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Stop B2H Coalition (STOP), a citizens' interest group, hereby submits its Opening Comments related to Idaho Power's 2017 Integrated Resource Plan. STOP presents its case that Idaho Power has the resources available to meet future needs without building the Boardman to Hemingway transmission line (B2H) and without building new thermal generating facilities. The early decommissioning of coal plants planned in the 2017 IRP is supported by STOP. The B2H which is at the core of the company's 2017 IRP preferred portfolio design is not supported by STOP.

OPUC Guideline 1,<sup>1</sup> the Prudency test<sup>2</sup> and STOP's concern for the long-term burden on ratepayers, set the overall tone for most arguments against the B2H. Specific concerns and challenges will be cited, as well as, citizen alternatives offered within the following Sections and Appendices.

Idaho Power is over-estimating its demand load forecast, under-estimating its energy efficiency and demand-side management capabilities, and has transmission resources currently available to meet its needs of the future. STOP also challenges the company's cost-estimates for the B2H transmission line, creating a dubious conclusion of the least-cost, lowest risk portfolio scenario, aka: "best cost/risk portfolio."

## **Section 1. Idaho Power has adequate firm Transmission**

*OPUC Guideline 5: Idaho Power has firm transmission rights and capacity which the company is unwilling to use or fully disclose. This section demonstrates and documents that the company has 350 MW of firm transmission which was not disclosed in its IRP. This more than meets the energy needs that Idaho Power claims it needs via B2H.*

Idaho Power's proposed action plan is centered on the construction of the Boardman to Hemingway transmission line (B2H) as the key "resource" action in the proposed Action Plan. Idaho Power is resolute in their request that the Oregon Commission acknowledge Idaho Power's request to construct B2H, despite a clear failure on the part of Idaho Power to conform to the OPUC Integrated Resource Planning Guidelines, and the inconvenient fact that electric transmission by itself is not a resource. Specifically, the IRP is devoid of any analysis of the

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<sup>1</sup>Guideline 1: Substantive Requirements. a. All resources must be evaluated on a consistent and comparable basis.... b. Risk and uncertainty must be considered.... c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers... and d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

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<sup>2</sup>"Prudence is determined by the reasonableness of the actions "based on information that was available (or could reasonably have been available) at the time." (In re PGE, UE 102, Order No. 99-033 at 36-37.) See also In re Northwest Natural Gas, UG 132, Order No. 99-697 at 52: ("In this review, therefore, we must determine whether the NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.")

underlying power resource actually represented by B2H in the IRP, which are short-term forward capacity purchases in the PNW for import into Idaho.

Idaho Power describes the B2H transmission line as a "supply-side resource," a concept which is absurd on its face. A transmission line does not supply any capacity or energy to meet loads. In some circumstances, a new transmission investment can be considered to create an "option" to acquire a resource in the future and this is exactly how the IRP Guidelines instruct the utility to consider possible transmission expansion not tied to reliability or the construction and integration of specific resources. Specifically, Guideline 5<sup>3</sup> states that "utilities should consider" electric transmission facilities as resource options, taking into account their value for making additional purchases and sales. Idaho Power makes no attempt to value B2H as an option using standard option pricing approaches. (This would entail determining the option value of B2H to Idaho Power ratepayers first, and then comparing that value to the cost of B2H.)

Instead of analyzing the option value of B2H, Idaho Power identifies B2H as a resource. To justify their selection of B2H as a resource, Idaho Power has apparently created a single 20 year point estimate forecast of power prices in the Pacific Northwest that is intended to support the wisdom of Idaho Power spending over \$250 million for a minority ownership share of B2H.<sup>4</sup> As shown below, this point estimate approach suffers from serious analytic shortcomings and flawed assumptions.

The OPUC must refuse to acknowledge the B2H action item in the IRP, as there is absolutely no substantive analysis in the record to support IPC's B2H action item. Idaho Power has failed to meet even the minimum requirements of the IRP as set forth in the Commission approved IRP Guideline 1: Substantive Requirements. Specifically, Idaho Power has failed to present and support a credible forecast of PNW purchase power delivered costs/prices over the planning horizon. Furthermore, IPC has treated the cost of purchase power imports from the PNW as a single point estimate for the entire IRP planning period, without consideration of any risk or uncertainty around that estimate, as required by the IRP Guidelines.

Even more duplicitous is IPC's failure to highlight to the Commission that in 2015, IPC actually acquired over 350 MW of additional long-term firm import capacity which is approximately the same amount of transmission originally sought via the proposed B2H transmission line<sup>5</sup>.

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<sup>3</sup>OPUC IRP Guideline 5: Transmission "Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies and improving reliability."

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<sup>4</sup>See IRP Appendix C, Page 76

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Specifically, IPC acquired more than 350 MW of incremental firm PNW import capacity through a complex "asset swap" with PacifiCorp<sup>6</sup>. The acquisition of this import capacity, via ownership of transmission lines formerly owned by PacifiCorp, came at a large cost, resulting directly in an over 43% transmission rate increase to Idaho Power ratepayers.<sup>7</sup> IPC has inexplicably failed to highlight this expensive transmission acquisition in their IRP, and has further failed to address why IPC still needs B2H after their 2015 acquisition of incremental transmission. As explained below, by Idaho Power's own admission, their IRP projects that in 2026, when B2H would come into service, Idaho Power will already be relying on imports to meet 17% of peak loads. Idaho Power has not addressed the price and supply risks of relying on spot markets to serve 17% of peak load, much less their desire to further increase their reliance on spot market purchases to meet over 25% of their peak loads with the addition of B2H.

### **Idaho Power Has Already Acquired 350 MW of Incremental PNW Import Capacity Without Building B2H**

Idaho Power appears to be obscuring the fact that they now hold considerably more long-term firm import capability from the PNW than they held when they last produced their 2015 IRP. Idaho Power correctly describes that the existing transmission system is rated to move up to 1200 MW of power from the PNW to Idaho (WECC Path 14) in a West to East direction and further correctly states that this capacity was and is fully subscribed.<sup>8</sup> What Idaho Power fails to identify in the IRP is that in 2015, there was a fundamental change in the allocation of those 1200 MW of transmission rights, effectively reallocating over 350 MW of the existing 1200 MW of capacity from PacifiCorp to Idaho Power.<sup>9</sup> The capacity reallocation was part of a larger "Asset Swap" between Idaho Power and PacifiCorp.

This asset swap transaction came at an enormous cost to Idaho Power Ratepayers and other users of the Idaho Power transmission system, requiring an approximate 47 percent increase in transmission rates over 2 years.<sup>10</sup> The following table from the WECC Path Rating Catalogue shows the allocation of Path 14 capacity before the Asset Swap transaction. It shows that the 1200 MW West to East transfer capability was allocated between BPA, PacifiCorp and Avista.

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<sup>6</sup> The 2011, 2013, and 2015 IRP's all said that IPC sought 350 MW of incremental summer peak import capability.

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<sup>7</sup> This footnote will reference the FERC docket #s for the 2015 asset swap and the specific table showing the incremental capacity acquired by IPC from PAC

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<sup>8</sup> IPC 2015 PTP Transmission Rate was \$22.48 and the rate today is \$34.90, a 55% increase over two years. See <http://www.oatiaoasis.com/ipco/index.html>

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<sup>9</sup> 2017 IRP page 58

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<sup>10</sup> See FERC Dockets EC15-54 and ER15-680.

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<sup>11</sup> See FERC Docket ER15-2292

<b>Allocation:</b>	<p>The transfer capability of the path is allocated among the interconnections as follows:</p> <ul style="list-style-type: none"> <li>• 2400 MW East-to-West:             <ul style="list-style-type: none"> <li>1587 MW IPC – PAC interconnection</li> <li>413 MW IPC - BPA interconnection</li> <li>400 MW IPC - AVA interconnection</li> </ul> </li> <li>• 1200 MW West-to-East:             <ul style="list-style-type: none"> <li>350 MW BPA - IPC interconnection</li> <li>400-510 MW PAC - IPC interconnection</li> <li>340-450 MW AVA - IPC interconnection</li> </ul> </li> </ul> <p>For the 1200-MW west-to-east, the sum of the PAC and AVA allocation cannot be greater 850 MW (Seasonal Allocations: Spring – AVA 400 MW and PAC 450 MW, Summer – AVA 340 MW and PAC 510 MW, and Winter – AVA 450 MW and PAC 400 MW).</p>
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Under terms of the asset swap and capacity reallocation, PacifiCorp received 1,090 MW of East to West capacity across Idaho and in turn, Idaho Power received rights to PacifiCorp's west to east capacity from the PNW to Idaho. The following table identifies the allocation of capacity between parties after the asset swap transaction closed in December of 2015. It shows that after the asset swap and capacity reassignment, IPC now holds approximately 82 percent of PacifiCorp's former west-to-east capacity allocation, or over 400 MW.<sup>11</sup> STOP is unable to find any evidence in the IRP that Idaho Power has disclosed, or otherwise considered this new capacity in their IRP.

	Directional Capacity Allocation BEFORE Asset Swap (MW)						Directional Capacity Allocation AFTER Asset Swap (MW)					
	West to East			East to West			West to East			East to West		
	IPC	PAC	TOTAL	IPC	PAC	TOTAL	IPC	PAC	TOTAL	IPC	PAC	TOTAL
<b>Borah-West Transmission Total</b>	1600	0	1600	2557	0	2557	1600	0	1600	1467	1090	2557
<b>Idaho-Northwest Transmission (WECC Path 14)</b>												
Hemingway-Summer Lake 500kV	0	550	550	0	1500	1500	450	100	550	0	1500	1500
Walla-Walla-Hurricane	0	398	398	0	398	398	325	73	398	0	398	398

Source: Joint Application for Authorization for Disposition of Jurisdictional Facilities, FERC Docket EC15-54, Exhibit C page 146

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□ PacifiCorp and Idaho Power are allowed to schedule up to 550 MW over the Hemingway-Summer Lake line and 398 MW over the Walla-Walla-Hurricane line respectively, but the simultaneous schedule across the two lines cannot exceed PacifiCorp's historical allocation of 510 MW as reflected in the WECC Path Rating Catalogue

It is possible that Idaho Power has in fact acknowledged this new capacity starting in 2026 when a mysterious jump in import capacity is identified that is unrelated to B2H. The following table compares the stated amount of capacity available for imports from the PNW in the 2015 IRP to the same line item in the 2017 IRP.

Calculation of Idaho Power's Proposed Reliance on Market Purchases (imports) to Meet Peak Loads														
	July-17	July-18	July-19	July-20	July-21	July-22	July-23	July-24	July-25	July-26	July-27	July-28	July-29	July-30
Firm Import Capability 2015 IRP	239	234	230	227	224	273	270	266	261	257	254	249	245	242
Firm Import Capability 2017 IRP	313	313	302	433	492	489	488	487	486	616	615	614	613	612
Increase over 2015 IRP	74	79	72	206	268	216	218	221	225	359	361	365	368	370
2017 Forecast July Peak Load (95% w/DSM and EE)	3195	3195	3310	3366	3417	3472	3528	3589	3640	3695	3753	3812	3870	3927
B2H in Service 2026	0	0	0	0	0	0	0	0	0	500	500	500	500	500
2017 IRP Monthly Surplus/Deficit	489	429	362	311	255	195	138	76	23	466	406	341	103	42
Percent of peak capacity needs met with market purchases	-5.5%	-3.6%	-1.8%	3.6%	6.9%	8.5%	9.9%	11.5%	12.7%	17.6%	18.9%	20.3%	26.1%	27.2%

Source: 2015 IRP at page 134 and 2017 IRP at page 126

As can be seen in the table, by Idaho Power's own admission, in 2026 they will be relying on over 600 MW of firm import capability to meet peak loads without B2H. This 600 MW of imports represents almost 18% of forecasted peak load in 2026 after DSM and EE. This is an astounding level of reliance on imports and lacks credibility. But Idaho Power does not want to stop there. Their preferred Portfolio 7 with B2H projects that market purchases will comprise over 27% Idaho Power's projected peak loads before the first generating resource (reciprocating engines) are added to the system in 2031.

### Idaho Power's Assumed Levelized Cost of PNW Market Purchases Is Not Credible

One of the fundamental requirements for any IRP is the identification of resource options and an analysis of the cost of each resource considered; both stand-alone costs and the cost of each resource when integrated into a utility's resource Portfolio. In fact, Oregon IRP Guideline 1a requires that all resources be evaluated on a consistent and comparable basis, yet the 2017 IRP contains no analysis of the cost, availability, price and supply risk of relying on PNW spot market purchases to meet firm peak load requirements. Furthermore, Idaho Power seems to believe that incremental imports of PNW spot market power is the preferred new resource in the

IRP, whether already existing import capability represents only 1 percent of peak supply, or represents more than 15 percent of peak supply as is the case for Idaho Power.

Remarkably, Idaho Power presents no analysis or material discussion of the "PNW imports" resource contained in the 2017 IRP. There is no discussion or forecast of forward power price curves in the PNW that is internally consistent with Idaho Power's forecast of natural gas prices (i.e., prevailing fuel prices). Idaho Power presents no analysis of the correlation between summer spot market prices and prevailing natural gas prices in the PNW. There is no analysis of the expected effect on spot market power prices when 1,300 MW of coal capacity is retired in the PNW in 2020.<sup>12</sup> Imports from the PNW don't even appear in the IRP Table of Supply Side Resources<sup>13</sup>. In short, Idaho Power apparently expects the Commission to take Idaho Power's recommendation to build B2H on faith.<sup>14</sup> The only relevant information on the cost of PNW imports appears in a single page of Appendix C that summarizes the Levelized Cost of Supply Side Resources.<sup>15</sup> A cursory examination of the levelized cost of PNW imports contained in Appendix C compared to actual market prices clearly indicates that Idaho Power has significantly understated the expected cost of a B2H/PNW Import resource. While STOP does not have the resources to independently perform the analysis the Idaho Power has failed to do, the limited examination of Idaho Power's conclusions explained below highlights the flawed assumptions underpinning Idaho Power's 2017 IRP.

## **PNW Imports Represent a Natural Gas Resource Strategy and Must be Evaluated As Such**

The choice of a resource Portfolio that relies primarily on expanded market purchases of power to meet summer peak loads represents a natural gas based resource strategy. This is an empirical fact. During periods of high demand in the PNW, the marginal cost of dispatching gas-fired generation typically sets the market price of power. As stated in the Council's 7<sup>th</sup> Power Plan:

"Since natural gas-fired plants are often the marginal generating unit, gas prices play an important role in determining the wholesale electricity prices. Variations in the future price of gas could have a significant impact on electricity prices for the region."<sup>16</sup>

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□ Both the 700 MW Centralia unit 1 and 600 MW Boardman coal plants are required to close by the end of 2020.

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□ 2017 IRP Appendix C, page 73

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□ See IRP Appendix C, page 73

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□ See Levelized Cost of Energy, IRP Appendix C, page 76

16

□ Power Council 7<sup>th</sup> Power Plan, <https://nwcouncil.org/media/6829307/wholesaleelectricity.pdf> page 11.



Idaho Power's IRP fails to account for the relationship between daily natural gas prices and the daily market price of power in the PNW. Instead, Idaho Power appears to have selected a single point estimate of monthly power prices to populate the Aurora model. This point estimate of monthly power prices used by Idaho Power to calculate the levelized cost of purchase power is already proving to be too low.

First, a simple comparison of actual on-peak PNW market prices in July and August of 2017 to Idaho Power's unsupported forecast of market prices shows that Idaho Power has materially underforecast the cost of purchase power in their Portfolio modeling. The following table shows the actual volume weighted average monthly price at MIDC this past summer alongside the actual monthly PNW gas price, and the implied market heat rate (i.e., the actual relationship between gas prices and power prices). The table also identifies the PNW power price that Idaho Power selected when calculating their levelized cost of PNW market purchases. Actual market prices in July 2017 were 24% higher than assumed by Idaho Power and actual market prices in August of 2017 were 98% higher than assumed by Idaho Power.

	Jul-16	Aug-16	Jul-17	Aug-17
Forecast MIDC Power Price Used by Idaho Power in Levelized Cost Calculation (\$/MWh)	NA	NA	\$ 24.27	\$ 28.18
Actual Weighted Ave. MIDC On-Peak Power Price (\$/MWh)	\$ 28.83	\$ 35.62	\$ 30.00	\$ 55.76
Actual as Percent of Forecast	NA	NA	124%	198%
Actual Weighted Ave. Malin Gas Price	\$ 2.64	\$ 2.66	\$ 2.69	\$ 2.69
Implied Heat Rate (Btu/kWh)	10,923	13,392	11,143	20,694
Source: US Energy Information Administration: <a href="https://www.eia.gov/electricity/wholesale/#history">https://www.eia.gov/electricity/wholesale/#history</a> and Attachment 5 to Response to Staff Data Request 56				

More importantly, Idaho Power's whole treatment of the B2H resource option suffers from a failure to reflect the inherent relationship between gas prices and market power prices, and the risk and volatility represented by a significant increase in reliance on the market to meet firm load commitments. For example, the implied market heat rate of July market power in the PNW was 10,900 in 2016 and 11,100 in 2017, or an average of 11,000 Btu/kWh. Based upon this

relationship, a \$1.00 increase in gas price would result in an \$11.00 per MWh increase in the market price of power.

The correct way to incorporate B2H transmission and market purchases into resource planning would be to treat B2H as an "option" to purchase market power based upon an implied market heat rate (monthly differentiated) and a forecast of gas prices. In this way, sensitivity analysis and risk assessments that test the robustness of resource portfolios under fuel price uncertainty would capture this relationship between market price risk and gas price risk. Idaho Power's IRP fails in this regard.

This fundamental flaw in their IRP Portfolio analysis leads Idaho Power to erroneous and unsupportable conclusions in support of building B2H to create an option to buy more power in the PNW. Specifically, Idaho Power appears to penalize non-B2H portfolios in the high gas price sensitivities based upon the higher cost of dispatching existing and new gas-fired resources, but does not similarly penalize B2H Portfolios that rely on relatively higher cost market purchases in this higher gas price environment. Such an approach fails to meet the clear requirement of IRP Guideline 1 that requires that *"consistent assumptions and methods should be used for the evaluation of all resources"*

B2H should be modeled by Idaho Power as an option to purchase peak summer market power at a price based upon an empirically supported market heat rate (e.g., 11,000 Btu/kWh) and the cost of gas. The Aurora model would then compare the cost of purchasing market power based upon the gas price and an 11,000 heat rate, to dispatching the next resource in the alternative fossil fuel portfolio. In the fossil fuel portfolio, the comparable option would be the reciprocating internal combustion engine (ICE) that would dispatch at a guaranteed heat rate of only 8,400 Btu per kWh<sup>17</sup>. This means that if the price of gas rises by \$1, the cost of market power would rise by \$11 MWh but the cost of power from the ICE unit would only rise by \$8.40 MWh. By extension, a combined-cycle combustion turbine would dispatch at a guaranteed heat rate of only 6,700 Btu/kwh and a \$1 rise in gas price would only increase the cost of power by only \$6.70 MWh, compared to the \$11 increase for purchased power.

### **Idaho Power Ignores Certain Costs of Importing PNW Power**

Idaho Power's specification of the cost of PNW imports ignores the cost of wheeling PNW power to the Idaho Power system. This is a significant and unacceptable oversight. PNW power prices are based upon the cost of undelivered power. While a party can transact (purchase) power at the PNW market price, that power still needs to incur wheeling costs to be delivered to a scheduling point where the power can be exported from the PNW to the Idaho Power system. Even with the construction of B2H, the B2H line will not access any power plants directly. Idaho Power will still need to pay for a transmission wheel and losses, likely over the BPA

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<sup>□</sup>2017 IRP Appendix C, page 73

transmission system, to get the power from whatever the generating source in the PNW to the Idaho Power System, including to B2H. If this transmission wheel is over the BPA transmission system to B2H, then Idaho Power would pay BPA's hourly transmission rate plus 1.9% for transmission losses. BPA's current transmission rate is \$4.23 MWh<sup>18</sup> and the cost associated with real power losses would bring the cost of wheeling up to about \$5 MWh. If the transmission is instead provided over the PacifiCorp system, the costs would be about double (\$10 MWh) as PacifiCorp's hourly transmission rate is \$7.70 MWh and PacifiCorp assesses losses at the rate of 4.45%. Based upon Idaho Power's representation of the levelized cost of PNW market power, their failure to properly account for wheeling costs alone means Idaho Power has understated the expected costs of imports by as much as 20 percent.

### **The Claimed Cost of B2H to Idaho Power Ratepayers is Significantly Understated Due to Phantom Transmission Revenue Credits**

In what appears to be a desperate attempt by Idaho Power to make the numbers for B2H work, they introduce the theoretical concept of substantial secondary transmission sales revenues as an offset to the cost of B2H. Without analytic support, they value these annual transmission sales revenues at a levelized benefit of \$9 MWh (i.e., credit against the annual fixed cost of B2H), and perform no sensitivity analysis around this assumption. To put this in context, this projection translates into over \$9 million/year levelized.<sup>19</sup> Idaho Power appears to have hardwired these large and speculative revenues into the Aurora model.

Idaho Power does not provide any support for this rosy estimate of secondary transmission revenues but a look at demand for existing capacity held by Idaho Power from the PNW to Idaho is illustrative of a lack of value for the path in all but the late spring months when excess PNW hydro drives PNW market prices low or even negative.

To test the credibility of Idaho Power's claim of lucrative revenues from secondary transmission sales, STOP examined the secondary revenues earned by Idaho Power in 2016 on the path after the capacity reallocation from PacifiCorp described above. The following table shows all secondary revenues earned by Idaho Power in 2016 on their share of the Northwest to Idaho path acquired from PacifiCorp. The table shows that in 2016 Idaho Power earned barely \$1 million in secondary revenues from third parties using Idaho Power's allocation of transfer capability from the PNW to Idaho during times when Idaho Power is not otherwise using their existing import capacity.

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<https://www.bpa.gov/Finance/RateInformation/RatesInfoTransmission/FY18-19/2018%20Rate%20Schedule%20Summary.pdf>

19

□  $350 \text{ MW} * \$9 * 33\% \text{ Capacity Factor} * 8760$

Line	Payment to IPC by	Energy Recd From	Energy Del To	Type	POR	POD	MWH received	MWH Delivered	Total Revenue	Rev/MWh
2	Iberdrola Renewables	PACW	PACE	NF	SMLK	BORA	3141	3141	\$14,229	\$4.53
3	Iberdrola Renewables	PACW	Sierra Pac Power	NF	SMLK	M345	791	791	\$3,583	\$4.53
4	Morgan Stanley	PACW	PACE	NF	SMLK	BORA	339	339	\$424	\$1.25
5	Morgan Stanley	PACW	PACE	NF	SMLK	BRDY	65	65	\$81	\$1.25
6	Morgan Stanley	PACW	PACE	NF	Walla Walla	BORA	1285	1285	\$1,609	\$1.25
7	Morgan Stanley	PACW	PACE	NF	Walla Walla	BRDY	175	175	\$219	\$1.25
8	Morgan Stanley	PACW	M345	NF	Walla Walla	M345	739	739	\$925	\$1.25
9	PacifiCorp	PACW	PACE	NF	SMLK	BORA	66107	66107	\$182,331	\$2.76
10	PacifiCorp	PACW	PACE	ST Firm	SMLK	BORA	48505	48505	\$133,782	\$2.76
11	PacifiCorp	PACW	PACE	NF	SMLK	BRDY	5070	5070	\$13,984	\$2.76
12	PacifiCorp	PACW	PACE	NF	WallaWalla	BORA	81394	81394	\$224,494	\$2.76
13	PacifiCorp	PACW	PACE	ST Firm	WallaWalla	BORA	126597	126597	\$349,169	\$2.76
14	PacifiCorp	PACW	PACE	NF	WallaWalla	BRDY	347	347	\$957	\$2.76
15	Powerex	PACW	PACE	NF	SMLK	BORA	17185	17185	\$75,637	\$4.40
16	Powerex	PACW	PACE	NF	SMLK	BRDY	1729	1729	\$7,610	\$4.40
17	Powerex	PACW	Sierra Pac Power	NF	SMLK	M345	2359	2359	\$10,383	\$4.40
18	Powerex	PACW	PACE	NF	WallaWalla	BORA	1883	1883	\$8,288	\$4.40
19	Powerex	PACW	PACE	NF	WallaWalla	BRDY	1641	1641	\$7,223	\$4.40
20	Powerex	PACW	PACE	NF	WallaWalla	M345	390	390	\$1,717	\$4.40
21	Shell Energy N. America	PACW	PACE	NF	SMLK	BORA	704	704	\$2,613	\$3.71
22	Shell Energy N. America	PACW	PACE	NF	SMLK	BRDY	15037	15037	\$55,813	\$3.71
23	Shell Energy N. America	PACW	PACE	ST Firm	SMLK	BRDY	1192	1192	\$4,424	\$3.71
24	Shell Energy N. America	PACW	Sierra Pac Power	NF	SMLK	M345	19483	19483	\$72,315	\$3.71
25	Shell Energy N. America	PACW	Sierra Pac Power	ST Firm	SMLK	M345	3274	3274	\$12,151	\$3.71
26	Shell Energy N. America	PACW	PACE	NF	WallaWalla	BRDY	2921	2921	\$10,842	\$3.71
27	Shell Energy N. America	PACW	Sierra Pac Power	NF	WallaWalla	M345	3265	3265	\$12,118	\$3.71
28	The Energy Authority	PACW	PACE	NF	SMLK	BORA	449	449	\$1,897	\$4.22
29	The Energy Authority	PACW	PACE	NF	SMLK	BRDY	50	50	\$211	\$4.22
30	Transalta Energy Marketing	PACW	PACE	NF	SMLK	BORA	4267	4267	\$17,314	\$4.06
31	Transalta Energy Marketing	PACW	Sierra Pac Power	NF	SMLK	M345	50	50	\$203	\$4.06
						<b>TOTALS</b>	<b>410434</b>	<b>410434</b>	<b>\$1,226,546</b>	

Source: Idaho Power 2016 FERC FORM 1

Basic economic realities would suggest that when existing transmission capacity across a certain path in a certain direction has little demand for use on a non-firm basis, expanding the capacity across the path as B2H would accomplish does nothing to increase demand for the path. Stated another way, the expected level of secondary transmission revenues accruing to Idaho Power by virtue of B2h is likely zero.

***STOP asks that the Commission investigate the company's acquired 350 MW of Incremental PNW Import Capacity which has not been disclosed.***

***STOP also asks the Commission to investigate the questionable costs of purchasing power, the natural gas resource strategy, and the calculation of transmission revenues into the cost by Idaho Power.***

## Section 2. The cost of the B2H transmission line must be verified

OPUC Guidelines 1, 5, 13 & Prudency test

The cost of the B2H has been \$1.2 billion for several years and more information should be shared with the public so an informed and prudent decision can be made. The best-cost/least risk portfolio choice is also dependent on a verified calculation. The Section above addresses the questionable costs of purchasing PNW power and transmission revenues. In fact, even simple cost calculation must be updated and submitted to a third party competent to audit and report to the Commission. A number of additional calculations need to be made (and updated) and the costs recalculated:

- a) The assumed inflation rate of 2.1% per year should be recalculated for the life of the project  not merely the 20 year planning period. The rate payers will be burdened with the cost of the B2H for 50-55 years  not 20.
- b) The cost of financing should also be calculated and shown. Again, for the entire project life and not for the planning period alone. For example, if Idaho Power's share is approximately \$286 million *before* financing here's what it looks like over 55 years using a prime rate of 1.5%:

Item	Terms			Payment Details			Totals	
	Original Principal	Annual Interest Rate	Years to Pay	Periods / Year	Payment / Period	Total Yearly Payment	Payout Over Life of Loan	Interest Over Life of Loan
Power Line	\$286,000,000	1.50%	55	12	\$636,643	\$7,639,716	\$420,184,399	\$134,184,399

The above is illustrative only, but if the financing is at a higher rate, this could easily lead to one-half-billion dollars in debt that Idaho Power customers will be responsible for.

- c) Cost overruns for transmission lines are between 30-50%<sup>20</sup>. Are they included? A prudent planner would calculate costs based on at least some cost overruns.
- d) A contingency cost, such as litigation, needs to be added to the B2H, as compared to over-run costs, which are different. The costs involved in burying the approximate 1.5 miles of the transmission line in front of the National Historic Oregon Trail Interpretive

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<sup>20</sup>Common Cost Overruns on Transmission lines: <https://www.utilitydive.com/news/cost-overruns-in-spp-transmission-projects-draw-ire-of-rtos-leaders/402680/>; [http://acadiacenter.org/wp-content/uploads/2016/06/AC\\_transmissionmemo\\_spreads\\_finalforweb.pdf](http://acadiacenter.org/wp-content/uploads/2016/06/AC_transmissionmemo_spreads_finalforweb.pdf); <http://www.sciencedirect.com/science/article/pii/S2214629614000942>; [http://www.brattle.com/system/publications/pdfs/000/004/843/original/Summary\\_of\\_Transmission\\_Project\\_Cost\\_Control\\_Mechanisms\\_in\\_Selected\\_US\\_Power\\_Markets\\_Pfeifenberger\\_Hou\\_Oct\\_2011.pdf?1378772134](http://www.brattle.com/system/publications/pdfs/000/004/843/original/Summary_of_Transmission_Project_Cost_Control_Mechanisms_in_Selected_US_Power_Markets_Pfeifenberger_Hou_Oct_2011.pdf?1378772134) (see C. Southwest Power Pool and E. California ISO.

Center, near Baker City, needs to be added. The B2H violates protections under the National Historic Trail Act and it is nearly certain to be litigated if burial of the line it is not included in the cost.

- e) The added surplus sales of generation are included as a cost offset in the AURORA portfolio modeling in Idaho Power's 2017 IRP. (This was also discussed on a technical level in Section 1, above.) In the IRP at p 64, the company admits that historically, additional transmission wheeling revenue has not been quantified for a transmission capacity addition. In the IRP modeling, the estimated incremental transmission wheeling revenue from non-native load customers was modeled as an annual revenue credit for B2H portfolios.
- f) We understand there is a 20% contingency fund. Is this fund included in the base cost or is it on top of the \$1.2 billion total? Are the above mentioned items included in this 20% contingency fund? Similarly, the rate of return on investment (ROI) or profit the company will make should be calculated and shown. We understand it to be in the range of 6.7%. Is the profit/ROI included or in addition to the \$1.2 billion? Separating these would be more transparent to the public and the Commission.
- g) An estimate of the cost increase to B2H ratepayer's energy bills should be calculated and shown. In Order No. 17-235, effective July 1, 2017, the Commission approved a revenue requirement increase of \$1,056,800, or 1.91 percent, associated with a 2025 end-of-life for both Valmy units. Is one to assume that approximately \$1 million in investment equates to approximately a 1.9% increase to the ratepayers?

*STOP asks the Commission to investigate the cost estimates provided by the company. In particular, STOP contends that the cost estimates do not reflect the entire cost of the B2H project over the life of the project. Rather, they only include some of the costs for the 20 year planning period. This lacks truthful integrity and does not seem to be a prudent reflection of true cost and risk that the ratepayers will be assuming.*

*STOP also asks the Commission to investigate the legitimacy and prudence of the utility adding potential revenues to off-set costs in their calculations. Future revenues, given the rapidly changing energy industry discussed in STOP's remaining comments, seem suspect at best. STOP would like to see revenue assumptions separated from the cost calculations to better compare the cost/risk to other portfolios in the IRP.*

## Section 3. Conservation, Energy Efficiency and Demand-side Management

*OPUC Guideline 1: Substantive Requirements. All energy sources must be evaluated on a consistent and comparable basis. All known resources for meeting the utility's load should be considered, including supply-side options ... and demand-side options which focus on conservation and demand response.*

What follows is referenced from Idaho Power's 2017 IRP ("Idaho Power 2017 Integrated Resource Plan" 2017) Appendix B: DSM Annual Report, with the page or section numbers from that document included where relevant.

Idaho Power has achieved much less in energy relative efficiency savings when compared to other utilities. Conservation and efficiency are widely acknowledged to be the area where the greatest savings can be achieved at the least cost and risk to the utility<sup>2</sup>.

### Idaho Power: Conservation and Efficiency in Oregon

Idaho Power's residential efficiency efforts in Oregon have focused on the same funding sources that have been on-going utility initiatives for decades. These include education and energy efficient lighting programs which made up 42.5% of the \$280 thousand in Oregon funding for 2016. Weatherization programs accounted for an additional 20.2%.

The only initiative which remotely touches on demand response is the A/C Cool program. A device attached to the air conditioning unit automates on/off cycling at preset intervals, helping moderate peak demand during the hottest summer days. That program is shown in Appendix 2 as having cost the utility a little less than \$42 thousand, 14.9% of total expenditures.

Darrel Anderson, Idaho Power's CEO, has stated that:

□ It is easier to develop incentives when people are paying 30 cents a kilowatt hour. □ (Fisher 2016) The reality is that hundreds of thousands of kilowatt hours have been saved by utilities whose average base charge is less than 12 cents kWh<sup>21</sup>. While Idaho Power describes customer satisfaction with its outreach efforts at length in their 2017 IRP, there is little evidence of increased energy savings outcomes since 2011.

### Idaho Power: Residential Customer Outreach

Idaho Power's efforts to persuade rate payers to conserve energy are insufficient and largely

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□ Delmarva Power & Light, P.S.C. Del No 8 – Electric, March 31, 2017 approximately 11 cents kWh; Public Service Company of New Mexico, 20th Revised Rate No. 1A, effective October 1, 2016 approximately 9 cents a kWh; NV Energy [nvenergy.com/rates](http://nvenergy.com/rates), w/o TOD savings, approximately 11 cents a kWh. The details are in Footnote Error! Bookmark not defined.b.

ineffective and those efforts appear to have flagged over time.

In 2016, residential customers' bills included an invitation to "Take the Smart-saver Pledge." Residents were asked to pledge an "energy saving behavior change" for three weeks, but to change their behavior for only one day each of those weeks. They were asked to choose from activities that included turning thermostats down one to three degrees, washing a full load of laundry in cold water and hang drying it, or using the crock pot or BBQ instead of the oven.

"Pledges" were sent to 367,221 customers. Those responding were eligible to win an Energy Star appliance. 937 pledges were received, and by responding to a follow up-survey customers were eligible to win one \$100 prize. 408 customers responded with all but one reported plans to continue with the energy saving changes. The utility rated the follow-up effort at 97% positive response but only achieved a miniscule .0011 % behavior change in its customer base. [pp. 21-22.]

Idaho Power's residential energy savings programs saw increases in the 2009-2011 period, but energy savings have been static or declining since then. [pp. 177-185]

Only two new energy programs have been added since 2009, with Easy Savings Kits and Educational Distributions added in 2015. It's unclear how kWh energy savings are measured for these efforts. [p. 178]

The A/C Cool Credit program mentioned previously has a total of 28,000 participants across the service area, just .063 % of residential customers. That program "was not actively marketed in 2016" although efforts were made to retain participants. [p. 34]

Idaho Power initiated successful TOD pricing with 1300 customers in 2013 (approximately .003% of residential customers). Idaho Power has not expanded the program in the intervening years.

Fifty percent of Idaho Power's overall residential energy efficiency savings are the result of the Energy Efficient Lighting program which distributes LED lights to its customers. [p. 175]

In 2016, Idaho Power saved 42,208 MWh through residential energy efficiency. As mentioned in the overview, other utilities have been more aggressive and much more successful in their efforts<sup>22</sup>.

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Delmarva Electric with 2/3 the number of residential customers saved 77,781 MWh.

PNM with 500,000 customers combines renewables: solar (505,640 MWh); wind (924, 618 MWh); and geothermal (519,742 MWh), to produce clean power for 154,000 homes (12.67 MWh per home or 1,950,000 MWh of total savings).



While the IRP forecasts growth of .09% per year for average energy demand, and 1.4% per year for peak-hour demand [2017 IRP, p.1], these forecasts fail to reflect the flat demand and declining average customer use the utility has seen from 2007 to 2016. This trend is true despite the fact that Idaho Power has not shown consistency in its efforts to meet peak demand by pursuing peak demand savings. Much more is possible.

### **Idaho Power: Agricultural and Commercial Conservation Initiatives**

The utility has had more success with its agricultural and commercial customers, much of which reflects the time and staff these organizations are willing to spend on what is often the largest expense they have. The result has been ever-increasing efficiency for those customers and a significant drop in demand. As a result, the effectiveness of those programs seems to have peaked.

Irrigation, which represents the majority of Idaho Power's DSM savings, achieved 303 MW peak demand savings in 2016, slightly less than its 2011 and 2012 savings of 340 and 320 MW, constituting only 2/3 of potential DSM savings in this sector. [p. 175]

Commercial peak demand savings reached 1.2 MW for new construction in 2014, with no savings in 2015 or 2016. Retrofits reached 7.8 MW in 2010 with zero subsequent savings in the following 6 years. [ p. 186]

Custom Projects, the largest Industrial sector achieved 9.5 MW in 2010, with marked declines in the following years, and zero savings in 2015 and 2016. [ibid. p. 187]

### **Idaho Power: Discussion of Service Area Conservation & Efficiency**

In the context of IRP planning, STOP notices that Idaho Power consistently under targets and therefore under-plans their savings of energy efficiency. This skewing results in over-inflated statement of need, working in the company's interest for rationalizing more facilities. This type of planning is not in the best interest of the ratepayers.

A clear example of this is demonstrated in the following slide produced by Idaho Power for its 2017 IRP Advisory Council meetings. Some data has been superimposed for comparison purposes. The slide below (Program Performance □ Incremental IRP Targets) demonstrates how Idaho Power continuously underestimates its demand side savings. Since 2010, Idaho Power significantly under plans its demand side saving by a rounded 37% □ the difference between the IRP targets for energy efficiency and the actual energy efficiency savings through initiatives in

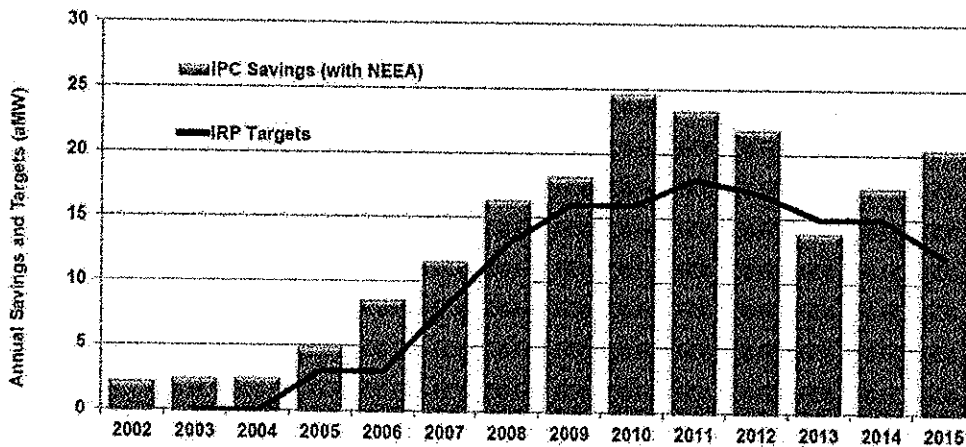
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NV Energy with 1 million customers, approximately twice the number for Idaho Power, saved 235,000 MWh. Ameren Missouri with 1.2 million residential and business customers plans over the next 3 years to add energy savings of 570,000 MWh.

conjunction with the Northwest Energy Efficiency Alliance (NEEA). If these energy efficiency and conservation savings, were reflected in the 2017 IRP planning and the company's "need" calculation, there would be a significant reduction in Idaho Power's power need. (Note: in 2013, there was no DSM program implemented by the company.)

Idaho Power can obtain much more in the way of energy savings through a more focused effort around conservation and efficiency. Given the decline in average demand, these untapped resources along with the rise of distributed generation (Section 4) would go a long way towards reducing the need to import energy from outside the service area with all of the expense and risk that involves.

## Program Performance – Incremental IRP Targets



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Idaho Power can obtain much more in the way of energy savings through a more focused effort around conservation and efficiency. Given the decline in average demand, these untapped resources along with the rise of distributed generation (Section 4) would go a long way towards reducing the need to import energy from outside the service area with all of the expense and risk that involves.

***STOP encourages the Commission to review Idaho Power's tepid attempts at Conservation and Energy Efficiency over the years and to not acknowledge the 2017 IRP until their Action Plan reflects improvements.***

***STOP also asks the Commission to investigate Idaho Power's cost comparisons of DSM to B2H. See Staff Question #56 regarding cost spreadsheet errors.***

*Furthermore, STOP offers the following "Citizen Alternative for Demand Response."*

## **Citizen Alternative: Demand Response**

*OPUC Guideline 7: Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

### **Overview**

There is little about demand response in the Idaho Power IRP ([Idaho Power 2017 Integrated Resource Plan]2017) separate from rate programs, and no broad discussion of an advanced metering infrastructure ("The NETL Modern Grid Strategy Powering Our 21st-Century Economy: Advanced Metering Infrastructure" 2008) (AMI). Most disturbing is the confusion evident in the one section of the IRP [Appendix B: DSM Annual Report] where initiatives are discussed as part of the *Irrigation Peak Rewards* program [p. 140]:

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

A metering infrastructure is just that, an infrastructure. The advancement comes with the addition of a backend server hosting a database, virtual private network communications between the utility and its customers, and digital control surfaces that facilitate those communications at the service endpoint where the metering is done.

No one is going to attach that framework to a customer's electric panel. Only the node components and the associated software will reside on customer premises. The utility should get clear definitions in place so that it can better communicate with its producer-consumers. To do that, it must train its staff in an understanding of those terms, and consistency in their use.

### **Idaho Power: Demand Response Capability**

Idaho Power has installed approximately 500,000 smart meters on residential sites. Advanced metering has saved countless miles of vehicular travel and the labor of reading meters for billing, connection and cancellations, as well as providing valuable information about power outages. The deployment of those meters is, however, only the first step in what is required to significantly enhance residential demand response savings.

The failure to build-out its metering Idaho puts Idaho Power at ever-increasing risk. It also costs its customers the savings they would receive from having digitally mediated demand response in place. As one example, research has shown that smart meters combined with time-of-use pricing can accomplish peak hour energy savings of over 10% (Jesso and Rapson 2015).

## **Idaho Power: Demand Response Needed Upgrades**

While Idaho Power often describes its future energy savings plans by saying that "the landscape has been prepared" the utility must take those next steps. That means build-out of the required information technology (IT), budgeting for the management of that technology, and the associated project management costs involved with full integration. That project management must include obtaining the commitment required of its producer-customers. While those elements require a high level of coordination and planning, the benefits can be very significant<sup>24</sup>.

## **Idaho Power: Demand Response Potential Benefits**

Many utilities emphasize the research they have conducted into demand response, and their partnerships in nationally funded pilot programs for solar energy, smart grids and smart meters<sup>25</sup>. Responding to criticism that Idaho Power has been slow to embrace alternative energy sources, however, the CEO responded at the Boise City Club that even though making large scale investments would earn the utility a return, they were unlikely to do so "given that [the utility] continues to be long on energy or have more regular power generation than it usually needs."

Leaving aside the fact that this hedge brings into question the need for 25% more power in 20 years, it also suggests that the utility lacks any organized effort to research and employ new energy saving technologies. Reinforcing this sentiment is the fact that the utility has openly stated that their research while "not organized or managed as a specific project," actively monitors smart grid-related technology advancements, articles, research, reports, demonstration projects, and demonstration results as applicable. That sounds like an academic exercise not a planning effort.

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"With at least ten years of published research and results of pilot programs already available with details of substantial savings, Darrel Anderson, addressing the Boise City Club, nonetheless said that the utility is still "preparing the landscape for future studies of renewables."

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NV Energy (1,096,213 residential customers) has initiated dramatic voluntary time-of-use rates. One option available to their customers is a summer rate of 50 cents on-peak hour, vs. .05 cents off-peak hour for residential charges. At the end of the year, customers' bills are compared with the charge for regular (non time-of-use) rate and if time-of-use proves more expensive, the difference in charges is credited to their bills and they may choose to withdraw from the program.

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Delmarva of Delaware refers to California smart meter pilot studies and Maryland's success with AMI; Florida's federal grants expanded Florida's smart metering system in 2012 with dramatic results which PNM (New Mexico) refers to as catalyst for their successful residential energy savings program. Additionally PNM participated 10 years ago as one of 16 successful nationally funded pilot programs combining solar with battery storage.

What they have made clear is that □As energy generation, consumption, and management technologies continue to improve, additional opportunities for the deployment of smart grid-enabled devices/appliances will become available□ it may be possible to create new products and services to help Idaho Power manage and optimize its system and help its customers manage their energy use, consumption, and distributed generation preferences. The areas currently being monitored include the management and integration of EVs, distributed resources, and microgrids.□[2017 Draft Smart Grid report.]

In short, the utility is looking for the very business model that is rapidly being adopted by producer-consumers as they defect from the grid and build partnerships that short-circuit traditional utilities. That’s what the future holds for Idaho Power if it persists in its goal of absolute control over the production and distribution of electricity. It needs to build partnerships with its customers, and quickly.

### **Idaho Power: Demand Response Future**

With the electric utility industry in near turmoil, Idaho Power’s tentative position in regard to the rapid and accelerating changes is risky at best and it has the potential to put the future of the utility in jeopardy. The time for action is now before events over-run their business model. Regulators must insist that Idaho Power conduct an in-depth analysis of energy efficiency and actual demand response projects, those that go well beyond Idaho Power’s narrow one-size-fits-all definition of demand management. There is simply too much risk and significant cost associated with the status quo.

## **Section 4. Distributed Generation**

*OPUC Guideline 12: Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

### **Lack of Prudence and resistance toward Distributed Generation**

Related to Section 3 above, where tepid attempts have been made at energy conservation and efficiency, the company seems resistant to emerging models of distributed generation to the point of failing the prudence test according to a number of cases in front of the Commission.

□Prudence is determined by the reasonableness of the actions □based on information that was available (or could reasonably have been available) at the time<sup>26</sup>. □Prudent information on this

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□ “Prudence is determined by the reasonableness of the actions ‘based on information that was available (or could reasonably have been available) at the time.’” (In re PGE, UE 102, Order No. 99-033 at 36-37.) See also In re Northwest Natural Gas, UG 132, Order No. 99-697 at 52: (“In this review, therefore, we must determine whether the NW Natural’s actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.”)

new emerging business model is available to Idaho Power. However, they do not have a vision of how they can fit into this new business model. They have a corporate culture of disrupting PURPA solar and battery opportunities, avoiding distributed generation, not renewing PPA's, and destabilizing rooftop solar in their service territory.

STOP believes that Idaho Power is not making prudent decisions, in light of:

A recent BPA decision. The cancellation of the I-5 Corridor Reinforcement Project, a 500KV transmission line, is an example. As the BPA administrator said in his decision letter, "Bonneville is committing to taking a forward-looking approach with its investment decisions, and the region can be certain that BPA will seek first to use efficiencies and build at the smallest scale possible to meet our customers' needs, ensuring Bonneville remains a reliable engine of economic prosperity and environmental sustainability in the Northwest."

A recent Washington State Utilities and Transportation Commission Draft Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Planning and Resource Acquisition<sup>27</sup> (DOCKETS UE-151069 AND U-161024), the Washington Commission discussed a framework for the future.

In the report, Section III titled STATEMENT OF THE REGULATORY ISSUE TO BE ADDRESSED on page 7 in Sections 26, 27, and 28 they said:

This requires us to look not just at the bulk power system that is the subject of integrated resource plans, but at the distribution grid, where state policies and declining technology costs are likely to both create challenges and offer solutions over time. Customer-sited generation facilities and growing demand to charge electric vehicles, while limited in Washington at present, have the potential to alter customer usage patterns dramatically and require distribution system upgrades to provide the flexibility needed to meet those changing demands.

Where distribution system upgrades were once a relatively simple question of building additional wires, poles, and transformers, distributed energy resources now allow utilities to apply the resource portfolio approach historically used in integrated resource planning to distribution planning. Despite that point of commonality, however, resource planning on the distribution system remains a fundamentally different process than integrated resource planning. Where an IRP considers the costs and benefits of resources at a system or portfolio level, more granular distribution planning analyzes the costs and benefits of resources on a locational basis, with the potential for hundreds of finite

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<sup>□</sup><https://www.utc.wa.gov/docs/Lists/Commission%20Calendar/Attachments/2058/U-161024%20UE-151069%20DRAFT%20Energy%20Storage%20Policy%20Statement.pdf>

locations with different characteristics. IRP models are not designed to do the type of locational analysis that distribution planning requires, and attempting to incorporate the myriad additional variables associated with various locations on the distribution system into an IRP model is simply infeasible.

We therefore intend to address the question of energy storage modeling on two levels. In this policy statement, we identify IRP modeling refinements and competitive procurement practices to ensure that energy storage is fairly evaluated and procured alongside other resources at the system level. In the IRP rulemaking, we intend to develop rule language to ensure that energy storage is fairly evaluated and procured alongside other resources – such as demand response, energy efficiency, distributed generation and infrastructure upgrades – at the distribution level.

*STOP believes these first 2 points lay out a new prudence where utilities should: 1) seek first to use efficiencies and build at the smallest scale possible to meet customers' needs, ensuring utilities remain a reliable engine of economic prosperity and environmental sustainability; and 2) distributed energy resources should allow utilities to apply the resource portfolio approach historically used in integrated resource planning to distribution planning.*

- h) Three cases that demonstrate Idaho Power's self-serving thinking regarding solar and battery PURPA opportunities, and disruption of net metering instead of prudent, forward-thinking are:

CASE NO. IPC-E-15-01 (ORDER NO. 33357) on August 2015 where Idaho Power's strategy to weaken PURPA solar is demonstrated by the Idaho Public Utility Commission (IPUC) decision. In this case, the Idaho Commission section at p 24 it was stated ...

"Finally, if the goal of PURPA was to "encourage" the development of renewable resources, Idaho has made significant advancements toward that goal. Both Idaho Power and PacifiCorp presented persuasive evidence of capacity surpluses. These two utilities have demonstrated that their supply of PURPA and non-PURPA power exceeds their current average loads. Tr. at 111, 117, 931. The abundance of PURPA generation extends the utilities' capacity surpluses to 2024 for Idaho Power and 2028 for PacifiCorp.

Where on page 32, in Ultimate Findings and conclusions, "IT IS HEREBY ORDERED that Idaho Power's Petition to reduce the length of its IRP-based PURPA contracts from 20 years to two years is granted."

This effectively shut down the development of many MW of solar resources in the company's service area. In the company's 2015 IRP at page 9, Uncertainty Related to PURPA Solar, the company complains,

The IRP load and resource balance includes 461 MW of solar PV from PURPA projects scheduled to be on-line by year-end 2016. The energy and peak-hour capacity of these projects was included in the PURPA forecast at the time the forecast was prepared. The risk of relying on these signed contracts is exemplified by the fact that 141 MW of the 461 MW were recently terminated due to inaction by the PURPA developers. The removal of the 141 MW of solar capacity increases peak-hour capacity deficits by approximately 75 MW.

Secondly, in CASE NO. IPC-E-17-01 Order 33785, Idaho Power files for a declaratory order regarding proper contract terms, conditions, and avoided cost pricing for battery storage. In this case, the IPUC in a press release says, "Since the facilities proposed by Franklin and Black Mesa utilize solar as the primary energy source, the commission determined that the projects would only be eligible for two year, negotiated contracts."

Idaho Power further strategically reduced the role of battery storage, as Redwood Energy LLC asserts, battery storage "is a dispatchable system that will offer ancillary grid services such as voltage support, load shifting, reserve capacity, load-balancing, [and] firming of variable generation or time-shifting to match load"<sup>28</sup>.

Third, in Case No. IPC-E-17-13 the company requests to Establish New Schedules for Residential and Small General Service Customers with on-site Generation. This is an attempt to change the way net metering works and depending on the ruling in this case it could create serious disincentives for rooftop solar and others wishing to install on-site generation to reduce load on the system. Or, it could lead to grid defection--customers leaving the grid entirely.

*STOP believes these 3 cases show: 1) the company did not want PURPA solar then complained about the termination of these contracts due to inaction by the PURPA developers. This is exactly what the company intended by its actions; 2) the company did the same with PURPA battery storage with its ancillary services; and 3) has filed to significantly alter how net metering has worked in Idaho and in most of the country.*

*This demonstrates a conscious effort by the company to not deploy the most prudent business method/resources for the ratepayer. The company appears to not want to use PURPA involving solar with battery storage and their ancillary services, or on-site generation, with their avoided costs to ratepayers, because Idaho Power cannot maximize its profits by building these resources themselves. If the company serves in the public interest the rate payers must win out over the*

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[http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1701/ordnotc/20170713FINAL\\_ORDER\\_NO\\_33785.PDF](http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1701/ordnotc/20170713FINAL_ORDER_NO_33785.PDF)



*shareholder. It goes to the basics of the Build vs Buy Bias OPUC UM 1276 that should be settled.*

- i) Battery storage gets minimal attention as the company only considers it as a "storage resource." The company refused to include detailed battery storage analysis in any of the portfolios the 2017 resource plan after being asked several times by Integrated Resource Plan Advisory Council (IRPAC) members. When in fact, batteries can offer many more ancillary services<sup>29</sup> to the grid and will be a huge asset in supporting peak loads especially in their identified localities. These ancillary services would add to grid stabilization, particularly given the volume of expected renewable resources being added to an increasingly decentralizing grid.

Even if batteries do not currently yield the "least-cost" alternative, it is commonly known that prices are dropping rapidly. To exclude detailed analysis in their planning at this time is not in compliance with OPUC Guideline 4 (e) that states the IRP Plan Components need "identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology."

- j) Distributed generation was a topic at a work session held at an IRPAC meeting. The only mention of distributed generation is in the IRP portfolios with Solar PV/Natural Gas and implementation is beyond the immediate action plan. The soonest implementation being portfolio 11 with solar next to a reciprocating engine in 2023. The company's statement to Guideline 12 Distributed Generation is on Page 158, 2017 Integrated Resource Plan Appendix C stating such.

The ongoing price declines and technological advances in energy generation and distribution could mean delaying big investments and could be a better & more prudent strategy. Yet, the 2017 IRP pays minimal attention to distributed generation technologies.

- k) And finally, the company in its 2017 IRP mentions on p 95, that it will not be renewing many of its PPA's within this planning period.

*STOP believes that Idaho Power is not providing a prudent analysis of the future of its industry, including the valuation of battery storage, ancillary services, solar and Combined Heat and Power - CHP (at peak localities), and other distributed generation technologies in this IRP. The company is gutting the benefits of PURPA, attempting to significantly alter how net metering works thus creating disincentives to*

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<sup>29</sup>[http://energystorage.org/system/files/attachments/irp\\_primer\\_002\\_0.pdf](http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf)

customers for energy efficiency, and cancelling many of its PPA's. Therefore is not in compliance with OPUC Guideline 12.<sup>30</sup>

## Distributed Generation - Industrial

As mentioned above, combined heat and power (CHP) systems<sup>31</sup> are scantily considered in the IRP. A measly 35 MW CHP project is discussed in table 6.3 Transmission assumptions and requirements on p 69 but no implementation schedule is found. The company needs to do more to look to local producers to meet load where no backbone upgrades are needed for distributed energy to meet load.

Combined heat and power (CHP) systems, also known as cogeneration, generate electricity and useful thermal energy in a single, integrated system. CHP is not a technology, but an approach to applying technologies. Heat that is normally wasted in conventional power generation is recovered as useful energy, which avoids the losses that would otherwise be incurred from separate generation of heat and power. While the conventional method of producing usable heat and power separately has a typical combined efficiency of 45 percent, CHP systems can operate at levels as high as 80 percent.

Idaho Power does not work well with industrial customers/users that would like to take advantage of Combined Heat and Power (CHP) cogeneration partnerships to together meet more of Idaho Powers need.

Major Customers with Thermal Loads Such as a Potato Plants use Natural Gas to Fire Boilers and Produce Steam. If Idaho Power were to incorporate CHP at the major customer locations the Natural Gas service load to the major customer would shifted to the CHP plant. The CHP plant would provide the utilities to the major customer, Idaho Power would benefit by freeing up resources on the transmission and distribution system serving the major customer. The environment benefits from the improved efficiency and cleaner burning turbines vs. old boilers.

Idaho Power provides and maintains infrastructure to serve each major customer, therefore, CHP does not require additional distribution or infrastructure if sized to the major customer load. This is a 1:1 energy offset with very little cost to Idaho Power.

Idaho Power could offer a favorable CHP energy rate and Steam / Utility Supply agreement with Major Customers as an incentive to partner or build CHP. This would mitigate investment risk and provide additional revenue streams for Idaho Power.

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**Guideline 12: Distributed Generation.** *Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

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<http://aceee.org/topics/combined-heat-and-power-chp>

Idaho Power could petition the PUC to include a measure similar to the custom efficiency tariff which would collect funds to deploy CHP through the rate classes intended. This is a widely accepted practice endorsed by the major customer already.

Idaho Power is not at any greater risk of load loss as there are no guarantees any major customer even without CHP continue to operate or require load. Idaho Power is still obligated to maintain and provide the resources to supply power to the major customer.

If the CHP customer were to terminate operations Idaho Power would still have an operational Gas Turbine Facility no different than the current facilities they operate. Additionally, Idaho Power could use a CHP plant and its thermal capacity to provide storage capacity for other technologies, Solar Thermal and Wind can be coupled with a CHP plant and provide export energy out of the distribution beyond the served load.

Example: Major Food Processor consumes 10MW of Power and Idaho Power Builds or Contracts for a 10MW CHP plant to serve the Food Processor electricity and steam. When operating, 10MW of Distribution capacity is freed up due to the Food Processor being parasitic to the CHP plant. There would be capacity to allow solar or wind to export out of that distribution point up to the 10MW parasitic.

Additionally, Solar Thermal and Solar PV could help peak the efficiency of the CHP plant through generation, preheating and storage which would allow the CHP plant to export energy out of the substation serving the major customer load. This could represent a free 10MW export potential. CHP attached to major thermal loads provides a low cost mechanism for Idaho Power to relieve near or at capacity distribution and transmission by distributing generation into areas with the greatest impact.

An additional benefit of CHP is almost always a significant reduction in real power losses due to lighter loadings on the distribution system.

The cost to deploy CHP is far less than the cost to build stand alone generation as there are multiple synergies and available assets at major customer locations already in place.

While Idaho Power, in the 2017 IRP on p 41 asserts some of the advantages, disadvantages, and costs. It also states ...

"To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different."

A promising technology is CHP wrapped around an above-ground compressed air energy storage installation. This has never been done before, that we know of, but the technology is off-the-shelf and the economics could probably work given the right host.

*STOP asks the Commission to query the individual customers the company has worked with to evaluate their satisfaction and outcome(s) of this cooperation as we are unaware of any CHP contracts currently in place.*

*STOP asks the Commission not to acknowledge this IRP and direct Idaho Power to analyze the full benefits and valuation of all distributed generation; and, the cost-benefit of these services.*

*STOP asks the OPUC to encourage Idaho Power to partner with its residential and industrial customers as a prudent way forward before building new expensive infrastructures.*

*Furthermore, STOP offers the following Citizen's Alternative.*

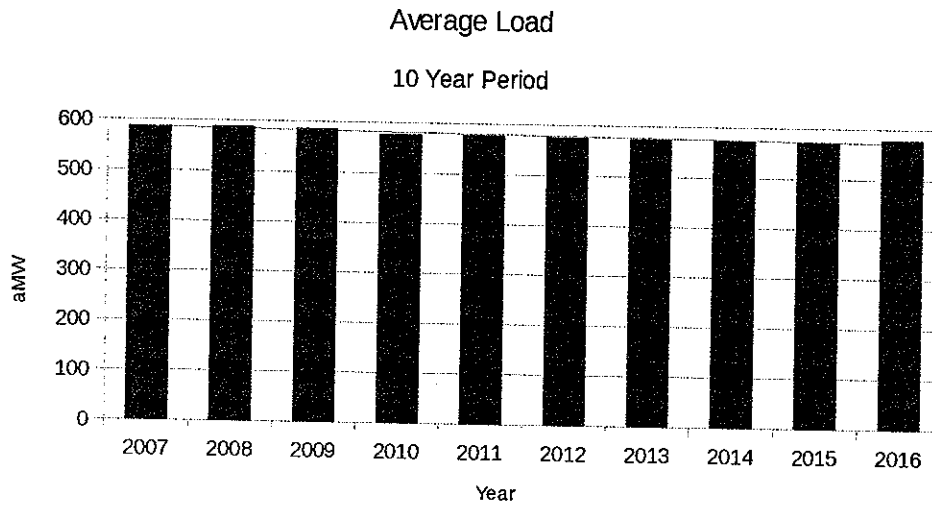
### **Citizen Alternative: Distributed Generation.**

#### **Overview**

To take advantage of rapidly emerging distributed generation (DG) provided by business and residential customers within its service area, Idaho Power should re-focus its business model, provisioning its grid resources to partner with this new class of producer-consumers. The cost of providing service to those users must be balanced by a thorough valuation of the ancillary services they provide, including those from storage (Burwen 2016). As part of this process, the utility has to disaggregate its customer charge into its constituent components in order to model future services from DG and include the value of those components provided by those resources. This should be a key part of all future 20-year integrated resource plans.

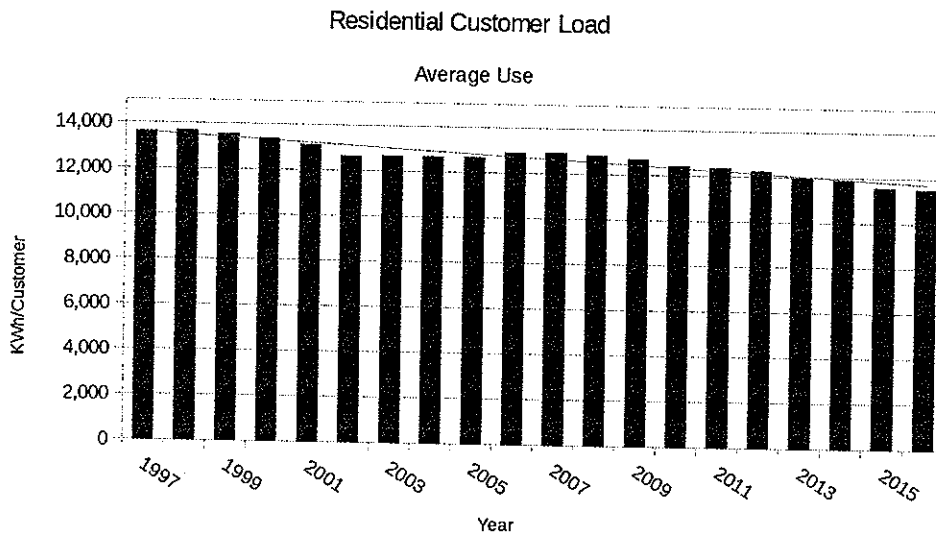
#### **Trends**

Over the last ten years Idaho Power's electric load has been flat, mirroring the trend at the national level (Fickling 2017) [Figure 1]:



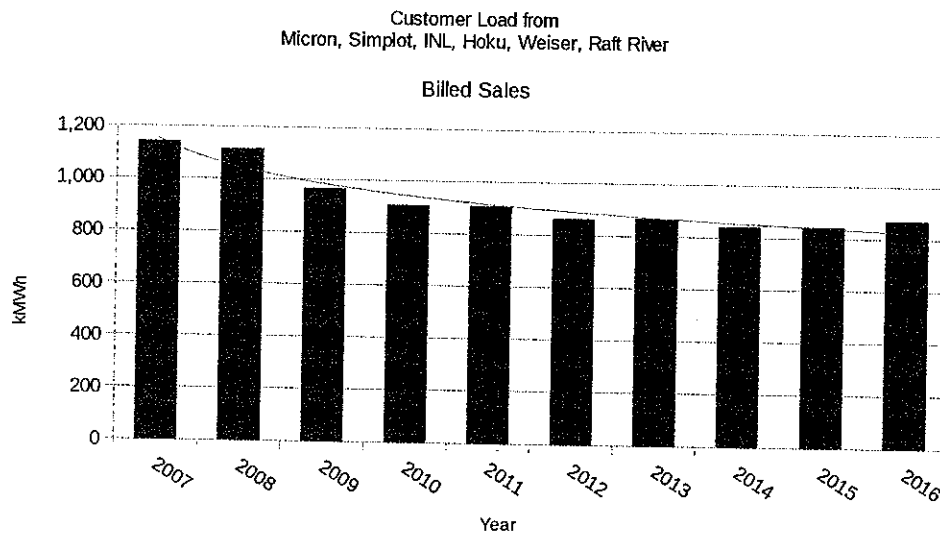
**Figure 1 - Idaho Power average load from 2007-2016**

Population growth has been matched, step-by-step, by a decline in the average customer load [Figure 2]:



**Figure 2 - Idaho Power residential customer load 1997-2015**

That downward trend is also evident in the utility's additional load from its industrial and regional customers as they implement conservation and build efficiency [Figure 3]:



**Figure 3 - Idaho Power additional customer load 2007-2016**

This downward pressure is expected to accelerate. Residential and commercial solar arrays with storage enabled micro-grids will surface a constellation of standalone power resources, as will battery equipped industrial co-generation facilities. The excess capacity from these resources can provide utility peaking power on a near instantaneous basis. They should be tapped by the development of an advanced metering infrastructure (AMI) (The NETL Modern Grid Strategy Powering Our 21st-Century Economy: Advanced Metering Infrastructure 2008), and by the strategic placement of additional battery storage to supplement and moderate those coming on-line from the producer-consumer class.

### **Business Models for Distributed Generation**

Attached storage will lead to a re-working on both the supply and demand sides. The utility should adapt to these changes over the next two years by developing a new line-of-business, one that has them acting as the broker for excess DG resources. This will require continuously recording power production and storage, and modeling their diurnal and seasonal availability. In order to facilitate this effort to the greatest extent possible, Idaho Power should leverage an AMI as the primary vehicle for collecting and analyzing information about grid-attached distributed generation.

Control surfaces<sup>32</sup> at the endpoints of digital networks running in parallel to power flows are transforming the utility business(Cardwell 2017). Most of the Idaho Power service area has excellent solar potential and while the utility will see a drop in power demand, it will also see an increase in power available from producer-consumers via those endpoints. Adapting to this transformation, Idaho Power should plan to increase its purchases of needed power and services from producer-customers. The company should also leverage its electric grid in the brokering of excess power resources as part of this business model.

## Valuation of Distributed Generation

First, storage resources offer many benefits that must be included in future IRP calculations. Once surfaced, the ancillary services provided by storage can be valued using a model developed by Portland General Electric<sup>33</sup>.

Second, the response from strategically placed battery storage mediated by networked intelligence is for all practical purposes instantaneous with no delay at all. This greatly simplifies the management of grid power flows, while reducing costly line losses. Mining the data about these management transactions can surface that value.

Third, a properly provisioned digital grid will enable electricity produced in the service area to propagate quickly and efficiently, allowing real-time markets for that power to develop and thrive. That's another benefit that can be quantified by mining the data from Idaho Power's AMI.

Lastly, though they are more difficult to quantify, the most important benefits of DG are resilience and grid security(Wellinghoff 2015). The growth of distributed generation in the Idaho Power service area can benefit all users through increased operational stability. This should be a future target for valuation by mining data over the longer term.

Idaho Power must invest in the digital assets necessary to identify, analyze, and value these benefits. In short, it needs to build a very different relationship with its customers going forward, one that partners with producer-consumers.

## Section 5. Conclusion

### “Idaho Power, a company culture out of step with Oregon”

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□These are network-attached digital devices including software-enabled smart meters and smart inverters<sup>4</sup>.

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□The model is described in<sup>1</sup>. Flexibility benefits from storage resources are combined with the value of the online capacity from those resources for a complete accounting of storage and ancillary services:

Net cost of capacity = Total installed cost – Operational benefits (flexibility operations & avoided costs)

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.”*

The insecurity of a centralized transmission system is not in our best public interest. If one large transmission line goes down due to terrorism or forest fire, we have entire cities blacked out and vulnerable. With distributed generation some areas would still have power. This is especially important for hospitals, local governmental units, emergency responders, our military bases and military preparedness in general.

Distributed generation has other advantages including reliability which is one of Idaho Power's values on their Vision, Values and Mission page. A large transmission line like B2H sited directly next to the current 230 corridor, does not offer reliability if a forest fire or terrorism (above) were to take out the line.

Idaho Power's dubious interest in avoiding the federal transmission corridor and apparent lack of full disclosure of its capacities, possibly to create a new corridor seems out of step with the current trends in transmission. The cancellation of the I-5 Corridor Reinforcement Project referenced above is an example.

BPA 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. Comparatively, Idaho Power appears to be taking a big risk; and when it fails, their customers in Malheur County will be stuck with the bill. B2H will be a stranded asset and we/they will be paying for it for a long time.

***STOP encourages the OPUC to order Idaho Power to re-consider its out-dated, centralized grid planning at ratepayer expense.***

***The OPUC should not acknowledge the 2017 IRP until all reasonable alternatives to long distance transmission have been investigated, including (but not least) Idaho Power's existing transmission resources and capacities.***

In the 2017 IRP, Idaho Power maintains a traditional utility model for building new and having a high rate of return on investment, over 6%, on a 21% share of a \$1.2 billion plus transmission line at the expense of rate payers. The emerging utility business model embraces new technologies that include renewable resources, battery storage with ancillary services, distributed grids, and greater energy efficiencies.

Idaho Power and its corporate culture are not in step with today's business model or Oregon's long history of energy conservation and innovation.



STOP offers "citizen alternatives" rooted in Oregon's innovation and pioneering spirit. It's time for Idaho Power to get on board! Wagons Ho!

STOP believes that our vision of the energy future is more in alignment with the long-term interest of Oregonians and the public at large. We believe that the Commission will agree. Idaho Power can do a better job at developing residential and commercial conservation programs including smart metering, investing in their own renewables and battery storage, and partnering with industrial customers before building new transmission lines. New jobs and careers can be created rather than temporary road building and construction of transmission towers.

Help us blaze the trail "toward to a new energy future!"

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