ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 17, 2014

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __Upon Commission Approval__

DATE: March 7, 2014

TO: Public Utility Commission

FROM: Brittany Andrus

THROUGH: Jason Eisdorfer, Maury Galbraith, and Aster Adams

SUBJECT: IDAHO POWER COMPANY: (Docket No. LC 58) Acknowledgement of 2013 Integrated Resource Plan.

STAFF RECOMMENDATION:

Staff recommends the Commission acknowledge Idaho Power Company's (Idaho Power or Company) 2013 Integrated Resource Plan (IRP) with revised action items, as reflected in Attachment B. The Company's proposed action plan can be found in Attachment A.

DISCUSSION:

Idaho Power filed its 2013 IRP on June 28, 2013. On October 8, 2013, Staff and Citizens' Utility Board of Oregon (CUB), Oregon Department of Energy (ODOE), and Renewable Northwest Project (RNP), filed initial comments regarding Idaho Power's 2013 IRP. On the same date, Staff received comments from citizen John Weber of Boise, Idaho, and added them to the record. The Company filed reply comments on November 8, 2013. A public workshop with the Public Utility Commission was held on December 2, 2013. Final comments by Staff, CUB, ODOE and RNP were filed January 15, 2014, and the Company's final comments were filed February 10, 2014.

The Company's filing included the IRP and three appendices. The 2013 IRP references two additional documents that were filed in February 2013 as part of the 2011 IRP Update (LC 53): *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (coal study),[1] and the *Wind Integration Study Report.*[2]

[1] Idaho Power 2013 IRP, p. 9.
[2] Id., p. 16.

In this report, Staff discusses the comments by the parties and the Company, referencing the near-term action plan (two to four years[3]), out-year action plan items, and other IRP issues. The original IRP action plan can be found in Attachment A, and Staff's proposed revisions to the action plan in Attachment B.

Coal Plant Investments

IRP Guideline 8, as modified by Order No. 08-339, contains four requirements related to environmental costs. Under this guideline, the utility must model a base case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility must also develop several compliance scenarios ranging from the present CO_2 level to the upper reaches of credible proposals by governing entities. Then, the utility must estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) cost and risk measures of its preferred portfolio and alternate portfolios. Guideline 8 directs the utility to identify the CO_2 emission cost adder level that triggers the selection of a portfolio that is substantially different from the preferred portfolio. In addition, Guideline 8 requires utilities develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law. OPUC Order No. 10-066.

CUB identifies flaws in the Company's analysis with regard to disparities between the life of the controls and the useful life of the plant. CUB proposes an analytical blue print—a Boardman-style phase-out that is summarized as follows: (1) analyze the cost of the potential pollution controls under different scenarios; (2) compare the broader range of pollution control scenarios to alternative investments, such as repowering with natural gas, building a CCCT, or relying on front office transactions; (3) investigate whether there is a plausible scenario for a phase-out that is at a lower cost than either of the two options; and (4) in the case of a plant that has a depreciable life less than the 20-year assumed useful life of the pollution control investments, analyze whether committing to close a plant at the end of its depreciable life would reduce pollution control costs.

Staff supports coal plant analysis that follows CUB's blue print outlined above. Staff is concerned that the coal analyses presented by the Company do not sufficiently consider alternative dates for pollution control equipment, shut down or other alternatives such as gas conversion. Staff is convinced that without this type of analysis, the coal plant analysis does not yield robust results with the best combination of costs and risks. Staff recommends that the Commission direct the Company to work with the IRP Advisory

[3] Order No. 07-047, Appendix A, IRP Guideline 4(n), p. 5.

Council, CUB and other interested parties to discuss the specific coal plant analyses that will be performed as part of the Company's next IRP filing.

Action Plan Item: Jim Bridger Units 3 and 4: Commit to the installation of selective catalytic reduction emission-control technology, 2013.

Background

Idaho Power has a one third interest in the four units at the coal-fired Jim Bridger plant in Wyoming, which provides 771 MW of capacity to the Company. PacifiCorp is the majority owner, and the plant operator. Idaho Power's action plan includes installing selective catalytic reduction (SCR) pollution control equipment at Bridger Units 3 and 4 by the end of 2015 and 2016, respectively, as required by the State of Wyoming and the U.S. Environmental Protection Agency. The SCR investment is significant; Idaho Power's application for a Certificate of Public Convenience and Necessity at the Idaho Public Utilities Commission stated that Idaho Power's total cost before AFUDC would be approximately $118 million.[4]

Parties' Positions

CUB recommends not acknowledging the Jim Bridger Units 3 and 4 pollution control investments because of flaws in the Company's analysis with regard to disparities between the life of the controls and the useful life of the plant. CUB also notes shortcomings in Idaho Power's coal study because a "Boardman-style phase-out" was not sufficiently addressed.[5] CUB recommends a "blue print" for coal analysis that is consistent with its final comments in LC 57,[6] the PacifiCorp 2013 IRP.

RNP recommends the Commission not acknowledge pollution control investments at Jim Bridger 3 and 4, because investing in coal units is generally not reasonable under scenarios with low natural gas costs and/or stringent CO_2 regulation, and because of the lack of analysis regarding alternative compliance proposals.

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[4] Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4, Idaho Public Utilities Commission, Case No. IPC-E-13-16, p. 7. "…the total cost of the Project before Allowance for Funds Used During Construction ("AFUDC") is $353,843,886. ldaho Power's share of that amount, the "Project Cost," is one-third, or $117,947,962, comprised of a $57,649,113 investment in Jim Bridger Unit 3 and a $60,298,849 investment in Jim Bridger Unit 4, before AFUDC."
[5] CUB Final Comments, p. 4.
[6] Id., p. 5.

Idaho Power Response

Idaho Power states that its Coal Study analyzed three alternatives to the SCRs, and the results demonstrate that the investment in the SCRs at Jim Bridger Units 3 and 4 is the least cost/least risk option. The analysis, "considered numerous existing and emerging regulations." Idaho Power asserts that, "these regulations encompass all of the known and reasonably anticipated regulations that may materially impact the operation of the Company's coal units."[7] In response to Staff's comments that Idaho Power should engage with Staff and stakeholders to ensure that appropriate scenarios are included, the Company states that, "Staff's recommendation is reasonable and the Company agrees to engage Staff and stakeholders when designing analysis related to future coal plant investments."[8]

Staff Position and Recommendation

Staff reviewed Idaho Power's coal study when it was filed with the 2011 IRP Update, Docket No. LC 53. In its final comments in LC 58, Staff explained that while Idaho Power did analyze three scenarios for Jim Bridger Units 3 and 4, Staff expected the Company to consider other alternatives, such as installation of reduced environmental controls in exchange for an early shut down based on tradeoffs as quantified by tons of emissions and the respective changes in capital costs. In addition to reviewing the coal study, Staff performed its own sensitivity analysis on the economics of the capital investment in Jim Bridger Units 3 and 4 under different carbon and gas prices. Extensive analysis has also been completed for the Jim Bridger Units 3 and 4 SCR investment in PacifiCorp's IRP (LC 57). Staff's conclusion based on the results of these analyses is that the SCR investment in these two units is reasonable.

Staff recommends the Commission acknowledge the following action plan item:

> *Jim Bridger Units 3 and 4: Commit to the installation of selective catalytic reduction emission-control technology, 2013.*

Action Plan Item: North Valmy Unit 1: Commit to the installation of dry sorbent injection emission-control technology, 2013.

Background

Idaho Power's share of the North Valmy coal-fired plant is 284 MW, or 50 percent. NV Energy owns the other 50 percent, and operates the plant. The Dry Sorbent

[7] Idaho Power Reply Comments, p. 6.
[8] Idaho Power Final Comments, p. 5.

Injection (DSI) emission control measure is required at North Valmy Unit 1 by December 31, 2014 to comply with federal Mercury Air Toxics Standards (MATS). The Company's share of the cost for this measure is estimated to be between $5 and $10 million.[9]

Parties' Positions

CUB is concerned about the discrepancy in planned retirement dates between the two plant owners. CUB notes that Idaho Power states that the end-of-life date for North Valmy is at or beyond the end of the 20-year planning period in Idaho Power's preferred portfolio, while the Nevada Energy has announced plans to close the plant in 2025.

RNP generally opposes the Company's proposed coal investments due to risk of increased environmental requirements.

Idaho Power Response

Idaho Power responds that it modeled North Valmy consistently with its current expectation of the end-of-life date. Idaho Power asserts that Nevada Energy cannot close the plant early without Idaho Power's consent, which it has not given. Also, Idaho Power modeled two portfolios that included a shortened end-of-life date for North Valmy and replacement of lost energy with other resources. These portfolios were higher cost than the preferred portfolio.

The Company states, "there is no currently planned closure of the two units at the North Valmy power plant…It is important to note that these dates are used for the sole purpose of establishing depreciable lives for accounting and ratemaking purposes and do not represent agreed upon decommissioning dates between NV Energy and Idaho Power. Neither company can decommission a unit without the consent of the other partner. Idaho Power is currently working with NV Energy to determine what would be required to establish common depreciation dates for both parties, which would be beneficial in analyzing the future operation of the plant."[10]

Staff Position and Recommendation

Due to the relatively small magnitude of the investment, Staff's assessment of the economics of the DSI investment at North Valmy Unit 1 is not changed by the possibility of a somewhat shortened operating life of the plant (e.g., 2025). However, the outcome

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[9]This range is from a February 2013 coal study presentation to the IRP Advisory Council. Specific cost information is in the confidential coal investment report.
[10] Idaho Power Reply Comments, pp. 9–10.

of any analysis of significant future investments will be heavily dependent upon the end-of-life date assumption. As stated in the coal analysis section above, Staff recommends that the Company engage with Staff and stakeholders to define the necessary analysis of any coal plant investments, and clarify its assumptions for operating life. Staff recommends that the 2015 IRP include information regarding the expected operating life of the North Valmy plant as well as its depreciable life for accounting purposes if different.

Staff recommends the Commission acknowledge the following action plan item:

> *North Valmy Unit 1, Commit to the installation of dry sorbent injection emission-control technology, 2013.*

Transmission Action Plan Items

Action Plan Item: Boardman to Hemingway: Ongoing permitting, planning studies, and regulatory filings, 2013 - 2018.

Action Plan Item: Boardman to Hemingway: Transmission line complete and in service, 2018.

Background

Boardman to Hemingway (B2H), which was first included in the Company's 2006 IRP, is a planned 300-mile 500-kV transmission line between northeast Oregon and southwest Idaho. In 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration (BPA), designating Idaho Power as the permitting project manager, and allocating capacity in megawatts (MW) on a seasonal basis. The allocations are as follows:[11]

	Idaho Power	BPA	PacifiCorp
West to East Capacity	350 (200 winter, 500 summer)	400 (550 winter, 250 summer)	300
East to West Capacity	85	97	818
Permitting Costs	21%	24%	55%

No funding agreement has been established as of this time for the construction phase of the project. However, BPA identified B2H as the preferred option for serving its loads in

[11] Idaho Power 2013 IRP, p. 77.

southeast Idaho.[12] PacifiCorp continues to include B2H in its Energy Gateway transmission expansion project, designated as Segment H, West of Hemingway.[13]

The B2H project timeline has been delayed until 2020 due in part to the announcement of delays by the Bureau of Land Management and new developments in the Energy Facility Siting Council process.[14]

Parties' Positions

RNP supports investment in B2H because it will provide economic benefits through access to markets; enable Idaho Power to reach renewable energy zones in the Northwest, facilitating the potential development of new renewable energy sources and allowing for increased regional reserve sharing to support integration of variable energy resources; and, provide reliability benefits.

Idaho Power Response

The Company's position in both reply and final comments is that the B2H project should be acknowledged as part of the 2013 IRP's preferred portfolio. In its final comments, the Company states, "as in past cases, the Company agrees that it will continue to treat B2H as an uncommitted resource in the next IRP and the Company will continue to provide the Commission and stakeholders updated analyses related to the project."

Staff Position and Recommendation

Staff supports the B2H permitting action plan item based on the results of the IRP portfolio modeling, which demonstrates that based on the current cost sharing arrangement and the net variable costs associated with wholesale power transactions, B2H is a cost-effective resource.

In its development of the 2015 IRP or in its next wind integration study (or both), Staff looks forward to an assessment of the effects that the availability of B2H will have on wind generation curtailments, access to sub-hourly scheduling (e.g., 15-minute), access

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[12] October 2, 2012 letter from BPA to Regional Customers, Stakeholders and other Interested Parties re Prioritization of Options for Service to Southeast Idaho: "From among the six potential service options BPA is currently considering, BPA has identified the option of Boardman-to-Hemingway with Transmission Asset Swap as its top priority for pursuit in Fiscal Year (FY) 2013 and beyond." http://www.bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Documents/SILS_Prioritization_Letter_10-01-12.pdf.

[13] PacifiCorp 2013 IRP, p. 74.

[14] Idaho Power Reply Comments, p. 2.

to future energy imbalance markets, and other benefits that may accrue that could provide support for intermittent resources.

Staff does not recommend acknowledgment of the construction of the project because it is beyond the two to four year timeframe for an IRP action plan.

Staff recommends the Commission acknowledge the following action plan item:

> *Boardman to Hemingway: Ongoing permitting, planning studies, and regulatory filings, 2013 – 2018.*

Staff recommends the Commission not acknowledge the following action plan item:

> *Boardman to Hemingway: Transmission line complete and in service, 2018.*

Action Plan Item: Gateway West: Ongoing permitting, planning studies, and regulatory filings, 2013 - .

Background

The Company's proposed action plan item for Gateway West is for its planned share of the segment of PacifiCorp's Energy Gateway project between Populus in eastern Idaho and Hemingway in western Idaho. Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, and between Cedar Hill and Hemingway. The Company also has 100 percent interest in the segment between Borah and Midpoint. CUB states that Idaho Power should analyze each segment individually, and request acknowledgment of only the segments of the project that it can demonstrate are cost-effective for its customers.

Parties' Positions

RNP supports Idaho Power's role in the Gateway West project, for reasons aligned with its support for investment in B2H.

CUB on the other hand does not support this action plan and recommends the Commission not acknowledge it. CUB's position is that the Company should analyze each segment of the Gateway West project individually and seek acknowledgment only for those segments that are cost effective for its customers.

Idaho Power Response

The Company states that this transmission project is needed to support reliable delivery to its load centers, and cites significant capacity constraints. The Company states, "these constraints limit Idaho Power's ability to site future resources east of the Treasure Valley and also restrict Idaho Power's ability to move additional energy, such as economic market purchases and sales, between the east and west sides of its system."[15] The Company also notes that, "in contrast to B2H, however, the Company is not seeking acknowledgment of Gateway West permitting as a supply side resource in and of itself. Rather, the Company requests acknowledgment that Gateway West is reasonable to address existing transmission system constraints and provide for future least cost resource development."[16]

Staff Position and Recommendation

Staff's recommendation in final comments was to not recommend acknowledgment of the Gateway West permitting activities, in part because Gateway West was not included in any portfolios evaluated in the IRP. Staff acknowledges, however, that because of the structure of the IRP modeling, the addition of this transmission capacity within Idaho Power's system would likely not be reflected in the economics of the different portfolios. While there is not sufficient information to support acknowledgment of the construction of the project, Staff concludes there is sufficient information in this IRP to support acknowledgment of the permitting-related activities that must occur prior construction.

For purposes of Idaho Power's next IRP, Staff recommends that the Company include in its 2015 IRP an analysis of the historical and projected power flows for the portions of the Gateway West project in which Idaho Power has an interest, in order to demonstrate specific constraint-related benefits.

Staff recommends the Commission acknowledge the following action plan item:

> *Gateway West: Ongoing permitting, planning studies, and regulatory filings, 2013 - .*

[15] Idaho Power Final Comments, p. 6-7.
[16] Idaho Power Final Comments, p. 7 (footnote).

Action Plan Item: Demand response: Have demand response capacity available to satisfy deficiencies up to approximately 150 MW, 2016 – 2017.

Background

In 2013, the Company submitted a request to the Commission to suspend two of its three demand response programs for 2013 because the load and resource balance forecast prepared for the 2013 IRP showed no need for peak load resources until 2016.[17] Under a settlement agreement in OPUC Docket No. UM 1653, the Company committed to restarting both the residential direct load control air conditioning program and the irrigation program beginning in the summer of 2014, with amended cost structures and program parameters.[18]

RNP supports Idaho Power's continuation of its demand response program to meet the Company's capacity needs.

Staff Position

Staff has been very supportive of the Company's commitment to maintaining a viable demand response program. The settlement agreement reached in Docket No. UM 1653 demonstrates that Idaho Power is treating demand response resources on an equivalent basis with other resources, as required in IRP Guideline 7.[19] Had the Company built a single-cycle combustion turbine in earlier years, it would not be able to simply stop using and stop paying for that resource; the capacity would still be available even if it were not needed, and the plant would continue to be in rate base. Demand response is a different kind of resource in that it can be ramped up and down to a greater extent than a generating resource, but abrupt year-to-year shifts could erode the program to the extent it would not be available at an adequate level in years when it is needed.

Because the program offering has changed for 2014, Staff recommends that Idaho Power update its assessment of demand response availability based on summer 2014 program participation by the end of 2014, and have the Energy Efficiency Advisory Group (EEAG) review any proposed revisions to the resource assessment.

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[17] Idaho Power did not file to suspend the third program, the commercial/industrial demand response program, because its contract with the third party vendor did not expire until February 2014.
[18] Order No. 13-482, Docket No. UM 1653.
[19] Order No. 07-047, Appendix A, p. 6.

Staff recommends that the Commission acknowledge Idaho Power's near-term demand response action plan item as follows:

> *Demand response: Have demand response capacity available to satisfy deficiencies up to approximately ~~150~~ 170 MW beginning in 2014, and increasing as needed through 2017, ~~2016–2017~~ 2014-2017.*

Out-year Action Plan Items

As stated in Staff's final comments and herein, Staff makes specific acknowledgment recommendations only for the resource actions proposed for the next two to four year period, consistent with the IRP guidelines.[20] In response to CUB's initial comments regarding "Action Plan Overforecasts,"[21] the Company stated that it, "requests acknowledgment only of the Action Plan items that occur within the next two to four years, consistent with the Commission's IRP Guidelines."[22]

The out-year action plan items are as follows:[23]

2019	Shoshone Falls	Shoshone Falls upgrade complete and in service.
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology.
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031.

Staff Recommendation

The Commission typically does not acknowledge action items planned more than four years in the future. Staff identifies nothing about these action plan items that warrants an exception to that practice.

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[20] Order No. 07-047, Appendix A, Guideline 4(n), Plan Components: "An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP…"
[21] CUB Opening Comments, p. 4.
[22] Idaho Power Reply Comments, p. 24.
[23] This list does not include the B2H construction action plan item (*Boardman to Hemingway: Transmission line complete and in service),* because it was addressed previously.

> *Staff recommends that the Commission not acknowledge the five action plan items above.*

With regard to the Shoshone Falls hydroelectric upgrade, Staff notes that this 49 MW project has been included in multiple IRPs as a committed resource. The 2013 IRP indicates that construction of the expansion project will start in 2016 and completed in 2019. As Staff stated in final comments, the previous acknowledgment, "…does not obviate the need for analysis of the yet-to-be constructed project, particularly if the completion date is postponed by four years." Staff recommends that a full financial analysis of this project be performed and shared with stakeholders and Staff as part of the preparation of the 2015 IRP.

Also, Staff recommends that in future IRPs, the Company differentiate between resource actions for which it is requesting acknowledgement and those that result from the planning process but do not fall within the Commission's guidelines for an action plan item.

Other Issues

Energy Efficiency

IRP Guideline 6, Conservation, states, "…the utility should include in its action plan all best cost/least risk portfolio conservation resources for meeting projected resource needs, specifying annual targets."[24] Idaho Power's 2013 IRP contains specific energy efficiency levels in the IRP.[25,26] These energy efficiency savings are derived from two categories: (1) forecasted savings from the current portfolio of programs; and (2) new resources based on a recent energy efficiency potential study conducted for the 2013 IRP process.[27] The IRP proposes that by 2017, the Company achieves 69 aMW of demand reduction from the current programs and 38 aMW of incremental, new resource savings.

Staff recommends that these two energy efficiency items be included in the Company's action plan for the 2013 IRP. In the Company's 2011 IRP (Docket No. LC 53), Staff made a similar addition to the action plan. Also, Staff repeats the recommendation it made in LC 53 that Idaho Power include its near-term energy efficiency targets in its action plan.

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[24] Order No. 07-047, Appendix A, p. 6.
[25] Idaho Power 2013 IRP, p. 43 and 44.
[26] Id., Appendix C, p. 31 through 72.
[27] Id., p. 37.

Staff recommends that the Commission add the following items to the IRP action plan:

> *Energy Efficiency: The average demand reduction of the current portfolio of energy efficiency programs for 2013 to 2017 energy efficiency programs will be 69 aMW.*
>
> *Energy Efficiency: The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW.*

NEEA

CUB, Idaho Power and Staff filed comments regarding the Company's actions to curtail its funding to the Northwest Energy Efficiency Alliance (NEEA) in the next five-year funding cycle. Staff will not respond in detail to each of Idaho Power's response comments as many of Idaho Power's comments note management or relationship concerns with NEEA, NEEA's Board or NEEA's management which are not germane to this proceeding. Staff once again notes that as a primary long-standing funder of NEEA, it is Idaho Power's responsibility to resolve the currently noted operational issues with NEEA.

Staff is not convinced of the reasonableness of Idaho Power's proposal to discontinue funding NEEA. Idaho Power has an obligation to acquire all cost effective energy efficiency. NEEA is one of Idaho Power's most cost effective energy investments. Aside from cost effective savings, Idaho Power's participation in NEEA lends additional benefits to Idaho Power, Idaho ratepayers and the region as a whole. A regional compact exists among over 100 Northwest utilities and efficiency organizations which fund NEEA. The premise of this compact creates the value chain delivered by NEEA to the region through broad market intervention and energy efficiency market development strategies. These actions, NEEA's programmatic activity, taken as a whole fall under the concept of "market transformation." Results of these activities include development of an energy efficiency products and practices pipeline. Filling the energy efficiency pipeline is, as Idaho Power's 2012 DSM report demonstrates, substantially valuable to Idaho Power and other NEEA funders. It is through aggregation of funding across the region that such activity is feasible and cost effective.

Additionally, NEEA's market transformation activities leverage Idaho Power's and other regional investments to affect market actors whose interests exist at the national scale. It is axiomatic that national market leverage could not be conducted cost effectively by any one utility. This understanding is again part of the foundation for our regional alliance and funding. Staff is concerned that Idaho Power's proposal to discontinue funding NEEA will lead to the erosion of the alliance, the savings acquired by the region, and the market transformation program methodology and practice development which is leveraged by Idaho Power and all the utilities in the region. The ability to influence the manufacturing decisions, market actions and distribution chain of national companies is of significant value to Idaho Power, its ratepayers and the region.

Staff is additionally concerned that should Idaho Power discontinue funding NEEA the costs associated with the region market transformation work will become unequally apportioned. Further, given the broad market impacts of NEEA's market transformation work, it is inevitable that the benefits of this work will unfairly accrue to non-participating Northwest ratepayers.

It is therefore the conclusion of Staff, given the multiple value chains created by NEEA, that Idaho Power should continue funding NEEA at a level equal to its regional funding share as agreed upon by the NEEA Board as part of its least cost/least risk plan.

Wind Integration Study

Parties' Positions

RNP states the Idaho Power's wind integration costs in the 2013 Wind Integration Study (WIS) are overstated, pointing out large differences between the Company's results and the wind integration costs for Portland General Electric, PacifiCorp, and the Bonneville Power Administration. RNP specifically criticizes Idaho Power's methodology for calculating forecast error on the difference between day-ahead forecasted generation and actual generation, resulting in overstatement of the balancing reserves required. RNP notes that the Technical Review Committee (TRC), required by Order No. 12-177, flagged this as a concern. RNP states that Idaho Power's wind integration study, "…did not receive the level of comprehensive review and participation by the Technical Review Committee that the Commission had envisaged in Order 12-177."[28]

Idaho Power states, "basing balancing reserve requirements on an analysis of day-ahead forecast errors more accurately represents how the electrical system is operated in reality in regards to how a utility uses market purchases and sales to keep the system balanced." The Company also notes that the fact that the less-than-ideal level of engagement of the TRC in the development of the WIS was an issue of timing, and cites its engagement of a TRC from the beginning stages of its recently initiated solar integration study.

[28] RNP Opening Comments, p. 9.

Staff Position

Staff shares RNP's concern that the Company's current wind integration study falls short of what should be provided. Staff questions the Company's assertion that day-ahead forecast errors are appropriate for a wind integration cost analysis. Staff agrees that the reduced level of TRC engagement was primarily an issue of timing. However, because the forecast error temporal assumption is critical to the results of a WIS, Staff anticipates that it would have significant concerns regarding use of the February 2013 WIS results in a future filing such as a filing to determine PURPA avoided costs.

Flexible Capacity IRP Guideline

Order 12-013 requires utilities to incorporate planning for flexible capacity in IRPs.[29] The analysis is to include a forecast of the demand and the supply for flexible capacity based on the balancing reserves needed and available at different time intervals. Then, flexible resources are to be evaluated on a consistent and comparable basis.
The Company's initial filing included in Attachment 3 a one page summary of its "Compliance with EV Guidelines," noting that Chapter 9 of the IRP addresses the requirement. The Company's assessment is as follows:

1) Idaho Power relies primarily on its hydroelectric system to meet reserve requirements
2) Idaho Power's Wind Integration Study Report details the effects of adding additional wind capacity to the Idaho Power system
3) The preferred portfolio in the 2013 IRP Idaho Power proposed no new intermittent renewable generation over the 20-year planning horizon, and the Company does not forecast a significant increase in intermittent generation from PURPA or from customer programs
4) Idaho Power does not forecast a need to increase flexible capacity associated with implementing resource portfolio 2, which adds B2H and demand response programs
5) Resource portfolio 2 is not expected to increase the supply of flexible resources over the 20-year planning horizon.

RNP recommends that the Company evaluate energy storage, including pumped storage and other storage to provide flexible capacity in addition to capacity. RNP believes that Idaho Power's analysis in this IRP does not meet the flexible capacity Commission's guidelines because it does not quantify the existing supply over multiple timescales.

[29] Docket No. 1461, Order no. 12-013, p. 16-18.

Staff recognizes that the Company has provided qualitative analysis that shows it is unlikely Idaho Power will need additional flexible capacity over the 20-year planning horizon, but agrees with RNP that the guideline asks for quantitative analysis of the size and timing of the flexible capacity resource balance. Staff recommends that Idaho Power substantially expand its analysis in the 2015 IRP. Staff is willing to work with Idaho Power and other stakeholders to help develop the quantitative analysis.

Conservation Voltage Reduction

Order 12-177, acknowledging Idaho Power's 2011 IRP, directed the addition of a conservation voltage reduction (CVR) action item:

> Action Item 4 - Conservation Voltage Reduction- The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

In the 2013 IRP, the Company states, "Idaho Power considers it prudent to validate the benefit of the CVR program before expanding it beyond the initial study area. New technologies and methods of measurement are available to validate energy savings and reduced peak demand…Idaho Power expects to complete the CVR analysis in 2016…the actual savings from the current CVR implementation are not significant enough to be incorporated into the IRP load and resource balance forecast."[30]

Order No. 13-481 in Docket No. UM 1675, Idaho Power Company 2013 Annual Smart Grid Report, states, "we direct Staff, in its evaluation of all Smart Grid Reports, to perform an independent analysis of the utility pilot programs, related research, and conclusions drawn regarding Conservation Voltage Reduction and Volt/Volt Ampere Reactive control programs to determine what is possible and what is not, and what is economic and what's not."

Staff is currently working on this analysis, and a workshop is forthcoming. Staff recommends that Idaho Power and Staff revisit this issue at the conclusion of the CVR Staff independent analysis.

[30] Idaho Power 2013 IRP, p. 45.

2011 IRP Solar Action Plan Item

Idaho Power's 2011 IRP contained an action plan item for a 500 kW to 1 MW solar demonstration project, to be completed by 2013. Project milestones included the preparation and issuance of an RFP in 2011, and an online date in late 2012/early 2013.

The 2013 IRP provides an update on this action item, stating, "with the recent issues surrounding PURPA in Idaho, the timing has not been suitable for Idaho Power to pursue the construction of a small-scale solar project." The Company notes that it is mandated to comply with the requirements of the Oregon Solar Incentive Program,[31] which include building a 500-kW, utility-scale solar facility by 2020. Idaho Power states that it will continue to evaluate the solar demonstration project and the potential benefits of receiving double RECs under the program if it is completed by the end of 2016.

Staff recognizes the challenges Idaho Power has faced with regard to its PURPA contracts in recent years. Staff recommends that the Company provide an updated analysis on the costs and benefits of this project, including the timing options and value of additional RECs, early in the development of the 2015 IRP.

Other Issues

Staff and other parties commented on several additional IRP issues, including the capacity contribution of solar resources, the capital costs of renewable resources, the load forecast, and the gas forecast. Staff's position is that these issues, while important, would not have altered the outcome of the preferred portfolio for the 2013 IRP. Staff recommends that parties engage in the stakeholder process for the development of the 2015 IRP in order for these issues to be fully vetted prior to the issuance of the final plan.

PROPOSED COMMISSION MOTION:

Idaho Power's 2013 Integrated Resource Plan be acknowledged with the revised action plan items recommended by Staff as contained in Attachment B to this report.

LC 58 Final Staff Report.docx

[31] ORS 757,370, 757.375.

Attachment A

Company's Proposed Action Plan

Year	Resource	Action
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology
2016–2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately 150 MW
2018	Boardman to Hemingway	Transmission line complete and in service
2019	Shoshone Falls	Shoshone Falls upgrade complete and in service
2019	Jim Bridger Unit 2	Commit to the installation of selective catalytic reduction emission-control technology
2020	Jim Bridger Unit 1	Commit to the installation of selective catalytic reduction emission-control technology
2020	Boardman	Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020
2024–2032	Demand response	Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031

Attachment B

Staff Recommended Action Plan

*Additions in **bold***

Year	Resource	Action	Staff Recommendation
2013–2018	Boardman to Hemingway	Ongoing permitting, planning studies, and regulatory filings	Acknowledge
2013–	Gateway West	Ongoing permitting, planning studies, and regulatory filings	Acknowledge
2013	North Valmy Unit 1	Commit to the installation of dry sorbent injection emission-control technology	Acknowledge
2013	Jim Bridger Units 3 and 4	Commit to the installation of selective catalytic reduction emission-control technology	Acknowledge
~~2016–2017~~ 2014-2017	Demand response	Have demand response capacity available to satisfy deficiencies up to approximately ~~150~~ **170 MW beginning in 2014, and increasing as needed through 2017**	Acknowledge as amended
~~2018~~	~~Boardman to Hemingway~~	~~Transmission line complete and in service.~~	Do not acknowledge
~~2019~~	~~Shoshone Falls~~	~~Shoshone Falls upgrade complete and in service.~~	Do not acknowledge
~~2019~~	~~Jim Bridger Unit 2~~	~~Commit to the installation of selective catalytic reduction emission-control technology.~~	Do not acknowledge
~~2020~~	~~Jim Bridger Unit 1~~	~~Commit to the installation of selective catalytic reduction emission-control technology.~~	Do not acknowledge
~~2020~~	~~Boardman~~	~~Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020.~~	Do not acknowledge
~~2024–2032~~	~~Demand response~~	~~Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031.~~	Do not acknowledge
2013-2017	**Energy Efficiency**	**The average demand reduction of the current portfolio of energy effiency programs for 2013 to 2017 energy efficiency programs will be 69 aMW**	**Acknowledge**
2013-2017	**Energy Efficiency**	**The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW**	**Acknowledge**