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February 16, 2018

VIA ELECTRONIC AND US MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket LC 68 - Idaho Power Company's 2017 Integrated Resource Plan ("IRP")

Attached for filing in the above-identified docket is Idaho Power Company's Final Comments. Confidential copies of Attachments 1-3 will be sent to the Filing Center and parties who have signed Protective Order 17-292 via US Mail.

Please contact this office with any questions

Sincerely,

Alisha Till

Alisha Till
Legal Assistant

Enclosures

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 68

In the Matter of: IDAHO POWER COMPANY'S 2017 Integrated Resource Plan.	**IDAHO POWER COMPANY'S FINAL COMMENTS**

February 16, 2018

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I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Final Comments to the Public Utility Commission of Oregon ("Commission"). These comments respond to the final comments of Staff of the Public Utility Commission of Oregon ("Staff"), the Oregon Citizens' Utility Board ("CUB"), STOP B2H Coalition ("STOP B2H"), Sierra Club, the Renewable Energy Coalition ("REC"), the Oregon Department of Energy ("ODOE"), and Gail Carbiener.

Idaho Power continues to request that the Commission acknowledge the Company's 2017 Integrated Resource Plan ("IRP"). The IRP satisfies each of the Commission's procedural and substantive requirements and presents robust and comprehensive analysis supporting the reasonableness of its short-term and long-term resource portfolio. The Company's preferred portfolio includes the following key short-term action items and assumptions:

- Intent to shut down Idaho Power's ownership share in North Valmy unit 1 by year-end 2019 and North Valmy unit 2 by year-end 2025;
- Development of the Boardman to Hemingway 500-kV transmission line ("B2H"); and
- Shutdown for units 1 and 2 of the Jim Bridger Coal-fired power plant, instead of making selective catalytic reduction ("SCR") investments.

Critically, the 2017 IRP represents a key milestone in the Company's ongoing efforts to develop the B2H line. Originally specified as a 285 MW transmission capacity resource in the Company's 2006 IRP's preferred resource portfolio, the B2H project has remained a paramount component of Idaho Power's preferred portfolios since the 2009 IRP and has consistently represented the least-cost, least-risk resource for customers. In each of the last four IRPs, the Commission has recognized that continued development of the project is reasonable. Here, the Company's least-cost least-risk preferred portfolio again includes the B2H project as a transmission resource. However, the Company now requests acknowledgment of the decision to both continue permitting/planning activities and to begin construction of the line. The Company intends to use acknowledgment of B2H in the 2017 IRP to support its Application for a Site Certificate to Oregon's Energy Facility Siting Council ("EFSC"). Acknowledgment of the Company's 2017 IRP is therefore essential to the continued advancement of the project so that it may be placed in service to meet customer needs.

II. BOARDMAN TO HEMINGWAY

A. B2H is Independent of PacifiCorp's "Energy Gateway" Projects.

Staff requests further explanation of how B2H fits into the larger "Energy Gateway" transmission project.[1] As an initial matter, "Energy Gateway" is nomenclature used by PacifiCorp, not by Idaho Power, to describe a combination of transmission projects including B2H and Gateway West.[2] While Idaho Power understands that PacifiCorp characterizes its interest in the B2H project as a portion of its Energy Gateway plan, Idaho Power's interest in Gateway West and B2H should not be construed as Idaho Power having broader interest in Energy Gateway or an acceptance of PacifiCorp's naming conventions.

As for the relationship between B2H and Gateway West, the benefits to Idaho Power of B2H are independent from Gateway West. The Gateway West line is a joint project between Idaho Power and PacifiCorp to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar Substation near Glenrock, Wyoming, to the Hemingway Substation near Melba, Idaho.[3] PacifiCorp serves as the permitting project manager for the project.[4]

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[1] Staff's Final Comments at 11.

[2] Future Energy Gateway segments include Gateway West, Gateway South, and B2H. *See* PacifiCorp's 2017 IRP at 57.

[3] Idaho Power Company's 2017 Integrated Resource Plan at 67 (hereinafter, "Idaho Power's 2017 IRP").

[4] Idaho Power's 2017 IRP at 67.

B. Construction Negotiations Will Commence Upon Submission of the Oregon Department of Energy's Draft Proposed Order.

Idaho Power, Bonneville Power Administration ("BPA"), and PacifiCorp have entered into a joint permitting agreement ("Permitting Agreement") for B2H, but have not yet entered into agreements governing construction and operation of the project. Pursuant to the original Permitting Agreement, the Bureau of Land Management's ("BLM") issuance of a Record of Decision would trigger the issuance of a Notice of Completion, which in turn would mark the initiation of development and construction negotiations among the co-participants. Staff requests an update on this process generally and has specifically inquired as to when the Notice of Completion will be issued and negotiations commenced.[5]

On February 13, 2018, the co-participants amended the Permitting Agreement (included here as Confidential Attachment 1) to include the following relevant changes:

- Rather than using BLM's issuance of a Record of Decision as the trigger for issuing a Notice of Completion and initiating development and construction negotiations, the co-participants agreed that negotiations will begin once EFSC submits a Draft Proposed Order.[6] EFSC is expected to submit its Draft Proposed Order for B2H in May of 2018.
- The window for conducting development and construction negotiations was reduced from 180 days (with an additional 180 days upon mutual agreement) to 120 days (with an additional 120 days upon mutual agreement).[7]
- Additional project activities were incorporated into the Permitting Agreement, including title searches and preparation of the geotechnical plan of development (enabling BLM

[5] Staff's Final Comments at 8.

[6] Confidential Attachment 1 at 15.

[7] Confidential Attachment 1 at 16.

to authorize geotechnical investigations in 2019).[8] Both activities were previously considered preliminary construction activities.

These modifications to the Permitting Agreement ensure that those project activities necessary to place the line in service by the mid-2020s are funded, while providing all three companies more certainty with respect to permitting and regulatory milestones.

C. Partnership Risks

In its final comments, Staff identifies two concerns related to the B2H co-participants—particularly, regarding the co-participants' commitment to developing B2H and the Company's ability to rely on asset-swaps between the eventual co-owners of the line. These concerns are addressed in turn, below.

1. Co-Participants in B2H Have Repeatedly Demonstrated Their Commitment to the Project's Development.

Staff remains concerned about "the commitment of B2H's majority owners to pay for the construction of the project," and suggests that "this risk is not fully captured" in Idaho Power's analysis.[9] However, this concern appears to discount co-participants' significant and ongoing demonstrations of their commitment to the project. Indeed, PacifiCorp recently submitted a $23 million payment to Idaho Power on January 26, 2018, to further the project's development. Collectively, PacifiCorp and BPA have expended $68 million in project expenses to date, including non-mandatory vesting payments.[10] As of January 26, 2018, both BPA and PacifiCorp had fully reimbursed Idaho Power for all expenses incurred through 2017. These large financial

[8] Confidential Attachment 1 at 46-47.

[9] Staff's Final Comments at 10.

[10] Non-mandatory vesting payments allowed PacifiCorp and BPA to elect to maintain their commitment to the project by compensating Idaho Power for each party's respective percentage interest in the project over time. These are non-mandatory payments because both PacifiCorp and BPA could elect not to make these payments and thereby forfeit their ongoing participation in the project's development. Both parties have chosen to maintain their participation by making these payments.

commitments are a strong demonstration of the co-participants' intent to fully develop the B2H project.

In response to the concerns voiced by Staff and others, Idaho Power recently performed a cost sensitivity analysis to assess risk associated with the B2H co-participants' commitment to the project.[11] This modeling demonstrates that B2H continues to provide customer benefits even with substantial cost escalation. Idaho Power's cost-share (based on partnership interest) could double with zero incremental capacity and the project would still provide the most cost-effective resource for customers.

In light of the amended Permitting Agreement, co-participants' ongoing financial commitments, and the above capital-cost risk analysis, Idaho Power strongly believes that the co-participants are committed to the B2H project's development and that the project will provide a cost-effective resource for customers.

2. Idaho Power Reasonably Anticipates that Co-Owners Will Have Defined Capacity Rights and Will Utilize Asset Swaps as Necessary.

Staff also requests clarification on the relationships among B2H co-participants and each party's potential use of the line.[12] In light of Staff's comments, Idaho Power offers two preliminary clarifications: First, ownership is not yet fixed. Given that ownership and operating agreements have not been executed, another entity could co-own the line in addition to the current B2H permitting co-participants. Second, each owning entity is expected to possess defined capacity rights commensurate with capital contribution. That is, a co-owner will not pay wheeling charges to any other entity to utilize its own defined capacity. However, any other user of each respective co-owner's defined capacity would be obligated to pay a wheeling charge—including a co-owner's use of another co-owner's defined capacity.

[11] The results of this analysis are presented in Appendix D – B2H Supplement under the "Capital Cost Risk" section.

[12] Staff's Final Comments at 10-11.

Staff expresses concern regarding "the likelihood the other partners will rely on asset swaps instead of forcing the Company to pay wheeling charges," and states that "Idaho Power has provided no evidence that BPA would allow for such an arrangement."[13] To clarify, the asset swaps referenced in all other correspondence with the Commission refer to existing assets, not to new facilities. Asset swaps are contemplated to maximize the use of the existing transmission system and to thereby save customers money.

As for the use of transmission asset swaps among the B2H co-participants, Idaho Power, BPA and PacifiCorp have extensively discussed such swaps. Indeed, transmission asset swaps were cited as a fundamental aspect of BPA's interest in the B2H project. In BPA's letter announcing prioritization of service options, it identified the "Boardman-to-Hemingway *with Transmission Asset Swap* as its top priority for pursuit."[14] BPA further created a 500 MW placeholder for the Southeast Idaho Load Service ("SILS") asset exchange in its transmission queue to provide asset swap capacity.[15] Thus, the co-participants—and BPA in particular—have demonstrated support for the use of asset swaps instead of imposing wheeling charges.

Nonetheless, in its IRP modeling, Idaho Power conservatively *did not* assume the use of asset swaps in the portfolio evaluation. If asset swaps had been included in the Company's modeling, the wheeling cost associated with market purchases in the Pacific Northwest would have been reduced. Thus, if Portfolio 7 were re-run to include the expected asset swaps, it would show reduced wheeling costs to acquire resources from the Mid-C trading hub; the associated incremental savings are estimated to be roughly $3 million to $5 million per year.

[13] Staff's Final Comments at 10-11.

[14] Bonneville Power Administration, Letter to Regional Customers, Stakeholders, and Other Interested Parties at 1 (Oct. 2, 2012), available at https://www.bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Documents/SILS_Prioritization_Letter_10-01-12.pdf (emphasis added).

[15] BPA's Long-Term Pending Queue, available at: https://www.bpa.gov/transmission/Reports/TransmissionAvailability/Pages/default.aspx (search "SILSASSETEXC").

D. B2H Provides Clear and Substantial Benefits for Idaho Power's Oregon Customers.

Staff asks the Company to provide a more detailed explanation of why Idaho Power's customers—and Oregon ratepayers in particular—are "better off with B2H."[16] B2H offers three key advantages to Idaho Power's Oregon customers: *First* and foremost, because B2H is part of the Company's least-cost, least-risk portfolio, customers will receive economic benefits resulting from the avoidance of higher-priced resources. *Second*, the project provides multi-faceted carbon reduction benefits through (1) the inclusion of B2H as a zero-emission transmission resource, (2) ability to access to low-cost renewable energy, and (3) more effective renewable integration, thereby supporting the Company's transition away from coal—and further aligning with the State of Oregon's carbon-reduction goals. *Third,* B2H provides unique flexibility in a changing generation landscape. Agnostic to the generation technology source of electricity, B2H allows for future development of cost-effective resources, moderates seasonal cost variability, and encourages regional resource diversity. All of these are direct benefits to Idaho Power's Oregon customers.[17]

1. B2H Will Effectively Reduce Regional Transmission Losses.

In its final comments, STOP B2H broadly contests the Company's claim that B2H will reduce regional transmission losses.[18] But STOP B2H also clearly concedes B2H's benefits at peak hour, acknowledging that it is "undoubtedly true that the B2H line can reduce regional losses by 100 MW on a peak hour."[19] To clarify, by placing the B2H line in service, *peak* total system losses can be reduced by over 100 MW. STOP B2H does not question this point.

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[16] Staff's Final Comments at 11.

[17] More detailed information on B2H benefits is available in Idaho Power's 2017 IRP, Appendix D on pages 42-50.

[18] Final Comments from the STOP B2H Coalition at 26-27 (hereinafter, "STOP B2H's Final Comments").

[19] STOP B2H's Final Comments at 26-27.

Notwithstanding these facts, STOP B2H claims that 100 MW peak hour savings is merely "cherry picking" data, and that *annual* loss savings from B2H may be less than 10 MW on average.[20] While Idaho Power acknowledges that this may be a reasonable average *annual* estimate, particularly as transmission loss reductions will inevitably vary, Idaho Power's analysis focused on the benefits at peak production, when regional losses can be effectively reduced.[21] This focus in no way undercuts the fact that—as STOP B2H recognizes—B2H provides clear overall annual transmission loss reductions as well.

Finally, STOP B2H suggests that any line loss reductions will be "offset" by grid losses related to "new market power purchases from distant markets," which would be enabled by the new transmission line.[22] This statement, while correctly describing a possible impact of transmission development, is misleading in this case. Assuming that STOP B2H performed an accurate analysis using its GRIDVIEW software, these "power purchases from distant markets" would already be factored into the 10 aMW line loss reductions calculated by GRIDVIEW. Thus, the benefits of B2H clearly overcome any increases in grid losses, as demonstrated by STOP B2H's own analysis.

It is important to note that in both cases—the 100 MW peak-hour loss savings stated in Idaho Power's 2017 IRP Appendix D or the 10 average MW annual loss savings determined through STOP B2H's GRIDVIEW analysis—the loss savings represent value to the western region, not Idaho Power's customers specifically, and thus are not included as part of the IRP analysis. Loss savings are mentioned in the Appendix D as a regional benefit.

[20] STOP B2H's Final Comments at 26.

[21] Idaho Power's 2017 IRP, Appendix D – B2H Supplement at 47.

[22] STOP B2H's Final Comments at 26.

2. B2H Increases Grid Reliability.

STOP B2H further argues that any large transmission investment is unwise because "adding a high-voltage power line to the existing grid will make the grid less stable."[23] Claiming that "[s]eminal research" since the 1980s "has confirmed this with real data," STOP B2H cites two articles for support.[24] After reviewing both articles, Idaho Power is unable to determine where ***either*** makes such a claim. On the contrary, the 2002 article cited by STOP B2H merely states that cascading outages have not decreased as fast, statistically, as one might have anticipated given the addition of new generation and transmission facilities,[25] while the 2004 news article discusses the prevalence of outages and efforts underway to minimize and/or cope with such issues.[26] Indeed, the news article's discussion of transmission notes the difficulty of pursuing transmission investment given the challenge of obtaining reimbursement, either in whole or in part.[27] Thus, it is unclear how either of the articles cited by STOP B2H relates to B2H, or to the project's ability to enable Idaho Power to reliably meet its customers' growing energy demands.[28]

[23] STOP B2H's Final Comments at 34.

[24] STOP B2H's Final Comments at 34; *see also id.* at 34 nn.17-18 (citing Benjamin A. Carreras & V. E. Lynch, *Critical points and transitions in an electric power transmission model for cascading failure blackouts*, 12 Chaos Interdisc. J. Nonlinear Science 985 (2002) and Peter Fairley, *The Unruly Power Grid*, IEEE Spectrum: Tech., Engineering, and Sci. News (Aug. 2, 2004) available at https://spectrum.ieee.org/energy/the-smarter-grid/the-unruly-power-grid).

[25] Carreras & Lynch, *supra* note 21, at 993 (noting that "cascading failure blackouts" may have multiple causes, including "power flow limits of the network lines"); *see also id.* ("In spite of technological progress and great investments to ensure a secure supply of electric energy, blackouts of the U.S. electric transmission grid are not uncommon.").

[26].Fairley*, supra* note 21.

[27] *Id.* ("If you were silly enough to think about investing in transmission, we would tell you that we don't have any idea how you're going to get reimbursed or how much you're going to get reimbursed.") (quoting Lester B. Lave, described as "a risk assessment expert and economics professor").

[28] Viewed charitably, it appears that STOP B2H is taking a single line from the news article out of context as conclusive support for its position. STOP B2H quotes: "increasing the rating of individual power lines often increases the frequency of large cascading failures, much as the suppression of individual forest fires eventually leads to major conflagrations." STOP B2H's Final Comments at 35. However, this line is described in the news article as a "thesis" posited by one "school of thought"—a perspective that urges a shift in focus toward, "not how to prevent blackouts, but how to survive them." Fairley*, supra* note 21. The cited perspective is far from fact; and is instead one academic group's theory based on abstract modeling. *Id*. (describing the feedback model employed by systems theorists).

Contrary to STOP B2H's comments, transmission lines improve grid stability, reliability, and economic efficiency. Notably, STOP B2H remarks that FERC has offered PacifiCorp an incentive ROE to build the Gateway projects.[29] Idaho Power feels strongly that FERC would not actively encourage transmission construction if doing so made "the grid less stable."[30]

3. B2H Provides More Reliable Service Than Gas or Fossil Power Plants.

STOP B2H further claims that it is "absurd" to consider transmission as more reliable than a power plant.[31] However, STOP B2H's arguments on this point are based on a mistaken understanding of forced outage statistics.

Before addressing the substance of STOP B2H's contention, Idaho Power would like to clarify a labeling error in Idaho Power's 2017 IRP, Appendix D, Table 8, discovered while preparing these Final Comments. In Table 8 and the accompanying text, the reported Equivalent Demand Forced Outage Rate (EFORd) statistics were mislabeled as "EFOR" (Equivalent Forced Outage Rate, without the demand requirement). However, this labeling error has no substantive impact on the Company's IRP analysis because the relative reliability of transmission resources compared to power plants remains unchanged.

EFORd is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings *when there is a demand on the unit to generate*. In other words, if the unit is asked to generate (demand on the unit) and is unable to do so (due to forced outages or deratings), this occurrence would be reflected in the EFORd. If a unit is forced out of service but there is no demand on the unit to generate during the outage, this occurrence would affect the unit's EFOR, but not the unit's EFORd. A unit's EFOR will always be higher than its EFORd.

[29] STOP B2H's Final Comments at 20.
[30] STOP B2H's Final Comments at 34.
[31] STOP B2H's Final Comments at 34.

As for the substance of STOP B2H's claim that transmission is less reliable than power plants, STOP B2H appears to misunderstand the EFOR metric. STOP B2H claims that "for a resource, de-rating includes the time that a resource is purposely operated at less than maximum capacity in order to provide balancing reserves to the system. Therefore, a higher EFOR for generating resources can be an indicator that the resource is valuable for system balancing to support grid reliability, not because the resource itself is unreliable."[32] This statement is simply incorrect. EFOR is a statistical measure of generator reliability and does not penalize a unit for providing reserves. The best EFOR and EFORd a unit can have is zero.

With respect to transmission, the best comparison to the generator EFORd statistic is unplanned transmission line outages. STOP B2H contends that transmission lines can also be de-rated for reasons other than being fully out of service: "transmission lines are constantly being de-rated due to their interactions with other transmission lines that suffer outages, are undergoing maintenance, or are subject to restrictive operating nomograms."[33] Idaho Power agrees that these three situations can cause transmission de-rates, but they do not necessarily relate to determining a transmission EFOR. Each item is addressed below individually:

- <u>Interactions with other transmission lines that suffer outages:</u> B2H will become a part of the Idaho to Northwest path. The path is rarely de-rated today for outages outside of the Idaho Power system.
- <u>Maintenance:</u> Maintenance is planned and does not affect EFOR. EFOR is a measure of unplanned or forced outages, not planned maintenance. Idaho Power schedules maintenance to avoid negative impacts to the grid.

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[32] STOP B2H's Final Comments at 36.

[33] STOP B2H's Final Comments at 36.

- Restrictive Operating Nomograms: Idaho Power achieved a WECC Accepted Rating for the addition of B2H to the Idaho-to-Northwest path.[34] The Idaho-to-Northwest path will have no restrictive operating nomograms.[35]

Given the above discussion, it is appropriate to compare generator EFORd statistics with transmission outage statistics. Gas and fossil generators, at a nationwide level, will only be available, when needed, 90-94 percent of the time. Transmission lines, and B2H specifically, are expected to be a be available more than 99 percent of the time. Given these facts, a transmission line connected to a deep and active market hub is undoubtedly the more reliable service.

E. Co-Participants in B2H are Aligned on Project Costs.

Staff asks for confirmation that co-participants in B2H are in alignment concerning the cost of developing the line.[36] Before submitting the cost estimate for inclusion in its IRP analysis, Idaho Power reviewed this cost estimate with BPA and PacifiCorp. The meeting minutes reflecting this item demonstrate that that no party objected to or raised issues regarding the cost estimate.[37]

F. Market Purchases

1. There is Adequate Market Depth to Support the Market Purchases Enabled by B2H.

STOP B2H claims that "[n]owhere in the IRP does Idaho Power address the risks associated with" increased reliance on market purchases to meet peak load needs.[38] This claim overlooks Idaho Power's thorough discussion of this issue in the Company's Reply Comments, filed on December 8, 2017, in response to Staff's previously-expressed concerns.[39] Idaho

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[34] Idaho Power's 2017 IRP, Appendix D – B2H Supplement at 28.

[35] Operating Nomogram refers to any operating limits that can be expressed with a linear algebraic expression.

[36] Staff's Final Comments at 11.

[37] The relevant section of these meeting notes is included as Confidential Attachment 2. Note, the confidential November draft minutes were approved at the next meeting.

[38] STOP B2H's Final Comments at 4.

[39] Idaho Power Company's Reply Comments at 27-34.

Power's analysis confirmed that "there is sufficient market depth to allow the Company to utilize the market transactions" enabled by B2H.[40]

More generally, STOP B2H believes that relying on market purchases is "a bad strategy" because PacifiCorp's 2017 IRP seeks to reduce reliance on front office transactions ("FOTs") through the acquisition of new wind resources.[41] As an initial matter, Idaho Power cannot comment on PacifiCorp's IRP plan or why that company may seek to develop additional wind capacity at this time. However, PacifiCorp's reduced use of FOTs and increased wind generation development both *support* Idaho Power's conclusion that there is—and will continue to be—adequate market depth for the projected market purchases. To the extent that PacifiCorp reduces its own market purchases and increases the supply of generation, there will be more available energy in the market to purchase.

[40] Idaho Power Company's Reply Comments at 27.

[41] STOP B2H's Final Comments at 3-5.

As shown in Figure 1, the Historical Generation Mix slide presented in the March 2017 Integrated Resource Plan Advisory Council ("IRPAC") meeting, Idaho Power has and will continue to rely on market purchases to meet system peak to a significant degree.

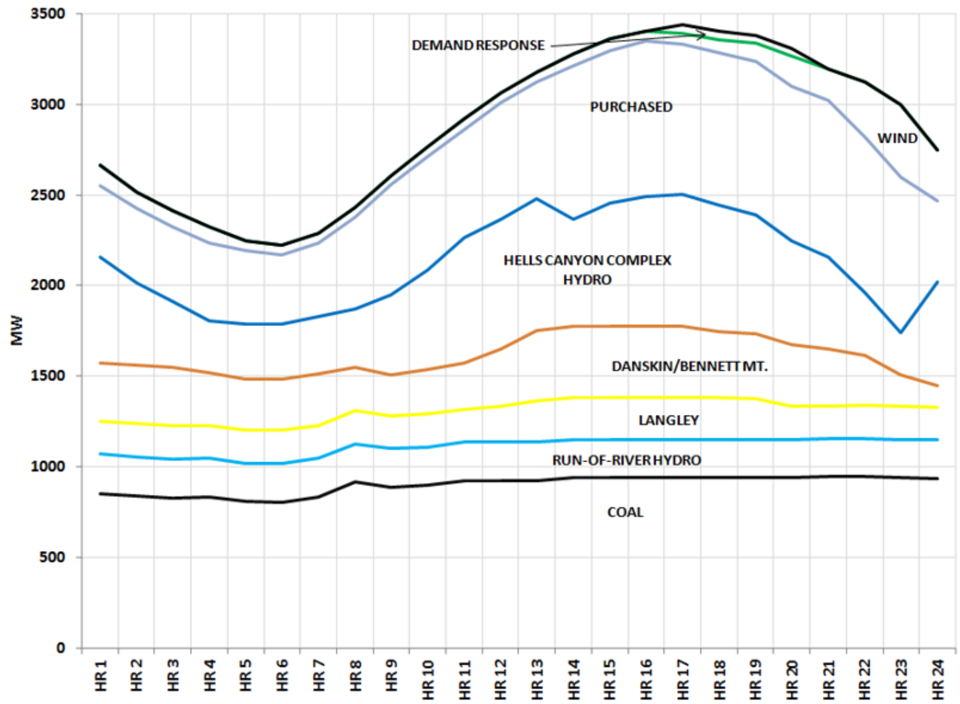

Figure 1. Historical Generation Mix for July 2, 2013

Market purchases have been an ongoing and important element in providing reliable and fairly priced energy to our customers. By sharing regional generating resources via electricity purchases and sales, utilities can achieve significant economic savings as compared to each utility constructing and generating all of its own supply. B2H will help the region continue to utilize generating resources effectively, while also providing its customers with greater access to least-cost electricity.

Importantly, Idaho Power is expanding both the quantity and type of market purchases to serve customer needs. Idaho Power currently participates in the electric markets in the West, which are hourly markets. Idaho Power is also joining an Energy Imbalance Market ("EIM"), which is a sub-hourly market, specifically designed to use transmission to more efficiently balance short term forecast error and to improve regional aggregate short-term resource stack dispatch economics. Idaho Power believes that access to both the electric markets and the EIM will allow the Company to make sufficient and economically-priced purchases as needed.

2. Where Peak Reliance on Market Purchases is the Least-Cost, Least-Risk Option for Customers, Such Reliance is Appropriate.

STOP B2H states that Idaho Power's projected use of market purchases is inappropriate because "Idaho Power will rely on FOTs to meet 26 percent of their summer peak obligation in 2029."[42] There are two problems with STOP B2H's argument.

First, STOP B2H's claim relies on Idaho Power's one-in-twenty peak load, coincident with a one-in-ten poor water year. While STOP B2H is correct that this is how Idaho Power plans to meet peak needs in such an atypical year, this forecast is not indicative of either a typical year or of the rate of typical market purchases.[43] Market purchases would be available if needed but need not be fully utilized. Again, Idaho Power will select the lowest cost option, utilizing B2H to economically import wholesale market energy to meet customer needs.

Second, STOP B2H fails to recognize that Idaho Power's reliance on market purchases is a result of its customers' unique peaking schedule. Unlike other Pacific Northwest utilities, Idaho Power's peak occurs in the late-June early-July timeframe. There is significant market power available to meet Idaho Power's needs at that time, as most other utilities are winter peaking and/or have late summer peaks.[44]

3. Market Purchases are Flexible.

STOP B2H argues that market purchases should not be increased because they "are inflexible and non-dispatchable within the hour."[45] STOP B2H's statement that market purchases

[42] STOP B2H's Final Comments at 4.

[43] Market purchases during a typical year are described in Idaho Power's 2017 IRP at page 126.

[44] This fact was further explained by Idaho Power's 2017 IRP, Appendix D at page 43.

[45] STOP B2H's Final Comments at 5.

are inflexible is incorrect. It is true that Idaho Power cannot direct the dispatch of general market purchases, but dispatchability is not a requirement. System balancing, however, *is* a requirement, and one which can be facilitated by market purchases. Not only can Idaho Power purchase power months and years in advance, day-ahead, or hour-ahead, Idaho Power can even purchase/sell power intra-hour. These timeframes are extremely flexible, allowing Idaho Power to purchase and sell power for system reliability and to acquire inexpensive power to best serve customers.

The future of flexibility is tied to increasingly robust regional markets, which allow utilities to more efficiently transact through a broad market in real-time. Transmission lines and high-capacity interconnections facilitate these regional markets and thereby increase flexibility.

G. Transmission Service

1. Third-Party Transmission Revenues are Appropriately Included in the IRP Analysis of B2H.

STOP B2H claims that "B2H will act to raise the cost of transmission for new renewables to unsupportable levels" by imposing "cross-subsidization" on third-party transmission customers and increasing the Open Access Transmission Tariff ("OATT") rate by "over 50 percent."[46] This argument (1) confuses the relationship between FERC-regulated transmission revenues and retail rates in arguing that transmission revenues are subsidies,[47] and (2) incorrectly concludes that transmission revenues will stifle new renewable energy development. For the sake of clarity, these issues are addressed in turn.

a. FERC-Regulated Transmission Service is Distinct from Retail Transmission Rates.

Idaho Power's transmission service is provided under a FERC-approved OATT. The OATT sets out the terms and conditions of service and rates to customers for transmission services. These FERC-regulated transmission rates (which include an authorized rate of return

[46] STOP B2H's Final Comments at 6.

[47] STOP B2H's Final Comments at 6.

("ROR") independent of the retail ratemaking) are charged to third parties who buy capacity on Idaho Power's transmission system to facilitate their movement of power. The revenues Idaho Power receives offset the Company's transmission-related costs or revenue requirement in base rates, to the benefit of retail customers.

By contrast, retail rates (which include recovery of transmission investments) are subject to approval by the Commission for the Company's Oregon jurisdiction and by the Idaho Public Utilities Commission ("IPUC") for the Company's Idaho jurisdiction. The Commission and the IPUC determine the appropriate level of transmission-related cost recovery from the Company's retail customers.

Thus, STOP B2H incorrectly describes the projected transmission revenues attributable to B2H as "cross subsidization."[48] Third-party transmission revenues are not a cross-subsidization from one set of customers to another because they are allocated to each jurisdiction. However, because these revenues do provide benefits to Idaho Power's customers, they are appropriately included as benefits in the IRP analysis of B2H.

b. Idaho Power's Transmission Rates Do Not Act as a Deterrent for Renewable Resources.

STOP B2H alleges that Idaho Power's transmission rates associated with B2H will stifle the growth of renewable resources that seek to wheel power through Idaho Power's system.[49] This argument misunderstands the way that renewable resources are incorporated into Idaho Power's system. Idaho Power's system has substantial renewable penetration, with 130 renewable projects totaling more than 1,100 MW of nameplate generation—a significant amount compared to Idaho Power's 3,422 MW system peak.[50] Each of these renewable projects have signed energy service agreements ("ESAs") with Idaho Power to deliver energy to Idaho Power's

[48] STOP B2H's Final Comments at 6.

[49] STOP B2H's Final Comments at 6.

[50] Idaho Power's 2017 IRP, Appendix C: Technical Appendix at 112-113.

customers. Projects that deliver energy in this way become designated network resources and are not subject to Idaho Power's OATT transmission rates. Indeed, there are no renewable projects on Idaho Power's system or outside of Idaho Power's system that currently pay for long-term firm transmission. Thus, STOP B2H's concern that transmission rates will suppress new renewable development is unfounded.

STOP B2H goes on to argue that only Idaho Power can "add unlimited resources to their own transmission system" because they can do so "without incurring any incremental fixed transmission charges."[51] This statement is misleading for two reasons. First, the addition of new resources often *requires* expansion of the transmission system through the addition of transmission plant, and this need is subsequently reviewed both by the Commission and by the IPUC. Thus, the Company's ability to add new resources is not "unlimited." Second, as explained above, independent power producers receive the same transmission treatment as the Company; a designated network resource is not subject to incremental transmission charges.

Failing to acknowledge that designated network resources would not pay transmission charges, STOP B2H proceeds to calculate what it describes as the "effective" transmission rates that a new renewable project would have to pay for firm transmission service under various capacity factor and transmission rate scenarios. STOP B2H's calculation assumes that a single renewable project would purchase long-term firm transmission service to be used for only a portion of time (40 percent capacity factor for a wind project and 25 percent capacity factor for a solar project), resulting in an "effective" transmission rate higher than the posted OATT rate.[52] While Idaho Power does not have any renewable projects utilizing transmission service in this manner, the Company is aware of merchant power producers who are able to optimize their transmission contracts by consolidating multiple projects under one merchant operator, thus

[51] STOP B2H's Final Comments at 8-9.

[52] STOP B2H's Final Comments at 7-8.

reducing their transmission wheeling costs. Idaho Power believes that, regardless of how a transmission customer chooses to use Idaho Power's transmission service, transmission customers should appropriately compensate retail customers for the use of the available capacity on the transmission system.[53]

2. B2H Does Not Face Imminent Obsolescence.

STOP B2H argues that the B2H transmission line "will be obsolete well within the 20-year IRP framework" due to increased use of micro-grids, distributed energy resources ("DER"), and storage.[54] While Idaho Power acknowledges that these tools will play a part in the utility of the future, they are not substitutes for a reliable transmission grid—particularly as renewable generation increases and as regional markets expand.[55]

For instance, Idaho Power will join the Western EIM in April of this year. There are also significant discussions underway across the West to either establish new or expand existing wholesale power markets. These markets are driven, in part, by increased renewable power generation which, as a generally variable, non-dispatchable resource, is relatively difficult to integrate onto the grid. Markets, by utilizing regional transmission interconnections, spread this

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[53] STOP B2H also states that it "remains confused" regarding the impact of Idaho Power's asset exchange with PacifiCorp, and particularly the transaction's impact on the Company's transmission formula rate. STOP B2H's Final Comments at 9. While STOP B2H acknowledges that "this issue is not directly germane to this IRP," it is explained in detail in Docket UP 315 by Idaho Power's Senior Vice President of Power Supply, Lisa Grow. *See In the Matter of PacifiCorp, dba Pacific Power, and Idaho Power Co.'s Joint Application for an Order Authorizing the Exchange of Certain Transmission Assets (Jim Bridger Plant)*, Docket No. UP 315. In that proceeding, Ms. Grow detailed FERC's treatment of the legacy agreements in Idaho Power's OATT formula rate and how the asset exchange resulted in a modification of the inputs within the formula rate that more accurately reflects Idaho Power's cost of service, benefitting Idaho Power's retail customers. Docket No. UP 315, Direct Testimony, Grow/10 (Dec. 19, 2014). Indeed, the Commission specifically concluded that "the transaction does not negatively affect transmission customers" of the two companies. Docket No. UP 315, Order No. 15-184 at 5 (May 21, 2015).

[54] STOP B2H's Final Comments at 28.

[55] *See* The Wind Energy Foundation, *Transmission Upgrades & Expansion: Keys to Meeting Large Customer Demand for Renewable Energy* at 36 (Jan. 16, 2018) available at http://windenergyfoundation.org/wp-content/uploads/2018/01/WEF-Corporate-Demand-and-Transmission-January-2018.pdf (concluding that "upgrading and expanding transmission is essential to deliver significant amounts of new renewable energy to large customers").

variability across an entire region, thereby allowing the least cost generation to balance the variable resources. It is widely understood that, as renewable generation grows, the need for flexible dispatchable resources will also grow. Regional transmission interconnections, effectively employed by wholesale power markets, will be instrumental in linking these complementary resources together.

Moreover, while the need for robust regional transmission is poised to increase, transmission has historically proven to be a particularly long-lived resource—as demonstrated by the durability and flexibility of Idaho Power's transmission interconnections. The existing 230 kV transmission between the Pacific Northwest and Idaho Power was built in the late 1950s and 1960s and was intended to carry surplus energy from Idaho Power to the Northwest. These lines, and the 500 kV line to Summer Lake—originally constructed to move Jim Bridger power to western loads—are now heavily used to import energy into the Idaho Power system. Similarly, Idaho Power plans to soon repurpose the Idaho-to-Nevada transmission line, originally constructed to move Valmy energy north. Following Idaho Power's exit from Valmy, Idaho Power will utilize the line to move power into the Idaho Power system from southern power markets. Even the 161 kV transmission line between Idaho Power and Montana serves as an example of the longevity and resilience of transmission resources. This line was constructed to facilitate the World War II war effort by delivering Idaho Power and Utah Power energy to Montana copper mines in the early 1940s. Today it is still used by Idaho Power to purchase excess Montana resources. Indeed, Idaho Power has no examples of an interconnecting transmission line that has become "obsolete."

H. Detailed Siting and Permitting Risk Assessments are Outside the Scope of this IRP.

ODOE expresses concern that the Company characterizes "all portfolios that include new generation or transmission assets" as being exposed to "similar permitting and siting risks."[56] Idaho Power certainly acknowledges that permitting and siting requirements will vary between resources according to location and resource type, and noted this fact in its IRP.[57] Each resource acquisition is unique and has specific requirements and risks which cannot be known until a given project is assessed in detail—including an evaluation of the particular location, fuel source, relevant water and air requirements, zoning, access, and infrastructure, to name a few relevant criteria. As a result, detailed, project-specific permitting risk assessments must lie beyond the scope of an IRP portfolio analysis.

I. B2H Effectively Minimizes Impacts on National Trail Resources.

The Lewis & Clark Trail Heritage Foundation ("LCTHF") briefly argues that "B2H does not adequately protect national trails resources because it provides for multiple crossings of the Oregon National Historic Trail."[58] While Idaho Power acknowledges LCTHF's concern, trail impacts will be appropriately considered as part of EFSC's siting process,[59] and have already been effectively minimized by a number of different measures, described below.

By way of background, Idaho Power has worked diligently with Federal and State agencies both to identify potential impacts to national trail resources and to develop Design Features, Selective Mitigation Measures, and Implementation Plans to protect these resources. Early in the project's development, best management practices and other measures for protecting trail resources were identified and were later refined into "Design Features"—measures adopted as

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[56] Reply Comments by the Oregon Department of Energy at 5.

[57] Idaho Power's 2017 IRP at 120 (noting that siting and permitting challenges "are not uniform for all resources or for all proposed resource locations").

[58] Lewis and Clark Trail Heritage Foundation Comments at 1.

[59] OAR 345-022-0090.

standard practices to be implemented during construction, operation, and maintenance activities on all lands, regardless of jurisdiction or ownership, as appropriate.[60]

For instance, Design Feature 31 requires implementation of the procedures set forth in the National Historic Preservation Act Programmatic Agreement—a culmination of efforts between Federal and State agencies and tribes to mitigate effects on cultural resources, including national trails. Additionally, Selective Mitigation Measure 10 provides that, at trail crossings, towers will be placed at the maximum distance from the crossing allowable by design and engineering requirements.[61] Lastly, several Implementation Plans for B2H seek to address and mitigate potential cultural resource impacts, including the Programmatic Agreement, Historic Properties Management Plan, and Inadvertent Discovery Plan. These plans provide for inventorying, evaluating, and protecting cultural resources, and set forth the treatment of any eligible or listed resource that cannot be avoided, as well as procedures for handling any inadvertent discoveries of such resources. Together, these Design Features, Selective Mitigation Measures, and Implementation Plans will adequately protect national trail resources. To the extent that additional protections may be required, EFSC is specifically authorized to consider possible impacts on historic trails and may further impose any necessary mitigation conditions.[62]

In addition to LCTHF's concern regarding the impact of B2H itself on historic trail resources, Gail Carbiener expresses concern regarding possible damage to the Oregon National Historic Trail, and asserts that Idaho Power will be unable to conduct geotechnical work without a site certificate.[63] While Mr. Carbiener is correct to state that "construction" cannot begin until

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[60] A full list of these Design Features can be viewed in the B2H EIS, Chapter 2—Proposed Action and Alternatives, Table 2-7, available at https://eplanning.blm.gov/epl-front-office/projects/nepa/68150/90588/108790/02.4_Chapter_2_Proposed_Action_and_Alternatives_Part_1_2.1_to_2.5.3.pdf.

[61] B2H EIS, Table 2-13.

[62] OAR 345-022-0090.

[63] Gail Carbiener [Final] Comments at 1-2 (hereinafter, "Carbiener's Final Comments").

the applicant has a site certificate, "construction" explicitly does *not* include "surveying, exploration, or other activities to define or characterize the site,"[64] which is precisely the role of geotechnical surveying.

III. PORTFOLIO DESIGN

A. Idaho Power Will Evaluate Capacity Expansion Modeling in the 2019 IRP.

Sierra Club and CUB continue to express concern with the Company's portfolio modeling, and particularly with the lack of capacity expansion modeling.[65] Idaho Power has stated that it is amenable to evaluating capacity expansion modeling in the 2019 IRP,[66] and reiterates that willingness here.

Idaho Power acknowledges that the portfolio design for the 2017 IRP did not evaluate as many portfolios compared to the 2015 IRP. That said, the Company continues to support its portfolio design and analysis for the 2017 IRP as purposefully focused and appropriate for meeting the expressed objective of informing the IRP's action plan on key decision points—namely, whether to continue to pursue B2H (the long-standing least-cost and least-risk resource) and whether to make the SCR investments at Jim Bridger units 1 and 2. Idaho Power did not explicitly describe these resource options as binary-type decisions, as four different options were studied for treatment of the Jim Bridger units and three different primary portfolio element designations were studied (B2H, solar PV/natural gas, and natural gas). Nevertheless, the Company believes it is appropriate to focus our inquiry by evaluating whether to make SCR investments or retire the Bridger units early, and whether to pursue B2H or an alternative. The portfolio design and analysis is successful in determining for each decision the preferred

[64] OAR 345-025-0006(5) (defining "construction" as "work performed on a site, *excluding* surveying, exploration or other activities to define or characterize the site, the cost of which exceeds $250,000") (emphasis added).

[65] Sierra Club's Final Comments at 2; Final Comments of the Oregon Citizens' Utility Board at 1.

[66] Idaho Power Company's Reply Comments at 44.

alternative of the two options. Moreover, the portfolio analysis accomplished the desired goal of yielding clear results on each question, determining that (1) the SCR investments are not economic and that the early retirement alternative should be pursued, consistent with Staff's findings and recommendation, and (2) B2H is the least-cost, least risk resource and should be pursued over B2H-alternative resources.

Thus, while Idaho Power's portfolio analysis in this proceeding effectively guided the Company's decision making on its expressed focused objectives, the Company remains committed to evaluating an enhanced portfolio selection methodology for the 2019 IRP.

B. Idaho Power's Modeling Accurately Characterized B2H and B2H Alternatives.

Idaho Power's comments in this section will respond to STOP B2H's claims that Idaho Power improperly specified existing transmission capacities in AURORA[67] as well as address STOP B2H's revisions to the LCOE calculation for B2H.[68]

1. B2H Provides Needed Flexible Capacity.

STOP B2H claims that "expensive and unnecessary transmission diverts capital from much needed investment in incremental flexible capacity and storage resources."[69] In raising this argument, STOP B2H overlooks the fact that B2H provides flexible capacity, supporting Idaho Power's preferred resource portfolio. Of the reasonable resource alternatives, the 2017 IRP analysis demonstrates that B2H is the least costly option to provide this service. STOP B2H would tie resource planning to hoped-for technological breakthroughs or to dramatic technological cost shifts. Such dependence on theoretical advances that do not yet exist is not prudent planning. Nor are these other incremental resources foreclosed or even hindered by B2H, as

[67] STOP B2H's Final Comments at 10.

[68] STOP B2H's Final Comments at 16-26.

[69] STOP B2H's Final Comments at 15.

most such resources would require transmission or distribution upgrades to support effective integration.[70]

2. Idaho Power's Portfolio Modeling Complies with Oregon's IRP Guidelines and Fairly Assesses B2H-Alternative Resources.

STOP B2H claims that Idaho Power manipulated its portfolios through "sleight-of-hand" in order to favor construction of B2H, and "effectively abdicated its responsibility under Oregon's IRP Guidelines to construct a representative set of resource portfolios."[71] Idaho Power strongly disagrees. First, contrary to STOP B2H's accusation, the process had no preconceived preferred portfolio.[72] Second, the 2017 IRP portfolios fully comply with the Oregon IRP Guidelines by effectively identifying the least-cost, least-risk portfolios that nonetheless provide reliable service throughout the IRP planning horizon.

Idaho Power included the most cost-effective resources in the portfolio analysis to assess the most compelling alternatives under a robust set of futures. By using the most economical resource options that, when combined, provided acceptable reliability levels, the Company was able to conduct a focused assessment of both the SCR and B2H investment options. While additional portfolios could have been constructed with more expensive resource options, this would merely have increased the volume—rather than the rigor—of the Company's analysis.

3. Transmission Constraints were Properly Modeled in AURORA.

STOP B2H claims that Idaho Power improperly constrained transmission capacity between the Pacific Northwest and Idaho in the AURORA base case.[73] STOP B2H is mistaken. The Company believes that STOP B2H's faulty conclusion relied on a subset of output from

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[70] *See* IRP Technical Appendix at 74.

[71] STOP B2H's Final Comments at 15.

[72] The characteristics of each resource considered was presented to, discussed with, and verified by the IRPAC, and are fully described in the IRP Appendix C -Technical Appendix, beginning on page 73.

[73] STOP B2H's Final Comments at 12-13.

AURORA, which was then misinterpreted by STOP B2H, leading to that party's erroneous conclusion.

EPIS, the developer of AURORA, provides an AURORA default database with every release of the model. The inputs in this default database are based on public information that is gathered from multiple sources, including FERC Form 1, the Energy Information Administration ("EIA"), and other openly-available data sources. The Company updates the AURORA default database with Idaho Power-specific inputs where information is more accurately known by the Company. In particular, the Company updates the model's fuel costs, plant capacities, heat rates, maintenance schedules, hydro shaping, demand, and ATC.

The AURORA default database consists of four transmission paths or interconnections from the Idaho Power zone to other zones. A zone represents a geographical electrical demand or balancing area. The AURORA setup run for the IRP portfolio analysis contains 44 zones and includes the entire Western Electricity Coordinating Council ("WECC"). The entire WECC is simulated in each AURORA run. The Company modifies the AURORA default setup to include seven transmission paths that connect to the Idaho Power zone, to more accurately reflect Idaho Power's existing transmission system. Figure 2 is a diagram of the zones and transmission paths that make up the WECC in AURORA.

Specific to the Idaho Power zone, the AURORA transmission path setup is shown below in Figure 2:[74]

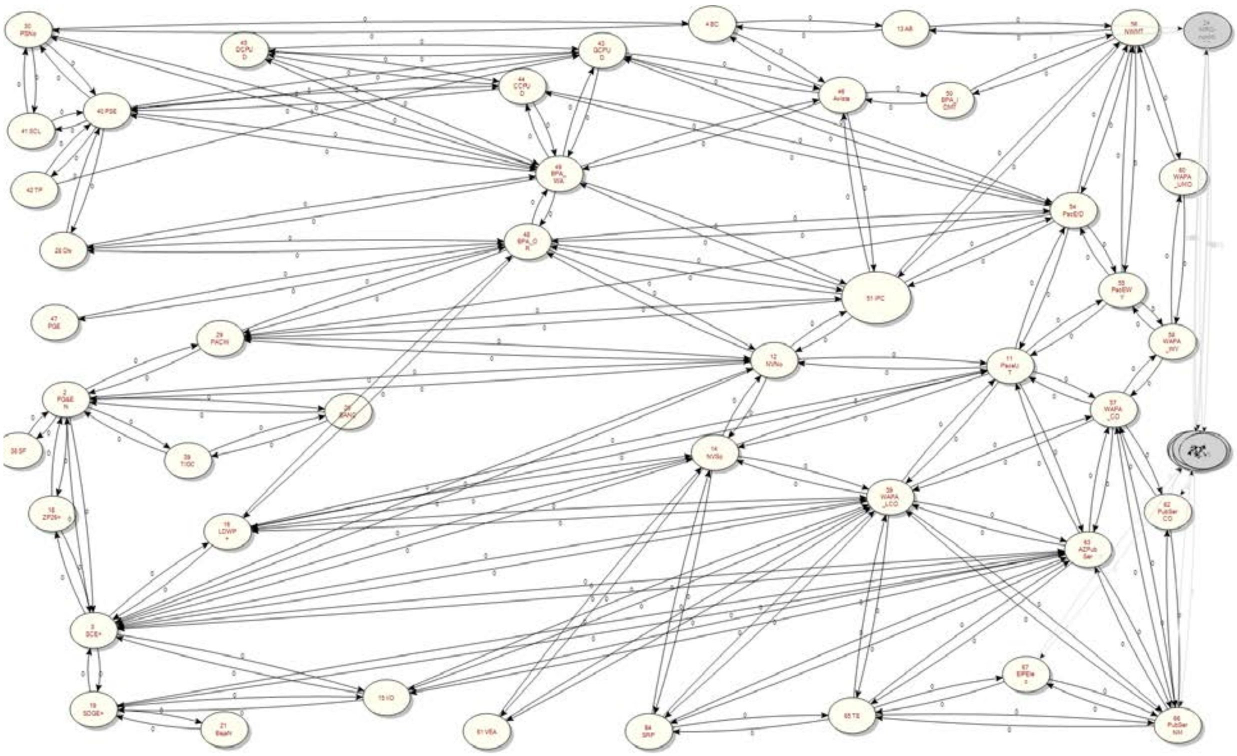

Figure 2. AURORA Transmission Path Setup

STOP B2H's claim that Idaho Power artificially limited transmission capacity currently available for Northwest imports appears to be based on misinterpreting AURORA data based on a single transmission path, provided in response to a data request, rather than the entire import capability modeled in AURORA.

In response to Staff Data Request 56, "Aurora B2H LCOE," the Company provided transmission information concerning a particular path, presented here as Figure 3.[75]

[74] Please note that the transmission capacity values in this figure have been zeroed out for presentation purposes.

[75] *See* Idaho Power's Response to Staff's Data Request 56, filename "609 to 612=WECC_PNW_Bonneville_OR-to-WECC_PNW_IdahoPowerTV".

ID
615to612=WECC_PNW_PacificorpEastID-to-WECC_PNW_IdahoPowerFE
609to612=WECC_PNW_Bonneville_OR-to-WECC_PNW_IdahoPowerTV
607to612=WECC_PNW_Avista-to-WECC_PNW_IdahoPowerTV
055to613=WECC_NevadaNorth-to-WECC_PNW_IdahoPowerMV
610to612=WECC_PNW_Bonneville_WA-to-WECC_PNW_IdahoPower
617to612=WECC_NorthwestMT_PUD-to-WECC_PNW_IdahoPower
94to612=WECC_PNW_PACWSouth-to-WECC_PNW_IdahoPower

Figure 3. Aurora B2H LCOE Transmission Path

The transmission path setup described in this response (609 to 612) represents the import path to the zone which contains the geographic area of Bonneville Power Administration's Oregon transmission system linked to the Idaho area that would be served by the B2H transmission line. Outside of the AURORA model, Idaho Power refers to this transmission line as the La Grande line. STOP B2H is correct in that the available capacity setup between these two zones in AURORA is limited until the B2H capacity is added. Lines connecting other geographic areas in the Northwest include the Lolo, Enterprise, and Idaho-Montana line. These lines are represented in the AURORA setup (as 607to612, 610to612, and 617to612 respectively), and include import capacity from their respective geographic zones.[76]

Of those seven transmission paths, the La Grande transmission path has one of the lowest ATC ratings of any path to the Northwest prior to 2026, which is the pre-B2H timeframe. Figure 4 below shows the La Grande import capacity over the IRP timeframe, as compared to total, or 100 percent, transmission import capacity.

[76] Idaho Power's 2017 IRP, Appendix D pages 13-16 provides more information on the physical connections and capacity between Idaho and the Pacific Northwest.

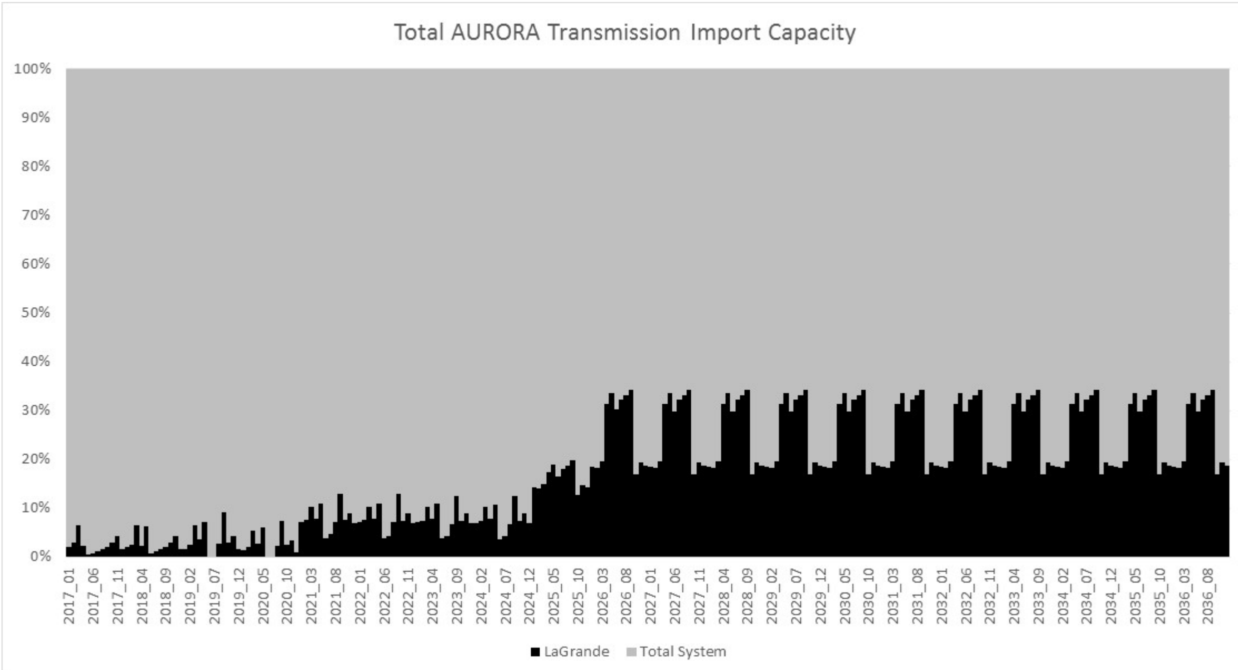

Figure 4. Total AURORA Transmission Import Capacity

Focusing on any one transmission path's values in isolation underestimates the Company's cumulative Pacific Northwest transmission capacity. Only the combined values reflect current operating characteristics of the Company. Idaho Power can only conclude that STOP B2H's analysis and conclusion must have mistaken a single path's analysis for the entire import capability modeled in AURORA.

4. Capacity Benefit Margin Was Properly Excluded from AURORA Modeling Because it is a Designated Emergency Resource Only.

STOP B2H argues that the Capacity Benefit Margin ("CBM") is equivalent to firm load capacity and available in all hours, and thus should have been included as available capacity in the AURORA model.[77] However, according to the definition of CBM, it is only available for emergency situations, as follows:[78]

> The amount of firm transmission capability preserved by the Transmission Provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission

[77] STOP B2H's Final Comments at 13.

[78] Idaho Power's OATT at 188 (adopting NERC's reliability standards),

> Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. *The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.*[79]

The Northern American Electric Reliability Corporation ("NERC"), which develops industry-wide reliability standards, confirms that CBM is to be used for emergencies only.[80] Thus, CBM was appropriately excluded from the Company's AURORA modeling, and the values used for ATC in the load and resource balance were consistent with the Company's ATC, as used to manage the system's reliability requirements.

5. Idaho Power Properly Calculated and Applied the Levelized Cost of Energy Metric.

In a series of arguments, STOP B2H argues that Idaho Power incorrectly calculated and applied the levelized cost of energy ("LCOE") metric.[81] In particular, STOP B2H argues that Idaho Power (1) incorrectly calculated the levelized costs of B2H used as inputs to AURORA modeling,[82] (2) understated the cost-of-capital component of LCOE associated with B2H,[83] (3) erroneously extracted wholesale market power costs from the output of AURORA simulations, and (4) improperly used LCOE to forecast secondary transmission revenues.[84] The Company addresses each argument in turn.[85]

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[79] NERC Glossary of Terms Used in Reliability Standards at 9 (defining "Capacity Benefit Margin"), available at https://naesb.org/pdf4/weq_srs051810w3.pdf. This definition was approved by FERC. *Mandatory Reliability Standards for the Bulk-Power System*, Docket No. RM06-16-000, Order No. 693 at (Mar. 16, 2007)

[80] *See* NERC MOD 004-1 ("Capacity Benefit Margin"), R10 ("The Load Serving Entity shall request to import energy over firm transmission capacity set aside as CBM only when experiencing a declared Energy Emergency Alert (EEA) 2 or higher.").

[81] STOP B2H's Final Comments at 16-25.

[82] STOP B2H's Final Comments at 16.

[83] STOP B2H's Final Comments at 19-20.

[84] STOP B2H's Final Comments at 22.

[85] During the preparation of the response to Staff Data Request 56, Idaho Power discovered a discrepancy in the LCOE presented in Figure 7.6 of the 2017 IRP. The Company's response to Staff Data Request 56 clarified the error, and Idaho Power promptly filed a letter in this docket, notifying all

a. STOP B2H Mistakenly Believes that LCOE Was Used for Portfolio Evaluation.

LCOE is *not* an AURORA input and was *not* used in the Company's portfolio modeling. The Company used LCOE to consistently compare resource options in the 2017 IRP process, and to illuminate the relative costs of each.[86] The Company determined each resource's LCOE using consistent workbooks and methodologies, allowing for an "apples-to-apples" comparison.

For portfolio modeling, total costs were determined according to total fixed and variable costs for all resources within each portfolio.[87] Variable costs were determined using an hourly dispatch model (AURORA) that includes operating costs specific to each resource; the Company was thus able to identify the cost-effectiveness of each resource.

b. STOP B2H Mistakenly Relies on FERC-Approved Transmission Rates to Calculate the Cost-of-Capital and Tax Factor Inputs to B2H's Revenue Requirement.

STOP B2H states that cost-of-capital and tax factor inputs used in the B2H revenue requirement (and used, in turn, to determine the LCOE for B2H) are incorrect. STOP B2H believes that the correct inputs are those in Idaho Power's FERC-approved transmission formula rate and in any incentive rates approved by FERC for application to B2H.[88] STOP B2H's cost-of-capital corrections are demonstrably incorrect.

As an initial matter, Idaho Power believes STOP B2H fundamentally misunderstands how transmission costs are recovered. As described above in Section II.G.1.a, it is retail rates paid by utility customers that provide for recovery of transmission costs. These rates are subject to approval by the Commission and by the IPUC for their respective jurisdictions. Thus, it is those commissions, *not FERC*, that determine the appropriate level of transmission-related cost

parties of the correction and clarifying that correction did not impact the relative ranking of resources or the results of the Company's portfolio analysis. *See* Docket No. LC 68, Idaho Power's Letter Regarding IRP Corrections at 1 (Oct. 4, 2017).

[86] Idaho Power's 2017 IRP, Figure 7.6 at 89.

[87] *See* Idaho Power's 2017 IRP, Figure 9.3 (Column 12).

[88] STOP B2H's Final Comments at 19.

recovery from the Company's retail customers. In contrast, FERC has jurisdiction over Idaho Power's transmission service (including the transmission formula rate inputs). However, because B2H is intended to serve Idaho Power's retail customers, Idaho Power appropriately used the cost-of-capital inputs approved by the state commissions in retail ratemaking as the inputs for its LCOE calculation.

Relying on two FERC orders issued in a docket unconnected with Idaho Power,[89] STOP B2H claims that PacifiCorp and Idaho Power received "special ratemaking treatment by FERC in the form of a 200 basis point incentive Return on Equity," and argues that such an incentive should have been included in Idaho Power's "LCOE inputs to the AURORA Model."[90] Setting aside the fact that LCOE was not used as an input to the AURORA model, Idaho Power was not a party to the referenced docket, nor has FERC authorized an incentive ROE adder for Idaho Power. As a result, it would have been entirely inappropriate for Idaho Power to add any incentive rate to its return on equity calculation.

c. Idaho Power Properly Calculated the Levelized Cost of Wholesale Energy.

STOP B2H claims that Idaho Power made a number of errors in post-processing the AURORA results, and that these errors undermine the Company's portfolio analysis.[91] For instance, STOP B2H notes that Idaho Power used a capacity factor of 100 percent and did not include either wheeling costs or transmission real power losses in post-processing of AURORA outputs when calculating the levelized cost of wholesale energy ("LCWE").[92] Each of these issues are discussed below.

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[89] STOP B2H's Final Comments at 20 (citing FERC Docket No. RM06-4-000, Order No. 679, Promoting Transmission Investment through Pricing Reform (July 20, 2006); FERC Docket No. EL08-75-000, Order on Petition for Declaratory Order (Oct. 21, 2008)).

[90] STOP B2H's Final Comments at 20.

[91] STOP B2H's Final Comments at 21.

[92] STOP B2H's Final Comments at 21.

First, it is worth reiterating that LCWE was only used in the LCOE cost ranking of various resources as presented in Figure 9.3 of the IRP. Thus, it was not used in AURORA modeling or in the Company's portfolio development. To the extent that STOP B2H claims to have identified errors in the Company's LCWE calculations, these do not impact the IRP portfolio analysis or the conclusion that B2H provides the least-cost, least-risk resource.

Second, STOP B2H claims the Company used a capacity factor of 100 percent in the LCWE calculation. The workpaper provided in response to Staff's Data Request 56 clearly shows that the Company used a capacity factor of 55 percent to calculate the LCWE. Because there are no fixed costs being spread over the amount of megawatt-hours determined by the capacity factor in the LCWE calculation, a change in capacity factor has no impact on the LCWE result.

Third, while the $28/MWh LCWE figure does not take into account wheeling and losses, AURORA modeling performed for each portfolio <u>*did include*</u> transmission wheeling expenses and losses. Moreover, the $28/MWh figure—which STOP B2H correctly notes was based on AURORA output[93]—is a reasonable estimate for the wholesale electric market. To calculate the LCWE for B2H, the Company used the mid-C market prices from AURORA to determine an estimate of market prices for the 20-year IRP time horizon. Including a wheeling cost in the calculation could increase the LCWE to the $32/MWh as STOP B2H recommends, which is higher than Idaho Power's estimate, but it does not impact the LCOE ranking of B2H. The Company further notes that a potential asset swap with BPA would eliminate or at least greatly minimize wheeling costs.

Lastly, the Company verified the LCWE calculation and reviewed the transmission losses. Transmission losses for high voltage transmission (*i.e.*, 500 kV) are minimal and do not change the result.[94]

[93] The referenced calculations were provided in a workpaper in response to Staff's Data Request 56.

[94] Transmission line loss reductions are discussed in detail above, in Section II.D.1.

d. STOP B2H's Concern Regarding Forecasted Transmission Revenues are Unfounded and Irrelevant to the Preferred Portfolio Results.

Lastly, STOP B2H disagrees with Idaho Power's forecasted transmission revenues, which help offset B2H costs.[95] The third-party transmission revenue credit in the B2H LCOE calculation is an estimate based on the best available information. It includes costs and revenues of expected OATT rate changes to third-party transmission system users. As described in Section II.G.1, above, Idaho Power believes it is reasonable to include estimated third-party transmission revenues in the LCOE calculation. Nonetheless, to address concerns over the inclusion of third-party transmission revenues, Idaho Power analyzed the impact of removing all third-party transmission wheeling revenue from the total portfolio cost analysis. This analysis revealed no change in the preferred portfolio outcome. Table 1 below reflects a revised version of Table 9.3 from the 2017 IRP and displays the net present value of each B2H Portfolio (P1, P4, P7 and P10), along with adjusted rankings for all portfolios, before the inclusion of any projected incremental wheeling revenues.[96]

Table 1. 2017 IRP Portfolios

2017 IRP Portfolios, NPV years 2017-2036 ($ x 1000)
B2H Revenue Credit Removed P1, P4, P7, P10

Portfolio				Variable Costs			New Resource Fixed Costs			Bridger	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Bridger Capacity Retirement (4)	Operating (AURORA) (5)	Rank (6)	Relative Difference (7)	Portfolio Fixed Costs (8)	Rank (9)	Relative Difference (10)	Bridger Fixed Costs (11)	Total Fixed + Variable Costs (12) =(5)+(8)+(11)	Lowest Cost Rank (13)	Lowest Cost Relative Difference (14)
P1	**SCR Invest, B2H, recips**	✓		**$ 5,782,181**	**10**	**$ 252,923**	**$ 131,054**	**1**	**$ -**	**$ 527,249**	**$ 6,440,484**	**3**	**$ 59,327**
P2	*SCR Invest, DR, recips, solar*			*$ 5,670,820*	*4*	*$ 141,562*	*$ 299,436*	*5*	*$ 168,382*	*$ 527,249*	*$ 6,497,505*	*6*	*$ 116,348*
P3	SCR Invest, DR, recips, CCCT			$ 5,731,938	8	$ 202,679	$ 271,669	4	$ 140,615	$ 527,249	$ 6,530,856	9	$ 149,699
P4	**Bridger 24_28, B2H, recips**	✓	✓	**$ 5,796,035**	**11**	**$ 266,777**	**$ 258,043**	**2**	**$ 126,989**	**$ 334,909**	**$ 6,388,987**	**2**	**$ 7,831**
P5	*Bridger 24_28, DR, recips, solar*		✓	*$ 5,577,721*	*2*	*$ 48,463*	*$ 653,937*	*10*	*$ 522,884*	*$ 334,909*	*$ 6,566,567*	*10*	*$ 185,411*
P6	Bridger 24_28, DR, recips, CCCT		✓	$ 5,729,526	7	$ 200,267	$ 443,808	8	$ 312,754	$ 334,909	$ 6,508,242	8	$ 127,085
P7	**Bridger 28_32, B2H, recips, CCCT**	✓	✓	**$ 5,755,589**	**9**	**$ 226,331**	**$ 259,615**	**3**	**$ 128,561**	**$ 365,952**	**$ 6,381,157**	**1**	**$ -**
P8	*Bridger 28_32, DR, recips, solar, CCCT*		✓	*$ 5,654,210*	*3*	*$ 124,951*	*$ 483,362*	*9*	*$ 352,308*	*$ 365,952*	*$ 6,503,524*	*7*	*$ 122,368*
P9	Bridger 28_32, DR, recips, CCCT		✓	$ 5,701,053	6	$ 171,794	$ 415,995	7	$ 284,941	$ 365,952	$ 6,483,000	5	$ 101,843
P10	**Bridger 21_22, B2H, recips**	✓	✓	**$ 5,807,951**	**12**	**$ 278,693**	**$ 364,615**	**6**	**$ 233,561**	**$ 283,328**	**$ 6,455,894**	**4**	**$ 74,738**
P11	*Bridger 21_22, DR, recips, solar*		✓	*$ 5,529,258*	*1*	*$ -*	*$ 767,183*	*12*	*$ 636,129*	*$ 283,328*	*$ 6,579,769*	*11*	*$ 198,613*
P12	Bridger 21_22, DR, recips, CCCT		✓	$ 5,689,172	5	$ 159,914	$ 699,009	11	$ 567,956	$ 283,328	$ 6,671,510	12	$ 290,353

[95] STOP B2H's Final Comments at 23-24.

[96] This table was originally provided in response to STOP B2H Data Request 26.

As the revised analysis demonstrates, P7 remains the lowest cost portfolio even with all third-party transmission wheeling revenues removed from the total portfolio cost. The Company believes this further demonstrates the value of B2H as a least-cost, least-risk resource in the Company's preferred portfolio.

Additionally, STOP B2H maintains that Idaho Power's assumptions regarding network load and specifically long-term firm ("LTF") reservations is "neither conservative nor credible."[97] STOP B2H's unfounded argument relies on its claim that Idaho Power will lose 710 MW of LTF wheeling once B2H is in service.[98] Idaho Power notes that the loss of BPA's 200 MW LTF contract, commensurate with B2H in-service, was already modeled in the IRP analysis. Idaho Power's modeling assumed PacifiCorp will retain its 510 MW of LTF contracts; however, Idaho Power believes there would be other third-parties interested in this limited capacity if PacifiCorp let these contracts expire. STOP B2H's argument is therefore unavailing.

C. Solar and Battery Storage Costs

STOP B2H objects to the expanded discussion of capacity and energy costs of B2H provided in Appendix D, first by claiming that the Company's analysis references the uncorrected LCOE of B2H, and second by arguing that Idaho Power's "capital cost per kilowatt at peak" metric in the revised solar tipping point chart is "misleading."[99] STOP B2H's assertions are both unpersuasive.

First, the Company's referenced Appendix D cost comparisons are based on the corrected—not uncorrected—LCOE figure for B2H.[100] Thus, STOP B2H's first contention is simply mistaken.

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[97] STOP B2H's Final Comments at 24.

[98] STOP B2H's Final Comments at 25.

[99] STOP B2H's Final Comments at 17.

[100] *See* Docket No. LC 68, Idaho Power's Letter Regarding IRP Corrections at 1 (Oct. 4, 2017).

Second, the "capital cost per kilowatt at peak" ($/kW-peak) metric recognizes that all kW of installed capacity are not the same with respect to on-peak capacity. In fact, to express capital costs strictly in terms of cost per kilowatt of installed capacity might more properly be characterized as misleading. To illustrate, suppose a load-serving entity has an identified need for 100 MW of on-peak capacity, and is considering the following two resources:

Resource A

- Capital cost per kW installed capacity = $2,000/kW
- On-peak capacity factor = 50% (*i.e.*, 1 kW installed capacity = 0.5 kW on-peak capacity)

Resource B

- Capital cost per kW installed capacity = $2,500/kW
- On-peak capacity factor = 100% (*i.e.*, 1 kW installed capacity = 1 kW on-peak capacity).

While resource B is a higher capital cost resource, it allows the resource need (100 MW) to be met at substantially lower total cost because of its higher on-peak capacity factor. Idaho Power's introduction of "capital cost per kilowatt at peak" as a metric simply accounts for the effect of on-peak capacity factor in total costs. As a transparent and useful metric, Idaho Power believes it served a clear purpose in the Company's supplemental analysis.

Sierra Club also continues to contest the Company's solar, energy storage, and energy efficiency resource assumptions.[101] Idaho Power believes that these issues were thoroughly addressed in the Company's Reply Comments.[102]

[101] Sierra Club's Final Comments at 8-10.

[102] Idaho Power Company's Reply Comments at 61-64.

IV. SUPPLY SIDE RESOURCES

A. Valmy

Staff raises three points of clarification concerning Idaho Power's Valmy analysis. First, Staff asks Idaho Power to support the reasonableness of the proposed two-year timeline for achieving a Valmy closure agreement.[103] Idaho Power and Valmy co-owner NV Energy have had, and continue to have, ongoing negotiations concerning Idaho Power's intent to shut down its ownership share of coal-fired operations at North Valmy unit 1 by December 31, 2019, and North Valmy unit 2 by December 31, 2025. Initial discussions yielded an executed Term Sheet signed on December 29, 2017, laying out initial provisions.[104] Idaho Power and NV Energy are now in the process of determining the fixed and variable cost responsibilities and finalizing a Definitive Agreement providing for Idaho Power's conclusive exit from both Valmy units. Idaho Power's discussions with law firms that have experience with dissolving partnerships and power plant closures suggest that the industry average is approximately two-years to reach an agreement between partners.

Second, Staff notes that the Company expects closing Valmy unit 1 to result in a decrease in variable power costs, but also projects that Valmy will provide 500,000 MWh of energy in Idaho Power's 2018 Annual Power Cost Update ("APCU"); Staff finds these results to be inconsistent, because "the Company would have purchased the 500,000 MWhs of power from the market in

[103] Staff's Final Comments at 13. Note, Sierra Club also generally challenges the reliability of Idaho Power's AURORA analysis, stating that, "[w]ithout access to the AURORA model, Sierra Club cannot verify the reasonableness of the input assumptions used in the runs that generated the market prices." Sierra Club's Final Comments at 7. Sierra Club goes on to suggest that, because the Company's AURORA modeling did not select Valmy units for retirement, the Company's analysis is further called into question. *Id.* However, long-term AURORA runs retire a limited amount of MW each year, and retired many other resources in this process. The fact that Valmy was not selected for retirement does not diminish the value of long-term run analysis in setting up future WECC resource stacks.

[104] The Term Sheet is included here as Confidential Attachment 3.

its most recent APCU if it were cheaper than running Valmy."[105] Staff therefore requests further explanation on this issue.

To clarify, the Company's 2018 APCU establishes a normalized level of power supply expenses. The Company uses the AURORA model to simulate the economic dispatch of the Company's resources under 89 water conditions, multiple gas prices, and normalized load. The impact of the various water and gas conditions in the APCU influence what resources are selected to run in AURORA. Because Idaho Power's system is primarily hydro-based, below average water conditions can have significant impacts on the reliance of other generating resources, market purchases and sales, and overall variable power supply expenses. The results of the AURORA modeled simulations under these multiple conditions are then averaged together to determine normalized net power supply expense ("NPSE") for the APCU.

Third, Staff asks the Company to address intergenerational equity impacts related to the early retirement of Valmy. Certainly, intergenerational equity issues are unavoidable in utility ratemaking and exist to a certain extent any time depreciation rates are changed. At the time Valmy was included in rates, Idaho Power's customers paid higher returns on undepreciated plant amounts for Valmy while paying lower depreciation expense than should have existed based upon what is known today. In contrast, customers today enjoy the benefit of 36 years' worth of depreciation resulting in a lower return component in their rates; however, based on the economics of the plant, higher depreciation expense is now warranted. Nonetheless, decisions for future customers must be made today, in light of the best available information. Idaho Power's analysis shows that the demonstrable benefits associated with exiting Valmy unit 1 at year-end 2019 outweigh the accelerated depreciation costs associated with this action—effectively serving both present and future customers. While these intergenerational inequities should be considered

[105] Staff's Final Comments at 13.

and analyzed when possible, they should not be given undue weight when considering the most economic choice for both current and future customers.

B. Jim Bridger

The Jim Bridger plant plays an important role in Idaho Power's system by providing approximately 700 MW of baseload capacity, as well as serving as a dispatchable resource responsive to load balancing requirements. Idaho Power uses Jim Bridger extensively to provide ramping services which increase overall system flexibility. These services are particularly important to allow for increased renewables penetration, which frequently entails substantial output volatility.

Nonetheless, the Company is moving toward a smooth transition from coal resources. One of the primary goals in the Company's portfolio design for the 2017 IRP was to evaluate SCR investments and retirement dates for the Jim Bridger coal plant. The 2017 IRP analysis determined that the SCR investments were not cost-effective. The Company's portfolios further evaluated a variety of early shutdown dates for Jim Bridger units 1 and 2. The Company is committed to pursuing the most cost-effective plan for the Jim Bridger plant. Idaho Power will continue to work with co-owner PacifiCorp and to pursue discussions with the State of Wyoming to determine the best plan for Idaho Power's customers.

1. Sierra Club's Economic Analysis Fails to Account for Accelerated Depreciation Impacts.

While Idaho Power responded to Sierra Club's Bridger critique in the Company's Reply Comments,[106] Sierra Club continues to assert that the Bridger Units are uneconomic.[107] Sierra Club's analysis continues to disregard the fact that the Bridger Units are rate-regulated resources rather than market-based generators, describing this distinction as "relatively immaterial" because

[106] Idaho Power Company's Reply Comments at 56-61.

[107] Sierra Club's Final Comments at 6-7.

"the utility has an obligation to serve energy with the lowest reasonable costs to its ratepayers."[108] But the fact that Idaho Power is a rate-regulated entity is material in the analysis.

As a regulated utility, Idaho Power invests in resources following public scrutiny and only after regulatory approval. In return, Idaho Power receives a reasonable rate of return for the life of that investment. Thus, any portfolios contemplating the early retirement of a resource must include the full recovery of that investment through an accelerated depreciation schedule, as well as the cost of any new resource. And accounting for the recovery of these costs, the 2017 financial modeling shows that keeping the Jim Bridger units in the Company's resource portfolios—without investing in additional SCRs—is lower cost on a net present value ("NPV") basis than replacing them with natural gas or solar resources. Sierra Club's analysis is faulty because it fails to account for the impacts of an accelerated depreciation schedule.

The Jim Bridger plant was completed in 1979 and has served our customers reliably and economically for many years. While technologies and market economics are changing, Jim Bridger is currently dispatching at a level needed to maintain system reliability and remains an important resource for our customers.

2. Idaho Power's Preferred Portfolio Properly Allows for Alternative Haze Compliance Pathways and is Consistent with Sierra Club's Position in Prior Proceedings.

Sierra Club continues to argue that Idaho Power cannot include portfolio options that fail to comply with the Wyoming State Implementation Plan ("SIP") because "[i]t would not be possible for [Idaho Power] to show that the proposed plan is "better than [Best Available Control Technology ('BART')]," and therefore worthy of a waiver of the current Clean Air Act deadlines" for SCR installation.[109] This argument is both inconsistent with Sierra Club's prior statements, and fails to recognize that Idaho Power's portfolios are explicitly contingent on receiving an

[108] Sierra Club's Opening Comments at 24.

[109] Sierra Club's Final Comment at 3-5.

alternative compliance plan. Thus, Idaho Power simply allows for the possibility that it may receive a "Better than BART" alternative for SIP compliance, consistent with the authority of the Wyoming Department of Environmental Quality ("WDEQ") and the Environmental Protection Agency ("EPA"). It does not propose to take any action absent such legal authority.

Notably, Sierra Club has previously argued that a utility was imprudent for *failing* to seek a "better than BART" alternative for SIP compliance. In PacifiCorp's 2016 rate case in Washington, Sierra Club sought to disallow that utility's installation of SCRs on Jim Bridger units 3 & 4 as imprudent, stating that PacifiCorp "should have pursued a 'better-than BART' alternative that could have allowed it to avoid installing the SCRs by committing to a plant wide plan that set retirement dates in exchange for deferring the deadline to install pollution controls and/or installing less expensive controls."[110]

Clearly then, it is not that Idaho Power's portfolios are in any way illegal, but merely that Sierra Club does not believe that Idaho Power will successfully obtain a "better than BART" alternative. This argument is premature. *If* Idaho Power receives acknowledgment of its least-cost, least-risk portfolio, and *if* the WDEQ and the EPA approve Jim Bridger's implementation plan, *then* Sierra Club may contest whether such authorization is appropriate. Regardless, it is plain that Sierra Club is simply contesting the likelihood of Idaho Power receiving an alternative compliance plan—a matter of opinion and probability, not legality.

Again, Idaho Power's preferred portfolio assumes that the Company can negotiate a settlement with the WDEQ and the EPA for a delayed shutdown and alternative Regional Haze compliance plan. As a result, each of the portfolios provide for the necessary legal approvals, which would be obtained before any action is taken. Naturally, additional analysis will be

[110] *In the Matter of Pacific Power and Light Co.*, Wash. Utils. & Transp. Comm'n, Docket No. UE 152253, Sierra Club's Initial Post-Hearing Brief at 3 (June 22, 2016).

performed as discussions with regulatory agencies progress in order to effectively determine acceptable levels of haze reductions.

C. Coal Price Forecasts

Sierra Club challenges the Company's coal price forecasts and asks for more detail regarding the source of the Company's coal price data.[111] The Company's 2017 IRP coal forecasts were based on the estimated coal prices from third-party suppliers and the Bridger Coal Company ("BCC") mine, according to figures available at the time. The BCC coal costs were based on then-current mine plans which assumed a surface mine operation until 2037.

The Company's coal forecasts reflect, in part, the BCC mine plan at the time the IRP was prepared. In this plan, highwall mining methods are used near the end of mine life. This method of surface mining allows for significantly lower-cost production. The timing of the decrease in coal costs is commensurate with the projected start of the highwall mining. Although coal production by highwall mining is significantly less expensive than traditional open pit methods, it precludes further production from the area and so must be performed just prior to mine closure.

D. Natural Gas Price Forecasts

Staff and REC express concern regarding Idaho Power's use of the EIA's High Oil and Gas Resource and Technology Case ("EIAHO") gas price scenario as an input, and question how this input may affect the economics of B2H and the Company's preferred portfolio.[112] Staff asks the Company to address the use of the EIAHO in greater depth and to demonstrate the interaction between variable and fixed costs in determining the lowest-cost rank of Portfolio 7.[113]

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[111] Sierra Club's Final Comments at 7.

[112] Staff's Final Comments at 6.

[113] Staff's Final Comments at 7.

Idaho Power acknowledges the parties' questions and their focus on the natural gas price forecast employed in the IRP analysis. The Company has been similarly focused on improving the rigor of IRP gas price forecasts, particularly in light of a history of consistent overestimation in past IRPs, as illustrated in Figure 5, below.[114] The Company looks forward to working with the parties to develop an appropriate gas forecast for the 2019 IRP.

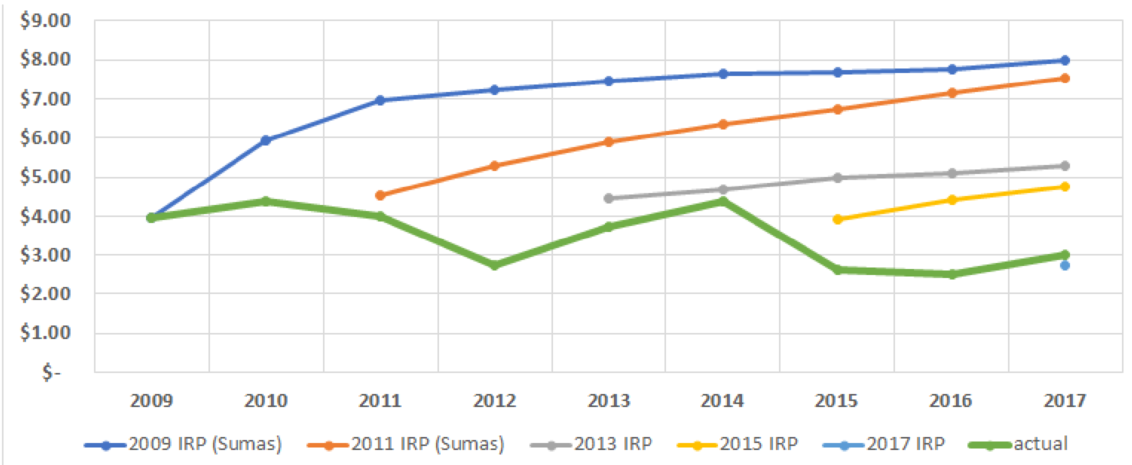

Figure 5. Planning Case Natural Gas Price Forecast ($/MMBtu)

1. The Benefits of the Company's Preferred Portfolio Withstand Substantial Gas Price Variation.

[114] Except where otherwise indicated, prices are based on the Henry Hub futures contract.

Staff and REC express concern that gas price deviations may undermine the economic benefits of the Company's preferred portfolio.[115] However, the Company's portfolio analysis included multiple natural gas price sensitivities, evaluating the variable costs for each portfolio up to 400 percent of the planning case.[116] In Table 9.3 of the 2017 IRP, shown below as Table 2, the variable costs for each portfolio are provided in column 5, labeled "Operating (AURORA)" under "Variable Costs."

Table 2. 2017 IRP Portfolios, NPV years 2017-2036 ($ x 1,000)

Portfolio Details				Variable Costs			New Resource Fixed Costs			Bridger	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Bridger Capacity Retirement (4)	Operating (AURORA) (5)	Rank (6)	Relative Difference (7)	Portfolio Fixed Costs (8)	Rank (9)	Relative Difference (10)	Bridger Fixed Costs (11)	Total Fixed + Variable Costs (12) = (5) + (8) + (11)	Lowest Cost Rank (13)	Lowest Cost Relative Difference (14)
P1	SCR invest, B2H, recips	✓		$5,782,181	10	$252,923	$91,266	1	–	$527,249	$6,400,696	4	$64,925
P2	SCR invest, DR, recips, solar			$5,670,820	4	$141,562	$299,436	5	$208,169	$527,249	$6,497,505	6	$161,733
P3	SCR invest, DR, recips, CCCT			$5,731,938	8	$202,679	$271,669	4	$180,403	$527,249	$6,530,856	9	$195,084
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	$5,796,035	11	$266,777	$207,739	2	$116,473	$334,909	$6,338,683	2	$2,912
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	$5,577,721	2	$48,463	$653,937	10	$562,671	$334,909	$6,566,567	10	$230,796
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	$5,729,526	7	$200,267	$443,808	8	$352,541	$334,909	$6,508,242	8	$172,470
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	$5,755,589	9	$226,331	$214,229	3	$122,963	$365,952	$6,335,771	1	–
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	$5,654,210	3	$124,951	$483,362	9	$392,096	$365,952	$6,503,524	7	$167,753
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	$5,701,053	6	$171,794	$415,995	7	$324,729	$365,952	$6,483,000	5	$147,229
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	$5,807,951	12	$278,693	$309,227	6	$217,961	$283,328	$6,400,507	3	$64,736
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	$5,529,258	1	–	$767,183	12	$675,917	$283,328	$6,579,769	11	$243,998
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	$5,689,172	5	$159,914	$699,009	11	$607,743	$283,328	$6,671,510	12	$335,739

As the table shows, fixed costs for each portfolio, provided in columns 8 and 11, remain static through the full range of natural gas price sensitivities. That is, these costs are unaffected by natural gas price increases. Thus, any change in portfolio cost ranking (column 13) or in portfolio relative cost difference (column 14) is driven by the effect of increasingly higher natural gas prices on variable (rather than fixed) costs (column 4).

[115] Staff's Final Comments at 27; Renewable Energy Coalition's Final Comments at 9 (hereinafter, "REC's Final Comments").

[116] Idaho Power's 2017 IRP at 112-113.

Idaho Power designed the natural gas price sensitivity analysis with the recognition that portfolios relying heavily on natural gas-fired generating capacity, or on the natural gas price-influenced wholesale electricity market, are likely to have less favorable economics with increasing natural gas prices. Conversely, portfolios that rely significantly on renewable (*e.g.*, solar or wind) generation are more likely to be shielded from the negative effects of increasing natural gas price. Tables 9.4 and 9.5 of the 2017 IRP, shown below as Tables 3 and 4, demonstrate that the natural gas price sensitivity analysis confirms this expectation. Specifically, portfolios with solar resources (P2, P5, P8, and P11) become increasingly more cost-competitive with P7, and P5 becomes the low-cost portfolio at 400 percent of the planning case natural gas forecast.

Table 3. Portfolio relative costs under nine natural gas prices forecasts. NPV years 2017-2036 ($ x 1,000)

Sensitivity	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Planning Case	$64,925	$161,733	$195,084	$2,912	$230,796	$172,470	–	$167,753	$147,229	$64,736	$243,998	$335,739
HH 125 Percent	$58,058	$142,953	$188,386	$7,376	$207,186	$173,025	–	$155,281	$142,220	$85,896	$229,666	$352,890
HH 150 Percent	$58,142	$129,040	$186,163	$13,472	$183,556	$172,346	–	$143,472	$138,386	$105,611	$212,513	$363,972
HH 175 Percent	$63,386	$120,284	$187,910	$19,377	$162,044	$174,491	–	$133,714	$136,153	$127,583	$196,759	$374,576
HH 200 Percent	$60,514	$102,090	$182,606	$23,856	$135,130	$171,846	–	$119,610	$128,671	$143,776	$174,778	$378,449
HH 225 Percent	$61,904	$92,582	$180,551	$28,388	$110,252	$172,598	–	$106,629	$125,133	$162,122	$154,081	$384,389
HH 250 Percent	$60,720	$76,879	$177,400	$31,620	$84,098	$167,438	–	$93,640	$118,182	$178,368	$130,579	$388,352
HH 300 Percent	$60,257	$50,595	$174,637	$44,796	$35,071	$168,937	–	$72,161	$114,453	$215,307	$89,851	$404,734
HH 400 Percent	$114,023	$50,128	$216,370	$126,783	–	$230,108	$61,658	$82,446	$156,364	$342,022	$61,587	$494,597

Note: Darker shading indicates increasing values.

Table 4. Portfolio rankings under nine natural gas price forecasts

Sensitivity	P1	P2	P3	P4	P5	P6	P7	P8	P9	P10	P11	P12
Planning Case	4	6	9	2	10	8	1	7	5	3	11	12
HH 125 Percent	3	6	9	2	10	8	1	7	5	4	11	12
HH 150 Percent	3	5	10	2	9	8	1	7	6	4	11	12
HH 175 Percent	3	4	10	2	8	9	1	6	7	5	11	12
HH 200 Percent	3	4	11	2	7	9	1	5	6	8	10	12
HH 225 Percent	3	4	11	2	6	10	1	5	7	9	8	12
HH 250 Percent	3	4	10	2	5	9	1	6	7	11	8	12
HH 300 Percent	5	4	10	3	2	9	1	6	8	11	7	12
HH 400 Percent	6	2	9	7	1	10	4	5	8	11	3	12

Note: Darker shading indicates increasing values.

Idaho Power recognizes that the economics of P7 are negatively affected by natural gas prices higher than the planning case forecast; however, the natural gas price sensitivity analysis indicates that the variable-cost effects of higher natural gas price on P7 outweigh its capacity (*i.e.*, fixed) cost savings only under extreme (400 percent of planning case) natural gas price futures. These results support the selection of P7 as least-cost and least-risk.

2. Idaho Power Reasonably Incorporated Forward Contracts Data into Gas Price Forecasts.

Idaho Power's gas price forecasts incorporated settled forward contract data from the Intercontinental Exchange ("ICE") to bolster its analysis.[117] REC claims that ICE settled forward contract data is not a reasonable tool to help formulate natural gas price forecasts.[118] Idaho Power believes that using ICE forward contract data to validate the EIA's gas forecast improves the rigor of the Company's forecasting, and confirms the selection of the EIAHO case over the EIA Reference Case.

REC argues that ICE data is not relevant because settled forward contracts are mere "option contracts."[119] Here, REC relies on statements from the Idaho Commission Staff describing ICE futures as "options" that merely reflect "what today's market is willing to pay now to have that option within the next six years."[120] As the Company explained in the Idaho IRP docket, Staff incorrectly described ICE futures as an option.[121]

An ICE future is a fix for floating swaps. The ability for one party or the other to exit such a transaction would require an offsetting transaction. For example, a party that buys 100 contracts could reverse this position by selling 100 contracts. Thus, price movements between the buy and sell transaction would result in gains or losses according to the direction the market moves. Many utilities and industrial companies, Idaho Power included, buy futures as a hedge to protect against

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[117] *See* Idaho Power Company's Reply Comments at 81.

[118] REC's Final Comments at 3.

[119] REC's Final Comments at 4.

[120] REC's Final Comments at 4.

[121] Idaho Pub. Utils. Comm'n, Docket No. IPC-E-17-11, Idaho Power Company's Reply Comments at 39.

prices going up without regard to their belief of which way prices may go. Conversely, gas producers often hedge to guarantee that their production will remain profitable in the event prices fall, protecting profitability and cash flow.

Idaho Power seeks to use the most accurate and complete information available in preparing its IRP. Because ICE data is based on actual market transactions, Idaho Power believes that this data helpfully informs the Company's gas price forecasting. Nonetheless, the Company understands parties' concerns relating to these gas price forecasts, and is committed to working with stakeholders, through the IRPAC process, to determine the appropriate natural gas price forecast to be used in the 2019 IRP.

V. DEMAND SIDE RESOURCES

A. Energy Efficiency

Staff states that it intends to recommend acknowledgement of Idaho Power's energy efficiency ("EE") action item 9—to "continue the pursuit of cost-effective energy efficiency,"[122]—if the Company offers: (a) a more transparent explanation for the decrease in savings, especially in the near-term, between the 2015 and 2017 IRPs, and (b) a description, with examples, of how the Company makes modeling decisions regarding technology adoption rates and how it treats retrofit vs. replacement opportunities.[123]

Idaho Power's anticipated EE savings reflect the results of independent third-party analysis. In advance of the 2017 IRP process, Idaho Power contracted with a third-party consultant, Applied Energy Group ("AEG"), to produce an Energy Efficiency Potential Study. AEG is a reputable third-party contractor with substantial experience conducting DSM potential studies—including studies in over 25 states and provinces for over 40 energy providers, including multiple studies for over a dozen companies in the northwest. Representatives of AEG attended

[122] Idaho Power's 2017 IRP at 135.

[123] Staff's Final Comments at 20.

the January 12, 2017 IRPAC meeting and presented the findings of Idaho Power's 2017 Energy Efficiency Potential Study, providing opportunity for feedback and questions from stakeholders. No serious concerns regarding AEG's results were raised at that time.

While Idaho Power did not directly perform the EE study, in the interests of more fully responding to Staff's concerns, the Company asked AEG to explain the decreased savings, as well as modeling decisions regarding technology adoption rates and the treatment of retrofit vs. replacement opportunities. AEG's response, included as Attachment 4, explains that the decrease in savings in the near-term is primarily due to the change in federal lighting standards and the change in base-year lighting saturations. Separately, reduced energy efficiency savings potential between the 2015 IRP and the 2017 IRP also reflects the 13 percent average reduction of the DSM Alternate costs between the two studies, which decreased the economic energy efficiency potential.

Far from being the "neglected step-child,"[124] Idaho Power's EE and demand response programs are progressive and successful.[125] In the last three years, Idaho Power has added energy efficiency measures to the Easy Savings, Energy House Calls, Home Energy Audit, Weatherization Assistance for Qualified Customers ("WAQC"), Weatherization Solutions for Eligible Customers, Heating & Cooling Efficiency, and Commercial and Industrial Energy Efficiency Programs. Idaho Power has also launched an array of new programs in the last three years, including Multifamily Energy Savings, Residential New Homes, Mail by Request Energy

[124] STOP B2H's Final Comments at 30.

[125] STOP B2H's claim that Idaho Power continues to survey "Customer Satisfaction" rather than "Results" is incorrect. STOP B2H's Final Comments at 31. As described in the accompanying text, Idaho Power relies on both energy savings results *and* customer education and awareness. Idaho Power is unable to verify STOP B2H's calculated ".0011% customer behavior change." *Id.* The Company's own analysis is rigorous and respected; each one of its EE activities is reported and copies of evaluations are included in the Demand-Side Management 2016 Annual Report, Supplement 2: Evaluation, available at: https://docs.idahopower.com/pdfs/EnergyEfficiency/Reports/Supplement2_evaluation.pdf. Idaho Power also regularly hires third parties to conduct impact assessments and process evaluations on its programs to ensure that they are well managed, accurately reported, and comparable to peer programs throughout the United States.

Efficiency Kits, New Customer Welcome Energy Efficiency Kits, Promotional Giveaways, Simple Steps Appliances, and Home Energy Reports. In 2016, Idaho Power's EE programs saved 171 giga-watt hours ("GWh"), enough energy to power over 14,000 average homes a year[126] at a levelized utility cost of 1.7¢/kWh and a levelized total resource cost of 3.6¢/kWh.[127]

To further support Idaho Power's EE goals, the Company meets quarterly with its Energy Efficiency Advisory Group ("EEAG"). Formed in 2002, EEAG provides input on enhancing existing DSM programs and on implementing EE programs. Currently, EEAG consists of 13 members from Idaho Power's service area and the Northwest. Members represent a cross-section of customers from residential, industrial, commercial, and irrigation sectors, as well as low-income households, environmental organizations, state agencies, the Commission, IPUC, and Idaho Power.

Regionally, Idaho Power is comparable to other utilities' percentage annual energy efficiency savings in retail sales. According to 2016 EIA data,[128] savings results for regional utilities range from 0.76 percent for PacifiCorp to 1.54 percent for Puget Sound Energy, with Idaho Power situated at 1.20 percent.[129] The EPA has further stated "that a 1.0% incremental savings, as a percentage of retail sales, is appropriate" and that "[t]his level was achieved by seventeen states and by numerous utilities of all ownership types in 2013."[130] Idaho Power exceeds EPA's parameters, even though Idaho Power's retail rates are among the lowest in the nation.

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[126] Idaho Power's 2017 IRP, Appendix B: DSM Annual Report at 1.

[127] Idaho Power's 2017 IRP, Appendix B: DSM Annual Report at 176.

[128] U.S. Energy Information Administration, 2016 Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files.

[129] EIA, *Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files*, available at: https://www.eia.gov/electricity/data/eia861/index.html.

[130] *Demand-Side Energy Efficiency Technical Support Document* at 52 (Aug. 2015) available at: https://www.epa.gov/sites/production/files/2015-11/documents/tsd-cpp-demand-side-ee.pdf.

B. Demand Response

Both Staff and STOP B2H provide feedback on Idaho Power's demand response ("DR") programs in their Final Comments. Staff asks Idaho Power to clarify why its currently commendable levels of DR are not projected to grow in the IRP despite forecasted load growth, and what activities the Company plans to undertake to address this stagnation of DR procurement.[131] Staff also questions if "the preferred portfolio reflects SB 1547's direction to acquire EE first and DR second prior to new generation resources."[132]

With respect to Staff's first concern, Idaho Power plans for DR capacity based on orders from both the Idaho and Oregon commissions,[133] and assesses its DR capacity through actual annual deployment of these resources. Idaho Power maintains DR programs even in years when the Company does not anticipate peak-hour capacity deficits, setting in place the program infrastructure for when capacity deficits return.[134] In Idaho Power's peak-hour load and resource balance,[135] the first capacity deficit of 34 MW occurs in July 2026 with no additional resources added. Considering that DR would not be needed prior to 2026 without new resources, the Company does not believe it is currently necessary to explore expanding demand response capacity.

Demand Response programs are designed to provide a resource to satisfy loads under extreme conditions. In so doing, DR programs can minimize or delay the need to build new on-peak supply-side resources, such as simple cycle combustion turbines. On a comparative basis, DR provides a very economic capacity resource and a very expensive energy resource.[136] DR

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[131] Staff's Final Comments at 21.

[132] Staff's Final Comments at 21.

[133] See In the Matter of Idaho Power Co., Staff Evaluation of the Demand Response Programs, Docket No. UM 1653, Order No. 13-482 (Dec. 19, 2013).

[134] Order No. 13-482 at 3.

[135] Idaho Power's 2017 IRP, Appendix C,

[136] Idaho Power's 2017 IRP at 89, Figures 7.5-7.6.

does not provide unlimited resources to satisfy peak load for extended periods. Load duration curves demonstrate that DR can satisfy about 10 percent of the Company's peak load for approximately 100 hours.

Idaho Power currently has 390 MW of DR load control, which is over 11 percent of its all-time system peak.[137] This is more relative DR capacity than any other utility in the Northwest or the West, excepting the Salt River Project in Arizona. The Northwest Power and Conservation Council's 7th Power Plan "assumes the technically achievable potential for DR in the region is over *eight percent* of peak load during winter and summer peak periods by 2035,"[138] while Idaho Power currently has *eleven percent* of its summer peak load under DR control, well in advance of this 2035 timeline. Indeed, Idaho Power provides the most summer DR in the Pacific Northwest region.[139]

Critically, the reliability and viability of DR programs are highly dependent on attracting and retaining participants. If these programs were called upon more in times of no need, such overuse would ultimately discourage long-term participation and deplete the available megawatt capacity when these programs are truly needed. This understanding is consistent with the UM 1653 settlement, in which the Company and parties agreed that participants in DR programs should be called on to provide a minimum of three dispatch events per season with no marginal costs.[140] However, the DR programs can be called upon to dispatch for up to sixty hours per

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[137] STOP B2H incorrectly states that the Company has limited its A/C Cool Credit program to .063 percent of its residential customers. STOP B2H's Final Comments at 30. Idaho Power has 6.37 percent, or approximately 28,000 of its residential customers enrolled in the A/C Cool Credit program. 2017 IRP, Appendix B, DSM Annual Report, page 31-33 ((28,315/444,431)*100). This figure does not reflect the customers who may not be eligible for the program based on lack of central air conditioning or heat pump or other factors.

[138] Northwest Power and Conservation Council, *7th Power Plan*, Chapter 14 ("Demand Response") at 14-2, available at: https://www.nwcouncil.org/media/7149925/7thplanfinal_chap14_dr.pdf (emphasis added).

[139] Northwest Power and Conservation Council, *7th Power Plan*, Chapter 9 ("Existing Resources and Retirements") at 9-28.

[140] *See* Order No. 13-482 at 3.

season if required.[141] By developing and using DR in this manner, DR programs can be relied on when the system really needs them.

Thus, the Company has included all cost-effective achievable energy efficiency in every portfolio—ahead of any other resource—and has included all needed cost-effective DR.

VI. REQUEST FOR WAIVER

The Company also requests a waiver from IRP Guideline 3(f), which requires a routine annual update on a utility's most recently acknowledged plan "on or before the acknowledgment order anniversary date."[142] In this case, an annual update would likely be due within a month of filing the 2019 IRP. The Commission has previously approved a waiver of Guideline 3(f) on this basis, and the Company acknowledges that an IRP update would still be required if the Company anticipates a significant deviation from its acknowledged IRP.[143]

VII. CONCLUSION

Idaho Power again appreciates the opportunity to file comments in this proceeding and continues to value the robust public process and participation in this case. Based on the detailed and comprehensive analysis provided in the Company's 2017 IRP, the extensive supplemental analysis provided by Appendix D: B2H Supplement, and the additional explanation contained in the Company's comments, Idaho Power has fully demonstrated that the preferred portfolio is the least-cost, least-risk means of serving customer need. In particular, Idaho Power has clearly shown that the B2H transmission line effectively and affordably meets the resource need identified in this IRP and will provide robust and diverse benefits to Idaho Power's customers.

[141] Order No. 13-482, Appendix A at 7.

[142] In the Matter of Pub. Util. Comm'n of Or. Investigation Into Integrated Resource Planning, Docket No. UM 1056, Order No. 07-002, Appendix A at 3 (Jan. 8, 2007).

[143] In the Matter of Idaho Power Co. 2013 Integrated Resource Plan, Docket No. LC 58, Order No. 14-253 at 17-18 (Jul. 8, 2014).

Idaho Power respectfully requests acknowledgment of the Company's 2017 IRP as meeting both the procedural and substantive requirements of Order Nos. 89-507, 07-002, 07-747, and 12-013. The Company also requests that the Commission specifically acknowledge two action items: (1) Idaho Power's intent to shut down its ownership share of coal-fired operations at North Valmy unit 1 by year-end 2019 and unit 2 by year-end 2025, and (2) Idaho Power's acquisition of B2H as satisfying EFSC's "Need" standard under its Least Cost Plan Rule, so that the Company can continue its path to achieving an in-service date consistent with its 2026 capacity deficit.

Respectfully submitted this 16th day of February 2018.

McDOWELL RACKNER GIBSON PC

Shoshana Baird

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

IDAHO POWER COMPANY

Attachment 1
Amended and Restated Joint Permitting Agreement

CONFIDENTIAL

February 16, 2018

ATTACHMENT 1 IS

CONFIDENTIAL PER PROTECTIVE

ORDER 17-292 AND WILL BE

PROVIDED SEPARATELY

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

IDAHO POWER COMPANY

Attachment 2
B2H Funding Committee Meeting Minutes

CONFIDENTIAL

February 16, 2018

ATTACHMENT 2 IS CONFIDENTIAL PER PROTECTIVE ORDER 17-292 AND WILL BE PROVIDED SEPARATELY

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

IDAHO POWER COMPANY

Attachment 3
Term Sheet

CONFIDENTIAL

February 16, 2018

ATTACHMENT 3 IS

CONFIDENTIAL PER PROTECTIVE

ORDER 17-292 AND WILL BE

PROVIDED SEPARATELY

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 68

IDAHO POWER COMPANY

Attachment 4
AEG Response

February 16, 2018

MEMORANDUM

To: Pete Pengilly

From: Ingrid Rohmund

CC: Kurtis Kolnowski and Fuong Nguyen

Date: February 2, 2018

Re: Response Comments in LC 68

In this memo, we provide a response to the following two statements made by OPUC Staff:

- Explain the decrease in projected EE savings, especially in the near-term, compared to savings projected in the past two IRPs
- Describe, with examples, how the Company makes modeling decisions regarding technology adoption rates and how it treats retrofit vs. replacement opportunities

AEG Response

Applied Energy Group (AEG) uses a rigorous, data-driven approach in performing potential studies. The AEG Planning Team (formerly with EnerNOC and Global Energy Partners) have been performing studies in the Northwest since 2008. AEG has adapted its approach over time, so it is consistent with the approach and the assumptions the Northwest Power and Conservation Council (the Council) uses to develop its Power Plans. Since 2008, AEG has aligned with the 5th, 6th, and now 7th Plan. Below, three important areas for alignment between AEG studies and the Council's Power Plans are identified:

- AEG uses a measure list in its studies that is consistent with measures tracked and vetted by the Regional Technical Forum (RTF). AEG also uses energy savings assumptions in its models that follow the Council's measure workbooks and guidelines. For example, as the RTF makes changes to measure savings, as was recently the case for ductless mini-split heat pumps, AEG incorporated the updated values into its studies. In addition, AEG staff participate in the RTF as corresponding members.
- AEG models retrofit and replacement measures separately, just as the Council does.
- AEG use the Council's ramp rates to estimate customer adoption of measures. The Council has separate ramp rates for retrofit and replacement measures and AEG applies these in its modeling.

Explain the decrease in projected EE savings, especially in the near-term, compared to savings projected in the past two IRPs.

Response: Table 1 shows a comparison of achievable potential savings, overall and by sector, between the 2014 and 2017 studies. The table presents the results for different calendar years, but it is appropriate to compare them in terms of the year of the study (e.g., Year 1). The table presents the results in four blocks of data:

- The 2017 study
- The 2014 study
- The difference between the 2014 study and the 2017 study in GWh
- The difference between the 2014 study and the 2017 study as a percent of savings from the 2014 study

Please note that the Commercial, Industrial, and Irrigation sectors have been combined in the summary of differences in the table.

Table 1: Comparison of Savings – Achievable Potential from the 2014 and 2017 Potential Studies (calendar-year basis)

Cumulative Savings (GWh)	Study Year 1	Study Year 5	Study Year 10	Study Year 15	Study Year 20
2017 Study (calendar year)	**2017**	**2021**	**2026**	**2031**	**2036**
Total	**104**	**603**	**1,209**	**1,702**	**2,226**
Residential	20	125	237	399	581
Commercial	20	140	332	509	704
Industrial	50	269	504	590	669
Irrigation	14	68	136	204	272
2014 Study (calendar year)	**2015**	**2019**	**2024**	**2029**	**2034**
Total	**99**	**697**	**1,401**	**2,029**	**2,471**
Residential	24	246	479	746	969
Commercial	23	151	383	574	727
Industrial	40	207	350	513	570
Irrigation	12	93	189	197	204
Difference (2017 vs 2014), GWh	**Study Year 1**	**Study Year 5**	**Study Year 10**	**Study Year 15**	**Study Year 20**
Total	5	-94	-192	-327	-245
Residential	-4	-121	-242	-347	-388
Com + Industrial + Irrigation	9	26	50	19	144
% Difference					
Total	5%	-13%	-14%	-16%	-10%
Residential	-17%	-49%	-51%	-47%	-40%
Com + Industrial + Irrigation	12%	6%	5%	1%	10%

From Table 1, it is evident that the residential sector accounts for the reduction in savings, since savings for the Commercial, Industrial, and Irrigation sectors combined increased in the 2017 study. There are several reasons the savings decreased, particularly in the early years, between the two studies.

- Lighting standard. The biggest difference is in the estimate of five-year cumulative savings. In the 2014 study, the five-year forecast ended in 2019, before the second phase of the EISA 2007 standard for general service lighting went into effect. In the 2017 study, the five-year forecast ended in 2021, after the EISA standard went into effect. Cumulative savings in the residential sector declined from 246 GWh to 125 GWh.

- Change in base-year lighting saturations. In the 2017 study, there was a higher saturation of CFL and LED lamps in the base year, reflecting accomplishments from Idaho Power programs and the beginning of a market transformation. This reduced the potential for savings from conversion to LEDs.
- Updated survey data. The 2017 study utilized the most recent Residential Building Stock Assessment, a survey of customers in the Northwest. This survey provided updated estimates of appliance saturations, as well as the saturation of retrofit measures. For example, there was a much higher saturation of homes that had already sealed and repaired ducting, resulting in a smaller applicable market for future savings potential.
- Alignment with the 7th Power Plan. This 2017 study referenced the Council's 7th Power Plan instead of the 6th Power Plan, which includes new measures, major revisions to previous measures, and substantial modifications to ramp rates. Updating to the 7th Plan ramp rates had the effect of reducing potential in the early years of the study.

Describe, with examples, how the Company makes modeling decisions regarding technology adoption rates and how it treats retrofit vs. replacement opportunities

As discussed above, AEG follows the methodology and uses the data provided by the Council when developing adoption (ramp) rates. In the most recent study, Idaho Power ramp rates aligned with ramp rates used in the Council's 7th Plan[1]. These are categorized as lost opportunity "LO" and retrofit "Retro" ramp rates. For all Council measures, the study began with an assignment of ramp rates to measures as the Council prescribes them. For similar, non-Council measures, AEG applied ramp rates for the most similar Council measures.

Please note that achievable potential estimated using Council methodology estimated in the 7th Plan includes potential realized from utility DSM as well as mechanisms outside of utility programs. These include NEEA initiatives, naturally occurring efficiency, and market transformation. In the model, purchasing decisions are "frozen" at base-year levels to account for this. The paragraphs below describe how the lost opportunity and retrofit ramp rates are handled within the Idaho Power 2017 study.

Lost opportunity ramp rates apply to purchase decisions made when a piece of equipment reaches its end of useful life (EUL) and must be replaced. In this situation, potential must be captured at the time of replacement or it is considered to be "lost" until the purchased unit reaches end of useful life. Only a fraction of all available appliances or equipment need to be replaced in a single year, which limits the number of units available for replacement. For example, if average use life of a refrigerator is ten years, then it is assumed that 10% of the refrigerators will be available for replacement in an average year. The lost opportunity ramp rates are then applied to that 10% of the market rather than the entire market. To compensate for this, lost opportunity ramp rate achievability increases every year until it reaches an 85% threshold set by the Council (or roughly 55% in the case of emerging technologies). Since some turnover is essentially "lost" as a result, the 20-year potential does not normally reach the steady-state achievability of 85%.

Retrofit ramp rates apply to purchasing decisions that can be made at any time, regardless of a measure lifetime. This includes to non-equipment measures, such as weatherization and equipment controls. This category also includes equipment-type measures that modify, rather than replace, the energy use of existing equipment. Examples include ductless mini-split heat pumps and smart thermostats, which both reduce the consumption of an existing HVAC system. For this category of measure, an upgrade or installation may be completed at any time, resulting in a larger applicable market in any given year. For example, if 100,000 homes

[1] Ramp rates for the 7th Power Plan and their assignment to measures may be found on the "ACHIEV" tab of the Council's "Master" supply curve workbooks for each sector published on their website:
https://nwcouncil.app.box.com/v/7thplanconservationdatafiles

have leaky ductwork mainly located outside the conditioned space, the applicable market for a duct repair and sealing measure would be 100,000 homes, rather than a much smaller subset as described in the lost opportunity case above. Per the Council's methodology, these installations occur over time, which is reflected in the Council's retrofit ramp rates. These retrofit ramp rates specify the percent of the entire market that could be achievably captured in each year. In contrast to lost opportunity rates, annual retrofit ramp rates sum to 85% rather than reach it in the steady state. By the end of the study period, this results in exactly 85% of the market being captured by utility or non-utility mechanisms since no installations are "lost" as described above.

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents in Docket LC 68 on the following named persons on the date indicated below by e-mail addressed to said persons at his or her last-known address indicated below.

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