

expected to align with the hours of IPC's system peak load. Instead, the highest-risk LOLP hours have shifted to later in the day when solar resources see an output reduction. Using the ELCC methodology, the Company found that the existing DR programs as currently structured are not effective at meeting system needs over the planning horizon providing an ELCC of only 17 percent.[4]

Idaho Power's Proposed Changes to DR Program Tariffs
To make the DR programs more effective at meeting system needs, IPC proposes the following changes to Schedules 23, 74, and 76.

For all three programs:

1. Better align the season, available event windows, and event duration, with the highest-risk LOLP hours by: a) extending the summer program season by one month to September 15; b) shifting the start and end times in which events can be called to later in the evening; and c) increasing the maximum number of event hours that can be called in a week from 15 to 16 hours. The filing summarizes these parameter changes in Table 2, which is excerpted below. (Note that Table 2 does not capture *all* parameters or changes of all three DR programs.)

Table 2: General Summary of Proposed DR Program Parameter Changes

Parameter	Current Program	Proposed Program	Change
Season	June 15th to August 15th	June 15th to September 15th	Season end date extended 1 month to September 15th
Available Event Times	1:00pm to 9:00pm	3:00pm to 11:00pm	Shifted start and end times by 2 hours
Weekly Maximum	No More than 15 Hours in a Week	No More than 16 Hours in a Week	Increased weekly maximum by 1 hour

2. Increase participation incentives to offset a potential decline in participation that may result from the extended event window. The filing summarizes incentive changes in Table 3, which is excerpted below.

[4] The ELCC methodology and the results of IPC's analysis of the effectiveness of is DR portfolio in the highest-risk LOLP hours is described in Attachment 2 of IPC's Advice No. 21-12.

Table 3: Summary of Proposed Demand Response Incentives

		Fixed Incentive	Variable Incentive	Incentive Adjustment
Flex Peak	Existing	$3.25 per kW per week = $29.25 per kW per season	$0.16 per kWh after 3rd event	$2.00 per kW not achieved per event & $0.25 after 3rd event
	Proposed Option	**$3.25 per kW per week = $42.25 per kW per season**	**$0.20 per kWh after 4th event**	**$2.00 per kW not achieved per event**
A/C Cool Credit	Existing	$5.00 per month = $15.00 per season	None	None
	Proposed Option	**$5.00 per month = $20.00 per season**	**None**	**None**
Irrigation Peak Rewards	Existing	$5.00 per kW & 0.76¢ per kWh, 2 months = $16.00 per kW per season	$0.148 per kWh after 3rd event & $0.198 for 9:00pm option	$5.00 per kW per opt out & $1.00 per kW after 3rd event
	Proposed Option	**$5.25 per kW & 0.80¢ per kWh, 3 months = $25.20 per kW per season**	**$0.18 per kWh after 4th event & $0.25 for 11:00pm option**	**$6.25 per kW per opt out**

3. Clarify the standards under which DR may be dispatched during system emergencies.
4. Change aspects of the tariff language to add clarity for customers.

For Irrigation Peak Rewards and Flex Peak programs:

1. Extend IPC’s deadline to pay customer incentives to better align with the availability of information from the Company’s billing system.
2. Adjust opt-out fees to effectively nullify a customer’s incentive if the customer opts out of four events per season, providing a disincentive to opt out of events.

For the Irrigation Peak Rewards program:

1. Allow customers that do not pay demand charges during the extra month added to the summer event season to receive their demand credit as an equivalent energy credit instead.
2. Waive opt-out fees when a DR event closely follows a planned or unplanned utility outage, recognizing that a second pumping outage may risk crop production.
3. Clarify that opt-out fees apply to customers who opt out of an event by manually overriding a dispatch command from IPC.
4. Remove marketing limitations imposed by the Stipulation, allowing IPC to expand the program to new customers that use either load control devices or rely on manual dispatch.

5. Impose an installation fee on customers with small pumps. This will allow the Company to maintain program cost-effectiveness while expanding participation to include small customers that offer less load reduction.

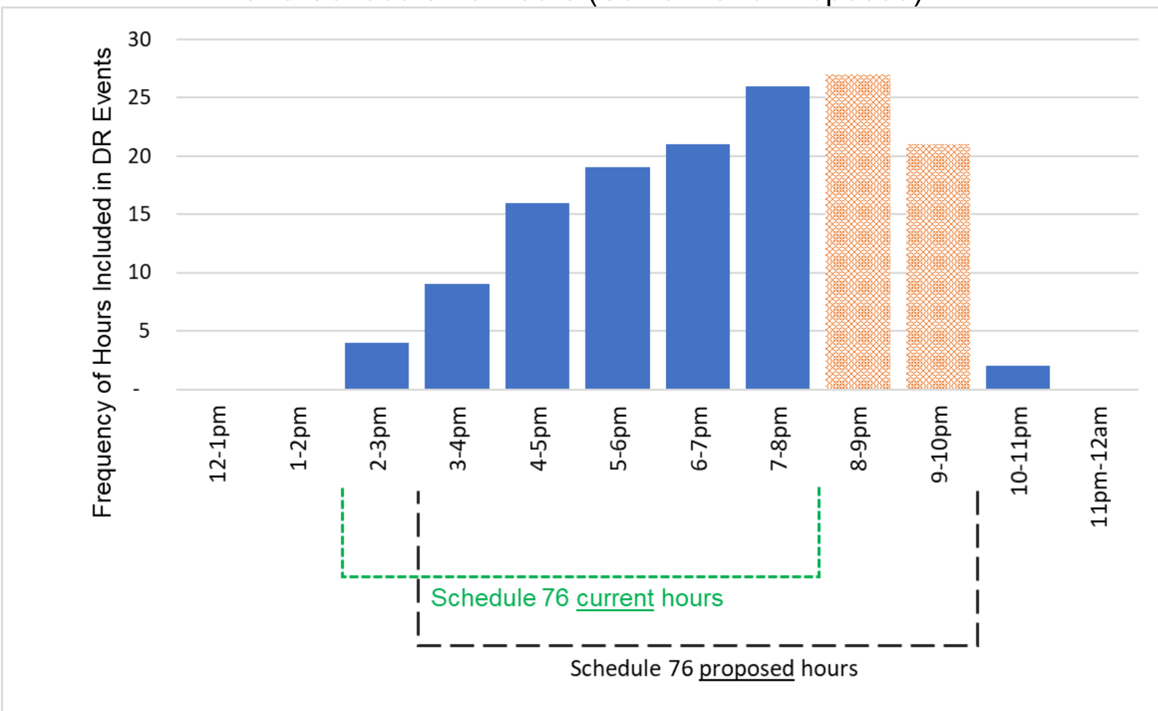
For the Flex Peak program:

1. Adjust the method for establishing the customer's baseline to improve accuracy. The baseline is used to calculate the "day-of adjustment", on which the customer's incentive is based.
2. Increase the amount of advanced notice from two hours to four hours in response to customer requests.
3. Streamline the dispatch process for IPC Load Serving Operations by matching the notice requirement for the Irrigation Peak Rewards program.

Staff's Analysis of Proposed Tariff Changes
Staff appreciates IPC's responsiveness to our 29 information requests. Staff finds that IPC's analysis demonstrates that the Company's highest-risk LOLP hours have shifted, and will continue to shift, to later hours in the day as more solar generation is added to the Company's system in the coming years.

Staff agrees with Idaho Power's analysis. Shifting the start and end times for DR events is necessary to target the hours of the Company's greatest resource adequacy risk. As a hypothetical example of this, Staff notes Figure 1 below. Staff generated Figure 1 after reviewing and analyzing data provided in response to information requests, in particular number 17. Figure 1 shows the current versus proposed Flex Peak program hours in comparison to the expected hours of DR deployment (for all three DR programs). The current ending hours of 8 pm for the Flex Peak program would miss many peak net demand times; adding the 8-9 pm hour to the program is crucially important to capture hours of system need. Staff's analysis showed a 91 percent correlation between frequency of dispatch and size of dispatch among hours with DR. The 8-9 pm hour is both most *often* dispatched and has the *largest* average dispatch. Thus, if the y-axis were *MW of DR dispatched* instead of *event hours*, Figure 1 would present a similar picture.

Figure 1: Frequency of Hours Included in DR Events, and Schedule 76 Hours (Current and Proposed)[5]



Critically, Idaho Power's analysis demonstrates that the program changes proposed in this filing, especially the shift to later hours in the day and extension of the summer season, will dramatically improve the effectiveness of the current DR portfolio by increasing the portfolio's ELCC from 17 to 56 percent.[6] As such, Staff supports the proposed changes.

Staff is deeply interested in the performance of the revised DR programs. As such, Staff requests that in 2023 Idaho Power provide the Energy Efficiency Advisory Group (EEAG) with program data on changes to customer participation and program performance, including:

- whether events are called during the 10-11 pm hour during the 2022 summer and whether those hours are needed, and
- load and resource balance during DR events, including gross demand and generating dispatchable and non-dispatchable supply resources.

[5] Current Schedule 76 hours are 2-8 pm and proposed hours are 3-10 pm. This detail differs from the summary-level information presented in Table 2.
[6] See IPC's Advice No. 21-12, Attachment 2.

Staff recognizes that the programs will be evaluated formally, but is interested in program performance data, and potential impacts and lessons, as soon as is practical.

Idaho Power's Proposed Changes to the DR Cost-effectiveness Calculation
Additionally, IPC proposes to change how the DR resource is valued in the cost-effectiveness calculation from the methodology outlined in the Stipulation. The Stipulation specifies that the annual value of the DR resource is equal to the levelized annual cost of the minimum size Simple-Cycle Combustion Turbine (SCCT) capacity resource that is deferred by the availability of the DR resource, plus the value of the estimated energy savings provided by the DR resource.

In this filing, IPC proposes a revised avoided cost calculation comprised of three components: 1) the levelized fixed cost of a proxy SCCT resource; 2) the value of the additional system benefits of the proxy resource relative to the DR resource, as the proxy resource's availability is not restricted in the way the DR programs' availability is; and 3) the ELCC of the nameplate capacity of the DR portfolio relative to the proxy resource. The Company assumed a nameplate capacity of the DR portfolio of 492 MW, based on a market potential assessment.[7] Using IRP analyses, IPC identified the following values for three components described above: the levelized fixed cost of the proxy SCCT capacity resource is $131.60 per kW per year; the value of the additional system benefits offered by the proxy SCCT resource compared to the DR portfolio is $38.11 per kW per year; and the ELCC of the DR nameplate capacity relative to the proxy resource is 55 percent. This resulted in an avoided cost of $51.42 per kW per year to be used in the DR cost-effectiveness calculation.

In discussing the filing with the Company, Staff asked how this $51.42 value compared to current program avoided costs, as calculated per the Stipulation. Idaho Power answered that current actual avoided costs are approximately $20 per kW per year. However, the current values reflect lower utilization, as discussed above. Estimating a more apples-to-apples comparison to the $51.42 value involves projecting current programs with improved utilization, and results in a value of $30-40 per kW per year.

Idaho Power reports that the proposed DR program changes described in this filing remain cost-effective under this new methodology. The Company further states that it will update the three components described above with every IRP cycle, will calculate DR program cost-effectiveness annually, and will report the results in its annual Demand-Side Management report. Staff supports this change.

Stakeholder Outreach
Staff appreciates the Company's stakeholder outreach to review the proposed changes to the DR programs prior to filing. This outreach included consultation with IPC's EEAG,

[7] See footnote 5 in IPC's Advice No. 21-12.

as required by the Stipulation, and also with the IRP Advisory Council, Staff, and DR program participants.[8]

Conclusion

DR is growing in its importance for managing a utility's load-resource balance as more variable energy resources are added to the utility's supply. The Oregon Legislature has prioritized the acquisition of cost-effective DR over new supply-side resources.[9] Idaho Power's 2021 IRP process has identified future capacity deficits, triggering IPC's review of the DR programs per the Stipulation. Staff finds that IPC's proposed changes to its existing DR programs are consistent with Oregon's legislative direction and with the Stipulation; responsive to system's highest hours of need, while considering customer impact; and designed to maintain the programs' cost-effectiveness. For these reasons, Staff finds that the changes proposed to DR program revisions are fair, just, and reasonable and should be approved.

PROPOSED COMMISSION MOTION:

Allow Idaho Power Company's Advice No. 21-12, revising demand response programs in Schedules 23, 74 and 76, effective with service rendered on and after February 15, 2022.

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[8] See IPC Advice No. 21-12, Table 4, for dates and audiences of IPC's stakeholder meetings, and Attachment 4 for a detailed description of feedback from DR program participants.
[9] See ORS 757.054(3).