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November 23, 2021

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P. O. Box 1088
Salem, OR 97301

RE: Tariff Advice No. 21-12
Proposed Modifications to the Company's Demand Response Programs

Attention Filing Center:

Idaho Power Company ("Idaho Power" or "Company") respectfully submits this tariff advice to the Public Utility Commission of Oregon ("OPUC" or "Commission") requesting authorization to modify certain program parameters related to its Demand Response ("DR") programs offered under Schedule 23, Irrigation Peak Rewards ("Schedule 23"), Schedule 74, Residential Air Conditioner Cycling Program ("Schedule 74"), and Schedule 76, Flex Peak Program ("Schedule 76"). The DR programs are voluntary programs offered to the Company's residential, irrigation, commercial, and industrial customers who are willing and able to reduce their electrical energy loads for short periods during summer peak days.

Idaho Power requests that the Commission authorize the proposed tariff sheets, included as Attachment 1, as filed with an effective date of February 15, 2022. The proposed effective date will provide the Company four months to solicit participation and implement the revised programs prior to the start of the DR program season on June 15, 2022.

CURRENT DEMAND RESPONSE PROGRAMS

Idaho Power currently offers three DR programs, which are available to each of the three major customer classes. The first program is the Residential Air Conditioner ("A/C") Cool Credit Program that was started as a pilot in 2002 and fully implemented in 2003. Customers' A/C units, or heat pumps, are controlled using switches that communicate via powerline carrier, and the units are cycled by the Company during an event to reduce load.

The second program is the Irrigation Peak Rewards Program offered to Schedule 24, Agricultural Irrigation Service, customers in the Company's service area. This program was established in 2004 and allows the Company to interrupt irrigation pumps during called events. It is Idaho Power's largest DR program in terms of capacity, and customers can participate with either a manual or automatic dispatch option based on the configuration of their equipment.

Finally, the Commercial & Industrial (“C&I”) Flex Peak Program (“Flex Peak”) started in 2009 and was originally managed by a third-party contractor. Idaho Power took over full administration of the program in 2015, and C&I customers that can offer load reduction of at least 20 kilowatts (“kW”) are eligible to participate. Participants manually reduce their nominated load when Idaho Power calls an event because direct load control devices are not utilized within this program.

Table 1 below summarizes Idaho Power’s DR portfolio capacity and costs for the last five summer seasons. Also, as reported in the DSM Annual Reports since 2016, the individual DR programs and the overall DR portfolio have been cost-effective each year.

Table 1: 5-Year Summary of Demand Response Load Reduction, Capacity and Cost by Jurisdiction

Year	System Max Load Reduction (MW)	Idaho Capacity (MW)	Oregon Capacity (MW)	System Capacity (MW)	Idaho Total Cost	Oregon Total Cost	Total System Cost
2020	336	346	20	366	\$7,296,376	\$418,536	\$7,714,912
2019	333	376	21	397	\$7,808,979	\$467,217	\$8,276,196
2018	359	367	16	383	\$7,887,176	\$282,243	\$8,169,419
2017	383	374	20	394	\$8,339,892	\$477,637	\$8,817,529
2016	378	372	20	392	\$8,960,263	\$511,104	\$9,471,367

BACKGROUND

In December of 2012, prompted by the lack of potential near-term peak-hour deficits identified in the load and resource balance analysis prepared for the 2013 Integrated Resource Plan (“IRP”), Idaho Power filed a request in Idaho (Case No. IPC-E-12-29) for authority to temporarily suspend two of its three DR programs (A/C Cool Credit and Irrigation Peak Rewards). In February of 2013, the Company filed the same request in Oregon (Tariff Advice No. 13-04).

During the suspension of the two Idaho Power-administered DR programs, the Company worked with stakeholders in both Idaho and Oregon through a collaborative workshop process to evaluate and identify the best long-term solution for either continuation or discontinuation of all three of Idaho Power’s DR programs. This process resulted in settlement agreements being reached in both states.^{1,2}

The settlement approved by the Commission in Order No. 13-482 will be referred to as the Settlement Agreement. There have not been significant changes to the Company’s

¹ *In the Matter of the Continuation of Idaho Power Company’s (A/C Cool Credit, Irrigation Peak Rewards, and Flex Peak Demand Response Programs for 2014 and Beyond, Case No. IPC-E-13-14, Order No. 32923 (Nov 12, 2013).*

² *In the Matter of Idaho Power Company Staff Evaluation of the Demand Response Programs, Docket No: UM 1653, Order No. 13-482 (Dec 19, 2013).*

three DR programs since the Settlement Agreement in 2013 in terms of how they operate from a dispatchability perspective. However, a change occurred in 2015 when the Company took over the administration of the Flex Peak Program from a third-party administrator.³

The Settlement Agreement includes several program specific requirements, including marketing limitations, the method for determining cost-effectiveness, and the Term of the Stipulation, as stated below:⁴

“This Agreement shall be in effect beginning on the date it is approved by the Commission and shall apply to Idaho Power’s DR Programs for 2014 and beyond until: a) a change occurs in Idaho Power’s system operations or cost-effectiveness of a DR Program that would warrant reevaluation of the Agreement’s terms; or b) the Commission sua sponte determines that an investigation should be conducted into Idaho Power’s DR programs; or, c) Intervenors in this docket request that the Commission conduct an investigation of the DR programs covered in this docket and the Commission grants their request. Should any of the above events occur, Idaho Power will consult its Energy Efficiency Advisory Group (“EEAG”) and then make an appropriate filing at the Commission.”

The Company believes it has experienced a change in system need and operations since the Settlement Agreement in 2013 and is therefore filing this Advice to make necessary modifications to the DR programs.

IRP CHANGES IMPACTING DEMAND RESPONSE EVALUATION

Historically, the Company has evaluated the maximum operational potential of its existing DR resources by their ability to meet the peak demand hour (peak load) during the summer months of June through August throughout the IRP planning horizon. This is consistent with how traditional supply-side resources have been evaluated, and therefore, when determining the capacity value of the Company’s DR portfolio in the 2019 IRP, the calculation was based on the DR portfolio’s ability to be utilized during the top one-hundred system load hours given the program parameters.

However, moving into the 2021 IRP planning process, the Company adopted a risk-based methodology, known as Effective Load Carrying Capability (“ELCC”), to evaluate the capacity contribution of the Company’s existing resources, expected future resources (including variable resources), and DR. This method evaluates the Company’s load and resource balance at the time of the highest-risk hours, rather than only analyzing a resource’s ability to meet peak load.

The ELCC risk-based methodology has identified that the primary hours of need for additional resources, or the highest-risk Loss-of-Load Probability (“LOLP”) hours, are no

³ New Schedule 76, Flex Peak Program, Tariff Advice No. 15-03, (Accepted Apr 28, 2015).

⁴ *In the Matter of Idaho Power Company, Staff Evaluation of the Demand Response Programs*, Docket UM 1653, Order No. 13-482 (Dec 19, 2013).

longer expected to align with the hours of Idaho Power’s system peak. This is due to the penetration of solar, wind, and other variable resources connected to Idaho Power’s system. In the preliminary 2021 IRP analyses, the highest-risk LOLP hours have been shown to shift to later in the day when solar sees an output reduction. As more solar comes onto the system, the Company expects the LOLP of the evening solar-ramping-hours to increase and drive the need for additional resources later in the day. Attachment 2 to this advice filing provides an overview of the ELCC methodology and the preliminary findings from the development of the 2021 IRP.

Utilizing the ELCC method described in Attachment 2, the Company found that the existing DR programs, as structured, are not effective at meeting system needs over the planning horizon. As more fully described below, certain parameters of the existing programs, specifically the current dispatch hours and the program season, limit the effectiveness of DR as a resource.

PROPOSED DEMAND RESPONSE PROGRAM PARAMETERS

Recognizing that the existing program parameters may limit the effectiveness of DR, the Company conducted several sensitivity analyses to determine the parameter adjustments needed to more effectively meet high-risk LOLP hours. These analyses were performed by modifying several program criteria and evaluating the impact to the ELCC of the DR portfolio.

As informed by the ELCC analyses more fully described in Attachment 2, the proposed changes to the DR program parameters are meant to align the programs to more effectively meet high-risk hours. Table 2 below highlights the overall proposed parameter changes to the Company’s DR portfolio. The available event days and available event times vary slightly between individual programs, but the table includes the full windows for all programs combined.

Table 2: General Summary of Proposed DR Program Parameter Changes

Parameter	Current Program	Proposed Program	Change
Season	June 15 th to August 15 th	June 15 th to September 15 th	Season end date extended 1 month to September 15 th
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

The ELCC analysis showed that the program season and the available event times were the variables that had the largest impact on increasing the effectiveness of the DR programs. Therefore, the program season was extended one month from August 15th to September 15th to capture high-risk hours later in the summer, and the available event times were shifted two hours to capture the shift in the highest-risk hours occurring later in the evening.

The weekly maximum hours the DR programs are available were adjusted by one hour (from fifteen hours per week to sixteen hours per week) to increase effectiveness and to better align with the event duration maximum of four hours. This change maximizes the availability of weekly DR dispatch that Idaho Power's Load Serving Operations group can utilize.

PROPOSED TARIFF CHANGES

The proposed tariff schedules have been included as Attachment 1. In order to assist in the review, Idaho Power has summarized each of the proposed tariff changes below.

Program Season, Available Event Times, and Weekly Maximum Hours

As described above, the Company is proposing to modify the program season, available event times, and weekly maximum hours for each of the programs:

- Flex Peak: The Company is proposing to extend the program season from August 15 to September 15, the available event times from 2:00pm-8:00pm to 3:00-10:00pm, and the weekly maximum hours from 15 to 16.
- A/C Cool Credit: The Company is proposing to extend the program season from August 15 to September 15 and the weekly maximum hours from 15 to 16.
- Irrigation Peak Rewards: The Company is proposing to extend the program season from August 15 to September 15, the available event times from 1:00pm-9:00pm to 3:00-11:00pm, and the weekly maximum hours from 15 to 16.

Program Incentives

To help minimize a potential decrease in customer participation, customers in all programs will earn more for their participation under the proposed programs as compared to the current program parameters and incentives.

- Flex Peak: The Company is proposing an increase in the variable incentive after four events, recognizing it may be more difficult for some customers to participate in the later evening hours. Because the Flex Peak program pays its participants weekly based on Nominated kW regardless of whether an event is called, participants will see an increase in the overall fixed incentive they receive due to the proposed program being extended by one month. The Company is also proposing to increase the threshold for the variable incentive payment from after three events to after four events. The variable incentive event qualification moving to after four events is to align with the extension of the season and the overall increase in fixed incentives customers will receive.
- A/C Cool Credit: Participants will receive an additional fixed incentive payment with the extension of the program to September 15th with no change to the monthly incentive amount.

- **Irrigation Peak Rewards:** The Company is proposing a higher monthly fixed incentive credit along with an increased variable incentive after the fourth event, recognizing it may be harder for customers to participate in the later evening hours. Because the Irrigation Peak program pays its participants monthly, regardless of whether an event is called, participants will see an increase in the overall fixed incentive they receive due to the proposed program being extended by one month. The Company is also proposing to increase the threshold for the variable incentive payment from after three events to after four events. The variable incentive event qualification moving to after four events is to align with the extension of the season and the overall increase in fixed incentives customers will receive.

The Company is also proposing to modify the incentive adjustment, or opt-out fee, for both the Irrigation and Flex Peak programs to align with the season's fixed incentive and to continue to send customers a proper disincentive signal for opting out of any event. The proposed incentive adjustment will approximately nullify a customer's incentive if the customer opts out of four events throughout the program season. Table 3 highlights the proposed changes in the incentive for each of the three programs.

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 3 rd event	\$2.00 per kW not achieved per event & \$0.25 after 3 rd 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 3 rd event & \$0.198 for 9:00pm option	\$5.00 per kW per opt out & \$1.00 per kW after 3 rd 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

Removal of Program Marketing Limitations

The Company is proposing to remove the restriction for the Irrigation Peak Rewards program outlined in Schedule 23 requiring that participation is only available to customers that have an existing dispatchable Load Control Device installed on their equipment or existing participants under the Manual Dispatch Option. By removing this provision, the

Company will have the ability to market the program to help maintain and/or grow DR capacity to meet high-risk hours identified in the 2021 IRP analysis.

Adjusted Flex Peak Program Day of Adjustment Calculation

The Company is proposing to modify the Day of Adjustment (“DOA”) calculation to change to how the DOA portion is applied to the Original Baseline kW in the Flex Peak program. The DOA is the difference between the Original Baseline kW demand and the actual metered kW prior to an event. The DOA is used to account for a customer using more or less energy than their Original Baseline kW on a given event day.

The proposed adjustment to the DOA is to use a scalar method given a four-hour advanced notification of an event. The Original Baseline kW for each event hour will be divided by the Original Baseline kW for the hour preceding the advanced notification to arrive at a scalar, or multiplier, for each individual hour. Each hour’s scalar is then multiplied by the actual kW registered during the hour preceding the event notification to calculate a participant’s Adjusted Baseline kW.

The Company believes the DOA scalar method is more accurate in calculating a customer’s baseline, and therefore, results in more accurate calculations of customer demand reduction and compensation.

Advance Notice of Program Events

The Company is proposing to move the notification period for the Flex Peak program to four hours from two hours based on feedback from customers and to better align with the Irrigation Peak Rewards program. Customers in several forums have expressed their desire to have a longer lead time on event days so that they can properly reduce load and minimize any incentive adjustments for not meeting their Nominated kW. The four-hour notification period also streamlines the DR dispatch process for the Company’s Load Serving Operations if Flex Peak and Irrigation Peak Rewards notification periods are the same.

Opting Out of Program Events

The Company is proposing to add a provision to Schedule 23 where opt-out fees can be waived in limited circumstances where unplanned or planned outages of at least three hours in duration occur up to twenty-four hours before an irrigation DR event or there is a multiday outage within seventy-two hours of an event. The Company is cognizant that calling a DR event that turns off irrigation water on peak days can potentially have an impact on crop production and a participant’s livelihood. An outage can also have a similar impact. The Company recognizes that a customer opting out of a DR event due to already experiencing a recent outage would receive an incentive adjustment when they cannot reasonably participate without further risking crop production. The Company believes adding this clause provides additional flexibility in the execution of the program, implements a tool to mitigate program attrition, and will help build and maintain positive relationships with customers.

The Company is also proposing to also add language that allows it to charge an opt-out fee to customers who override the dispatch command on their device. This is a practice the Company currently implements to prevent customers from inappropriately earning an incentive when they take action to manually opt out of an event but do not contact the Company. Adding this language to the tariff provides additional clarity to customers.

Irrigation Peak Rewards Small Pump Installation Fee

The addition of an installation fee is to maintain cost-effectiveness for participants that have smaller measured horsepower pumps and therefore less load reduction. The Company is proposing to open the Irrigation Peak Rewards program to all potential customers, and an installation fee for the smaller load reduction pumps is necessary given the expense of the initial setup compared to the capacity benefit. This is consistent with a previous requirement that was contained in Schedule 23 prior to the marketing limitations implemented as part of the Settlement Agreement.

Irrigation Peak Rewards Out-of-Demand Season Energy Credit

The Out-of-Demand Season Energy Credit would apply to the portion of Irrigation Peak Rewards participants whose billing cycles do not align with the proposed DR season end date of September 15th. The irrigation season, as defined in Schedule 24, begins with the meter read date of the May billing period and ends with meter read date for the September billing period. Further, the irrigation season (in-season) has a demand charge per kW of billing demand where out-of-season does not. Therefore, some customer's billing demand could end before September 15th based on their billing cycle, and they would not receive a demand credit as part of the fixed incentive for their participation in the DR program.

The Out-of-Demand Season Energy Credit is being added to appropriately compensate these participants and is structured so the demand portion of the fixed incentive is paid using a dollar per kWh value. The Out-of-Demand Season Energy Credit is calculated to be equivalent between customers who will receive a demand credit, because their in-season billing cycles end on or after September 15th, and the customers whose out-of-season billing cycles start before September 15th.

Timing of Incentive Payments

The Company is proposing to extend the timing of incentive payments for the Flex Peak program from no more than 30 days after the program season concludes to no more than 45 days. The Company is also proposing to extend the variable incentive payment for the Irrigation Peak Rewards program from no more than 45 days after the end of the program season to no more than 70 days after the end of the program season. The Company has found compliance with the existing requirements to be challenging due the timing of information being available from the Company's billing system. Extending the dates by which payments will be issued will allow the Company adequate time to quantify, review, and issue incentive checks by the time required in the tariff schedule.

Program Use During System Emergencies

The purpose of modifying the emergency use language in the tariffs for the three DR programs is to add clarity around the use of DR during a system emergency, and that if an emergency were to occur, the programs would be dispatched in accordance with NERC standards and/or Idaho Power's Rule J.

Miscellaneous Tariff Changes

The last major revisions to the tariffs occurred in 2013 as part of the Settlement Agreement. In the years that have passed since those revisions, the Company has gained valuable experience implementing the program provisions and explaining the tariff requirements to customers. The Company's program specialists' field and respond to a multitude of phone calls and emails each year, and through those conversations, have identified areas where the tariff language could be expanded or clarified to enhance understanding. With these language changes, the Company is not intending to implement new or different requirements; rather, it views these modifications as necessary to improve clarity.

COST-EFFECTIVENESS

Cost-effectiveness of the DR programs is currently determined based on the method outlined in the Settlement Agreement. The existing method establishes the avoided cost for the three programs by calculating the avoided capacity cost of a single 170 MW SCCT multiplied by an equivalency factor, levelized over 20 years, plus the corresponding deferred energy savings for 60 program hours.

The Company is proposing to modify the avoided cost calculation such that the DR programs are compared to an equivalent alternative resource on a cost per kW per year basis to determine cost-effectiveness. The equation below represents how the Company plans to quantify cost-effectiveness:

$$\begin{aligned} & \text{(Levelized Fixed Cost Proxy Resource – Additional Benefits) x} \\ & \text{ELCC of Annual DR Capacity Compared to Proxy Resource} \\ & = \$ \text{ per kW year DR Avoided Cost} \end{aligned}$$

The three components of the proposed alternative cost calculation are (1) the levelized capacity fixed costs of a proxy resource, (2) the additional system benefits of the proxy resource, and (3) the ELCC of the annual DR nameplate capacity compared to a proxy resource.

The proxy resource used to evaluate the cost-effectiveness of the proposed DR programs is a Simple-Cycle Combustion Turbine ("SCCT"), with a 2022 levelized fixed cost of \$131.60 per kW per year. This value represents the fixed cost per kW per year if the Company were to build the SCCT instead of running the DR programs.

Because an SCCT is not restricted to operate for only a defined number of hours like DR, it provides additional benefits and reliability to the Company's system. To determine the approximate value of the additional benefit, the Company completed a Production Cost Model ("PCM") in Aurora by including the SCCT and DR in two separate runs of a 2019 IRP PCM subset. The additional system benefits of the SCCT over the first 5 years of the planning horizon equated to \$38.11 per kW per year compared to an equally effective 492 MW⁵ DR portfolio. The Company believes calculating the additional benefit value is important because it identifies the economic value a supply side resource has beyond the system benefits DR can provide.

The ELCC of the annual DR nameplate capacity is calculated by first obtaining the amount of perfect generation displaced by the proposed DR programs (i.e. DR's perfect resource effectiveness). An SCCT is not a perfect generator and has an EFOR greater than zero. By using the same ELCC methodology, but factoring in an SCCT's EFOR, the Company can determine the size of an effective-equivalent SCCT to the DR portfolio's perfect resource effectiveness. The $ELCC_{SCCT}$ of the DR programs is calculated by taking the quotient between the capacity of the effective-equivalent SCCT and the DR nameplate capacity. Using a 492 MW DR portfolio, the effective equivalent SCCT's nameplate was determined to be 272 MW based on the Company's projected 2023 load and resource balance. This results in an $ELCC_{SCCT}$ of 55 percent given a DR portfolio capacity of 492 MW ($272 \text{ MW} \div 492 \text{ MW} = 55\%$).

A program and a portfolio would be considered cost-effective as long as its dollar per kW costs are less than the avoided cost value. Using the values above, the avoided cost value would be \$51.42 per kW per year assuming a 492 MW capacity program.

$$(\$131.60 - \$38.11) \times 55\% = \$51.42 \text{ per kW per year}$$

The Company intends to update all three components with every IRP cycle, will calculate cost-effectiveness annually, and will report the results in the annual DSM report.

CUSTOMER AND STAKEHOLDER FEEDBACK

In preparation of this advice filing, Idaho Power held multiple meetings with customers and stakeholders to solicit feedback and input on the modifications under consideration. Table 4 summarizes the customer and stakeholder touchpoints over the course of the last several months.

⁵ The Company utilized a Northwest Power and Conservation Council ("NWPCC") assessment of DR potential for the Northwest region to determine the DR potential that may be available in Idaho Power's service area. The Company concluded that Idaho Power's service area has 584 MW of DR potential. From the 584 MW of potential, the Company determined that 492 MW would have similar program parameters such as seasonal restrictions, hours per year, etc. Therefore, 492 MW of traditional nameplate DR can be modeled using the same ELCC methodology, and the results can be utilized to establish programs and incentives that will remain cost-effective as the size of the DR portfolio changes over the planning horizon. See Attachment 3 for the NWPCC assessment.

Table 4: Formal Customer & Stakeholder Engagement Touchpoints

Group	Date
IRPAC Meeting	April 8, 2021
EEAG Meeting	May 5, 2021
Idaho Public Utilities Commission Staff Discussion	July 7, 2021
Idaho Public Utilities Commission Staff Discussion	August 9, 2021
Public Utility Commission of Oregon Staff Discussion	August 9, 2021
IRPAC Meeting	August 10, 2021
EEAG Meeting	August 12, 2021
Flex Peak Program Customer Seminar	August 31, 2021
Irrigation Peak Rewards Customer Seminar	August 31, 2021
Idaho Irrigation Pumpers Association (“IIPA”) Meeting	September 10, 2021

In addition to the touchpoints highlighted in Table 4, Idaho Power also conducted a survey with current and potential DR participants to gauge their ability to participate in the DR programs with modifications to certain program parameters. Included as Attachment 4 is an overview of customer and stakeholder input.

IMPLEMENTATION AND CONSISTENCY OF PROGRAM CHANGES

Idaho Power plans to implement the changes described above for the 2022 demand response season that begins on June 15, 2022, and anticipates that it will need some lead time to finalize program marketing materials, engage with customers on modified program parameters, conduct program workshops, and enroll customers in preparation for the 2022 DR season. A Commission order received by February 15, 2022 would position the Company to best meet these timeframes.

Additionally, Idaho Power has filed the exact same proposed Program design in its Idaho jurisdiction (Case No. IPC-E-21-32) and endeavors to keep consistency of the Program across its Idaho and Oregon jurisdictions. The importance of offering a consistent Program across the Idaho Power service area cannot be overstated. Offering two separate program designs could create confusion amongst customers and could inhibit participation. In addition, program infrastructure is designed to implement consistent programs across jurisdictions. Differing programs in the Company’s two jurisdictions could cause increased costs associated with maintaining separate program infrastructure.

CONCLUSION

The Company has applied an enhanced risk-based capacity planning methodology to determine new proposed operating parameters that will greatly improve the ability of DR to meet future high-risk LOLP hours. The Company then built upon this new planning methodology to develop a proposed economic valuation calculation to inform program compensation levels and cost-effectiveness. The changes proposed above would improve the ELCC of the Company’s DR portfolio by approximately 40 percent. The Company believes that the enhanced analysis has identified changes that improve the DR programs in meeting

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future resource needs, and that this improvement is not only necessary, but also benefits customers and the reliability of the system alike.

If you have any questions regarding this filing, please contact Zack Thompson at (208) 388-2982 or zthompson@idahopower.com.

Sincerely,

A handwritten signature in cursive script that reads "Connie Aschenbrenner".

Connie Aschenbrenner
Rate Design Senior Manager

CA:sg

Enclosures

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)

PURPOSE

The Irrigation Peak Rewards Program (the Program) is an optional, supplemental service that permits participating agricultural irrigation Customers taking service under Schedule 24 to allow the Company to turn off specific irrigation pumps with the use of one or more Load Control Devices. In exchange for allowing the Company to turn off specified irrigation pumps, participating Customers will receive a financial incentive for load reductions during the calendar months of June, July, August, and September for each metered service point (Metered Service Point) enrolled in the Program. (C)

AVAILABILITY

Service under this schedule is available on an optional basis to Customers with a Metered Service Point or Points receiving service under Schedule 24 where the Metered Service Point serves a water pumping or water delivery system used to irrigate agricultural crops or pasturage. (D)

The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, Billing Demand, location, pump horsepower, pumping system configuration, or electric system configuration. Past participation does not ensure selection into the Program in future years. Participation may be limited based upon the availability of Program equipment and funding.

Each eligible Customer who chooses to take service under this optional schedule is required to enter into a Uniform Irrigation Peak Rewards Service Application/Agreement (Agreement) with the Company prior to being served under this schedule. The Agreement will grant the Company or its representative permission, on reasonable notice, to enter the Customer's property to maintain one or more Load Control Devices on the electrical panel servicing the irrigation equipment associated with the Metered Service Points that are enrolled in this Program and to allow the Company or its representative reasonable access to the Load Control Device(s). By entering into the Agreement, each Customer also agrees to not increase for the sole purpose of participating in the Program the capacity, horsepower (HP) or size of the irrigation system served by the Company.

PROGRAM DESCRIPTION

Service under this optional, supplementary Program permits the Company to turn off specified irrigation pumps for a limited number of hours during the period of June 15 through September 15 (Program Season). The Company will utilize dispatchable Load Control Devices to turn off specific irrigation pumps during Load Control Events. In limited applications, a select group of eligible Customers will be permitted to manually interrupt electric service to participating irrigation pumps during Load Control Events (See the Manual Dispatch Option). In exchange for allowing the Company to interrupt service to specified irrigation pumps, participating Customers will receive a financial incentive for usage that occurs during the calendar months of June, July, August, and September for each Metered Service Point enrolled in the Program. (C)

DEFINITIONS

Bill Credit. The Bill Credit is the sum of the Demand Credit and the Energy Credit applied to the Customer's monthly bills for usage that occurs during the calendar months of June, July, August, and September of each calendar year. This amount may be prorated for the number of days during the months of June, July, August, and September that fall in the Customer's billing cycle to correspond with the Program Season. The Bill Credit amount may be applied directly to participating Customers' bills or provided in the form of a check. (C)

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

DEFINITIONS (Continued)

Demand Credit. The Demand Credit is a demand-based financial incentive provided in the form of a credit on the monthly bill for the Metered Service Point enrolled in the Program. The monthly Demand Credit is calculated by multiplying the Program kW by the demand-related incentive amount for the Interruption Option selected by the Customer. The Demand Credit will be included on the Customer's monthly bills for usage that occurs during the calendar months of June, July, August, and September of each year. This amount may be prorated for the number of days during the months of June, July, August, and September that fall in the Customer's billing cycle to correspond with the Program Season.

(C)
(C)

$$\text{Demand Energy Credit} = \text{Program kW} \times \text{demand-related incentive amount}$$

Energy Credit. The Energy Credit is an energy-based financial incentive provided in the form of a credit on the monthly bill for the Metered Service Point enrolled in the Program. The monthly Energy Credit is calculated by multiplying the Program kWh by the energy-related incentive amount for the Interruption Option selected by the Customer. Customers identified to have an out-of-demand season billing cycle will receive only an out-of-demand season energy credit for the applicable billing period. The Energy Credit will be included on the Customer's monthly bills for usage that occurs during the calendar months of June, July, August, and September of each year. This amount may be prorated for the number of days during the months of June, July, August, and September that fall in the Customer's billing cycle to correspond with the Program Season.

(N)
(C)
(C)

$$\text{Energy Credit} = \text{Program kWh} \times \text{energy-related incentive amount}$$

Load Control Device. Load Control Device refers to any technology, device, or system utilized under the Program to enable the Company to initiate the Load Control Event.

Load Control Event. Refers to an event under the Program where the Company requests or calls for interruption of specific irrigation pumps either manually or with the use of one or more Load Control Devices.

Nominated Demand. Nominated Demand is the amount of demand that participants under the Manual Dispatch Option must declare as planned to be available during Load Control Events.

(T)

Notification of Program Acceptance. An interested Customer must sign and return to the Company an Agreement specifying the Metered Service Point(s) to be included in the Program. If a Customer is selected for participation in the Program, a notification of acceptance into the Program will be mailed to participants, which will include a listing of the Metered Service Point(s) that have been enrolled.

Program kW. The Program kW is the demand amount, as measured at the Customer's meter in kilowatts (kW) associated with the applicable billing period, that is multiplied by the applicable incentive amount to determine the Demand Credit under the Automatic Dispatch Interruption Option. Under the Manual Dispatch Interruption Option, the Program kW will be based upon the maximum measured interval kW during the 24-hour period preceding 8:00 A.M. MDT the day of the announcement of a Load Control Event, minus the average interval kW during an event.

(C)
(N)
|
(N)

Program kWh. The Program kWh is the energy amount, as measured at the Customer's meter in kilowatt-hours (kWh) associated with the applicable billing period, that is multiplied by the applicable incentive amount to determine the Energy Credit under each Interruption Option.

(C)

Program Season. The Program Season is the period June 15 through September 15 of each year.

(C)

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

DEFINITIONS (Continued)

Variable Energy Credit. The Variable Energy Credit is an energy-based financial incentive provided for the Metered (M) Service Point enrolled in the Program. The Variable Energy Credit is calculated by multiplying Variable Program kWh by the energy-related incentive amount for the Interruption Option selected by the Customer. The Variable Energy Credit is paid in the form of a check no later than 70 days after the Program Season. The Variable Energy Credit does not apply to the first four Load Control Events. (C) (D)
Variable Energy Credit = Variable Program kWh x variable energy-related incentive amount (M)

Variable Program kWh. The Variable Program kWh is the demand amount for the associated billing period, as (C) measured at the Customer's meter in kilowatts (kW) multiplied by the hours of interruption for the Metered Service Point for each Load Control Event. The Variable Program kWh is multiplied by the applicable variable incentive (C) payment to determine the Variable Energy Credit under each Interruption Option. (C)
Variable Program kWh = Program kW x hours of interruption for each Load Control Event

INTERRUPTION OPTIONS

Under the Interruption Options, the Company will dispatch remotely service interruptions to specified irrigation pumps any Monday through Saturday during the Program Season between the hours of 3:00 P.M. (C) and 10:00 P.M. Mountain Daylight Time (MDT), excluding holidays (Standard Interruption). Customers (C) may elect to participate until 11:00 P.M. MDT (Extended Interruption) and will receive a larger Variable (C) Energy Credit. Service interruptions may last up to 4 hours per day and will not exceed 16 hours per (C) calendar week and 60 hours per Program Season. During each Program Season the Company will conduct a minimum of three Load Control Events. Customers participating in the Automatic Dispatch Option may not receive advance notification of a Load Control Event, but will be notified after the Load Control Event begins. Customers participating in the Manual Dispatch Option will receive advance notification at least 4 hours prior to a Load Control Event. The Company will provide notice of a Load Control Event via the following communication technologies: telephone, e-mail and/or text message. If prior notice of a pending Load Control Event has been sent, the Company may choose to revoke the Load Control Event and will provide notice to Customers up to 30 minutes prior to the Load Control Event.

Customers who elect to participate in the Program may be eligible for one of the following Interruption Options:

Automatic Dispatch Option. A dispatchable Load Control Device will be connected to the electrical panel(s) serving the irrigation pumps associated with the Metered Service Points enrolled in the Program. The Load Control Device utilized under the Automatic Dispatch Option will provide the Company the ability to send a signal that will interrupt operation or not allow the associated irrigation pumps to operate during dispatched Load Control Events. This option requires that all pumps at the Metered Service Point be controlled. (C)

Under the Automatic Dispatch Option, the Program kW will be based upon the monthly Billing Demand, as measured in kW, for the associated Billing Period. The Program kWh under this option will be based upon the monthly energy usage, as measured in kWh, for the associated Billing Period.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INTERRUPTION OPTIONS (Continued)

Automatic Dispatch Option (Continued)

Each time a customer chooses to opt-out of one of the Load Control Events a fee of \$6.25 per kW will be assessed based upon the current Billing Period's kW. The opt-out fee will not exceed the total Bill Credit for the Program Season. Any opt-out fee will be applied at the end of the Program Season or after the applicable billing cycle closes. Opt-out fees may be waived for circumstances involving planned or unplanned outages of 3 hours or more occurring within 24 hours of a Load Control Event or a multiday outage within 72 hours of an event. At its discretion, the Company may assess an opt-out fee should it be determined the participant overrode the command to the dispatch device thereby allowing the pump to run during the load control event.

(D)
(I)
(D)
(N)
(M)
(N)

Manual Dispatch Option. Customers are eligible to manually control Metered Service Points with of at least 1,000 cumulative HP, or Metered Service Points that have been determined by the Company to be limited by load control device communication technology or installation configuration. Under the Manual Dispatch Option, eligible Customers have the flexibility to choose which irrigation pumps at a Metered Service Point will be interrupted during each dispatched Load Control Event. Customers electing this option must notify the Company of their Nominated Demand during the enrollment period prior to June 1 of each year.

(C)
(D)
(N)

Customers participating in the Manual Dispatch Option are required to provide no less than their Nominated Demand during each Load Control Event. Each time a customer chooses to provide less than their Nominated Demand during one of the Load Control Events, an opt-out fee of \$6.25 per kW will be assessed on the Nominated Demand not made available for interruption. The opt-out fee will not exceed the total Bill Credit for the Program Season. Any opt-out fee will be applied at the end of the Program Season or after the applicable billing cycle closes. Opt-out fees may be waived for circumstances involving planned or unplanned outages of 3 hours or more occurring within 24 hours of a Load Control Event or a multiday outage within 72 hours of an event.

(C)
(I)
(D)
(N)
(N)

Under the Manual Dispatch Option, the Program kW will be based upon the maximum measured interval demand during the 24-hour period preceding 8:00 A.M. MDT the day of the announcement of a Load Control Event, minus the average demand during an event, as measured in kW over applicable load profile metering intervals. This applies to each Load Control Event initiated during a Billing Period. If there are no Load Control Events during a Billing Period, then the Program kW will be the Nominated Demand. The Program kWh under this option will be based upon a calculated value, as measured in kWh. The Program kWh will be calculated separately for each Billing Period by multiplying the monthly Program kW by the ratio of the monthly energy usage to the Billing Demand for the associated Billing Period.

INCENTIVE STRUCTURE

Incentive payments under the Interruption Options will be determined based on a fixed payment and a variable payment. The fixed portion of the incentive payment will be paid through a Bill Credit and the variable portion will be paid by check no more than 70 days after the end of the Program Season. The first four Load Control Events will not be subject to the Variable Energy Credit. The variable payment will be based on the number of hours a participant's pump is interrupted during the Program Season and their associated Program kW after the first four Load Control Events.

(C)
(C)

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

INCENTIVE STRUCTURE (Continued)

Fixed Incentive Payment			Variable Incentive Payment	
<u>Demand Credit</u> (\$ per Program kW)	<u>Energy Credit</u> (\$ per Program kWh)	<u>Energy Credit (\$ per Program kWh) for Out-of-Demand Season Billing Cycles</u>	<u>Standard Interruption Variable Energy Credit</u> (\$ per Variable Program kWh)	<u>Extended Interruption Variable Energy Credit</u> (\$ per Variable Program kWh)
\$5.25	\$0.008	\$0.021	\$0.18	\$0.25

(M)

(N)

(M)(I)

INSTALLATION FEES

An installation Fee of \$500 will be required for any new participating Metered Service Point with measured horsepower of 30 or less. The Installation Fee is non-refundable except when a Customer elects early termination and prior to the installation of a load control device at their pump location.

(N)

(N)

TERM OF AGREEMENT AND TERMINATION

The term of the Agreement, as it applies to each Metered Service Point accepted for participation, shall commence on the date the Agreement is signed by both the Customer and the Company and shall automatically renew on March 15 of each calendar year unless notice of termination is given by either party to the other prior to the annual renewal date or unless otherwise terminated as follows:

1. A Customer may terminate the participation of a Metered Service Point and avoid the Termination Fee by notifying the Company or its representative before the Program Season.
2. A Customer who terminates the participation of a Metered Service Point anytime between June 15 and September 15 of each calendar year shall pay the Company a Termination Fee. This fee, will be included on the Customer's monthly bill following termination of participation. The Customer's Bill Credit shall be prorated for the number of days in that month the Customer satisfactorily participated in the Program. Upon terminating participation of a Metered Service Point under the provisions of item 2, the Customer may not re-enroll the Metered Service Point into the Program until the following calendar year and the applicable Termination Fee has been paid in full.

(C)

Termination Fees:

Automatic Dispatch Option: \$500.00 per Metered Service Point terminated under item 2

3. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a Load Control Event at a Metered Service Point, the Agreement as it applies to that Metered Service Point will be automatically terminated. In addition, the Customer will be subject to each of the following:
 - a. The Customer will be required to reimburse the Company for the cost of replacement or repair of the Load Control Device(s), including labor and other related costs.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

TERM OF AGREEMENT AND TERMINATION (Continued)

Termination Fees: (Continued)

- b. An applicable Termination Fee, as provided under item 2, will be applied to the Customer’s monthly bill following the termination of participation.
- c. The Company will reverse any and all Demand Credits and/or Energy Credits applied to the Customer’s monthly bill(s) for the Metered Service Point as a result of the Customer’s participation in the Program during the current year.

Note: A service disconnection for any reason does not terminate the Agreement.

SPECIAL CONDITIONS

The provisions of this schedule do not apply for any time period that the Company utilizes a Load Control Device installed under this Program to interrupt the Customer’s load for a system emergency in accordance with NERC standards, Idaho Power’s Rule J, or any other time that a Customer’s service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular Service, Energy or Demand Charges associated with a Customer’s standard service schedule.

(M)

(N)

(N)

(M)

IDAHO POWER COMPANY
Uniform Irrigation Peak Rewards Service
Application/Agreement

(M)

THIS AGREEMENT Made this ____ day of _____, 20____ between _____ hereinafter called Customer, whose billing address is _____, and IDAHO POWER COMPANY, a corporation with its principal office located at 1221 West Idaho Street, Boise, Idaho, hereinafter called Company. This Agreement shall automatically renew on March 15 of each calendar year unless notice of termination is given by either party to the other prior to the annual renewal date. This Agreement is for the Metered Service Point(s) identified on the attached worksheet (Worksheet):

The Customer designates the following person as the Customer's authorized contact:

Authorized Contact: _____
Phone: _____ Cell Phone: _____
Email: _____

(D)

NOW, THEREFORE, The Parties agree as follows:

1. The Uniform Irrigation Peak Rewards Service Application/Agreement must be signed by the Customer and the Customer must be the person who is responsible for paying bills for retail electric service provided by the Company at the Metered Service Point(s) identified on the Worksheet.
2. The Customer understands that the information concerning the Metered Service Point(s) on the Worksheet is based on the best information currently available to the Company. The Bill Credit amounts are estimates based on the previous year's billing history for the Metered Service Point(s) specified on the Worksheet. Customers without sufficient billing history will be provided an estimated Bill Credit based on the stated cumulative horsepower at the Metered Service Point. The Bill Credit estimates are provided for illustration purposes. The Customer agrees to specify which Metered Service Point(s) listed on the Worksheet the Customer wishes to enroll in the Program and the Interruption Option selected for each specified Metered Service Point. For Metered Service Points enrolled in the Manual Dispatch Option the Customer must notify the Company of Nominated Demand amounts by June 1 of each year.
3. From time to time during the term of this Agreement and with prior reasonable notice from the Company, the Customer shall permit the Company or its representative to enter the Customer's property on which the enrolled Metered Service Point(s) are located to permit the Company or its representative to install, service, maintain and/or remove Load Control Device(s) on the electrical panel that services the Customer's irrigation pumps. The Load Control Device(s) may remain in place on the Customer's property upon termination of the Agreement unless the Customer specifically requests removal.
4. The Customer understands and acknowledges that by participating in the Program, the Company shall, at its sole discretion, have the ability to interrupt the specified irrigation pumps at the Metered Service Point(s) enrolled in the Program according to the provisions of the Interruption Option selected. The Company retains the sole right to determine the criteria under which a Load Control Event is scheduled for each Metered Service Point. The Customer also understands and acknowledges that if a Metered Service Point provides electricity to more than one irrigation pump, each pump will be scheduled for service interruption simultaneously, excluding Metered Service Points participating in the Program under the Manual Dispatch Option.

(M)

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)

(Continued)

IDAHO POWER COMPANY
Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

- 5. For the Customer's satisfactory participation in the Program, the Company agrees to pay the Customer the Demand Credit and/or Energy Credit corresponding to the Interruption Option selected by the Customer. The Bill Credit included on the Worksheet is based upon the billing history for the Metered Service Point(s) specified on the Worksheet, for the months of June, July, August, and September of the prior year. The Bill Credit will be paid in the form of a credit on the Customer's monthly bill or provided in the form of a check. The Demand Credit may be prorated for the months of June, July, August, and September depending on the Customer's billing cycle. (M)
- Metered Service Points participating under the Manual Dispatch Option, will receive a Bill Credit from the Company within 30 days of billing due to the extensive data analysis required to process interval metering data. Any applicable Variable Energy Credits will be paid by check no more than 70 days after the end of the Program Season. (C)
- 6. If the Customer terminates this Agreement anytime between June 15 and September 15 of the current calendar year while the Metered Service Point(s) are still connected for the Customer may not re-enroll that Metered Service Point into the Program until the following calendar year and the applicable Termination Fee has been paid in full. (N)
- 7. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a Load Control Event at a Metered Service Point(s), the Agreement as it applies to that Metered Service Point will be automatically terminated. The Customer will also be required to reimburse the Company for all costs of replacement or repair of the Load Control Device(s), including labor and other related costs, pay the Company the applicable Termination Fee which sum will be included on the Customer's monthly bill and the Company will reverse any Demand Credits applied to the Customer's monthly bill(s) for the Metered Service Point as a result of the Customer's participation in the Program during the current year. (C)
- 8. The Company's Schedule 23, any revisions to that schedule and/or any successor schedule are to be considered part of this Agreement. (M)
- 9. This Agreement and the rates, terms and conditions of service set forth or incorporated herein and the respective rights and obligations of the Parties hereunder shall be subject to valid laws and to the regulatory authority and orders, rules and regulations of the Idaho Public Utilities Commission and such other administrative bodies having jurisdiction.
- 10. Nothing herein shall be construed as limiting the Idaho Public Utilities Commission from changing any terms, rates, charges, classification of service or any rules, regulations or conditions relating to service under this Agreement, or construed as affecting the right of the Company or the Customer to unilaterally make application to the Commission for any such change.
- 11. In any action at law or equity under this Agreement and upon which judgment is rendered, the prevailing Party, as part of such judgment, shall be entitled to recover all costs, including reasonable attorneys fees, incurred on account of such action.

SCHEDULE 23
IRRIGATION PEAK REWARDS
PROGRAM
(OPTIONAL)
(Continued)

IDAHO POWER COMPANY
Uniform Irrigation Peak Rewards Service
Application/Agreement
(Continued)

- 12. The Company retains the sole right to select and reject the participants to receive service under Schedule 23. The Company retains the sole right for its employees and its representatives to install or not install Load Control Devices on the Customer's electrical panel at the time of installation depending on, but not limited to, safety, reliability, or other issues that may not be in the best interest of the Company, its employees or its representatives.
- 13. Under no circumstances shall the Company or any subsidiary, affiliates or parent Company be held liable to the Customer or any other party for damages or for any loss, whether direct, indirect, consequential, incidental, punitive or exemplary resulting from the Program or from the Customer's participation in the Program. The Customer assumes all liability and agrees to indemnify and hold harmless the Company and its subsidiaries, affiliates and parent company for personal injury, including death, and for property damage caused by the Customer's decision to participate in the Program and to reduce loads.
- 14. The Company makes no warranty of merchantability or fitness for a particular purpose with respect to the Load Control Device(s) and any and all implied warranties are disclaimed.

(M)

(M)

(APPROPRIATE SIGNATURES)

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)

PURPOSE

The Residential Air Conditioner Cycling Program is an optional, supplemental service that permits participating residential Customers an opportunity to voluntarily allow the Company to cycle their central air conditioners with the use of a direct load control Device installed at their residence. Customers will receive a monetary incentive for successfully participating in the Program during the Air Conditioning Season.

DEFINITIONS

AC Cycling is the effect of the Company sending a signal to a Device installed at the Customer's residence and instructing it to cycle the Central Air Conditioning compressor for a specified length of time.

Air Conditioning Season is the period that commences on June 15 and continues through September 15 of each calendar year. (C)

Central Air Conditioning is a home cooling system that is controlled by one or more centrally located thermostats that controls one or more refrigerated air-cooling units located outside the Customer's residence.

Cycling Event is a period during which the Company sends a signal to the Device installed at the Customer's residence, which instructs the Device to begin AC Cycling.

Device is a direct load control device installed at a Customer's residence that enables the Company to conduct AC Cycling.

Notification refers to the Customer's indication of intent to initiate or terminate participation in the Program by either contacting the Company's Customer Service Center, providing written notice or submitting an electronic Application via the Company's website.

Opt Out is the term used to describe the two times each Air Conditioning Season in which the Customer may choose to temporarily not participate in AC Cycling by providing advanced Notification to the Company.

Program Operation Area describes the area in which the Program will be offered to Customers and is comprised of the Company's service territory within the State of Oregon where the infrastructure required to support AC Cycling has been installed and is operational.

AVAILABILITY

Service under this schedule is available on an optional basis to Customers taking service under Schedules 1 and 5 who have Central Air Conditioning located at their residences and live within the Program Operation Area. Customers may request to be added to the Program at any time during the year by providing Notification to the Company.

Service under this schedule may be limited based upon the availability of Program equipment and/or funding. The Company shall have the right to select and reject Program participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, energy usage, residential location, size of home, or other factors. Customers' Central Air Conditioning equipment must be fully functional and comply with the National Electric Code (NEC) standards. Customers who are renting or leasing their home must provide to the Company written proof of the express permission of the owner of the Central Air Conditioning system prior to acceptance into the program.

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)
(Continued)

TERMS AND CONDITIONS

Upon acceptance into the Program, Customers will be subject to the following terms and conditions:

1. Each eligible Customer who chooses to take service under this optional schedule is thereby giving the Company or its representative permission, on reasonable notice, to enter the Customer's residence or property to install a Device and, in certain cases, either a mass memory meter or an end-use meter and to allow Idaho Power or its representative, with prior notice to the Customer, reasonable access to the Device or other Program-related equipment following its installation.
2. Customers added to the Program during the Air Conditioning Season must be effectively participating in the Program prior to the 20th day of the month in order to receive an incentive payment for that month.
3. A Customer may Opt Out of the Program two times during the Air Conditioning Season.
4. A Customer may discontinue participation in the Program without penalty by providing Notification to the Company.
5. If there is evidence of alteration, tampering, or otherwise interfering with the Company's ability to initiate a Cycling Event, the Customer's participation in the Program will be terminated and the Customer will be required to reimburse the Company for the cost of replacement or repair of the Device or other Program equipment and the Company will reverse any amounts credited to the Customer's bills during the past twelve months as a result of the Customer's participation in the Program.

PROGRAM DESCRIPTION

1. At the Company's expense, the Company or its representative will install a Device at the Customer's residence.
2. A financial incentive of \$5.00 per month for each of the four months June, July, August, and September will be paid to each Customer who successfully participates in the Program. This incentive will be paid in the form of a credit on the Customer's monthly bill for each month that the Customer successfully participates in the Program, beginning with the July bill and ending with the October bill. Incentive payments are limited to one controlled Central Air Conditioning unit per metered service point. Customers who have more than one Central Air Conditioning unit at a metered service point may participate in the Program. A Device must be installed at each Central Air Conditioning unit. However, no additional incentive will be paid. (C)
3. The Company will send a signal to the Device to initiate a Cycling Event. A Cycling Event may be up to four hours per day on any weekday during the Air Conditioning Season, excluding holidays. A Cycling Event may occur over a continuous 4-hour period or may be segmented throughout the day at the Company's discretion in order to optimize available resources. Cycling Events may occur up to 16 hours each week and will not exceed a total of 60 hours per Air Conditioning Season. During each Air Conditioning Season, the Company will conduct at least three Cycling Events. Mass memory meters or end-use meters may be installed on some Customers' residences or Central Air Conditioning units for program evaluation purposes. The residences or Central Air Conditioning units selected for installation of the meter shall be at the Company's sole discretion. (C)

SCHEDULE 74
RESIDENTIAL AIR CONDITIONER
CYCLING PROGRAM
(OPTIONAL)
(Continued)

SPECIAL CONDITIONS

The Company is not responsible for any consequential, incidental, punitive, exemplary or indirect damage to the participating Customer or third parties that results from AC Cycling, from the Customer's participation in the Program, or of Customer's efforts to reduce peak energy use while participating in the Program.

The Company makes no warranty of merchantability or fitness for a particular purpose with respect to the Device and any and all implied warranties are disclaimed.

The Company shall have the right to select the AC Cycling schedule and the percentage of Customers' Central Air Conditioning systems to cycle at any one time, up to 100%, at its sole discretion.

The provisions of this schedule do not apply for any time period that the Company interrupts the Customer's load for a system emergency in accordance with NERC standards, Idaho Power's Rule J, or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this schedule will not affect the calculation or rate of the regular Service or Energy Charges associated with a Customer's standard service schedule.

(N)

SCHEDULE 76
FLEX PEAK
PROGRAM
(OPTIONAL)

PURPOSE

The Flex Peak Program (the Program) is a voluntary program that motivates Participants to reduce their load during Company initiated demand response events. A participating Customer will be eligible to receive a financial incentive in exchange for being available to reduce their load during the calendar months of June, July, August, and September. (C)

AVAILABILITY

The Program is available to Commercial and Industrial Customers receiving service under Schedules 9, 19, or a Special Contract Schedule.

The Company shall have the right to accept Participants at its sole discretion based on criteria the Company considers necessary to ensure the effective operation of the Program. Selection criteria may include, but will not be limited to, total Program capacity, a Facility Site location, or amount of capacity provided at a Facility Site.

To participate in the Program, a Customer must sign and return the Program Application and worksheet provided by the Company specifying the Facility Site(s) to be enrolled in the Program. To enroll in the Program, Customers must be capable of providing a minimum load reduction of 20 kW per Facility Site or an aggregate reduction of 35 kW if participating under the Aggregated Option. If a Facility Site is accepted for participation in the Program, a Notification of Program Acceptance will be mailed to the Participant within 10 business days of the Company receiving the Program Application. Notification of Program Acceptance will include a listing of the Facility Sites that have been enrolled.

PROGRAM DESCRIPTION

The Company will initiate Program Events for a maximum of 60 hours during June, July, August, and September. During Program Events, Participants will be expected to reduce load at their Facility Site(s). Participants will be eligible to receive a financial incentive in exchange for their reduction in load. (C) (C)

DEFINITIONS

Actual kW Reduction. The kilowatt (kW) reduction during a Program Event, which is the difference between a Participant's hourly average kW measured at the Facility Site's meter and the corresponding hour of the Adjusted Baseline kW.

Adjusted Baseline kW. The Original Baseline kW plus or minus the "Day of" Load Adjustment amount.

Aggregated Option. Multiple Facility Sites belonging to a single Participant that are grouped together per the customer's request with a single Nominated kW for participation in the Program. Under this option, the Company will sum the individual performance data from each enrolled Facility Site before calculating any incentive amounts.

Business Days. Any day Monday through Friday, excluding holidays. For the purposes of this Program, Independence Day and Labor Day are the only holidays during the Program Season. If Independence Day falls on Saturday, the preceding Friday will be designated the holiday. If Independence Day falls on Sunday, the following Monday will be designated the holiday. (C)

SCHEDULE 76
FLEX PEAK
PROGRAM
(OPTIONAL)
(Continued)

DEFINITIONS (Continued)

"Day of" Load Adjustment. The difference between the Original Baseline kW and the actual metered kW during the hour prior to the Participant receiving notification of an event. Scalar values will be calculated by dividing the Original Baseline kW for each Program Event hour by the Baseline kW of the hour preceding the event notification time. The scalars are multiplied by the actual event day kW for the hour preceding the event notification time to create the Adjusted Baseline kW from which load reduction is measured. The Adjusted Baseline kW for each hour cannot exceed the maximum kW amount for any hour from the Highest Energy Use Days or the hours during the event day prior to event notification. (D)
(C)
(N)
(N)
(D)
(N)

Event Availability Time. Between 3:00 p.m. and 10:00 p.m. Mountain Daylight Time (MDT) each Business Day. (C)

Facility Site(s). All or any part of a Participant's facility or equipment that is metered from a single service location that a Participant has enrolled in the Program. For those Participants who have enrolled under the Aggregated Option, Facility Site will refer to the combination of individual Facility Sites selected for inclusion under the Aggregated Option.

Fixed Capacity Payment. The Weekly Effective kW Reduction multiplied by the Fixed Capacity Payment rate (as described in the Incentive Structure section). Participants are paid based on the average event kilowatt reduction. (N)
(N)
(N)

Highest Energy Usage Days. The three days out of the immediate past 10 non-event Business Days that have the highest sum total kW as measured across the Event Availability Time. (C)

Hours of Event. The timeframe when the Program Event is called and Nominated kW is expected to be reduced. The Hours of Event will not be less than two hours and will not exceed four hours.

Nominated kW. The amount of load expressed in kW that a Facility Site commits to reduce during a Program Event.

Nominated kW Incentive Adjustment. An adjustment made when a Facility Site does not achieve its Nominated kW for a given hour during a Program Event. The adjustment will be made for each hour the Nominated kW is not achieved. The total Nominated kW Incentive Adjustment will not exceed the total incentive amount for the Program Season (as described in the Incentive Structure section).

Notification of Program Acceptance. Written confirmation from the Company to the Participant. The Notification of Program Acceptance will confirm each Facility Site enrolled in the Program, as well as the Nominated kW amount for each Facility Site.

Original Baseline kW. The arithmetic mean (average) kW of the Highest Energy Usage Days during the Event Availability Time, calculated for each Facility Site for each hour. (C)

SCHEDULE 76
 FLEX PEAK
 PROGRAM
 (OPTIONAL)
 (Continued)

The following table provides an example of the calculation of the Original Baseline kW between hours of 3:00 p.m. and 10:00 p.m. using the (3) Highest Energy Usage Days of 5, 7, and 9. (C)

Day	3-4 PM (kW)	4-5 PM (kW)	5-6 PM (kW)	6-7 PM (kW)	7-8 PM (kW)	8-9 PM (kW)	9-10PM (kW)	Sum Total (kW)
1	3000	3100	3000	3200	3000	3200	3150	21650
2	3200	3100	3200	3200	3100	3300	3300	22400
3	3100	3200	3100	3100	3200	3100	3200	22000
4	3250	3400	3300	3400	3300	3400	3200	23250
5	3300	3400	3300	3400	3400	3500	3400	23700
6	3100	3000	3200	3100	3100	3200	3300	22000
7	3400	3300	3400	3300	3400	3300	3200	23300
8	3300	3200	3300	3300	3300	3200	3100	22700
9	3400	3500	3350	3400	3500	3400	3350	23900
10	3250	3300	3300	3200	3200	3200	3300	22750
Original Baseline (kW)	3367	3400	3350	3367	3433	3400	3317	

Participant. Any Customer who has a Facility Site that has been accepted into the Program.

Program Application. Written form submitted by a Customer who requests to enroll a Facility Site in the Program.

Program Event. A time period when the Company requests or calls for reduction of the Nominated kW.

Program Season. June 15th through September 15th of each year. (C)

Program Week. Monday through Friday.

Variable Program kWh. The kWh savings amount calculated by multiplying the Actual kW Reduction by each of the Hours of Event for the Facility Site during each Program Event beyond the first four Program Events. (C)

Variable Energy Payment. An energy-based financial incentive provided to the Participant. The payment is calculated by multiplying the Variable Program kWh by the Variable Energy Payment Rate (as described in the Incentive Structure section). The Variable Energy Payment does not apply to the first four Program Events. (N)
(N)
(N)

Weekly Effective kW Reduction. The average of the Actual kW Reduction for all events in a Program Week or in the absence of a Program Event, the Weekly Effective kW Reduction will equal the Nominated kW for that Program Week.

SCHEDULE 76
FLEX PEAK
PROGRAM
(OPTIONAL)
(Continued)

PROGRAM EVENTS

The Company will dispatch Program Events on Business Days during the Program Season between the hours of 3:00 p.m. and 10:00 p.m. MDT. Program Events will last between two to four hours per day and will not exceed 16 hours per calendar week and 60 hours per Program Season. During each Program Season the Company will conduct a minimum of three Program Events. Participating Customers will receive advance notification at least four hours prior to the Program Event. The Company will provide notice of a Program Event via the following communication technologies: telephone, text message, and e-mail to the designated contact(s) submitted by the Participant in the Program Application. If prior notice of a pending Program Event has been sent, the Company may choose to revoke the Program Event initiation and will provide notice to Participants no less than 30 minutes prior to the Program Event.

REQUIREMENTS OF PARTICIPATING FACILITIES

Participants will have the flexibility to choose what equipment will be used to reduce the Nominated kW during each Program Event. Participants must notify the Company of their Nominated kW via the Program Application. Once the Program Season begins, the Participant must submit the nomination change request form online (located at www.idahopower.com/flexpeak) via email by Thursday at 10:00 a.m. MDT of the proceeding week to notify of any changes in Nominated kW. The Nominated kW may be raised or lowered each week without restriction any time before the third minimum Program Event is called. After the third Program Event is called, the Nominated kW may still be raised or lowered, but may not exceed the highest Nominated kW prior to the third Program Event being called.

INCENTIVE STRUCTURE

Incentive payments will be determined based on a Fixed Capacity Payment, a Variable Energy Payment, and any applicable Nominated kW Incentive Adjustment. Both the Fixed Capacity and Variable Energy Payments will be paid by check or bill credit no more than 45 days after the Program Season concludes on September 15th.

When a Program Event is called and a Participant exceeds the Nominated kW, the Fixed Capacity Payment will be capped at 20 percent above original Nominated kW.

<u>Fixed Capacity Payment Rate*</u> (*to be prorated for partial weeks)	<u>Variable Energy Payment Rate*</u> (*does not apply to first four Program Events)
\$3.25 per Weekly Effective kW Reduction	\$0.20 per kWh

Participants are expected to reduce their load by the Nominated kW during each hour of each Program Event for the duration of the event. Each time a Participant fails to achieve a load reduction of up to the Nominated kW during a Program Event, a Nominated kW Incentive Adjustment will apply.

SCHEDULE 76
FLEX PEAK
PROGRAM
(OPTIONAL)
(Continued)

INCENTIVE STRUCTURE (Continued)

For Program Events, the Nominated kW Incentive Adjustment will be \$2.00 per kW for each hour the Nominated kW is not achieved during that interval. The total Nominated kW Incentive Adjustments will not exceed the total incentive amount for the Program Season. (D)
(D)

TERMS OF PARTICIPATION

Participants must submit a Program Application initially, but are automatically re-enrolled each year thereafter. Participants will be notified prior to each Program Season of the automatic re-enrollment. This Program Application must include the Facility Site(s) they wish to enroll and the initial Nominated kW for each Facility Site. If a Participant requests the Aggregated Option they must specify this on the Program Application.

1. A Participant may terminate their participation in the Program at any time during or before the Program Season by notifying the Company in writing.
2. Upon terminating participation of a Facility Site, the Participant's incentive payment shall be prorated for the number of Business Days of participation in the Program. The Participant may not re-enroll the Facility Site into the Program until the following calendar year.

SPECIAL CONDITIONS

The provisions of this Program do not apply for any time period that the Company requests a load reduction during a system emergency in accordance with NERC standards, Idaho Power's Rule J, or any other time that a Customer's service is interrupted by events outside the control of the Company. The provisions of this Program will not affect the calculation or rate of the regular Service, Energy, or Demand Charges associated with a Participant's standard service schedule. (C)
(C)

Attachment 2
Effective Load Carrying Capability Overview
Advice No. 21-12
November 23, 2021

Historically, Idaho Power Company (“Idaho Power” or “Company”) has evaluated the maximum operational potential of its existing Demand Response (“DR”) resources by their ability to meet the peak demand hour (“peak load”) during the summer months of June through August throughout the Integrated Resource Planning (“IRP”) planning horizon. This is consistent with how traditional supply-side resources have been evaluated, and therefore, when determining the capacity value of the Company’s DR portfolio in the 2019 IRP, the calculation was based on the DR portfolio’s ability to be utilized during the top one-hundred system load hours given the program parameters.

For the 2021 IRP planning process, the Company adopted a risk-based methodology, known as Effective Load Carrying Capability (“ELCC”), to evaluate the capacity contribution of the Company’s existing resources, expected future resources (including variable resources), and DR. This method evaluates the Company’s load and resource balance at the time of the highest-risk hours, rather than only analyzing a resource’s ability to meet peak load.

The ELCC risk-based methodology has identified that the primary hours of need for additional resources, or the highest-risk Loss-of-Load Probability (“LOLP”) hours, are no longer expected to align with the hours of Idaho Power’s system peak. This is due to the penetration of solar, wind, and other variable resources connected to Idaho Power’s system. In the preliminary 2021 IRP analyses, the highest-risk LOLP hours have been shown to shift to later in the day when solar sees an output reduction. As more solar comes onto the system, the Company expects the LOLP of the evening solar-ramping-hours to increase and drive the need for additional resources later in the day. Attachment 2 to this advice filing provides an overview of the ELCC methodology and the preliminary findings from the development of the 2021 IRP.

Utilizing the ELCC method, the Company found that the existing DR programs, as structured, are not effective at meeting system needs over the planning horizon. As more fully described below, certain parameters of the existing programs, specifically the current dispatch hours and the program season, limit the effectiveness of DR as a resource.

Key Definitions

Effective Load Carrying Capability: ELCC is a reliability-based metric used to determine the peak capacity credit of any given resource and captures an individual generator’s contribution to overall system reliability. It is primarily driven by the timing of high-risk LOLP hours. For example, a generator that contributes a significant level of capacity during high-risk LOLP hours will have a higher ELCC than a resource that delivers the same capacity during medium to low-risk LOLP hours. Utilizing multiple test years, ELCC values are determined and assigned to existing and selectable resources in the Aurora model for different scenarios, sensitivities, and portfolios in the IRP.

The ELCC of a resource is determined through a multi-step process. First, the Company calculates the perfect generation, in mega-watts (“MW”), required for the system to achieve a Loss-of-Load Expectation (“LOLE”) of 0.05 days per year with all market purchases set equal to zero. An LOLE of 0.05 days per year represents the statistical probability that the Company’s available generation capacity is only insufficient to serve demand one time in the span of twenty years. Next, the resource being evaluated is added to the system and the Company once again calculates the perfect generation required to meet the same LOLE threshold. The perfect generation of the system with the resource is subtracted from the perfect generation of the system without the resource and then divided by the evaluated resource’s nameplate capacity to obtain the resource’s ELCC as shown in the equation below.

$$\text{ELCC} = \frac{\text{PG}_1 - \text{PG}_2}{\text{Resource}_{\text{NP}}}$$

PG_1 = Perfect generation required to achieve LOLE of 0.05 days/year without including evaluated resource

PG_2 = Perfect generation required to achieve LOLE of 0.05 days/year when including evaluated resource

$\text{Resource}_{\text{NP}}$ = Nameplate capacity of the evaluated resource

Loss-of-Load Probability: LOLP is the statistical likelihood, between zero and one, of the system demand exceeding the available generating capacity during a given time period, typically an hour. The LOLP for an hour can be calculated by comparing the system net load to a statistically derived resource capacity probability distribution curve for any given hour. The resource capacity probability distribution curve is the probability (based on resource capacities, historical resource availability, and statistical forced outage rates) the Company will have more than a certain amount of generation available to it at any given time.

Loss-of-Load Expectation: LOLE is the expected number of days per time period for which the available generation capacity is insufficient to serve the demand at least once per day. The LOLE can be calculated by adding the maximum LOLP from each day for a time period (typically over the course of a year). The difference between LOLP and LOLE is that LOLP identifies high and low-risk hours in regard to system load exceeding generation capacity, and the maximum LOLP from each day over the course of 365 days are summed together to calculate the LOLE.

Net Load: Net load is the total system load minus any non-controllable resources, i.e., generation that is either (1) not controlled by Idaho Power, or (2) has limited or zero flexibility. Examples of generation resources Idaho Power does not have operational control over are wind, solar, and PURPA resources. Run-of-river hydro is an example of a resource with limited flexibility.

Equivalent Forced Outage Rate: An EFOR represents the number of hours a generation unit is forced off-line compared to the number of hours the unit runs (planned maintenance is not factored into a unit’s EFOR). For example, an EFOR of 3 percent means a generator is forced off, or incurs an unplanned outage, 3 percent of its running time. A perfect generator is a generation unit whose EFOR value is 0 percent, meaning that it is always available and never forced off-line. A perfect resource does not actually exist in practice, but it is used as a “standard” to enable ease of comparison between different generation options.

Analysis

Idaho Power conducted the ELCC analysis on the current DR programs to identify how effective they are at meeting future high-risk LOLP hours. The ELCC of DR was calculated using a multi-step process. First, every day in a test year was sorted from highest to lowest based on their net peak load in MW. Second, a daily MW target was set for each day based on the highest net load hour within the day and the size of the dispatchable DR group. The Company determined that an approximate 50 MW group size results in a capacity amount that is operationally manageable yet still large enough to have a meaningful impact on reducing system load. It also most closely aligns with how Idaho Power's Load Serving Operations group dispatches the programs.

After sorting the days and establishing a daily target, the analysis identified if the day was within the DR season's start and end dates and if the day was not a weekend or holiday. If the day met the DR program parameters, the algorithm would analyze each hour of the day and compare the hourly net load with the daily target. If the net load was above the target, the function would dispatch DR MW groups in that hour. The algorithm then iterates over the remaining hours in that day until DR had been dispatched to reduce the net load for each of the hours initially above the daily target, or DR capacity had been exhausted. After completing one day, the algorithm re-sorts all of the remaining days in the test year by net peak load and repeats the process. In this manner, the algorithm dispatches the DR programs in a way that maximizes their usage and effectiveness. The algorithm lastly creates a dispatch pattern by adding all the groups into a single load shape.

The ELCC of DR is obtained by first determining the perfect generation needed to achieve an LOLE of 0.05 days per year without any DR on the system. Next, the DR load shape derived using the algorithm described above is added to the system, and the perfect generation is calculated again. The ELCC of DR is then calculated by taking the difference between the two perfect generation values and dividing it by the DR portfolio's nameplate capacity.

The Company internally developed the LOLE MATLAB® algorithm within the MATLAB® software it is utilizing for the IRP planning process. The algorithm is computationally intensive, composed of several scripts, and requires specialized software to effectively and accurately run the calculations that model Idaho Power's existing and future resources.

Using the current program parameters, the ELCC of a 380 MW DR portfolio is estimated to be approximately 17 percent. That is, of the total 380 MW DR portfolio capacity, only 65 MW can be relied upon to meet the highest-risk LOLP hours. The analysis was completed by evaluating the current DR programs over four historical test years. The historical test years were used for weather shaping, scaled to have the same peak load as the forecasted 2023 system peak, and included the known solar resources that will be online in 2023 such as the 120 MW Jackpot Solar Project.

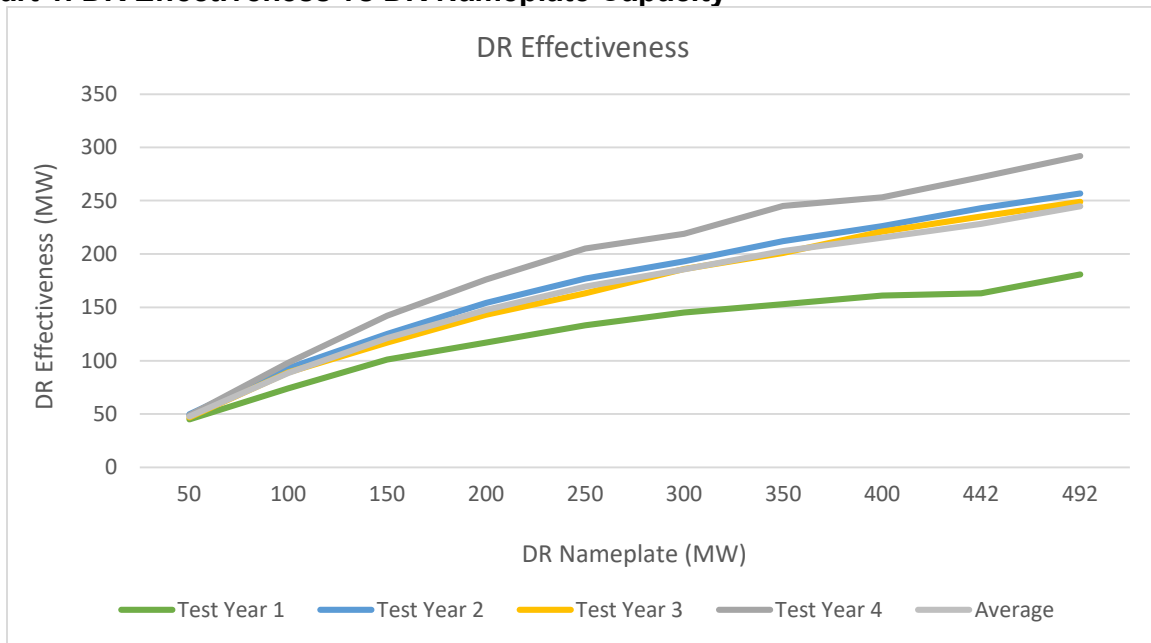
Table 1 below shows the resulting ELCC value for each test year along with the average effectiveness in meeting high-risk LOLP hours across those years given the current program parameters.

Table 1. Current Demand Response Program ELCC

Test Year	Current Demand Response ELCC (%)
Test Year 1	14.21%
Test Year 2	33.20%
Test Year 3	12.10%
Test Year 4	7.90%
Average	16.84%

Idaho Power also analyzed the effectiveness of varying levels of DR capacity as shown in Chart 1. The Company analyzed the effectiveness of DR capacity in 50 MW increments. The chart shows that DR effectiveness, and therefore ELCC, diminishes as DR nameplate capacity increases.

Chart 1. DR Effectiveness vs DR Nameplate Capacity



While the nameplate of the proposed DR portfolio is still unknown, the Company estimates the approximate ELCC of a DR portfolio with the proposed parameters to be 56 percent with a 380 MW nameplate capacity. This would be approximately a 40 percent improvement in effectiveness from the current program parameters. The main drivers of the increased effectiveness are the shift in the dispatch time period and extending the program season by one month to September 15th.

Charts 2 through 5 below depict Idaho Power's LOLP hours under various solar resource scenarios and how the highest-risk hours begin to shift as more solar is added to the system. While the time of the Company's system peak load has historically occurred between 5:00pm and 8:00pm, the highest-risk LOLP hours are expected to occur between 7:00pm and 10:00pm, with some medium-risk hours leading up to 7:00pm and from 10:00pm to 11:00pm, over the 2021 IRP planning horizon.

Chart 2 reflects July’s hourly LOLP with no solar resources. The highest-risk hours are between 3:00pm and 8:00pm.

Chart 2. July LOLP - Test Year 2 Shape – No Solar Resources and No Demand Response

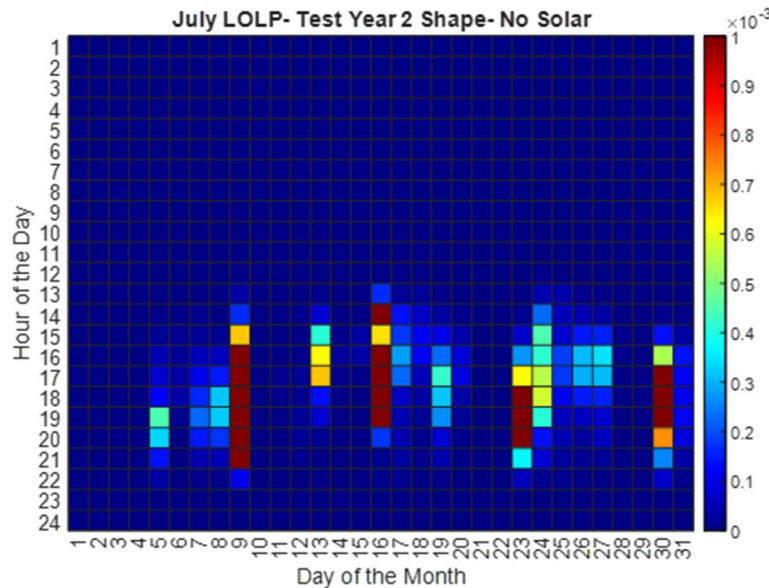


Chart 3 reflects July’s hourly LOLP with 316 Megawatts (“MW”) of solar resources on the system, which is reflective of the solar capacity in 2020. The highest-risk hours of need shift later in the day from 4:00pm to 9:00pm.

Chart 3. July LOLP - Test Year 2 Shape – 2020 Solar Resources and No Demand Response

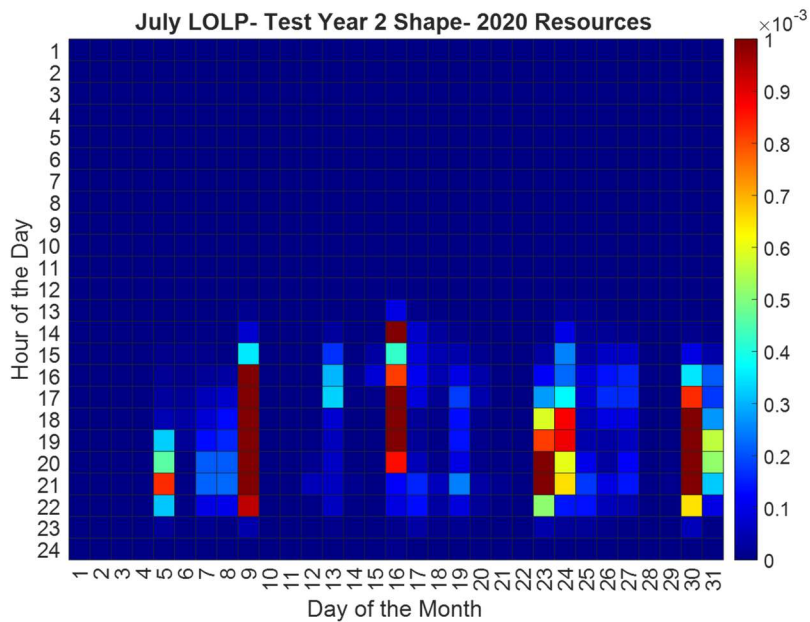


Chart 4 reflects July’s hourly LOLP with 436 MW of solar resources on the system, which includes the 120 MW expected from the Jackpot Solar Project in 2023. The highest-

risk hours continue to shift later in the day, moving to 5:00pm to 10:00pm. This scenario also shows the 10:00pm and 11:00pm hours starting to have a higher risk probability.

Chart 4. July LOLP - Test Year 2 Shape – 2023 Solar Resources and No Demand Response

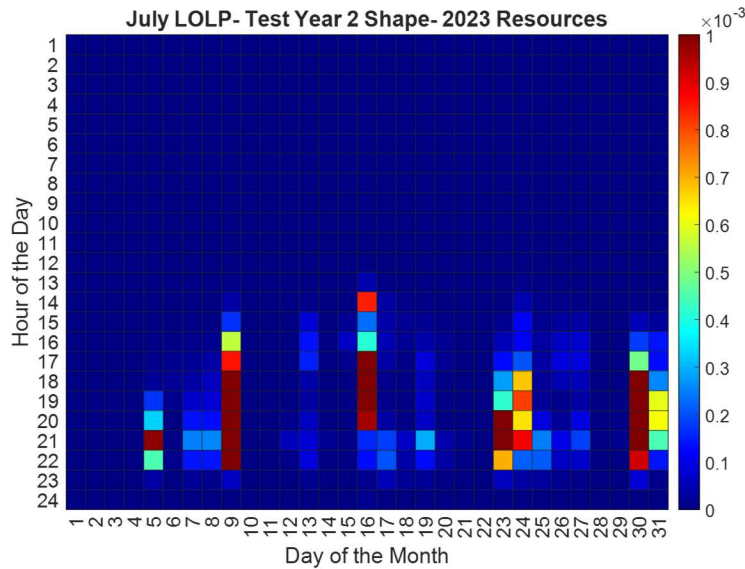
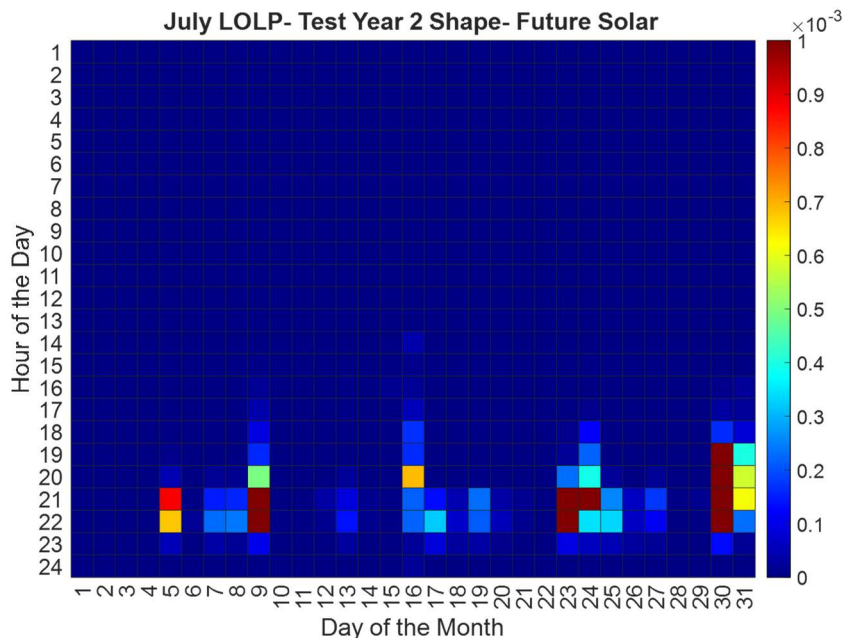


Chart 5 reflects July’s hourly LOLP with 836 MW of solar resources on the system, which includes 400 additional MW as compared to the connected 2023 solar capacity and is potentially reflective of the future system as solar becomes more prevalent. The highest-risk hours really condense into the later hours of the day.

Chart 5. July LOLP - Test Year 2 Shape – Future Solar and No Demand Response



Changes in the 2021 IRP

In the 2021 IRP, the Company will plan for an LOLE threshold of 0.05 days per year, which represents a statistical probability of the Company being resource insufficient one day in twenty years. The two primary reasons the Company ultimately chose to plan for a 0.05 days per year LOLE threshold are:

1. The Company operates a power system highly dependent on hydroelectric resources, which can vary dramatically from year-to-year due to water conditions. A poor water year can significantly affect hydroelectric resource availability, especially during summer months.
2. The LOLE methodology utilizes historical data to make forward looking decisions. Recently, weather extremes have been occurring with greater frequency. Therefore, by planning for an LOLE of 0.05 days per year, the Company expects to be able to maintain a similar level of reliability that Idaho Power's customers and regulators expect moving forward.

Idaho Power's resources are split into three primary categories: dispatchable resources, non-controllable resources, and energy-limited resources when modeled in the LOLE calculation.

- Idaho Power's dispatchable resources include the Hells Canyon Complex, natural gas plants, Bridger and Valmy coal plants, and various transmission assets. These resources are modeled using a monthly outage table that factors in their generating capacities and EFORs.
- Non-controllable resources are modeled by using four years of historical hourly output data to provide realistic weather shapes. Non-controllable resources are resources for which Idaho Power does not have direct operational control over such as wind, solar, dairy digestors, non-wind and non-solar PURPA projects, run-of-river hydroelectric plants, and geothermal generation.
- Dispatch shapes for energy-limited resources such as battery storage and DR are created based on net load.

Conclusion

The assumption that the highest-risk hours of capacity shortfall directly correspond with the hours of highest load is only valid for a system with little or no variable resource penetration. With the Company's existing resources, and the projected additions of more variable resources coming onto the system, the hours of highest-risk will not necessarily align with the hours of highest load. The Company believes that the ELCC method accurately captures the Company's future resource adequacy risks. The ELCC method still considers DR's ability to contribute capacity given the program parameters, but the hours of need are identified using probabilistic and statistical methods as opposed to utilizing the top one-hundred system load hours.

IPC Demand Response Potential Analysis Based on NWPCC's Draft 2021 Northwest Power Plan

IPC Potential Based on Program Type		
Product	2041 NWPCC Ramped Achievable Potential MW by Year by Product	Idaho Power MW Allocation ¹
ResCPP	251.4	29.9
ComCPP	134.1	15.9
IndCPP	108.7	12.9
IndRTP	24.2	2.9
ResERWHDLCGrd	867.3	103.1
ResERWHDLCswch	76.5	9.1
ResBYOT	63.1	7.5
NRCoolSwchMed	48.1	5.7
NRTstatSm	23.0	2.7
NRCoolSwchSm	15.2	1.8
NRirrSmMed	464.0	55.2
NRirrLg	393.7	46.8
ResACSwch	194.1	23.1
NRCurtailInd	174.1	20.7
NRCurtailCom	38.7	4.6
DVR	560.9	66.7
ResTOU	214.0	25.4
ResEVSEDLCSwch	72.3	8.6
ResHPWHDLCGrd	6.3	0.7
ResHPWHDLCswch	0.8	0.1
MW Total	3,730	443

Adjusted IPC Potential Based on Program Type ²		
Product	Summer Achievable Potential (MW)	Idaho Power MW Allocation ³
ResCPP	251.4	29.9
ComCPP	134.1	15.9
IndCPP	108.7	12.9
IndRTP	24.2	2.9
ResERWHDLCGrd	867.3	103.1
ResERWHDLCswch	76.5	9.1
ResBYOT	63.1	7.5
NRCoolSwchMed	48.1	5.7
NRTstatSm	23.0	2.7
NRCoolSwchSm	15.2	1.8
NRirrSmMed	0.0	0.0
NRirrLg	0.0	0.0
ResACSwch	0.0	0.0
NRCurtailInd	0.0	0.0
NRCurtailCom	0.0	0.0
DVR	560.9	66.7
ResTOU	214.0	25.4
ResEVSEDLCSwch	0.0	0.0
ResHPWHDLCGrd	0.0	0.0
ResHPWHDLCswch	0.0	0.0
MW Total	2,386	284

IPC DR Potential Allocation	NWPCC Region (MW)	IPC Service Area (MW)	IPC Allocation Ratio (%) ⁴
System Peak	31,125	3,700	11.89%
DR Potential	2,386	284	N/A

Potential (MW)

IPC Estimated Minimum DR Capacity with Proposed Changes		300
IPC Service Area DR Potential	+	284
IPC DR Total Potential		584
Possible Future Programs with Different ELCC ⁵	-	92
IPC Traditional DR Potential		492

Legend

Pricing Program
Possible Future Program
Current IPC Program
Possible Future Program with different ELCC
High Cost Program

(1) Multiplied by 11.89% allocation ratio

(2) Removes potential from current IPC programs and programs considered to be high cost

(3) Multiplied by 11.89% allocation ratio

(4) Calculated by taking IPC's proportion of the region's system peak (3,700 ÷ 31,125 = 11.89%)

(5) DVR + ResTOU = Future Programs with Different ELCC (66.7 + 25.4 = 92.1)

**Attachment 4
Overview of Customer & Stakeholder Meetings
Advice No. 21-12
November 23, 2021**

During the development of Idaho Power Company’s (“Idaho Power” or “Company”) Advice No. 21-12, the Company held ten formal touchpoints, plus several informal conversations with customers and stakeholders, to solicit feedback on the proposed Demand Response (“DR”) programs. Throughout the meetings, Idaho Power explained the need for modifications to the DR programs, presented the program parameters the Company was proposing to change, and provided opportunities for stakeholder questions and input regarding the changes the Company was considering. The Company also discussed the proposed approach to evaluating cost-effectiveness with both the Public Utility Commission of Oregon (“OPUC”) Staff and the Idaho Public Utilities Commission (“IPUC”) Staff.

Survey of Current and Potential Program Participants

The Company also conducted a customer survey with current and potential DR program participants. The survey sought to understand how moving the dispatch hours later into the day would impact customers’ ability or willingness to participate. Table 1 outlines the results by customer class for one of the questions asked in the survey.

Table 1: Percentage of Survey Respondents Able to Participate During Proposed Program Hours (No Incentive Consideration)

Percentage of Respondents Able to Participate			
Time Period	A/C Cool Credit	Irrigation Peak Rewards	Flex Peak
5pm – 9pm	87%	88%	79%
6pm – 10pm	80%	59%	71%
7pm – 11pm	77%	30%	67%

The percentage of respondents for each program answering in the affirmative that they would be able to participate decreased as the time period requested shifted into the later hours of the day. The most dramatic decrease came from the Irrigation Peak Rewards participants where only 30 percent of survey respondents said they were able to participate between 7:00pm and 11:00pm. While the Company anticipates there will be an impact to DR participation as a result of the parameter changes, it is difficult to quantify the exact capacity impact on the DR portfolio at this time.

Flex Peak and Irrigation Peak Rewards Customer Seminars

At the Flex Peak and Irrigation Peak Rewards seminars held on August 31, 2021, customers generally indicated they understood the need for the program changes. One Flex Peak participant shared that their ability to provide load reduction may be less during later hours, because their operations wind down at the end of the day, indicating it may be more difficult to achieve the same amount of reduction they have historically provided during the earlier hours. Another participant indicated that other utilities offer shorter windows for events (i.e., two hours instead of four hours), and one participant asked clarifying questions about

the day-of-adjustment component of the baseline calculation. The reasoning behind the minimum number of events was also discussed.

The Irrigation Peak Rewards participants asked several clarifying questions in their seminar about the program parameters, whether they can opt into certain participation time blocks, if time blocks will vary throughout the season, how the incentives are calculated and provided to participants, whether new pump sites will be allowed to participate, and clarifying questions about program notice requirements.

Idaho Irrigation Pumpers Association (“IIPA”) Meeting

The IIPA contacted the Company after the August 31, 2021 customer seminars and requested an additional meeting to be held on September 10, 2021. After the Company presented its proposed program approach, the IIPA suggested the Company look at the effectiveness of having Irrigation Peak Rewards participants split into groups based on dispatch times. This included a group that would have a defined end time and another group that would be available for all hours of the proposed event time period. The suggestion was based on the IIPA indicating that certain customers may prefer to have a more defined time block due to their specific irrigation equipment setup.

Based on the IIPA’s suggestion, the Company conducted an analysis using three different scenarios that incorporated irrigation groups in three additional ways. These scenarios were all different from the original scenario the Company evaluated in its Effective Load Carrying Capability (“ELCC”) analysis described more fully in Attachment 2 to Advice No. 21-12 but were evaluated using the same methodology. The three alternative design concepts were (1) all irrigation groups being available from 6:00pm to 10:00pm, (2) a large portion of the program capacity being available from 6:00pm to 10:00pm with a smaller portion occurring for four hours sometime between 3:00pm and 11:00pm, and (3) a large portion of capacity being available for four hours sometime between 3:00pm and 9:00pm with a smaller portion occurring for four hours sometime between 3:00pm and 11:00pm.

The results showed that each different scenario reduced the overall effectiveness of the program in a significant way. The third option had the least impact but still had a reduction in effectiveness of approximately 10 percent. However, it is important to note that the effectiveness of the third option would likely get worse over time as more variable resources are added to Idaho Power’s system, causing the hours from 9:00pm to 11:00pm to become more critical. For this reason, Idaho Power is proposing Irrigation Peak Rewards customers participate in one of two possible options: (1) four hours sometime between 3:00pm and 10:00pm, or (2) four hours sometime between 3:00pm and 11:00pm. Having two options is consistent with the current Irrigation Peak Rewards program where participants can elect to participate until 8:00pm or 9:00pm.

Additional Stakeholder Meetings

In addition to the customer and customer-representative meetings described above, the Company also met with its Integrated Resource Planning Advisory Council (April 8, and August 10, 2021), its Energy Efficiency Advisory Group (May 5, and August 12, 2021), the IPUC Staff (July 7, and August 9, 2021), and the OPUC Staff (August 9, 2021). The Company’s proposed modifications were informed by each of these customer and stakeholder discussions.