SEAN COSTELLO
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0312
IDAHO BAR NO. 8743

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5918

Attorney for the Commission Staff

RECEIVED
2017 NOV 27 PM 2:31
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2017 INTEGRATED RESOURCE PLAN	**CASE NO. IPC-E-17-11** **COMMENTS OF THE COMMISSION STAFF**

COMES NOW the Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Sean Costello, Deputy Attorney General, and in response to the Notice of Modified Procedure and Notice of Comment Deadline issued in Order No. 33889 on September 26, 2017, in Case No. IPC-E-17-11 to submit the following comments.

BACKGROUND

On June 30, 2017, Idaho Power Company filed its 2017 Integrated Resource Plan (IRP). The IRP is a status report on a utility's ongoing, evolving plans to adequately and reliably serve its customers at the lowest system cost and least risk over the next 20 years. The Commission requires the utility to update the IRP biennially, allow the public to participate in its development, and to implement the IRP. *See* Order Nos. 22299 and 25260. The Company's pending Application asks the Commission to acknowledge that it has complied in filing its 2017 IRP. By acknowledging the IRP, the Commission has stated that it is acknowledging the Company's ongoing planning process, not the conclusions or results reached through that process. *See* Order No. 33441.

More specifically, the Commission has asked that a utility's IRP explain its current load/resource position, its expected responses to possible future events, and the role of conservation in its explanations and expectations. The IRP should also 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.

In this case, in its Application, the Company explained that its 2017 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 2017 IRP. The IRP filing consisted of four documents: (1) the 2017 IRP; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2014 Annual Report; and (4) Appendix C – Technical Appendix.

The Company noted that it incorporated stakeholder and public input into its 2017 IRP by working with an Integrated Resource Plan Advisory Council (IRPAC), consisting of various stakeholders, and held eight IRPAC meetings while developing the 2017 IRP, including a workshop designed to explore the potential for distributed generation to defer grid investment.

The Company further explained that the primary goals of its 2017 IRP are to: (1) identify sufficient resources to reliably serve growing demand for energy over the 20-year planning period (2017-2036); (2) ensure the selected resource portfolio balances cost, risk, and environmental concerns; (3) give balanced treatment to supply-side resource and demand-side measures; and (4) involve the public in the planning process in a meaningful way.

STAFF REVIEW

Staff actively participated in the IRPAC and believes the Company's IRP satisfies the Commission's requirements as specified in Order No. 22299. Although Staff believes the IRP satisfies these requirements and several aspects of the IRP were well-constructed, Staff also finds that this IRP has significant deficiencies which unduly influenced the final portfolio selection. While IRPs are conducted every two years to capture any changes anticipated in the planning period, the Company repeatedly emphasized the importance of this IRP in making two critical resource decisions that must be initiated before the next IRP: 1) investing in Selective Catalytic Reduction Units (SCRs) for Units 1 and 2 at its Jim Bridger Coal Facility in Wyoming and 2) evaluating the economics of the Boardman to Hemingway transmission line (B2H).

Staff supports the Company's analysis of generation, average energy forecasting, and the analytical construction of its portfolio development process, but believes that the Company's methodology for peak capacity forecasting, the natural gas price assumptions, and similarity of the modeled portfolios to each other combined to make this IRP far less robust than the 2015 IRP process. In addition, the Company did not take any steps towards improving its methodology for modeling demand-side resources similarly to supply-side resources.

Load and Resource Balance

The Company's system peak and load forecasts reflect continued growth in the Company's service territory. The IRP anticipates the number of customers will grow from 534,000 in 2016 to 756,000 by 2036. The Company anticipates that average energy use will grow by 0.9 percent per year (a reduction from the 1.2 percent increase forecasted in the 2015 IRP) and peak hour demand to grow by 1.4 percent per year (a reduction from the 1.5 percent increase forecasted in the 2015 IRP).

The 2017 IRP predicts 1.22 percent residential load growth, 0.74 percent commercial load growth, 0.58 percent irrigation load growth, 0.70 percent industrial load growth, and additional firm load growth of 0.76 percent. Nearly all of these are reductions from the 2015 IRP forecasts, which were 1.3 percent for the residential, 1.0 for commercial, 0.5 for irrigation, 2.0 for industrial, and 0.6 for additional firm load growth. The Company's forecasts also show that the greatest increases in load appear in the early years of the planning period (2017 through 2022) with the increases leveling off in the out years (2022 through 2036).

The Company's load and resource balance compares the capabilities of existing Company resources with monthly forecast average load and peak demand over the 20-year IRP planning period. Without new resources, the Company expects a capacity deficit in July 2026 (the 2015 IRP predicted a 2025 capacity deficit) and the first average load (energy) deficit in July 2029 (the 2015 IRP predicted no deficits through 2034). The Company forecasts that first year peak hour capacity deficit of 34 MW in 2026 grows to 986 MW in 2036. The largest capacity deficits occur in the summer months when irrigation load coincides with residential and commercial air conditioning load.

As it has for several IRP cycles, the Company uses the 70^{th} percentile water conditions and the 70^{th} percentile average load for energy planning. For peak-hour capacity planning, the Company uses 90^{th} percentile water and 95^{th} percentile peak-hour load.

Staff notes that the Company's load and resource balance analyses are sensitive to its growth rate assumptions and believes that the Company should include an analysis of the sensitivity of projected peak capacity deficit dates to changes in assumed growth rates in future IRPs. Staff also believes that the Company's peak load forecasts could be improved by incorporating class-specific forecasts in its analysis.

In a typical year, the Company generates approximately 73 percent of its energy requirement using Company-owned resources and purchases the remaining 27 percent. The Company's hydroelectric resources account for the largest share of energy (39 percent) provided to Idaho Power's customers, followed by coal (24 percent) and diesel/natural gas generation (10 percent). *See* IRP at 23.

To some degree, the ability of all of these resources to deliver power is dependent on local environmental conditions, but the Company's hydroelectric resources in particular, are heavily dependent on forecasted hydrological and watershed conditions such as stream flow, snow pack, and temperature. The Company forecasts resource capacity with stochastic models that take these variables into account, and uses the results to determine the probabilities of streamflow conditions necessary to operate its hydroelectric plants. The Company bases its energy adequacy analysis on 70th percentile stream flow condition. It bases its peak hour resource adequacy on 90th percentile streamflow conditions. Staff acknowledges the Company's comprehensive approach to modeling its resource capabilities, particularly its hydroelectric modeling.

The Company's average monthly load forecast predicts the amount of energy that it expects customers to use each month. The average energy load forecast is used to predict the variable costs that the Company incurs producing and procuring energy. The Company developed its monthly average load forecast by adding together the individual 70th percentile forecast monthly loads from each of its customer classes. These class-specific forecasts were developed using assumptions about customer growth rates for each class, energy consumption as a function of weather (Heating Degree Days), and assumptions about changes in average consumption per customer over time. Staff believes this methodology is sufficient for the IRP planning process, but also believes that the Company should include an analysis of the methodology's sensitivity to growth rate and modeling assumptions.

While average energy forecasting is an important aspect of resource planning, decisions to build or buy generation and transmission plant are driven primarily by peak demand rather than average load. Despite the oversized importance of peak demand forecasting in resource planning, Staff notes that the Company's system peak demand forecasting methodology is much less refined than its average load forecasting methodology. The Company's peak demand forecast model was developed by applying monthly 95th percentile peak temperatures to a single system-wide regression model, rather than to the multiple class-specific forecasts, which is how the average energy forecast was developed. These values were then extrapolated for 20 years resulting in an average 1.4 percent system-wide growth rate per year.

Because of the impact of peak capacity deficits on resource planning needs, Staff conducted a sensitivity analysis to determine the effects of a slightly smaller peak growth rate would have on the Company's first capacity deficit. Staff's analysis found that an extremely small (0.1 percent) decrease in the annual projected growth rate pushed the Company's first capacity deficit date out by an entire year.[1] Larger changes in either direction compounds the impact to the first capacity deficiency date. Since all portfolios modeled in the IRP process must

[1] This finding is consistent with the difference between the results of the Company's 2015 and 2017 IRP analyses. Using a 1.5 percent peak load growth assumption in the 2015 IRP, the Company identified a 2025 first capacity deficit date. In the 2017 IRP, the Company used a 1.4 percent peak load growth assumption and identified a 2026 first capacity deficit date.

meet the first annual capacity date, a small change to this internally-generated growth rate assumption can have major impacts on the forecasted resource costs identified by the Company in the IRP process.

Given the importance of demand forecasting to the IRP results, Staff believes that the Company should refine its demand model to include individual coincident peak demand forecasts for each customer class, similar to how it creates average load forecasts. Staff also believes that the Company should include sensitivity analyses for the Company's key growth rate and modeling assumptions. This will help the Company and stakeholders identify the potential for the system to be overbuilt in the event that the demand forecast over-estimates actual demand and identify the most cost-effective ways to meet capacity deficits in the early years of the IRP planning period.

Natural Gas Price Forecast

The most critical difference in this IRP was the Company's decision to change the source of its natural gas price forecast. In the 2013 and 2015 IRPs, the Company used the EIA's Henry Hub reference case forecast adjusted for Sumas basis pricing to reflect the Company's city gate price. The reference case is the median forecast which the Company specifically requested to use for IRP planning purposes in its 2013 IRP. At the time, the Company explained that the EIA planning case was the most credible gas price forecast available. Stakeholders at that meeting were in near unanimous agreement.

In the 2017 IRP, the Company made an abrupt and unexpected departure from that position. Instead of using the reference case, the Company announced that it would use the EIA's Henry Hub "High Oil and Gas Resource and Technology Case."[2] This forecast assumes extremely low natural gas prices throughout the 20-year planning period on the basis that natural gas drilling technology will advance so quickly beyond currently available technology that production will increase at a volume that keeps natural gas prices almost entirely flat for next twenty years. As demonstrated in Attachment A[3] it is the lowest EIA gas price forecast.

---

[2] This is not to be confused with the EIA's Mountain Region forecast, also available in high, low, and reference ranges, which is used in SAR methodology pricing calculations.

[3] Attachment A is slide #5 from the Company's January 12, 2017, IRPAC presentation. The "2017 EIA Low" reflects the "High Oil and Gas Resource and Technology Case" and the "2017 EIA Planning" case represents the reference case.

This change surprised stakeholders and prompted intense discussions during the IRP meetings. In those meetings, the Company defended the shift by stating that the EIA reference case had over-estimated the price of natural gas over the past two IRP cycles. In its view, the move to the "High Oil and Gas Resource and Technology Case" corrected that over-estimation and is reasonable because it is consistent with Intercontinental Exchange (ICE) futures natural gas settles transactions. *See* Attachment A.

In the IRP meetings, stakeholders stated that many in the natural gas industry, including forecasters, failed to anticipate shale gas fracking and the unprecedented fall in natural gas prices. Stakeholders also asked the Company why it was reasonable to assume that six years of Intercontinental Exchange (ICE) futures prices would persist over the subsequent fourteen years even though the Company's graph shows no data beyond 2023. The Company merely maintained that the futures market reflects actual transactions occurring for those years and therefore serves as a credible indicator about what prices will be in the future.

After much discussion, the IRPAC stakeholders unanimously opposed moving to the new forecast. Importantly, Idaho Power's Oil and Gas Industry advisor on the IRPAC repeatedly voiced concerns with the new forecast because he believes natural gas prices are likely to rise as utilities across the country shift from coal-fired generation to natural gas generation and as exports of Liquefied Natural Gas (LNG) increase.

Staff conducted considerable research on this issue in Case No. GNR-E-17-02, where the Company proposed the EIA "High Oil and Gas Resource and Technology Case" as the basis for SAR Methodology avoided costs. That research informed Staff's analysis of the Company's 2017 IRP and, as a result, Staff disagrees with the Company's logic and position on this issue.[4]

First, the EIA has significantly reduced the reference case forecast to capture the decline in market prices. Staff also confirmed with the EIA that the reference case includes ICE future options as a key component of its near-term price forecasting. This is standard practice in natural gas price forecasting and is clearly demonstrated by the low gas price in early years of the reference case.

[4] Staff notes that Idaho Power withdrew its request to switch to the EIA's "High Oil and Gas production case" in Case No. GNR-E-17-02 on August 23, 2017.

Second, ICE futures contracts are option contracts. They provide buyers and sellers the option to make the trade at a certain price on a certain day if both parties still agree to those terms when the contract date arrives. Futures options include clauses that allow either party to exit the agreement by paying a penalty or losing the upfront cost paid to secure the option. Under that structure, buyers and sellers in the futures market are protected from drastic divergences between their contracted futures prices and actual spot market prices.

Third, buyers participate in the ICE futures market as a hedge specifically because they believe future spot market prices will be higher than prices available on the spot market on that day and year. Sellers in the futures market also understand that prices are likely to rise, but are willing to commit to those prices to ensure that at least some of their product sells. So rather than being a reflection of actual future spot market pricing, ICE futures options are merely a reflection of what today's market is willing to pay now to have that option within the next six years.

Fourth, the volume of trades in the futures market declines dramatically over time as very few buyers or sellers are willing to commit to a futures option beyond the sixth year. As shown in Attachment B,[5] trading volume is highest in the first year, steadily declines through the remaining five years, and ceases to exist entirely by 2028. Staff believes it is unreasonable to base a 20-year forecast on six years of declining sales volume data.

Lastly, using a very low natural gas price forecast is the equivalent of planning to a "best case" scenario. This directly contradicts how the Company plans for water conditions, average load, and peak-hour capacity. As previously noted, the Company uses 70th percentile water conditions and the 70th percentile average load for energy planning. For peak-hour capacity planning, the Company uses 90th percentile water and 95th percentile peak-hour load. While the EIA reference case would be approximately a 50th percentile gas price assumption, Staff estimates that the "High Oil and Gas production Case" forecast is closer to perhaps a 5th or 10th percentile assumption. Since the Company does not assume favorable conditions for any of its other planning metrics, Staff does not believe it is appropriate to assume the lowest available gas price forecast.

Most importantly, assuming extremely low gas prices creates a disproportionate upside price risk. A very low gas price forecast makes resources whose variable costs are closely linked

[5] Attachment B is Idaho Power's response to Simplot's Request for Production No. 13, pages 2-4, in GNR-E-17-02.

to gas prices (such as natural gas plants and transmission) appear less costly than other resources which have lower variable price risk (such as coal-fired or solar generation). That means that an IRP could use the low gas price forecast to select large capital investments which are linked to natural gas. The Company benefits from the capital investment and passes the significant risk of variable price increases to customers.

Equal Treatment of Demand and Supply-Side Resources

Staff continues to have two concerns with the Company's treatment of demand-side resources in its planning process. First, the Company still includes non-utility costs when assessing the costs of DSM, and second, the Company deducts demand-side resources from the load forecast rather than modeling it alongside supply-side resources similar to the method used by Avista, PacifiCorp, and other regional utilities. The Company's current practice minimizes the amount of cost-effective energy efficiency included in the resource plan and also means that each portfolio and every future scenario includes exactly the same amount of energy efficiency, despite the fact the value of energy efficiency rises in a high natural gas or high carbon scenario.

In Order No. 33441, the Commission encouraged the Company to 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." In its Application in this case, the Company maintains that it "led discussions with the 2017 IRPAC describing its approach of developing portfolios that include an IRP target for energy efficiency expansion under planning (or expected) case inputs and assumptions." The Company believes that changing its methodology is not warranted because the contractor who developed its Conservation Potential Assessment (CPA), Applied Energy Group (AEG), adhered to the standards outlined in the National Action Plan for Energy Efficiency (NAPEE) Guide for Conducting Energy Efficiency Potential Studies. However, AEG's practices and the NAPEE standards are both consistent with Staff's position as it relates to the equal treatment of demand and supply-side resources in the IRP process.

Idaho Power directed AEG to include non-utility costs when it established the costs of demand-side resources in its potential study. Including costs not incurred by the utility is inconsistent with supply-side planning practices. During the January 12, 2017, IRPAC meeting referenced in the Company's Application, Staff asked AEG how difficult it would be to include only utility-costs in its CPA assessment. AEG confirmed that it would be quite simple and that AEG had already produced a CPA for another state using that methodology.

The NAPEE guidelines, which are generally quite broad, specifically permit using utility-only costs when modeling energy efficiency (*see* NAPEE at 3-6 though 3-7) and do not address or take any position on how energy efficiency potential should be incorporated in IRPs.

Regardless of the methodology used to determine the amount of energy efficiency potential, the Company still fails to incorporate energy efficiency as a resource alongside supply-side resources in its IRP modeling process. Instead, it still deducts the energy efficiency potential from forecasted load and then, with the exception of some additional demand response, builds supply-side resources to meet the remaining load. This means that the exact same amount of energy efficiency is included in every resource portfolio and in all possible risk scenarios (e.g., high gas prices, low hydroelectric conditions, high carbon prices) even though the value of energy efficiency obviously increases under each of those circumstances.

In contrast, Avista has moved from a static, non-utility cost analysis – similar to Idaho Power's current methodology – to an almost entirely dynamic, utility cost-based analysis of demand-side resources between its 2015 and 2017 IRPs. AEG performed Avista's CPAs in both of those IRPs.

Deferred Transmission and Distribution

Consistent with the Company's previous commitments and the encouragement provided it in Order No. 33365,[6] the Company has studied the value of transmission and distribution benefits that can be deferred with demand-side resources. The results of this study were presented to the IRPAC on October 13, 2017. While Staff appreciates the Company's analysis, the benefits were calculated using a 7-year stream of deferred investments rather than the 20-year stream used in all other resource investments. Pursuant to Order No. 33908, Staff looks forward to working with the Company through its Energy Efficiency Advisory Group (EEAG) to address this issue and "report back to the Commission if the 20-year analysis is not acceptable." *See* Order at 7.

[6] Case No. IPC-E-15-06.

Portfolio Design

The Company designed the portfolios for this IRP in order to make two important near-term resource decisions: 1) deciding to make SCR investments required for Jim Bridger Units 1 and 2 by 2022 and 2021, respectively; and 2) deciding to proceed with the B2H transmission line. A series of systematic alternatives to each of those resources investments was analyzed and modeled to inform both decisions.

The Company states that four scenarios were analyzed to study the SCR investments:

1) Scenario 1: Install SCRs and operate Units 1 and 2 through the entire planning period;
2) Scenario 2: Do not make SCR investments and retire Units 1 and 2 in 2028/2024;
3) Scenario 3: Do not make SCR investments and retire Units 1 and 2 in 2032/2028; and
4) Scenario 4: Do not make SCR investments and retire Units 1 and 2 in 2022/2021.

Under each of these four Jim Bridger scenarios, the Company developed three alternatives (for a total of 12 portfolios),[7] which are:

(a) A portfolio including B2H and reciprocating gas engine generation;

(b) A portfolio including utility-scale solar and reciprocating gas engine generation; and

(c) A portfolio including reciprocating gas engine generation and a Combined Cycle Combustion Turbine (CCCT).

This approach is a more systematic method for designing resource portfolios than the previous IRP. Although the systematic approach can be preferable because it provides a more meaningful way to ensure that portfolios within the design do not unintentionally exclude the most beneficial portfolio, the method used by the Company falls short in a very critical way: the original 12 resource portfolios only analyzed three categories of generation (natural gas fired generation, transmission, and utility-scale solar).

Considering that the Company went to great lengths to research, produce, and update the fixed and variable costs of about 30 resources before designing portfolios, Staff asked the Company in the IRP meetings why it chose to constrain the resources that it modeled so dramatically. In response, the Company reiterated that the purpose of this IRP was to determine if the Company should invest in SCRs at Bridger and pursue B2H. The Company believed that these resources were the least expensive and therefore provided the most difficult threshold that the SCR/B2H decisions must pass in order to be economic.

---

[7] All 12 portfolios comply with the final Clean Air Act (CAA) Section 111(d) mass-based emission limits.

At Staff's request, the Company added 50MW of cost-effective demand response to the non-B2H portfolios. However, no other least cost resources, such as additional cost-effective energy efficiency, time-of-use rates, or any other type of generation were included in any portfolio.

In addition, the Company made no effort to design portfolios in order to minimize risk and cost in a most probable future. Staff continues to believe that a better portfolio design approach would be to forecast a host of specific future scenarios around customer load, gas, hydro, and carbon variations and then strategically select resource portfolios to mitigate the largest and most likely risks associated with each scenario. The Company maintained that its Bridger retirement dates were future scenarios around which its portfolios were designed. But since the decision to run or retire the plant lies with the plant owners, it does not qualify as an exogenous risk for the Company to mitigate.

Another Staff concern with the portfolio design process is the assumption that the Bridger units could avoid SCR installation on the compliance dates of 2022/2021 in exchange for early retirement. The Company maintains that similar agreements have been reached across the West on multiple coal plants. Staff does not dispute that. However, current EPA leadership may be less inclined to encourage early retirement of coal plants than the leadership in place when previous deals were struck. If early retirement in lieu of SCRs is not achievable, customers could end up paying for SCRs in addition to the other resources which were built in advance to replace the Unit 1 and 2 generation.

Portfolio Selection

After completing the portfolio design process, the Company analyzed each portfolio for cost and risk in a two-step process.

First, fixed and variable costs were calculated to establish the net present value (NPV) over the 20-year planning period for all twelve portfolios. The lowest cost option was Portfolio 7, which included Bridger Units 1 and 2 retiring in 2028/2032, B2H coming online in 2026, and then either a reciprocating engine or a CCCT being built in all but one year between 2031 and 2036.

Second, all 12 portfolios were subjected to stochastic risk analysis to see how the ranking of portfolio cost changed when the three variable assumptions were changed: natural gas prices, customer load, and hydroelectric generating conditions. The Company created a set of 100 iterations based on those three variables and then calculated the 20-year NPV for each of the 12 portfolios. Portfolio 7 was the lowest cost portfolio for 92 of the 100 stochastic iterations, and also the lowest for average, median, lowest minimum value, and lowest maximum value.

This was not a surprising result. The insufficient resource diversity among the 12 portfolios meant that as the input assumptions change, the cost of nearly all the portfolios would rise and fall together. This is especially true when many of the portfolios rely so heavily on resources susceptible to natural gas price changes, including transmission and natural gas-fired generation.

Although a risk assessment of very similar resources is not very robust, the Company's analysis confirmed that Portfolio 5 (which included 520 MW of installed solar capacity and B2H) had the 10th highest average cost across the futures, but the lowest variation in cost across the futures. In contrast, Portfolio 7 (B2H and natural gas plants) had the lowest average cost but the 9th highest standard variation. This means that Portfolio 5 is far less susceptible to changes in the input variables than Portfolio 7. However, the Company maintains that the $20 million difference in standard deviation between Portfolio 5 and Portfolio 7 is dwarfed by the $175 million average price difference between the two portfolios. That is true, but in part because the average resource costs of Portfolio 7 benefit more from the Company's unreasonably low gas price forecast than the resources costs in Portfolio 5. Staff also notes that unreasonably low gas prices assumptions disadvantage portfolios with coal-fired generation and SCR investments.

Based on the results of the stochastic risk analysis, the Company selected Portfolio 7 as its preferred portfolio. In addition, the variable price risk in Portfolio 7 being disproportionately borne by customers, Staff is also concerned that Portfolio 7 assumes that Bridger Units 1 and 2 would be allowed to operate for 10 and 7 years, respectively, after the mandated SCR compliance dates.

Action Plan

The stated goal of this IRP was to make a determination on SCR investments at Bridger and the economics of B2H. The Company states that its action plan for 2017 through 2021 includes beginning and successfully completing negotiations necessary to allow Bridger Units 1 and 2 to operate beyond their compliance dates without SCRs and retire in 2028 and 2032.

Regarding B2H, the Company states that the action plan includes continued permitting as well as preliminary construction beginning in 2018. The action plan also includes moving forward with the previously determined plan to retire Valmy Units 1 and 2 in 2019 and 2025 and acquire the subsequent transmission availability from northern Nevada. Other items in the action plan include proceeding with the Gateway West transmission project, pursuing the cost-effective energy efficiency identified through the CPA process, preparing for EIM participation in April 2018, ongoing involvement in the CAA Section 111(d) proceedings, and investigation of solar PV contribution to peak and loss of load probability in preparation for the 2019 IRP.

Staff believes this plan is adequate to implement the preferred portfolio. However, Staff believes that the Company's methodology for peak capacity forecasting, the limited energy efficiency resource modeling, the very low natural gas price assumptions, and similarity of the modeled portfolios to each other combined to make this IRP far less robust than its predecessor.

RECOMMENDATIONS

After reviewing the Company's 2017 IRP, Staff believes that the Company performed sufficient analysis, gave reasonably equal consideration of supply and demand-side resources, and provided acceptable opportunities for public input, resulting in an IRP that satisfies the requirements set forth in Commission Order Nos. 25260 and 22299. Staff thus recommends the Commission acknowledge the Company's 2015 IRP.

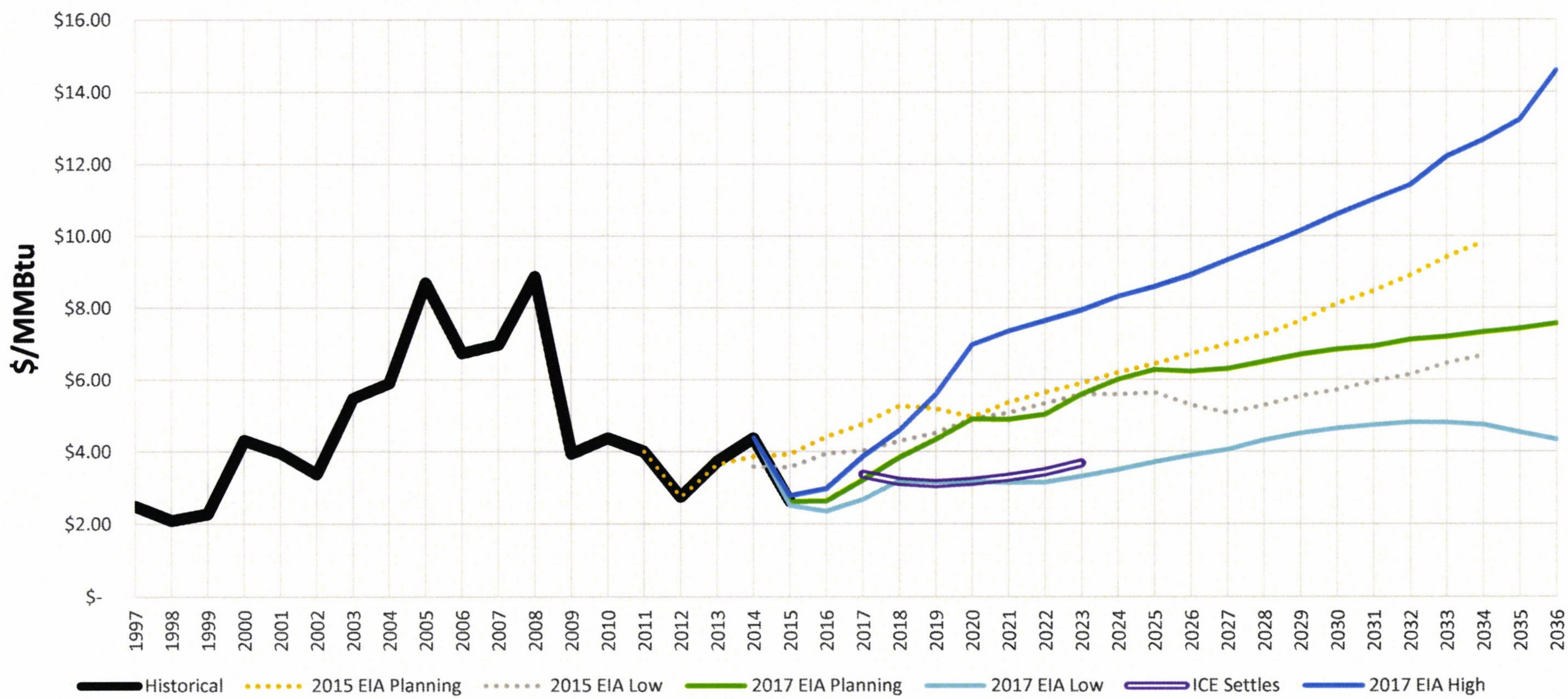
Respectfully submitted this 27th day of November 2017.

Sean Costello
Deputy Attorney General

Technical Staff: Stacey Donohue
Michael Morrison

Umisc/Comments/ipce17.11scsdmm comments

Henry Hub Natural Gas Prices (Nominal Dollars)



Attachment A
Case No. IPC-E-17-11
Staff Comments
11/27/17

Open interest as of: June 12, 2017	Henry Hub Natural Gas Last Day Financial Volume		Henry Hub Natural Gas Futures		
	Contract size= 2,500 mmBtu		Contract size= 10,000 mmBtu		
Month	Open Interest	Total mmBtu	Open Interest	Total mmBtu	Total Open Interest in mmBtu
JUL 17	56,517	141,292,500	211,088	2,110,880,000	2,252,172,500
AUG 17	52,128	130,320,000	193,740	1,937,400,000	2,067,720,000
SEP 17	49,427	123,567,500	169,951	1,699,510,000	1,823,077,500
OCT 17	62,089	155,222,500	184,150	1,841,500,000	1,996,722,500
NOV 17	47,450	118,625,000	72,670	726,700,000	845,325,000
DEC 17	48,653	121,632,500	67,213	672,130,000	793,762,500
JAN 18	64,155	160,387,500	112,080	1,120,800,000	1,281,187,500
FEB 18	35,064	87,660,000	45,083	450,830,000	538,490,000
MAR 18	41,473	103,682,500	73,996	739,960,000	843,642,500
APR 18	50,676	126,690,000	88,466	884,660,000	1,011,350,000
MAY 18	35,278	88,195,000	39,935	399,350,000	487,545,000
JUN 18	33,128	82,820,000	21,988	219,880,000	302,700,000
JUL 18	34,738	86,845,000	25,281	252,810,000	339,655,000
AUG 18	35,146	87,865,000	19,928	199,280,000	287,145,000
SEP 18	33,322	83,305,000	17,601	176,010,000	259,315,000
OCT 18	46,051	115,127,500	41,946	419,460,000	534,587,500
NOV 18	31,355	78,387,500	20,692	206,920,000	285,307,500
DEC 18	33,445	83,612,500	22,788	227,880,000	311,492,500
JAN 19	19,929	49,822,500	10,716	107,160,000	156,982,500
FEB 19	16,547	41,367,500	3,528	35,280,000	76,647,500
MAR 19	18,857	47,142,500	4,810	48,100,000	95,242,500
APR 19	14,321	35,802,500	5,680	56,800,000	92,602,500
MAY 19	14,497	36,242,500	1,558	15,580,000	51,822,500
JUN 19	14,078	35,195,000	1,432	14,320,000	49,515,000
JUL 19	14,334	35,835,000	1,303	13,030,000	48,865,000
AUG 19	14,297	35,742,500	1,257	12,570,000	48,312,500
SEP 19	13,962	34,905,000	1,214	12,140,000	47,045,000
OCT 19	14,777	36,942,500	3,397	33,970,000	70,912,500
NOV 19	14,180	35,450,000	1,444	14,440,000	49,890,000
DEC 19	15,015	37,537,500	1,452	14,520,000	52,057,500
JAN 20	11,147	27,867,500	942	9,420,000	37,287,500
FEB 20	10,177	25,442,500	532	5,320,000	30,762,500
MAR 20	10,785	26,962,500	595	5,950,000	32,912,500
APR 20	9,877	24,692,500	761	7,610,000	32,302,500
MAY 20	10,344	25,860,000	639	6,390,000	32,250,000
JUN 20	9,976	24,940,000	543	5,430,000	30,370,000
JUL 20	10,465	26,162,500	526	5,260,000	31,422,500
AUG 20	10,506	26,265,000	490	4,900,000	31,165,000
SEP 20	10,167	25,417,500	490	4,900,000	30,317,500
OCT 20	10,397	25,992,500	514	5,140,000	31,132,500
NOV 20	10,085	25,212,500	521	5,210,000	30,422,500
DEC 20	10,015	25,037,500	819	8,190,000	33,227,500
JAN 21	5,197	12,992,500	138	1,380,000	14,372,500
FEB 21	4,792	11,980,000	129	1,290,000	13,270,000
MAR 21	5,162	12,905,000	117	1,170,000	14,075,000
APR 21	4,902	12,255,000	82	820,000	13,075,000
MAY 21	5,065	12,662,500	68	680,000	13,342,500
JUN 21	4,976	12,440,000	68	680,000	13,120,000
JUL 21	5,127	12,817,500	66	660,000	13,477,500
AUG 21	5,164	12,910,000	67	670,000	13,580,000
SEP 21	4,948	12,370,000	74	740,000	13,110,000
OCT 21	4,975	12,437,500	69	690,000	13,127,500
NOV 21	4,856	12,140,000	68	680,000	12,820,000
DEC 21	5,018	12,545,000	103	1,030,000	13,575,000

Open interest as of: June 12, 2017	Henry Hub Natural Gas Last Day Financial Volume		Henry Hub Natural Gas Futures		
	Contract size= 2,500 mmBtu		Contract size= 10,000 mmBtu		
Month	Open Interest	Total mmBtu	Open Interest	Total mmBtu	Total Open Interest in mmBtu
JAN 22	3,749	9,372,500	5	50,000	9,422,500
FEB 22	3,388	8,470,000	5	50,000	8,520,000
MAR 22	3,757	9,392,500	6	60,000	9,452,500
APR 22	3,701	9,252,500	13	130,000	9,382,500
MAY 22	3,805	9,512,500	14	140,000	9,652,500
JUN 22	3,672	9,180,000	13	130,000	9,310,000
JUL 22	3,777	9,442,500	14	140,000	9,582,500
AUG 22	3,773	9,432,500	14	140,000	9,572,500
SEP 22	3,663	9,157,500	13	130,000	9,287,500
OCT 22	3,891	9,727,500	13	130,000	9,857,500
NOV 22	3,509	8,772,500	13	130,000	8,902,500
DEC 22	3,621	9,052,500	2	20,000	9,072,500
JAN 23	2,478	6,195,000	3	30,000	6,225,000
FEB 23	2,360	5,900,000			5,900,000
MAR 23	2,595	6,487,500			6,487,500
APR 23	2,516	6,290,000	11	110,000	6,400,000
MAY 23	2,595	6,487,500	13	130,000	6,617,500
JUN 23	2,516	6,290,000	11	110,000	6,400,000
JUL 23	2,571	6,427,500			6,427,500
AUG 23	2,571	6,427,500			6,427,500
SEP 23	2,492	6,230,000			6,230,000
OCT 23	2,571	6,427,500	4	40,000	6,467,500
NOV 23	2,492	6,230,000			6,230,000
DEC 23	2,571	6,427,500			6,427,500
JAN 24	1,740	4,350,000			4,350,000
FEB 24	1,636	4,090,000			4,090,000
MAR 24	1,740	4,350,000			4,350,000
APR 24	1,688	4,220,000			4,220,000
MAY 24	1,740	4,350,000	2	20,000	4,370,000
JUN 24	1,688	4,220,000	1	10,000	4,230,000
JUL 24	1,740	4,350,000			4,350,000
AUG 24	1,740	4,350,000			4,350,000
SEP 24	1,688	4,220,000			4,220,000
OCT 24	1,740	4,350,000			4,350,000
NOV 24	1,688	4,220,000			4,220,000
DEC 24	1,740	4,350,000			4,350,000
JAN 25	1,092	2,730,000			2,730,000
FEB 25	984	2,460,000			2,460,000
MAR 25	1,092	2,730,000			2,730,000
APR 25	1,056	2,640,000			2,640,000
MAY 25	1,092	2,730,000	1	10,000	2,740,000
JUN 25	1,056	2,640,000			2,640,000
JUL 25	1,092	2,730,000			2,730,000
AUG 25	1,092	2,730,000			2,730,000
SEP 25	1,056	2,640,000			2,640,000
OCT 25	1,092	2,730,000			2,730,000
NOV 25	1,056	2,640,000			2,640,000
DEC 25	1,092	2,730,000			2,730,000
JAN 26	536	1,340,000			1,340,000
FEB 26	488	1,220,000			1,220,000
MAR 26	536	1,340,000			1,340,000
APR 26	520	1,300,000			1,300,000
MAY 26	536	1,340,000			1,340,000
JUN 26	520	1,300,000			1,300,000

Open interest as of: June 12, 2017	Henry Hub Natural Gas Last Day Financial Volume		Henry Hub Natural Gas Futures		
	Contract size= 2,500 mmBtu		Contract size= 10,000 mmBtu		
Month	Open Interest	Total mmBtu	Open Interest	Total mmBtu	Total Open Interest in mmBtu
JUL 26	536	1,340,000			1,340,000
AUG 26	536	1,340,000			1,340,000
SEP 26	520	1,300,000			1,300,000
OCT 26	536	1,340,000			1,340,000
NOV 26	520	1,300,000			1,300,000
DEC 26	536	1,340,000			1,340,000
JAN 27					-
Feb 27					-
Mar 27					-
Apr 27					-
May 27					-
Jun 27					-
Jul 27					-
Aug 27					-
Sep 27					-
Oct 27					-
Nov 27					-
Dec 27					-
JAN 28	217	542,500			542,500
FEB 28	203	507,500			507,500
MAR 28	217	542,500			542,500
APR 28	210	525,000			525,000
MAY 28	217	542,500			542,500
JUN 28	210	525,000			525,000
JUL 28	217	542,500			542,500
AUG 28	217	542,500			542,500
SEP 28	210	525,000			525,000
OCT 28	217	542,500			542,500
NOV 28	210	525,000			525,000
DEC 28	217	542,500			542,500

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 27TH DAY OF NOVEMBER 2017, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-17-11, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

LISA D NORDSTROM
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-mail: lnordstrom@idahopower.com
dockets@idahopower.com

TIMOTHY E TATUM
MICHAEL J YOUNGBLOOD
IDAHO POWER COMPANY
PO BOX 70
BOISE ID 83707-0070
E-MAIL: ttatum@idahopower.com
myoungblood@idahopower.com

PETER J. RICHARDSON
RICHARDSON ADAMS, PLLC
PO BOX 7218
BOISE ID 83702
E-mail: peter@richardsonadams.com

DR. DON READING
6070 HILL ROAD
BOISE ID 83703
E-mail: dreading@mindspring.com

ERIC L. OLSEN
ECHO HAWK & OLSEN, PLLC
505 PERSHING AVENUE STE 100
PO BOX 6119
POCATELLO ID 83205
E-mail: elo@echohawk.com

ANTHONY YANKEL
12700 LAKE AVENUE UNIT 2505
LAKEWOOD OH 44107
E-mail: tony@yankel.net

C. TOM ARKOOSH
ARKOOSH LAW OFFICES
802 W BANNOCK STREET STE 900
PO BOX 2900
BOISE ID 83701
E-mail: tom.arkoosh@arkoosh.com
erin.cecil@arkoosh.com

PETE BENNETT
MICRON TECHNOLOGY INC.
8000 SOUTH FEDERAL WAY
BOISE ID 83707
E-mail: cbennett@micron.com

THORVALD A. NELSON
EMANUEL T. COCIAN
KIM STANGER
HOLLAND & HART
6380 S. FIDDLERS GREEN CIRCLE
STE 500
GREENWOOD VILLAGE CO 80111
E-mail: tnelson@hollandhart.com
etcocian@hollandhart.com
kcstanger@hollandhart.com
khall@hollandhart.com

GREGORY M ADAMS
RICHARDSON ADAMS, PLLC
515 N 27TH STREET
BOISE ID 83702
E-mail: greg@richardsonadams.com

GLORIA D SMITH
SIERRA CLUB
2101 WEBSTER STREET, SUITE 1300
OAKLAND CA 94612
E-mail: gloria.smith@sierraclub.org

JIM KREIDER
STOP B2H
60366 MARVIN RD
LA GRANDE OR 97850

Jo Nelson
SECRETARY