

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1653

In the Matter of

IDAHO POWER COMPANY,

Staff Evaluation of the Demand
Response Programs.

ORDER

DISPOSITION: STIPULATED SETTLEMENT AGREEMENT ADOPTED

I. INTRODUCTION

We opened this docket to address Idaho Power Company's request to change its Demand Response programs to reflect the company's projection that there will be no peak-hour capacity deficits, for which the DR programs were designed, until 2016. Following a number of workshops with parties, Idaho Power filed a motion to approve a stipulated settlement agreement resolving all contested issues. In this order, we grant Idaho Power's motion and adopt the parties' stipulated settlement agreement.

II. BACKGROUND

Idaho Power's three voluntary Demand Response (DR) programs were created to reduce the demand for energy during highest-use summer days, lessening demand for power when electricity demand is at its highest and is most expensive to produce or purchase. The three programs are:

- (1) A/C Cool Credit, for residential customers (Schedule 74): The A/C Cool Credit Program is an optional load control program for residential customers. On select summer afternoons, customers' air conditioners cycle on and off by means of a small "Cool Switch" installed outside near their A/C unit, reducing electrical demand during periods when usage often peaks.
- (2) Irrigation Peak Rewards, for agricultural customers (Schedule 23): The Peak Rewards Program reduces peak electrical load during hot summer afternoons by partnering with agricultural irrigation customers to reduce the demand on the electrical system when demand is highest. The program is optional, with three options for agricultural irrigation customers: an electric timer option, an automatic dispatch option, and a manual dispatch option. All three options include a combination of fixed and variable payments to customers, and operate

by preventing pumps from operating at participating service locations during periods when electricity demand is at its highest.

- (3) FlexPeak Management for commercial and industrial customers: The FlexPeak Management Program reduces power usage during periods of system peak demand. Commercial and industrial customers of Idaho Power are open to enroll in the program through EnerNOC. Participants agree to reduce a set amount of electricity consumption in response to Idaho Power's peak demand and other system needs. Participants receive recurring payments in return for enrolling in the network and being on call to respond to demand response dispatches. The FlexPeak Program is not offered under a tariff, because customers sign contracts directly with EnerNOC.

During the development of its 2013 Integrated Resource Plan, Idaho Power performed a Peak Load and Resource Balance analysis that projected that there will be no peak-hour capacity deficits until 2016.¹ As a result of the projected lack of peak-hour capacity deficits that would trigger use of its DR programs, Idaho Power filed for changes to the three DR programs before the Idaho Public Utilities Commission (IPUC)² and this Commission.³ Idaho Power requested authority to suspend the A/C Cool Credit and Irrigation Peak Rewards Programs, and informed the Commission of contract changes affecting the FlexPeak Management Program, in docket UM 1473.

In April 2013, the IPUC temporarily suspended the A/C Cool Credit and Irrigation Peak Rewards DR programs in Idaho for 2013, pending the outcome of a series of workshops the parties proposed to conduct to evaluate the DR programs for 2014 and beyond. Likewise, in a decision at a public meeting in April 2013, we approved Idaho Power's Advice No. 13-04, resulting in the temporary suspension of the A/C Cool Credit and Irrigation Peak Rewards Programs in Oregon for 2013.

This docket was opened to address proposed changes to Idaho Power's DR programs, and a prehearing conference was held on June 3, 2013. The parties to these proceedings and parallel proceedings taking place before the IPUC held a series of workshops. Based on those workshops, and subsequent settlement discussions, the parties have agreed to resolve all contested issues.

¹ Idaho Power explains that this reduction in forecasts for peak and average energy results from lingering effects of the recession, as well as the generating capacity contribution of the Langley Gulch combined cycle combustion turbine (CCCT), which became operational during the summer of 2012.

² See IPUC Case Nos. IPC-E-12-29 and IPC-E-13-04.

³ See Advice No. 13-04, proposing to suspend Idaho Power's residential and irrigation demand response programs for the summer of 2013. The company did not request suspension of its FlexPeak Management Program because the program is implemented through the company's contract with a third-party vendor that expires in February 2014. Idaho Power also proposed to work with stakeholders to reassess the programs, and to propose program changes to be implemented for 2014 and beyond. Commission Staff recommended that Idaho Power's Advice filing be allowed to go into effect May 1, 2013.

III. DISCUSSION

A. Stipulation

Idaho Power, Commission Staff, the Citizens' Utility Board of Oregon, EnerNOC, Inc, and Oregon Irrigation Pumpers Association filed a stipulated settlement agreement on November 15, 2013.⁴ The settlement agreement is attached as Appendix A to this order. In short, the stipulation maintains current DR programs even in years when Idaho Power does not anticipate peak-hour capacity deficits, so that the program infrastructure will be ready when capacity deficits return. To accomplish this, the stipulating parties intend for Idaho Power to offer revised programs to current program participants, and to leverage the investment in existing DR infrastructure, by using the demand response equipment for purposes beyond reducing peak loads.⁵

The stipulation provides that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, measured over 20 years, plus the corresponding deferred energy savings for 60 program hours. The parties calculate an annual value of \$16.7 million dollars for the entire DR program portfolio. The parties stipulate that the demand response value calculation will include this value even in years when the IRP shows no peak-hour capacity deficit. The annual value calculation will be updated with each IRP.

The parties propose changes to the DR programs intended to maintain the programs' current customers and infrastructure, while not promoting the programs during the current period of peak-load sufficiency. For the A/C Cool Credit Program, the parties propose that all residential customers who are presently enrolled in program will stay in it, and will receive a fixed incentive for at least three dispatch events each season. For the Irrigation Peak Rewards Program, participation will be limited to past service locations where an active, working load control device exists, and will provide a fixed incentive for a minimum of three dispatch events per season, with a variable incentive for dispatch events in addition to the three minimum events. Finally, the parties stipulate that Idaho Power will not actively seek to expand the FlexPeak Management Program, but will make the program available for current customers with either a fixed or a variable incentive structure for a minimum of three dispatch events per season.

The parties stipulate that Idaho Power will provide the parties a one-time letter report by October 15, 2014. The letter will compare 2012 information to best available 2014 information for the A/C Cool Credit and Irrigation Peak Rewards Programs. Additional reporting on these programs will be provided in the Annual DSM report provided to the Commission in March or April of each year.

⁴ The stipulating parties note that nearly 50 individuals representing 20 different organizations attended one or more workshops. As a group, workshop participants were able to reach consensus.

⁵ The parties provide the following examples of alternative uses for DR equipment: load following, non-spinning operating reserves, improved reliability during emergency situations, and flexibility to address delays in building new supply-side peaking resources.

To implement the proposed changes, the parties stipulate to the program modifications reflected in the company's revised tariff Schedule 23 (Irrigation Peak Rewards Program) and tariff Schedule 74 (Residential Air Conditioner Cycling Program), attached to the parties' stipulated settlement agreement.

B. Resolution

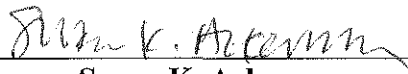
After reviewing the parties' proposed settlement agreement and supporting testimony, we conclude that the settlement agreement is in the public interest and we grant Idaho Power's motion to approve the stipulated settlement agreement. We find the settlement agreement to be a reasonable resolution for maintaining the current DR programs.

IV. ORDER

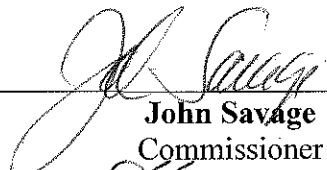
IT IS ORDERED that:

1. The stipulated settlement agreement between Idaho Power Company, the Staff of the Public Utility Commission of Oregon, the Citizens' Utility Board of Oregon, EnerNOC, Inc., and the Oregon Irrigation Pumpers Association, attached as Appendix A to this Order, is adopted.
2. Idaho Power Company is directed to file revised tariff Schedules 23 and 74, consistent with the terms of the stipulated settlement agreement, with an effective date of January 1, 2014.

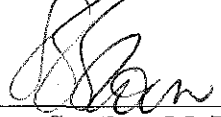
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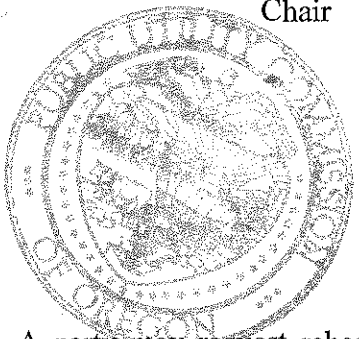
Susan K. Ackerman
 Chair



John Savage
 Commissioner



Stephen M. Bloom
 Commissioner



A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

**DEMAND RESPONSE PROGRAMS
SETTLEMENT AGREEMENT**

This Stipulated Settlement Agreement ("Settlement Agreement" or "Agreement") is entered into by and among the following participants to the demand response workshops: Idaho Power Company ("Idaho Power" or "Company"), the Staff of the Oregon Public Utility Commission ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Oregon Irrigation Pumpers Association ("OIPA"), and EnerNOC, Inc ("EnerNOC"). These entities and individuals are collectively referred to as the "Parties," and individually as a "Party," to the Agreement.

In late 2012, the Load and Resource Balance Analysis performed during the development of Idaho Power's 2013 Integrated Resource Plan showed no peak-hour capacity deficit until 2016. Idaho Power, therefore, filed for changes to its A/C Cool Credit program, Irrigation Peak Rewards program, and FlexPeak Management program (collectively "DR Programs") in Docket Nos. IPC-E-12-29 and IPC-E-13-04 in Idaho and Tariff Advice No. 13-04 and letter filed in UM 1473 in Oregon. Given that the Company also operates these programs in Oregon, the OPUC opened Docket No. UM 1653 in order to allow for the programs to be reviewed simultaneously in both Oregon and Idaho;

The A/C Cool Credit program and Irrigation Peak Rewards program were temporarily suspended in 2013, contract changes were made for the FlexPeak Management program, and the Parties attended a series of five workshops ("DR Workshops") - some by phone, others in person - in Idaho to address changes to the program for 2014 and beyond. The workshops

focused on how the Company includes demand response ("DR") in its Integrated Resource Plan ("IRP"), how it calculates cost-effectiveness of DR, the purpose of DR, Idaho Power's DR Programs and design, and settlement options for Idaho Power's DR Programs in 2014 and beyond. An additional workshop was held in Oregon for the benefit of Oregon stakeholders on October, 9, 2013 at which the results of the Idaho Workshops were reviewed and Parties discussed settlement;

As a result of the DR Workshops in Idaho and Oregon, the Parties reached agreement on certain aspects of Idaho Power's DR Programs.

NOW THEREFORE, in consideration of the mutual promises set forth herein, the sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. **Recitals.** The above-stated recitals are incorporated and made a part of this agreement to the same extent as if the recitals were set forth in full at this point.

2. **Public Interest.** This Agreement is a fair, just, and reasonable compromise of contested issues and its acceptance by the Oregon Public Utility Commission ("OPUC" or "Commission") would be in the public interest. The Agreement and its acceptance by the Commission will reasonably resolve the issues related to Idaho Power's DR Programs. Therefore, the Parties recommend that the Commission approve the Agreement and all of its terms and conditions without material change or condition pursuant to OAR 860-001-0350(7).

3. **Term.** 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 Idaho Power determines 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) Intervenor 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.

4. **Concepts.** The Parties agreed that the following overarching demand response concepts should guide Idaho Power's implementation of its DR Programs:

a. The Company must:

i. Use existing demand response resources when possible. This includes using, to the extent possible, current demand response equipment owned or available to Idaho Power and participating demand response customers, which currently represents approximately 400 megawatts ("MW") of potential demand response capacity.

ii. Include demand response offerings for all three customer classes (residential, commercial/industrial, and irrigation).

iii. Keep costs as low as possible.

iv. Reevaluate the value calculation as the IRP changes.

v. Take a long-term outlook. In order to have viable demand response programs in the long term, the programs must continue in the short term.

vi. Calculate the avoided cost used for demand response by using the avoided capacity cost of a 170 MW single cycle combustion turbine ("SCCT") multiplied by the

effective load carrying capacity ("ELCC"), measured over 20 years, plus the corresponding deferred energy savings for 60 program hours.

vii. Strive for consistency in dispatch requirements across DR Programs.

b. Uses for demand response beyond reducing peak loads may be: load following, non-spinning operating reserves, improved reliability during emergency situations, and flexibility to address delays in building new supply-side peaking resources. The workshop participants broke into small groups and discussed the possibilities of load following and reserves. Based upon these workgroup findings, Idaho Power will investigate the feasibility of using demand response as operating reserves and make a determination on feasibility by the end of the 3rd quarter of 2014. If Idaho Power determines that a pilot is feasible, it will create a proposal and work with Staff of the Idaho and Oregon Commissions and other interested stakeholders to develop a pilot program.

c. This Agreement applies only to Idaho Power's Demand Response Programs, and the concepts are not applicable to any of the Company's other DSM Programs.

5. **Resource Size.** The minimum size of the deferred resource used for the value calculation is 170 MW. It is appropriate for Idaho Power to incur and recover costs based on deferring this resource.

6. **Value.** The annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, measured over a period of 20 years, plus the corresponding deferred energy savings for 60 program hours. As of the date of this Agreement, the calculation leads to an annual value of \$16.7 million dollars for the entire DR Program

portfolio. The demand response value calculation shall include this value even in years when the IRP shows no peak-hour capacity deficit. The annual value calculation will be updated with each IRP based on changes that include, but are not limited to need, capital cost, or financial assumptions.

7. **A/C Cool Credit Program.** Idaho Power will implement the A/C Cool Credit program in a manner consistent with the tariff Schedule 81. A true and correct copy of the tariff is attached to this Agreement as Attachment 1 and is incorporated herein as if set forth in full at this point.

a. **Participants.** Participants are residential customers who are presently enrolled in the program and have a load control device installed. All paging devices installed at current participants' residences will be replaced with AMI-compatible devices, with the goal of completing replacement in time for the 2014 program season. Idaho Power will not actively promote the A/C Cool Credit program to solicit new participants through marketing tactics, but will accept new participants in this program who request to participate, regardless of whether they were previously participants in the program. In order to use existing equipment, Idaho Power will contact and attempt to recruit customers who move into a home that already has a load control device installed. If a customer enrolls in the A/C Cool Credit program at a residence that has a paging device, the load control device will be replaced with an AMI-compatible device. Idaho Power will also attempt to recruit participants who change residences to a location that does not have a load control device. An A/C Cool Credit program load control device will remain in place unless a customer requests the load control device be removed.

b. Program Details. The A/C Cool Credit program will be available from June 15 through August 15, Monday through Friday, excluding holidays. Each dispatch event will last no longer than four hours for each participant. Dispatch events will not occur more than 15 hours per week or 60 hours per season. In the event of a system emergency, demand response capacity from the A/C Cool Credit program will be available for immediate dispatch. Idaho Power will conduct a minimum of three dispatch events per season. No advanced notice to participants is required prior to executing each dispatch event. Participants, with advance notice, may opt out of two events per season.

c. Incentive. Participants will receive a fixed incentive of \$15 for the season, which will be issued as a credit on one or more of the participant's monthly bills for the program months.

d. Program Size. If participation in the A/C Cool Credit Program changes, Parties to this Agreement may file an application to modify the program as set forth in Section 3.

8. Irrigation Peak Rewards Program. Idaho Power will implement the Irrigation Peak Rewards program in a manner consistent with the tariff Schedule 23. A true and correct copy of the tariff is attached to this Agreement as Attachment 2 and is incorporated herein as if set forth in full at this point.

a. Participants. Participation is limited to past Irrigation Peak Rewards service locations where an active, working load control device exists as described in more detail in Attachment 2. The Company will not actively market the Irrigation Peak Rewards program as described in more detail in Attachment 2.

b. Program Details. The Irrigation Peak Rewards program will be available from June 15 through August 15, Monday through Saturday, from 1:00 p.m.-9:00 p.m., excluding holidays. Each dispatch event will last no longer than four hours for each participant. Dispatch events will not occur more than fifteen (15) hours per week or sixty (60) hours per season. In the event of a system emergency, demand response capacity from the Irrigation Peak Rewards program will be available for immediate dispatch. Idaho Power will conduct a minimum of three dispatch events per season. Participants with Interruption Option 3 will be given at least four hours advanced notification. There will be no notification required for participants with Interruption Options 1 and 2. Participants may opt out of an event. An opt-out fee of \$5.00 per kilowatt ("kW") per event will apply for the first three events and \$1.00 per kW per event for subsequent events. The opt-out fee will not exceed the total bill credit for the program season.

c. Incentive. Participants will receive a fixed incentive in the form of a demand and energy component which is approximately \$16 per kW per season, as set forth in more detail in Attachment 2. The fixed incentive shall include the above-mentioned three minimum dispatch events. If Idaho Power conducts dispatch events in the Irrigation Peak Rewards program in addition to the three minimum dispatch events, Participants will receive a variable incentive of \$0.148 (or \$0.198 for the 9:00 p.m. option) per kWh as set forth in more detail in Attachment 2, which, with the realization rate included, results in a cost to Idaho Power of approximately \$0.22 per kWh.

9. FlexPeak Management Program. Idaho Power will implement the Flex Peak Management program using the following design parameters.

a. Participants. Idaho Power will not actively seek to expand the capacity of the FlexPeak Program. Participants are industrial and large commercial customers.

b. Program Details. The FlexPeak Management program will be available from June 15 through August 15, Monday through Friday, from 2:00 p.m.-8:00 p.m., excluding holidays. Each dispatch event will last up to four hours per participant within the available program hours. Dispatch events will not occur more than 60 hours per season. In the event of a system emergency, demand response capacity from the FlexPeak Management program will be available. Idaho Power will conduct a minimum of three dispatch events per season. There will be two hours advanced notice to participants.

c. Incentive. A fixed and variable incentive structure may be appropriate, as long as the variable portion is low enough that it does not prevent the program from being dispatched. If a variable and fixed incentive structure is used, a minimum of three dispatch events will be included in the fixed incentive. The variable incentive will be paid to participants if Idaho Power conducts dispatch events in the FlexPeak Management program for more than the three minimum dispatch events.

10. Reporting. Idaho Power Company will provide a one-time, short letter report to Parties to this Agreement by October 15, 2014. The letter will compare 2012 information to best available, preliminary information for the 2014 program season for the A/C Cool Credit and Irrigation Peak Rewards programs. For both programs, the letter will compare the number of program participants, enrolled capacity, estimated load reduction in megawatts (MW), total program costs, and cost per MW of estimated load reduction. Additional reporting on these

programs will be provided, thereafter, in the Annual DSM report provided to the OPUC in March or April of each year.

11. **Confidentiality.** The Parties agree that this Stipulation represents a compromise in the positions of the parties. As provided in OAR 860-001-0350(3), without the written consent of all parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

12. **Commission Procedure.** The Stipulating Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission order. Nothing in this paragraph provides any Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

No Party shall be deemed to have agreed that any method, theory, or principle of regulation or cost recovery employed in arriving at this Agreement is appropriate for resolving any issues in any other proceeding in the future.

13. **Entire Agreement.** This Agreement and its attachments constitute the entire agreement between the Parties regarding the subject matter hereof. There are no oral or written understandings, representations, or commitments of any kind, express or implied, which are not expressly described in this Agreement.

14. **Severability.** If, after Commission approval of this entire Agreement without modification, any immaterial term or provision of this agreement that is found to be void, prohibited, or unenforceable by local, state, or federal law shall be ineffective only to the extent of such prohibition or unenforceability without invalidating the remaining provisions of this Agreement. Upon a determination that any material term or provision is void, prohibited, or unenforceable by local, state, or federal law, the Parties shall negotiate in good faith to modify this Agreement to maintain the original intent of the Parties without such material provision.

15. **No Third-Party Beneficiaries.** No right or obligation contained in this Agreement shall inure to the benefit of any person or entity not a Party or successor or assign of a Party.

16. **Counterparts.** This Agreement may be executed in counterparts and each signed counterpart shall constitute an original document.

[signature page follows]

ORDER NO.

13 482

DATED this ___ day of October 2013.

Idaho Power Company

Theresa Drake

By _____
Theresa Drake
Customer Relations & Energy Efficiency
Manager

**Oregon Public Utility Commission
Staff**

By _____
Johana Reimenschneider
Assistant Attorney General

Oregon Irrigation Pumpers Association, Inc.

By _____
Lynn Tominaga
Executive Director of OIPA

By _____
Melanie Gillette
Director, Regulatory Affairs

Citizens' Utility Board of Oregon

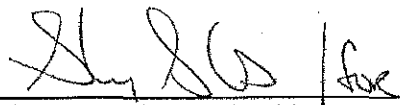
By _____
Catriona McCracken
General Counsel/Reg.Prog.Dir.

DATED this 21st day of October 2013.

Idaho Power Company

Oregon Public Utility Commission Staff

By _____
Theresa Drake
Customer Relations & Energy Efficiency
Manager

By  _____
Johana Reimenschneider
Assistant Attorney General

Oregon Irrigation Pumpers Association, Inc. EnerNOC, Inc.

By _____
Lynn Tominaga
Executive Director of OIPA

By _____
Melanie Gillette
Director, Regulatory Affairs

Citizens' Utility Board of Oregon

By _____
Catriona McCracken
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DATED this ___ day of October 2013.

Idaho Power Company

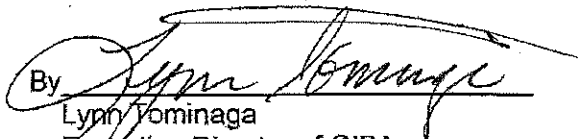
**Oregon Public Utility Commission
Staff**

By _____
Theresa Drake
Customer Relations & Energy Efficiency
Manager

By _____
Johana Reimenschneider
Assistant Attorney General

**Oregon Irrigation Pumpers Association,
Inc.**

EnerNOC, Inc.

By 
Lynn Vominaga
Executive Director of OIPA

By _____
Melanie Gillette
Director, Regulatory Affairs

Citizens' Utility Board of Oregon

By _____
Catriona McCracken
General Counsel/Reg. Prog. Dir.

ORDER NO.

13 482

DATED this ___ day of October 2013.

Idaho Power Company

**Oregon Public Utility Commission
Staff**

By _____
Theresa Drake
Customer Relations & Energy Efficiency
Manager

By _____
Johana Reimenschneider
Assistant Attorney General

Oregon Irrigation Pumpers Association, Inc.

EnerNOC, Inc.

By _____
Lynn Tominaga
Executive Director of OIPA

By Melanie Gillette
Melanie Gillette
Director, Regulatory Affairs

Citizens' Utility Board of Oregon

By _____
Catriona McCracken
General Counsel/Reg.Prog.Dir.

ORDER NO.

13 482

DATED this 30th day of October 2013.

Idaho Power Company

**Oregon Public Utility Commission
Staff**

By _____
Theresa Drake
Customer Relations & Energy Efficiency
Manager

By _____
Johana Reimenschneider
Assistant Attorney General


Oregon Irrigation Pumpers Association, Inc.

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By  _____
Catriona McCracken
General Counsel/Reg.Prog.Dir.