Office of the Secretary
Service Date
December 23, 2015

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2015 INTEGRATED RESOURCE PLAN	))))	**CASE NO. IPC-E-15-19** **ORDER NO. 33441**

On June 30, 2015, Idaho Power Company filed its 2015 Integrated Resource Plan (IRP) to explain how it expects to meet its customers' energy needs for the next 20 years. After the Company filed its IRP, the Commission invited interested persons to submit comments in the case. *See* Order No. 33346. The Commission Staff, Idaho Conservation League (ICL), Sierra Club, Snake River Alliance (SRA), and numerous individuals filed comments, and the Company filed a reply.[1] Having reviewed this record, we find that the Company's 2015 IRP discusses the subjects required by the Commission's prior Orders. We thus acknowledge that the 2015 IRP has been filed. Our decision is further explained below.

THE IRP PROCESS

An IRP is a status report on the utility's ongoing, changing plans to adequately and reliably serve its customers at the lowest system cost and least risk over the next 20 years. The report informs the Commission and the public about the utility's plans, and is similar to an accounting balance sheet; i.e., it is a "freeze frame" look at the utility's fluid, resource planning process. *See* Order No. 22299. The IRP is meant to demonstrate to the public that the Company has prepared for, and considered, many scenarios through a reasonable planning process. The Commission thus expects a utility to have vigorously tested the IRP's assumptions to ensure the IRP accurately reflects changing markets and customer demand.

The Company must update its IRP every two years and allow the public to participate in the development of the IRP. *See id.* and Order No. 25260. The final IRP must include the subjects required by the Commission's prior Orders, including Order Nos. 22299 and 25260. In summary, the final IRP should explain the Company's present load/resource position, expected responses to possible future events, and the role of conservation in those responses. It also

[1] On October 21, 2015, the Company filed a letter and replaced page 9 of its reply comments to clarify it had not changed its policy to pursue all cost-effective energy efficiency. The Company explained it "will continue to pursue all cost-effective energy efficiency. Idaho Power does not and has not viewed the achievable potential as a 'ceiling' for the pursuit of cost-effective energy savings and will continue to pursue energy efficiency beyond the achievable potential when possible."

should discuss "any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand- and supply-side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold." *See* Order No. 22299. The IRP should separately address:

- "Existing resource stack," by identifying all existing power supply resources;

- "Load forecast," by discussing expected 20-year load growth scenarios for retail markets and for the federal wholesale market including "requirements" customers, firm sales, and economy (spot) sales. This section should be a short synopsis of the utility's present load condition, expectations, and level of confidence; and

- "Additional resource menu," by describing the utility's plan for meeting all potential jurisdictional load over the 20-year planning period, with references to expected costs, reliability, and risks inherent in the range of credible future scenarios.

Id.

If the Commission finds the IRP discusses these required subjects, then it will enter an Order acknowledging that the Company filed the IRP. By acknowledging the IRP, the Commission is acknowledging the Company's ongoing planning process, not the conclusions or results reached through that process.

THE 2015 IRP

A. Overview

Idaho Power's 2015 IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and an action plan that details how the Company intends to implement the IRP. The IRP filing consists of four documents: (1) the 2015 IRP; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2014 Annual Report; and (4) Appendix C – Technical Appendix.

In developing the IRP, the Company obtained public input by working with an Integrated Resource Plan Advisory Council (IRPAC) consisting of various stakeholders. The Company held 12 IRPAC meetings, and also public working group meetings to discuss energy efficiency, solar resources, and coal resources. The Company presented the IRP to the public at different community meetings, to civic groups, and through seminars as requested.

B. IRP Goals and Assumptions

With the 2015 IRP, the Company attempted to: (1) identify sufficient resources to reliably serve growing energy demands over the next 20 years; (2) ensure the Company's preferred portfolio of resources balances cost, risk, and environmental concerns; (3) treat supply-side resources and demand-side measures equally; and (4) involve the public in the planning process. The Company noted that the 2015 IRP makes many assumptions about what will occur over the next 20 years, including that: (1) the Company will continue to be responsible for acquiring sufficient resources to serve its customers and operate as a vertically-integrated utility; and (2) the Company will add about 196,000 customers and increase its load by 1.2% per year for average energy demand and 1.5% per year for peak-hour demand. The Company plans to meet this increased demand by combining demand-side measures with additional Company-owned resources.

C. Preferred Resource Portfolio

With the 2015 IRP, the Company selected a preferred resource portfolio that assumes the Boardman to Hemingway (B2H) transmission line will be completed and the North Valmy power plant will be closed in 2025, and that the Company will add 60 megawatts (MW) of demand response and 20 MW of ice-based thermal energy storage in 2030, and a 300 MW combined-cycle combustion turbine in 2031. The Company stated it needs no more resources before North Valmy closes in 2025, and that the Company's ability to serve customers with existing resources before shields the preferred resource portfolio from risks of uncertainty surrounding: (1) planned, but yet-to-be-built, solar generation under the Public Utility Regulatory Policies Act of 1978 (PURPA); (2) the impact of the federal Environmental Protection Agency's (EPA's) proposed regulations under Section 111(d) of the Clean Air Act (CAA); (3) the B2H line's completion date; and (4) retirement planning for North Valmy. The Company notes, however, that even with this uncertainty it is prudent to complete B2H and retire North Valmy early. The Company stated it can still adjust the timing of those actions as warranted.

D. Action Plan

The Company's short-term action plan for 2015 to 2018 addresses preferred resource portfolio items like B2H permitting and planning, and collaborating with North Valmy's co-owner, NV Energy, on planning for North Valmy's closure. The action plan also discusses: permitting and planning for the Gateway West transmission line; evaluating how EPA's regulations may impact fossil fuel plants; pursuing cost-effective energy efficiency; amending a Federal Energy Regulatory Commission license to adjust for the 50 MW Shoshone Falls project expansion, and completing up to a 4 MW upgrade by 2019; completing selective catalytic reduction (SCR) retrofits for Jim Bridger Units 3 and 4; and evaluating the economics of SCR retrofits for Jim Bridger Units 1 and 2.

E. Response to Order No. 32980

In the Company's 2013 IRP case, the Commission ordered the Company to ensure its future IRPs account for national developments that could impact resource planning. *See* Order No. 32980. Consistent with that Order, the Company's 2015 IRP accounts for the federal EPA's regulations implementing Section 111(d) of the CAA.

The Commission also ordered the Company to collaborate with stakeholders about using energy efficiency as a resource. In response, the Company notes that it relies on its Energy Efficiency Advisory Group for stakeholder input on energy efficiency and demand response matters. The Company stated that it held two Energy Efficiency Working Group meetings for stakeholders and that these meetings led the Company to continue investigating energy efficiency-related transmission and distribution benefits. The Company also noted that it updated the IRPAC on its efforts, and will evaluate whether energy efficiency programs and measures can defer growth-related transmission and distribution investments.

The Commission also directed the Company to be actively involved with North Valmy and promptly advise the Commission of developments that could impact the Company's reliance on that resource. Consistent with this aspect of the Order, the Company explained that it and NV Energy have been discussing North Valmy's future. The Company noted that balancing the potential impact of EPA's carbon regulations with the economic impact to customers and their service needs is an important part of the Valmy discussions.

THE COMMENTS

Commission Staff, ICL, Sierra Club, SRA, and 42 individual customers commented on the 2015 IRP. Commenters observed that the 2015 IRP is an improvement over prior IRPs. Nevertheless, some concerns persist, and commenters thus offered suggestions for improving future IRPs. The Company filed a reply that addressed some of these issues. The comments and the reply are summarized below.

A. Customer Comments

Customers commented on a variety of subjects. For example, some customers applauded the Company's efforts to lessen reliance on coal by proposing to retire both North Valmy coal plants by 2025. Others, however, urged the Company to close North Valmy Unit 1 even sooner, by 2019, to better protect the environment and potentially save customers $75 million over the next 20 years. Some customers also suggested that the Company should decommission the Jim Bridger coal plant instead of retrofitting it with expensive pollution controls.

One customer questioned the Company's plan to upgrade the Shoshone Falls hydro facility in 2019 when the Company needs no more resources until 2025. The customer suggested that the Company's next IRP should forecast both solar PV and battery storage in conjunction with the natural gas forecast, evaluate more types of battery storage, better account for future growth in the use of electric vehicles, and consider a residential DSM program with meters that display real-time data on energy use, cost, and CO2.

Some customers expressed concern about the limitation on PURPA power contracts set forth in Case No. IPC-E-15-01.[2] One customer recommended establishing a competitive renewable energy procurement mechanism, like California's Renewable Auction Mechanism, to meet future load. Another customer expressed concern that the Company's IRP and potential reliance on an Energy Imbalance Market (EIM)[3] to meet load could subject Idaho to brown-outs,

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[2] In IPC-E-15-01, the Commission reduced the length of certain PURPA contracts from 20 years to two years. The Commission found the utilities do not need additional generating capacity, that PURPA and non-PURPA generation exceeds Idaho Power's and Rocky Mountain's minimum average loads, and that given the undisputed evidence that avoided costs are decreasing, retaining fixed rates for 20 years would violate PURPA's Section 210(b) mandate that avoided costs rates shall not exceed a utility's avoided costs. *See* Order Nos. 33357 and 33419. The Commission's Orders were not appealed.

[3] An EIM is a means of supplying and dispatching electricity to balance generation and load fluctuations by aggregating the variability of generation and load over multiple balancing authority areas. *See* Order No. 32980 at 14.

significant primary utility voltage loss, and enable the Company and other utilities to artificially inflate demand by restricting power supply available to the market.

One customer believes the Company inflated the expense of portfolios containing pumped-storage hydropower projects. The customer criticized the Company for assuming those projects would cost $5,000 per kW instead of the more realistic, $2,000-$2,500 per kW used by other utilities. The customer suggested that using the lesser costs would ensure the Company's future IRPs more fairly consider portfolios that have pumped-storage projects.

Another customer claimed the Company overestimated the cost of solar photovoltaic (PV) resources. The customer noted that the IRP's lowest cost for solar PV is $105 per MWh over 30 years when far less expensive solar PV exists in Idaho. In particular, the customer observed that the Company buys solar power from First Wind and Grand View at prices ranging from $63-$74 per MWh over 20 years. In reply to this and similar comments (for example, from the Sierra Club), the Company explained that solar cost estimates rely on a third-party report on resource costs. The Company noted that the costs of solar PV resources, as well as other resources, was extensively discussed with the IRPAC and public participants and will continue to receive considerable attention during the development of the 2017 IRP to properly reflect changes in the PV solar market.

B. Staff Comments

Staff stated that the 2015 IRP complies with the Commission's Orders and is an improvement over the 2013 IRP. Staff thus recommended that the Commission acknowledge the Company's 2015 IRP. Staff particularly supported the Company's development and modeling of a variety of portfolios that include many resource retirement and replacement scenarios, alternatives to B2H, and expanded energy efficiency and demand response resources. Staff also supported the Company's proposed pilot projects including ice-based thermal energy storage, community solar, and solar PV to address distribution feeder loss. Staff noted that the Company also modeled CAA Section 111(d) compliance possibilities, stochastic risk, and at the request of stakeholders provided a year-to-year price variability risk assessment for each portfolio, as well as a tipping point analysis to evaluate how declining capital costs for utility-scale solar PV and pumped hydro generation affect total portfolio costs. Staff opined that the Company performed extensive analyses, gave reasonably equal consideration to supply and demand-side resources, and provided acceptable opportunities for public input.

While Staff recommended that the Commission acknowledge the IRP, Staff also suggested that the Company consider the following four issues when developing future IRPs.

1. Screen Cost Effectiveness with the Utility Cost Test. Staff reiterated its recommendation from prior cases that the Company should use the Utility Cost Test (UCT) and not the Total Resource Cost test (TRC) to screen energy efficiency potential for cost-effectiveness.[4] In reply, the Company noted that the Commission has never precluded it from using the TRC, and has stated that "the Company may (but need not exclusively) emphasize the UCT" (*see* Order No. 33365 at 9-10). Further, using the TRC is consistent with the Memorandum of Understanding that Staff and Idaho's IOUs signed in 2010, and with the orders of the Oregon PUC. *See* OPUC Order No. 94-590, requiring program administrators to use the TRC.

2. Simultaneously Model Demand-Side and Supply-Side Resources. Staff stated the Company could better incorporate energy efficiency into the IRP by modeling demand-side resources simultaneously with supply-side resources, as do PacifiCorp, Avista, the Northwest Power and Conservation Council, and Puget Sound Energy. In reply, the Company explained that it commits all achievable energy efficiency potential to every portfolio regardless of need, and thus gives preferential treatment to energy efficiency over supply-side resources. In fact, the Company does not identify whether it needs additional supply-side resources until after it applies all cost-effective energy efficiency to the load and resource balance. The Company stated that, despite what other utilities may do, the Company's method is consistent with Idaho policy and Commission Orders requiring utilities to pursue all cost-effective energy efficiency.

3. Design Portfolios to Mitigate Risk. Staff observed that the Company designed resource portfolios based on stakeholder preferences. Staff recommended that the Company's future IRPs design resource portfolios by forecasting specific scenarios and then strategically selecting resource portfolios to mitigate the most significant risks of those scenarios.

4. Preferred Portfolio Selection. Staff (along with the ICL, SRA, and individual customers as noted above) expressed concern that the Company may have ignored its own

[4] The TRC and UCT test a DSM program's cost-effectiveness from different perspectives. In summary, the TRC compares program administrator costs and customer costs to utility resource savings, and assesses whether the total cost of energy in a utility's service territory will decrease. The UCT, on the other hand, compares program administrator costs to supply-side resource costs, and assesses whether utility bills will increase. Under both tests, a program or measure is deemed cost-effective if it has a benefit/cost ratio above 1.0.

quantitative analysis when choosing the preferred portfolio. In particular, Staff noted that the Company's preferred portfolio, which contemplates closing North Valmy Unit 1 in 2025, is more costly and risky than portfolios that would close North Valmy Unit 1 in 2019. In reply, the Company explained that closing North Valmy Unit 1 in 2019 would increase annual depreciation expense by $6 million more than the expense would be if North Valmy Unit 1 were to close in 2025. Moreover, customer rate increases due to capital additions to keep North Valmy Unit 1 operating would accelerate if the plant were to close in 2019 instead of 2025. When added to the uncertainty in the assumptions used for the different portfolios, this need for immediate additional cost recovery from customers led the Company to determine it would be imprudent and unreasonable to close North Valmy Unit 1 by 2019. The Company believes its preferred portfolio is lower risk than a portfolio with a 2019 closure, and that it promotes near-term rate stability and is a reasonable glide path to reducing coal generation on the Company's system.

C. ICL Comments

ICL noted the 2015 IRP contains a "robust consideration of future coal plant operations, uses better data for future supply-side options, and considers a range of compliance options for the [CAA] 111(d) rule. . . ." ICL also commended the Company for working "collaboratively with stakeholders and thinking creatively about analytical inputs and methods." With regard to coal unit analysis, ICL stated that the Company developed a "methodology to consider this issue that should be a best practice for utilities around the country." And, for the performance and cost of solar power, ICL noted that the Company "worked with stakeholders to develop a robust method for assigning a peak capacity contribution for solar." ICL recommended, however, that the Company take additional actions on the following subjects:

1. Solar Performance. ICL suggested the Company reconsider its use of a 90% exceedance factor when correlating five-minute generation profiles with specific high-load hours for purposes of assigning a peak capacity contribution for solar. While ICL acknowledged that a 90% exceedance factor aligns with other peak-hour forecasts, it questions whether "planning to be wrong 90% of the time is an appropriate metric as opposed to a 70% factor used for energy planning."

2. CAA 111(d) Compliance Options. ICL maintained that the Company should update its analysis of CAA 111(d) compliance options to reflect that the EPA has issued a final rule. The Company also should explore how to account for the full cost of carbon pollution

beyond the cost of pollution controls, including impacts to the hydroelectric system and energy demands due to changes in rainfall and temperature patterns, the public health due to hotter drier weather, and the potential for wildfires that could threaten remote generation or transmission lines. *See also* SRA Comments (requesting the Commission direct the Company to address the social cost of carbon in the 2017 IRP).

3. <u>Energy Efficiency Potential</u>. While ICL agreed with the Company's using of a third-party efficiency study to forecast technical, cost-effective, and achievable energy efficiency potential, ICL disagreed with the level of achievable potential that the Company used to set the load-and-resource balance. ICL noted that the level of achievable potential is less than the cost-effective potential because achievable potential is calculated based on assumptions on market maturity, customer preferences, and expected program participation. ICL stated that the Company may be able to influence these assumptions and exceed achievable potential by improving program design, marketing, and customer engagement. For the 2017 IRP, ICL urged the Company to identify and strive to acquire an optimal amount of efficiency between the achievable and cost-effective levels. ICL suggested that if the selected portfolio includes additional efficiency beyond the achievable level, then the Company can work with the EEAG to identify the hurdles assumed to limit uptake and devise strategies to acquire the resource.

In reply, the Company noted that not all cost-effective energy efficiency is achievable, and that the achievable potential as determined by its third-party consultant is the upper limit for cost-effective energy efficiency savings. The Company subsequently clarified, however, that despite this comment, the Company has not changed is policies and "will continue to pursue all cost-effective energy efficiency." The Company "does not and has not viewed the achievable potential as a 'ceiling' for the pursuit of cost-effective savings and will continue to pursue energy efficiency beyond the achievable potential when possible." *See* Company letter filed October 21, 2015. The Company also stated that it strives to continuously improve its program design and operation while keeping costs in check. Lastly, the Company believes that creating a separate multi-year implementation plan, as suggested by ICL, is unnecessary and would create an additional administrative burden. The Company explained that its current planning and reporting on DSM activities is comprehensive and adequate and involves regular updates to the EEAG and the filing of any annual DSM report.

D. Sierra Club Comments

The Sierra Club stated that the 2015 IRP is the "latest step along a path of continuous improvement in the Company's recent resource planning activities," and "is the best IRP yet." Sierra Club Comments at 1-2. However, Sierra Club believes changes are needed in how the IRP treats transmission and distribution (T&D) costs. Sierra Club expects that distributed generation (both solar PV and natural gas-fired reciprocating generators) and enhanced information system enabled demand-management opportunities can reduce T&D expenditures; however, the Company's AURORA cost model does not identify these potential T&D cost savings. Sierra Club believes that updating the IRP analysis to include T&D costs can reveal even more cost-effective resource alternatives than the IRP currently considers. Sierra Club thus asked the Commission to direct the Company to improve the 2017 IRP by: (a) expanding the scope of future cost analyses to consider all relevant T&D expenditures, not just generation costs; and (b) making a concerted effort to ensure in the 2017 IRP solar PV costs are more fairly estimated.

E. SRA Comments

The SRA commended the Company for its IRPAC planning process being "increasingly transparent and accessible to the public," and recommended the Commission accept the 2015 IRP. However, SRA noted that the Company has more than enough supply-side resources, which has unfortunately led the Company to curtail its demand response programs. SRA expressed concern that emphasizing thermal power production resources while interrupting demand response resources sends the wrong message to customers and raises questions about the Company's commitment to reducing its greenhouse gas emissions.

SRA specifically requested that the Company take action on the following subjects:

1. <u>IRPAC Process</u>. SRA would like the Company to broaden public participation by more visibly publicizing IRPAC meetings and exploring other methods to engage with stakeholders, such as periodically holding evening meetings so customers and others can have input at various stages of the IRP's development.

2. <u>Pilot Projects</u>. SRA appreciates that the IRP proposes three pilot projects: solar PV to address distribution feeder voltage loss; ice-based thermal energy storage; and community solar. The Company has promised, and SRA asked the Commission to ensure, that the Company's 2017 IRP will report on the Company's early experiences with solar PV to address

distribution feeder voltage loss. SRA also urged the Commission to support the Company's proposed ice-based thermal energy storage pilot project. Lastly, SRA asked the Commission to hold the Company accountable for implementing its community solar pilot projects so all customers are assured the Company is committed to pursuing solar power as part of its supply-side portfolio.

3. B2H Transmission Project. SRA does not oppose the Company including B2H in its preferred portfolio, and commended the Company for sharing information on the B2H process. But given the gravity that a B2H delay could have on the balance of the Company's preferred portfolio and the potential for increased CO2 emissions, such as with new natural gas projects, SRA urged the Commission to require the Company to submit quarterly public reports on the status of B2H project.

4. Solar Power. SRA disagreed with the Company's and Commission's positions on utility-scale solar power and the Commission's Order No. 33357 in Case No. IPC-E-15-01. SRA believes the Commission should direct the Company to ensure the levels of solar power production called for in the Idaho Energy Plan. SRA noted that Idaho has some of the most favorable solar potential in the nation, but Idaho is not contributing even a MW of solar power to the western grid. SRA asked the Commission to reiterate that the 2012 Idaho Energy Plan envisions robust development of solar energy, and that utilities should plan for and encourage solar power development in their service territories. Or, if the Commission disagrees, then it should provide guidance to the Legislature in preparing to update the Energy Plan.

5. Electric Vehicle Projections. SRA believes the Company inaccurately estimates the number of licensed electric vehicles in its territory. SRA thus suggested that the Commission direct the Company to frequently update its electric vehicle projections and the implication for the Company's load forecasts.

6. EIM Participation. SRA would like the Company to supply additional information on its plans for possibly participating in a western EIM. In reply, the Company noted that in September 2015 it announced its withdrawal from Northwest Power Pool's effort to establish an EIM, and its corresponding plans to study the costs and benefits of participating in the Cal-ISO EIM. The Company stated that it expects to finalize its decision about the Cal-ISO EIM in 2016. However, the Company believes a detailed analysis of EIM participation is outside the scope of

the IRP, which addresses the adequacy of system resources, although a limited reporting of high-level EIM developments would be appropriate for the 2017 IRP.

FINDINGS AND DISCUSSION

Idaho Power is an electrical corporation and public utility. *See Idaho Code* §§ 61-118, -119, and -129. The Commission has jurisdiction over the Company and the issues in this case under Title 61 of the Idaho Code, including *Idaho Code* § 61-501. Having reviewed the record in this case, we find that the Company's 2015 IRP satisfies the requirements set forth in the Commission's prior Orders. We thus acknowledge that the Company has filed the 2015 IRP. In doing so, we reiterate that an IRP is a working document that incorporates many assumptions and projections at a specific point in time. It is a plan, not a blueprint, and by issuing this Order we merely acknowledge *the Company's ongoing planning process*, not the conclusions or results reached through that process. With this Order, the Commission is not approving the IRP or any resource acquisitions referenced in it, endorsing any particular element in it, or opining on the prudency of the Company's decision to select its preferred resource portfolio. The appropriate place to determine the prudence of the IRP or the Company's decision to follow or not follow it, and the validation of predicted performance under the IRP, will be a general rate case or another proceeding in which the issue is noticed.

The Commission appreciates the Company's collaboration with stakeholders in developing the 2015 IRP, and the numerous well-written comments received in this case. We encourage the Company to continue to increase stakeholder involvement in the IRP process. Stakeholders offered many laudatory comments about the 2015 IRP. And as the Company develops the 2017 IRP, we believe it is appropriate for the Company to continue to use the IRPAC meetings and other outreach opportunities to further explore issues raised in this case. For example, in the interest of transparency, we encourage the Company to more clearly explain to stakeholders why the Company chose Portfolio 6(b) and its 2025 closure of North Valmy Unit 1 as the preferred portfolio, and why the Company believes it is imprudent to select Portfolio 9 or another portfolio that would close Unit 1 in 2019. We also believe it would be proper for the Company to further explore whether its IRP could more effectively incorporate energy efficiency by using a model that is similar to those used by PacifiCorp, Avista, the Northwest Power and Conservation Council, or Puget Sound Energy. It would also be appropriate for the Company to update stakeholders about the status of B2H, participation in an EIM, solar PV cost estimates, and the penetration of electric vehicles and their impact on the Company's load as the 2017 IRP is being developed.

ORDER

IT IS HEREBY ORDERED that the filing of the Company's 2015 IRP is acknowledged.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 23rd day of December 2015.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

Kristine Raper

KRISTINE RAPER, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

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