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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION FOR APPROVAL OF CHANGES TO THE IRRIGATION PEAK REWARDS PROGRAM.	CASE NO. IPC-E-10-46

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

PETER PENGILLY

Q. Please state your name, address, and present occupation.

A. My name is Peter Pengilly. My business address is 1221 West Idaho Street, Boise, Idaho.

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

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Customer Research and Analysis Leader in its Customer Relations and Energy Efficiency group.

Q. Please describe your educational background.

A. In May of 1976, I received a Bachelor of Science Degree in Anthropology from University of Idaho, Moscow, Idaho. In 1986, I began attending Boise State University, and in 1992, I received a Bachelor of Science Degree in Mathematics. I continued at Boise State University after graduation as an adjunct professor in mathematics while completing courses specializing in statistics.

I have since attended numerous seminars and conferences on statistical analysis and on pricing issues related to the utility industry and have attended seminars and courses involving public utility regulation. These courses include Edison Electric Institute's ("EEI")

Advanced Rate Course and New Mexico State University's Center for Public Utilities Rates Course and The Restructuring Electric Industry Course. Additionally, I have attended numerous conferences and forums on energy efficiency and demand response, including the Demand Response Coordinating Committee ("DRCC") meetings, the E-Source Forum, and Bonneville Power Administration post-2011 energy efficiency meeting.

Q. Please describe your work experience.

A. From 1976 until 1986, I worked as an archaeological technician on contract with various universities, government agencies, and private contractors. At the same time, I was involved in managing a small family-owned business. From 1986 until 1992, I was employed by the Idaho State Historical Society managing their Archaeology laboratory. In 1992, I went to work as a Research Analyst for the Idaho Department of Correction. In 1993, I transferred to the Idaho Department of Labor as a Research Analyst Supervisor under the auspices of the Bureau of Labor Statistics. This position included supervising a staff as well as performing a variety of economic and statistical analyses and reporting. I was employed by Idaho Power Company in December of 1999 as a Senior Pricing Analyst in the Pricing and Regulatory

Services Department. My duties as a Senior Pricing Analyst included the development of alternative pricing structures, management of pricing programs, the analysis of the impact on customers of rate design changes, and the administration of the Company's tariffs. In that position I helped develop several demand response programs, a time-of-use pilot program, and a critical peak pricing program.

In 2006, I was promoted to my current position as Customer Research and Analysis Leader in the Customer Relations and Energy Efficiency Department. In this position I am responsible for the research, analysis, forecasting, and reporting associated with Idaho Power's energy efficiency and demand response programs. As such, I am a member of the Northwest Energy Efficiency Alliance ("NEEA") cost-effectiveness expert committee, a representative at the Pacific Northwest Demand Response Project ("PNDRP"), Idaho Power's representative at the Regional Technical Forum ("RTF"), and a member of the E-Source DSM Executive Council.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will discuss the Company's recent review of the effective integration of demand response into Idaho Power's electrical system. Further, my testimony will describe a number of proposed modifications to the Irrigation Peak Rewards Program (Program), Schedule 23, which are based upon the findings of the review.

CURRENT PROGRAM OVERVIEW

Q. Please provide an overview of the current Irrigation Peak Rewards Program.

A. The Irrigation Peak Rewards Program, Schedule 23 is a voluntary load control program currently available to agricultural irrigation customers. The purpose of the Program is to reduce the Company's system summer peak loads. If not for the Program, growing summer peak loads would likely require the construction of additional simple cycle gas peaker capacity to meet system peak a few hours each year.

Under the Program, the Company turns off all irrigation pumps behind a participating metered service point during the summer, Monday through Saturday, with the use of an electric switch or a switch that is communicated with via cell phone or power-line carrier technology via Idaho Power's Automated Meter Infrastructure ("AMI") system. Customers who have irrigation service usage greater than 1,000 cumulative horsepower ("hp") have the option to manually interrupt electric service to their irrigation pumps. In exchange for allowing the Company to turn their pumps off, participating Customers receive a monthly monetary incentive during the Program period.

Load reduction is achieved by turning off specified irrigation pumps for up to 4 hours per day, for up to 15 hours per week, and for up to 60 hours per Program Season. The Program operates during the Company's typical peak season of June 15th through August 15 (Program Season).

Q. In the past has Idaho Power's Irrigation Peak Rewards Program achieved its targets?

A. Yes. Each year the Program has met or exceeded the targets set for participation and megawatt ("MW") reduction.

Q. Does the Company conduct an annual review of the Program to analyze the effectiveness of Program provisions?

A. Yes. Each year the Company evaluates the operations of the Program to ensure that the Program design is cost-effective. The annual review process also includes an evaluation of other programmatic aspects such as operational efficiency and customer satisfaction. These findings are reported in the Demand-Side Management Annual Report filed with the Commission on March 15 of each year.

PROGRAM REVIEW 2010

Q. How has this year's Program review differed from reviews performed in prior years?

A. In 2010, the Company enhanced its traditional annual review by conducting an additional study in conjunction with its 2011 Integrated Resource Plan ("IRP") analysis. This study was conducted in an effort to ensure that Program design is aligned with the resource needs identified by the IRP. The primary objectives of this effort were to: (1) leverage the IRP analysis to determine the Company's future capacity needs that can be cost-effectively met with demand response and (2) design and operate demand response programs in a manner that satisfies the identified resource need. The proposed Program modifications are a direct result of that review.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. Exhibit No. 1 contains slides presented at the November 18, 2010, Integrated Resource Plan Advisory Council (IRPAC) meeting. Exhibit No. 2 details the proposed incentive payment structure and provides examples of incentive payments at different hours of operation.

Q. Please describe the 2010 Program review.

A. The first part of the review involved an analysis of the impact that the Company's demand response programs had on the Company's peak-day load shape in 2010. The results of this analysis are detailed on page 1 of Exhibit No. 1. As can be seen on page 1 of Exhibit No. 1, the Company's demand response programs clearly had an effect on the peak-day loads. However, it can also be seen that the Company's resulting peak demand occurred after 8:00 p.m., after the demand response program operational period of 1:00 p.m. to 8:00 p.m. In addition, the peak demand that occurred at 9:00 p.m. was at a level much greater than demand during the demand response program operational period, thereby creating a "trough effect" in the load shape.

Ideally, demand response would flatten the peak-day load shapes as shown on page 2 of Exhibit No. 1. A flat load shape during the demand response program operational period would indicate that 100 percent of the demand reduction provided by the programs is avoiding the need for capacity rather than something less than 100 percent that would exist under the "trough effect." In other words, a "trough" in the peak-day load shape suggests that the demand reduction was not optimally aligned with the load conditions.

The second part of the review centered around the Company's IRP process with input from representatives from Idaho Power's demand response program managers and planners, generation dispatch, power supply planning, and transmission planning. The Company began by analyzing the load duration curves for the year's forecast in the 2011 IRP process to determine a maximum potential level of demand reduction that could be expected from a resource that is available 60 hours per year. Sixty hours is the Program's maximum hours of load control. The results of the load duration analysis can be seen on page 3 of Exhibit No. 1. The Company then leveraged its 2011 IRP analysis to determine its projected demand response resource need over the planning period under extreme load conditions.

The results from the resource need analysis and the analysis of demand reduction potential were then analyzed together, as shown on page 4 of Exhibit No. 1, to determine the appropriate level of demand response to pursue through Idaho Power's programs.

Q. Please describe page 4 of Exhibit No. 1.

A. Page 4 of Exhibit No. 1 provides a schedule of the appropriate level of demand response to be pursued by the Company through its demand response programs. Column F of the schedule details the annual demand response needed over the next five years according to a resource adequacy analysis. A resource adequacy analysis compares the Company's existing and committed resource capacity resulting from its most recent IRP analysis, in this case the 2011 IRP, against the amount of forecasted annual peak-hour demand under 95^{th} percentile (extreme load conditions) to determine future capacity need. This approach applied a methodology and utilized inputs consistent with the Company's 2011 IRP analysis. Column G of the schedule details the level of demand response resource potential identified by a load duration curve analysis. Column H of the schedule provides the estimated amount of demand response that should be pursued by the Company by identifying the lesser of the resource need in Column F and the demand response potential in Column G. According to the results in Column H, under 95^{th} percentile load conditions, the Company's annual capacity need is expected to vary from a minimum of 155 MW to a maximum of 322 MW in the next five years, a difference of over 50 percent.

Q. What conclusions has the Company reached following its review of the information provided on Exhibit No. 1?

A. After a thorough review of the information contained on Exhibit No. 1 and after extensive interdepartmental discussion, the Company has concluded that its need for demand response extends beyond 8:00 p.m. to at least 9:00 p.m. Further, the Company has concluded that its annual capacity need during the highest 60 hours of demand is expected to vary by over 50 percent during the next five years.

Q. How did these findings and conclusions help shape the proposed Program modifications?

A. Based upon the findings and conclusions reached by the Company in its 2010 Program review and analyses, a number of potential Program modifications were indentified. First, in response to the need for load reduction until 9:00 p.m., the Company explored methods by which it could extend the interruption period for a subset of participants. Second, based upon the anticipated annual variations in capacity needed, the Company explored a number of methods to better align annual Program costs with the annual capacity need. Specifically, the Company explored modifications to the Program's incentive cost structure that would move from the current 100 percent fixed structure to a cost structure that would allow for some portion of the costs to vary in proportion to the projected capacity need.

PROPOSED PROGRAM CHANGES

Q. Please describe the proposed Program modifications.

A. The Company is proposing the following Program modifications:

1. Include the 8:00 p.m. to 9:00 p.m. Mountain Daylight Time ("MDT") hour as an "Extended Interruption" option on a voluntary basis;

2. Change the incentive cost structure for the Program from a fixed payment methodology to a methodology that combines a fixed and variable incentive payment. The proposed incentive structure pays participants a portion of their total incentive for participation alone (fixed) and a portion based on how much the Company utilizes the Program (variable);

3. Include one Program test event per Program Season not subject to a variable payment;

4. Modify the requirements under the Program's Dispatchable Option 3 to align with the proposed incentive structure; and

5. Modify the opt-out penalty for the Program.

Q. Did the Company develop the proposed changes to the Program with input from other interested parties external to Idaho Power?

A. Yes. The Company met separately with representatives of the Idaho Irrigation Pumpers Association ("IIPA") and the Commission Staff to inform them of the findings from the Company's recent resource planning analyses and to seek input regarding potential Program modifications supported by those analyses. On November 4, 2010, Company representatives met at its Mini-Cassia office in Heyburn, Idaho with representatives of the IIPA. Subsequently, Company representatives met with Commission Staff on November 9, 2010, and again with representatives of the IIPA on December 2, 2010.

The results of the 2010 analysis and general Program changes were also presented at the October 26 meeting of the Energy Efficiency Advisory Committee ("EEAG") and the November 18 meeting of the IRPAC.

Q. Did the Company receive input from the IIPA or the Commission Staff that was ultimately included in the proposed Program modifications?

A. Yes. At IIPA's suggestion, the Company is proposing to pay a higher "Extended Interruption" Variable Energy Credit incentive payment to customers selecting to participate from 8:00 p.m. to 9:00 p.m. MDT. In working with the IIPA, it was noted that it can be a hardship for some customers to get systems restarted before nightfall. Therefore, the Company is recommending that this "Extended Hours" option be offered on a voluntary basis rather than a requirement for all customers. Under this option, Customers who are willing to accept an extended interruption period will receive a higher incentive payment for event hours.

Q. Do you expect this modification to improve the effectiveness of the Program?

A. Yes. As discussed earlier in my testimony, the Company experienced substantial loads on or about the 8:00 p.m. MDT hour during interruption days when Program participants resumed their energy consumption. Customers will benefit by having the Company extend the time period to 9:00 p.m. MDT in order to reduce the peak at this hour. This modification will provide a better opportunity to fully utilize the full value of the Program by reducing loads across the entire peak period.

Q. Please describe the proposed incentive payment structure.

A. The proposed incentive payment structure for Dispatchable Interruption Options 1, 2, and 3 will include a variable incentive payment in addition to the current fixed incentive payment. The variable portion of the incentive will represent approximately 60 percent of the total incentive amount for an average participant and be based on the number of interruption hours multiplied by the amount of monthly billing demand measured in kilowatts ("kW"). Currently, the incentive payment structure is a fixed amount that only varies based on the customer's monthly billing demand and energy usage; it does not vary based on the number of interruption hours (i.e., use of the Program). Overall, the proposed changes result in a larger incentive payment, as compared to what participants currently receive, if the Program is dispatched at the maximum of 60 hours per Program Season. The Company is not proposing any changes to the incentive structure for the Timer Option.

Q. How does the modified incentive structure for the Dispatchable Interruption Options address the Company's concerns regarding the projected variations in capacity need over the coming years?

A. The Company believes that having a portion of the incentive based on the actual utilization of the resource more closely aligns the cost of demand response with the variable capacity needed. The summers of 2009 and

2010 were good examples of how weather and load variation can create a situation where demand response resources are not as critical to the system.

Q. What specific incentive changes are being proposed by the Company in this filing?

A. For the Timer Option, the incentives will not change. For Dispatchable Options 1, 2, and 3, the participants will be paid a fixed Demand Credit of $5.00 per kW and an Energy Credit of $0.0038 per billed kWh. The variable portion of the incentive will be $0.35 per kWh calculated as the Billing Demand multiplied by the interruption hours of the Program. Participants willing to reduce demand in the 8:00 p.m. to 9:00 p.m. hour will receive a variable incentive payment of $0.40 per kWh, calculated as the Billing Demand, multiplied by the interruption hours of the Program. Exhibit No. 2 details the incentives and provides examples of the incentive payments at different hours of interruption.

Q. Can you further describe Exhibit No. 2?

A. Exhibit No. 2 includes a table that illustrates the impact of the modified incentive payment structure based on a hypothetical participant with a 125 horsepower pump. The table provides the individual payment components based on a 40 percent fixed and 60 percent variable incentive payment structure. The table compares the current incentive payment structure to the proposed incentive payment structure. The fixed energy (kWh) incentive is based on an average participant's usage over the eight-week Program period. The variable kWh incentive is determined by multiplying the kW demand by the number of event hours. The table illustrates that if the Company has no demand response events, it will pay 40 percent of the current incentive; the Company will pay 106 percent of the current incentive if the Program is fully utilized at 60 hours.

Q. What is the basis for the proposed 40 percent fixed and 60 percent variable incentive payment structure?

A. As discussed earlier in my testimony, the Company estimates that the annual need for demand response resources under extreme conditions (95th percentile) will vary in the next five years by more than 50 percent. If the Company were to limit annual Program participation to match the annual capacity need, it could potentially reduce its incentive costs by over 50 percent in at least one of those years. However, because varying Program participation could have unwanted impacts to customer satisfaction and ultimately long-term participation levels, the Company opted to move to the proposed variable payment structure. The Company believes that the 60 percent variable payment structure is reflective of the variations in cost that would exist under a variable participation approach. Furthermore, the Company anticipates that the proposed level of fixed incentive will be adequate to retain current participants.

Q. Why is the Company proposing that one dispatched test event each year not receive a variable incentive payment but rather be paid entirely with a fixed payment?

A. It is possible that the Company may not have a need for load control events in a particular summer. By dispatching at least one event per Program Season, the Company can test Program equipment and communication channels to ensure that the load reduction is available when needed. Having at least one event per Program Season will also keep participants familiar with the Program and help them manage their Program expectations. A single test event that is incentivized by a fixed payment also removes any disincentive for Idaho Power to use this event.

Q. What additional requirements is the Company proposing for Dispatchable Option 3?

A. The Company is proposing the following modifications to Dispatchable Option 3: (1) to require participants to nominate their load reduction, (2) to change the opt-out policy, and (3) to change the baseline from which participants' load reduction is calculated.

Q. Why is the Company proposing that Dispatchable Option 3 participants nominate the amount of load reduction they can provide?

A. Currently under Dispatchable Option 3, participants have the option to provide any portion of their load during a load control event. Under the current incentive structure, a participant could be paid a larger incentive if no events were called. This has not been a significant issue in the past because normally the Company has called at least one event per Billing Period.

Under the Company's proposed changes to Dispatchable Option 3, participant's fixed incentive payment will be calculated based on the nominated load reduction and energy use if no load control events are dispatched. This will reduce the chance of the Company overpaying participants if no load control events are dispatched.

Q. Please describe the current opt-out penalty under the Dispatchable Interruption Options.

A. Currently, the opt-out penalty is $0.005 per monthly billed kWh per opt-out occurrence for customers selecting the Dispatchable Interruption Options 1 and 2 under the Program. Currently, Dispatchable Option 3 participants do not pay an opt-out penalty.

Q. Please describe the proposed opt-out penalty under the Dispatchable Interruption Options.

A. The Company is proposing a $1.00 per kW opt-out penalty for all Dispatchable Interruption Options.

Q. Why is the Company proposing a change in the opt-out penalty?

A. First, the $1.00 per kW will make it easier for customers to estimate what an opt-out is going to cost ahead of time, which could influence their decision to opt-out. Second, it is now imperative that Dispatchable Option 3 participants be subject to the opt-out penalty. For example, under the current Program provisions, if a Dispatchable Option 3 participant has nominated the full load of a pump station, then their fixed portion of the payment would be based on that amount. During events when the customer chose not to turn the whole pumping station off, the Program would pay the fixed portion on potential load reduction the Company would not be receiving. If they did not provide the full amount of nominated kW, the penalty would apply to the difference between what they provided and what they nominated.

Additionally, Dispatchable Option 3 participants are not restricted to five opt-outs per season as are Dispatchable Options 1 and 2 participants. Under the proposed changes, if Idaho Power fully utilized the Program for the maximum 60 hours during the Program Season, and if the Participant did not provide the entire nominated kW more than five times, then the penalty would never exceed 100 percent of the credit. This will encourage Dispatchable Option 3 participants to provide at least the kW amount nominated.

Q. How is the load reduction for participants under Dispatchable Option 3 determined?

A. To be eligible to participate in Dispatchable Option 3, participants must have interval meters installed at their Metered Service Points. Idaho Power analyzes this meter data after an event and determines the amount of load reduction by subtracting the actual demand from a baseline demand (Program kW).

Q. How is the current baseline for load reduction Program kW determined for Dispatchable Option 3 participants?

A. The current Program kW for Dispatchable Option 3 participants is the maximum demand in the 24 hours prior to an event.

Q. What change is the Company proposing for the calculation of the baseline Program kW under Dispatchable Option 3?

A. The Company is proposing to calculate the Program kW based upon the average demand between the 10:00 p.m. and 11:00 a.m. MDT immediately prior to an event, as measured in kW over the load profile metering intervals, during each load control event initiated during a Billing Period.

Q. Why is the Company proposing a change to this baseline calculation?

A. In the past, there were a few instances where a high demand was registered prior to the event for a short duration and did not accurately represent the customer's load prior to an event. By changing the calculation of Program kW for Dispatchable Option 3 participants, it will more accurately represent the load reduction provided by the customer and minimize the risk of paying the customer for demand reduction that the Company did not actually receive.

COST-EFFECTIVENESS

Q. Has the Company performed an analysis to determine that the proposed Program design is cost effective?

A. Yes. The benefit/cost (B/C) analysis for the Irrigation Peak Rewards Program is based on a 20-year model that uses financial and Demand-Side Management alternative costs assumptions from the IRP. As published in the 2009 IRP, for peaking alternatives such as demand response programs, a 162 MW simple-cycle combustion turbine is used as a cost basis. Idaho Power's cost-effectiveness model representing the Program over a 20-year period is updated annually with actual benefits and costs. The model is currently updated through 2009 and will be updated with 2010 actual expenses and benefits after the 2010 financial books are closed and reported.

Q. Considering the proposed changes, is the Program still cost-effective?

A. Yes. The current Program's B/C ratio as reported in the Demand-Side Management 2009 Annual Report was 1.50 over a 20-year planning period. When considering the proposed Program changes, several assumptions were changed for the Program in future years. Participation was assumed to remain fairly constant through the planning period. Because of the proposed variable pricing, the incentives were analyzed based on zero dispatched load control events, with three dispatched events, with seven dispatched events, and at full utilization of the Program with 15 dispatched events. Under all scenarios, the B/C ratios are greater than one.

CUSTOMER PAYMENT

Q. Please describe how the proposed incentive amounts will be paid to the participants.

A. For participants in the Timer Option and Dispatchable Interruption Options, the fixed portion of the incentive will be paid as a credit on their bills. The variable portion of the incentive payment for the Dispatchable Interruption Options will be paid in the form of a check issued no more than 60 days after the August 15th end date of the Program Season.

Q. Why is the Company proposing that the variable portion of the incentive be paid by check after the end of the Program?

A. By using this method of payment, the Company can avoid issues with its billing system. It will also highlight to the participants that they are paid the fixed incentive through the bill credit and that the variable portion of the payment is based on the amount of time the Program operates.

<u>REVISED SCHEDULE 23</u>

Q. Has the Company prepared a revised Schedule 23, Irrigation Peak Rewards Program, which reflects the proposed modifications to the Program?

A. Yes. Idaho Power included Schedule 23, Irrigation Peak Rewards Program, as an attachment to the Company's Application in legislative and final format.

Q. Are there any other changes to Schedule 23 that should be pointed out?

A. Yes. The Company is proposing to add clarifying language regarding participation in the Program. Specifically, language has been added to indicate that Program participation may be limited based on the Company's need for peak load reduction.

In addition, the Company is proposing a housekeeping clarification to indicate that customers participating under Dispatchable Option 3 have the flexibility to choose which irrigation pumps will be interrupted and how the pumps will be interrupted during each dispatchable load control event.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-10-46

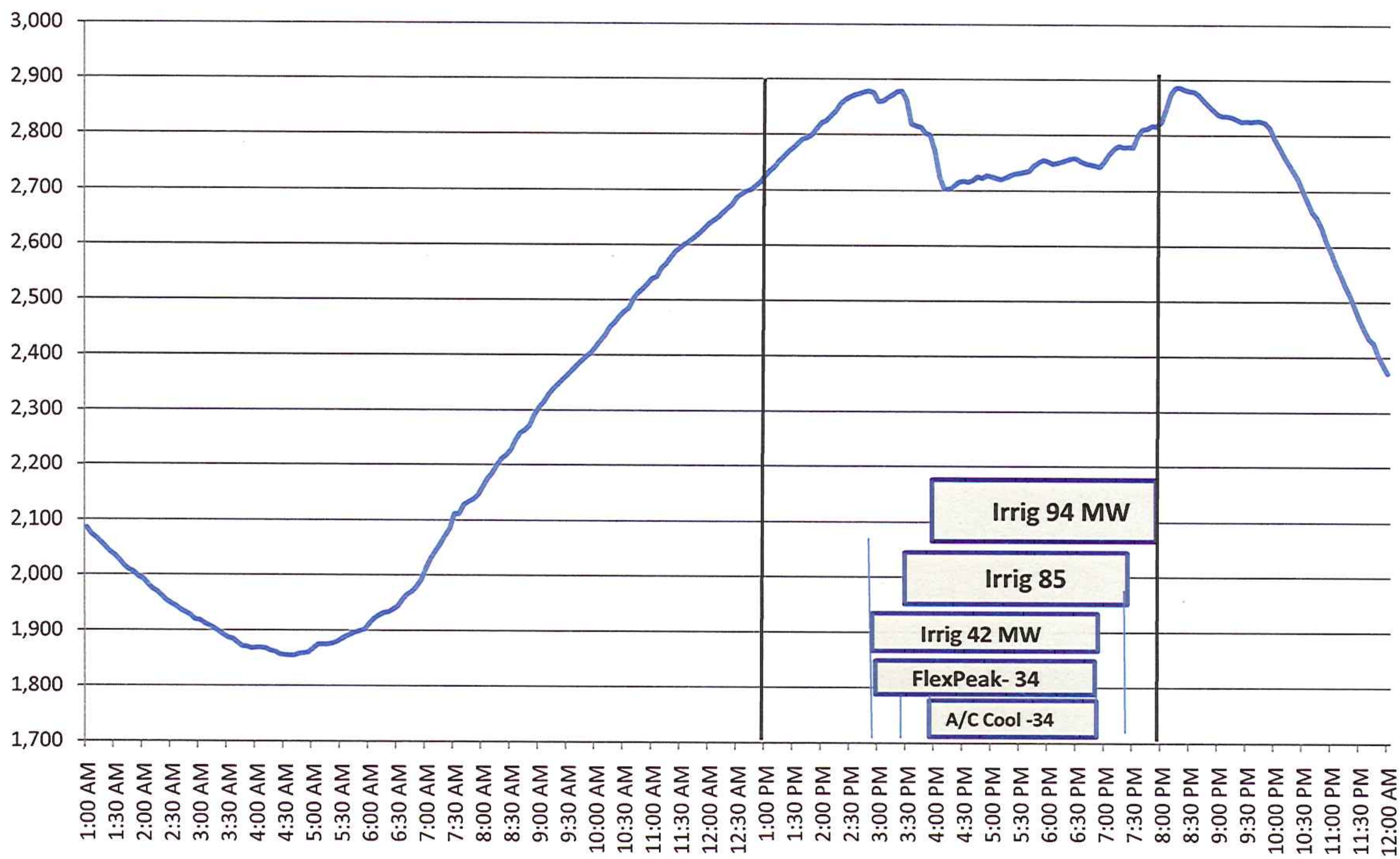
IDAHO POWER COMPANY

PENGILLY, DI
TESTIMONY

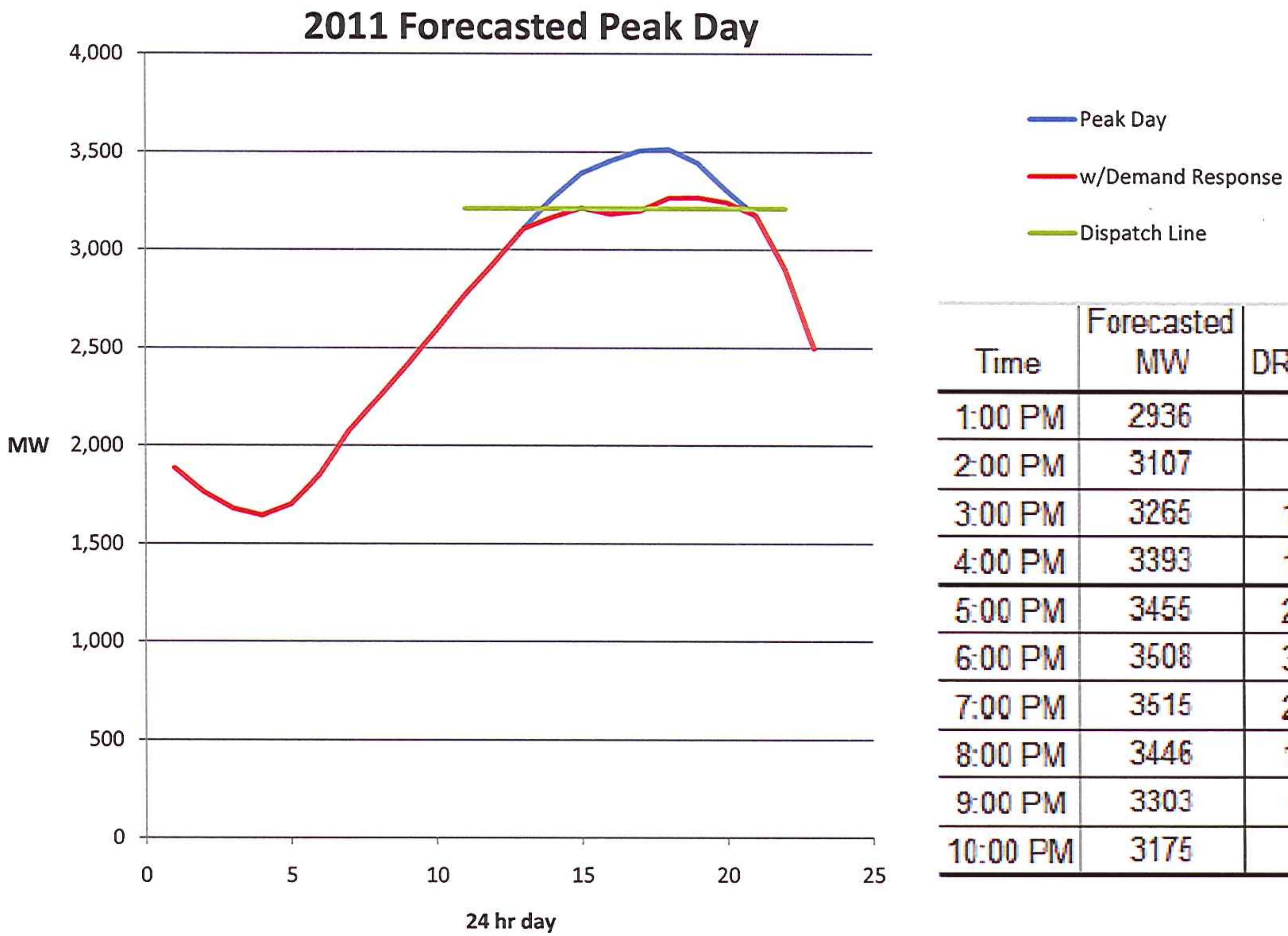
EXHIBIT NO. 1

Demand Response Dispatch

July 16, 2010

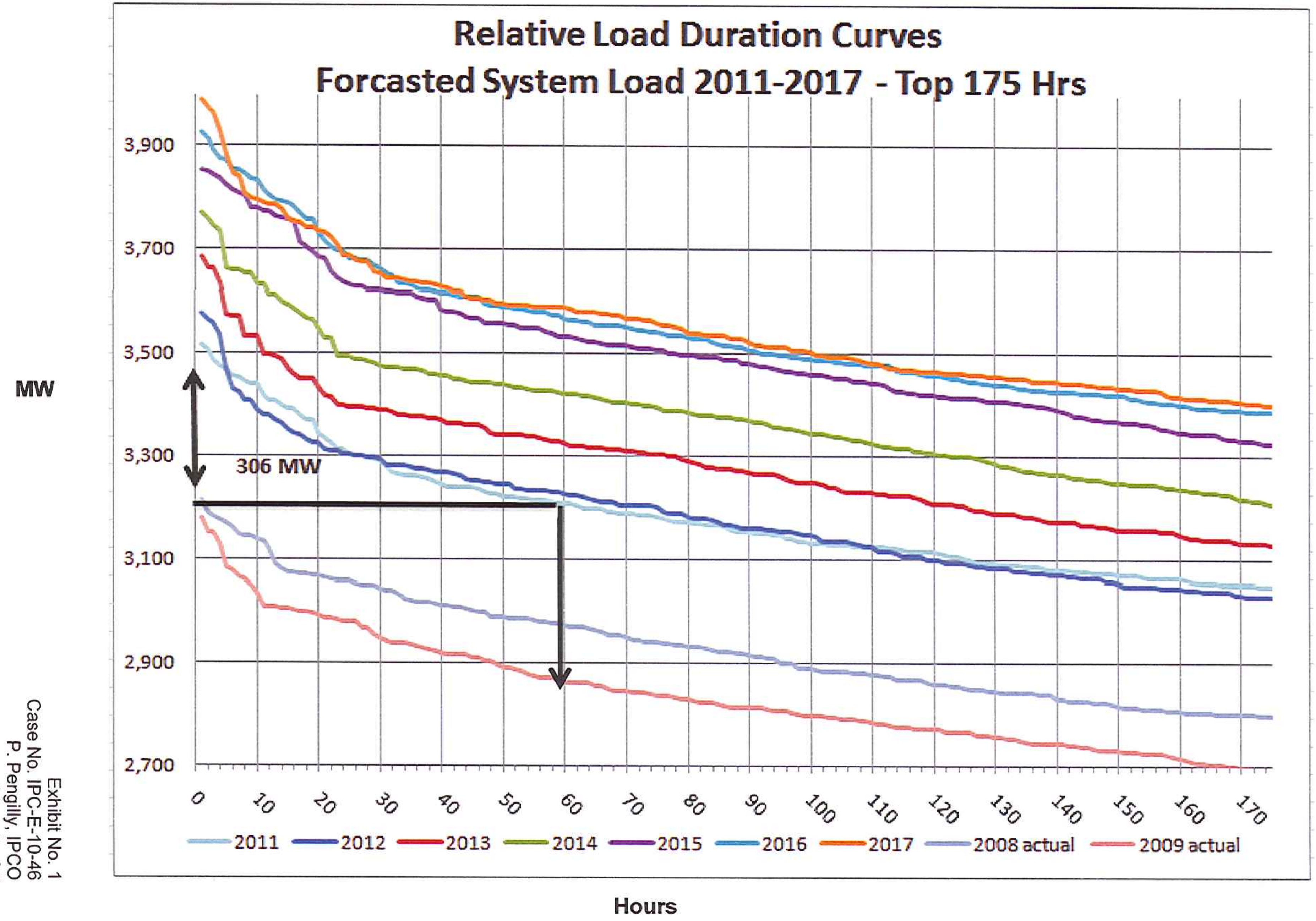


Theoretical 2011 Dispatch of 310 MW of Demand Response



Time	Forecasted MW	DR MW
1:00 PM	2936	
2:00 PM	3107	
3:00 PM	3265	100
4:00 PM	3393	180
5:00 PM	3455	273
6:00 PM	3508	310
7:00 PM	3515	250
8:00 PM	3446	177
9:00 PM	3303	60
10:00 PM	3175	

Load Duration Analysis



Analysis Results

A	B	C	D	E	F	G	H	I
Year	Peak Load (MW)	60th Hour Peak Load (MW)	Energy Efficiency (MW)	Existing and Committed Supply-Side Resources (MW)	L&R Balance Deficit Position w/o DR Programs (MW)	Achievable DR with 60 Hour Programs (MW)	Demand Response Target (MW)	Operational Target (MW)
2011	3,515	3,209	17	3,120	378	306	306	330
2012	3,430	3,227	34	3,241	155	203	155	310
2013	3,684	3,326	50	3,390	244	358	244	315
2014	3,770	3,422	65	3,386	319	348	319	315
2015	3,854	3,532	79	3,382	393	322	322	321
2016	3,925	3,566	93	3,379	453	359	359	351
2017	3,991	3,588	108	3,374	509	403	403	351
2018	4,056	3,650	122	3,368	566	406	406	351
2019	4,123	3,711	136	3,363	624	412	412	351
2020	4,190	3,827	150	3,358	682	363	363	351

Minimum

BEFORE THE

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CASE NO. IPC-E-10-46

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PENGILLY, DI
TESTIMONY

EXHIBIT NO. 2

Incentive Payment Structure Examples

125 Hp (100 kW)	Current Incentive Structure (100% Fixed & 0% Variable)			Proposed Incentive Structure (40% Fixed & 60% Variable)					
A	B	C	D	E	F	G	H	I	J
	Fixed	Fixed	Total	Fixed	Fixed	Variable	Total	% of Fixed	% of Current
	($/kW)	($/kWh)**	$	($/kW)	($/kWh)**	($/kWh)*	$	%	%
Incentives	$4.65	$0.031		$5.00	$0.0038	$0.35			
0 Events(0 hrs)	$930	$2,269	$3,200	$1,000	$278	$0	$1,278	100%	40%
3 Events(12 hrs)	$930	$2,269	$3,200	$1,000	$278	$420	$1,698	75%	53%
7 Events(28 hrs)	$930	$2,269	$3,200	$1,000	$278	$980	$2,258	57%	71%
15 Events (60 hrs)	$930	$2,269	$3,200	$1,000	$278	$2,100	$3,378	38%	106%

* kWh = kW demand x number of event hours

** based on an assumed average hours of operation of 732 hours