BEFORE THE UTILITIES AND TRANSPORTATION COMMISSION OF WASHINGTON

IN THE MATTER OF RULEMAKING FOR INTEGRATED RESOURCE PLANNING	)))))	**DOCKET UE-161024**

COMMENTS OF THE ENERGY STORAGE ASSOCIATION

The Energy Storage Association ("ESA") appreciates the opportunity to provide feedback on the rules related to the utility Integrated Resource Plans ("IRP") as requested by the Washington Utilities and Transportation Commission ("Commission") in Docket UE-161024, issued on September 6, 2016.

Since its inception 26 years ago, the ESA has promoted the development and commercialization of safe, competitive, and reliable energy storage delivery systems for use by electricity suppliers and their customers. ESA's nearly 200 members comprise a diverse group of electric sector stakeholders, including electric utilities, energy service companies, independent power producers, technology developers—of advanced batteries, flywheels, thermal energy storage, compressed air energy storage, supercapacitors, and other technologies—component suppliers, and system integrators. Several ESA member companies operate in Washington state.

The comments in this document are limited to sections (B), (E), and (F) of the CR-101 filing. ESA wishes to note that other sections of the docket are likely to include considerations important to energy storage, and that these comments should not be construed as bounding the conversation on energy storage in this docket.

B. Energy Storage

ESA supports the Commission's interest in merging Docket UE-151069 with the instant docket, provided it does not delay further progress on the topic. As ESA stated in its September 25, 2015, comments in that proceedings, modeling of the potential costs and benefits of energy storage technologies can and should be improved. ESA appreciates the Commission's interest in ensuring that the full range and value of energy storage services are appropriately accounted for in utility IRPs; given the lack of activity in Docket UE-151069, ESA recommends that all preceding information from that docket be revisited in the instant docket in a timely fashion.

Additionally, ESA wishes to include further information on approaches to modeling energy storage that were not fully captured in Docket UE-151069. Informational barriers to incorporating into advanced energy storage in IRPs remain, despite previous discussions at the Commission and at other states' utility commissions: utility planners often artificially constrain the scale of storage deployment, models use inaccurate and out-of-date cost information, and models themselves are not granular enough to capture the operations of advanced storage. Utilities are thus missing the opportunity to analyze, evaluate, and procure advanced storage as a cost-effective capacity resource, putting ratepayers at risk of otherwise avoidable costs.

Whereas a year ago those informational barriers may have continued to present a challenge, they are increasingly negligible, and the Commission can move forward today with the benefit of learning-by-doing in other places. Advanced energy storage is now regularly deployed in tens of megawatts (MW) and is commercially available at project scales up to 100 MW—on par with gas power plants. Storage cost data is increasingly available in public sources, many of which are updated annually or quarterly. Finally, there are several validated commercial models available today that can capture the intra-hourly operations of different resource options. If utilities and utility commissioners update their approach to storage in IRPs, the choice of storage as a capacity resource can be made on a least-cost economic basis today, avoiding costs for ratepayers.

I. Utilities and Utility Commission Should Use Updated Modeling Methods for Storage

Many utility IRPs use methods that do not adequately model advanced storage. IRP models use three inputs—forecasted demand, the capital cost of available technologies, and those technologies' operating profiles—to calculate economic long-term resource options. Typical production cost models are relatively simple and calculate economic options by modeling generator operations to meet expected load for each hour over a period of many years. Some utilities employ even simpler models that extrapolate from a small sample of hours for each season to simulate load and generator dispatch patterns for many years. These models are simple because they adequately capture the relatively simple operations of traditional generation units relevant to long-term planning.

In contrast, current-day advanced energy storage provides value through its flexibility to offer multiple applications, including intra-hourly grid services like frequency regulation or ramping support. A large-scale energy storage resource dedicated to providing peak capacity when needed—typically a four-hour period in afternoon and early evening—can also provide grid services for the many hours when that peak capacity is needed. Storage resources can do this because they are "always on," in contrast to traditional generation units that need to be started up and shut down to provide services to provide peak capacity and other services.

As such, utilities and utility commissions should update methods in future IRPs to accurately model advanced storage. Utilities should employ models that use sub-hourly intervals that capture the flexibility of storage operations to provide both capacity and grid services. Several validated commercial models are available that can examine calculate economic resource options including intra-hourly dynamics, such as PLEXOS. Furthermore, at a minimum utilities should use an hourly chronological production cost model, rather than sampling from a small set of hours from each season; otherwise, forcing advanced storage resources into a small number of sample hours will result in erroneous extrapolation for long-term planning by overlooking the greater operational value that they bring to the grid.

II. Proper Advanced Storage Modeling Should Consider All Benefits to the System

Some operational benefits of storage can be directly assigned to the individual unit in question. Among these benefits are (1) regulation, (2) load following, and (3) contingency reserves. When the direct operational benefits of storage are modeled, they can represent as much or more than the capacity value of storage. For example, findings from Portland General Electric's most recent draft IRP—which modeled system operations at 15-minute intervals over the course of a future year—found that operational benefits of storage were expected to be ~$90/kW-yr, approximately two times larger than the modeled capacity value of ~$40/kW-yr.[1]

Some operational benefits of storage accrue to the entire system as avoided costs. Among these benefits are (1) reduced operating reserve requirements; (2) reduced start-up and shut-down costs of all generation facilities; (3) improved heat-rate of thermal plants and consequently reduced emissions; (4) reduced uneconomic dispatch decisions, in the form of uplift or revenue sufficiency guarantee payments; (5) reduced curtailment of renewable resources; (6) reduced risk of exposure to fuel price volatility. Additionally, if IRPs are to take account of distribution-connected resources, then additional benefits include locational values associated with (7) avoided transmission and distribution upgrades and (8) reduced local peak demand. As an example, a Massachusetts state-commissioned study of large-scale energy storage deployment quantified a number of these system benefits, finding that they were in fact greater than the value of the direct, compensated services of storage.[2] Indeed, because these benefits increase the efficiency of the overall grid, the must be accounted for at a system level, rather than at the level of an individual storage resource.

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[1] See Chapter 8 in *Portland General Electric 2016 Draft Integrated Resources Plan*, issued 26 Sep 2016, available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-09-16-draft-irp.pdf

[2] See *State of Charge: Massachusetts Energy Storage Initiative Study*, Sep 2016, available at http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf

U.S. National Laboratories and others have sought to quantify the avoided costs of energy storage using commercially available production cost models.[3] For example, NREL's 2015 study of California market estimated storage will result in avoided costs from other generators as \$35.70 – \$58.50/kW-yr.[4] The conclusion of these studies is that the avoided cost and flexibility benefits of advanced storage providing capacity are significant and need to be captured. While it is beyond the scope of this document to quantify all such benefits or provide a methodology to do so, utilities and utility commission should seek to account for these benefits when including storage in IRPs.

These uncaptured benefits are significant and represent a substantial addition to the value of storage. Recognizing that utilities may have to use models available to them currently and that intra-hourly dynamics or ability to capture system benefits of storage flexibility may not be available in such models, the simplest method to incorporate such storage benefits into IRPs is to use a "net cost" approach, as outlined by Portland General Electric in their 2016 draft IRP and illustrated in Figure 1 below:

Net cost of capacity = Total installed cost – Operational benefits

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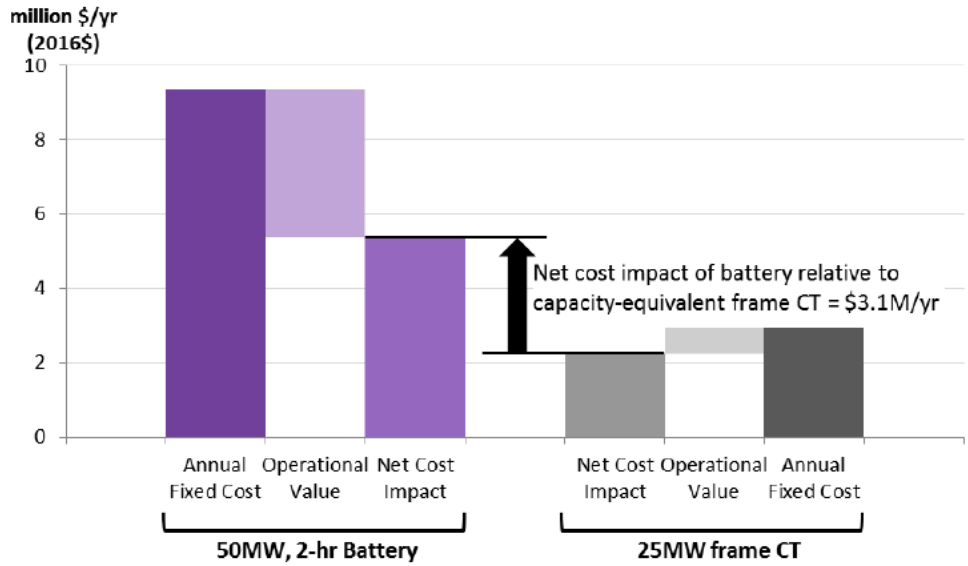
[3] For example, see:

- National Renewable Energy Laboratory, *Operational Benefits of Meeting California's Energy Storage Targets*, Dec 2015, available at http://www.nrel.gov/docs/fy16osti/65061.pdf
- National Renewable Energy Laboratory, *The Value of Energy Storage for Grid Applications*, May 2013, available at http://www.nrel.gov/docs/fy13osti/58465.pdf
- Sandia National Laboratory, *NV Energy Electricity Storage Valuation*, June 2013, available at http://www.sandia.gov/ess/publications/SAND2013-4902.pdf
- Sandia National Laboratory, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide*, Feb 2010, available at http://www.sandia.gov/ess/publications/SAND2010-0815.pdf

[4] See NREL, *Operational Benefits of Meeting California's Energy Storage Targets*, 2015.

Figure 1 Example of Net Cost of Capacity Calculation in PGE 2016 Draft IRP[5]



III. IRPs Should Use Up-to-Date Advanced Energy Storage Current and Forecasted Costs

Up-to-date cost data is increasingly available for advanced energy storage serving as a capacity resource (i.e., 20-100 MW capacity / 4-hour duration). Based on recent cost data from IHS Research[6] and GTM Research[7], ESA estimates that a 50-100 MW, 4-hour lithium-ion battery storage facility commissioned from leading suppliers in 2016 has a total installed cost of between $1,650 and $1,850 per kW of capacity. Moreover, those costs are expected to continue declining rapidly, with a number of sources estimating costs to drop a further 40-50% by 2020[8]. This estimate

[5] See Figure 8-6 in *Portland General Electric 2016 Draft Integrated Resources Plan*.
[6] See IHS, *Future of Grid Connected Energy Storage*, Nov 2015, available at https://technology.ihs.com/512285/grid-connected-energy-storage-report-2015
[7] See GTM Research, *Grid-Scale Energy Storage Balance of Systems 2015-2020*, Jan 2016, available at https://www.greentechmedia.com/research/report/grid-scale-energy-storage-balance-of-systems-2015-2020
[8] See:

- Slide 70 in keynote presentation by Michael Liebrich from the BNEF New Energy Finance Summit, 5 Apr 2016, available at https://data.bloomberglp.com/bnef/sites/4/2016/04/BNEF-Summit-Keynote-2016.pdf#71
- Slide 17 in Lazard's *Levelized Cost of Storage Analysis Version 1.0*, Nov 2015, available at https://www.lazard.com/media/2391/lazards-levelized-cost-of-storage-analysis-10.pdf#18
- IHS, "Price Declines Expected to Broaden the Energy Storage Market, IHS Says," 23 Nov 2015, available at http://press.ihs.com/press-release/technology/price-declines-expected-broaden-energy-storage-market-ihs-says
- GTM, *Grid-Scale Energy Storage Balance of Systems 2015-2020*, Jan 2016, available at https://www.greentechmedia.com/articles/read/grid-scale-energy-storage-balance-of-systems-costs-will-decline-41-by-2020

suggests that current technology costs are already significantly lower than estimates from one to two years prior, and those costs will continue to decline rapidly. Thus, the Commission should ensure that utility planners seek up-to-date information and forecast storage technology on a declining cost curve over the course of the IRP window.

Moreover, as previously discussed, the most accurate way to model storage is as a *net cost of capacity*, which subtracts unmodeled operational benefits from total installed costs. Assuming just the illustrative values from the NREL 2015 study on avoided start-up/shut-down costs of ~$20/kW-yr and avoided fuel costs of ~$10/kW-yr and an 8% discount rate, the figure for net cost of capacity from storage in 2016 would range from $1,350 to $1,550 per kW of capacity—equivalent to 20-30% of installed cost. While this figure is illustrative, it points to the magnitude of impact on costs in conducting such a calculation.

Finally, note that total installed costs are described as a capacity value ($/kW). Since storage provides varying services in addition to capacity, this metric is preferable to $/kWh, which is more appropriate for just the supply of electricity.

C. Requests for Proposals

ESA agrees that narrowly tailored solicitations may be appropriate in some cases, particularly regarding demand resources considered as conservation measures. ESA wishes to raise to the attention of the Commission the increasing use of all-source RFPs for peak load reduction, such as have been issued by utilities in New York state.[9] These RFPs are effectively auctions for capacity from distributed resources; while not necessarily conventionally defined conservation measures, they aim at a similar purpose.

E. Transmission and Distribution Modeling

[9] See ConEd's BQDM Project at https://conedbqdmauction.com; see also PSEG-LI's South Fork and Western Nassau solicitations at https://www.psegliny.com/page.cfm/AboutUs/Proposals/SouthFork and http://www.psegliwnrfp.com, respectively.

I. Integrating Transmission and Generation Planning

ESA is not presently aware of utilities that integrate transmission expansion planning and generation expansion planning. This particularly impacts the evaluation of advanced energy storage resources, which are technically capable of interchangeably providing both transmission capability and reliability services as well as supply services. Modeling software such as PLEXOS can integrate transmission and supply planning into a single process. That said, utility modeling and optimization tools also require effective specification of energy storage resources to produce effective outcomes; as storage can interchangeably provide transmission and generation services, this requires particular attention to model effectively. Such consideration is not without precedent; for example, FERC currently has an open docket exploring how to incorporate such multiple-use storage into markets and planning.[10]

Ultimately, even if an integrated model is not considered feasible due to computational limits and complexity, a standardized approach on how to value energy storage as supply and as infrastructure using available tools is also lacking.

II. Distribution System Impacts of Storage and Contribution to IRPs

Washington utilities' IRPs do not currently contemplate the role of customer-sited energy storage as a demand resource. This is largely due to the long-established convention that IRPs plan for generation to follow load; that is, IRPs treat demand only as an input, forecasting anticipated load amounts and curves and then matching supply to those estimates. Moreover, demand resources as portfolio solutions are generally limited to traditional demand response, i.e., the ability for customers to modify their consumption when requested, either behaviorally or through load controls. Due to the limited capabilities of traditional demand response, in all states, including Washington, demand response is not considered in IRPs.

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[10] See FERC Docket AD16-25, *Utilization In the Organized Markets of Electric Storage Resources as Transmission Assets Compensated Through Transmission Rates, for Grid Support Services Compensated in Other Ways, and for Multiple Services*.

Customer-sited battery energy storage is quickly emerging as a more effective form of demand response that will increasingly contribute to system resources. Battery energy storage is faster-responding than behavioral demand response, as resources can be dispatched automatically in response to system control signals and can be dispatched on an ongoing basis without customer intervention. Battery energy storage is also more reliable than demand response, as resources can be directly measured in real-time to positively confirm deliveries and do not interrupt customer consumption. Furthermore, because battery energy storage is inherently scalable, there are not the same physical limits on flexibility as controllable load demand response.

As a result, customer-sited battery energy storage can provide a "generation-following" capability that traditional demand resource cannot. And by modeling customer-sited energy storage deployment, planners can include load that follows generation in their IRPs. As the electric grid is expected to integrate increasing volumes of non-dispatchable renewable generation over the coming decade, utilities will need more flexible resources, and "generation-following loads" can contribute in a quantifiable and reliable manner to meeting that need. Thus, IRPs should consider customer-sited battery energy storage as a demand resource alongside supply resources as part of possible portfolios to ensure least-cost planning. In this way, customer-sited battery storage can enable broader types of generation procurement with potentially lower cost and better performance relative to any policy goals that could be included in the IRP process. Recent planned deployments in California indicate that customer-sited battery storage can be procured at a scale significant within the planning window of any IRP today.[11] Moreover, general market trends suggest that as customer-sited battery storage economics continue to improve, U.S. installed capacity of customer-sited

[11] Southern California Edison's 2014 Local Capacity Resource procurement included 135 MW of customer-sited battery energy storage; see http://on.sce.com/2aWMbMC. The 2016 Demand Response Auction Mechanism procurement included 880 kW of customer-sited battery energy storage; see https://cpucadviceletters.org/documents/1383/view/ and https://cpucadviceletters.org/documents/1377/view/

battery storage in 2020—well within the timeframe of existing IRPs—is expected to increase by approximately 20 times the capacity installed in 2015.[12]

ESA recommends that the Commission direct Washington utilities to establish a method for assessing the potential contribution that customer-sited storage can make to the solution portfolio. These assessments can then be used in IRPs, as well as inform distribution system planning.

F. Flexible Resource Modeling

As previously discussed in this comment, almost all utilities are not accounting for sub-hourly resources in current IRP models. Those utilities that are using sub-hourly modeling in their IRPs have only started doing so recently, such as the previously referenced Portland General Electric 2016 Draft IRP that was released in September 2016. There are readily available models, such as PLEXOS, FESTIV, and PSO, that can model operations in sub-hourly intervals. While ESA is not aware of the full extent of their use by planners, a simple internet search query reveals a number of planning studies by different parties utilizing such models. While computational resources may be limited for such models over long time periods, nevertheless they can be employed for shorter periods to reveal resource operations and value not otherwise captured in hourly models—and doing so can begin a conversation on how to adapt those insights to IRPs. Moreover, as computing power advances over time, ESA expects such models to become increasingly usable and unconstrained by computational resources.

Conclusion

ESA acknowledges the Commission for the scope of the instant docket and heartily supports efforts to ensure that all economic options are examined to ensure least-cost resource

[12] 2015 installed capacity of customer-sited (residential and non-residential) storage was 35 MW; 2020 estimated installed capacity is 674 MW. See GTM Research, *U.S. Energy Storage Monitor: Q2 2016*, June 2016, presentation available at http://energystorage.org/system/files/resources/gtm_research_-_esa_q2_2016_presentation_2016_06_14_final.pdf

planning. ESA looks forward to supporting the Commission in its exploration and working with the Commission, utilities, and other stakeholders to devise IRP methods that adequately capture all resource options, including energy storage, to save otherwise avoidable costs to ratepayers while meeting system reliability needs.

DATED this 2nd day of November, 2016.

Respectfully submitted,

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