BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL TO MODIFY ITS DEMAND RESPONSE PROGRAMS.	))))))	CASE NO. IPC-E-21-32

IDAHO POWER COMPANY

DIRECT TESTIMONY OF

QUENTIN NESBITT

Q. Please state your name and business address.

A. My name is Quentin Nesbitt and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Customer Research and Analysis Leader in the Customer Relations and Energy Efficiency Department. I am responsible for overseeing the Company's analysis and reporting of all Demand-Side Management ("DSM") programs. I have been directly involved in the operation of the Company's Demand Response ("DR") programs in prior roles and was tasked to lead the team to redesign them for the future based on my prior experience.

Q. Please describe your educational background.

A. I earned a Bachelor of Science degree in Agricultural Engineering from the University of Idaho in 1989 and received my Professional Engineering license in 1992.

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1991 as an Agricultural Representative in the Company's Energy Management Department where I was responsible for providing customer service to irrigation and agricultural customers. Later in 1991, I was promoted to an engineering position where I provided technical support for Idaho Power Agricultural Representatives. This involved DSM program design and operation, pump testing, new service requests, investigation of high bills, and irrigation system evaluation and consultation. In 2002, the department was reorganized as the Customer Relations Department, and I took on additional duties as the agricultural customer segment advocate/expert where I coordinated Company activities that affected agricultural customers. In October of 2014, I was promoted to Energy Efficiency Program Leader and was responsible for overseeing the Company's Commercial and Industrial ("C&I") and Irrigation DSM programs. In June of 2020, I accepted my current position as Customer Research and Analysis Leader.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's proposed modifications to its DR programs that will allow them to more effectively meet system needs. This is based on updated analyses and methodologies used in the Company's 2021 Integrated Resource Plan ("IRP") planning process and discussed in further detail in Mr. Ellsworth's testimony.

My testimony will (1) provide a history and background of the current DR programs, (2) discuss the proposed program changes to meet the highest-risk hours identified in the Loss of Load Expectation ("LOLE") and Effective Load Carrying Capability ("ELCC") analyses adopted for use in the upcoming 2021 IRP, and (3) outline the Company's proposed method for evaluating the cost-effectiveness of DR.

I. <u>CURRENT DEMAND RESPONSE PROGRAMS</u>

Q. How does Idaho Power design its DR programs?

A. The Company's DR programs are designed to minimize or delay the need to build new supply-side resources. The DR programs are intended to reduce peak-hour electricity demand, thus minimizing the need for selecting supply-side alternatives that would only be needed for a few hours. These potential hours typically occur during low hydro generation and high load events, and the programs are designed to be available to meet potential system capacity deficits during these hours. The deficits are expected to be relatively large in magnitude but short in duration. Therefore, Idaho Power has determined it can be cost-effective for its customers to utilize DR programs rather than building a supply-side resource that would only be required to operate for a small number of hours.

Q. What are the DR programs the Company offers and when were they established?

A. Idaho Power offers three DR programs 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 C&I Flex Peak Program ("Flex Peak") that 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 since direct load control devices are not utilized within this program.

Last 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.

Q. Please summarize the recent demand reduction and associated program costs of the Company's DR programs.

A. Idaho Power's DR portfolio capacity and costs for the last five summer seasons are found in Table 1 below. 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

Q. Please provide an overview of how the current framework for the DR programs was established.

A. 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 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). The Flex Peak program (previously called FlexPeak Management) was not impacted by the Company's request because it was under contract with a third-party administrator at the time.

During the suspension of the two Idaho Power 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 Idaho Public Utilities Commission ("Commission") in Order No. 32923 will be referred to as the Settlement Agreement.

Q. How does the Settlement Agreement dictate how the DR programs currently operate?

A. Most notably, the Settlement Agreement includes several program specific requirements, including marketing limitations, the method for determining cost-effectiveness, and the Term of the Stipulation, as outlined below.[3]

> 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 change occurs in Idaho Power's system operations or cost-effectiveness of a DR Program that would warrant

[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).

[3] Case No. IPC-E-13-14, Motion to Approve Settlement Agreement, Attachment 2, pp. 2-3 (Oct 2, 2013).

> reevaluation of the Agreement's terms. In such event Idaho Power will consult its Energy Efficiency Advisory Group ("EEAG") and then make an appropriate filing at the Commission. Similarly, a party to this Agreement, may petition the Commission to open a docket to reevaluate the terms of this Agreement if Idaho Power experiences a change in system operations or the cost-effectiveness of a DR Program so warrants.

As more fully described in Mr. Ellsworth's testimony, the Company believes it has experienced a change in system need and operations since the Settlement Agreement in 2013 and is therefore opening this case to make necessary modifications to the DR programs.

Q. Have there been any major changes to the Company's DR programs since the Settlement Agreement in 2013?

A. There have not been significant changes to the three DR programs in terms of how they operate from a dispatchability perspective. However, a major change occurred in 2015 when the Company took over the administration of the Flex Peak Program from a third-party administrator.[4] This was done to increase administrative efficiency, reduce the program's cost to customers, and provide transparency into the incentives paid to customers.

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[4] *In the Matter of Idaho Power Company's Application for Approval of New Tariff Schedule 82, a Commercial and Industrial Demand-Response Program (Flex Peak Program)*, Case No. IPC-E-15-03, Order No. 33292 (May 7, 2015).

II. Proposed Program Changes

Q. What are the overall parameter changes being proposed to the Company's three DR programs?

A. As informed by the LOLE and ELCC analyses explained in Mr. Ellsworth's testimony, the proposed changes to the DR program parameters are meant to align the programs to more effectively meet high-risk hours. Table 2 below summarizes the primary program components and 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 15th to August 15th	June 15th to September 15th	Season end date extended 1 month to September 15th
Available Event Days	Weekdays and Saturdays No Sundays or Holidays (July 4th)	Weekdays and Saturdays No Sundays or Holidays (July 4th & Labor Day)	No Change Includes the additional Labor Day Holiday under the expanded season
Available Event Times	1:00pm to 9:00pm	3:00pm to 11:00pm	Shifted start and end times by 2 hours
Event Maximum	Maximum 4 Hours per Day	Maximum 4 Hours per Day	No Change
Weekly Maximum	No More than 15 Hours in a Week	No More than 16 Hours in a Week	Increased weekly maximum by 1 hour
Minimum Season Events	3 Events	3 Events	No Change
Season Maximum	Maximum 60 Hours for Program Season	Maximum 60 Hours for Program Season	No Change

Q. Please explain the rationale for each of the overall changes.

A. 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. It is expected that as renewable resources, such as solar, are added to the system, high-risk hours will occur later in the day.

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 ("LSO") group can utilize.

The available event days, the event maximum, the minimum season events, and the season maximum are all parameters that remain unchanged, as specified in Table 2. Modifying these parameters were found to have a minimal impact on increasing the ELCC of DR.

Q. Did the Company engage any stakeholders during the development of the proposed changes?

A. Yes. The Company has held ten formal touchpoints, plus several informal conversations with stakeholders, to solicit feedback on the proposed DR programs. The Company also conducted a customer survey with current and potential DR program participants, which will be discussed in further detail later in my testimony. Table 3 below shows the dates the Company engaged with Staff, EEAG, the Integrated Resource Plan Advisory Council ("IRPAC"), and customer groups during the process. Please reference Exhibit No. 2 to my testimony for the invitations to the customer seminars that were sent to all existing Flex Peak and Irrigation Peak Rewards participants.

Table 3: Formal Stakeholder Engagement Touchpoints

Stakeholder Group	Date
IRPAC Meeting	April 8, 2021
Energy Efficiency Advisory Group Meeting	May 5, 2021
Idaho Public Utilities Commission Staff Discussion	July 7, 2021
Idaho Public Utilities Commission Staff Discussion	August 9, 2021
Oregon Public Utility Commission 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

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 Idaho and Oregon Commission Staff.

Q. What feedback did the Company receive from customers at the seminars held on August 31, 2021?

A. Generally, customers indicated they understood the need for the program changes during the Flex Peak seminar. 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.

Program Dispatch Hours

Q. Did the Company receive additional feedback from participants after the August 31, 2021 customer seminars?

A. Yes. The IIPA contacted the Company 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.

Q. Based on the IIPA's suggestion, did Idaho Power evaluate other dispatch design options?

A. Yes. 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 ELCC analysis described in Mr. Ellsworth’s testimony 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.

Q. What were the results of the customer survey?

A. Idaho Power 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.

For example, the survey sought to understand how moving the dispatch hours later into the day would impact customers' ability or willingness to participate. Table 4 below outlines the results by customer class for one of the questions asked in the survey.

Table 4: 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.

Participant Compensation

Q. How are specific program design items being modified to address these participation concerns?

A. To help minimize a potential decrease in customer participation, customers will earn more for their participation under the proposed programs as compared to the current program parameters and incentives. Table 5 below shows the proposed changes for each of the three programs.

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Table 5: Summary of Proposed Demand Response Program Design Changes

		Event Duration	Event Window	Minimum # of Events	Event Notification	Fixed Incentive	Variable Incentive	Incentive Adjustment
Flex Peak	Existing	2-4 hours	2:00 to 8:00pm	3 events	2 hours prior to event	$3.25 per kW per week = $29.25 per kW per season	$0.16 per kWh after 3rd event	$2.00 per kW not achieved per event & $0.25 after 3rd event
	Proposed Option	**2-4 hours**	**3:00 to 10:00pm**	**3 events**	**4 hours prior to event**	**$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	Up to 4 hours	Not defined	3 events	None	$5.00 per month = $15.00 per season	None	None
	Proposed Option	**Up to 4 hours**	**Not defined**	**3 events**	**None**	**$5.00 per month = $20.00 per season**	**None**	**None**
Irrigation Peak Rewards	Existing	Up to 4 hours	1:00 to 9:00pm	3 events	4 hours prior to event	$5.00 per kW & 0.76¢ per kWh, 2 months = $16.00 per kW per season	$0.148 per kWh after 3rd event & $0.198 for 9:00pm option	$5.00 per kW per opt out & $1.00 per kW after 3rd event
	Proposed Option	**Up to 4 hours**	**3:00 to 11:00PM**	**3 events**	**4 hours prior to event**	**$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**

The Company is proposing an increase in the variable incentive after four events for the Flex Peak program, 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 A/C Cool Credit program 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.

For the Irrigation Peak Rewards program, the Company is proposing a higher monthly fixed incentive credit along with an increased variable incentive after the fourth event, again recognizing it may be harder for customers to participate in the later evening hours.

Number of Program Events

Q. Does the Company propose to keep the requirement of three minimum events?

A. Yes. As previously approved by the Commission, the three minimum events per season help the Company test and improve program operations and execution to ensure reliable capacity reduction is achieved when DR is called upon.[5] This minimum requirement also keeps customers engaged with DR program terminology, rules, processes, notifications, opt-outs, and performance. In addition, more events leads to better customer relationships. Without minimum events, the programs could go years without being utilized or tested. When programs are not used consistently, equipment and systems may not work as planned, and as a result, the demand reduction could be less than expected.

[5] Case No. IPC-E-13-14, Motion to Approve Settlement Agreement, Attachment 2, pp. 6-8.

Q. Why is the Company proposing to increase the threshold for the variable incentive payment for the Flex Peak and Irrigation Peak Rewards programs from after three events to after four events?

A. 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.

Opting Out of Program Events

Q. Why is the Company changing the amount of the incentive adjustment when customers opt out of program events?

A. The change to the incentive adjustment, or opt-out fee, for both the Irrigation and Flex Peak programs is to align with the season's fixed incentive and to send customers a proper disincentive signal for opting out of any event. The proposed incentive adjustment will approximately nullify a customer's fixed incentive if the customer opts out of four events throughout the program season. The Company feels this properly creates a disincentive for customers to opt out except under extreme conditions. This also removes the possibility of a customer signing up with the intention of opting out of all events and minimizes the likelihood of customers planning to only participate in the first three or four events before opting out of the rest.

Q. Are there any other updates to the program tariffs being proposed that are outside of the adjustments being made to address the high-risk hours?

A. Yes. The updated tariffs are included as Attachment 1 to the Application and explained more fully below.

Removal of Program Marketing Limitations

Q. What modification is Idaho Power proposing in Schedule 23?

A. The Company is proposing to remove the restriction 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 maintain and/or grow DR capacity to meet high-risk hours identified in the 2021 IRP analysis. Based on the results of the customer survey explained earlier in my testimony, the Company anticipates there may be an initial decrease in participation due to the proposed parameter changes. Opening up participation to new irrigation customers by removing the current marketing restrictions can help mitigate a potential decrease in DR capacity.

Adjusted Flex Peak Program Baseline kW Calculations

Q. What is the current Adjusted Baseline kW calculation for the Flex Peak program?

A. The current Adjusted Baseline kW calculation for the Flex Peak program is the sum of the Original Baseline kW and the Day of Load Adjustment ("DOA"). The Original Baseline kW is calculated using the industry standard "3 and 10 method." The 3 and 10 method utilizes the three highest energy use days during the event availability window from the 10 previous non-event or weekend days to establish the original baseline.

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 Company's current DOA takes the difference between the Original Baseline kW and subtracts or adds the actual metered kW two hours before an event with a maximum adjustment cap of 20 percent. This difference is then added or subtracted to each hour's Original Baseline kW to arrive at a participant's Adjusted Baseline kW.

Q. How does Idaho Power propose to change the Adjusted Baseline kW calculation for the Flex Peak program?

A. The proposed Adjusted Baseline kW calculation will still incorporate the Original Baseline kW and a DOA.

The Company is only proposing a change to how the DOA portion is applied to the Original Baseline kW, and the Original Baseline kW will still be calculated using the 3 and 10 method.

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. Charts 1 and 2 below give an example of how the Adjusted Baseline kW is calculated using the DOA scalar method.

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Chart 1. DOA Scalar Method

Hour Period	Hour	Event Day kW	Original Baseline kW	Scalar Value	Adj. Baseline kW	Actual kW Reduction
12am-1am	1	110	100			
1am-2am	2	110	100			
2am-3am	3	110	100			
3am-4am	4	110	100			
4am-5am	5	110	100			
5am-6am	6	110	100			
6am-7am	7	110	100			
7am-8am	8	110	100			
8am-9am	9	110	100			
9am-10am	10	110	100			
10am-11am	11	120	100			
11am-12pm	12	130	110			
12pm-1pm	13	140	110			
1pm-2pm	14	150	120			
2pm-3pm	15	160	130			
3pm-4pm	16	170	140			
4pm-5pm	17	50	140	1.27	165	115
5pm-6pm	18	50	140	1.27	165	115
6pm-7pm	19	50	130	1.18	154	104
7pm-8pm	20	50	120	1.09	142	92
8pm-9pm	21	80	110			
9pm-10pm	22	90	110			
10pm-11pm	23	90	100			
11pm-12am	24	90	100			

Adjustment Period

Time of notification (12:00 PM)

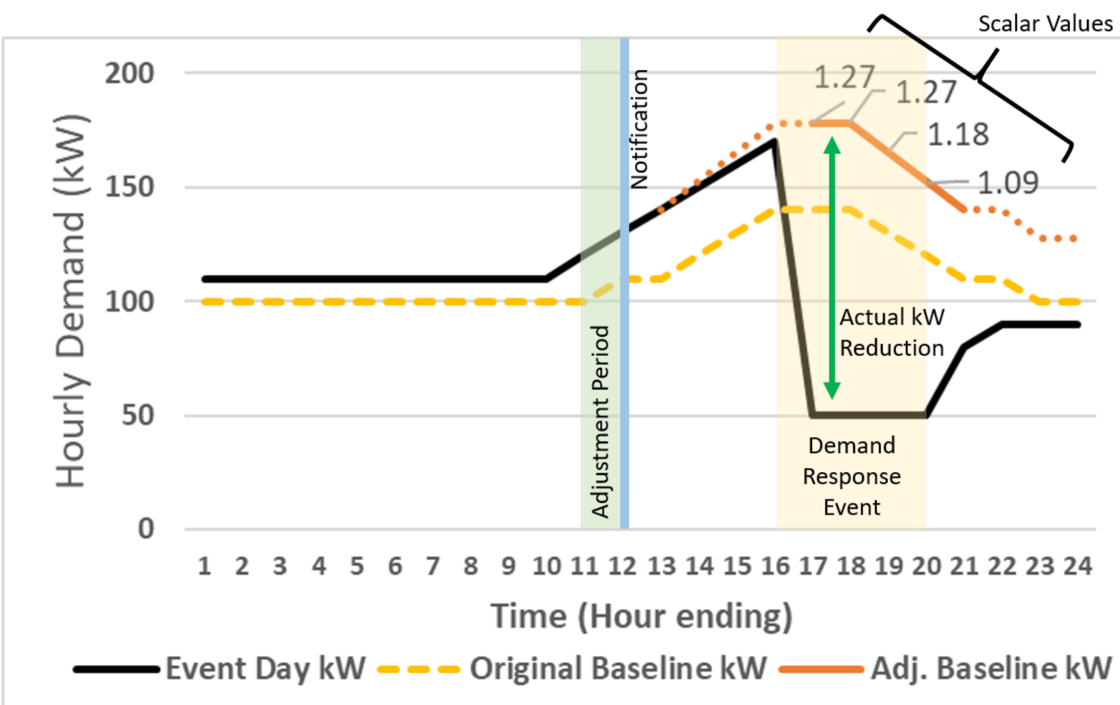
Demand Response Event

1) Scalar Values calculated by dividing each hour Original Baseline by the Adjustment Period

2) Adjusted Baseline kW is calculated by multiplying Event Day kW at the Adjustment Period by each Scalar Value

3) Actual kW Reduction is calculated by subtracting the Event Day kW from the Adjusted Baseline kW

Chart 2. Adjusted Baseline vs Event Day kW Reduction



Q. Why is the Company proposing a DOA scalar method to calculate a customer's Adjusted Baseline kW?

A. The Company believes this method is more accurate in calculating a customer's baseline, and therefore, results in more accurate calculations of customer demand reduction and compensation. The Company conducted an analysis based on actual customer loads during peak days and determined that the four-hour DOA scalar method was more accurate 86 percent of the time as compared to the current DOA.

Advance Notice of Program Events

Q. Why is the Company proposing to move from a two-hour advanced notification period to a four-hour advanced notification period for the Flex Peak program?

A. The Company is proposing to move the notification period to four 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 LSO if Flex Peak and Irrigation Peak Rewards events are called on the same day.

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Opting Out of Program Events

Q. Why is the Company proposing to allow the waiving of opt-out penalties in the Irrigation Peak Rewards program?

A. The Company is proposing to add a provision 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.

Q. Please describe why the Company is adding language that allows it to charge an opt-out fee to customers who override the dispatch command on their device.

A. 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

Q. Please describe why the Company is adding an installation fee for a select set of new participants in the Irrigation Peak Rewards Program.

A. 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.

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Irrigation Peak Rewards Out-of-Demand Season Energy Credit

Q. Please explain the Out-of-Demand season Energy Credit added to the tariff that would apply to some Irrigation Peak Rewards customers.

A. 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 15^{th}. 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 15^{th} 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 15^{th}, and the customers whose out-of-season billing cycles start before September 15th.

Timing of Incentive Payments

Q. Why is the Company proposing to adjust the incentive payout timing?

A. 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 calculation of the Flex Peak incentive payments is handled outside of the Company's customer relations and billing system ("CR&B"). A program specialist relies on hourly metered data to quantify the applicable incentive payments. In preparation of the 2021 program payments, the Company was found to be out of compliance with the existing requirement of 30 days. This was due to the additional complexity associated with the program being dispatched five times, and the Company required additional time to review the payments for accuracy. Extending the date by which payments must be issued by an additional 15 days will provide the Company adequate time to complete the initial calculation and review in advance of mailing checks.

The calculation of the Irrigation Peak Rewards variable incentive payments is also handled outside of CR&B, and the program specialist relies on billing data to calculate the incentive payment amounts. The current requirement to issue checks within 45 days provides adequate processing time for the majority of customers, but in preparation of the 2021 incentive payments, the Company found the billing determinants for a small number of participants were not available prior to the tariff deadline. These were for customers that have multiple service points and have elected to receive summary billing. Extending the date by which payments must be issued by an additional 25 days will provide the Company adequate time to compile all necessary billing components.

Program Use During System Emergencies

Q. Why are modifications to the emergency use language in the tariffs needed?

A. 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.

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Miscellaneous Tariff Changes

Q. Why is the Company proposing to modify language or provide additional details in certain sections of the tariff schedules?

A. 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.

III. COST-EFFECTIVENESS OF DEMAND RESPONSE

Q. How is cost-effectiveness currently determined for the Company's three DR programs?

A. 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 Simple Cycle

Combustion Turbine ("SCCT") multiplied by the ELCC,[6] levelized over 20 years, plus the corresponding deferred energy savings for 60 program hours. The avoided capacity cost is updated with every IRP planning cycle. If the total annual cost of operating the Company's three DR programs is less than the avoided cost outlined in the Settlement Agreement, the programs are considered cost-effective during the annual prudence review.

Q. How does the Company propose to modify the avoided cost calculation?

A. 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.

Q. What are the components of the proposed avoided cost calculation?

A. As described in greater detail in Mr. Ellsworth's testimony, along with how the value of each component is derived, the three components of the proposed alternate cost calculation are: (1) the levelized capacity

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[6] At the time the ELCC was developed in 2013, the Company studied the top 100 hours of peak demand of each year over the prior five years. Of those top 100 hours, approximately 7 percent occurred outside of program hours. As a result, an ELCC of 93 percent is currently applied to determine the value of demand portion of the avoided capacity calculation. The purpose of the ELCC is to reflect the ability of a peaking resource, such as a SCCT, to be used year-round where the DR programs can only be dispatched during certain hours between June 15th and August 15th each year.

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.

Q. What is the proposed avoided capacity equation to determine the dollar per kW per year avoided cost value for the DR programs?

A. The equation below incorporates the components listed above as follows:

(Levelized Fixed Cost – Additional Benefits) x
ELCC of Annual DR Capacity Compared to Proxy Resource
= $ per kW year DR Avoided Cost

Q. How would cost-effectiveness be determined using the proposed equation?

A. The Company proposes to evaluate cost-effectiveness at both the individual program and portfolio level. A dollar per kW cost would be calculated annually for each of the Company's DR programs and the overall portfolio, assuming the maximum 60 hours of operation. The per kW costs would then be compared to the avoided cost value. A program and a portfolio would be considered cost-effective as long as their dollar per kW costs are less than the avoided cost value.

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For example, using the values from Mr. Ellsworth's testimony, the avoided cost value would be \$51.42 per kW per year assuming a 492 MW capacity program.

(\$131.60 - \$38.11) x 55% = \$51.42 per kW per year

Q. How often will the Company update the components of the proposed avoided cost equation?

A. The Company intends to evaluate all three components with every IRP planning cycle to establish baselines, but the values used in the cost-effectiveness calculation will be updated with every DSM annual reporting cycle. For example, the ELCC component of the equation is dependent on the capacity of the DR programs. Therefore, the value used in the cost-effectiveness calculation may change in-between IRP planning cycles if capacity changes, but the baselines will reset with every acknowledged IRP. The levelized cost value of the proxy resource will change every year to ensure the value is in the equivalent year's dollars with the baselines derived from the acknowledged IRP as well. The Company proposes to annually run the production cost models from the most recently acknowledged IRP to update the additional system benefits of the proxy resource component since this value is also dependent on the total DR portfolio capacity. All three components and cost-effectiveness will be reported in the annual DSM report, and a request for a prudence determination on the

DR program costs will be sought in each year’s DSM prudence case.

Q. Do you expect the modified programs as proposed in this filing to be cost-effective?

A. Yes. The Company anticipates that the cost of each individual program and the overall DR portfolio will be less than $51.42 per kW per year. This value is derived using 492 MW of traditional DR potential identified from the Northwest Power and Conservation Council assessment referenced in Mr. Ellsworth’s testimony. The Company evaluated future program costs with the proposed incentives against the $51.42 value and believes the DR programs will remain cost-effective in the future. The Company also recognizes that near-term DR capacity will most likely be less than the 492 MW. A lower capacity results in a higher ELCC, and a higher ELCC value increases the $ per kW per year avoided cost in the proposed equation.

IV. IMPLEMENTATION OF PROGRAM CHANGES

Q. When does Idaho Power wish to implement these program changes?

A. Idaho Power plans to implement the changes described above for the 2022 demand response season that begins on June 15, 2022.

Q. If the Company’s proposed changes are approved by the Commission, how long will it take for Idaho Power to market the modified programs with proposed changes and enroll customers for the 2022 DR season?

A. Idaho Power 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.

V. CONCLUSION

Q. Please summarize your testimony.

A. Idaho Power proposes several DR program modifications informed by the risk-based methodology utilized in the 2021 IRP analysis, which has identified a change in system need and operations since the Settlement Agreement in 2013. The rationale behind the changes is to ensure the Company has a portfolio of cost-effective DR programs that effectively meet system needs. As described in Mr. Ellsworth’s testimony, the changes proposed above would improve the ELCC of the Company’s DR portfolio by approximately 40 percent. The Company believes this improvement is not only necessary but also benefits customers and the reliability of the system alike.

Q. Does this complete your testimony?

A. Yes, it does.

DECLARATION OF QUENTIN NESBITT

I, Quentin Nesbitt, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Quentin Nesbitt. I am employed by Idaho Power Company as a Customer Research and Analysis Leader in the Customer Relations and Energy Efficiency Department and am competent to be a witness in this proceeding.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit No. 2 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibit are true and accurate.

4. I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 1st day of October 2021, at Boise, Idaho.

Signed:

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-32

IDAHO POWER COMPANY

NESBITT, DI

TESTIMONY

EXHIBIT NO. 2

Flex Peak Invitation

Join us for a one-hour virtual seminar on proposed updates to the Flex Peak program

Dear Flex Peak Participant:

Please join us for a one-hour virtual seminar to provide feedback on proposed updates to the 2022 Flex Peak demand response program.

Attendees will learn why program modifications are needed, view comparison of the current program and proposed new program design, discuss the proposed timeline of changes and have an opportunity to provide comments and feedback.

Date: Aug. 31, 2021

Time: 9:30 to 10:30 a.m.

Join: email ZVanHooser@idahopower.com to receive a virtual meeting link and a reminder email.

To join the meeting, open the link and follow the directions to download the WebEx app.

https://idahopower.webex.com/idahopower/j.phpMTID=m3f0f5649dfdb330e47f6580d3ae6f43f

Once downloaded enter the member number and meeting password below:

- Meeting number (access code): **1457 43 6485**
- Meeting password: **UgyE4nfss38**

To join by phone, dial **1-650-479-3208** and enter the access code: **1457436485##**

If you are unable to attend, share with any appropriate colleague at your business that may be familiar with the program. We really want to hear from you — your input and feedback is important to us.

Zeke VanHooser, Idaho Power

1221 W. Idaho St., Boise, ID 83702

Irrigation Peak Rewards Invitation

Join us for a one-hour virtual seminar on proposed updates to the Peak Rewards program

Join us for a one-hour virtual seminar to provide feedback on proposed updates to the 2022 Irrigation Peak Rewards demand response program.

Date: Aug. 31, 2021

Time: 12-1 p.m.

Join: Email Irrigation@idahopower.com to receive a virtual meeting link and a reminder email.

OR to join the meeting, open the link below and follow directions to download the WebEx app a few minutes before the meeting starts.

https://idahopower.webex.com/idahopower/j.phpMTID=m4cb8f5e40c15b00144f628342014a58b

After downloading the app, enter the meeting number and meeting password below:

- Meeting number (access code): **145 461 8350**

- Meeting password: **YBmY9Vjdb68**

To join by phone, dial **1-650-479-3208** and enter the access code: **145 461 8350##**

Please note: If we have more than one email address on file for your farm's Peak Rewards event notifications, all email addresses will receive this seminar invitation. We welcome and value your feedback. For questions, contact Tonja Dyke, tdyke@idahopower.com, 208-388-5356 or Dan Axness, daxness@idahopower.com, 208-388-2586.

Idaho Power Irrigation

1221 W. Idaho St., Boise, ID 83702