STOP B2H Coalition

"Protect Our Land, Preserve Our Heritage"

60366 Marvin Road, La Grande, Oregon 97850
www.stopb2h.org info@stopb2h.org

January 8, 2021

Please accept the enclosed Final Comments from the Stop B2H Coalition pertaining to Idaho Power Company's Second Amended 2019 IRP.

Thank You,

Co-Chair, Stop B2H Coalition

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of **Idaho Power Company** **SECOND AMENDED 2019 INTEGRATED** **RESOURCE PLAN**	**Docket LC 74**

STOP B2H Coalition

Final Comments

Submitted

January 8, 2021

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Introduction

Stop B2H Coalition (STOP), a grassroots, Eastern Oregon citizens' organization, with 900 members and 9 member organizations, hereby submits its Final Comments on Idaho Power's 2019 Second Amended Integrated Resource Plan – LC 74. STOP is extremely concerned with the accuracy and validity of the data in LC 74. Idaho Power obviously shares these concerns since the IRP was delayed 5 times over the 17 months. In the company's 2019 Second Amended Integrated Resource Plan on page 2 they stated, "that the changes to the conclusions and actions contained in this second amendment are relatively modest." We couldn't disagree more. There have been significant changes, some that we will point out here in our Final Comments.

STOP is concerned that the company wants to postpone many modeling details questioned by staff and interveners until the 2021 IRP. Some are to correct anomalies and refine the AURORA capacity expansion modeling process (Long-Term Capacity Expansion - LTCE) for WECC optimized portfolios and Idaho Power's manually adjusted optimized portfolios[1]. Others are to bring the budget into the current decade, to negotiate and sign a construction agreement with seemly reluctant partners and develop "hard" financial numbers from which one can build the least cost least risk portfolio with confidence. Something this IRP, does not have. We have felt like we are in a shell game: wondering whether or not certain resources maybe misrepresented or certain risks unstated to the commission and ratepayers, while in financial disclosures to the Securities and Exchange Commission and investors/shareholders, a different risk scenario is shared.

STOP could be agreeable to postponing many modeling details if this 2019 IRP was not acknowledged. This would include not allowing the company to proceed with Action Items 5 and 6 (Boardman to Hemingway), as stated in Order 18 176 Idaho Powers 2017 IRP, which is to: 5 - Conduct ongoing permitting, planning studies, and regulatory filings and; 6 - Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Mid-C

STOP does not agree with the company's analysis of the flexibility, liquidly, reliability, and low cost of market purchases at the Mid-Columbia energy trading market (Mid-C). The company lays out six characteristic of a successful trading market[2] which we believe the Mid-C market cannot meet. Given the upcoming resource inadequacy in the Mid-C as stated in the Northwest Power and Conservation Councils - Pacific Northwest Power Supply Assessment for 2024[3], the Idaho Public Utility Commissions docket IPC-E-19-14[4] acknowledging Idaho Powers PPA for Jackpot Solar where in the staff report [5] they determined that the PPA prices for Jackpot over a 20 year period were less than market purchases in the mid-c over the same 20 year period.

Additionally the company has market purchase choices in other major market hubs like California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California) which have not been analyzed or compared to the mid-c in a comprehensive way. The company should be required to analyze these other markets and compare them to the Mid-C in a comprehensive and understandable way.

Transmission

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1 2019 IRP Review Report: Process and Findings Page 1

2 Second Amended 2019 Integrated Resource Plan—Appendix D Page 7

3 https://www.nwcouncil.org/reports/pacific-northwest-power-supply-adequacy-assessment-2024

4 https://puc.idaho.gov/Case/Details/3675

5 https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1914/Staff/20191126Comments.pdf

The company states … "Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho[6]". STOP believes much of this discussion has been manufactured by the company to support this claim. STOP in discovery questions found that the company often goes above PATH 14's west-to-east commercial rating of 1200 MW to 1600 MW during the summer[7]. In STOP's data request 114 the company states:

> The Path 14 west-to-east commercial rating is not intended to represent the Path 14 real-time transmission flow limit. The commercial rating specifically represents a transactional limit, or how much energy can be scheduled on the transmission path. Transmission schedules are not allowed to exceed the transmission commercial rating, but transmission flows can exceed the commercial rating if no real-time reliability issues are present. This flow above the scheduled power on the path is generally referred to as 'unscheduled flow' which is caused by commercial transactions not matching system physics in a large interconnected transmission system.

There has not been a date that we could find, where the company could not purchase the power it wanted from the Mid-C. It holds back 330 MW of CBM and 280 MW of TRM, seemingly only on PATH 14[8]. It will not use conditional firm energy on PATH 14 in the resource stack while many other utilities including the BPA will, they are not looking at non-wire solutions as other utilities are[9] and the BPA has[10]. The capacity available on many of its transmission routes between the 3rd or 4th version of this IRP per OPUC staff information request 119. The company has not taken a hard look at other alternatives because they do not want to. They want to build the B2H and it appears that they are creating the data environment to support that desire.

Additionally PacifiCorp can no longer state the value of the B2H in its 2019 IRP to its system. It is evaluating another 500 kV line from Hemingway south to the California intertie, which might look like the original segment H of PacifiCorp's Gateway project, which was to the Captain Jack substation.

STOP appreciates this opportunity to submit final comments on Idaho Power's Second Amended 2019 IRP. STOP does so with significant consternation and fatigue.

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[6] Second Amended 2019 Integrated Resource Plan—Appendix D Page 9

[7] STOP DR 114

[8] Second Amended 2019 Integrated Resource Plan—Appendix D Page 13

[9] https://www.utilitydive.com/news/non-wires-alternatives-whats-up-next-in-utility-business-model-evolution/446933/

[10] https://www.bpa.gov/Projects/Projects/I-5/Documents/letter_I-5_decision_final_web.pdf

Where Are the B2H Partners?

After 15 years, Idaho Power does not have committed partners to build the B2H. This section discusses the permitting partners present day reservations with the B2H.

PacifiCorp and BPA are coparticipants in the permitting of the B2H project (also referred to as funders)[11]. The least cost portfolio in the IRP is built on the premise that Idaho Power is a 21% financial partner with PacifiCorp and the BPA at 55% and 24%, respectively. These percentages also represent the B2H Capacity and permitting cost allocation in MW[12].

Table 6.2 B2H capacity and permitting cost allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	350: 200 winter/500 summer	400: 550 winter/250 summer	300
Capacity (MW) east to west	85	97	818
Permitting cost allocation	21%	24%	55%

Partner Commitment Overview

BPA's level of participation is questionable. Anything less than their 24% funding level must impact the least cost, least risk portfolio, as the math will change. The solutions being offered are just words with no facts or numbers to decide upon in this IRP. STOP is in monthly communication with their BPA contact, Rafael Kaup, Public & Community Engagement|Communications. We've been asking him or another spokesperson to speak on BPA's behalf or issue a press release and stop letting Idaho Power talk for the BPA, without success. We only know what the BPA is thinking through Idaho Power's lens. It should be noted that the BPA is is continuing to make its "business case." Multiple options are still being studied, including the B2H, on how to serve their SE Idaho load customers.[13]

PacifiCorp in their 2019 IRP goes out of their way to remain non-committal on signing a construction agreement for the B2H until Oregon's EFSC issues a site certificate[14]. Meanwhile PAC is newly evaluating a southern Oregon route to the California intertie which resembles their original gateway segment H from Hemingway to Captain Jacks.[15]

BPA Details

As was disclosed in the Second Amended 2019 Integrated Resource Plan the BPA is no longer interested in the original funding arrangement as laid out in the Joint Permit Funding Agreement. Idaho Power in trying to keep the BPA involved stating …

> However, the B2H co-participants are exploring an alternative asset, service, and ownership arrangement under which Idaho Power would assume BPA's contemplated 24 percent ownership share in B2H, and Idaho Power would provide BPA and/or its customers with transmission wheeling service across southern Idaho.[16]

IPC further states …

[11] Page 36 Second Amended 2019 Integrated Resource Plan—Appendix D
[12] Second Amended 2019 IRP Page 81
[13] https://www.bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx
[14] PAC 2019 IRP p 78/pdf101
[15] PAC 2019 IRP p 83/pdf 106
[16] Second Amended 2019 IRP Page 19 – Boardman to Hemingway Participant Update

> Importantly, the contemplated arrangement will have an immaterial impact on Idaho Power's analysis of B2H in this *Second Amended IRP*. While Idaho Power's formal ownership interest and share of the cost of B2H would increase, the company's original 21 percent ownership share would continue to reflect the company's approximate share of the costs for B2H used to serve Idaho Power's retail customers[17].

Idaho Power claims that whatever deal they hope to work out with the BPA, absorbing BPA's share would not impact the least cost, least risk portfolio in this Second Amended IRP. The company states, "Idaho Power's share of the B2H project could almost double, and the least-cost B2H portfolio would still be more cost-effective than the least-cost, non-B2H portfolio under planning conditions.[18]" And as STOP pointed out in its opening comments, included here by reference, IDACORP in a November 2019 SEC filing set aside an additional $324 million[19] in case this occurred. The money is in place to be used.

STOP's Conclusion: BPA

We are being asked to take Idaho Power's word that whatever happens with the 24% of BPA's share, that the least cost, least risk portfolio scenarios will not change. Based on the number of errors found in this IRP already, STOP believes a prudent person would ask to see proof of these calculations in new portfolios before any decisions can be made on what the least risk, least cost portfolio is in the IRP. Idaho Power should be required to do a tipping point analysis to determine how much more cost they can take on until another portfolio becomes the least cost, least risk portfolio.

PacifiCorp Details

The following is a review of the discussions on the B2H in PacifiCorp's 2019 Acknowledged IRP and supports and expands upon the statements made above:

1. The B2H in their 2019 IRP Action Plan refers to permitting only and construction is not in this action plan. Section 3 Transmission Action Items at 3 f[20]:

3f	**Boardman to Hemmingway:** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.

2. In PAC's 2019 IRP in the section "Plan to Continue Permitting – Boardman to Hemingway", under next steps, the company says …

   Given the extensive list of benefits noted above, PacifiCorp is committed to participating in the B2H project in accordance with the terms of the Joint Funding Permitting Agreement through the final Oregon Department of Energy Facilities Siting Council's permitting process and will continue to evaluate the benefits to PacifiCorp's customers prior to commitment of entering into a project construction agreement. Additionally, PacifiCorp will continue to review possible benefits of the project

[17] Second Amended 2019 IRP Page 19 – Boardman to Hemingway Participant Update
[18] IPUC Staff Request No 35/STOP B2H's Data Request No 40
[19] STOP B2H Coalition Opening Comments p 57
[20] PacifiCorp's 2019 IRP p 278

as it continues to participate in project development activities, including moving forward with preliminary construction and construction agreement negotiations[21].

3. In OPUC Data Request 91 PacifiCorp indicated that are evaluating another option from Hemingway to South-Central Oregon / Northern California:

   OPUC Data Request 91 (p. 90 of staff opening comments)

   > **Transmission, Battery Storage, Action Plan -** Given all the benefits of B2H listed on page 78 in the 2019 IRP, please provide a detailed explanation of why the Company did not include B2H in any of its new transmission integration options in System Optimizer.
   >
   > **Response to OPUC Data Request 91**
   >
   > The company interprets the question to be asking why Boardman to Hemingway (B2H) was not included "among" the new transmission options modeled in the System Optimizer (SO) model, as no transmission option is included "in" another modeled transmission option in the 2019 Integrated Resource Plan (IRP). Based on the foregoing understanding, the company responds as follows: In the IRP topology, the B2H project requires two transmission paths linking three "bubbles" for proper representation. Specifically required are transmission paths from Borah to Hemingway, and from Hemingway to South-Central Oregon / Northern California. Using the transmission option methodology, the SO model cannot endogenously enforce the simultaneous inclusion of both parts of the B2H option when the project is selected. The Hemingway bubbles' interconnections are essential to the value of B2H, precluding the simplification of the option to only consider a path from Borah to South-Central Oregon/Northern California. Please also refer the company's response to OPUC Data Request 84, subpart (b).

4. In OPUC staff's opening comments in PAC's 2019 IRP, under Boardman to Hemingway, they wonder why PAC is not including construction of the B2H in their IRP[22]:

   > **Boardman to Hemingway**
   >
   > In the 2017 Idaho Power Company IRP, the Oregon Commission acknowledged B2H construction. [100] It is unfortunate that PacifiCorp failed to include B2H as an endogenous transmission modeling option, since it would serve as a major artery enabling Wyoming wind to be exported to Oregon load and the Pacific Northwest. Staff questions whether PacifiCorp's Utah reinforcement projects, including Gateway South, have value for Oregon customers without B2H to connect them with Oregon load. Therefore, Staff cannot recommend acknowledgement of the projects at this time. [100 See Order No. 18-176. Pages 9-11.]
   >
   > When Staff asked PacifiCorp why B2H was not included as an endogenous transmission option in the IRP in a data request, the Company stated that the B2H project requires two transmission paths linking three "bubbles" for proper representation, and therefore is too complex for endogenous selection in SO. Specifically, the Company claims that transmission paths from Borah to Hemingway, and from Hemingway to South-Central Oregon / Northern California are required. Additionally, PacifiCorp said the "Hemingway bubbles' interconnections are essential to the value of B2H, precluding the simplification of the option to only consider a path from

[21] PAC 2019 IRP p 78
[22] OPUC Staff's Initial Comments in PacifiCorp 2019 IRP, p 49

Borah to South-Central Oregon/Northern California." [101] [101 See PacifiCorp response to Staff Data Request 91, included in Attachment A to these initial comments]

PacifiCorp's explanation of why B2H cannot be modeled endogenously seems counterintuitive. The Company seems to be evaluating B2H as a connecting resource to California, but B2H will facilitate connection between the Mona substation and Mid-C hubs, enabling bidirectional flows, and therefore does not need a path to California to estimate important project benefits. The Company's narrative appears to conflate Midpoint-to-Summer Lake flow with B2H, and appears to ignore the planned series compensation allowing for more differentiated flow across this path. Staff plans to investigate this claim further in order to understand why the Company views B2H as too complex to be viewed as a connection between two nodes.

In summary, the B2H line appears to be a simple connection between two System Optimizer nodes, and Staff has not yet heard a thorough explanation of why PacifiCorp cannot allow it to be selected endogenously.

In Staff's opinion, the Company's very limited analysis of B2H calls into question whether major transmission investments were evaluated on consistent and comparable basis. Staff would be highly interested in seeing analysis that reverses the order of the construction of projects, allowing PTC wind to be constructed closer to Oregon load along with the shorter B2H line in 2024. Charting of projected line utilization in both directions would also be helpful for Energy Gateway and jointly planned line segments. Staff would like to work with the Company to investigate the possibility of obtaining information showing actual current flows, and how those flows are projected to change in each direction with each additional segment of Energy Gateway on an hourly basis, across a calendar year, and in aggregate by summing line flows in both directions.

Conclusion

The burden rests on PacifiCorp to demonstrate the benefits of Gateway South and Utah reinforcements to Oregon customers, and Staff cannot recommend acknowledgment of this project until the Company demonstrates these benefits. The Company has failed to sufficiently assess arterial transmission projects recognized and acknowledged by the Commission (B2H), while seeming to place favorable assumptions on projects that reinforce reliability in other states (Energy Gateway South).[23]

5. In the OPUC Commissions disposition of the PacifiCorp's 2019 Integrated Resource Plan in order 20-186 their conclusions on B2H are in section 4 "Transmission Action"[24]:

   a. **Transmission Actions**
   "PacifiCorp seeks to continue its participation in the development agreement for Boardman to Hemingway, and seeks to continue permitting efforts for the remaining segments of Gateway West."

   b. **a. Comments**
   "Third, for the large projects such as Boardman to Hemingway and the remaining segments of Gateway West, NWEC requested new analyses in the 2021 IRP. NWEC requested a full non-wires assessment for the remaining elements of Gateway West. NWEC also requested the 2021

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[23] OPUC Staff's Initial Comments in PacifiCorp 2019 IRP, p 49
[24] PacifiCorp's 2019 Integrated Resource Plan-Order 20-186 p 20-21

IRP include the potential system benefits and the full set of commercial arrangements with Idaho Power Company and the Bonneville Power Administration concerning Gateway West and Boardman to Hemingway."

c. **b. Resolutions**
"For the third category of conditions relating to non-wires alternatives, we accept PacifiCorp's offer of a Commission workshop before the 2021 IRP is filed. The workshop should address how PacifiCorp's IRP relates to its long-term transmission plan. We would like to explore whether the IRP examines the economics of different transmission upgrades and the long-term transmission plan such that we could or should acknowledge a transmission upgrade in the IRP based on economics. PacifiCorp noted at the public meeting that transmission upgrades that are driven by contractual or OATT requirements are more the company's concern (and less of a state-Commission concern), and we would like to discuss how PacifiCorp may be able to differentiate the drivers of transmission upgrades going forward. We would also like to begin a discussion about what an alternatives assessment such as a non-wires assessment requested by NWEC would look like in the IRP. We indicated concern over PacifiCorp frontloading customer costs of transmission, and we would like to have better visibility into plans for transmission projects that will involve our acknowledgement and will have significant retail customer costs, and how an alternatives assessment could consider lower cost options.

STOP's Conclusion: PacifiCorp

PacifiCorp is hedging their bets, staying non committal, and looking at another 500 kV transmission line to the California intertie, possibly the same as in the original segment H from Hemingway to Captains Jacks.[25] Could this be a strategy to work around the BPA, the mid-c, and create a more direct route to the California markets? PacifiCorp has stated it has no intention to consider a construction agreement until the ODOE/EFSC issues a site certificate, which could run in to mid-2022 and beyond. Idaho Power has no firm partners and we are wasting rate payer money in the permitting process.

Regarding Idaho Power's partners, STOP Requests the Commission to:

1. Not acknowledge this IRP because of the infirmities in the funding commitments of the partners. The numbers used to create the portfolios cannot be validated because we do not know the value/amount of the partner's contributions by Idaho Powers admissions.
2. Specifically not acknowledge and put on hold pre-construction and construction activities until Idaho Power has signed contracts with all construction partners and a new financial analysis can be performed on an updated 2021 budget. Otherwise we are squandering ratepayer money since the utilities will likely have full rate recover for permitting.
3. Ask Idaho Power work with the BPA to:
   a. Come to an agreement on funding and financing of B2H *before* the next IRP begins.
   b. Develop a new suite of portfolios with contractually verifiable costs before moving forward so the least cost, least risk portfolios can be evaluated based on hard numbers.
   c. If b. cannot be done instruct Idaho Power to conduct a tipping point analysis. This tipping point analysis should determine how much more cost/expense Idaho Power can absorb in the preferred portfolio until another portfolio becomes the least cost, least risk portfolio.

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[25] PAC 2019 IRP p 83/pdf 106

d. Ensure that the B2H budget has been updated to 2021 values and this revised budget is used for the portfolio analysis.

Informed decisions that will have significant impacts on ratepayers and society should not be made with information as flimsy as the company is presenting.

4. Ask Idaho Power work with PacifiCorp to:

   a. Come to an agreement on funding and financing of B2H *before* the next IRP begins.
   b. Determine if they are going to build B2H together, or build a Captain Jack variant to the California Intertie together, or Idaho Power will build the B2H without PAC, or PAC will build a Captain Jack variant to the California Intertie without IPC;
   c. Implement actions that mirror items 5 b and c above (in the PacifiCorp IRP) also for Idaho Power. This would include a full non-wires assessment, including the potential system benefits and the full set of commercial arrangements with PacifiCorp and the Bonneville Power Administration concerning Boardman to Hemingway."This is a way the commission can get Idaho Power and PacifiCorp on the same sheet of music for the B2H.
   d. That all pre-construction and construction activities be halted until Idaho Power has signed all construction partners and a new financial analysis can be performed. Otherwise we are squandering ratepayer money since the utilities have full rate recover for permitting.

The Cost of B2H

Idaho Power's cost estimate has been and continues to be $1 to 1.2 billion for the B2H and it has not been updated since November 2018. The company states that their 20% contingency for unanticipated expenses, within this $1 to 1.2 billion budget, is accurate and adequate to absorb fluctuations in labor, market prices, and inflation. The company states, "Idaho Power's share of the B2H project could almost double, and the least-cost B2H portfolio would still be more cost-effective than the least-cost, non-B2H portfolio under planning conditions.[26]"

In December 2019 the Idaho Power Company filed their 10K Annual Report. (Full excerpts are provided below this section.) In that report in the Integrated Resource planning section (p16) the company states to shareholders:

> However, as noted in the 2019 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third-party development of renewable resources, fuel commodity prices, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These uncertainties, as well as others, will likely result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions. As of the date of this report, proceedings relating to the amended 2019 IRP are pending at the IPUC and OPUC.

In the Boardman to Hemingway section of the report (p 53) they tell their shareholders of their concerns. In the first paragraph they say:

> Total cost estimates for the project are between $1.0 billion and $1.2 billion, including Idaho Power's AFUDC. This cost estimate is preliminary and excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate.

In the third paragraph they say:

> These preliminary estimates of Idaho Power's share of early construction costs could significantly change as the construction timeline nears and as the project participants further align on future activities, allocation of ownership interests, and cost estimates.

In the long term planning section (p 54) they reiterate the same concern:

> However, as noted in the 2019 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third-party development of renewable resources, fuel commodity prices, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These uncertainties, as well as others, likely will result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions.

STOP's Conclusion

It can't be both ways. One story to the commission and ratepayers stating that the budget is fine and well and that it can be doubled and the least cost, least risk portfolio won't change. Another story to shareholders, is expressing possible short falls and market concerns. Common sense says that since 2018 costs have increased given the international trade wars, inflation, and a pandemic the current budget estimate cannot be accurate.

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[26] IPUC Staff Request No 35/STOP B2H's Data Request No 40

Will the 20% contingency fund still cover all contingencies as the company has stated over and over. STOP does not think so.

Regarding Idaho Power's costs STOP Requests the commission to:

1. Insist that Idaho Power update their B2H cost estimates, in coordination with their partners, with the help of a third party to validate and ensure accuracy *before* they begin the 2021 IRP.
2. Include the concerns the company shares with shareholders in their 10K statements with the commission and ratepayer on the B2H in their IRP's.
3. In the section above, "Where are the B2H Partners?" a 24% funding margin is being negotiated between IPC and the BPA. Marginal increases in B2H's costs will certainty impact the least cost, least risk portfolios. Idaho Power should be required to do a tipping point analysis to determine how much more cost they can absorb until another portfolio becomes the least cost, least risk portfolio. These are considerable variables that pose significant risk to ratepayers for making the best possible decision.

Supplemental information: Excerpts from the 10K filing – with highlights

Full text from the 10K pdf p 16

As noted above, on January 31, 2020, Idaho Power amended the originally filed 2019 IRP with additional information and modeling results. The updated 2019 IRP identified a preferred resource portfolio and action plan, which includes the completion of the Boardman-to-Hemingway transmission line in 2026, the end to Idaho Power's participation in coal-fired operations at the North Valmy plant units 1 and 2 in 2019 and 2025, respectively, the end to Idaho Power's participation in coal-fired operations at the Jim Bridger plant by 2030, including the exit from two of the four Jim Bridger plant units in 2022 and 2026, respectively, and the addition of a 120- MW solar resource in 2022. However, as noted in the 2019 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third-party development of renewable resources, fuel commodity prices, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These uncertainties, as well as others, will likely result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions. As of the date of this report, proceedings relating to the amended 2019 IRP are pending at the IPUC and OPUC.

Full text from the 10K pdf p 53

Boardman-to-Hemingway Transmission Line: The Boardman-to-Hemingway line, a proposed 300-mile, high-voltage transmission project between a substation near Boardman, Oregon, and the Hemingway substation near Boise, Idaho, would provide transmission service to meet future resource needs. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration to pursue permitting of the project. The joint funding agreement provides that Idaho Power's interest in the permitting phase of the project would be approximately 21 percent, and that during future negotiations relating to construction of the transmission line, Idaho Power would seek to retain at least that percentage interest in the completed project. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including Idaho Power's AFUDC. This cost estimate is preliminary and excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate.

Approximately $106 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through December 31, 2019. Pursuant to the terms of the joint funding arrangements, Idaho Power has received

$72 million as of December 31, 2019, from project participants for their share of costs. As of the date of this report, no material co-participant reimbursements are outstanding. Joint permitting participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

Idaho Power's share of the remaining permitting phase of the project (excluding AFUDC) is included in the capital requirements table above, which includes approximately $105 million of Idaho Power's share of estimated costs related to design and early construction, which are primarily included in the table in the period 2022-2024. These preliminary estimates of Idaho Power’s share of early construction costs could significantly change as the construction timeline nears and as the project participants further align on future activities, allocation of ownership interests, and cost estimates.

The permitting phase of the Boardman-to-Hemingway project is subject to federal review and approval by the U.S. Bureau of Land Management (BLM), the U.S. Forest Service, the Department of the Navy, and certain other federal agencies. The BLM issued its record of decision for the project in November 2017, approving a right-of-way grant for the project to cross approximately 86 miles of BLM-administered land. The U.S. Forest Service issued its record of decision in November 2018 authorizing the project to cross approximately seven miles of National Forest lands. In September 2019, the Department of the Navy issued its record of decision authorizing the project to cross approximately seven miles of Department of the Navy lands. In November 2019, third parties filed a lawsuit in the federal district court of Oregon, challenging the BLM and U.S. Forest Service records of decision for the Boardman-to-Hemingway project. On February 13, 2020, Idaho Power filed a motion to intervene in the legal proceeding. The litigation is in its initial phases and remains pending as of the date of this report.

In the separate Oregon state permitting process, the Oregon Department of Energy (ODOE) issued a Draft Proposed Order in May 2019 that recommends approval of the project to the state's Energy Facility Siting Council (EFSC). The ODOE is expected to issue a Proposed Order in the first half of 2020. Idaho Power currently expects the EFSC to issue a final order and site certificate in 2021. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line will be in 2026 or some time thereafter.

Full text from the 10K pdf p 54

Long-Term Resource Planning*:* The IPUC and OPUC require that Idaho Power prepare biennially an IRP. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side, demand-side, and transmission options, and identifies potential near-term and long-term actions. Idaho Power filed its most recent IRP with the IPUC and OPUC in June 2019, which was amended in January 2020. The 2019 IRP identified a preferred resource portfolio and action plan, which includes the completion of the Boardman-to-Hemingway transmission line in 2026, the end to Idaho Power's participation in coal-fired operations at the North Valmy plant units 1 and 2 in 2019 and 2025, respectively, the end to Idaho Power's participation in coal-fired operations at the Jim Bridger plant by 2030, with the exit from two of the four Jim Bridger plant units in 2022 and 2026, respectively, and the addition of a 120 megawatt (MW) solar resource in 2022. However, as noted in the 2019 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third-party development of renewable resources, fuel commodity prices, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These uncertainties, as well as others, likely will result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions. Additional information on Idaho Power's 2019 IRP is included in Part I, Item 1 - "Business - Resource Planning" in this report.

What Capacity measure was acknowledged for Idaho Power?

STOP asks the commission to clarify what capacity measure they acknowledged for the B2H in Idaho Power's 2017 IRP. We believe it was for Idaho Power's 21% of a 2050 MW bi-directional transmission line as described in table 6.2?

Table 6.2 B2H capacity and permitting cost allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	350: 200 winter/500 summer	400: 550 winter/250 summer	300
Capacity (MW) east to west	85	97	818
Permitting cost allocation	21%	24%	55%

Or, was it for a 500 kV transmission line without partners?

STOP believes it was the Commissions intention to acknowledge Idaho Power's 21% share of a 2050 MW bi-directional transmission line as described in table 6.2. Clarification will assist everyone in clearing-up some of the current day confusion.

In Idaho Power's 2017 IRP final public hearing we believe it was Commissioner Bloom's intention to only acknowledge IPC's 21% share of the B2H. A review of the video of the final 2017 IRP hearing[27] shows Commissioner Bloom at 4:16:18 say …

> "My concerns are that Idaho power is the 24% participant and the two big parties, BPA which we can't control, and PAC doesn't even have it in their IRP. So if we acknowledge this IRP for Idaho power this is not an acknowledgement for PAC. They are going to have to do all their own work on this to convince us that it's still in the money."

PacifiCorp has not done their work to convince the commission that they are still in the money. Instead they have created more doubt.

The BPA is continuing to make its "business case". Multiple options are still being studied, including the B2H, on how to serve their SE Idaho load customers[28].

With apologies STOP raises the issue of EFSC here at the OPUC. Again, based on the deliberations at the final hearing of the 2017 IRP, we know that the OPUC does not want to concern itself with the rules, interpretations or actions of another state agency. Commissioners Bloom and Decker spoke to this[29] and then Chair Hardie summarized in the written Order:

> "… Although our acknowledgement includes Idaho Power's Boardman to Hemingway (B2H) related action items, we note that our acknowledgement is limited to our interpretation of IRP standards specific

[27] https://oregonpuc.granicus.com/MediaPlayer.php?view_id=1&clip_id=293&meta_id=14009

[28] https://www.bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

[29] Bloom: "…So for the people that don't have to live this all the time, acknowledgement is not approval, it's not pre approval, we're just saying it's reasonable. From what we know now. And from what we know, now. I think it's reasonable. And that's much different than the EFSC certificate. We're not affected by their process, I don't know what they're affected by our process. And I don't care because we're trying to do our job as best we can."

Decker: "…And despite that, our decision has a lot of significance here because many of the land use impacts are located in Oregon and this the Oregon EFSC has a central role. They their role differs to our IRP process for the question of need, even though our IRP standards for the least cost least risk way of serving utility customers might be somewhat different than those outlined in the EFSC."

> to the Public Utility Commission, and does not interpret or apply the standard of any other state or federal agency."[30]

We find ourselves caught in the middle of two state agencies because ODOE/EFSC uses ORS 469.300(11)(a)(C) to define an energy facility as 'a high voltage transmission line…with a capacity of 230,000 volts or more….' whereas, the OPUC acknowledged Action Items 5 and 6. ODOE/EFSC's definition will allow Idaho Power to build the B2H by itself regardless of the least cost, least risk portfolio acknowledged by the OPUC.

Idaho Power explained it to ODOE/EFSC this way in "Attachment 4: DPO Comment, Applicant Responses, Department Response in Proposed Order Crosswalk Tables":

> On May 18, 2018, in Order No. 18-176, the Oregon Public Utility Commission (OPUC or Commission) acknowledged Idaho Power's 2017 IRP Action Plan, with modifications, including Action Item 5 to conduct ongoing permitting, planning studies and regulatory filings for the B2H transmission line, as well as Action Item 6 to conduct preliminary construction activities, acquire long lead materials, and construct the B2H Project (see Order No. 18-176, p. 9). *The Commission described B2H as a "new single-circuit 500-kV transmission line, approximately 300 miles long between the proposed Longhorn Station near Boardman, Oregon, and the existing Hemingway Substation in southwest Idaho" [emphasis added]* (Order No. 18-176, p. 5). Thus, the Commission's Order No. 18-176 acknowledged the construction of B2H as proposed in the ASC, and not "a much smaller transmission line" as argued by the commenter[31].

ODOE staff response is:

> As explained in the section, and in accordance with ORS 469.300(11)(a)(C), for purposes of the EFSC review and assessment, the Department considers the 'capacity' of the proposed transmission line to be measured in volts (or kilovolts), not megawatts, and in this case, the proposed facility is primarily a 500-kV transmission line facility. ORS 469.300(11)(a)(C) defines an energy facility as 'a high voltage transmission line…with a capacity of 230,000 volts or more…."[32]

Given the framing of the acknowledgement above and the definition of a transmission line in ORS 469.300(11)(a)(C), EFSC will give Idaho Power a site certificate to build the B2H by itself if it meets their other standards. No partners needed.

In other words, Idaho Power can get the site certificate from EFSC without PacifiCorp, or the BPA, or anybody. Was this the commission's intention? By reference we include the Least Cost Plan Rule section[33] in STOP's opening comments for more background.

The OPUC acknowledged the 2017 IRP and was possibly unaware how their wording of that acknowledgement could be used by Idaho Power, to possibly frame the acknowledgement incorrectly before ODOE/EFSC.

We feel that ratepayers' interests are not being considered as paramount because two state agencies have narrowed their analysis so strictly that we the ratepayers are falling through the cracks.

STOP regretfully and respectfully is asking the commission to clarify the capacity acknowledgement in the 2017 IRP. Was it for the entire 500 kV of the B2H transmission line, regardless of partner financial commitment, or was it for 21% of the capacity of the B2H as described in Table 6.2 (above) B2H Capacity and permitting cost allocation and as Commissioner Bloom described it?

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[30] Order No. 18 176, May 23, 2018
[31] Attachment 4: DPO Comment, Applicant Responses, Department Response in Proposed Order Crosswalk Tables pdf p109-112
[32] Attachment 4: DPO Comment, Applicant Responses, Department Response in Proposed Order Crosswalk Tables pdf p109-112
[33] STOP Opening Comments p 24-35

B2H, Carbon, Risk and Portfolio Modeling

B2H and Carbon

Just like the two earlier incarnations of this beleaguered 2019 IRP, Idaho Power continues to falsely claim that their Preferred Portfolio, reflecting a "buy from the market" strategy anchored by the construction of B2H, reflects a commitment to a clean energy future. Idaho Power doubles down on this false claim in this Second Amended 2019 IRP. For example, in the introduction on page 2 of the Second Amended 2019 IRP, Idaho Power asserts to this Commission that:

> "The Company's final IRP continues to demonstrate a clear trajectory toward Idaho Power's clean energy future, as reflected in the key resource decisions in the Company's Preferred Portfolio: (1) 400 megawatts (MW) of new solar generation; (2) development of the Boardman-to-Hemingway (B2H) transmission line; and (3) complete exit from coal resources by 2030. The development of B2H, in particular, provides a crucial carbon-free, supply-side resource that supports renewables and enables the Company's transition away from coal."[34]

Again, on page 6 of the Second Amended 2019 IRP, Idaho Power claims that "Idaho Power's Preferred Portfolio and Action Plan Enables Idaho Power's Clean Energy Future:"

> "The Company's new end-to-end IRP produced a Preferred Portfolio and Action Plan that continues to support the Company's key action items as set forth in the previous Amended IRP. Crucially, the *Second Amended 2019 IRP* continues to show a clear path toward a clean energy future through the procurement of new solar resources, a transition away from coal, and the development of B2H as a least-cost and carbon-free supply-side resource."[35]

Despite these lofty proclamations, STOP has been unable to find any factual support for such proclamations in the Second Amended 2019 IRP or its Appendices but STOP found plenty of evidence presented by Idaho Power in the IRP that refutes Idaho Power's proclamations.

Appendix C of the Second Amended 2019 IRP contains Idaho Power's "Oregon Carbon Emission Forecast"; a forecast produced by AURORA of the total projected Carbon Emissions by Idaho Power's system under their Preferred Portfolio.[36] These annual carbon emissions under the Preferred Portfolio are presented in tabular format in a Table that can be found on page 71 of Appendix C of the Second Amended 2019 IRP.[37] STOP has extracted key columns from the emissions forecast for analysis.

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[34] Introduction: Second Amended 2019 IRP p 2
[35] Introduction: Second Amended 2019 IRP p 6
[36] Second Amended 2019 IRP Appendix C p71
[37] Readers of this Second Amended IRP cannot be faulted for missing this Table as the IRP itself contains no mention of or reference to this Table of CO2 emissions and the Table of Contents of Appendix C does not identify any Tables or Figures in the document.

Year	Resource CO2 Emissions	Market Purchases CO2	Total CO2 Emissions	Cumulative Carbon Emissions changes in % from 2019
2019	4,100,667	287,475	4,388,142	
2020	4,206,715	274,662	4,481,377	2.12%
2021	4,165,188	350,488	4,515,676	2.91%
2022	4,423,053	349,999	4,773,052	8.77%
2023	3,932,304	436,275	4,368,579	-0.45%
2024	3,932,231	535,493	4,467,724	1.81%
2025	4,323,190	524,129	4,847,319	10.46%
2026	3,935,017	792,624	4,727,641	7.74%
2027	3,535,890	879,349	4,415,239	0.62%
2028	3,538,173	1,003,592	4,541,765	3.50%
2029	2,345,650	1,480,651	3,826,301	-12.80%
2030	2,610,779	933,734	3,544,513	-19.23%
2031	1,687,670	1,432,465	3,120,135	-28.90%
2032	1,610,320	1,506,697	3,117,017	-28.97%
2033	1,671,532	1,599,885	3,271,417	-25.45%
2034	1,678,076	1,610,612	3,288,688	-25.06%
2035	1,848,815	1,527,210	3,376,025	-23.06%
2036	1,843,975	1,588,386	3,432,361	-21.78%
2037	1,833,284	1,550,450	3,383,734	-22.89%
2038	1,787,418	998,475	2,785,893	-36.51%

Table: 1

The AURORA carbon emissions forecast for Idaho Power is the sum of emissions from Idaho Power's thermal resources plus the carbon content of Idaho Power's market purchases. To assist in interpreting the tabular data, STOP has added a column to the forecast that calculates Idaho Power's forecasted cumulative progress towards decarbonizing their system by comparing annual carbon emissions forecasted by AURORA under the preferred portfolio over the 20-year planning horizon to the AURORA forecast of carbon emission in year 1 (i.e., 2019). For example, it can be seen in the table that under their preferred portfolio, Idaho Power expects that CO2 emissions in 2028 will be 3.5 percent higher than in 2019.

The CO2 emissions forecasted by AURORA under Idaho Power's preferred Portfolio (**as presented in Table 1, above)** can also be **represented graphically as follows in Exhibits 1 and 2.**

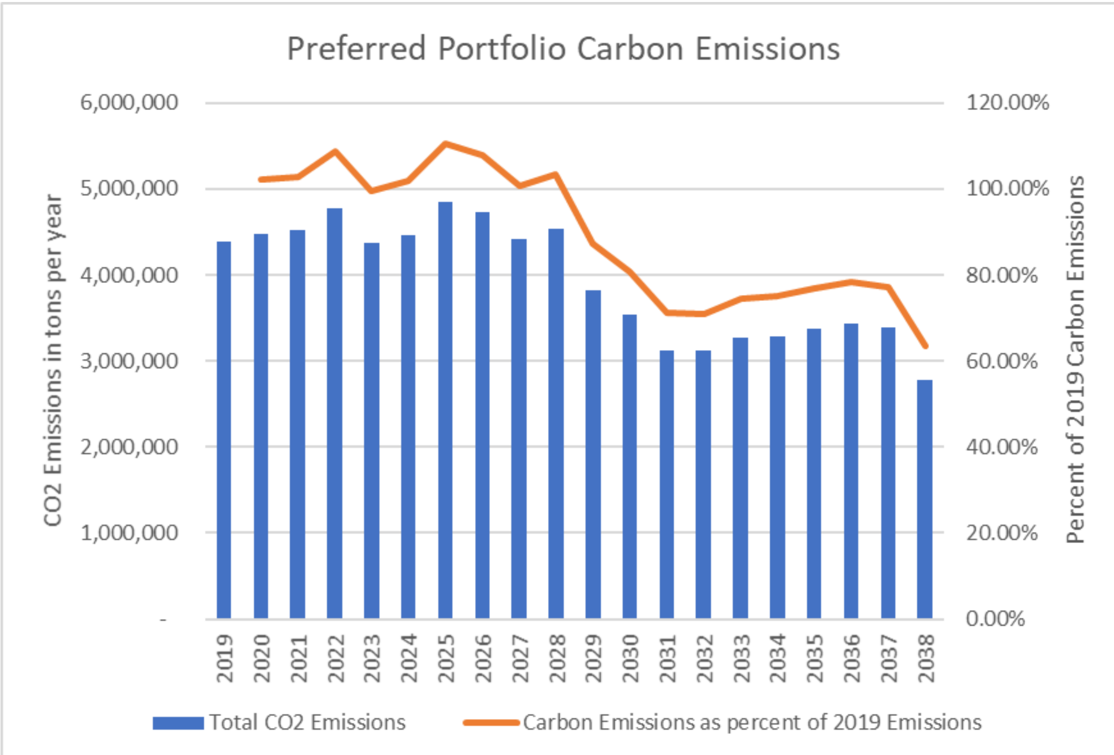

Exhibit 1.

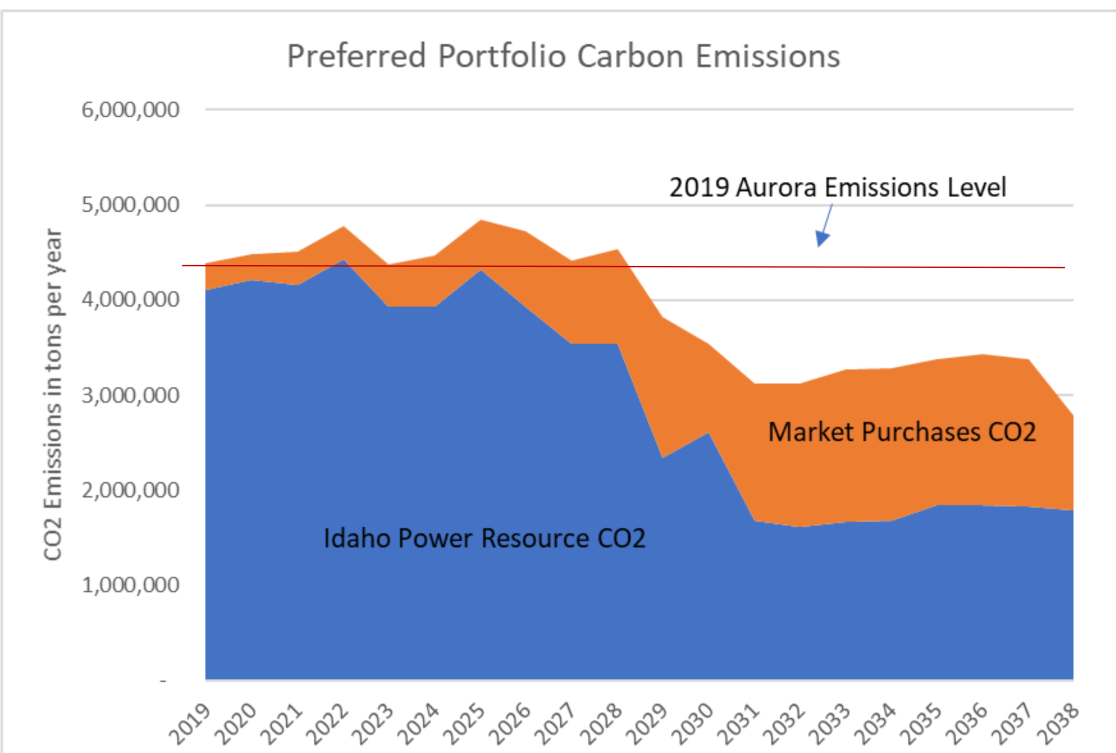

Exhibit 2.

Idaho Power may believe that their preferred Portfolio "shows a clear path to a clean energy future", but STOP is bewildered. Under Idaho Power's preferred Portfolio, Idaho Power projects that their system will exhibit increasing carbon emissions over the first eight years of the planning period. In fact, Idaho Power is projecting that in 2025, carbon emissions from their system will be 10.46% higher under their preferred Portfolio than they are today and will not even start to decline below today's level until 2029. [38] This persistent increase in Idaho Power's CO2 emissions occurs despite the addition of the 120 MW Jackpot Solar and the exit of one Bridger Unit in 2022, the exit of a second Bridger unit in 2026 and the addition of B2H in 2026. In fact, in the three years after adding B2H (2026-2028), CO2 emissions on the Idaho Power system continue to increase.

Idaho Power's preferred Portfolio does not show a clear path to a clean energy future. On the contrary, STOP believes (as we have consistently maintained throughout the 2017 IRP and this IRP) that the evidence clearly shows that Idaho Power's fixation on a "market purchases" strategy and the construction of B2H is more accurately described as a clear path to a high carbon future for Idaho Power. As can be seen, B2H is ineffectual at moving Idaho Power rapidly toward a clean energy future and the reason falls squarely on Idaho Power's passion for market purchases and B2H.

The Governor's Executive Order 20-04 directs the Public Utility Commission when carrying out its regulatory functions to:

> "Determine whether utility portfolios and customer programs reduce risks and costs to utility customers by making rapid progress towards reducing GHG emissions consistent with Oregon's reduction goals."[39]

STOP implores this Commission to recognize the carbon heavy foundation of Idaho Power's Second Revised 2019 IRP and to reach a determination that Idaho Power's preferred portfolio fails to make even modest progress towards reducing GHG emissions consistent with Oregon's reduction goals and Executive Order No. 20-04. The Commission should not acknowledge any part of this IRP. To acknowledge this IRP which Idaho Power has manually optimized to ensure increasing carbon emissions for the next eight years would be contrary to the Commissions responsibilities under Executive Order No. 20-04.

The Commission should not trust Idaho Power's representations around carbon reductions. Idaho Power distorts its CO2 emissions history while hiding recent large increases in the "carbon Intensity "of their existing gas-fired resources. STOP will explain below how Idaho Power distorts its carbon emissions record and how and why it has actually been increasing the carbon intensity of its existing gas-fired resources.

Idaho Power claims in this IRP that:

> "Idaho Power is committed to reducing the amount of CO2 emitted from energy-generating sources. Since 2009, the company has met various voluntary goals, initiated by shareholders, to realize its commitment to CO2 reduction. As of 2018, Idaho Power's carbon emissions intensity, expressed as pounds of CO2 per MWh generated, has decreased by 46 percent compared to 2005 levels. Our current goal is to ensure the average CO2 emissions intensity of our energy sources from 2010 to 2020 is 15- to 20-percent lower than 2005 levels."[40]

Idaho Power's choice of calendar year 2005 as the base year against which progress toward carbon reduction is measured is duplicitous. It is common knowledge that the biggest predictor of Idaho Power carbon emissions in any year is the amount and shape of the hydro runoff. As Exhibit 3 below shows, the more hydro available, the

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[38] These are Idaho Power's own numbers and have not been adjusted or modified in any way by STOP in creating these visual aids.
[39] Executive Order No. 20-04 p 8
[40] Second Amended 2019 IRP p 12

less Idaho Power needs to operate their gas and coal resources. Conversely, in a poor hydro year, Idaho Power must run their thermal resources harder to meet load resulting in much higher carbon emissions.

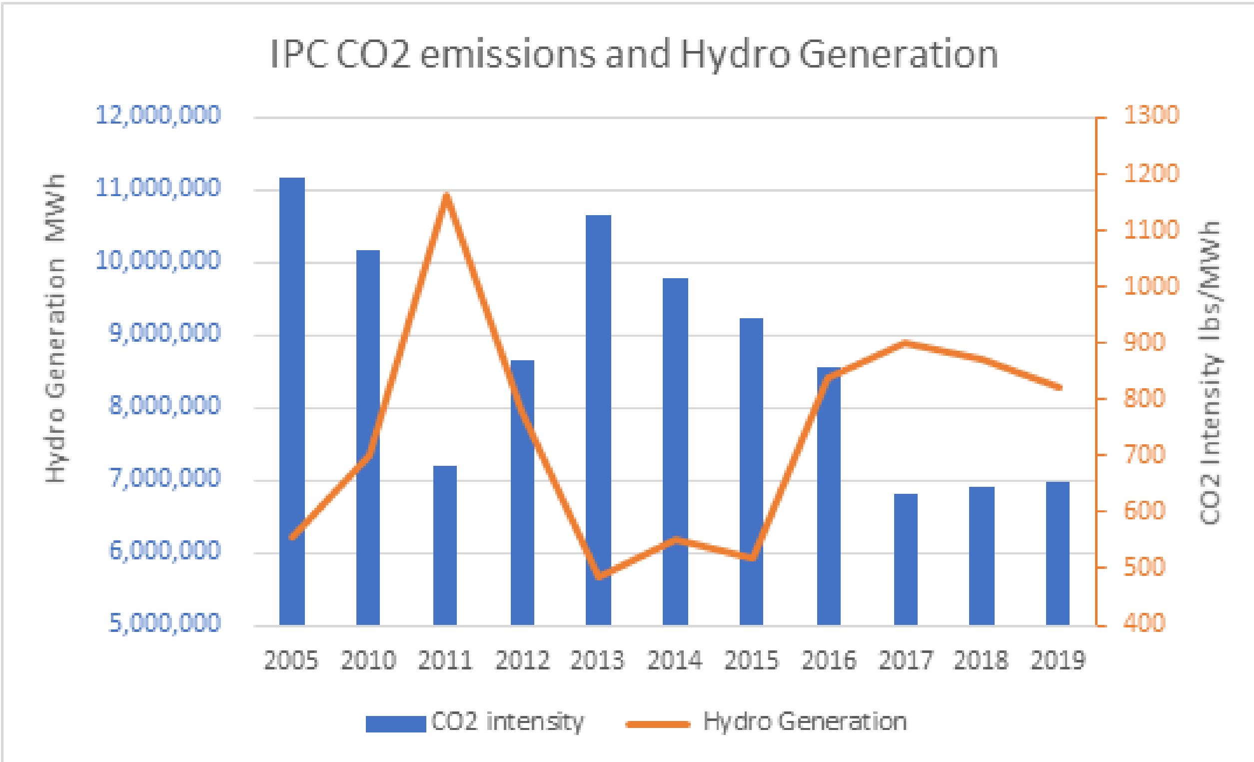

Exhibit 3.

Idaho Power is telling this Commission that 2005, the poorest hydro year in recent history is the baseline against which their commitment to carbon reduction should be measured. STOP believes this is duplicitous. In a hydro based system like Idaho Power's, measuring carbon intensity across all resources including hydro is meaningless, if not misleading. The effect of year-to-year hydro variation obscures Idaho Power's actual progress in reducing emissions; especially the degree to which Idaho Power operates its thermal resources in a responsible, efficient manner, or not. STOP has examined the carbon intensity of Idaho Power's individual resources and has concluded that Idaho Power has quietly embarked on a high-carbon operating strategy for its gas-fired resources and unfettered trading in the EIM appears to be the motive.

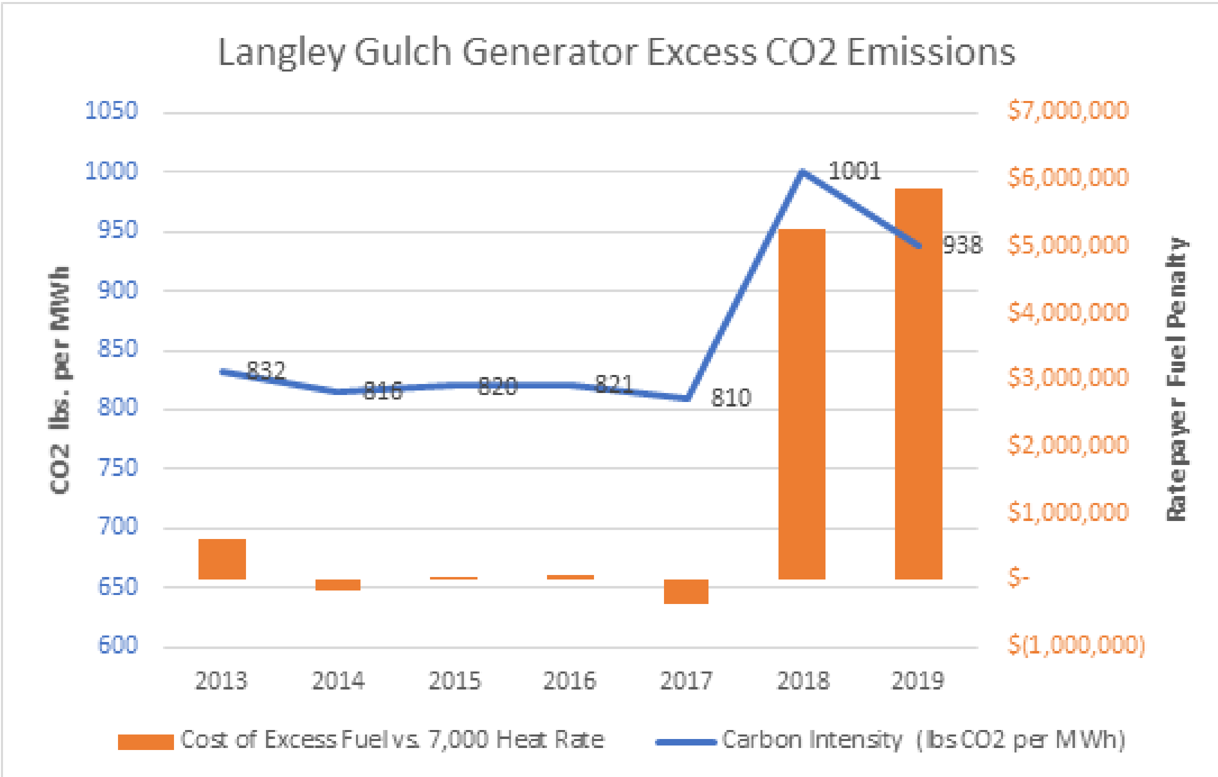

Exhibit 4.

For example, STOP has examined the carbon intensity of power generated by Idaho Power's Langley Gulch combined cycle gas plant over the period 2013 to 2019. Built In 2012, Langley Gulch is a high efficiency combined cycle plant capable of achieving efficiencies approaching 50 percent in actual operation, which is under a 7,000 Btu-kWh heat rate.[41] If Idaho Power operates Langley Gulch efficiently and achieves a nominal 7,000 Btu-kWh heat rate in actual operation, the carbon intensity of Langley Gulch will be 819 lbs. of CO2 per MWh.[42]

As can be seen in the Exhibit 4 above, for the first five years after building Langley Gulch (2013-2017), Idaho Power operated Langley Gulch in a responsible manner consistently achieving low carbon intensity. Over the five-year period of 2013-2017, the carbon intensity of Langley Gulch generation averaged 820 lbs. of CO2 per MWh, a commendable performance. Beginning in 2018 (when Idaho Power first joined the EIM and continuing through 2019 however, Idaho Power profoundly changed the operating regime of Langley Gulch resulting in gross inefficiencies in operation.[43] In the two-year period 2018-2019, the carbon intensity of Langley Gulch generation jumped by almost 20% to an average of 969 lbs. of CO2 per MWh, or over 8,000 Btu-kWh heat rate.

This curious operation of Langley Gulch by Idaho Power in 2018-2019 resulted in almost 200,000 tons of unnecessary CO2 emissions and over $10 million of unnecessary fuel costs, at actual 2018-2019 gas prices, to the detriment of ratepayers (see Table "Langley Gulch" below). Under the EIM, the "benefits" of the EIM accrue to stockholders while this $10 million of excess fuel costs is paid by ratepayers.

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[41] A kilowatt-hour of power contains 3,412 Btu. A heat rate of 7,000 implies an efficiency of 49 percent (7,000/3,412 = 49%)

[42] (7,000 heat rate *1000) =7 MMBtu of gas *117 lbs. CO2 per MMBtu = 819 lbs. CO2 per MWh

[43] STOP does not know the drivers behind this wasteful and expensive operation of Langley Gulch but maintaining the plant in wasteful hot standby to bid into the EIM, frequent operation at partial load, and operating power augmentation (duct firing) to achieve quick and dirty ramping capacity for EIM participation are likely contributors.

Idaho Power is not unique in engaging in potentially abusive operations of their gas-fired generating resources to aggressively trade in the EIM. Portland General has been particularly egregious in its operation of its gas-fired resources; Carty in particular. STOP believes that the OPUC should investigate utility abuses in the EIM. At a minimum, STOP encourages the Commission to be more – circumspect when utilities like Idaho Power tailor their IRP's to promote expanded EIM trading to the detriment of a carbon sensitive portfolio strategy.

ANALOGY

		Langley Gulch					
	2013	2014	2015	2016	2017	2018	2019
Net Continuous Plant Capability (MW)	300	300	300	300	300	300	300
Plant hours connected to load	5,250	4,027	6,132	5,443	5,079	4,287	5,549
Percent of year connected to load	59.9%	46.0%	70.0%	62.1%	58.0%	48.9%	63.3%
Average Hourly Capacity Factor	82.3%	86.8%	90.4%	87.0%	88.6%	87.9%	90.2%
Net Generation (MWh)	1,295,859	1,049,182	1,662,770	1,420,178	1,350,692	1,131,020	1,501,436
Average cost of fuel ($/MMBtu)	$ 4.39	$ 5.37	$ 2.95	$ 2.81	$ 3.31	$ 2.98	$ 3.86
Average BTU per KWh of Net Generation (Heat Rate)	7,107	6,971	7,007	7,021	6,920	8,557	8,014
Actual Annual Capacity Factor	49.3%	39.9%	63.3%	54.0%	51.4%	43.0%	57.1%
Average Capacity Factor when Connected to Load	82.3%	86.8%	90.4%	87.0%	88.6%	87.9%	90.2%
Total Fuel Burned (MCF)	8,967,970	7,121,881	11,344,468	9,708,637	9,101,138	9,423,468	11,716,727
Heat Content	1,027	1,027	1,027	1,027	1,027	1,027	1,027
Toal Fuel Burned (MMBtu)	9,210,105	7,314,172	11,650,769	9,970,770	9,346,869	9,677,902	12,033,079
Cost of Excess Fuel vs. 7,000 Heat Rate	$ 608,704	$ (163,389)	$ 34,336	$ 83,805	$ (357,663)	$ 5,247,774	$ 5,876,681
Excess fuel burned (MMBtu)	138,657	(30,426)	11,639	29,824	(108,055)	1,760,998	1,522,456
Excess CO2 Emissions (117 lbs per MMBtu) in	8,111.43	(1,779.94)	680.90	1,744.69	(6,321.24)	103,018.39	89,063.68
Total CO2 Emissions	538,791.15	427,879.05	681,569.97	583,290.06	546,791.82	566,157.25	703,935.10
Carbon Intensity (lbs CO2 per MWh)	832	816	820	821	810	1001	938

Source: FERC Form 1 filings for Idaho Power, 2013-2019

Portfolio Risk Analysis

In STOP's opening comments, STOP explained to the Commission that Idaho Power had incorrectly evaluated and presented the results of their portfolio scenario analysis and failed to consider carbon risk at all in their stochastic analysis. In their Reply Comments, Idaho Power chose to completely ignore STOP's valid criticisms of their scenario analysis and summarily dismissed STOP's criticisms of their stochastic analysis. STOP is confident that Commission staff will hold Idaho Power accountable for failing to perform a credible assessment of the risks around their preferred Portfolio. Nevertheless, STOP feels compelled to once again explain the infirmities underlying Idaho Power's failed attempt at assessing portfolio specific risks associated with climate change and carbon pricing.

Scenario analysis, while a relatively crude form of uncertainty analysis, is useful in understanding which uncertain variables have a material effect on evaluated portfolio costs and can help identify which uncertain variables are associated with the worst potential outcomes. Scenario analysis alone, however, does not illuminate the likelihood of good and bad outcomes which requires more advanced statistical tools such as a stochastic analysis.

Idaho Power to their credit performed a scenario analysis confirming that two major uncertainties, future gas prices and future carbon costs, would have a significant effect on the NPV of each portfolio studied. Idaho Power created four optimized portfolios and evaluated each portfolio against alternate futures (scenarios) for gas prices and carbon prices. Idaho Power then calculated the mean (expected portfolio NPV) for each of the four optimized portfolios, and the standard deviation around the unique mean of each Portfolio. Then, inexplicably, Idaho Power created a visual aid (Figure 9.1)[44] that presented the standard deviation of each Portfolio around the point estimate NPV of the "planning cases" and not around the expected NPV of those planning cases. Standard deviation as a measure of variability of a Portfolio's NPV under uncertainty is correctly calculated from the deviations around a Portfolio's mean or expected value NPV. Idaho Power has instead presented a meaningless comparison of standard deviations against random, estimates of Portfolio NPV as chosen by Idaho Power. This is grossly misleading.

In opening comments, STOP correctly pointed out that Idaho Power's stochastic analysis was inadequate because Idaho Power apparently decided that future carbon cost uncertainty did not warrant evaluation at all in their stochastic analysis. In reply comments, Idaho Power belittled STOP's observations and implied that high future carbon costs have such a low probability of occurring that consideration of carbon cost uncertainty in their stochastic analysis would be of little value. [45]

STOP has examined the stochastic analysis in this Second Amended 2019 IRP and discovered that Idaho Power improperly structured their stochastic analysis to bias the analysis against all portfolios that were optimized under a high carbon cost future. Idaho Power did this by hard-wiring different carbon price inputs into AURORA depending on which Portfolio was being studied. A stochastic analysis is so named because it looks at variables that can be characterized by a random probability distribution, but Idaho Power has incorporated carbon price risk into the stochastic analysis with a non-random probability distribution that correlates 100 percent with the carbon future that for which the portfolio was optimized. This means that Idaho Power has structured the stochastic analysis under the assumption that if Idaho Power performs a stochastic analysis of Portfolio 2 which was optimized for a "planning carbon" scenario, then there is 100 percent probability of a planning carbon future in all simulations. Conversely, when Idaho Power performed a stochastic analysis on Portfolio 12 or any other portfolio optimized for high carbon, then there is 100 percent certainty of a high carbon price future in all simulations and no possibility of a low carbon price future.

This analysis is the COVID-19 equivalent of saying if we increase testing, we will have cases of COVID-19, but if we stop testing, we will not have more cases of COVID-19. In this case, Idaho Power is saying "if we choose our preferred portfolio, then it is guaranteed that the future will reflect planning carbon assumptions, but if we choose a portfolio optimized for a high carbon future, then it is 100% guaranteed that the future will reflect high carbon costs." This hidden bias against every Portfolio optimized for a high carbon cost future in the stochastic analysis ensures that Idaho Power will always prefer a Portfolio with little or no renewables. Perhaps this is why Idaho Power provided no statistical analysis whatsoever of the results or insights gained from their improper stochastic analysis. Idaho Power's only comment addressing the results of their stochastic analysis was the statement

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[44] Second Amended IRP p. 114 Figure 9.1

[45] Idaho Power Reply Comments p30 "the high carbon cost assumption reflects the highest cost assumption in the California Energy Commissions Integrated Energy Policy Report, ensuring that results from carbon modeling were extremely conservative. STOP B2H's analysis, in contrast, fails to recognize the relatively low likelihood that these high-cost cases will actually occur"

"The widely ranging costs are an indication that portfolio exposure to cost drivers is sufficiently evaluated. Further, the stochastic analysis suggests that changes in strong cost drivers do not shift the relative cost difference between portfolios significantly and thus does not favor one portfolio over another."[46]

The Commission cannot possibly find that this Idaho Power IRP has satisfied even the minimum standards in the IRP Guidelines as they address risk and uncertainty, much less the directives in Executive Order 20-04.

Adjustments to the AURORA model

Under the guise of a late-stage IRP Review, Idaho Power has implemented certain questionable inputs into the Aurora model. While Idaho Power explains that these changes did not change the recommendation and preferred Portfolio in this IRP, it appears clear to STOP that Idaho Power has manipulated the Aurora model base case data inputs in an apparent effort to stage the model for the next IRP.[47] Perhaps the clearest example of this manipulation of the Aurora model is Idaho Power's unexplained sensitivity analysis around peaker O&M costs.

Prior to the Second Amended 2019 IRP, peaker O&M and startup costs were correctly entered into the AURORA model, (a model that has been carefully validated by the vendor and is used by many utilities and regulators across WECC.) Variable O&M as well as startup costs is fundamental to a model like AURORA that is based upon the simulation of efficient security-constrained economic dispatch of resources across WECC. In this Second Revised 2019 IRP modeling, Idaho Power has fundamentally changed the dispatch logic for Idaho Power peakers by moving variable O&M costs (which accrue as the unit is operated) to a single startup cost which is incurred only when the unit is started.

It is clear to STOP that Idaho Power has made changes in peaker cost inputs to Aurora for the purpose of making the peakers look much more expensive to own and operate that they really are. In the next IRP, we expect IPC to propose a "repowering" of their Danskin peaker units which will be justified based on the big decrease in Portfolio NPV that magically results from replacing the Danskin units.[48]

The foundation of the Aurora model is the simulation of hourly resource dispatch in the WECC. Since fixed costs (i.e., sunk costs) do not affect the dispatch decisions in the model, it is only the variable costs, or costs that vary with unit dispatch that are considered within AURORA. The largest variable cost when dispatching thermal resources is the cost of fuel. (This cost has been vetted extensively in these proceedings and is not an issue with the Idaho Power peakers.)

Non-fuel variable O&M costs are those costs directly related to the dispatch of the plant. These variable O&M costs are appropriately considered as a $ per MW adder to the fuel cost when making dispatch decisions. Variable O&M costs for gas peaker plants are typically low because there are few consumables other than gas in the generating process.[49]

Non-fuel variable O&M costs also typically include an adder of $1-$2/MWh to reflect the eventual need to perform scheduled major maintenance. Major maintenance such as turbine overhauls is usually required after a

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[46] Second Amended 2019 IRP p 123

[47] STOP uses the term "staging" as a polite synonym for "rigging the model"

[48] Second Amended 2019 IRP p 39

[49] The many peaker plants across WECC that have installed selective catalytic reduction (SCR) will experience incremental operating costs for urea/ammonia injected into the SCR's, and an additional adder to reflect the consumption of catalyst, but Idaho Power's peakers do not have any emissions controls.

set number of operating hours, typically 5,000-15,000 hours. While these adders do not represent a direct cost on that hour, they are important to explicitly consider when establishing a dispatch stack, so dispatchers understand the full cost of dispatching a unit.

Startup costs generally fall into two categories.

1) Fuel Penalty: There is a fuel penalty when starting any thermal resource because the unit will be firing for a period before it is synchronized to the grid and until it can ramp sufficiently to achieve full-load efficiencies. This is reflected in most models as a heat rate penalty, so the model sees a higher fuel cost per MWh for the first hour or two as the plant ramps. The cost of start-up fuel can be significant for a combined cycle gas plant because the plant can take several hours to start and ramp to full load from a cold start. Simple Cycle peaker plants (SCCT) are quicker starting so fuel costs at startup are minimal and usually ignored in a simplified model like Aurora.[50]
2) 'Equivalent Operating Hour" penalty: Cold starts create more wear and tear on a thermal plant and will accelerate the time when major capital maintenance must be performed. This is usually accounted for in a model by charging more than one equivalent operating hour for any hours in startup. These equivalent operating hour penalties for startup tend to be much more significant for a combined cycle plant than for a simple cycle peaker.

Idaho Power's peaker O&M inputs to Aurora in the Amended IRP as shown below appear consistent with the typical underlying dispatch economics of peaker plants:[51]

	Variable O&M ($/MWh)											
Peaker Plant	January	February	March	April	May	June	July	August	September	October	November	December
Bennett Mountain	$ 2.68	$ 2.76	$ 2.82	$ 2.91	$ 2.91	$ 2.96	$ 3.02	$ 3.02	$ 2.94	$ 2.92	$ 2.78	$ 2.68
Danskin 1	$ 2.53	$ 2.60	$ 2.64	$ 2.72	$ 2.72	$ 2.76	$ 2.82	$ 2.82	$ 2.75	$ 2.74	$ 2.61	$ 2.53
Danskin 2	$ 2.53	$ 2.60	$ 2.64	$ 2.72	$ 2.72	$ 2.76	$ 2.82	$ 2.82	$ 2.75	$ 2.74	$ 2.61	$ 2.53
Danskin 3	$ 2.53	$ 2.60	$ 2.64	$ 2.72	$ 2.72	$ 2.76	$ 2.82	$ 2.82	$ 2.75	$ 2.74	$ 2.61	$ 2.53

In the Second Amended 2019 IRP, Idaho Power eliminated the roughly $3 MWh variable O&M adder in AURORA and replaced it with an hourly adder of over $100 per MWh for the first hour of operation.

AURORA Inputs for Second Amended 2019 IRP		
	Variable O&M	**Start Up Cost**
Peaker Plant	**$/MWh**	**$/MW per Start**
Bennett Mountain	$ -	$ 102
Danskin 1	$ -	$ 114
Danskin 2	$ -	$ 109
Danskin 3	$ -	$ 109

Idaho Power explains on page 49 in the Review Report that the Aurora model was dispatching the natural gas peaking plants for more hours a year than they are normally dispatched by Idaho Power and commissioned a sensitivity to investigate it:

> "Peak-Day Comparison - The resource stack dispatched to meet demand through a peak day in the model was compared to the resource stack used to meet peak demand in the summer of 2017. This is a visual comparison to ensure resources are dispatching in the model in a reasonable manner. Natural gas provided a similar proportion of the resource stack in the model during peak hours. *However, natural*

[50] AURORA employs simplified dispatch logic which is adequate for doing high level portfolio studies. In-depth system simulations are typically performed using highly detailed Production Cost models such as Gridview.
[51] STOP DR#112

> *gas peaker plants (SCCTs) are dispatched in the model for a longer duration than actual dispatch indicates. [emphasis added]* While some variations between the model and actual dispatch are reasonable, as market conditions are expected to vary between the modeled forecasts and historical values, the Review Team conducted a sensitivity to explore this issue further. The sensitivity is described in Section 5.5 (Natural Gas Plant Step IV validation and verification)."[52]

However, when reviewing Section 5.5 of the Review Report it appears the Review Team found a different problem: the Aurora model was starting the peakers too frequently.

> Peaking Plants– A sensitivity analysis was performed that changed the maintenance calculation of two peakers—Bennett Mountain and Danskin 1—from a variable O&M charge (which spreads maintenance costs across MWh) to a cost per start. The small peakers (Danskin 2 and 3) were also included in a separate start cost sensitivity analysis. The sensitivity analysis showed that the use of a variable O&M charge in the model resulted in understatement of the total maintenance costs, while the use of a cost per start captured the full cost of plant maintenance. ***Further, the use of a cost per start showed a decrease in the number of starts without a corresponding decrease in total energy.*** *[emphasis added]* To further validate the results, the sub-team compared the results of the AURORA output to actual 2019 maintenance costs. The variance between the modeled maintenance costs and 2019 actuals was within 3 percent, a variance the sub-team considered reasonable. The sensitivity analysis showed minimal change in total portfolio NPV cost compared to the amended 2019 IRP (ranging from an approximate 0.8 percent increase in NPV for P2(3) up to about a 1.2 percent increase for P16-4)."[53]

STOP wonders what Idaho Power is doing. Idaho Power claims in Section 5.1 of the Review Report that the problem is that the AURORA model is dispatching the peakers for longer duration (i.e., more energy) than actual dispatch records show, yet in Section 5.5 of the Review Report, Idaho Power claims that the variable O&M adder in AURORA resulted in an "understatement of the total maintenance costs". This second statement does not make sense. Modeling 101 would tell you that if you add a variable O&M cost to each MWh and it does not recover the variable O&M costs, then you have set the variable O&M rate per MWh too low in the model. STOP submitted a data request that asked Idaho Power to explain whether they had conducted a sensitivity where they incorporated corrected (higher) variable O&M adders to the AURORA model that would recover total maintenance costs. Idaho Power replied that

> "the Company increased the variable O&M component in an attempt to capture all the maintenance costs, however, increasing the variable O&M cost increases the dispatch cost of the plant for every hour, creating an unrealistic unit commitment. The startup cost only affects the first four hours in terms of unit commitment; therefore, it was determined to be a more accurate method for capturing the maintenance costs."[54]

Idaho Power is not being forthcoming.

- Idaho Power claimed they first embarked on these peaker sensitivities because the AURORA model was operating the peakers for more hours per year (and/or more hours each time they are started) than Idaho Power typical does. Yet when they increased the hourly O&M charge which reduced the hours of dispatch in AURORA, Idaho Power claims it was "an unrealistic unit commitment". Idaho Power did not explain why it was unrealistic.

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[52] Review Report p 49
[53] Review Report p 54-55
[54] Idaho Power response to STOP DR 113

- Idaho Power's solution to whatever problem they were trying to solve was to eliminate any hourly charge for variable O&M and instead make the start charge high enough in the model to recover O&M costs through start-up charges alone. Idaho Power does not explain why they determined that this change did not result in a realistic unit commitment nor does Idaho Power explain why this change increased the NPV of their preferred Portfolio by approximately $70 million.

- STOP tested Idaho Power's claims against 2019 actuals for the peakers and Idaho Power's explanation does not make sense. For Danskin 1, the variable O&M approach used in the Amended 2019 IRP results in total maintenance costs of $666,041 which is over $35,000 more than Idaho Power's new approach in the Second Amended 2019 IRP. The credibility of Idaho Power's representations is even more challenged in the case of Bennet Mountain, which would recognize over $900,000 in variable O&M under 2019 actual dispatch applied to the Amended 2019 IRP inputs, but less than $400,000 under Idaho Power's radical new approach applied in the Second Amended 2019 IRP.

	AMENDED 2019 IRP-Hourly Variable O&M			SECOND AMENDED 2019 IRP-All O&M in Startup Costs				
	2019 Calendar Year Actual Net Generation (MWh)	**2019 Calendar Year AURORA Average Hourly O&M Rate ($MWh)**	**2019 Total Variable O&M at Aurora Rates**	**Capacity**	**AUORA Start Up Cost $/MW**	**AURORA Total Cost per Start**	**2019 Calendar Year Actual Starts**	**2019 Total Variable O&M using only Start Up Costs**
Danskin 1	247,906	$ 2.69	$ 666,041	178	114	$ 20,292	31	$ 629,052
Bennett Mountain	317,878	$ 2.87	$ 911,250	178	102	$ 18,156	22	$ 399,432

What is most curious is that Idaho Power has tweaked the dispatch logic in AURORA based on conflicting reasons with a result that the NPV of their preferred Portfolio increased by over one percent, or about $70 million compared to the Amended 2019 IRP, but Idaho Power thinks it is not a big deal because "this is a minimal change."[55] The change is about the same as the asserted NPV difference between the Preferred Portfolios with and without B2H. Idaho Power has not explained why they chose the new approach and why a $70 million change in portfolio NPV without any change in underlying cost inputs is a "minimal change."

STOP believes the answer lies in Idaho Power's professed intent to "repower" the Danskin Turbines, which means they could retire the units and replace them with new gas-fired units and request accelerated depreciation of the remaining Danskin rate base.[56] STOP believes that Idaho Power has deliberately adjusted the AURORA model to artificially increase the portfolio NPV, so they can claim big savings from repowering the Danskin units, savings so enormous that they should be allowed to retire the Danskin units early but still recover all their investment in the existing Danskin units because ratepayers will still come out ahead based upon the rigged AURORA modeling results.

STOP encourages the Commission to refuse to acknowledge this IRP. To do otherwise will unjustly reward this nefarious behavior by Idaho Power. Given all the infirmities surrounding this IRP, acknowledging this IRP would be wholly inconsistent with the Commission's responsibilities under Executive Order 20-04.

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55 2019 IRP Review Report: Process and Findings P54-55
56 Second Amended 2019 IRP p 39

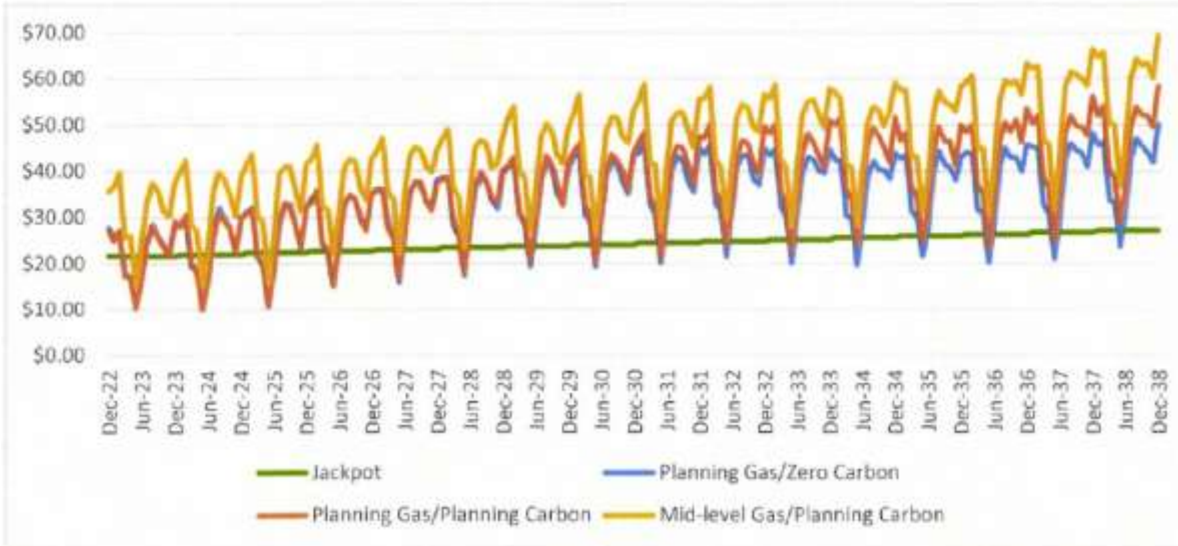
Mid-C Market and Jackpot

The IPUC staff report[57] on Jackpot Solar, CASE NO. IPC-E-I9-14[58], determined that the PPA for Jackpot Solar was less expensive than market purchases at the Mid-C. It provided Idaho Power customers with less expensive, clean renewable energy over the 20 year period modeled rather than the more carbon intensive Mid-C market hub. These saving are probably even greater now given the growing resource inadequacy at the Mid-C market and it is providing jobs to Idahoans.

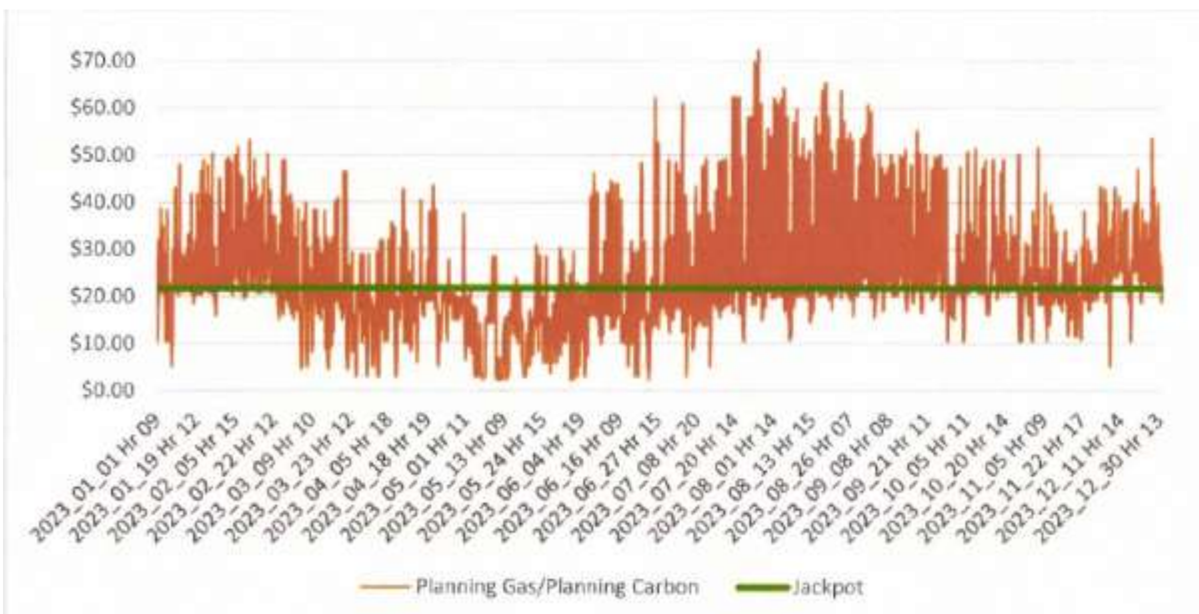
Picking up the staff report at the Market Price to Contract Price Analysis section this is what the IPUC staff determined and based on this analysis the IPUC Commission approved the Jackpot Solar PPA.

> **Market Price to Contract Price Analysis**
>
> Staff conducted a market price to contract price comparison, mainly because of issues and shortcomings in the Company's 2019 IRP analysis. Normally, Staff would have used a 2019 IRP-modeled analysis on a stand-alone basis to evaluate Jackpot Solar, but due to deficiencies, Staff placed increased weight on this analysis to determine its recommendation. Staff believes this analysis adds validity because the cost of Jackpot Solar is primarily energy cost with only a small amount of capital. The analysis showed a $145,000 savings during the first year of the PPA, and increased savings thereafter.
>
> **Analysis Method and Results**
>
> Staff performed several comparisons between the contract price and market prices generated for the Mid-Columbia market hub (Mid-C) generated by Aurora. The analysis include both average hourly and monthly comparisons over likely alterative futures. If the assumption is made that market prices are an acceptable surrogate for the marginal energy cost of ldaho Power's system, then customers should see a cost saving with the addition of Jackpot Solar to the Company's resource mix.
>
> Staff first compared the contract price against average monthly market prices for several alterative futures modeled in Aurora. One of the main functions of Idaho Power's implementation of Aurora is to predict hourly market prices across all the hubs in the WECC region. Predicted Mid-C market prices were used for the comparisons because Idaho Power transacts most of its market purchases through the Mid-C hub. Although in the initial years of the contract, the forecasted monthly average market price reflects some months of the year that are lower than the contract price, this is not the case in the majority of future years since market prices are predicted to increase faster than contract prices. Price comparisons for three alterative futures across the 2019 IRP planning horizon are reflected in the graph below: (1) Planning Gas/Planning Carbon; (2) Planning Gas/Zero Carbon; and (3) Mid Gas/Planning Carbon.

[57] https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1914/Staff/20191126Comments.pdf p 10-13
[58] https://puc.idaho.gov/Case/Details/3675



Comparing average monthly prices gives a general indication of how the contract prices compare with overall market prices, but does not provide the granularity needed to compare prices when Jackpot Solar will be producing energy. To compare the price when Jackpot Solar will be producing energy, Staff compared several years of average hourly market prices to the contract price only when Jackpot Solar is producing energy. This comparison for the first full year of the contract uses Planning gas/Planning carbon Mid-C prices as illustrated as an example in the graph below.



Although the market price is lower than the contract price for 52% of hours during the first year of the contract, the total cost difference when market prices are higher than the contract price is much greater than when market prices are lower than the contract price. In other words, if the Company had to pay market prices instead of the contract price for the same amount of Jackpot Solar generation, the cost would be much higher. This is made clear by examining how much larger the orange area is above the contract price line (green line) compared to the orange area below the line in the graph above.

Staff quantified the cost difference by calculating the cost of energy produced by Jackpot Solar using the contract price and compared it against the cost for an equivalent amount of energy using the market price. The results show that the cost of energy using the contract price is approximately $145,000 less. For the second year of the contract, the annual cost is $492,000 lower using the contract price. The difference continues to grow for subsequent years since the average market price increases at a rate faster than the contract price.

Shortcomings of the Market Price-to-Contract Price Analysis

Staff identified two shortcomings that can affect the validity of this analysis. First, neither the REC benefits generated by the project nor the transmission upgrade capital costs are included in this analysis. However, Staff did compare the annualized cost of the transmission upgrades and determined that the annualized REC benefits more than covered the additional transmission upgrade cost, minimizing the effect of this shortcoming.

Second, as mentioned earlier, a market price to contract price comparison assumes that market prices are equivalent to the marginal energy cost in Idaho Power's system. This assumption only holds true if the market is consistently the marginal cost resource in Idaho Power's system. This is not always the case. The Company's IRP model captures the marginal resource in the Company's resource stack for every hour modeled over the planning horizon. By performing model runs with and without Jackpot Solar, as described in Staff s "expected" analysis, the savings generated by including Jackpot Solar will always reflect the marginal avoided cost for whatever resource is at the margin and available to meet load. The additional benefit of an IRP-modeled analysis is that it captures potential changes in future resources that can affect the marginal cost.

Market Purchase Opportunities in the PNW

Just like in the 2017 IRP, Idaho Power misrepresents the depth and liquidity of the PNW power markets in this Second Amended 2019 IRP. STOP attempted to illuminate these misrepresentations to the Commission in the 2017 IRP, but STOP was unpersuasive. Confident that they had fooled the Commission, Idaho Power doubled down in this Second Amended 2019 IRP claiming that not only was the PNW market rich with surplus power that could only be accessed with B2H, but Idaho Power also now shamelessly claims that purchases from the PNW enabled by B2H would be “carbon free” power.[59][60]

STOP recognized when reviewing this 2019 IRP that STOP would probably never be persuasive to this Commission on the fallacy of Idaho Power’s B2H preferred market purchase portfolio unless Commission staff were to independently reach the same conclusion that STOP has. Because of this, STOP’s opening comments proposed that Idaho Power be required to identify and explain to the Commission the actual PNW resources behind each hourly purchase from the PNW in AURORA.[61] Idaho Power ignored this suggestion in reply comments.

STOP reiterates to this Commission that Idaho Power’s representations of the PNW market in this IRP and Appendix D are incorrect and it has become clear that Idaho Power has manipulated the AURORA model inputs

[59] “The development of B2H, in particular, provides a crucial carbon-free, supply-side resource” LC 74 Idaho Power Company’s Amended Application p2
[60] “development of B2H as a least-cost and carbon-free supply-side resource” Second Revised 2019 IRP p 6
[61] STOP Opening Comments p 8

to try to make B2H look like a good investment. For example, Idaho Power's spreadsheet provided to STOP in response to STOP DR No. 106 shows that Idaho Power's Preferred Portfolio Studies that included B2H assume that the 600 MW Boardman coal plant, the 670 MW Centralia #1 coal plant and the 670 MW Centralia #2 coal plant would continue operating and selling power into the PNW (MIDC) market through the entire 20 year planning period.[62] The spreadsheet also include the 268 MW TransAlta Centralia gas plant through the entire 20 year planning period. In fact, the Boardman and Centralia #2 coal plants closed permanently in late 2020 and Centralia #1 will close at the end of 2024 pursuant to a binding Agreement between the owner TransAlta and the State of Washington. The TransAlta Centralia gas plant closed in 2014.

It is understandable that B2H will look better in AURORA if Idaho Power includes over 1800 MW of phantom coal generation selling into the MIDC market in AURORA for the twenty-year planning period. This is exactly what Idaho Power has done by assuming Boardman and both Centralia plants operate through the entire 20-year planning period in the AURORA preferred Portfolio P14. It also appears that Idaho Power apparently made undisclosed changes to their AURORA transmission inputs when adding B2H to a Portfolio, including zeroing out BPA's existing wheeling charges assessed to Idaho imports from the PNW, by incorporating a phantom asset swap with BPA into the B2H cases.

STOP does not have the resources to tease out all the ways that Idaho Power has failed in their attempts to employ the AURORA model to perform credible capacity expansion studies and understand that probably only Commission Staff can obtain greater transparency and honesty from Idaho Power on the true dynamics of the PNW market. We note that Commission Staff are monitoring PNW resource supply adequacy studies at both the Northwest Conservation Council and Northwest Power Pool. We commend Commission staff for this diligence.

[62] LC 74 IPC to Stop B2H DR 106 Attachment.xlsx

Value to Ratepayers of Reducing CBM

In their reply comments, Idaho Power did not acknowledge or otherwise address STOP's suggestion on evaluating CBM as a supply-side resource. Instead, Idaho Power misrepresented STOP's comments and invented a new undefined term "emergency transmission" to belittle STOP's suggestion.[63] The Commission should recognize Idaho Power's tortured discussion of what they call "emergency transmission" as distracting from STOP's valid suggestion to use AURORA to evaluate the benefits of various portfolio strategies that would, over the longer-term planning horizon, reduce the need to designate CBM on the Idaho to Northwest path for the benefit of Idaho Power ratepayers.

In STOP's opening comments, STOP explained that Idaho Power should evaluate the extent to which adding new resources within the Idaho Power BAA could allow Idaho Power to eliminate the need for some or all of the existing 330 MW Capacity Benefit Margin set-aside on Path 14 Idaho-Northwest. Doing so would enable up to 330 MW of new long-term firm capacity on Path 14 for use by Idaho Power ratepayers at no incremental cost to Idaho Power's ratepayers (unlike B2H).

STOP stands by its Opening Comments concerning the potential for CBM reductions to provide a low cost, low risk supply side resource to Idaho Power's ratepayers. As such, STOP incorporates our opening comments on "Value to Ratepayers of Reducing CBM" by reference in these final comments.[64] Idaho Power has failed to satisfy the IRP Guideline 1:

> "*All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response"*[65]

Finally, although appearing to be unrelated to CBM, Idaho Power revealed in a data response[66] that they have been selling 200 MW of their CBM reservation on a conditional firm basis to BPA since 2016. If confirmed by FERC, this would appear to be a material violation of Idaho Power's OATT[67] punishable by a civil fine of up to $1 million per day for every day that Idaho Power has been in violation, plus restitution for any and all market participants that have been harmed. Aside from misleading this Commission about CBM, abuse of the CBM privilege by Idaho Power is an enforcement issue for FERC and not the OPUC. As such, STOP will pursue this issue through FERC's Enforcement Division. Should FERC ultimately find that Idaho Power has violated its OATT and assess a financial penalty(s) against Idaho Power, STOP urges this Commission to be vigilant that Idaho Power not be allowed to shift the responsibility for paying these penalties from Idaho Power stockholders to Idaho Power ratepayers.

STOP's Conclusion

For the many reasons cited in these Final Comments, as well as Idaho Power's failure to even consider possible supply side resource actions to reduce the need for CBM in this IRP, STOP asks the Commission to direct Idaho Power to evaluate CBM reductions as a supply-side resource in Idaho Power's pending 2021 IRP.

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[63] Idaho Power's Company's Reply Comments p11-12
[64] STOP B2H Coalition Opening Comments p19-23
[65] Order No. 07-002
[66] Response to STOP DR#025
[67] Idaho Power Transmission Business Practices Section 23 – Capacity Benefit Margin (CBMID) may be found on Idaho Power OASIS. "Transmission capacity reserved for CBM is posted as non-firm point-to-point ATC on the transmission paths upon which it is held."

Load and Sales Forecast

Important Changes are Needed in Idaho Power's Sales Forecasts

Response to Idaho Power's Reply Comments of May 15, 2020: "Long-Term Load Forecasting is a Complex Process" (Page 62, Line 18)

The discrepancies in Idaho Power's sales projections – described in detail below in STOP's reply to Idaho Power's comments – must be corrected prior to OPUC acknowledgment of its IRP. Idaho Power electric sales have been flat for thirteen years. Across the country, sales are now being driven downward by the economics of the coronavirus pandemic.

In their most recent December projection, the Energy Information Administration's (EIA)[68] stated that 2020 would see an overall 5.9% drop in retail electric sales to the commercial sector, and an 8.8% drop in sales to the industrial sector. That decline is partially offset by a 1.5% rise in residential electric sales, but the overall result is a decrease of 3.9%. The EIA is also cautious about its future projections given the reality of the pandemic[69]. This change in demand coupled with the uncertainty around future sales, makes it imperative that Idaho Power correct its sales model going forward.

The STOP comments to which Idaho Power responded on May 15th, referenced clear evidence from the EIA that the trend towards declining electric sales is a national one. The State of Idaho has seen exactly the same factors at work and Idaho Power needs to acknowledge that reality. The increase in Idaho's residential population has been perfectly matched by a decrease in average residential use. The trend shows up in both the industrial and commercial sectors as well. The result has been flat sales for thirteen years. Yet the 2013, 2015, 2017, and 2019 IRPs all badly failed to account for that trend as we have clearly shown in our initial comments, and through the additional analysis we are herein submitting for Idaho Power, and for the OPUC and its staff to review.

Now, with the national economy in a dire state, there has been a further decline in sales, one more factor this poorly performing model must try to accommodate.

Economic Growth and Flat Electric Sales

It is time for Idaho Power to discard the underlying premise of economic growth as a driver for forecasting electric sales70. The decoupling of those two started decades ago, yet that reality has done nothing to inform this

68 The December forecast states that:

> *EIA forecasts that consumption of electricity in the United States will decrease by 3.9% in 2020. EIA expects retail sales of electricity in the commercial sector to fall this year by 5.9% and by 8.8% in the industrial sector. EIA forecasts residential sector retail sales will rise by 1.5% in 2020. Milder winter temperatures in early 2020 led to less residential consumption for space heating, but this effect was offset by increased summer cooling demand and increased electricity use by more people staying home in response to the pandemic.*

69 The EIA's cautionary statement states that:

> *The December Short-Term Energy Outlook (STEO) remains subject to heightened levels of uncertainty because responses to COVID-19 continue to evolve. Reduced economic activity related to the COVID-19 pandemic has caused changes in energy demand and supply patterns in 2020 and will continue to affect these patterns in the future*

70 The EIA has this to say about the change in the relationship:

> *Growth in economic activity (measured as gross domestic product) has tended historically to be coupled with increases in electricity use as populations grow and generate more goods and services. However, more recently this*

or previous Idaho Power IRPs. Instead, the company has largely predicated its sales projections, and the resources it claims to need, on economic growth that was irrelevant and has now become problematic. Given the current economic environment, all of the 2019 IRP projections that were questionable previously are now dangerously so.

The utility must ground its Integrated Resource Planning in the reality of a rapidly changing and radically changed marketplace, and it must do so quickly for the sake of its customers. None of Idaho Power's estimates of future sales should be accepted at face value by the OPUC until this is done. The underlying assumption for these estimates is badly outdated.

Error Analysis of Idaho Power Sales and Load Forecasting

In its comments, the utility claims that it uses:

> *"...the most informed and reasonable forecasting methodologies..."*

The amount of complexity in that approach has, however, done nothing to improve the utility's projections from IRP to IRP as shown in Figure 1.

As the chart shows on the far right, the 2019 IRP failed to predict the actual 2019 sales (yellow), with an overshoot of 200Mwh. That is a systematic problem in both the 2015 (dark orange) and 2017 (light orange) IRPs as well. Each have approximately that same amount of error in their sales projection – about 200Mwh – for the very year the projections are being made.

The implication is that the model does not "learn" from IRP to IRP. In other words, the model has no memory: it does not incorporate previous information into future projections. That is a serious failing which compromises the utility's modeling paradigm.

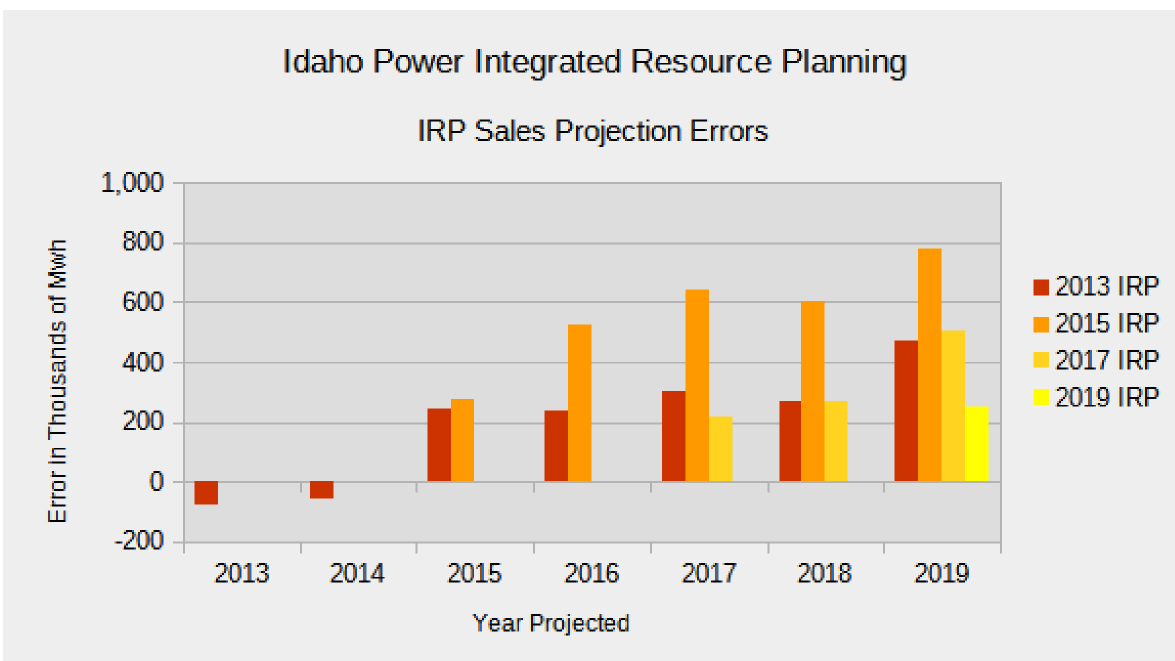

Figure 1: Systematic forecasting errors in Idaho Power 2013, 2015, 2017 and 2019 IRPs

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relationship has been decoupling in many countries. The amount of decoupling in various countries is caused by many factors—including the countries' relative level of development, electrification, economic makeup, and income levels.

There is yet another systematic forecasting failure: the further in time each forecast looks into the future, the larger the error. This divergence from the actual data is visible in all three previous IRPs. This can be seen by focusing on a single colored bar-chart for each projected year—2013 to 2019 in Figure 1—or by examining Figure 2 which averages the error by the future year of the projections. For example, the two year bar in Figure 2 averages forward projections from the IRPs for:

- 2013 (projecting the 2015 sales)
- 2015 (projecting the 2017 sales)
- 2017 (projecting the 2019 sales)

The projections for 5 and 6 years into the future are from the 2013 IRP, which is coincidentally the most accurate. Yet that IRP still significantly overestimates future sales by hundreds of thousands of kWh as it projects a half-dozen years into the future. The 2015, and 2017 IRPs perform significantly worse. This is, once again, an indication of a failure in the modeling process to account for prediction errors in previous IRPs.

The Dynamics of Model Building

There is a clear need to either incorporate error correction into the forward looking projections developed for Idaho Power, or to choose a much simpler modeling paradigm.

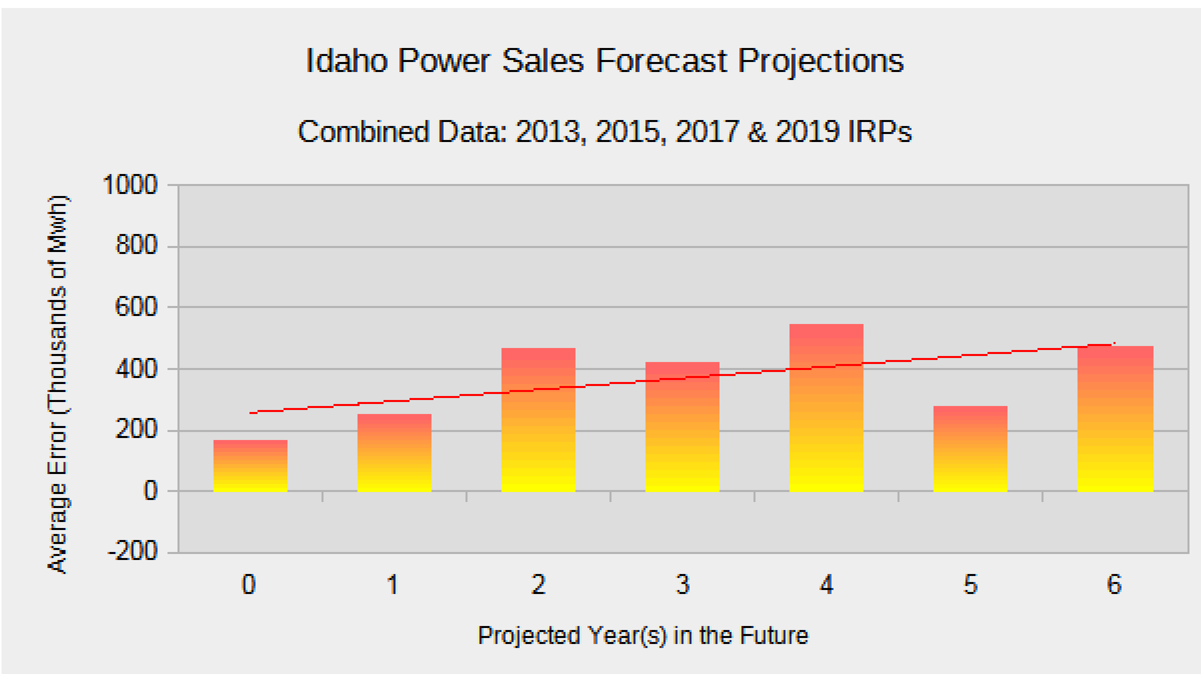

Figure 2: Average error by projected year in the future.

Given this forecasting problem, the Oregon Public Utility Commission must continue to ask whether the utility has incorporated any feedback in their models. Has Kalman filtering, spectral decomposition, or time-series analysis been applied to the long-term projections to keep the errors from propagating? If not, why not?

More to the point, the hyper-complex mixed regression analyses employed for the utility's simulations of sales and load forecasts, dependent as they are on an impossibly large collection of open-ended parameters, is at the root of the problem, one which leads:

> *...the Company to test and measure end-uses, intensities, climatology, residuals, structural change, and serial correlation, among other factors.*

Does Idaho Power realistically expect to track all of this complexity over its entire service area even as an ever-greater number of its customers install more energy efficient appliances and choose energy-saving business processes, while adopting microgrids, and producing distributed generation?[71] To what end, given the error propagation shown in Figure 1 and Figure 2?

These exponentially increasing data requirements will only drive the utility's analytical needs into the computing stratosphere. That is an expensive and unnecessary distraction which isn't working and which will only prove disastrous given the failure of the company to buildout its advanced metering infrastructure and to implement demand management so as to obtain and make use of the data about instantaneous sales demand. That information would be invaluable for real-time forecasting in a well designed model, one that brings feedback into play with projections informed through machine learning.

OPUC staff is correct in asking for the incorporation of time-series analysis at a minimum into these models as they are currently constructed. Such an approach would surely reveal very high serial correlation for the actual time-lagged year-over year sales figures during the period of flat growth. Beyond that, STOP feels that it is a serious mistake for the company to use such arcane and invariably error-prone data mining efforts for what is a straightforward exercise in statistical modeling, one that must include provisions for built-in feedback to mitigate errors.

Trend Analysis of Idaho Power Sales Data

Idaho Power's response to our comments include the following admonition:

> *In contrast, a simple linear trend analysis selects a specific start and end point to measure growth without considering exogenous factors. Such a simplistic extrapolation can be misleading. For instance, STOP B2H points to information showing that weather-adjusted sales growth between 2007 and 2018 was flat.* ***Yet using the same data that STOP B2H compiled, if the measurement period began only a few years later, the average annual growth in sales jumps back up to nearly 1 percent.*** [emphasis added]

This statement begs the question of why any statistical analyst would choose to reduce the sample size[72] of a relevant dataset. To reiterate, there are two distinct and easily identified periods to the Idaho Power sales data, driven by national trends: the high-level exogenous factors surfaced through the work of the Energy Information Administration.

To drive this point home, we have included side-by-side boxplots for each of those periods (Figure 3). Those plots visually convey the significant difference in the power sales trajectory for those two periods over the last forty-eight years extracted from the company's own sales data. The stark difference in the spread of the data (tick marks above and below) and how that spread bounds the center quartiles (rectangle) and the median (dark black line) are revealed when the data is explored in this way.

71 This trend is sure to accelerate as climate change becomes a driver of business processes.

72 We have expanded our analysis to include the 2019 sales data obtained from a FERC filing. That data once again shows a sales decline from the previous year.

The sizable variation in, and the unconstrained rise of, electric sales during the growth period are both completely absent from the flat period. Moreover, the decline in electric demand caused by the on-going pandemic will likely result in more downward pressure on sales and even less variability.

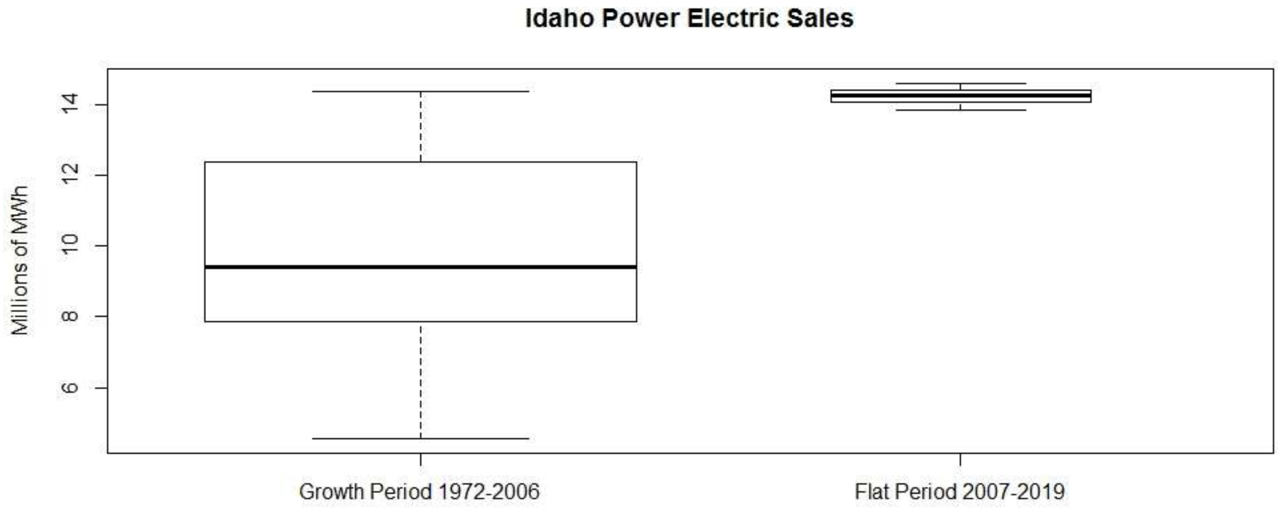

Figure 3: Boxplots for the growth period and the flat period in Idaho Power sales data.

There is nothing in this data record to justify the unrealistic growth assumptions in Idaho Power's sales or their load forecasts[73]. There was very little volatility in sales during the period 2007 to 2019, and there will be even less going forward given the dramatic change in the economic forecast and *"unprecedented disruption"* to the US power sector.

Sales Modeling Paradigms

Idaho Power would be wise to scrap its Byzantine attempts at tracking every energy sink embedded in its sales data, and simply use straightforward statistical projections with feedback built in to provide error correction in real time. It would cost much less, and give better results, greatly mitigating the future cost and risk to its customer base. It would also better prepare the utility for rapid assessment and utilization of the on-going influx of distributed generation.

If Idaho Power insists on using the entire data set to forecast growth, there are robust approaches to the modeling effort. In the engineering world, spline interpolation is used for just such a purpose. The growth period and the flat period can be incorporated into a straightforward curve-fitting exercise, one which acknowledges the distinct nature of the growth and flat segments while insuring the existence of a continuous first order derivative to provide computational flexibility.

Another option is to model the sales and load data using the well-established technique of non-linear regression. STOP performed just such an analysis. The results are shown in Figure 4. The analytical details can be found in the addendum at the end of this document.

[73] A separate analysis is available for load, though it does not include load data for 2019.

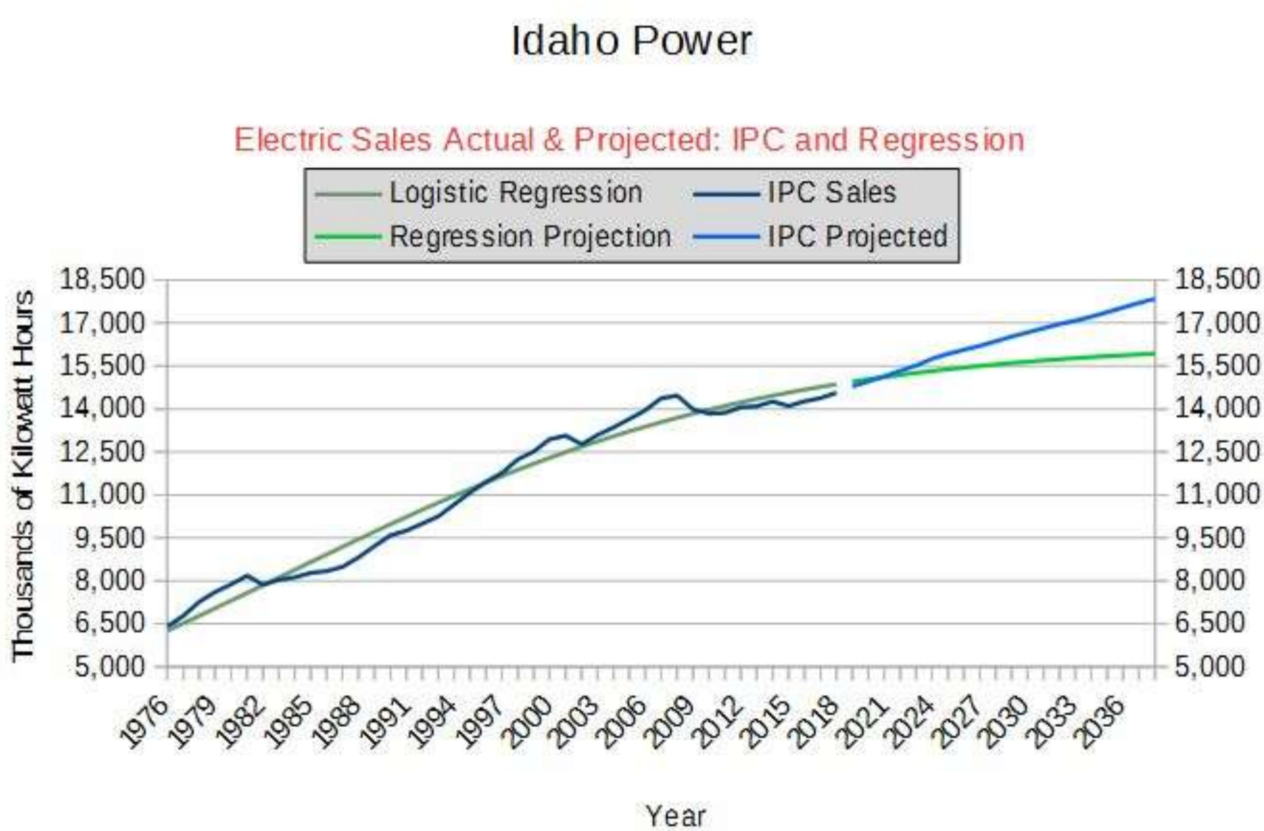

Figure 4: Logistic regression fit to Idaho Power sales data from 1972 to 2019 with projections to 2038.

Utilizing the entire 48 year sales record, and with no assumption of distinct growth/flat periods, the logistic regression results in a minuscule 0.3% year-over-year growth rate. It nonetheless provides a very good fit while forecasting a reduction in sales of over 2Mwh by 2038 when compared with the Idaho Power projection.

Statistical Modeling and Computing Power

The missives in Idaho Power's comments, about modern statistical packages and computational power, are seriously misplaced. Any modeling effort is about accuracy. Given the amount of error generated by the company's forecasts, taken directly from the company's own 2019 and previous IRPs, those packages[74] and their associated computing resources do not appear to be modeling anything useful.

The basic rule of garbage-in, garbage-out is only exacerbated by building complex models and sending them off to burn expensive computing cycles if they don't return realistic answers relevant to the forecasting task at hand. This effort fails that test.

74 STOP itself used the **R** statistical package for its analytical work in this response.

Addendum

Nonlinear Regression Model of Idaho Power Sales Data: 1972 to 2038

The logistic regression in Figure 5:

$$S(t)=\frac{S_\infty}{1+Ae^{(\alpha t)}}$$

Figure 5: Logistic regression

was fit onto Idaho Power electric sales data (1976-2018) and compared to the company's projection going forward to 2038.

The result is shown in Figure 4.

Fitting a line is straightforward. The equations have a closed solution that can be found using nothing more complicated than a hand calculator. By comparison, a non-linear regression can only be solved iteratively, and with properly targeted initial estimates for the parameters. Computational power trivializes the former, while the latter takes more work.

In Figure 5, $S(t)$ is electric sales for year t while S_∞, A, and α are the parameters for the fit. S_∞ is the asymptote towards which the logistic curve progresses as it marches off to infinity. That value was initially set at 14,500 by eyeballing the data—a starting point for the iterative progression to a solution.

A and α were estimated from the existing dataset. That work is explained in full below. Care has to be taken with the parameter estimates, given the complexity of the non-linear solution space. The iterative approach to a given solution can go off on the wrong computational track taking everything to a set of parameters that bear no relationship to the reality of the data.

To obtain realistic values for those parameters, we extracted a formula for a line from the logistic equation—under reasonable assumptions—and then used existing sales data to get the slope and the intercept for that line. The parameters are embedded in the equations that result, and they can be extracted using algebra. That was the approach taken.

Two of the sales data points, (1975, 6413) and (2002, 12767), were used to fit a line and extract an initial set of parameters. Choosing those points was, again, simply done by visual examination of the data. It looks as if a reasonable line can be drawn through those two points, one that approaches most of the points in between, so they were recruited for the parameter estimation.

In order to insure that the computations didn't exceed the capacity of the computer's storage registers, the dataset was re-scaled. The "years" were set to run from 1 to 43, while the values for sales were divided by a thousand. For example, the two points used in the parameter fit were set to 6.413 and 12.767. At the end of the process, the data were reworked by adding back the base year and multiplying the resulting estimates by a thousand.

R, a freely available statistical system, was used to get the regression accomplished iteratively, starting with the parameters derived from the line-fitting exercise. The results are shown in below, with the solutions for S_∞, A, and α near the bottom.

The residual sum of squares—the squared differences between the regression estimates and the actual data summed over all 43 points—is good. The residual errors are, however, not normally distributed. An examination of the residuals for the Q-Q plot (Figure 6) and an application of the Shappiro-Wilk normality test (Figure 7) show that this is not quite the case.

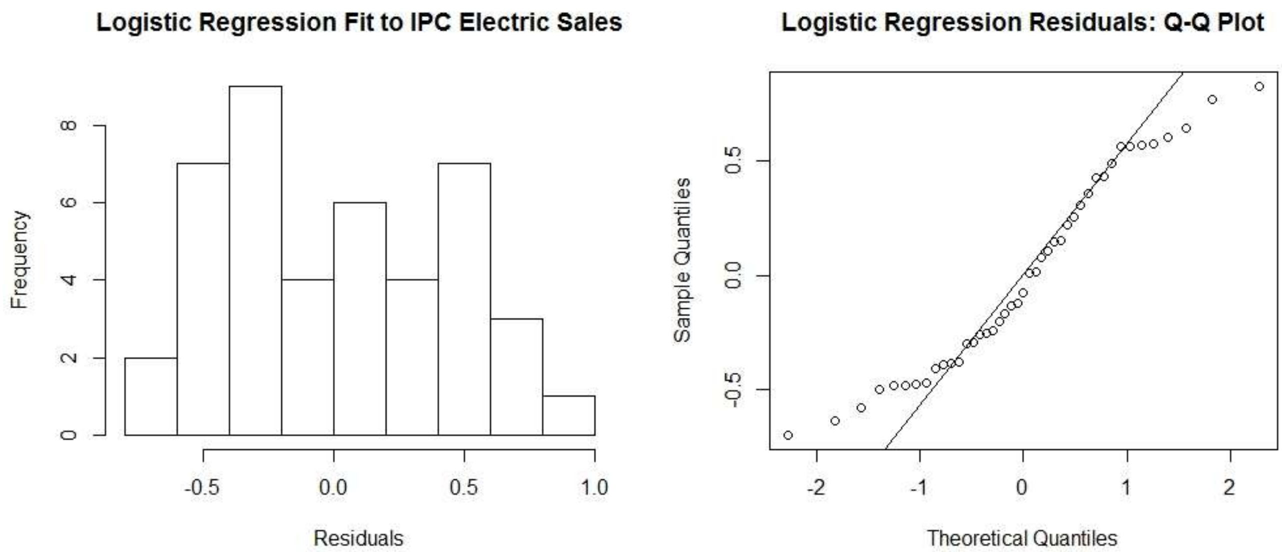

Figure 6: Histogram of residuals and a Q-Q plot: logistic fit to Idaho Power electric sales, 1976 to 2018

Large positive and negative excursions from the logistic curve, give an almost mirror-symmetric look to the Q-Q plot of the residual quantiles in Figure 6 hinting at the variability as the sales data go through both positive and negative excursions from the fitted line. The null hypothesis of 95% confidence for normally distributed errors must therefore be rejected despite the excellent fit to the existing data.

Results of the non-linear regression analysis

```
> attach(IPC.Sales)
> library(nls2)
> nls2(Sales ~ Sinf/(1+A*exp(alpha*Year)),
        start=list(Sinf = 14.5, A = 0.5751, alpha = -0.0173),
        control = nls.control(maxiter=150),
        trace = T)
212.7508 :  14.5000  0.5751 -0.0173
211.5625 :  12.64063423  0.44547792 -0.03011755
112.2848 :  13.74225603  0.68959800 -0.04177167
30.81919 :  15.37662263  1.11603048 -0.05315525
9.608512 :  16.53657061  1.64070594 -0.06474283
7.885915 :  16.37915272  1.71872324 -0.06579271
```

```
7.884602 :  16.36324702  1.72186544 -0.06600584
7.884599 :  16.36554291  1.72209321 -0.06598516
7.884599 :  16.36511646  1.72206826 -0.06598953
7.884599 :  16.36519765  1.72207338 -0.06598871
Nonlinear regression model
  model: Sales ~ Sinf/(1 + A * exp(alpha * Year))
   data: <environment>
    Sinf          A       alpha
16.36520    1.72207    -0.06599
 residual sum-of-squares: 7.885

Number of iterations to convergence: 9
Achieved convergence tolerance: 4.646e-06
```

```
        Shapiro-Wilk normality test

data:  fit$residuals
W = 0.94615, p-value = 0.04319
```

Figure 7: Normality test of residuals from logistic regression on Idaho Power electric sales

Demand Side Management

The Second Amended 2019 IRP presents a glowing narrative of company's clean energy goals and achievements with demand side resources, but with a deeper dive, we are not convinced that IPC has embraced these goals. It also appears that there is an attempt to confuse and frustrate reviewers[75].

Demand Response allows customers:

> *"...to help utilities manage peak electric demand … avoid construction of new power plants, avoid purchases of high-powered electricity, enhance grid reliability, reduce power use from fossil fuels."*[76]

The NWPCC's Seventh Power Plan[77] found demand response the cheapest way to meet capacity needs and more DSM should be used; and in the pacific northwest, "load growth over the next five years is almost entirely met by targeted energy efficiency savings."[78] However, rather than aggressively implementing energy efficiency and demand-response programs as least cost, and dispatching them first (especially for peak-demand) to reduce costs and to avoid building new projects, Idaho Power confesses that they use their demand-response only *after* other resources are deployed. Staff commented on this[79] during opening comments in the Amended 2019 IRP and the company replied that it will now focus these resources to shave peak loads—an action which the company makes sound like is new and innovative.

Considering that very little has changed in the Second Amended 2019 IRP, STOP stands by our opening comments from the Amended 2019 IRP. The company's DSM efforts (energy efficiency-EE and demand response-DR) are really the "same 'ole." And even with Action Item #9 in the 2017 IRP[80], we still do not see IPC behavior reflecting "continue the pursuit of cost-effective energy efficiency" or "greater studies of residential savings opportunities, …" Rather, IPC has squandered years in meeting other utilities and entities (apparently), only to conclude that we may see a new study in the 2021 IRP! Case in point, in the company's reply comments, they tout that "(T)he company *initiated a discussion* regarding the methodology for the potential study to be utilized in the 2021 IRP at an April 28, 2020 EEAG webinar…" [emphasis added]

In other words, the "initiated discussions" began *two years after* Order 18-176. The company's clean energy goals amount to obvious green-washing unless something radically turns around and very quickly. We fear another "new study" in which *might be* ready by the 2021 IRP and then another IRP later before we see any meaningful EE or DR plan before the commission, and yet another IRP before we might see genuine implementation of new EE or DR programs.

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[75] For example: fragmented information because of 3 versions of the IRP; data included in the 2017 but not in 2019 (e.g.: the table with DR costs-levelized capacity (fixed) costs); information buried in footnotes (ie: the newer Annual Report introduced via footnote).

[76] https://www.oregon.gov/puc/utilities/Pages/Energy-Demand-Response.aspx

[77] https://www.nwcouncil.org/reports/seventh-power-plan and Final Staff Report for PAC's 2019 IRP, p34.

[78] Pacific Northwest Power Supply Adequacy Assessment for 2024, NWPCC, P. 5.

[79] Staff commends Idaho Power's continually successful demand response programs. However, Idaho Power's past comments suggest a paradigm in which the Company thinks about demand response as a resource *to be preserved*. See, for example, the Company's Final Comments for the 2017 IRP:

> Critically, the reliability and viability of DR programs are highly dependent on attracting and retaining participants. If these programs were called upon more in times of no need, such overuse would ultimately discourage long-term participation and deplete the available megawatt capacity when these programs are truly needed.40

Given increasing levels of intermittent resources, the capacity cost differences in storage and demand response, and the eventual return of capacity deficits, an evolution of the Company's "to be preserved*"* paradigm may be in order. (Staff Opening comments, Second Amended 2019 IRP, p. 15)

[80] Order No. 18-176, p. 16.

They are hiding behind new and complex methods for analysis (e.g.: UCT and TRC studies) but if these studies are anything like their inexperience with "complex" capacity expansion modeling which delayed this 2019 IRP multiple times, how long do ratepayers of the region have to wait? Customers deserve more and innovative EE and DR options to be rolled-out quickly.

There also appears to be some hiding behind their 2013 settlement agreement whereby they are not required to implement more DR until there is a company identified capacity deficit. We ask the commission to please investigate and determine if this is still appropriate today given the necessary transformation that utilities must undertake to address climate change and frankly, to survive.

Demand Response

Again, we stand by our opening comments. Idaho Power's Energy Savings have remained relatively static since 2015, and have actually declined since 2010—2012. In the past three IRPs (since 2015) the data show declining DR savings. There has been a net loss since 2012 of 95 MW of DR savings. ***See Tables 13, 14, and 15 (below) from our opening comments in April 2020.***

By the end of this planning period in 2036, according to this IRP and preferred portfolio, IPC will have added 45MW more of DR savings, achieving 435 MW of DR savings, which comes close to their peak saving year at 454 MW in 2012—eight years ago!

Table 13: Energy Efficiency and Demand Savings 2010-2012

Peak Years of Total Energy Savings kWh		Demand Savings MWW	
2010	193,592,637	2011	420
2011	183,476,312	2012	454

Table 14: Demand Response 2012=21019

	IRP							
	2012		2015		2017		2019	
Program	Demand Response	MWH Saved	Demand Response	MWH Saved	Demand Response	MWH Saved	Demand Response	MWH Saved
A/C Cool*	Homes: 36,454	Peak: 44.9	Homes: 29,000	Peak: 36	Homes: 27,949	Peak: 33	Homes: 25,845	Peak: 29
Oregon			377	0.5	368	0.4	337	0.4
Flex Peak			Sites: 72	26	Sites: 128	29	Sites: 131	33
Oregon			Sites: 6	14	Sites: 9	13	Sites: 9	2
Irrigation (peak awards)				305		295		288
Oregon				8		7		9
Total Saved w/Oregon		454		367		378		359

Table 15: Energy Efficiency 2015-2019

	2015	2017	2019
Energy Efficiency	kWh Saved		
Residential Total	23,818,91	41,208,496	42,322,925
Oregon	712,918	1,060,326	1,328,353
Irrigation Total	13,856,301	12,933,743	18,068,066
Oregon	171,110	2,813,387	3,022,103
Commercial Total	96,653,211	85,960,800	92,736,946
Oregon	5,420,699	7,304.292	6,532,197
Total Saved (w/Oregon)	162,533,155	163,487,859	175,845,637

*Totals also include other programs not listed above

As a result of comments by most intervenors (in the 2017 IRP and in opening comments in this docket's first Amended 2019 IRP), Idaho Power has added 15 MW of DR in this newer, Second Amended IRP. However the timing is very disconcerting: with 5 MW starting "earlier" in 2030 (as opposed to 2031) and 5 MW in the last two years of the planning horizon in 2037 and 2038. Essentially IPC is asking the commission to acknowledge this Second Amended IRP with nothing new in the way of DR for at least ten years! What are they waiting for?

Considering the Governor of Oregon's Executive Order 20-04 on climate, STOP believes that IPC is not taking our state's climate agenda serious; or worse, they are figuring out ways to "game the system" and avoid Oregon's environmental and clean energy aspirations.

Energy Efficiency

Under-forecasting energy efficiency targets has become so chronic that it is no longer possible to have any confidence in their resource forecasting needs. This has been raised in past IRPs and at IRPAC meetings over the years contributing to STOP contention that this Second Amended IRP is erroneous and suspect.

Customers obviously *can and do exceed* the targets consistently. This table (two versions and dates, below[81]) speak for themselves, as the graphs seem to be comparing the same values but look very different. The company enjoys touting how well they are implementing EE programs; but when you start with low targets, anything looks good. How can we really know what is possible and moreover, how can we trust the resource stack forecast (which includes EE)?

[81] IRPAC meeting slides from 2017 IRP meetings; and LC 74, Idaho Power 2019 IRP, p. 59, Figure 5.2.

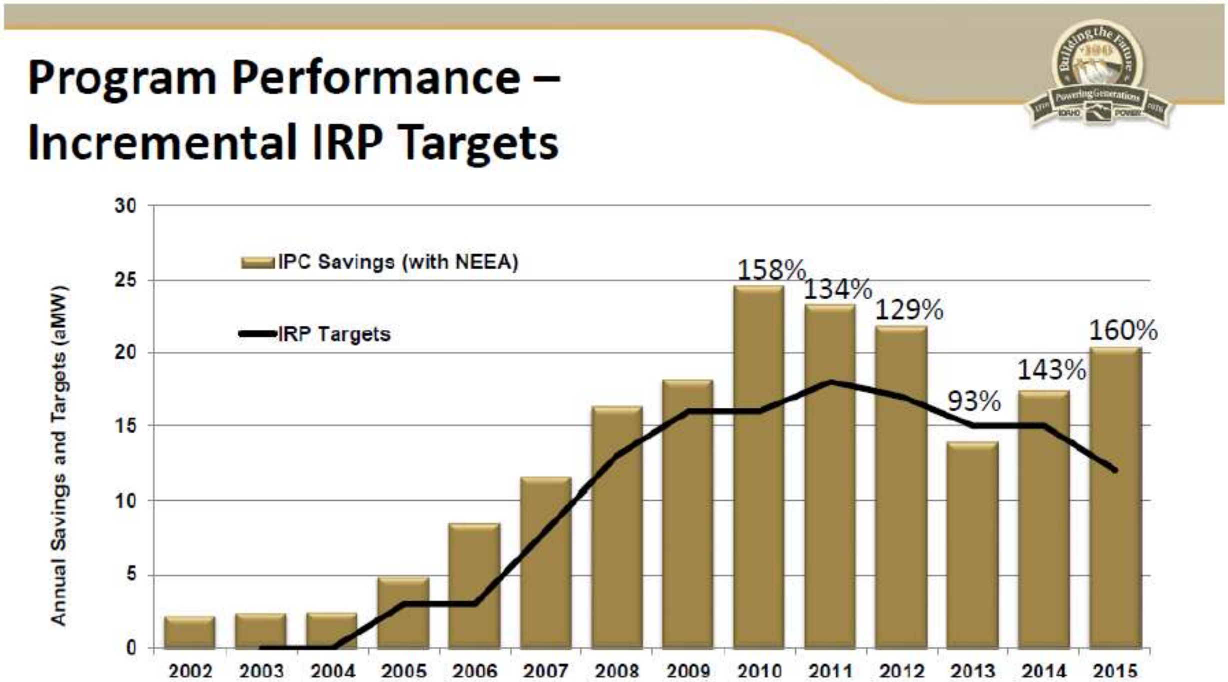
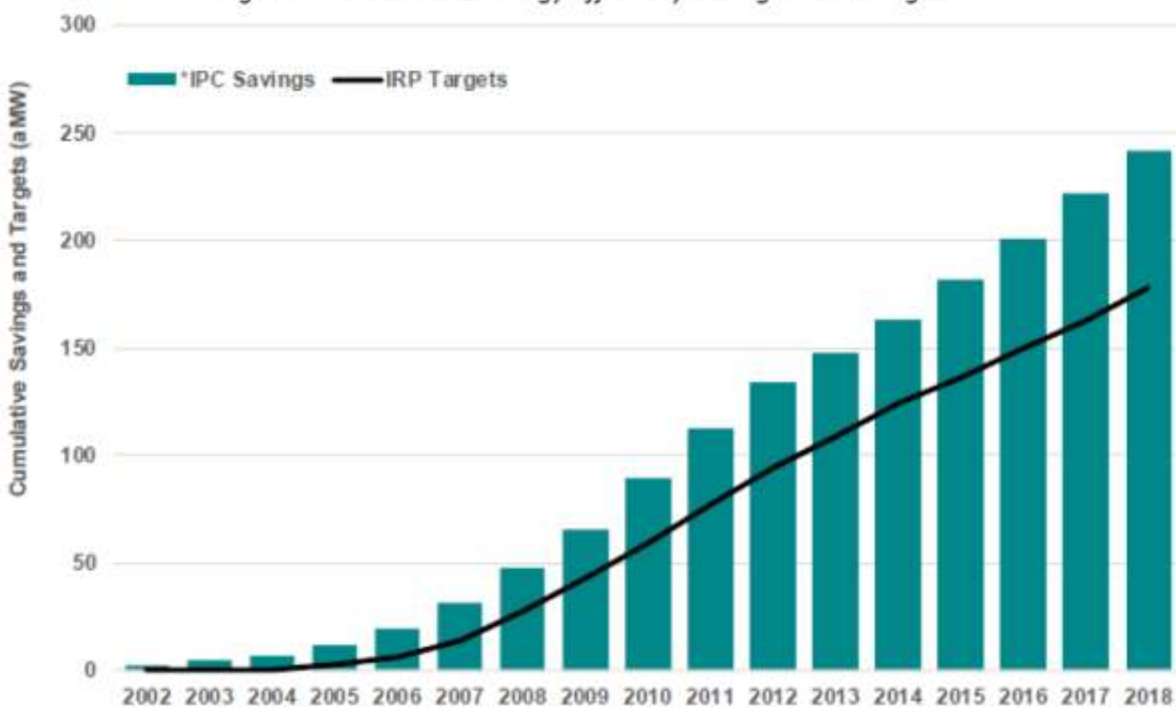


Figure 3 – Cumulative Energy Efficiency Savings vs IRP Targets[23]



Advance Metering Infrastructure (AMI)

STOP appreciates CUB's data request #74 regarding AMI deployment and the timing of the roll out of the Time Based Rate Designs.[82] Regardless of the slow roll out of AMI infrastructure which STOP commented on in the

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[82] What are IPC's plan to utilize the AMI? Please tell us what features are activated and what new features will be activated to assist ratepayers. When will these time based rate designs be deployed and how many MW of demand response do you anticipate by category: 1) critical peak pricing (CPP), 2) variable peak pricing (VPP), 3) time-of-use (TOU) pricing, and 4) critical peak rebates (CPR)? Pdf p47

2017 IRP, STOP commends the company for finally reaching 92% deployment. It is also positive that the basic services, such as bill data and outage scoping and restoration are being implemented. These are important milestones. However, we are dismayed that the company is not eagerly utilizing this innovative infrastructure's potential, which may account for the slow deployment. Time based rate design is only the beginning! But it appears that the company will move slowly and not fully implement until they *have to* in 2026 (if they have deficits, according to the company's response to CUB's data request). This is more discouraging news for customers ready to partner with the utility or manage their own energy efficiencies and energy usage better.

Conclusion: DSM

STOP also compliments commission staff and other intervenors for their diligent review of demand-side resources in their opening comments. The questions asked by staff were on point and very reasonable. It is unfortunately that IPC responded with pages of empty answers. These pages talk about new valuations methods for calculating cost-effectiveness of EE options, the planned new methodologies and a third-party consultant for developing the new economically achievable EE potential study, but in the end we learn that we won't get a full assessment and plan until the 2021 IRP[83], and no new DR programs for another ten (10) years.

Too much demand-side management analysis is being pushed into the future (at least until the 2021 IRP). Since it is already 2021, it might be time to consider this IRP meaningless. We can anticipate that in the 2021 IRP, the company *may have* an energy saving demand management plan, however, there is reasonable doubt that we will see anything being implemented until 2023 or more likely 2026. That would be a sad and missed opportunity for innovation and clean energy. It will be a missed opportunity for Idaho Power to strategically position themselves in this new emerging energy democracy[84] as well as reach their clean energy commitment by 2045.

STOP believes that the company is not complying with OPUC Guideline 7 and 8 and they should be asked to do more. Their on-going decrease in demand response from 2012 to present—while not adding any additional DR for another ten years into the future to 2030 is irresponsible. We believe that their half-hearted efforts to fulfill Action Item 9 from the 2017 IRP is disappointing especially in these times of changing energy landscape and climate change efforts across the world. We believe that the company's roll-out of innovative programs utilizing their deployed AMI is a missed opportunity for energy efficiency, reducing loads, and shaving off peak demand. We believe their plan is NOT in the best interest of Oregon ratepayers and our planet. Directing the company to pursue more robust DSM would better align with the Governor's carbon policies as well.

STOP requests that OPUC address these issues with the company.

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[83] IPC reply comments pp 52-54.
[84] Institute for Local Self-Reliance: "Let's Talk About Solar, Equity, and Monopoly Power in 2021"

Conclusion

STOP reiterates one last point in the Substantive Requirements of *OPUC Guideline 1d*, that the:

> *"the plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies."*

In the 2019 Second Amended IRP, Idaho Power maintains a traditional utility model for building new and having a high rate of return on investment: over 10% on a 21% share of a $1.2 billion plus transmission line—all at the expense of ratepayers. Meanwhile, emerging utility business models embrace new technologies including renewable resources, battery storage with ancillary services, distributed grids, virtual grids, and greater energy efficiencies. Idaho Power and its corporate culture are not in step with today's industry vision, or with our state's long history of energy conservation and innovation, such as the Energy Trust of Oregon.

These trends—distributed generation, storage, and local distribution—have many advantages, including "reliability," which is one of Idaho Power's values on their Vision, Values and Mission page. Increasing and expanding reliance on a centralized transmission system is not in the best long-term interest of the public.[53] Sparking or an act of terrorism could result in a catastrophic wildfire caused directly or indirectly by a large powerline—one sited directly next to an existing 230MW corridor such as B2H. Microgrids, while providing for distributed generation, could still function if they were equipped to disengage from the larger grid and they were provisioned with storage. This could be especially important for hospitals, local governmental units, emergency responders, our military bases and preparedness in general. There is too much at stake for Eastern Oregon. The $1.2 billion proposed B2H investment, STOP contends, should be directed elsewhere, or eliminated altogether. BPA still has not committed any resources other than the initial environmental and permitting studies for the B2H. BPA appears more in step with the long-term public interests of the citizens of the northwest and Oregon, as they found other solutions to their I-5 Corridor Reinforcement Project and are carefully evaluating their B2H business case. They have put out signals that they are not on board with the 24% share as they were at the start of this IRP and Idaho Power is trying to keep them on board and has moved resources to absorb a greater share of the B2H project which changes the least cost, least risk analysis.

If the BPA goes forward with the B2H when the business case is completed, there will be a series of public meetings which will take more time and still could see the BPA withdrawing from the project. There is also a federal NEPA lawsuit pending on the federal ROW, which could further delay permitting and construction. Putting the B2H on hold, saving the ratepayer additional permitting costs would be a prudent move.

Pacific Corps' has not included the B2H in their 2019 action plan; and has also not committed any resources other than allowing their ratepayers to fund their portion of the initial environmental and permitting studies for the B2H. They are also considering another route across southern Oregon to the California intertie.

PacifiCorp and Idaho Power need to BOTH have commission acknowledgment before the hugely expensive and environmentally risky, B2H project moves forward. Particularly because it appears the ODOE/EFSC will give Idaho Power a site certificate without any partners which destroy the least cost, least risk modeling.

STOP has identified many errors and misstatements by Idaho Power in this Second Amended 2019 IRP, but most important, Idaho Power has under-represented the level of existing transmission capacities in the Aurora model, and is holding more CMB in reserve than needed thus creating a large modeling bias in favor of the B2H transmission line. If this nefarious bias were corrected, B2H would likely not be the "least cost/lowest risk" portfolio. The Commission should not acknowledge the entire the 2019 IRP as it stands and at minimum should pause continued permitting and construction of the B2H until partners are signed, a solid budget developed, so a least cost, least risk portfolio can be developed with confidence.