BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 68

In the Matter of	]	Gail Carbiener's Comments
IDAHO POWER COMPANY	]	
2017 Integrated Resource Plan	]	

I appreciate the opportunity to comment on the Idaho Power Company's 2017 Integrated Resource Plan. I have read and followed IRPs from IPC including 2011, 2013, 2015 and now 2017. I have also read the IRPs of Portland General Electric and PacifiCorp.

Based upon these IRP presentations by IPC, several general conclusions have become obvious.

1. **Not surprising, assumptions made by Idaho Power always lead to the support of the preferred portfolio.**
    a. Natural Gas price costs have been significantly over estimated in forecasts, especially when adding the additional costs for Idaho City Gate transportation.
    b. Demand Response by clients has been under estimated significantly across all types of electric users.
    c. Energy Efficiency has always been underestimated.
    d. Average Load forecast in 2017 IRP finally was reduced to 1894aMW at year 2021, when in 2013 they were 1934aMW and in 2015 they were 1941aMW. Even so, the estimates go up sharply after the 2-4 year planning period.
2. **Right or wrong, the October 4, 2017 letter making corrections to the B2H calculations continue to deteriorate confidence in IPC conclusions. Especially when it effects the preferred portfolio.**
3. **Idaho Power continues to change the combination of resources used in developing their IRP. We know times change, but lack of any consistency from IRPs makes it almost impossible for the public and ratepayers to provide knowledgeable constructive comments to the Commission.**

a. **The 2015 IRP is history, but let us remember staff's comments on page 4.**

*"Furthermore, IRP guidelines established in Order No. 07-047 state that a utility's IRP's ""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.""**13** This is in contrast with the entire reliance on B2H in preferred portfolio P6(b), which given the projects complex and uncertain process, seems to have a far greater "commitment risk" than dispatchable and manageable resources like demand response or reciprocating engines. A dispatchable resource enables the Company to rely on its energy when needed, creating additional value in the form of reliability and capacity."*

b. If we review changes for North Valmy Units 1 & 2, from IRP 2015 to IRP 2017, We find on page 82 of the 2017 IRP this paragraph:

A review of a North Valmy Unit 1 shutdown year-end 2019 determined the likelihood of customer economic benefits associated with the 2019 retirement outweighs the diminished 2015 IRP qualitative risks. The 2017 IRP load and resource balance impact of retiring North Valmy units 1 and 2 in 2019 and 2025, respectively, is mitigated by the assumption that import capacity across the Idaho–Nevada transmission path will be available. For the 2017 IRP, Idaho Power assumed new resources will not be required to replace retiring North Valmy units, as the existing transmission path can satisfy hourly peak needs.

Retirement of Valmy #1 in 2019 and Valmy #2 in 2025 seems anything but a sure deal. Sierra Pacific doing business as NV energy is 50% co-owner with IPC. The 2017 IPC IRP includes a baseline assumption for the early retirement of Valmy Unit 1 at the end of 2019 and Valmy Unit 2 at the end of 2025.

#13 Commission Order No. 07-047, Appendix A, at Guideline 1, c., Docket No. UM 1056, February 09, 2007.

Sierra Triennial IRP of 2016 did not include these closing dates. The Nevada PUC said in December directive it was surprised NV Energy had done only a “cursory review” of the need to re-examine Valmy’s costs. NV Energy maintains it needs Valmy to meet reliability concerns during peak demand, but intends to comply with the order to produce a new “lifespan analysis plan” for Valmy’s two coal-fired units by February 2018. Kevin Geraghty, Senior Vice President of Energy Production at NV Energy on September 17, 2017 asserted the continued viability of the North Valmy generating station. NV Energy will consider closing the plant when it no longer proves economic viable for customers. Current trends do not point to early retirement. “I wouldn’t see any decision really forthcoming about what’s going to happen maybe until we get closer to 2020, 2021.” Until then, the public shouldn’t anticipate any decision from NV Energy. #1

As a result of these comments, there appears to be significant risk in the treatment of the Valmy units. IPC should prepare a portfolio that includes retirements of both Valmy units in 2025, for cost and risk comparisons.

c. **Idaho Power now analyses only two key resource actions in the 2017 IRP the capital investment in environmental retrofits at Jim Bridger units 1 and 2, and the B2H transmission line.**
   Other resources all use Natural Gas, so effectively B2H is compared with Natural Gas costs used in generation. Idaho Power has no need for additional resources until at least 2026 and with small additions of generation can go until 2029! The Commission should require Idaho Power to prepare additional cost/risk portfolios.

4. **Idaho Power is asking the Commission to specifically acknowledge Idaho Power's acquisition of B2H in the Action Plan to satisfy EFSC's "Need" standard under its Least Cost Plan Rule. It has become clear that most organizations commenting have been and are questioning the need for the Transmission Line. This issue was determined**

#1: energycentral, September 5, 2017

In 2010 by ALJ Sarah Wallace in her ruling, reproduced below. It is my hope that the Commission will specifically draw the difference between "need" in an IRP and a rule at Energy Facilities Siting Council.

On March 2, 2010, Nancy Peyron and Move Idaho Power (collectively MIP) moved for a contested case hearing addressing the B2H line, including the opportunity to conduct discovery, submit testimony, and conduct cross-examination of witnesses. MIP argues that contested case proceedings are warranted because the EFSC is required to conduct energy facility siting proceedings as contested cases. Because of the EFSC's rules regarding the effect of Commission-acknowledged IRPs, the EFSC will not conduct a contested case to determine whether the applicant has demonstrated a need for B2H. Instead, the EFSC will rely on the Commission's acknowledgement to conclude that the need standard has been met. Thus, according to MIP, this Commission should conduct a contested case to determine the "need" for the B2H transmission line to ensure that opponents of the line are not deprived of "the contested case process guaranteed by law."[3]

On March 16, 2010, Idaho Power, the Citizens' Utility Board of Oregon, PacifiCorp, dba Pacific Power, and Portland General Electric Company filed responses urging denial of MIP's motion for a contested case hearing. Also on March 16, Stop Idaho Power filed a memorandum in support of MIP's motion.

The Commission's role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk.[4] Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[5] Because the Commission does not finally determine the individual rights, duties, or privileges of any party during the IRP process, IRP dockets are not considered "contested cases" under the Oregon Administrative Procedures Act,[6] and the Commission does not use contested case procedures. An acknowledgement order is not a final order subject to judicial review because it does not "preclude further agency consideration of the subject matter" of the order.[7]

MIP's sole argument in support of its request for a contest case hearing is the potential affect of the Commission's acknowledgement at the EFSC. MIP argues that this Commission should provide the legal process that the EFSC is "circumventing" by relying on the Commission's acknowledgment order to determine need. The legislature delegated the authority to determine the need for the proposed transmission line to the EFSC, not to this Commission. The Commission would be exceeding its legislatively delegated authority if it attempted to determine whether the EFSC's need standard has been met. If MIP believes that EFSC's process is deficient, then MIP should raise the issue at the EFSC. It is not this Commission's role to compensate for alleged deficiencies in another agency's processes. MIP's motion for a contested case hearing is denied.

a. **The Idaho Power's 2-4 year Action Plan allows that 2019 Integrated Resource Plan will be in front of the Commission. Decision on B2H seems more appropriate at that time. The EFSC is currently in the process of analyzing Idaho Power's Site Application, and may provide some indication of their direction. The public has met in work session with EFSC and is determined to participate fully.**

5. **The Commission Staff back in 2009 had significant concerns about B2H that seem just as important in 2017 IRP. "Staff additionally recommends that the Commission require that Idaho Power provide third-party documentation in support of the Company's construction cost estimates." Has a third party determined B2H construction costs, and where in 2017 are these costs detailed?**
6. **Qualitative Risks are grossly understated, for B2H.**

   Portfolio P7 is significantly more exposed to permitting and siting risk. Idaho Power has put all future resources prior to 2026 on the successful approval of the B2H power line. Contrary to IPC's statement on "much progress has been made," the BLM refuses to issue a Record of Decision which would trigger negotiation with partners for a funding agreement for construction.

   a. PacifiCorp the 54% scheduled owner did not even ask for B2H acknowledgement in its 2017 IRP. PacifiCorp made these statements in the 2017 IRP:

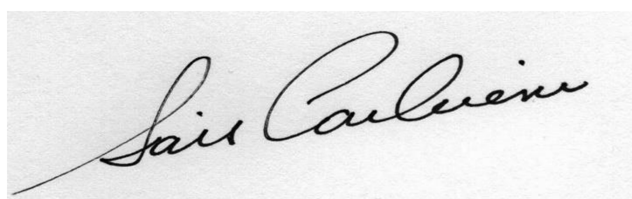
      "During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint. These customers, however, were unable to commit due to the upfront costs and lack of firm contracts. In 2010, the Company entered into memorandums of understanding to explore potential joint development opportunities with Idaho Power Company on its Boardman to Hemingway project and with Portland General Electric Company (PGE) on its Cascade Crossing project. In 2011, the Company announced the indefinite postponement of the 500kV Gateway South segment between the Mona substation in central Utah and Crystal substation in Nevada. In January 2012, the Company signed the Boardman to Hemingway Permitting Agreement the Boardman to Hemingway project was pursued as an alternative to PacifiCorp's originally proposed

> *transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). PacifiCorp plans to continue forward in support of the project under the Permit Funding agreement and* ***will assess next steps post-permitting based on customer need and possible benefits. (my emphasis)*** *In January 2013, the Company notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that terminated by its own terms."*

The Oregon Public Utility Commission should NOT acknowledge Action items #5 & #6. Idaho Power has not indicated what they will do if either PacifiCorp or BPA do not continue after the funding agreement expires. IPC is not financially capable of construction alone. The risk to ratepayers in significant.

Dated the 13th day of November, 2017

Respectfully submitted,



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