<u>Questions provided to PSE prior to July 26 TAG meeting</u>

Technical Advisory Group (TAG) – Initial Comments to Generic Resource Costs – response provided by PSE on August 7, 2018

<u>Brian Grunkemeyer – Comments via Email on 7/18/18</u>

1. Battery "Operating Range"

   HDR response: *This was intended to characterize operating range (maximum and minimum for this resource). However, the number noted in the spreadsheet is the minimum load. This will be updated to reflect 2% to 100% i.e. a 98% operational range with discharge capability down to 2%.*

2. Pumped Hydro Project Locations

   HDR response: *HDR considered a generic project in line with the other options considered in the IRP process. HDR has been and is active in actual pumped storage project developments (in the Pacific Northwest and throughout the country) and our experience with these projects was considered in the generic performance/cost development for this effort.*

3. Solar Costs

   HDR response: *HDR agrees with the potential for solar PV costs to decrease over time. This is in-line with the EIA NEMS data presented in Section 2.4.1 of the draft report. The costs developed for this assessment are a representation of current (2018) project costs. The solar costs developed for this assessment are representative of cost data observed across multiple ongoing RFP process throughout the US. HDR would generally expect some economies of scale to be observed for larger solar projects. However, the project size considered herein (25 MW) is considered to be in the "utility-scale" range and a reasonable representation of resource costs.*

   PSE response: *Based on discussion at the TAG meeting, HDR will update solar and wind resource costs to reflect greater economies of scale, which PSE can then break down into smaller sizes, assuming PSE purchases a portion of the resource.*

Bill Westre – Comments via email on 7/20/18 and in letter dated June 12, 2018

Email:

1. Can you release my June 12th letter (attached) to the TAG group and to the IRPAG group as well?

   PSE response: *The letter dated June 12 was included in the meeting materials for the July 26 TAG meeting and uploaded to pse.com.*

2. I have a question for HDR with regard to Table 4.4-1 of the Generic Resource Cost document: Does the "Net Output" term indicate output after the Net Capacity factor is applied or is it the nameplate rating or something else? This makes a big difference in the resulting data.

   HDR response: *In the context of this report, "Net Output" refers to the maximum generating capability of the facility net of any auxiliary, or parasitic, loads. The maximum generating capability of the facility that does not consider facility auxiliary loads is often referred to as the "Gross Output" and, as such, Net Output equals Gross Output less the auxiliary load. Auxiliary loads could include lighting, standby loads, transformer losses, etc. Net Output (expressed in MW) does not consider energy production (i.e. MWh based on capacity factor) but rather the generating potential, accounting for auxiliary loads, at a given point in time.*

Letter:

1. Comparison to Lazard

   HDR response: *Agree that Lazard is a reputable data source and this, as well as many others, were considered in the development of generic resource costs for this effort. In looking at the Lazard slide deck, it is somewhat unclear as to what the specific approach or reference basis was for some of the data presented. For instance, it is not clear what is included in the wind "EPC" and "Construction" cost categories. HDR has typically observed a different breakdown of costs for wind: development, wind turbine generators, balance-of-plant (BOP), and owner's costs.*

2. Cost trends for solar/wind

   HDR response: *HDR developed generic resource costs in current day, 2018 dollars, and also investigated potential future capital cost trends considering EIA NEMS forecasts (base forecasts adjusted based on HDR's current day opinion of probable costs).*

3. Consideration of data from RFPs

   HDR response: *HDR has participated and is actively participating in many RFP processes throughout the country, both as an extension of the owner administering the RFP and, when there isn't a conflict, supporting the development of responses to RFPs. HDR agrees that the information gleaned through these processes is critical to resource planning cost development.*

However, HDR also notes the importance of comparing "apples-to-apples" (evaluated) costs, as "as-bid" costs often do not represent final conformed project costs.

4. Consideration of data from PPAs

   HDR response: *HDR agrees that valuable information can be gleaned from PPA pricing. HDR makes the same note regarding PPA pricing as for costs indicated in RFP pricing (unless the PPA pricing comes from a fully-executed agreement). Certain assumptions, such as financing, tax credit monetization, developer returns, etc. are required, which produce some uncertainty with respect to capital and operating costs that are considered in the PPA pricing.*

5. Montana wind costs – wind farm + transmission

   HDR response: *See previous discussion re wind farm costs. HDR's analysis considers transmission interconnection costs but does not consider any transmission network upgrades and/or wheeling charges.*

6. Consistent reporting of data/information

   HDR response: *HDR has attempted to present the data for all resource types in the same format and with the same units: capex in $/kW, fixed O&M costs in $/kW-yr, variable O&M costs in $/MWh, etc.*

Renewable Northwest (Amanda Jahshan) – Comments via email on July 25, 2018

1. In the 2017 IRP, PSE used a generic 30% owner's cost for wind, which when applied to DNV-GL's total of 1,489 $/kW came out to a PSE total cost of 1,936 $/kW. In the draft HDR report a ~10% owner's cost is used for on-shore wind (p37), but the total project cost is still 1,939 $/KW (Washington, p36). How can they be the same with a reduction in owner's cost percentage?

   PSE response: *In the 2017 IRP, the 30% adder was for owner's costs and Interconnection costs. The current report from HDR has an EPC cost $1,656 plus $386 for owner's costs and interconnection, bringing to the total cost to $2,042. The owner's costs and interconnection costs added together are approx.. 23% of the EPC cost.*

2. DNV-GL's numbers for the last IRP had the wind-turbines coming in at 1,080 $/kW. HDR's draft number for major equipment is 1,231 $/KW (Washington, p36). What caused it to increase?

   HDR response: *As discussed in the Technical Advisory Group (TAG) meeting on 7/26, HDR's estimate considers larger (4 MW class) wind turbine generators. With the unit being larger, and with the larger units having less market penetration, HDR is currently carrying a conservative (higher-end) cost for the wind turbine generator equipment. HDR cannot speak to the basis for DNV-GL's costs.*

3. Re: Table 4.4.1, what is covered by "Indirects"?

   HDR response: *Indirect costs for an EPC project include: construction equipment, engineering, field construction services/management, EPC contingency, general and administrative (G&A) costs, and contractor fees.*

4. Re: Renewable Energy Table from slide 13, what drove the decision for Site 2 to be at Great Falls?

   HDR response: *HDR worked with PSE to identify a region of Montana with a more attractive wind regime as compared to a site located in close proximity to the Colstrip transmission line. PSE response: After discussion with stakeholders, HDR will be reexamining locations to focus on better than average wind sites, which would better reflect where developers would seek to build plants first.*

5. Re: Renewable Energy Table from slide 13, shows solar having a 25 MW Winter Peak Net Output. Does this mean the capacity value of solar will no longer be assumed to be zero?

   HDR response: *The net output refers to the maximum generating capability at a given set of ambient conditions (in this case, winter) and does not articulate accredited capacity/resource adequacy contribution. PSE response: PSE performs an Effective Load Carrying Capability (ELCC)* *analysis. Results of that analysis will be presented at a future TAG meeting, when that analysis has been completed.*

6. The capacity factors seem very low compared to the levels in the last IRP- why?

   HDR response: *Note the capacity factors listed are average annual net capacity factors and are not seasonable specific/intended to represent quantity of contribution to accredited capacity for resource adequacy. The table noted indicates peak capacity credit versus the annual average capacity factors indicated in the HDR analysis.*

7. Renewable Northwest worked with Energy Strategies LLC on an Assessment of the Cost Competitiveness of MT Wind Energy (webinar slides attached for convenience). The assessment considered locations at Great Falls (MT-A), Fort Benton (MT-B), Harlowton (MT-C), Livingstone (MT-D) and near-Colstrip (MT-E) as can be seen in the map (attached).

   The assessment indicated that during PSE's winter peaks all sites considered had 50+% capacity factors, but the highest was at Harlowton (MT-C, see below). Would you consider modelling Harlowton too?

   HDR response: *PSE to advise as to whether additional wind site modeling will take place. PSE response: After discussion with stakeholders, HDR will be reexamining locations to focus on better than average wind sites, which would better reflect where developers would seek to build plants first.*

8. Re: Table 4.4.3, are there more details and cost breakdowns of the "assumptions" and "arrangements?"

   HDR response: *HDR developed an opinion of probable costs for a breaker-and-a-half (BAAH) interconnection substation connected to the wind farm via a 5 mile 115 kV transmission line. Published/industry standard unit costs (e.g. $/mile transmission costs) were considered for the radial line and HDR's in house database was considered in the estimate for the BAAH interconnection substation. Similar to the generation assets, HDR developed costs and has provided a representative breakdown of major cost categories.*

9. Do the draft transmission assumptions for Montana include any lost "opportunity cost" for utilizing PSE's owned transmission capacity on the CTS system, or for utilizing PSE's long term rights of BPA's Montana/Eastern Intertie?

   HDR response: *No, they do not. This is outside of HDR's scope. PSE response: As with the 2017 IRP, there is not expected to be a stranded cost associated with the Colstrip transmission line.*

Available transmission capacity may be purchased by another deverloper, if not needed for PSE's retail customers.

10. According to our understanding of the Northwestern transmission system, a Great Falls project should not require a 75 mile lead line. What assumptions did you make?

    HDR response: *HDR, at the direction of PSE, assumed that the wind farm would need to interconnect to a substation along the Colstrip transmission line. A detailed injection/interconnection analysis has not been completed as part of this analysis. PSE response: HDR will be reviewing these assumptions to determine if a better location or delivery arrangement may look more cost effective.*

11. It is our understanding that a 115 kV line should be able to carry 300 MW of wind. If so, are the costs of that line being spread proportionally over the 100 MW plant or fully assigned?

    HDR response: *Currently, the full cost of the 115 kV transmission line is being carried by the 100 MW farm. PSE response: HDR will update solar and wind resource costs to reflect greater economies of scale, which PSE can then break down into smaller sizes, assuming PSE purchases a portion of the resource.*

<u>Climate Solutions (Kelly Hall) – Comments via email on July 25, 2018</u>

1. Owner's costs indicated in report versus actual numbers used in calculations

   HDR response: *HDR is looking into this based on the comment in the 7/26 TAG meeting*

2. Differences between HDR and Black&Veach and DNVGL cost estimates

   HDR response: *PSE provided a comparison of the 2017 inputs and the current 2019 inputs for reference. Basis of estimating is discussed in the report and was discussed in the 7/26 TAG meeting. HDR cannot speak to the estimating basis for Black & Veatch.*

3. Basis for using AEO's NEMS trends versus NREL or other estimates with more rapid cost declines

   HDR response: *NEMS is a commonly used forecast in resource planning activities (e.g. Portland General Electric also considers NEMS trends). Other forecasts may be considered by PSE in the planning process. PSE response: PSE's base assumptions typically utilize the NEMS data, because it is a consistent source for all resources used for modeling in the IRP.*

   PSE response: *In the 2017, PSE examined a more aggressive cost curve for solar resources. The result was that the different cost curve did not affect the least-cost mix of resources (2017 IRP, Chapter 6, page 6-58).*

4. Using estimates for a 100 MW wind farm and 25 MW solar farm versus larger projects

   HDR response: *As discussed during the July 26 TAG meeting, PSE will investigate potential economies of scale associated with larger wind and solar projects.*

NW Energy Coalition (Amy Wheeless) – Comments via email on July 25, 2018

1. What are the dates of the costs used for various resources? How do the numbers in the HDR report compare to NREL, Lazard or the NW Power & Conservation Council's most recently adopted revisions to gas, solar and wind costs?

   HDR response: *Costs presented in the HDR report are in overnight 2018 dollars representing turnkey EPC project delivery in current market conditions. PSE response: PSE provided a detailed comparison of the draft HDR resource costs for the 2019 IRP and what was used in the 2017 IRP. We do not have a similar comparison list with the other references cited.*

2. The 85% capacity factor for the combined cycle gas generator seems very high; why was that capacity selected? The 85% does not appear to factor in the impact of varying hydro; how was interannual variation in water flow assessed?

   HDR response: *This capacity factor was assumed only for the purposes of estimating non-fuel variable operations and maintenance (O&M) costs (this is true for the other thermal assets as well). Anticipated capacity factors for the dispatchable thermal resources will be determined in production cost/portfolio optimization modeling. The initial 85% assumption, for the purposes of estimating non-fuel variable O&M costs, was provided to HDR by PSE. PSE response: As described during the TAG meeting, actual dispatch will have little impact on the average non-fuel variable O&M costs. The actual forecast dispatch of combined cycle gas generators will be an output of the modeling, not an input—we just need a starting point for variable, non-fuel O&M.*

3. Why are only F-class natural gas generators considered, given that G/H/J class machines are ordered and were also considered in the recent revision of the emissions performance standard?

   HDR response: *F-class natural gas combustion turbines were considered for the proxy simple and combined cycle technologies based on direction from PSE. F-class technology was considered a reasonable representation of frame combustion turbine technology (as is noted in the question, larger turbines exist and also a number of smaller turbines exist). F-class technology was also considered reasonable in the context of PSE's portfolio and potential capacity needs identified in the planning process.*

4. What data sources were used with the NREL software to generate net capacity for wind and solar?

   HDR response: *For wind, 2012 NREL data is considered in the NREL software. Typical Meteorological Year (TMY) data was considered for solar. Specifically, the TMY3 data set was considered.*

5. The simple trend analysis does not capture the rapid cost drops in evolving new technology – were other methodologies considered? Why not use several methodologies to double check outcomes?

   HDR response: *NEMS is a commonly used forecast in resource planning activities (e.g. Portland General Electric also considers NEMS trends).*

6. Regarding solar, are the costs AC or DC? If AC, how did HDR calculate the conversion from AC to DC cost?

   HDR response: *Information in the report is presented for a 25 MW AC solar facility. A DC:AC ratio of approximately 1.3 was considered in this evaluation.*

7. Why is PV lifetime assumed to be 20 years, rather than 25 years?

   HDR response: *HDR has observed both 20 and 25 years considered in specifying design life for solar PV facilities (note this is the design life but facilities, if properly operated and maintained, could operate longer). Adjusting this value will not affect HDR's analysis.*

8. Can the data from the report tables and charts be provided in Excel format? This would enabled IRP participants to formulate better analysis and comments to PSE.

   PSE response: *PSE will provide the tables in Excel format.*

Post meeting verbal comments from Kathi Scanlan (WUTC) concerning battery energy storage solution (BESS) storage duration and David Nightingale (WUTC) concerning wind met data (off-shore buoy and on-shore data set) will also be considered for report revision.