BEFORE THE PUBLIC UTILITY COMISSION

OF OREGON

In the Matter of Idaho Power Company 2017 Integrated Resource Plan	Docket LC 68

Final Comments from the STOP B2H Coalition

REDACTED

Submitted January 18, 2018

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I. Introduction

The Stop B2H Coalition (STOP), as intervener in this docket LC68, commends the OPUC for the open and transparent forum for reviewing, clarifying and analyzing the 2017 Idaho Power Integrated Resources Plan (IRP.) STOP wanted to commend Idaho Power for the same; however, over the course of recent months the company has introduced a new capacity expansion strategy which was not presented or developed in the participatory IRP process.

Instead, Idaho Power has proffered an expanded list of benefits in a 175 page document titled "Appendix D-B2H Supplement", a trove of unsupported claims and analytic conclusions not previously presented for public review and evaluation. As a further insult to the public review process mandated by the State of Oregon IRP Guidelines[1], Idaho Power released this Appendix D in the late stages of the LC-68 schedule after parties had filed initial comments and after Idaho Power filed reply comments. Nonetheless, STOP has made diligent efforts to understand and evaluate this new information in the tight timeframe imposed on interveners by Idaho Power's late filing, and to provide the highest quality reply comments possible given the limited resources available to STOP.

STOP also analyzed Idaho Power's responses to our opening comments and citizen alternatives regarding Distributed Generation, Energy Efficiency, as well as Reliability. We are not only dissatisfied with the company's responses and plans, we are further concerned about their ability to sustain themselves into the future, given the rapidly changing energy industry and consumer behavior.

Finally, in Idaho Power's attempt to expedite Oregon's review and regulatory processes, STOP asserts that delaying acknowledgement of various components of the IRP are warranted, and NOT acknowledging Action item # 6 is in the best interest of ratepayers and the State of Oregon.

II. Flawed Analysis of B2H Transmission Costs & Capacity Expansion Strategy

STOP has investigated Idaho Power's cost analyses for the B2H and justification for a new transmission-based capacity expansion strategy (market purchased/"Front Office Transaction") and the findings are troubling. Idaho Power has:

A. Introduced a new strategy by using Market Purchases/FOTs;
B. Misconstrued the flexibility of Market Purchases/FOTs;
C. Raised the cost of transmission for new renewables to unsupportable levels; and
D. Biased their Aurora modeling in favor of B2H and misstated or understated data inputs.

A. Market Purchase/Front Office Transactions (FOTs) Dependence is a bad strategy

The Stop B2H Coalition (STOP) cannot escape the irony of Idaho Power's aggressive attempt to orient their twenty year resource strategy exclusively towards establishing for the first time, and expanding

[1] IRP Guidelines UM 1056; Order No. 07-002

reliance on Market Purchases, or what PacifiCorp refers to as Front Office Transactions (FOTs), to meet Idaho Power's system peak resource needs. Idaho Power's B2H partner PacifiCorp has relied on a relatively small amount of FOTs to meet their system peak resource needs in recent IRP's, but in an about-face, PacifiCorp argued before the Commission last month that they now see a need to build a major 500 kV transmission line to enable new wind resources that are "needed" to reduce PacifiCorp's currently modest reliance on FOTs.[2] Idaho Power on the other hand, a utility that has never advocated reliance on FOTs in any recent IRP, is now claiming their new least cost resource strategy requires the building of a new 500 kV transmission with the primary goal to establish a new reliance on FOTs to serve Idaho Power's peak loads, Even more astounding, Idaho Power proposes to aggressively pursue this new market purchase (FOT) resource acquisition strategy and dependency to where Idaho Power will rely on FOTs to meet 26 percent of their summer peak obligation in 2029 (see Table 1)

Table 1 shows how aggressive Idaho Power's new FOT strategy is as compared to the one PacifiCorp is backing away from. PacifiCorp's 2017 IRP projects that reliance on FOTs will reach 11 percent of peak load in 2025, if no new physical resources are added to their system, and recently advocated a need before the Oregon Commission to reduce this level of reliance on FOTs by acquiring over 1,000 MW of wind resources.[3] Idaho Power, on the other hand, forecasts in their IRP that they will be relying on market purchases (FOTs) to meet 13 percent of peak load in 2025 if no physical resources are added to their system, and then advocates further increasing reliance on market purchases (FOTs) by building B2H, a transmission line that Idaho Power evaluates as a 350 MW supply side resource. Nowhere in the IRP does Idaho Power address the risks associated with such an aggressive turn to market purchases (FOTs) to meet peak load needs, nor does Idaho Power address the "single shaft" risk of adding a lumpy 350 MW capacity resource to their system that ratepayers will be paying on for 50 years.

[2] See OPUC Docket LC-67 http://apps.puc.state.or.us/edockets/docket.asp?DocketID=20532

[3] See video transcripts of Commission Workshops Dec. 5, 2017 and Dec. 11, 2017. These transcripts are available at http://www.puc.state.or.us/Pages/Live-Stream.aspx

Table 1												
IDAHO POWER AND PACIFICORP PLANNING FOTs (Market Purchases) AS A PERCENT OF SUMMER PEAK OBLIGATIONS												
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IDAHO POWER 2017 IRP												
2017 Forecast July Peak Load (95% w/DSM ahd EE)	3,195	3,310	3,366	3,417	3,412	3,528	3,589	3,640	3,695	3,753	3,812	3,870
July Transmission Available For FOTs /1	313	234	302	433	492	489	488	487	986	1,116	1,115	1,114
2017 IRP Monthly Surplus/Deficit	429	362	311	255	195	138	76	23	466	406	341	103
FOTs Deployed for L/R Balance	-	-	-	178	297	351	412	464	520	710	774	1,011
PERCENT OF JULY PEAK MET WITH FOTs	**0%**	**0%**	**0%**	**5%**	**9%**	**10%**	**11%**	**13%**	**14%**	**19%**	**20%**	**26%**
PACIFICORP 2017 IRP												
Summer Peak inc. Reserves	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135	N/A	N/A	N/A
July FOTs Deployed	547	927	858	1,023	1,146	1,070	1,113	1,284	1,223	N/A	N/A	N/A
PERCENT OF JULY PEAK MET WITH FOTs	**5%**	**8%**	**8%**	**9%**	**10%**	**10%**	**10%**	**11%**	**11%**	N/A	N/A	N/A
/1 Includes 500 MW B2H starting in 2026												
Sources: Idaho Power 2017 IRP at page 126 and PacifiCorp 2017 IRP at page 91												

B. Market purchases (FOT's) are inflexible and non-dispatchable within the hour

It is important to understand that the concept of a dispatchable resource, which means the resource can be turned on and turned off as needed to balance generation and load. Market purchases (FOTs), however, are forward purchase transactions in fixed, hourly increments. Once power is purchased for delivery in any future hour, it represents a "must take" obligation that must be scheduled in that hour and once scheduled, it cannot be turned down or dispatched off for the duration of that hour[4]. The only way to dispatch-off market power once purchased is to resell the power prior to the deadline for hour-ahead schedule changes. Consequently, not only are market purchases devoid of any capability to balance the variable output from intermittent resources, market purchases are actually less dispatchable than any generating resource, including variable renewable resources themselves that can at least be dispatched off (curtailed) when necessary for reliability reasons.

C. B2H will raise the cost of transmission for new renewables to unsupportive levels: *A collateral attack on Oregon's carbon reduction goals*

Idaho Power portrays a B2H/FOT approach to capacity expansion as "providing abundant clean, renewable energy"[5], having "unique qualitative benefits associated with ….expanded penetrations of intermittent renewable energy sources"[6] , and providing "flexibility to integrate renewable resources[7]. Idaho Power even goes so far as to claim that market purchases (FOTs), the actual resource represented by B2H, are "Fast-ramping resources capable of balancing the variable output from intermittent

[4] A failure to take (receive) market power once scheduled is a security violation and subjects the purchaser to mandatory penalties.

[5] Appendix D-B2H Supplement p12

[6] IRP p8

[7] IRP p60

renewable resources".[8] These claims are false as STOP explains below, B2H will act to raise the cost of transmission for new renewables to unsupportable levels, while contributing nothing to the critical need to expand Idaho Power's base of flexible capacity resources capable of balancing the variable output from new renewable resources.

Idaho Power wants the Commission to accept a new principle in this IRP that the (apparent) ability to shift costs of transmission investments like B2H to third-party transmission that do not benefit from B2H customers is an attractive attribute of B2H, and touts that "Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs". Indeed, Idaho Power estimates that these third-party transmission customers are estimated to pay about 22 percent of the cost associated with B2H".[9] While this is the first time Idaho Power has promoted this questionable principle of cross-subsidization to justify a new investment in an IRP proceeding, it is not the first time that Idaho Power (and B2H equity partner PacifiCorp) have lobbied the Commission to embrace the concept of shifting transmission costs to third party transmission customers that do not benefit from their investments or inter-company exchange activities.

As STOP's initial comments first revealed in this IRP proceeding, in 2015 Idaho Power and PacifiCorp filed for approval by the OPUC and the Federal Energy Regulatory Commission (FERC) of a complex asset exchange and capacity reallocation transaction.[10] In that proceeding before the OPUC, Idaho Power's witness testified that the exchange of assets would result in an increase in Idaho Power's OATT transmission rate charged to third party transmission customers,

> "lead[ing] to higher transmission revenues which serves as a revenue credit to retail customers' rates. The increase in the revenue credit is the main driver of the revenue requirement benefit derived from the Legacy Replacement [asset exchange]".[11] [12]

What Idaho Power chose not to highlight for the Commission in UP 315 nor in this IRP Docket is the enormous magnitude of these OATT rate increases charged to "third party transmission customers" of Idaho Power, and that those third party transmission customers will include the new renewable resources that Idaho Power professes to support through their B2H/FOT resource strategy. STOP will substantiate in these comments that B2H would directly result in Idaho Power OATT transmission rate of over 50 percent.

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[8] IRP p91 and Appendix D-B2H Supplement p12 identify B2H as "Balancing, flexibility providing", which Idaho Power defines as "Fast-ramping resources capable of balancing the variable output from intermittent renewable resources." IRP p91

[9] Appendix D-B2H Supplement at page 41

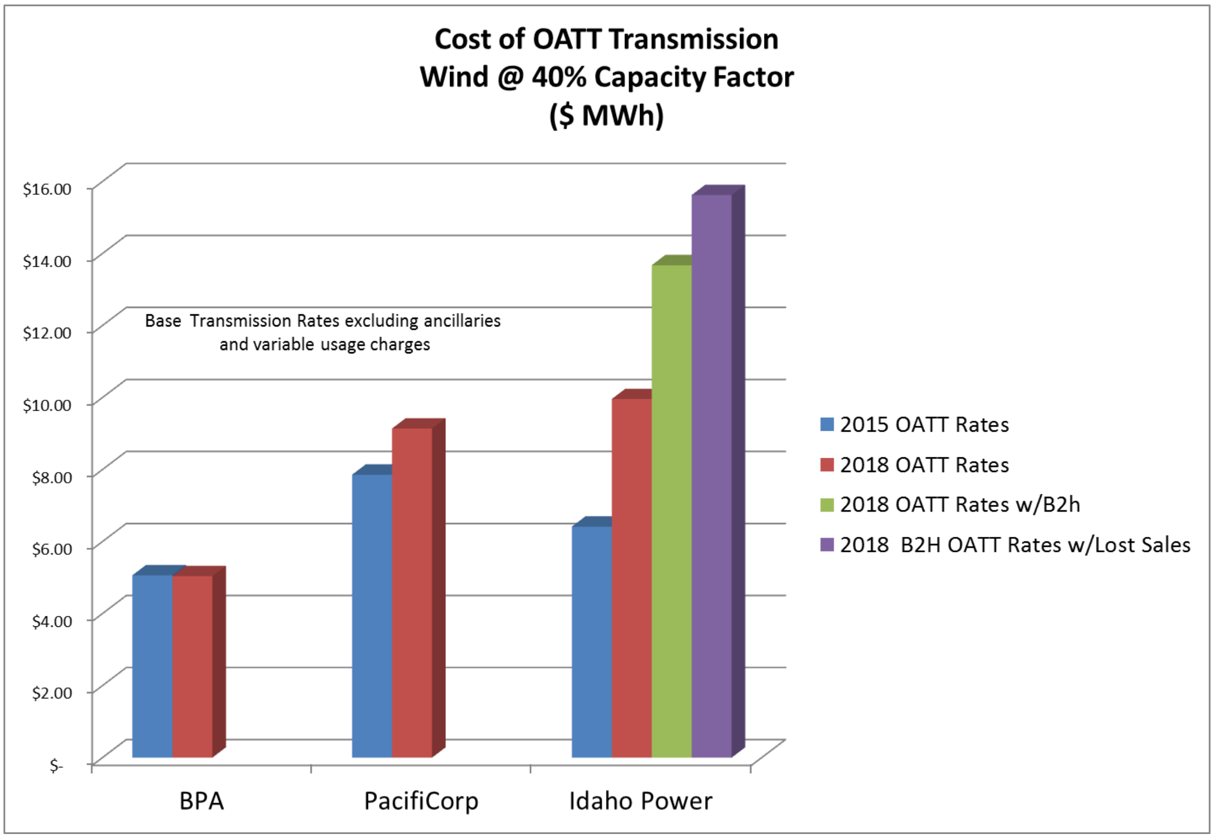
[10] See FERC Dockets EC15-54 and ER15-680, and OPUC Docket UP 315

[11] See Testimony of Lisa M. Grow, Exhibit Idaho Power/100 in OPUC Docket UP 315

[12] At the same time Idaho Power was telling the Oregon Commission that increasing the OATT rate charged to third party transmission customers was the main driver of the revenue requirement derived from the asset exchange transaction, Idaho Power was telling FERC that "the Transaction is consistent with the public interest, does not raise any cross-subsidization concerns, and the Transaction's proposed rates, terms, or conditions are just and reasonable and not unduly discriminatory or preferential". See Joint Motion for Leave to Answer and Answer of Applicants in FERC Docket No. EC15-54-000

STOP has investigated the increased transmission rates that new renewable resources already face when they need OATT transmission service across the Idaho Power System, or for transmission out of the Idaho Power system, resulting directly from the asset exchange. The results are shocking.

The graph below compares the effective transmission rates charged by BPA, PacifiCorp and Idaho Power in 2015 against the rates now in effect in 2018,[13] that are charged to a new renewable wind resource assuming the wind resource has a 40 percent annual capacity factor. The graph illustrates the impact of the asset exchange on Idaho Power transmission rates, and shows the additional incremental rate impact that B2H would have on Idaho Power's transmission rate.[14]

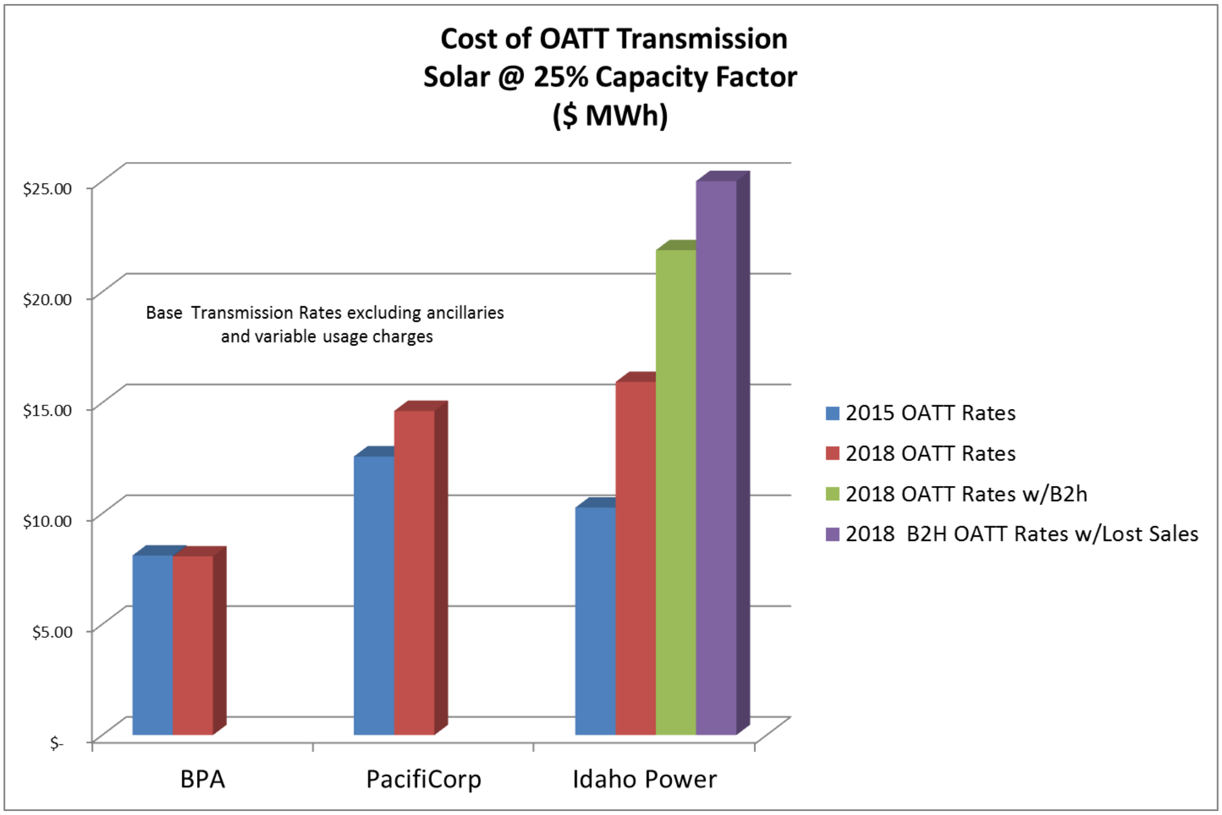


The graph clearly shows the huge impact on Idaho Power's rate charged to new wind resources primarily resulting from the asset exchange; an increase to $9.96 MWh or 55% over the $6.42 MWh rate in effect in 2015. Assuming Idaho Power's B2H costs as stated in the IRP, the addition of B2H would

[13] BPA transmission rates can be found at https://www.bpa.gov/Finance/RateInformation/Pages/default.aspx
PacifiCorp transmission rates can be found at http://www.oasis.oati.com/ppw/index.html
Idaho Power transmission rates can be found at http://www.oasis.oati.com/ipco/index.html

[14] The rate impact of B2H is calculated using the first year revenue requirement from LC 68 - IPC's Attachment 19-Tab 1- to Staff's DR 89 (00034343-2xCEFFF).xlsx and the projected third party transmission sales estimates of Idaho Power as delineated on page 41 of Appendix D-B2H Supplement, using Idaho Power's formula transmission rate model Informational Filing at http://www.oasis.oati.com/IPCO/IPCOdocs/FINAL_Transmission_Rate_October_1_2017-Sept_30_2018_Final_Informational_Posting.xlsx

push this rate up to over $13.50 MWh, or 113 percent above the 2015 rate. Finally, the graph shows the true B2H rate impact that would occur if Idaho Power incorporated corrected costs and lost transmission sales in their estimated cost of B2H, a rate of over $15.50 MWh, or 144 percent. (These cost corrections and lost transmission sales are explained later in these Reply Comments.)



The effective rate increases charged to a new solar transmission customer of Idaho Power are even more shocking (see graph above). In 2015, Idaho Power's effective transmission rate charged to a new 25 percent annual capacity factor solar project was $10.26 MWh. Today, the effective rate charged to a new 25 percent capacity factor solar project is $15.94 MWh. Assuming Idaho Power's B2H costs as stated in the IRP, the addition of B2H would push this rate to almost $22 MWh. Finally, the graph shows the true B2H rate impact that would occur if Idaho Power incorporated corrected costs and lost transmission sales in their estimated cost of B2H, a rate of $25 MWh. (These cost corrections and lost transmission sales are explained later in these Reply Comments.)

STOP notes that all new resources needing transmission on the Idaho Power system, or across the Idaho Power system, are required to pay the above OATT rates for new firm transmission, but not network customers of Idaho Power using network transmission service to serve load (Idaho Power native loads and BPA southern Idaho loads).[15] Idaho Power can add unlimited new resources to their own transmission system for the benefit of native load customers without incurring any incremental fixed

[15] Network customers are charged for transmission based on load, not resources.

transmission charges.[16] (This may explain Idaho Power's apparent willingness to drive-up their transmission rates to ever higher levels while reducing PERPA contract periods which has the effect of discouraging new resource development in Idaho that is not owned by Idaho Power.)

D. Aurora Modeling is Improperly Biased in Favor of B2H and Costs are Calculated Incorrectly

It appears that Idaho Power has made a critical mistake in their Aurora modeling that results in large, fictitious cost penalties to all non-B2H Portfolios. Correcting these deficiencies in Idaho Power's IRP analysis would negate Idaho Power's conclusion of material cost advantages of a B2H/FOT capacity expansion strategy in favor of a balanced portfolio of renewable resources and flexible capacity resources. It is clear that Idaho Power's proposed B2H/FOT action plan would bring enormous costs and risks to ratepayers and environmental impacts in the State of Oregon, without any prospect of material benefits.

1. Idaho Power has improperly restricted PNW energy imports in the Aurora model

In our initial comments, STOP asserted that Idaho Power had acquired valuable incremental transmission capacity rights as a result of an asset exchange transaction with PacifiCorp in 2015. STOP was relying on testimony by Idaho Power before the Commission when seeking approval of the asset exchange in 2015.[17] This testimony stated that due to the asset exchange, Idaho Power would be allocated 450 MW of west to east transmission capacity on the Summer Lake to Hemingway line, and 325 MW of west to east transmission capacity on the Walla Walla to Enterprise line. Both lines are part of the Northwest to Idaho import path. In their reply comments and in response to data requests, Idaho Power clarified that they did not receive any incremental firm capacity through the asset exchange, but the asset exchange did lower import costs through a reduction in wheeling charges from third parties.

STOP remains confused as to what value Idaho Power received through the asset exchange to offset the high costs of the asset exchange resulting from loss of third party transmission revenues; a transaction which required an over 40 percent increase in Idaho Power's OATT transmission rate charged to new renewable resources. Nevertheless, STOP understands and agrees that this issue is not directly germane to this IRP, and is willing to accept Idaho Power's explanation.

What is germane to this IRP proceeding, however, is understanding how Idaho Power's existing transmission access (1,280 MW of capacity ownership between the Northwest and Idaho[18]) is reflected in Idaho Power's portfolio modeling exercises using the Aurora model. Due to its detailed hourly economic dispatch logic, the Aurora model is well suited to simulate the economic dispatch of a utility's resources, especially for hydro based utilities like Idaho Power that have significant flexibility to store and shape energy into the most valuable hours. As Idaho Power explains in their reply comments, "the AURORA model determines the lowest cost alternative of either self-generating or importing via a

[16] See Part III of Idaho Power's OATT, available at http://www.oasis.oati.com/IPCO/IPCOdocs/IPC_OATT_Issued_2018-01-10.pdf
[17] See Direct Testimony of David M. Angell in OPUC Docket UP 315 Exhibit Idaho Power/200
[18] Appendix D-B2H supplement at page 13

market purchase with losses and transmission wheeling costs to serve load, and considers both generation and market constraints in its modeling".[19]

Because of the critical importance that simulating the lowest cost alternative of either self-generating or importing via market purchases has for a hydro-based utility like Idaho Power, it is very important that the base case data inputs to AURORA model that specify market characteristics and constraints, including transmission constraints, reasonably represent the actual market in which Idaho Power dispatches its resources, and buys and sells market power. If user specified transmission constraints on accessing remote wholesale power are too relaxed in the model (i.e., too much capacity between the Northwest and Idaho), the portfolio simulations will tend to unfairly inflate the value of wholesale market transactions, and artificially inflate the value that market purchases will have in offsetting the fixed costs and variable operating costs of Idaho Power's existing generation assets. Conversely, if user specified transmission constraints on accessing lower cost remote energy resources and wholesale power are too restrictive, then portfolio simulations will underestimate the value that could be achieved through optimizing the dispatch of a utility's existing fleet of resources.

Accurate specification of transmission constraints is especially critical when any of the Portfolios being analyzed include major transmission investments designed to reduce a particular transmission constraint, like the B2H Portfolios in Idaho Power's 2017 IRP portfolio analysis. If the AURORA base case underrepresents existing transmission access to remote wholesale markets with lower cost power options, then AURORA analysis of Portfolios that include portfolios with a major a transmission line like B2H (that relaxes that constraint) will be unreasonably biased in favor of the Portfolio that contains the transmission line.

2. Idaho Power has Improperly Specified Existing Transmission Capacities in the AURORA Model

Idaho Power admits that it already has at least 250 MW to 350 MW of import capacity from the Northwest available for its own use. For example, on page 14 of Appendix B-B2H Supplement Idaho Power states that it was able to use 307 MW of imports from the Northwest to serve Idaho Power's native load in 2017, and on page 15 Idaho Power forecasts 243 MW of access to Northwest markets on a forward looking basis. Historical transaction data confirms that this forecast if anything is low.

In response to a STOP data request, Idaho Power provided hourly transaction (schedule) data across the Northwest to Idaho Path from 2013 to present.[20] The data clearly show that Idaho Power regularly engages in imports and exports of energy in amounts exceeding [redacted] over the Northwest to Idaho Import Path. For example, the graph below plots Idaho Power's actual net hourly schedules (imports and exports between the Northwest and Idaho) by Idaho Power on July 1 of 2017. July 1 was a Saturday and the beginning of a four day holiday weekend, a day that typically has lower loads relative to a weekday.

[19] Idaho Power Reply Comments at page 27

[20] LC 68 IPC to STOP B2H DR025 CONF ATTACH.xlsx

[redacted]

As the graph shows, on July 1, 2017, Idaho Power was [redacted] [redacted] in light load hours (LLH) and [redacted] [redacted] in heavy load hours (HLH).

The second graph below plots Idaho Power's actual net hourly schedules between the Northwest and Idaho on July 5, 2017, the first workday after the July 4th holiday, a day which tends to have higher loads.

[redacted]

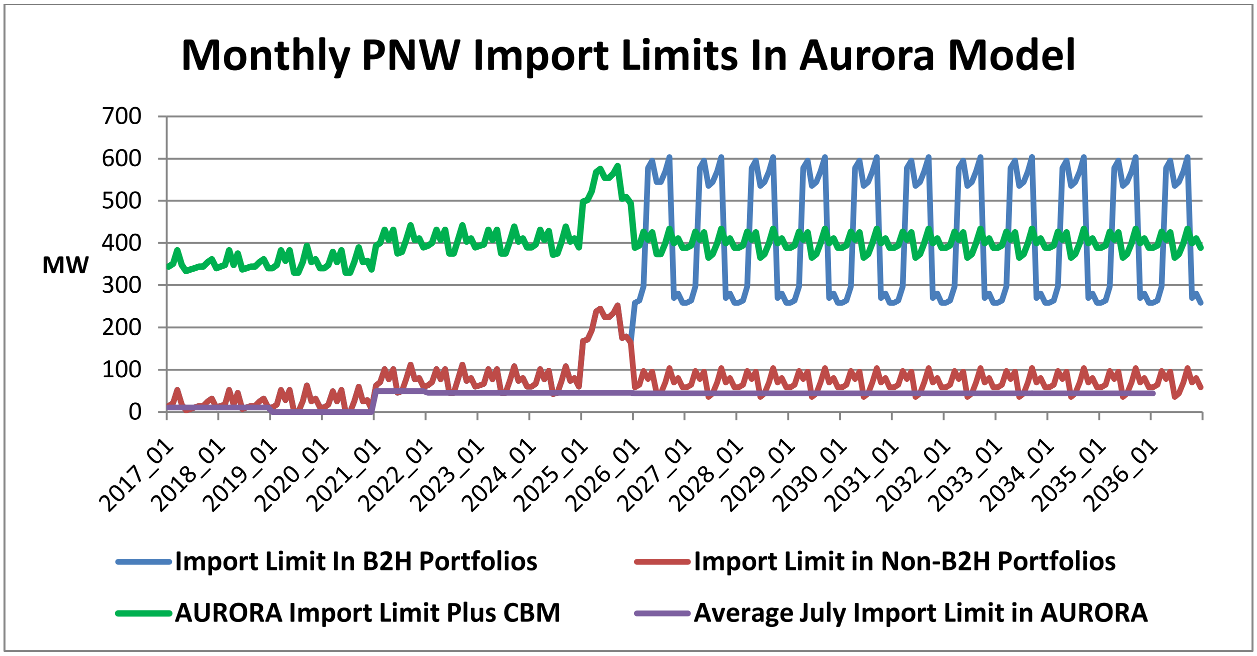
As the graph shows, on July 5, 2017, Idaho Power was [redacted] and those [redacted] over nine continuous heavy load hours ending 2:00 pm to 10:00 pm.

Based upon [redacted] [redacted], and Idaho Power's own admissions, one would expect to see AURORA minimum transmission capacities between the Northwest and Idaho that exceed 300 MW. This is not the case. STOP examined the transmission capacities that Idaho Power has actually specified in the AURORA model and discovered that Idaho Power has artificially limited transmission capacity available for Northwest imports in the AURORA model to less than 100 MW. [21]

3. Idaho Power Has Improperly Constrained Transmission Capacity Between the Northwest and Idaho in the AURORA Base Case

Idaho Power has constrained the AURORA model to severely limit imports from the Northwest. Specifically, hourly imports from the PNW are limited to less than 75 MW average across all months and all years in the AURORA Base Case, and to less than 45 MW in all July months across all years. The following graph shows actual transmission import limits from the Northwest that have been input into the AURORA Model by Idaho Power.

[21] DR 56_Aurora B2H LCOE (00221175xBCD5C).xlsx



The red line in the graph shows the actual import limits specified by Idaho Power in the Aurora model and the blue line shows the import limits specified in the B2H Portfolios (all Portfolios are the same until 2026).

By making all non-B2H portfolios look unreasonably high cost due to artificial constraints on economic dispatch in the AURORA model, the AURORA model overstates the portfolio cost savings that can be expected if B2H were built. Idaho Power has clearly biased the AURORA analysis in favor of B2H. This bias renders any results and conclusions Idaho Power has reached from the 2017 IRP portfolio analysis as unreliable at best. The Commission should find this unacceptable.

STOP believes there is a relatively straightforward and defensible way to remove this bias and align the Idaho Power's AURORA inputs more closely with reality. The Commission should direct Idaho Power to increase the existing Northwest to Idaho transmission constraint in the AURORA base case by no less than 330 MW in all months, the amount of the Capacity Benefit Margin (CBM) that Idaho Power reserves for their native load, <u>and to rerun the AURORA Model for all twelve Portfolios</u>.

4. CBM Capacity is Equivalent to Firm Load Capacity for Idaho Power and Available in All Hours

Of the total existing import capacity between the Northwest and Idaho of 1,280 MW, Idaho Power has withheld fully 612 MW from the firm transmission sales market. This is entirely appropriate and in fact is not discretionary on Idaho Power's part, but is a requirement of Idaho Power's tariff. The components of this 612 MW are 330 MW for a Capacity Benefit Margin (CBM) and 282 MW as a Transmission Reliability Margin (TRM). While the TRM can be expected to be unavailable in whole or in part during many hours of the summer due to unscheduled flow (loop flow), CBM is expected to be available essentially all hours of the year.

To understand why CBM should be included as available capacity in the AURORA model, it is important to understand what CBM is and what it means for Idaho Power to reserve CBM. CBM is defined in Idaho Power's OATT as:

> **"Capacity Benefit Margin (CBM)** – The amount of firm transmission capability preserved by the Transmission Provider for Load-Serving Entities (LSEs), whose loads are located on the Transmission 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."[22]

A critical factor to understand about CBM is that it represents an actual, voluntary reservation of capacity by Idaho Power. Because it is a discretionary reservation by Idaho Power for the benefit of native load customers, FERC requires that CBM be reflected as a firm use of Idaho Power's transmission system in the transmission rate setting process (i.e., Idaho Power's Formula Transmission Rate), and CBM is allocated a proportionate share of Idaho Power's transmission revenue requirement. Based upon Idaho Power's current FERC jurisdictional transmission rates, Idaho Power native load customers are allocated costs of $11.5 million per year for the privilege of reserving CBM.

CBM is available on a <u>firm</u> basis to Idaho Power native load customers only in case of emergency generation deficiencies. During all other times, Idaho Power's transmission function must make the entirety of CBM available for non-firm use on a first-come, first-served basis <u>subject to priority access by Idaho Power's native load customers</u>. Following are the relevant descriptive provisions Idaho Power's OATT.

> "CBM amounts are offered as non-firm ATC on paths where it is allocated."[23]

> "Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm PTP transmission service."[24]

To summarize, CBM are amounts of firm transfer capability (import capacity) that Idaho Power withholds from the firm transmission market, but makes available for non-firm use on all hours of the year. Idaho Power has priority access to CBM on a non-firm basis for the benefit of native load customers, and can step in front of any other party (bump them off) for the benefit of importing market power to serve native load customers. For this priority access, Idaho Power's native load customers are assessed $11.5 million of Idaho Power's FERC jurisdictional transmission revenue requirement each year.

In summary, CBM is available at all times for priority use by Idaho Power's native load customers, a reservation for which Idaho Power's native load customers pay $11.5 million a year. CBM should be reflected in the AURORA model as import capacity available to Idaho Power on a year-round basis. The Commission should direct Idaho Power to increase the existing Northwest to Idaho transmission constraint in the AURORA base case by no less than 330 MW in all months, the amount of the Capacity Benefit Margin (CBM) that Idaho Power reserves for their native load, and to rerun the AURORA Model

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[22] OATT at 1.2
[23] OATT Attachment C, Methodology to Asses Available Transfer Capability at 4.4
[24] OATT at 14.2

for all twelve Portfolios. This would reduce the current bias in favor of B2H that Idaho Power has structured in the AURORA model.

5. Expensive and unnecessary transmission investment diverts capital from much needed investment in incremental flexible capacity and storage resources

In their dogmatic crusade to build B2H, Idaho Power has ignored the critical need to augment their current system with new cost-effective flexible incremental supply-side capacity and storage resources as existing coal resources are retired and new resources are added. The Commission should not excuse Idaho Power's failure to constructively address this pressing need in the 2017 IRP.

Through portfolio design sleight-of-hand and incorrect specification of resource characteristics, Idaho Power has effectively abdicated its responsibility under Oregon's IRP Guidelines to "construct a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system."[25] Specifically, Idaho Power first establishes the false premise that market purchases (FOTs) are dispatchable and represent "fast-ramping resource(s) capable of balancing the variable output from intermittent renewable resources".[26] As STOP explained above, market purchases are only dispatchable in fixed hourly increments, and by definition are incapable of contributing to balancing the variable output from intermittent renewable resources.

Based upon this false narrative that B2H (market purchases/FOTs) provides dispatchable and flexible capacity to the system, Idaho Power then constructs a small set of portfolios for evaluation that appear carefully constructed to support a finding that portfolios containing B2H are the least-cost. Idaho Power calls this approach to portfolio specification factorial design, a portfolio design approach first introduced in this IRP. The Commission should examine this in greater detail.

Building on this narrative, Idaho Power claims that B2H "has unique qualitative benefits associated with Idaho Power's participation in an energy imbalance market (EIM)".[27] Idaho Power also claims that B2H will benefit customers by delaying or avoiding the construction of additional resources to serve summer peak load and "improve(ing) the ability to more efficiently implement advanced market tools, such as the EIM." Such claims are not only false, they directly contradict Idaho Power's economic analysis supporting its decision to participate in the EIM as presented in Attachment 1 to Idaho Power's Reply Comments filed in this Docket and previously filed in docket UM 1821.

Staff in their initial comments in this docket requested the Company provide analysis or documents presenting the benefits of EIM participation and how it might impact the B2H project. Idaho Power responded with Attachment 1 to their Reply Comments; an energy imbalance market economic analysis dated February 2016 prepared by Energy and Environmental Economics, Inc (E3).[28] A cursory

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[25] IRP Guideline 4(h)

[26] IRP p91 and Appendix D-B2H Supplement p12 identify B2H as "Balancing, flexibility providing", which Idaho Power defines as "Fast-ramping resources capable of balancing the variable output from intermittent renewable resources." IRP p91

[27] IRP p8

[28] IPC's Reply Comments Attachment 1, Idaho Power Energy Imbalance Market Analysis, February 2016 at p11

examination of this report clearly rebuts Idaho Power's representation of the relationship of B2H (market purchases/FOTs) and the EIM.

Specifically, E3 clarifies that market purchases do not provide benefits associated with Idaho Power's participation in an energy imbalance market (EIM). Those benefits can only be provided by real physical resources and not by market purchases (FOTs).

> "Pooling flex reserves can reduce variable dispatch and generator commit costs, especially as operators accumulate greater experience with the EIM. However, each BA still needs to serve peak loads and provide system flexibility; thus, *participation in the EIM does not reduce the physical generation capacity that a BA needs*" (emphasis added)[29]

The facts are that the EIM is predicated on and designed with the objective of achieving power system efficiencies by pooling within-hour physical balancing resources across a wide geographical footprint across the <u>existing</u> transmission system. It is extremely unlikely that expensive transmission system expansions like B2H would ever provide sufficient flex reserve pooling efficiencies across the grid to support, in even a small way, a $1.2+ billion investment in a new transmission line. Fortunately, there is a way to empirically test this theory and it will happen automatically when Idaho Power joins the EIM this coming April. In April, the EIM operator will begin pooling Idaho Power's within hour balancing resources across the EIM footprint and optimizing the dispatch of all EIM balancing resources every 5 minutes within each schedule hour, subject to transmission constraints. If any transmission constraints between Idaho and the Northwest prevent the most efficient redispatch of balancing resources in any 5 minute period, then the EIM Operator will track the transmission constraints and also track the actual cost of those constraints due to a less economic redispatch of balancing resources in that hour. By this time next year, Idaho Power will have documented evidence of any within hour constraints, or lack thereof, on EIM within-hour redispatches due to constraints in moving power between the PNW and Idaho, as well as the actual costs resulting from such constraints, if any. Prior to developing this information, Idaho Power's claims that B2H will benefit the EIM are wholly unfounded and unlikely at best.

6. Idaho Power has materially understated the B2H levelized cost of energy

In this IRP, consistent with Oregon's IRP Guidelines, Idaho Power has appropriately compared different supply side resources based upon their respective levelized cost of energy (LCOE). What is new in this IRP is Idaho Power's attempt to evaluate a transmission line as a supply side resource, and specifying market purchases (FOTs) as the underlying energy resource enabled by the transmission line. Evaluating a transmission line as an option to access lower cost resources is a valid concept and clearly accommodated within Oregon's IRP Guidelines. Unfortunately, Idaho Power didn't get it right as STOP explains below. Idaho Power has:

1) understated the cost-of-capital component of the B2H revenue requirement
2) understated the levelized cost of market purchases (FOTs), and
3) understated the B2H LCOE by crediting the LCOE with theoretical revenue increases from third party transmission customers. Idaho Power will actually experience a net loss of existing third party transmission revenues if B2H is built.

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[29] Idaho Power Energy Imbalance Market Analysis, February 2016 at p12

7. Idaho Power has obscured the true LCOE of B2H in their Reply Comments and in Appendix D-B2H Supplement

On October 4, 2017, Idaho Power informed the Commission and parties of certain corrections to the IRP. The filing advised parties that because of a mistake in transferring a number from source documents to several Tables in the IRP, the LCOE for B2H in the IRP showed $39 MWh in multiple places, when the correct number was $46, or 18 percent higher than reflected in the IRP.[30] Specifically, the incorrect number is shown in the 2017 IRP at Table 7.3 "Resource attributes" on page 92, Figure 7.6 "Resource Attributes" on page 92, and in Appendix C the "Levelized Cost of Energy" table on page 76.[31]

STOP appreciates notification of this correction and understands that it may have been impractical at the time to issue public errata to reflect the change in the public IRP documents. However, when Idaho Power published its Appendix D-B2H Supplement on December 8, STOP would have hoped that Idaho Power would had taken that opportunity to place corrected tables in the public record, especially given the renewed and expanded discussion of the capacity cost and energy cost of B2H in Appendix D.

Inexplicably, Idaho Power fails to seize the opportunity to correct the public IRP documents by including corrected Tables and Figures showing the LCOE of B2H when Appendix D was published. In fact, the expanded discussion of capacity and energy costs of B2H in Appendix D only references the B2H LCOE twice in the document, and in both cases references the <u>uncorrected</u> LCOE of B2H[32]. Instead of correcting the record in Appendix D, Idaho Power introduces a brand new cost metric to describe the capacity cost of B2H; the "*capital cost per kilowatt at peak*".[33] Idaho Power does not define this new cost metric in Appendix D, and the metric itself is misleading, has never been used before in any IRP STOP is aware of, and is completely without merit.[34] Idaho Power has not only invented a new cost metric uniquely applied only to B2H in this IRP, use of this new metric is inconsistent with Oregon's IRP Guidelines.[35] Nonetheless, Idaho Power proceeds to use this new metric to make brand new frivolous and misleading comparisons of B2H to other Resources in both Appendix D and in Reply comments.

For example, Idaho Power relies on this misleading metric to support a brand new claim in Appendix D that "The B2H total capital cost per kilowatt at peak is 62 percent of the cost of the next lowest-cost resource".[36] As further evidence of Idaho Power's bad behavior, Idaho Power in their reply comments produce a new incarnation of the "solar tipping point analysis" originally performed at the request of IRPAC and included in the original 2017 IRP.[37] This revised tipping point analysis presented in Idaho Power's reply comments employs a wholly new calculation of LCOE based upon the misleading "capital

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[30] Letter from Lisa Rackner to Filing Center dated October 4, 2017
http://edocs.puc.state.or.us/efdocs/HAH/lc68hah165442.pdf

[31] While this error distorts the comparison of B2H against other resources in the IRP documents, it did not directly affect Idaho Power's analysis or conclusions

[32] Appendix D-B2H Supplement at pages 1 and 61

[33] Appendix D-B2H Supplement at pages 6-7

[34] The "capital cost per kilowatt at peak" metric is misleading without reference to a "capital cost per kilowatt at non-peak". Idaho Power claims the "capital cost per kilowatt at peak" for B2H is $548 ($748 * 350/500), but doesn't acknowledge that the comparable "capital cost per kilowatt at no-peak" of B2H would be $1,309 ($748*350/200).

[35] Oregon's IRP Guideline 1 requires that "Consistent assumptions and methods should be used for evaluation of all resources."

[36] Appendix D-B2H Supplement at page 7

[37] 2017 IRP at page 118

cost per kilowatt at peak" metric. Not surprisingly, B2H is now shown as astoundingly cheaper compared to solar, cheaper even than originally presented in the IRP.

Specifically, in the original IRP, Idaho Power concluded that "Only when solar PV prices dropped more than 50 percent did the NPV ranking of the preferred portfolio (P7) change".[38] Now, in light of Staff's concerns regarding the robustness of the 2017 IRP portfolios, Idaho Power has revised the solar tipping point analysis in their Reply Comments. Idaho Power's revised analysis, based on the misleading new "capital cost per kilowatt at peak" metric, now concludes that despite a 10 percent assumed drop in solar costs from those assumed in the IRP, "the costs for solar and battery storage resources must decrease more than 90 percent from their current levels to be less costly than B2H."[39] Staff should not be persuaded by this revised tipping point analysis. In fact, Idaho Power's revised analysis should heighten Staff's concerns.

8. The Levelized Costs of B2H Used in the Portfolio Modeling Are Calculated Incorrectly

The 30 year levelized costs of B2H used as inputs to Aurora in the portfolio modeling are incorrectly calculated, and the presentation of those costs in the publicly accessible 2017 IRP materials is understated. These errors consist of a combination of incorrect cost-of-capital inputs, errors in extracting wholesale market power costs from the output of Aurora simulations, and faulty secondary transmission revenue estimates. When the cost of lost third party transmission sales is included, the true cost of B2H to Idaho Power ratepayers is over 100% higher than presented in the 2017 IRP documents.

To expose these errors as clearly as possible, STOP will perform a step-by-step workup of the B2H Total Cost Per MWh as reported in the IRP, with clear justification for and estimated impact of each correction. In an effort to be as clear as possible, STOP will record each correction on the following Tables 2a-f, which STOP has extracted from the 30 Year Levelized Cost of Energy table reported on Page 76 of the 2017 IRP-Appendix C.

Table 2

LCOE of B2H AS ORIGINALLY PRESENTED IN IRP

30-Year Levelized Cost of Energy (at stated capacity factors)

Supply Side Resources	Levelized Cost of Capital	Levelized Non-Fuel O&M	Levelized Fuel	Levelized Wholesale Energy	Levelized Transmission Revenue	Levelized Total Cost per MWh	% INCREASE ABOVE IRP	Capacity Factor
Boardman to Hemingway (350 MW)	$18	$3	$0	$28	-$9	$39	0%	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

Table 2 above is replicated from IRP Appendix C at page 76. The first step is to incorporate the correction provided by Idaho Power stating that the above Cost of Capital number was incorrectly stated

[38] Reply Comments at page 46

[39] Reply comments at pages 47-48

in the IRP. The correction increased the Cost of Capital number reported in the IRP tables from $18 to $24, and the Total Cost per MWh number to $45, a 16 percent increase over the total reported in the IRP. This correction is displayed in Table 2A below.

Table 2A

LCOE of B2H AS CORRECTED BY IDAHO POWER ON OCTOBER 4

(NOTE: CORRECTED NUMBERS USED IN AURORA MODELING)

30-Year Levelized Cost of Energy (at stated capacity factors)

Supply Side Resources	Levelized Cost of Capital	Levelized Non-Fuel O&M	Levelized Fuel	Levelized Wholesale Energy	Levelized Transmission Revenue	Levelized Total Cost per MWh	% INCREASE ABOVE IRP	Capacity Factor
Boardman to Hemingway (350 MW)	$24	$3	$0	$28	-$9	$45	16%	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

The next step is to incorporate corrections to the return-on-capital inputs used to calculate the B2H Revenue Requirement and associated levelized cost of capital.[40]

9. Corrections to Cost-of-Capital Inputs to LCOE

Idaho Power applied incorrect return-on-capital and tax factor inputs when calculating the B2H LCOE for input into the Aurora model. Specifically, Idaho Power used the return on capital and tax factor inputs approved by the Idaho PUC for calculating Idaho Power's retail revenue requirement and retail rates.

While these would be the correct inputs to use for calculating the retail revenue requirement associated with Idaho generating resources and distribution assets, the correct inputs to use for calculating the transmission revenue requirement associated with Idaho Power's transmission assets are FERC authorized inputs as reflected in Idaho Power's FERC approved transmission Formula Rate and any incentive rates approved by FERC for application to B2H.[41]

FERC has exclusive jurisdiction over Idaho Power's transmission revenue requirement and open access (OATT) transmission rates, including the return-on-capital and tax factor inputs used to calculate the Idaho Power's FERC jurisdictional transmission revenue requirement. Once this transmission revenue requirement is established pursuant to Idaho Power's FERC authorized Transmission Formula Rate, a

[40] All corrections to the levelized cost of capital in Table2a-2f are calculated using Idaho Power's LCOE Non-Confidential spreadsheet provided in response to staff data request No. 89: LC 68 - IPC's Attachment 19- Tab 1- to Staff's DR 89 (00034343-2xCEFFF).xlsx

[41] Idaho Power's FERC Formula Rate calculator can be found at http://www.oasis.oati.com/IPCO/IPCOdocs/FINAL_Transmission_Rate_October_1_2017-Sept_30_2018_Final_Informational_Posting.xlsx

share of the transmission revenue requirement is allocated to Idaho Power native load customers and becomes a fixed cost component of Idaho Power's retail revenue requirement and retail rates. [42]

If the OPUC acknowledges B2H and it is built, Idaho Power will receive special ratemaking treatment by FERC in the form of a 200 basis point incentive Return on Equity (Incentive ROE) pursuant to FERC Order No. 679[43] and a FERC Order on Petition for Declaratory Order issued by FERC on October 21, 2008.[44] In 2008, PacifiCorp, the majority equity partner in B2H petitioned for and received FERC incentive ratemaking treatment for the entire Gateway West transmission project, including Gateway West Segment H (Boardman to Hemingway)[45] and said incentive ROE applies to Idaho Power's share of B2H.

STOP asked Idaho Power why they have not reflected the 200 basis point incentive in their LCOE inputs to the Aurora Model (STOP Data Request No. 19). Idaho Power responded that "Idaho Power was not a party to this docket [EL08-75-000] nor does the FERC order authorize an incentive ROE adder for the Company". Idaho Power is unforthcoming. A plain reading of the FERC Order clearly shows that the incentive ROE was awarded to the Gateway West project in whole and in parts, not to any specific Company. In fact, FERC went out of its way to promote their approval of the incentive ROE for Gateway West as encouraging equity partners like Idaho Power to join the Gateway West project with PacifiCorp.

> "We find here that granting the ROE incentive, together with abandoned plant recovery, will encourage greater participation from potential equity partners."[46]

STOP has correctly included a 200 basis point incentive ROE in the recalculation of the LCOE of B2H. Table 2B below identifies the correct (FERC authorized) cost of capital inputs Idaho Power should have used in developing LCOE inputs to the Aurora model.

COST	IPUC[47]	FERC
Debt	5.728%	5.010%
Preferred Stock	0	0
Common Equity	10%	10.7%
WEIGHTED COST OF CAPITAL	7.863%	8.047%
COMPOSITE TAX RATE	3.2071%	3.622%
B2H WEIGHTED COST OF CAPITAL (includes 200 basis point incentive return)		9.115%

[42] Under FERC ratemaking, Idaho Power's FERC approved revenue requirement is allocated between OATT customers and Idaho Power's native load customers based upon each customer's respective usage of Idaho Power's transmission system.

[43] FERC Order No. 679, Promoting Transmission Investment through Pricing Reform, July 20, 2006. The order is available at https://www.ferc.gov/whats-new/comm-meet/072006/E-3.pdf

[44] ORDER ON PETITION FOR DECLARATORY ORDER, October 21, 2008 in Docket EL08-75-000 The Order is available at https://www.ferc.gov/whats-new/comm-meet/2008/101608/E-31.pdf

[45] PacifiCorp identifies Boardman to Hemingway as Gateway West Segment H their 2017 IRP. See PacifiCorp 2017 IRP at page 18. PacifiCorp's 2017 IRP is available at https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

[46] ORDER ON PETITION FOR DECLARATORY ORDER, October 21, 2008 in Docket EL08-75-000 at page 22

[47] Source: LC 68 - IPC's Attachment 19- Tab 1- to Staff's DR 89 (00034343-2xCEFFF).xlsx

Correcting Idaho Power's cost of capital inputs, combined with the correction of Idaho Power's typographical error (Table 2A), results in a LCOE of $49 MWh, which is 26 percent higher that reflected in the 2017 IRP documents. This correction is displayed in Table 2B below.

Table 2B								
LCOE of B2H CORRECTED TO REFLECT FERC APPROVED COST OF CAPITAL INPUTS								
30-Year Levelized Cost of Energy (at stated capacity factors)								
Supply Side Resources	**Levelized Cost of Capital**	**Levelized Non-Fuel O&M**	**Levelized Fuel**	**Levelized Wholesale Energy**	**Levelized Transmission Revenue**	**Levelized Total Cost per MWh**	**% INCREASE ABOVE IRP**	**Capacity Factor**
Boardman to Hemingway (350 MW)	$28	$3	$0	$28	-$9	$49	26%	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

The next step is to correct the calculation of the levelized cost of Wholesale Energy.

10. Corrections to Levelized Cost of Wholesale Energy

The Levelized Wholesale Energy column in all Tables 2a-f represent the variable energy component (market purchases) of the B2H resource in Idaho Power's IRP. Idaho Power calculated the levelized cost of wholesale energy (LCWE) at $28 MWh. This $28 cost of wholesale market purchases in the B2H Portfolios is not an input into the Aurora model as are the cost of capital inputs, but rather the LCWE is calculated from the output of the Aurora modeling of B2H portfolios and displayed in the IRP tables for informational purposes.

STOP examined the selected Aurora output files provided to Staff in response to Staff data request No. 56 in an attempt to understand the Aurora outputs of Portfolio 7 and to understand how Idaho Power calculated the LCWE from those output files.[48] What STOP found were three apparent errors in Idaho Power's post-processing of the Aurora results. Specifically:

1. Idaho Power calculated the LCWE based on a 100 percent capacity factor usage of PNW import capacity over the 20 year period 2017-2036 (i.e., the calculation by Idaho Power assumed that all available PNW import capacity specified in AURORA was used at all times to import power). The proper way to calculate the LCWE is to base the calculation on the average monthly capacity factor usage of the PNW import capacity each month as simulated by the Aurora model, which the Aurora output shows as approximately 26 percent.
2. Although the Aurora model simulations calculate transmission wheeling costs for each wholesale market transaction, Idaho Power did not include wheeling costs in their post-processing of AURORA outputs when calculating LCWE, and
3. Although the Aurora model simulations calculate real power losses for each wholesale market transaction, Idaho Power did not include transmission real power losses in their post-processing of Aurora outputs when calculating LCWE.

[48] LC 68 - Staff's DR 56_Aurora B2H LCOE (00221175xBCD5C).xlsx

Correcting these three errors in the calculation of LCWE increases the LCWE by 16 percent above the cost of wholesale energy reported by Idaho Power in the IRP. Table 2C below displays the aggregate effect of correcting the LCWE and correcting the cost-of-capital inputs, combined with the correction of Idaho Power's original typographical error (Table 2A). The result is a LCOE of B2H that is 38 percent higher than reported by Idaho Power in the IRP documents.

Table 2C

LCOE of B2H WITH CORRECTED COST OF CAPITAL, CORRECTED WHOLESALE ENERGY

30-Year Levelized Cost of Energy (at stated capacity factors)

Supply Side Resources	**Levelized Cost of Capital**	**Levelized Non-Fuel O&M**	**Levelized Fuel**	**Levelized Wholesale Energy**	**Levelized Transmission Revenue**	**Levelized Total Cost per MWh**	**% INCREASE ABOVE IRP**	**Capacity Factor**
Boardman to Hemingway (350 MW)	$28	$3	$0	$32	-$9	$54	38%	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

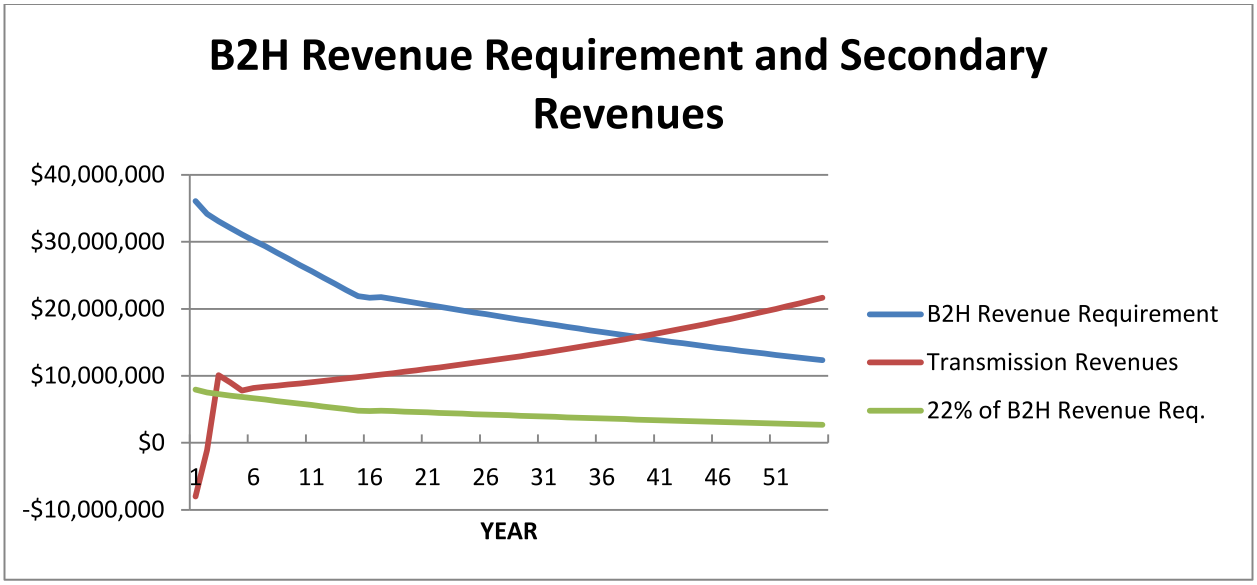
11. Corrections to Levelized Transmission Revenue Forecast

The largest and most significant errors in Idaho Power's cost evaluation of B2H derive from their assumptions regarding future revenue credits to native load customers from sales of transmission services to third-party OATT customers of Idaho Power. Idaho Power correctly explains that all existing transmission customers pay a share of Idaho Power's transmission revenue requirement, including any increases in Idaho Power's transmission revenue requirement resulting from B2H, based on a ratio of each customer's usage of the transmission system. Idaho Power further forecasts that third party transmission system usage will approximate 22 percent of the total usage by all customers on the Idaho Power transmission system when B2H enters service.[49]

STOP disagrees with this forecast, and will elaborate on that below. First though, even if one accepts Idaho Power's forecast that third-party users will pay 22 percent of the total transmission system annual revenue requirement when B2H enters service, Idaho Power has made a material error in the way it has modeled this revenue credit over the 50 year service life of B2H.[50] The simple graphic below serves to highlight this error. In the graph below, STOP shows the nominal annual B2H Revenue Requirement and the nominal annual transmission revenue credited actually used by Idaho Power to calculate levelized cost inputs into the Aurora model.

[49] Appendix D-B2H Supplement at page 41

[50] Idaho Power's forecast of the nominal annual B2H revenue requirement and nominal annual transmission revenues are specified in Attachment 19 to Staff's data request No. 89.



The blue line above is the forecasted nominal annual revenue requirement for B2H. The red line is the nominal annual transmission revenues from third party transmission users on the Idaho Power transmission system as forecasted by Idaho Power. According to Idaho Power's projection, existing third party transmission users will pay an increasing share of B2H over time, paying over half the cost of B2H in 20 years and more than 100 percent of the B2H revenue requirement by year 40. STOP knows of no regulator approved rate design methodology that would allow such cross-subsidization to occur and it certainly is not allowed by FERC.

STOP believes that the green line above, which represents a constant 22 percent contribution to the B2H revenue requirement over the life of B2H, is more consistent with Idaho Power's proffered theory that third party transmission customers will pay approximately 22 percent of B2H costs.

Table 2D below presents the B2H Levelized Total Cost per MWh with the corrected levelized transmission revenue forecast, based upon the constant 22 percent transmission revenue contribution to the B2H revenue requirement (green line in graph above) and the corrected levelized cost of capital number of $28, the corrected LCWE of $32, and the revised levelized transmission revenue number of -$6. Incorporating all these corrections results in a B2H levelized Total Cost per MWh of $57, which is 46 percent higher than reported in the IRP documents.

Table 2D								
LCOE of B2H WITH CORRECTED COST-OF-CAPITAL, CORRECTED WHOLESALE ENERGY, AND CORRECTED TRANSMISSION REVENUE								
30-Year Levelized Cost of Energy (at stated capacity factors)								
Supply Side Resources	**Levelized Cost of Capital**	**Levelized Non-Fuel O&M**	**Levelized Fuel**	**Levelized Wholesale Energy**	**Levelized Transmission Revenue**	**Levelized Total Cost per MWh**	**% INCREASE ABOVE IRP**	**Capacity Factor**
Boardman to Hemingway (350 MW)	$28	$3	$0	$32	-$6	$57	46%	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

12. Corrections to Reflect Lost Transmission Sales

Idaho Power appears completely unaware of the long-term adverse impact that B2H would have on third party transmission revenues at enormous cost to Idaho Power's native load customers. According to Idaho Power, they "chose to *conservatively* (emphasis added) assume that third-party use (network customers and transmission wheeling customers) across Idaho Power's transmission system would remain static following the construction of B2H". Specifically, they assumed that after B2H enters service, they will retain 861 MW of network load and transmission customer usage. [51] This assumption by Idaho Power is neither conservative nor credible.

A simple examination of Idaho Power's existing network load and transmission customer usage shows why this assumption is not credible. The Tables below identify existing third party usage of the Idaho Power Transmission System.[52]

The first Table identifies 250 MW of existing network load on the Idaho Power System. This network load can be reliably assumed to continue. The second Table identifies existing long-term firm OATT transmission customers (wheeling customers) of Idaho Power. It shows that 70 percent of current wheeling sales are to BPA (200 MW west-to-east) and PacifiCorp (510 MW east-to-west). These two customers are both equity participants in B2H along with Idaho Power. BPA's share of west-to-east capacity over B2H is 250 MW summer and 550 MW winter, and PacifiCorp's share of east-to-west capacity over B2H is 600 MW year around.[53]

[51] Appendix D-B2H Supplement at page 40

[52] Source: Idaho Power's 2017 Informational Filing, August 28, 2017 - Schedule 5. The filing is available at http://www.oasis.oati.com/IPCO/IPCOdocs/FINAL_Transmission_Rate_October_1_2017-Sept_30_2018_Final_Informational_Posting.xlsx

[53] Appendix D-B2H Supplement, Appendix D3, B2H Funding Agreement, Exhibit D-Permitting Interest Work Paper

Idaho Power Current Transmission Sales (Annual MW)	OATT PTP Sales	Network Sales	Total Transmission Sales	Lost Third Party Sales With B2H
Idaho Power Native Load		2283	2283	
Idaho Power CBM		330	330	
Idaho Power OATT PTP	162		162	
BPA/BLM Network		250	250	
BPA OATT PTP	200		200	200
PacifiCorp OATT PTP	510		510	510
Seattle City Light OATT PTP	101		101	
TOTAL	**973**	**2863**	**3836**	**710**

It is not credible to forecast that either BPA or PacifiCorp will continue to take OATT (wheeling) service from Idaho Power after they have made an expensive investment in B2H and replaced the capacity on the Idaho Power system with ownership capacity on B2H.

The loss of BPA and PacifiCorp wheeling revenues (710 MW) represents $25 million in lost revenues to Idaho Power at current OATT transmission rates. Furthermore, it would leave only 513 MW of remaining third party sales on the Idaho Power transmission system, or about 18 percent, that could contribute to the cost of B2H. STOP has calculated the net loss of transmission revenues that would occur if Idaho Power were to build B2H (incremental transmission revenues due to OATT rate increase less lost transmission sales revenues).

Table 2E below includes all previous correction plus a correction to reflect the net loss of transmission revenues that would occur if Idaho Power were to build B2H. Incorporating lost transmission revenues results in a net levelized cost of lost transmission revenues of $20, and a Levelized Total Cost of $83, which is 113 percent higher than reported in the IRP documents

Table 2E

LCOE of B2H WITH CORRECTED COST OF CAPITAL, CORRECTED LEVELIZED WHOLESALE ENERGY CORRECTED TRANSMISSION REVENUE AND LOST TRANSMISSION SALES

30-Year Levelized Cost of Energy (at stated capacity factors)

Supply Side Resources	**Levelized Cost of Capital**	**Levelized Non-Fuel O&M**	**Levelized Fuel**	**Levelized Wholesale Energy**	**Levelized Transmission Revenue**	**Levelized Total Cost per MWh**	**% INCREASE ABOVE IRP**	**Capacity Factor**
Boardman to Hemingway (350 MW)	$28	$3	$0	$32	$20	$83	113%	33%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

Finally, Table 2F below includes all previous corrections and a final correction to the levelized Cost-of-Capital. Idaho Power's calculated levelized cost-of-capital of B2H was based upon an estimated B2H capacity factor of 33 percent. Examination of the output results of the Aurora simulation of Portfolio P7 revealed an average capacity factor use of PNW import capacity of only 26 percent. Recalculating the levelized cost of capital using a 26 percent capacity factor, along with all other corrections results in a levelized cost of capital of $36, and a Levelized Cost of Energy of $91 MWh; fully 134 percent higher than reported in the IRP documents.

Table 2F

LCOE of B2H WITH CORRECTED COST OF CAPITAL, CORRECTED WHOLESALE ENERGY, CORRECTED CAPACITY FACTOR CORRECTED TRANSMISSION REVENUE AND LOST TRANSMISSION SALES

30-Year Levelized Cost of Energy (at stated capacity factors)

Supply Side Resources	Levelized Cost of Capital	Levelized Non-Fuel O&M	Levelized Fuel	Levelized Wholesale Energy	Levelized Transmission Revenue	Levelized Total Cost per MWh	% INCREASE ABOVE IRP	Capacity Factor
Boardman to Hemingway (350 MW)	$36	$3	$0	$32	$20	$91	134%	26%
CCCT (1x1) F Class (300 MW)	$26	$6	$28	$0	$0	$59		70%
SCCT - Frame F Class (170 MW)	$118	$36	$43	$0	$0	$197		10%
Reciprocating Gas Engine (18.8 MW)	$41	$18	$35	$0	$0	$94		25%
Solar PV - Utility Scale 1-Axis (30 MW)	$62	$12	$0	$0	$1	$74		27%

E. B2H May Not Reduce Regional Transmission Losses as Idaho Power Claims

Idaho Power makes an unsupported claim that "the B2H project is expected to reduce electric losses by more than 100 MW in the Western Interconnection" and further characterizes this as a "considerable savings for the region".[54] Idaho Power's entire discussion of transmission losses in Appendix D2-B2H supplement consists of only 13 lines of text, and the 2017 IRP did not address transmission losses at all

The facts are that the pattern of transmission losses on the regional transmission grid constitute a complex and dynamic issue, one that cannot be captured in a few words referencing a single peak hour of the year. More important than cherry picking that hour in order to report transmission loss savings, is to understand how a transmission line will affect grid losses over an entire operating year. The increased transmission losses resulting from new commercial transactions, those enabled by a new transmission line, can change resource dispatch patterns in the western interconnection with a large effect on overall system losses.

It is undoubtedly true that the B2H line can reduce regional losses by 100 MW on a peak hour, but cost studies using the GRIDVIEW production cost model have shown the **annual** loss savings from B2H to be considerably lower (less than 10 average MW).[55] To the extent that a new transmission line enables new market power purchases from distant markets, that line will, in many cases, directly cause a large increase in grid losses. Those will offset the loss savings due to the transmission line itself.

[54] Appendix D-B2H Supplement at page 47

[55] Should the Commission wish to learn more about transmission losses and B2H, the Commission should request such studies from Idaho Power

For example, if Idaho Power were to turn off their 300 MW Langley Gulch power plant on a peak summer day and instead buy 300 MW of power from the MID-C market (e.g., power from Grand Coulee dam), regional transmission losses would **increase** by over 15 percent, or over 45 MW.[56] The loss savings from adding distributed generation can be much greater than the 15 percent savings in the above example.

STOP believes that the inclusion of transmission losses is of overriding importance for Integrated Resource Planning. Idaho Power should be required to do a credible assessment of the transmission loss implications that are a product of their resource portfolios. That would be true for any IRP, but it is especially relevant for this IRP.

III. The Future is Now: Distributed Generation, Energy Efficiency, Reliability

A. General response to Idaho Power comments

The rapid development of digital grids, both at the utility scale, and of microgrids at campus scale[1], are a centrifugal force draining power away from long-distance transmission lines and devolving it both regionally and locally. Incorporating control surfaces - smart inverters and smart meters - and then embedding those digital elements within microgrids is where power engineering is going[57].

Utilities can overlay the network and database components of an advanced metering infrastructure (AMI)[3] on top of that to facilitate the rapid integration of power from producer-consumers, and the delivery of value added services by the utility. This would seem to be one profitable avenue paving the way for a viable transition in what is by any measure a rapidly changing business.

The failure of Idaho Power to seriously address their plans for an AMI in the 20-year projection provided by the Integrated Resource Plan is problematic at best. The worst case scenario indicates an alarming failure to keep pace in a very disruptive energy environment[58].

The biggest threat to the utilities, and it is existential, is that prices are dropping at a steady rate for solar, and even more quickly for storage[5]. While the combination has not yet reached economic viability, the trend is very clear as can be seen below (Figure 1). Once the price-point is reached, and

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[56] The loss savings in this example assumes that B2H has been built and is in service. Should the Commission wish to learn more about the implications of resource siting decisions and expanded reliance on market power imports, the Commission should request such information from Idaho Power.

[57] The wealth of information about microgrid evolution, and the tools available to power engineers and grid designers, is typified in this statement from the USDOE's portfolio of microgrid activities[2]:

> *The Microgrid Design Toolkit (MDT), which was developed by Sandia National Laboratories, is a decision support software tool for microgrid designers that is intended to be used in the early stages of the design process.*

[58] O'Brien Browne the Instructor in International Management at the Orfalea College of Business, and Andreas Forwald, CEO Grünwald Technologies & Sloan MBA, are very clear about the threat to utilities[4]:

> *The first hit was the computer mainframe industry in the 1980s, then the conventional camera business of the 1990s was transmogrified followed by the telecommunication industry in the 2000s: and now it is the turn of the electric power utilities to take their place on the anvil of technological and societal change. These behemoths are forced to radically reshape themselves or face extinction.*

that will happen long before the 20 year projections in the Idaho Power Integrated Resource Plan, the results will be catastrophic for any electric utility that is unprepared.

The logic is iron-clad. Without the work necessary to fully integrate their largest purchasers into the existing grid, those customers will be the first to produce their own power, store it, and then start building markets for the excess using micro-grids at campus scale. That combination of innovation and entrepreneurship is at the heart of US economic progress and it is unstoppable. Electric utilities must prepare for this inevitable reality. If they are unwilling or unable to do that, the transition will short-circuit utility business models, bleed their remaining ratepayer base, and send them into a downward spiral.

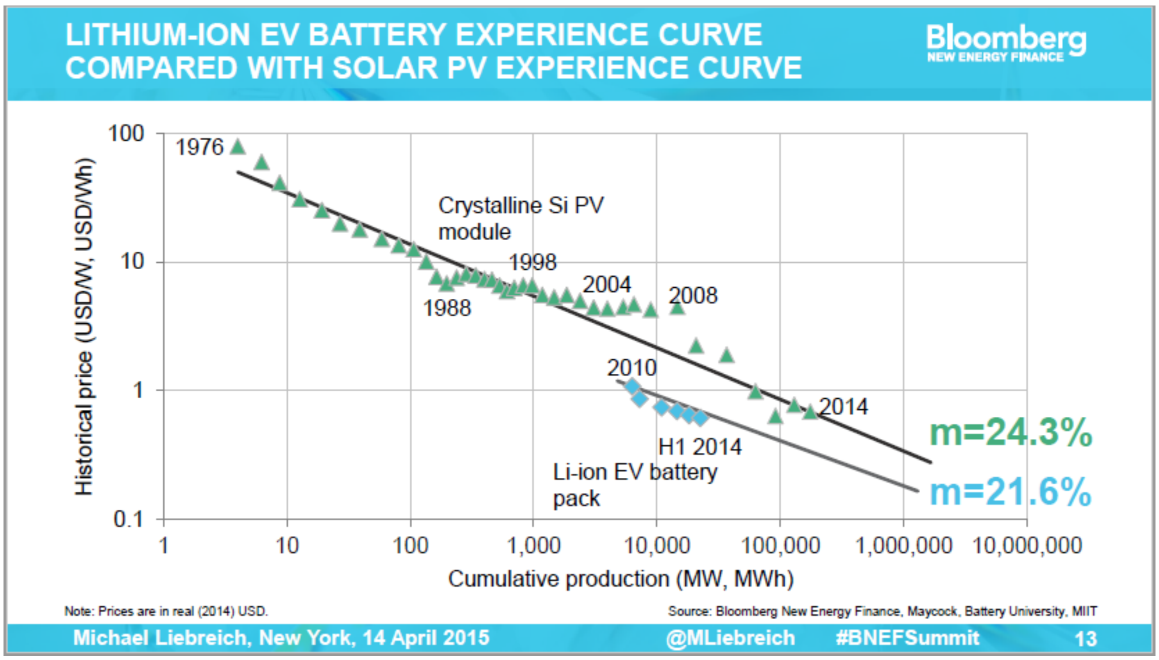

Figure 1 - Price/production comparison for lithium-ion battery and solar electrovoltaic cells.[6]

The question the PUC must address is one that has a much longer cost/benefit timeframe than a 5-year business cycle or 10 years of rapid technological innovation. It is this: why is 50-year financing an acceptable option for a high-voltage power line that will be obsolete well within the 20-year IRP framework? Examining what the past 50 years of technological change – from 1967 to 2017 – have wrought provides a stark lesson about what is in store for power production, consumption, and transmission[4]. This revolution needs to be addressed quickly by Idaho Power, and by all electric utilities.

The difficult decision facing the Public Utility Commission is whether the status quo of long-distance power transmission, with all the line losses that entails, and with Idaho Power's disregard for rapid technological change, will saddle its ratepayers with an unnecessary burden for the next 50 years. The looming threat is of great harm to its customers and to local and regional economies, in both the risk those ratepayers will take on, and in the cost they will increasingly shoulder.

B. Specific Response to Idaho Power's Comments

1. Distributed Generation

There is irony in Idaho Power's response to our comments on distributed generation[7]. On page 65 of their reply, they has the STOP B2H Coalition urging Idaho Power to:

"*…use efficiencies and build at the smallest scale possible…*"

…a quote which in fact comes directly from the current Administrator of the BPA, one of Idaho Power's partners in the proposed Boardman to Hemingway 500KV line. The entire quote gives context to his statement:

*"Bonneville is committing to taking a forward-looking approach with its investment decisions, and the region can be certain that **BPA will seek first** to use efficiencies and build at the smallest scale possible to meet our customers' needs, ensuring Bonneville remains a reliable engine of economic prosperity and environmental sustainability in the Northwest."*[8]

This is a rational approach to the local and regional asset dispersion inherent in the emerging modular grid. It acknowledges a valuable but decentralized resource base.

Contrary to the criticism of BPA in Idaho Power's response on page 66[7], there is no contradiction in its partner's stated position. Such scaling will "*allow it to remain a reliable engine of economic prosperity and environmental sustainability in the Northwest"*. Proper selection and development of storage resources at a targeted scale, combined with the emergence of digital controls in a well-provisioned system of integrated microgrids, will deliver redundancy[9], allow for the aggregation of valuable ancillary services[10], and provide much greater grid resilience and security to the electric power system[59].

The company's statement on page 66[7] that:

At present, neither distributed solar nor storage resources represent cost-effective resources, particularly on a scale necessary to supplant a resource like the B2H line.

…ignores the 20-year projection inherent in the IRP process. We are not asking how the company expects to pay its bills right now. We are instead asking for a rational forecast, within the two decade scope of the IRP, of the changes the utility expects to see and how it is planning for them.

[59] In a report to Congress on the effects of hurricane Sandy and the effort to mitigate those effects, the National Academy of Sciences had this to say[11]:

> *Microgrids achieve resiliency by islanding from the central grid during an outage. Their on-site generators then supply local customers. Buildings served by microgrids can act as electrified oases, places of refuge where community members can seek shelter, charge phones, get medical help, buy food and fuel cars. Utilities also are designing microgrids to power headquarters that workers can use as base camp while restoring the grid.*

The arrival of battery storage will serve to greatly increase the resiliency of these systems.

Idaho Power cannot have it both ways, asking for the right to a 50-year financing of the B2H line while simultaneously refusing to address the cataclysmic changes engulfing the power industry[12] and threatening its 100 year-old business model. That model is going to disappear[60], again well within the 20-year IRP planning horizon, putting the utility and its customers at great risk. What is the plan to deal with that?

Care has to be taken that the IRP process not become a shell game, with the public and regulators trying to figure out which 2-year plan might eventually harbor the relevant information. The disruption is happening right now. Idaho Power's response to the rapidly developing solar market has made that clear[14], [15]. The planning process around that disruption should also be surfaced right now.

2. Energy Efficiency

Energy Efficiency is Idaho Power's neglected step-child. STOP asserted that in the past decade Idaho Power has achieved much less in EE saving in comparison to other utilities. Idaho Power disagreed, but provided no references to other utilities, many of which have doubled their energy savings. Instead, the Company cites an award from the 2017 State Energy Efficiency Scorecard which lists Idaho as one of the most-improved 15 states this year. The following excerpt summarizes Idaho's 2017 score:

Idaho added the most to its score this year, rising in the ranks from 33rd to 26th. ***Although the state's utility savings have yet to rebound to peak levels seen in 2010 and 2011, they have edged upward recently thanks to resurgent levels of spending on demand-side management programs.*** *Idaho has also seen a recent increase in electric vehicle registrations and updates to building energy codes modeled on the 2015 International Energy Conservation Code (IECC), due to take effect in January 2018.* ***This was the state's best finish since 2012.***

The STOP B2H Coalition commends Idaho Power for improved building codes and increased electric vehicle registrations, but agrees with the American Council for an Energy Efficient Economy that Idaho Power has, as we previously commented, made little progress in energy savings during the past 8 years. The fact that Idaho Power celebrates achieving an EE rating that places the utility still below half of the states in the U.S. is telling. Oregon and Washington are rated 5th and 7th respectively.

STOP questioned Idaho Power's failure to maximize utilization of the 500,000 smart meters, installed in 2011, for peak demand savings. Using smart meters, other utilities have achieved peak demand energy savings of up to 10%. (p. 19) Idaho Power has limited its A/C Cool program to .063% of its residential customers. Idaho Power chose not to reply.

STOP noted that Idaho Power has added only two new energy efficiency programs since 2009. In reply, Idaho Power states that it:

"…has continually added new measures to its energy efficiency programs, and all but two are offered in both the Idaho and Oregon jurisdictions. These 23 programs comprise over 275 energy efficiency measures..."

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[60] That risk was made clear four years ago by the electric utilities' own think tank, the Edison Electric Institute[13].

The program titles they listed represent tepid efforts that have produced negligible results. The fact remains that Idaho Power continues to survey "Customer Satisfaction" rather than "Results." That a utility would fill 3 pages of its IRP detailing an energy savings program that produced a 97% positive customer response but achieved a miniscule .0011% customer behavior change suggests a disconnect from reality.

In reference to CHP, Idaho Power refers to "substantial logistical and administrative difficulties, which have proven surprisingly challenging." (p.67[7]) As noted, other utilities have achieved remarkable energy savings related to broad adoption of CHP. Those utilities have managed to overcome the logistical and administrative difficulties encumbering Idaho Power.

In reference to renewable energy, and specifically the potential of solar as an energy source, the STOP B2H Coalition joins Sierra Club in stating that Idaho Power is unreasonably pessimistic in forecasting costs of solar. Idaho Power states "Only when solar prices dropped more than 50% did the NPV ranking of the preferred portfolio (P7) change." (Reply, p. 46). Given the rapid decline in the price of solar modules (Figure 1), STOP believes that the 50% drop may have already occurred.

The utility's overall response to the question of energy efficiency is inadequate. Idaho Power is unable or unwilling to properly factor into its estimate of future electric demand the significant decrease in that demand brought about through energy efficiency. A simple linear projection of the Idaho Power's own data is all that would be needed.

Yet the utility turns this failure on its head on page 68[7]:

To be clear, however, the Company does not consider the achievable potential as a ceiling or limit for the Company's energy efficiency efforts. This is demonstrated by the fact that Idaho Power has exceeded its energy efficiency potential estimate in three of the last four years.

Increasing energy efficiency is the new normal[16] and it needs to be an integral part of all demand projections, rather than fodder for public relations. Making matters worse, the company engaged in a convoluted, unnecessary, and undoubtedly expensive modeling process to obtain its efficiency estimates. That process ignores Occam's razor[61] and it has the undesirable effect of burying the rise in efficiency the utility has actually seen. Real data should be the basis for those projections.

The analysis of peak demand is also highly problematic. We have the following comments from Idaho Power which noted that their AEG study revealed:

"the hourly methodology increased the on-peak potential energy efficiency value by 43 percent by 2036 over the pre-2015 IRP method used in the load and resource balance. When combined with demand response, in 2036, demand-side resources account for more than 900 MW of reduced system peak, which equates to a nearly 18 percent reduction in system peak load."

[61] Occam's razor is the principle which states that, among competing hypotheses, the one with the fewest assumptions should be selected.

…followed by this statement on page 68[7]:

"Idaho Power did not use the peak analysis provided by AEG because the analysis was not dynamic relative to the Company's forecasted peak hours and the forecast only provided estimates for peak summer and winter hours."

Yet the data from the utility itself shows that if Idaho Power's had chosen to make effective energy programs a priority, their peak demand forecasts would be markedly lower.

In their Reply Comments, IPUC staff noted (IPUC Staff Comments, IPC-E-17-11, November 27, 2017, pp. 5 & 6):

"While average forecasting is an important aspect of resource planning, decisions to build or buy generation and transmission plants are driven primarily by peak demand rather than an average load. Despite the importance of peak demand forecasting in resource planning, Staff notes that the Company's system peak demand forecasting methodology is much less refined than its average load forecasting methodology."

"Because of the impact of peak capacity deficits on resource planning needs, Staff conducted a sensitivity analysis to determine the effects of a slightly smaller peak growth rate would have on the Company's first capacity deficit. Staff analysis found that an extremely small (0.1%) decrease in the annual projected growth rate pushed the Company's first capacity deficit date out an entire year."

The STOP B2H Coalition concurs with IPUC Staff recommendations:

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

In summary, IPUC Staff commented that the 2017 IRP was much less robust than its predecessor due to (IPUC Staff Comments, IPC-E-17-11, November 27, 2017, p. 14):

"…the Company's methodology for peak demand forecasting, limited energy efficiency modeling, very low natural gas price assumptions, and the similarity of the modeled portfolios to each other."

3. Demand Response

Idaho Power misquotes the clear statement of its failure to understand what an advanced metering infrastructure is. Here is the quote from Idaho Power's original IRP:

To participate in the Automatic Dispatch Option, either an ***advanced metering infrastructure (AMI)*** *or a cellular control device is attached to the customer's electrical panel that allows Idaho Power to remotely control the pumps.*

Here is the utility's response to our questions about that understanding on page 77[7]:

The Company uses a power line carrier system Aclara Two Way Automated Communications (TWAC) system and its **Automated Meter Infrastructure** *system (AMI) to deploy most of its DLC programs.*

The term has mysteriously morphed into something with a very different meaning. The industry, including *Aclara*, is clear about what constitutes an advanced metering infrastructure and what it's used for[3]. Idaho Power, however, seems to have serious problems grasping the concept, that it's a communications framework for utility-consumer partnerships within its entire service area, one that will play a major role in new utility business models as utilities increasingly partner with the emerging class of producer-consumers.

The comments on pages 77-78[7] then try:

…to clarify STOP B2H's statement that "no one is going to attach that framework to a customer electric panel"

…with a convoluted attempt at clarifying the utility's own confusion. They suggest that it's just a way:

to participate in the Irrigation Peak Rewards program. In 2016, Idaho Power had 2,286 service points (panels) with DR devices attached, with 50 in its Oregon area. Additionally, in 2016, 28,315 A/C Cool Credit participants had DR devices on or near their central A/C units, with 368 in Oregon.

…before explaining that there is something to the larger idea:

Idaho Power believes that it is effectively deploying demand response for its customers, and will continue to improve and upgrade its technology as economically and logistically feasible.

None of this is magic. We know how to setup networks – including power line networks, and wired and wireless networks – and the hardware and upgradeable software to link the endpoints of those networks back to utility nodes. We know how to have the resulting communications links encrypted through a virtual private network that tunnels through a standard TCP/IP based intranet for security. Lastly, we know how to house the information gathered through those communications links in formal databases, for effective value-added data mining.

All of those elements constitute the framework, the infrastructure. Comparing the endpoints of the network to that framework is the equivalent of claiming that the cloud services you use reside within your data phone. It's upside down.

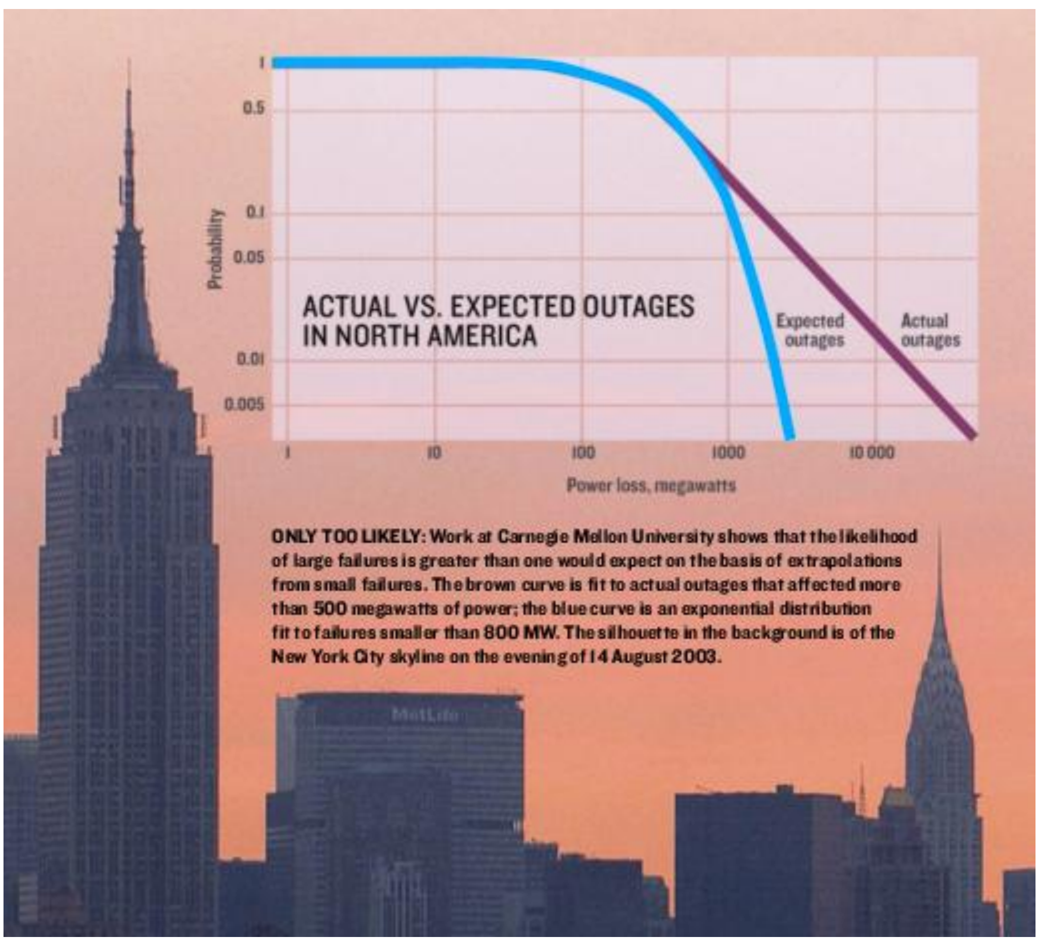
Given the crucial importance of an AMI build-out to all modern electric utilities, Idaho Power' s response is at best enigmatic, and at worst dangerously uninformed. The utility needs to include a clear statement of what it is doing to link up with its customers, all of them. It needs to openly state how far along it is, and it needs to incorporate that into its planning process. This development should be going on not in 2, 10 or 20 years, but right now. It is that crucial to any effective electric utility resource planning effort.

C. Idaho Powers claim that a transmission line is "significantly more reliable than a Power Plant" is absurd

Adding a high-voltage power line to the existing grid will make the grid less stable. Seminal research conducted since the 1980s has confirmed this with real data[17]. An excellent overview of that research and its implications was published by the IEEE in 2004[18]. The power grid has feedback built in. It has all the characteristics of the non-linear dynamical system that it is:

Plotting the logs of the frequency of blackouts versus their magnitude, [the researchers] observed that the frequency of large blackouts was much higher than they expected. Rather than falling off sharply to fit the bell curve produced by a Gaussian, or normal, distribution, the frequency of blackouts fell off much more slowly.

*The curve fit what is called a power law—which refers not to the power in a circuit but to the fact that the probability of a blackout is related to its magnitude by some constant exponent (*Figure 2*).*



ONLY TOO LIKELY: Work at Carnegie Mellon University shows that the likelihood of large failures is greater than one would expect on the basis of extrapolations from small failures. The brown curve is fit to actual outages that affected more than 500 megawatts of power; the blue curve is an exponential distribution fit to failures smaller than 800 MW. The silhouette in the background is of the New York City skyline on the evening of 14 August 2003.

Figure 2 - The power law distribution for grid outages in North America[18]

In modeling done with the assumption of feedback[62]:

*…**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.*

The stark reality about such systems is that they are exquisitely sensitive to any changes, however slight, in system conditions. That makes the occurrence of specific power outages unpredictable. The probability and size of such failures is, however, tractable. This is why we now know that large blackouts follow a power-law distribution.

Resistance to the idea that the power grid is "chaotic"[63] has fallen away as blackouts keep happening[19]:

Power system experts … cite other recent notables, such as Western Europe in 2006, Brazil in 2009, and twice in India [in 2012]. The commonality is evidence to the experts that cascading failures are a dangerous facet of modern power grids that remains all but impossible to predict or prevent. "Large blackouts are likely to recur at regular intervals," says Ian Dobson, a cascading failures expert and electrical and computer engineering professor at Iowa State University.

The message is clear. Large blackouts are not a bug that can be swatted away with mitigation measures, but a "feature" of large power grids.

In a foretelling of the destruction of the large power grid in Puerto Rico after a hurricane, the article[19] predicted that very possibility:

… more frequent blackouts are also likely, a result of the increasing incidence of extreme weather such as thunderstorms, hurricanes, and blizzards predicted by climate models.

The USDOE suggests that mitigation measures are one of the keys to dealing with this fact of grid life[20]:

Microgrids, which are localized grids that are normally connected to the more traditional electric grid but can disconnect to operate autonomously, are another way in which the reliability and resiliency of the grid can be improved. Microgrids use advanced smart grid technologies and the integration of distributed energy resources such as backup generators, solar panels and storage. Because they can operate independently of the grid during outages, microgrids are typically used to provide reliable power during extreme weather events.

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[62] The power grid can periodically see reversals in power flows from one direction to the other, the very essence of feedback.

[63] Such systems are only chaotic in the sense that they can transition from one apparently stable regime to a completely different part of the solution space.

Research and real life experience argue strongly for turning away from ever-larger grid components, to a more modular grid. Microgrids will bring greatly improved resilience to the services – hospitals, police stations, fire stations, assembly points, food distribution centers and more – that are essential both in emergency and non-emergency situations.

The development of a modular grid promises greater resilience and the ability to withstand the loss of external power. Large power grids can only bring the guarantee of large power failures.

Idaho Power nonetheless, descends to a new low in their Appendix D-B2H Supplement, in the section titled "Resource Reliability"[64]. The utility makes the absurd claim that a transmission line is "significantly more reliable than a power plant", and endeavors to support this claim with deceptive statistics. Specifically, Idaho Power claims that a metric known as "Equivalent Forced Outage Rate" (EFOR) is appropriate for comparing the reliability of resources compared to the reliability of a transmission line.[65] Idaho Power correctly describes that EFOR "is calculated based on the amount of time a transmission line, or generator, is either de-rated or forced out of service while needed". 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.

Notwithstanding that EFOR is not an appropriate metric to use for comparing resource and transmission reliability, Idaho Power doesn't even fairly represent the EFOR of transmission lines in their Appendix D discussion. If they had, it would show that transmission lines tend to have much higher EFOR's than generating resources, because 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.

Idaho Power's comparison is misleading though because Idaho Power didn't even present EFOR statistics for transmission lines in Appendix D. Instead they presented transmission line statistics for Sustained Circuit Outage Frequency or SCOF. That metric only measures sustained forced outages and it does not include de-rates. Idaho Power then proceeds to compare transmission line SCOFs against EFORs for generating resources. This looks very much like a case-study in lying with statistics, of which this representation in Appendix D is the poster child.

The Commission should ignore Idaho Power's comparison of transmission reliability and resource reliability in Appendix D.

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[64] Appendix D-B2H Supplement at pages 46-47

[65] The interested reader can find detailed instructions on interpreting NERC generator reliability metrics, including EFOR, at this link https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&cad=rja&uact=8&ved=0ahUKEwjplNen5uHYAhVB9WMKHdeWCasQFggyMAE&url=http%3A%2F%2Fwww.nerc.com%2Fpa%2FRAPA%2Fgads%2FDataReportingInstructions%2FAppendix_F%2520-%2520Equations.pdf&usg=AOvVaw3r96o7bQr8USplIXofrL5U

IV. Conclusion

Idaho Power has failed to do a credible portfolio analysis in this IRP and has not met even the minimum requirements of Oregon's IRP Guideline. STOP has identified many errors and misstatements by Idaho Power in these proceedings, but most important, Idaho Power has grossly under-represented the level of existing transmission capacities in the Aurora model, creating a large modeling bias in favor of the B2H transmission line. If this nefarious bias were corrected in the AURORA modeling, B2H would likely become the highest cost Portfolio among Portfolios studied by Idaho Power. <u>The Commission cannot acknowledge B2H based upon these deficiencies</u>. STOP requests the Commission to direct Idaho Power to:

1. Remove the bias in favor of B2H that Idaho Power has engineered into the Aurora model, and perform a new Portfolio analysis using corrected cost inputs for B2H.
2. Reevaluate and improve its energy efficiency and demand response programs bringing them more up-to-date with most utilities.
3. Modify the schedule in LC-68 to allow Idaho Power time to correct their faulty analysis and present the results to the Commission, and provide an opportunity for intervenors to conduct discovery and respond to Idaho Power's corrected Portfolio studies.

At a minimum, the Commission <u>cannot acknowledge Action Item #6</u>. In addition to the errors and biased analysis that STOP presented above, by their own admission in their reply document, Idaho Power promises to "reevaluate in 2019," (p. 15) "use diverse portfolio selections in 2019," (p.44) and "expects experience will modify the 20 year resource plan (Appendix D, p. 6)." It does not seem prudent to rush construction approval for the B2H transmission line while Idaho Power has yet to convincingly demonstrate that it is "needed."

Acknowledgement of action item #6 should be Denied until the many deficiencies identified in this docket by the interveners are corrected and improvements are made. A clear reasonable doubt has been raised about the "facts" in this docket. Based on the information that is available and supplied by the interveners and what Idaho Power should have reasonably known about emerging new technologies and what other utilities are doing about it appears that Idaho Power is in an alternative fact reality. Their constant repetition that the B2H has been in every portfolio since 2005 doesn't mean that it still is a good idea. Prudency requires an assessment of the present and an analysis of the future.

The company in their cover letter to the 2017 IRP states, "as part of its permitting activities, Idaho Power is seeking a site certificate for the construction of B2H from Oregon's Energy Facility Siting Council (EFSC). The Commission's acknowledgement of Idaho Power's acquisition of B2H in the Action Plan will serve as the Company's satisfaction of EFSC's "Need" standard under its Least Cost Plan Rule." Due diligence has not been done therefore acknowledgement has not been earned.

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