DOE-National Lab Comments on Draft E3 Study:

"BPA Lower Snake River Dams Project Draft Final Results"

DOE commends BPA for engaging E3 in this study and appreciates the accelerated schedule within which it was conducted. A technical review of the study was conducted by DOE and National Lab staff. Following are consolidated comments.

Note that some of this feedback, if addressed, would require substantive new work, and time. This is especially true for our comments on the scenarios, and on ELCC treatment and assumptions. We encourage discussions in the near term to determine whether and how to address those comments.

LARGER COMMENTS

Scenarios

- Several of the Modeled Scenarios Appear Implausible: We question the inclusion of the two "Limited Technology" scenarios, as well as the "2024 LSR Replacement" scenario. On the latter, even with an extremely accelerated process that leads to dam removal, would a 2024 removal-and-replacement scenario be feasible? If not, we recommend revising this scenario to include a more realistic yet still accelerated assumption—2027 replacement, or whatever makes sense. On the former, the two "Limited Technology" cases not only eliminate or severely restrict combustion technologies, but they also offer the model no other realistic 'long duration' storage options. Yet several options exist, most obviously producing electricity still with hydrogen but using fuel cells as the conversion mechanism. Alternatively, a wide variety of emerging longer-duration storage technologies could prove viable. The result are two scenarios that are implausible in design, and equally implausible in future likelihood. The scenarios should be eliminated or revised. If BPA-E3 feel that these scenarios, as designed, offer some value as 'bogeys', at a minimum we recommend that they be presented solely as "what if" scenarios in the "with LSR" section of the presentation. These scenarios should not be used to estimate replacement costs of LSR removal (slides 39 on).
    - The study examines LSRD breaching in 10 years (2032) and in 2 years (2024), consistent with the approach used in the CRSO EIS
    - Forecasting the availability of when emerging technology will be mature enough to replace firm, existing resources is not an exact science. With the current political landscape and climate policies, replacing with natural gas also may not be feasible. Multiple scenarios were run to demonstrate how changing assumptions in the technology available gives a range of replacement costs. It is expected that a scenario with unlimited hydrogen fuel cells would be broadly similar to the base case with gas + hydrogen combustion turbines available, but the LSR dams replacement may be more expensive depending on the long-term fuel cell capital cost assumed. Other emerging long-duration storage technologies were deemed to not have sufficiently robust cost forecasts for inclusion in this study, but would provide a similar benefit to the system as the hydrogen resources modeled.
- A Tax Credit Extension Scenario Should Be Considered: Based on the appendix slides, the analysis appears to assume that existing tax credits phase out—as per current statute. Alternatively, it is also plausible that existing tax credits will be extended, and that new ones may be created. We recommend at least one scenario that assumes extended and possibly expanded tax credit

availability. Even if BPA is unable to directly access such credits through ownership, their availability for private entities should reduce the effective cost of LSR replacement. Running a scenario or side analysis to investigate these possible cost-reducing effects of longer-term clean energy tax credits would usefully supplement the current analysis.

  - From a societal standpoint someone has to pay the cost for replacement. Extending the tax credit could reduce the costs of replacement resources in the form of subsides but the cost transfers from rate payers to tax payers. A tax credit extension could have some impact on the total replacement costs, but that impact is expected to be relatively modest as most of the replacement costs are due to fixed costs to replace the dams' RA capacity and fuel costs to replace their output; renewable energy build overall is a minority portion of the replacement costs.

Input Assumptions

- ELCC Values and Influence on Overall Results Deserve Attention: The capacity credit assumptions and results are likely extremely important in estimating the costs of having to replace the LSR dams' grid benefits. One of the footnotes states "…a significant portion of the costs is capacity costs to replace the dams' RA capacity contributions". We have a few comments and concerns:
  - Cost Reporting: Can the fraction of the 'cost of LSR replacement' that comes from capacity needs be calculated? Based on the low raw LCOE costs of wind and solar, it seems logical that the capacity credit costs might make up half or even more of the total cost. If true, then all capacity-credit related assumptions and results are extremely important.
    - E3 has pulled cost components for Scenario 1 and Scenario 2 in its public summary deck. Replacing the firm capacity costs ~1/3 to 1/2 of the replacement costs in those scenarios. We agree that it is an important driver of replacements needs and costs.
  - Capacity Credit of LSR Dams Should be Investigated, and Possibly Revised: The analysis assumes that the LSR dams have, in effect, a 65% ELCC and so a resource adequacy value of 2.2 GW. Since the estimated replacement costs is driven in large measure by resource adequacy, confidence is needed on the capacity credit assigned to the LSR dams. As well, given the importance of resource adequacy to the analysis, it is important that ELCC estimates employed for the LSR dams use similar methods to those used for other resources. Some advocates in the Northwest have presented data and analysis suggesting that a much lower capacity credit is warranted, maybe half that assumed in the E3 study, see: Addressing-the-LSR-Peaking-Capacity.pdf (nwenergy.org). DOE has not independently assessed the linked paper, or the capacity credit of the Lower Snake River dams. But given the critical nature of this single input parameter, we recommend that E3 evaluate the linked paper and LSR output data during periods of system stress to either validate or revise the assumed 65% capacity credit. If a proper ELCC-type study for these facilities has not been conducted, then a review of historical output during periods of peak historical winter and summer (net) load could be used as an approximation. Under the decarbonization scenarios, a focus on the winter period or maybe the early fall (lower PV, so potentially high net load) may be relevant. Overall, more work is needed to validate these assumptions.
    - The 65% value was derived from the NW region-wide value for hydro in the PNUCC 2021 assessment. This is the same value used for all NW hydro capacity accreditation in the E3 RESOLVE model.

    - BPA has provided news releases of the crucial energy and reserves provided by the LSR dams during cold snaps and heat events: https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20210616-pr-08-21-lower-snake-river-dams-provided-crucial-energy-and-reserves-in-winter-2021.pdf. This data contrasts with the specific days that NWEC chose to select for their analysis and indicates a higher output level, plus a reserves provision on top of power output that can also support maintaining resource adequacy.
    - E3 has reviewed the hourly LSR Dams output provided by BPA for the low water year used in the RESOLVE inputs (2001). In this data, the maximum output of the LSR Dams in January was 1.8 GW. If the reserve provision was 200 MW on top of that amount, the resource adequacy contributions are estimated to be ~57% ([1.8 + 0.2] / 3.483). The contributions were lower during August of the 2001 hydro year, but E3 believes that most of the loss of load risk will transition back to the winter under the high electrification scenario considered in this study.
    - For a previous (non-public) project, E3 completed ELCC calculations for specific storage hydro dams in the Northwest, showing an average of 66% annual ELCC. The LSR Dams were not specifically analyzed, but Brownlee, another dam on the Snake River, was analyzed and found to have a 75% annual ELCC. ELCC calculations for storage hydro are quite complex and depend on interactions within the hydro fleet, between the hydro fleet and other resources (like solar and wind), and the proportion of summer vs. winter load during high load years that may change with electrification load growth. E3 therefore believes the 65% value assumed in this study is a reasonable approximation of the LSR Dams capacity contributions but recognizes there is some uncertainty around the exact value (impacting in the ballpark range of up to 10-15% of the replacement costs). (Note: these ELCCs were generally lower than the 10-year lookback initially proposed for hydro capacity counting in the WRAP.)
  - Storage ELCC: The capacity credit of storage seems to be substantially lower than what has been calculated in other regions, particularly for the 12-hr storage duration, after the first few GW of storage is deployed. We did not review the referenced study, but details on how these assumptions were created would be important within this slide deck. Information that would be helpful would include: (1) What does the winter peak look like? (time of day, duration, etc.); (2) What do resource profiles look like on that day, such that a combination of wind, solar, and 12-hour storage cannot contribute significantly? (3) Are interactions between wind, solar, and storage considered at all? (4) Are the scenarios in the referenced study similar enough to the scenarios in the LSR study to apply the same parameterization? Finally, are such low ELCC values for storage, even 12-hour storage, consistent with the 65% ELCC assumption made for the LSR dams?
    - The low energy storage ELCCs assumed in this study are derived from E3's 2019 Northwest RECAP analysis.
      - See here: https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf.

- The low ELCC for storage is driven by the fact that the NW hydro system has huge amounts of energy storage built into it. Loss of load events are often driven during lower hydro conditions, when the NW is energy-constrained, meaning that there is insufficient energy for charging storage and extended duration energy shortfalls.
- Puget Sound Energy's ELCC analysis indicates ~30% ELCC for 4-hr storage additions in their territory. Avista's IRP similarly concludes a low ELCC for storage (4-hr gets 15%, 8-hr 30%, and 12-hr 58%).
- Solar and wind resources are modeled on a 2D "surface", meaning their interactive effects are explicitly modeled. DR and storage were modeled on their own independent penetration curves.

- ELCC Implementation--Exogenous or Endogenous: It appears that ELCC values are exogenous to the scenarios, but that fails to capture the impact of load—both load shape and load level—in determining ELCC. Can E3 provide more information on how these values are implemented? As well, the ELCC values on slide 22 depict ELCC by capacity deployed. When operationalized in the Resolve model, are these ELCC values linked to capacity amounts, or percent of energy? The deep decarbonization cases represent larger power systems, with higher amounts of load. One would anticipate, in such a case, that the ELCCs would drop more slowly relative to deployed GW--does Resolve appropriately capture that?
  - Implementation of the above mentioned solar and wind ELCC surface in RESOLVE is tied to both the capacity penetration of each technology AND the peak load of the system. It increases as peak load grows. Storage and DR ELCCs are not dynamic due to limitations of the older vintage of RESOLVE used in the Northwest model.

- Technologies Considered: (1) Why are dedicated H2 plants excluded in most of the scenarios while dual fuel is available—what is the rationale based on technology maturity or resource availability?
  - The rationale is based on technology maturity/resource availability. Currently there are efforts underway to blend H2 with natural gas in large combustion turbines and eventually move towards 100 percent H2, such as LADWP's Intermountain Power Plant replacement In general, since these hydrogen resources are selected for capacity needs, not energy (until 2045), the solution would generally be similar under these scenarios:
    - A) if H2 only plants, these would be selected across the horizon for capacity, but not run until zero-GHG energy needed in 2045, with existing gas operating with increased output for energy needs;
    - B) if dual fuel gas+H2 modeled, these are selected across the horizon, operate on natural gas in the near-term, then switch to H2 by 2045 as needed.
  - One scenario allows the model to select dedicated H2 plants, which it does following the general trend noted in scenario A above.

  (2) How can the CCS and dual fuel techs be used under the 0 MMT by 2045 scenarios without CDR offset?
  - Dual fuel can burn 100% hydrogen in 2045 and hence produce zero-carbon generation. CCS is assumed to be allam cycle with a net capture rate of 100% (waste stream of ~420 ppm of CO2).

  (3) The table shows 90-100% capture rate for CCS, but can 100% truly be achieved?

- E3 assumes that CCS would be allam cycle and achieve a 100% net carbon capture rate.

(4) Why is offshore wind considered alongside CCS and Nuclear-SMR? Floating offshore wind is less mature than fixed-bottom, to be sure, but should at least be considered as a possible baseline technology.

- Floating offshore wind could go in either bucket. Other than some generation timing diversity, it was generally not seen as particularly beneficial since the NW has access to equal capacity factor onshore wind in MT and WY at a lower cost than floating offshore wind. Hence offshore wind was selected in the limited tech scenarios that show extremely large wind buildouts, which stretched the limits of onshore wind resource potential.

- Hydrogen Cost Appears Overly Conservative: The assumed cost of delivered hydrogen declines to ~$40/mmBTU by 2045. This is a conservative assumption. Current biodiesel is $20-30/MMBtu. Even with conservative H2, the lack of availability of other renewable/biomass fuels results in high replacement costs in these scenarios. The cost of hydrogen-CCGTs in the model may be largely driven by CapEx, so perhaps this conservatism does not greatly impact modeled results. Nonetheless, given the importance of hydrogen in the analysis, we recommend a review of this assumption and possible development of a less conservative input assumption.
    - The hydrogen fuel assumption does drive some of the replacement cost for the deep decarbonization scenario, but only in the year 2045. E3 calculated this H2 cost assuming off-grid production via CoreNW wind, with storage in above ground tanks and truck-based deliveries (due to limited depleted gas fields and salt deposits in the NW). A more optimistic scenario would have to assume a larger regional hydrogen pipeline network with access to cheaper underground storage. A sensitivity on hydrogen prices was not in scope for this project, but we suspect the impact on resource needs and NPV replacement costs would be relatively small.
- Additional Resolve Inputs: Why are 90% and 100% capture rate CCS so similar in $/kW-yr costs on slide 65? Why are H2 peakers and combined-cycle units almost identical in cost?
    - Cost differences for 90% vs. 100% CCS are based on E3 internal analysis of emerging technology costs. H2-enabled peakers and CC's use an approximately 10% cost adder in the near-term that declines to assume parity with single fuel natural gas plants by 2050.
- Transmission Representation: Are the system-wide benefits of transmission (assumed to be needed for out of region wind and solar) considered? Is there any assumed resource adequacy contribution from this transmission, which could be provided from external "clean firm" resources? Also unclear more broadly how opportunity for imports and exports of all electricity services (energy, capacity, ancillary services) are being treated.
    - RESOLVE contains a zonal dispatch model with relevant transmission links from the CoreNW zone to the other zones represented across the WECC. RESOLVE also captures new transmission costs for building wind and solar plants beyond the capabilities of the existing grid. Resources on new transmission outside of the CoreNW (e.g. WY wind) provide RA value from the resource they deliver, but do not provide any additional value from external "clean firm" resources, which would come at an additional investment costs for those clean firm resources. We model

external coal plants as providing both energy and RA, but did not model additional unspecified imports providing capacity. This would generally be consistent with a highly electrified California, whereby California loss of load risk moves from summer to winter. Increasing RA imports would lower total build but not change the marginal replacement needs for the LSR dams. CoreNW A/S needs are modeled as met by resources in the CoreNW zone.

Presentation

- The Cost Reporting on Slides 39-42 Should be Expanded: Cost results can usefully be presented in numerous ways, depending on context. Given varying contexts, we recommend presenting these costs in numerous ways. The NPV results may be relevant if Congressional appropriations were to be used to cover replacement costs. The percentage increase in BPA Tier 1 rates is relevant if BPA's Tier 1 customers were to fully pick up the tab. We recommend presenting the results in at least one additional way: as a percentage increase in retail electricity rates among all customers in the NW. As well, then presenting the annual results on slide 40, we presume these are presented in real terms, and are not discounted: please clarify in slide as appropriate.
    - Footnote added specifying real 2022 $. However, we disagree with the framing that the replacement costs for the LSR Dams would be spread across all NW customers. The power from these dams goes to BPA's public power customers, so they would be the customers in need of the replacement resources to replace the LSR dams.

External Review

- External Review Process: Does BPA anticipate issuing the final report without an opportunity for external stakeholder review of a draft? It may be productive to discuss the possible value, advantages, and disadvantages of offering regional stakeholders an opportunity to review and comment on the draft—recognizing that conducting such a review would entail time and budget.
    - BPA to respond

ADDITIONAL (SMALLER) COMMENTS

- Focus on the Core NW Region: The study is focused on a region of the Northwest that includes Washington, Oregon, and portions of Idaho and Montana. Yet the policy review early in the PPT includes California and lacks any discussion of the policy context in Montana and Idaho. At a minimum, this seemingly incongruous treatment deserves explanation.
    - This only really impacts the Avista load that is in Idaho and Avista has already made a pledge to reach 100% clean electricity by 2045. The MT load covered is all BPA, which is already non-emitting. Added footnote to the "about this study" slide to clarify.
- Slide 6: "Decarbonization is creating a current and deepening need for capacity." This isn't strictly true. There's always a need for firm capacity. But if that capacity is emitting and there exists a requirement to get to zero or very low carbon, then just like energy services, capacity services need to be replaced. Statement should be clarified for accuracy.
    - Removed "current" per this comment's recommendation.

- Slides 9-10: For clarity, might wish to note that the company specific data here come from an E3 review of the latest vintage of each company's IRP. This is implied, but at least one reviewer was confused as to the source of those data.
    - Tweaked language to clarify this
- Slide 11: May want to add a little bit of additional information on *why* the power cuts were made, based on CAISO's report on these outages. http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf.
    - Added a bullet on the root causes identified in the CAISO report
- Slide 20-21: "RESOLVE resource adequacy constraint requires capacity to meet peak demand + a 16% planning reserve margin". Why 16%, and why is that different from 15% shown on slide 20?
    - Corrected this slide. A 15% PRM was assumed, this was a typo.
- Slide 25: (1) "Reaching a zero emissions electric system with high electrification and reasonable levels of renewable additions requires new technologies such as hydrogen combustion turbines or nuclear SMRs." This is then followed by sub-bullets focused on SMR and H2. Those sub-bullets make it sound like one strictly requires EITHER SMR or H2, but there may be other longer-duration storage options or flexibility options such as fossil-CCS that could fill those needs as well. Recommend being less technology prescriptive, especially since only a subset of options are modeled, and focusing more on the services needed, with examples of SMR and H2 technologies. As well, are new technologies really "required" or just "cost-effective" if they exist. (2) It is not decarbonization that drives peak needs, it's electrification when paired with the CO2 constraint. (3) "Additional renewables backed by dispatchable hydrogen plants are needed". Renewable energy technologies are not "backed up" by hydrogen, any more than nuclear plants are backed up by peakers, or peakers backed up by baseload. They provide different services.
    - These points are appreciated. Updated bullets to read:
        - Hydrogen combustion turbines and nuclear SMRs were selected when made available
        - Other emerging technologies (natural gas with carbon capture and storage, advanced geothermal, ultra long duration batteries, etc.) may also provide the same "clean firm" service needed to meet reliability needs in a zero-carbon grid
- Slide 36: This slide or others ideally would show load and how storage is being charged/discharged to help meet load. In addition, as per an earlier comment, we suggest adding slides showing why storage (and VRE) resources have such low ELCCs.
    - We will consider refining the dispatch charts as time and budget allow. Slides 21 and 22 are intended to explain why the hydro interactive effects limit storage ELCC value.
- Slide 49: "Inverter based generation cannot inherently provide inertia, but may still be able to provide fast frequency response via grid forming inverters." Two comments: (1) Inverters do not need to be "grid-forming" to provide FFR, so should alter text accordingly. (2) A lot of research is happening in this space. What is missed is the inertia requirements of the grid in various forecasted years and how any deficit would be mitigated via technology.
    - Removed "grid forming" per comment. Since these benefits were addressed qualitatively, we did not analyzed inertia requirements and whether the NW faced a deficit in future years.

- <u>Slide 50:</u> "Large hydro is historically a major provider of black start services when required." This would be better stated as declared hydro. Many facilities have the capability but don't offer it since it puts them within specific requirements of black start units.
    - <u>Adjust per recommendations.</u>