White Paper on the Value of Energy Storage to the Future Power System

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Northwest **Power** and **Conservation** Council

Contents

Executive Summary

This whitepaper is a product of action item ANLYS-16, *"Research and develop a white paper on the value of energy storage to the future power system*" from the Council's 7th Power Plan.

Energy storage seems to have found some initial legs for development in the United States. Regulatory policy, state level mandates, grid modernization programs, and declining technology costs have together created market conditions in which hundreds of storage projects were deployed throughout the country between 2012 and 2016. These projects combined to add nearly 1 GW of new capacity to an existing energy storage fleet that has been composed primarily of pumped hydropower and totaled 23.5 GW across all technologies. Three large scale (100+ MW) projects contributed the majority of this new capacity and the remainder was primarily in small scale (100's kW to 1's MW) battery projects. The initial outlook for 2017 indicates that the key drivers which set up growth over the last several years in particular will continue to encourage new development and that this will primarily be in battery storage with increasingly longer discharge durations owing to falling technology costs.

The East Coast and California have been far and away the most active regions for storage development. In the East coast, new regulatory changes (FERC Order 755 in 2011) have layered on top of a robust ancillary services market to encourage the development of storage for economic fast frequency response. This market dominated new storage development from 2011-2015 but has since shrunk due to regulatory changes and declining values for regulation on the account of low natural gas fuel prices.

In California, aggressive policy has mandated the development of 1,325 MW of new energy storage by 2020 (AB 2514 in 2010). Investor-owned utilities in California have begun executing on this in earnest and California is now far and away the most active region for development with more than half of the nation's projects in 2016 (by number of projects and by capacity) being completed there. This activity has since been bolstered by a mandate to procure an additional 500 MW of customer-sited, behind-the-meter storage to be split evenly between the state's three investor-owned utilities (AB 2868 in 2016). On top of that, California re-opened their self-generation incentive program (SGIP) in 2017 with 80% (~$450M) of the budget marked primarily (~$390M) for large-scale (> 10 kW) storage and the balance (~$60M) for residential (< 10 kW) projects. The SGIP program provides funding on a $/Wh basis and awards are granted through a lottery over several separate allocation periods. In either case, whether by mandate or by SGIP or by some other means, the projects being developed in California are still typically not economic without subsidy or the ability to rate base mandated procurement; the state is still very much in a learning phase while acting as the leading edge of national storage development.

Policy makers, regulators, utilities, and regional planners within the Northwest have also begun to explore the potential for energy storage to be a cost-effective resource for the region. The state of Washington has provided funding for several storage projects through grid modernization programs and the Utilities and Transportation Commission (UTC) staff previously released a whitepaper on incorporating storage during integrated resource plan (IRP) development. The UTC is now considering storage and IRP planning in the combined docket U-161024 and a draft policy statement was released in Q1 2017 which indicated that the UTC may be considering significantly strengthening the extent to which storage must be evaluated on a comparative basis in the potential procurement of bulk generating resources and even upgrades to the transmission and distribution system.

In Oregon, the Public Utilities Commission (PUC) issued a final order on December 28, 2016 on Docket No. UM 1751 which required the state's two investor-owned utilities to each submit several project proposals by January 1, 2018 to procure a minimum of 5 MWh (maximum of ~40 MW) of new storage. Initial candidate project proposals are due July 15, 2017 for interim review and comment. The commission will evaluate all final proposals and approve those which meet the guidelines of the order and provide sufficient benefit to be in the interest of the public to provide cost recovery. Contracting for those projects must be in place by January 1, 2020.

The Montana Public Service Commission directed NorthWestern to specifically evaluate pumped storage in their next IRP, expected in 2018 (Docket N2015.11.91 in 2017). A storage task force was created in Idaho however no project development or policy is expected.

Taken together, a primary thread underlying much of the activity within the region is planning. Current planning processes typically evaluate the cost effectiveness of new candidate resources primarily on the basis of contributions to capacity or capacity and energy, often using models without sub-hourly resolution. This is important for storage because it is currently unlikely for any storage technology to pencil out as economic on the basis of capacity contributions for resource adequacy alone. However, a single storage project may be able to deliver several additional values beyond capacity that could combine to make storage an economic least-cost resource. It is not currently common in the region for those values to be considered as fully as may be possible.

It was a goal of this whitepaper to work with the Generating Resources Advisory Committee (GRAC) and other subject matter experts to describe promising candidate storage technologies, the values they may provide to the system, the breadth and depth of the market to-date, and the extent to which policy and planning opportunities could help to better evaluate the suite of benefits storage may provide the power system. Staff is thankful to the input and feedback from the Advisory Committee members.

Introduction

Energy storage has reemerged as a topic of keen interest for consumers, utilities, regulators, and decision makers within the region and across the country. Recent resource retirements, regulatory changes, technology innovations, and strong year-on-year growth of variable resource generation (*e.g.* wind and solar power) have led policy makers and system planners to investigate whether and how energy storage may be deployed to increase reliability and lower costs. The Council's Seventh Power Plan recognized the regional interest and potential opportunity and created an action item (ANLYS-16) to assist in the development of a white paper on the value of energy storage to the future power system. This document is the outcome of that action item and was developed in collaboration with a diverse group of stakeholders and subject matter experts to best reflect current and future expected regional policy and development activity.

Storage developments within the last five years have provided new and useful insights about the potential values of both traditional and emerging storage technologies and the market structures in which they operate. Utilities, independent power producers, and even behind-the-meter residential and commercial and industrial (C&I) customers have deployed energy storage from kilowatt (kW) to megawatt (MW) scale to capture a multitude of economic and system reliability benefits in regions across the country. Nevertheless, it is not yet clear if the industry is at an inflection point and is now poised for significant growth, or if instead the nascent field of energy storage will remain so for the foreseeable future.

The intent of this whitepaper is to define and describe the technologies, costs, values, and opportunities for utility scale, front-of-meter storage located on the transmission and distribution system. Utility-scale storage technologies considered as in-scope include pumped hydropower, flywheels, and front-of-meter batteries. This is not an all-inclusive list of potentially viable technologies and notable exceptions considered as out-of-scope for this paper include behind-the-meter storage of all types including thermal hot water heaters. The exclusion of thermal hot water heaters and other similar forms of customer-sited storage is not a reflection of their lack of promise; indeed, such technologies have long been explored and even piloted in the region, particularly for demand response applications. Instead, thermal storage technologies are considered as out-of-scope for this paper because the Council is first taking them up through the Demand Response Advisory Committee given the region's experience and will subsequently consider them from the perspective of an energy storage resource potentially capable of providing many or all of the benefits and values described herein.

By describing the to-date technology, market, planning, and policy landscape, this white paper has been developed to help utilities and regional system planners to understand and assign value to the energy, capacity, ancillary service, and infrastructure investment deferral benefits which may be accessible through the unique stacked value streams of energy storage. It is envisioned that interested parties could use the guidance provided in this work to incorporate utility-scale energy storage into resource adequacy and system dispatch models for economic valuation during integrated resource plan (IRP) development.

This paper begins by describing the value streams which may be accessible to an energy storage project, then describes storage technologies and their typical costs and capabilities, and finally transitions to discuss the national and regional policy and storage development activity that has taken place thus far.

An appendix provides more detailed information about technologies, value streams, and resource plans. Future collaboration with stakeholders will lead the development of a regional opportunity assessment.

Value Streams and Technologies

Value Streams

A reliable and economic power system is built upon on the planning, procurement, and dispatch of many services beyond energy and capacity alone. Identifying which of those services storage can provide and at what cost is central to an economic evaluation of energy storage at both a utility and regional level.

The value streams of focus for this whitepaper are those that have the strongest applicability to many forms of utility-scale, front-of-meter storage. They are shown with temporal scale in Figure 1, summarized in Table 1, and described in significant detail in in Appendix Subsection Value Streams. The extent to which a specific storage technology could access a given value stream is described in the Technologies subsection.

Importantly, many of these value streams are not unique to storage and an apples-to-apples comparison of the net benefit of storage as a resource option *vs.* a traditional gas peaker, for example, would require that both resources have the same depth of analysis from a value stream perspective.

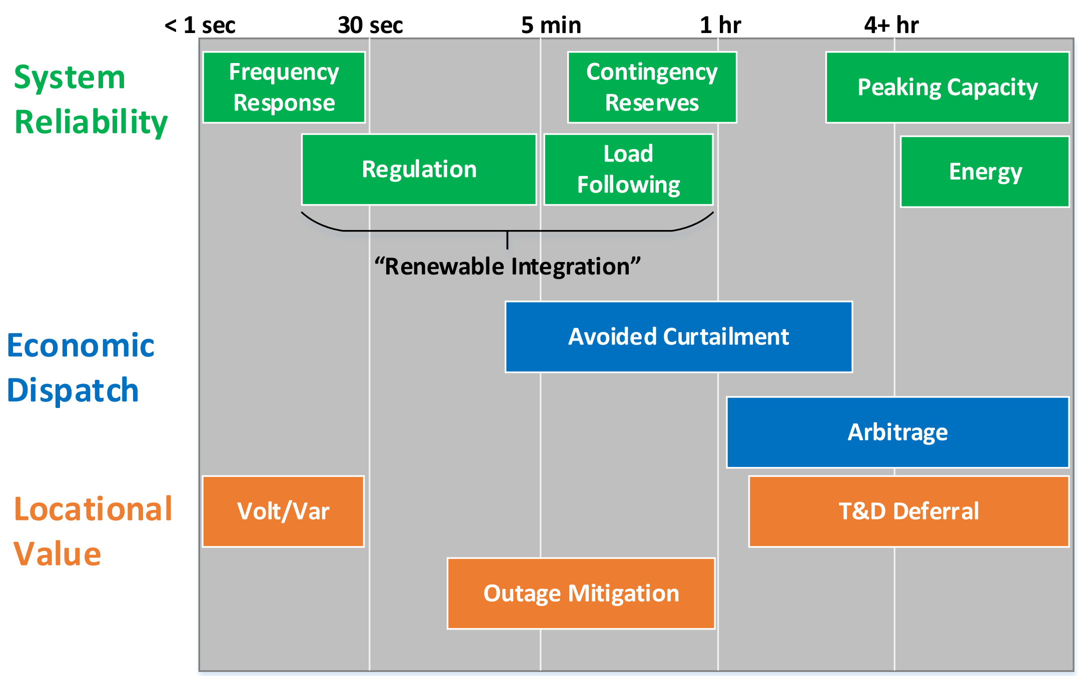

Figure 1: Key value streams within the power system and their associated timescales of action.

System Reliability	**Peaking Capacity:** Ensures sufficient capacity is available to meet forecast peak demand within planning horizon. Most common driver for new resource additions.
	Energy: Ensures sufficient energy is available to meet total forecast need within planning horizon. Energy storage systems do not create energy directly and therefore cannot help with energy requirements on a net basis.
	Frequency Response: Autonomous generator action taken on the timescale of seconds to arrest grid destabilizing frequency excursions.
	Regulation: Coordinated dispatch of additional resources occurring on the timescale of 5 seconds to 5 minutes.

	Load Following: Economic dispatch of flexible resources on the timescale of 5 minutes to 1 hour.
	Contingency Reserves: Reserves available for grid emergencies.
	Renewable Integration: Some renewables tend to increase regulation and load following reserve requirements due to their intermittent, non-dispatchable fuel source (sun, wind, *etc.*). The cost (in $/MWh) of providing these integration services can be calculated and used as a combination proxy value for analyses based on models which not include reserve requirements or do not have sub-hourly capabilities.
Economic Dispatch	**Energy Time-Shifting/Arbitrage:** Store energy when price is low and discharge when price is high.
	Avoided Curtailment: Storing electric energy during times of oversupply to avoid curtailment and continue to collect RECs, if available.
Locational Value	**Local Volt/Var Control:** Provide reactive power (VARs) within the distribution system to maintain nominal grid voltage and enhance the power carrying capability of transmission system.
	Transmission Upgrade Deferral: Reduce loading on transmission paths during peak demand periods to relieve congestion and defer investments in upgrades.
	Distribution Upgrade Deferral: Reduce loading on distribution circuits during peak demand periods to defer investments in upgrades.
	Local Outage Mitigation And Recovery: Harden distribution corridors prone to unplanned outages with back-up asset capable of supporting entire downstream load for reliability and resilience. Could also potentially include black start benefits in some regional grid reliability planning contexts.

*Table 1: Description of key value streams within the power system. A * indicates that a value stream is unique to storage. Additional details are available in Appendix Subsection Value Streams.*

Determining the dollar benefit (in units of $/kW-year) of each value stream can be more involved and less direct in the Northwest than it might be in other regions where a wholesale market for electric capacity and ancillary services would be available to provide transparent pricing signals. Instead, a utility or planning entity in the region would determine the price of many of the value streams (*e.g.* capacity, regulation, load following, contingency reserves) through production cost models already used during planning processes. Other value streams (*e.g.* T&D deferral) require a level of analysis more detailed than what is typically done during resource planning to, for example, identify circuits at or near maximum loading and determine the economic benefit of deferring investment given the time value of money. Still other value streams (*e.g.* outage mitigation) are more difficult to assign a concrete benefit to for a specific system and may require a literature review to determine a more generalized estimate or location specific survey. A forthcoming paper from the Pacific Northwest National Laboratory (PNNL) will provide, among other things, reference ranges for many of the above value streams; these reference ranges may be helpful for cursory analyses in lead up to a more detailed study of a specific system.

Stacking Value Streams

Long-term system planning practices often do not capture values beyond capacity and energy as fully as those values may actually be present. This means that those other monetizable values including regulation, T&D upgrade deferral, *etc.* are typically not significant in determining the least-cost resource for procurement.

Under different planning paradigms the total value of a single storage system could potentially be augmented by several additional value streams beyond capacity and energy, only some of which are accessible to traditional generators. For example, a single battery storage project could be developed directly on the distribution system and be scheduled to deliver some firm capacity at a given time while simultaneously holding back a portion of output for balancing reserves. Further, that storage element could effectively lower its “fuel cost” by charging with less expensive off-peak energy in advance of the firm delivery schedule.

A least-cost evaluation that “stacks” the values accessible to each candidate resource could close the benefit gap for storage and potentially result in rate-payer savings through more economic resource selections (Figure 2). Importantly, only some benefits can be executed concurrently while others may only be accessible at the cost of not providing a different specific value stream at a given time. For example, providing frequency regulation uses energy and therefore diminishes the ability of the storage asset to provide backup power in the event of an unplanned outage. It is therefore very important to carefully scale any proxy benefit values (such as a fixed dollar amount for outage mitigation) when that benefit is stacked with other potentially competing value streams. Any values derived directly from production cost models may also need scaling if they are in competition with proxy values that did not directly affect the operation of the resource in the model but otherwise would be in competition in a real life implementation. A recently published report from PNNL on The Salem Smart Power Center has an excellent analysis demonstrating competitive uses in a live system.

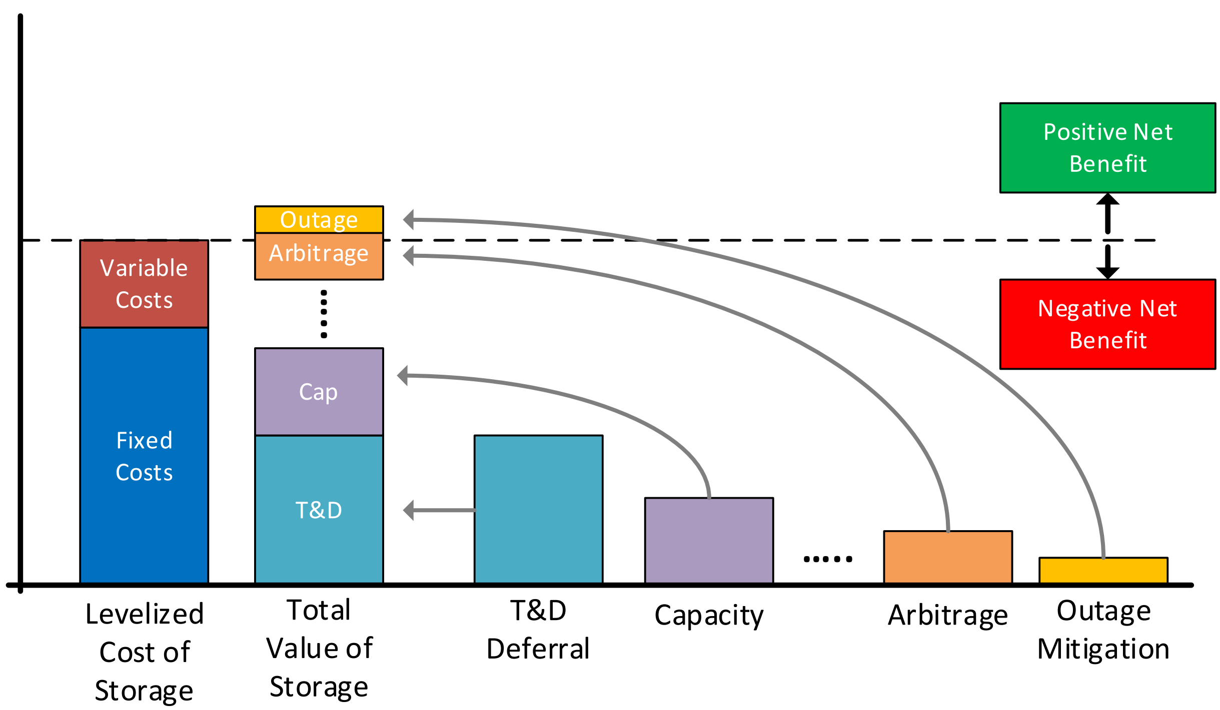

Figure 2: An economic analysis which “stacks” all values provided by an energy storage may result in a positive net benefit. This level of system analysis is beyond typical IRP activities.

An analysis based on models which capture all value streams directly can be computationally intensive due to the sub-hourly timescale of action for many benefits and is not currently executed by the majority of utilities within the region. While that may be feasible in the future, in the interim, some utilities within the region have taken steps to work towards an analysis of storage that includes at least some of the value streams beyond energy and capacity.

- At least one regional utility used a full 15 minute dispatch model with forecast error to capture the value of energy, capacity, regulation, and reserves but not frequency response (too small of a timescale) or T&D benefits (too granular of a system model). This model was done for just a single test year due to computational times.
- At least two other utilities identified specific candidate circuits within their distribution system and used 3rd party software to evaluate the economic benefit of energy storage when dispatched to capture multiple benefit streams co-optimally.

The latter approach appears to be more in line with the storage evaluation guidance which may emerge from ongoing work currently under execution by the Washington and Oregon utility commissions and described in the Northwest Regional Development and Policy subsection. A complete description of the planning approaches taken by each investor-owned utility and their outcomes is given in Appendix Subsection Detailed Regional Development and Planning Activity.

Technologies

The technologies considered within this section are described in Table 2. A much more detailed description is available in Appendix Section Technologies.

Battery: Li-Ion Thousands of small-scale batteries connected together to form a grid-scale resource	***Pros:*** • Reliable, bankable supply chain • Relatively high energy density ***Cons:*** • Cycle-limited due to energy storage capacity degradation • Flammable material requires extra consideration during siting
Battery: Flow Two large tanks store electrolytes which are pumped into a reversible power producing cell. A selectively permeable membrane within cell keeps fluids from mixing. Several different flow chemistries have been developed.	***Pros:*** • Some chemistries do not degrade and can be cycled indefinitely ***Cons:*** • Relatively low energy density • Relatively low round trip efficiency
Flywheels A spinning mass is accelerated to convert and store electrical energy as kinetic energy. The mass can then be decelerated to convert the stored kinetic energy back to electrical energy. A near-frictionless bearing and vacuum enclosure are used to minimize standby energy loss.	***Pros:*** • Very responsive ***Cons:*** • Relatively low energy capacities
Pumped Hydropower An electric machine pumps water from a lower reservoir to an upper reservoir to convert and store electrical energy as potential energy. The water can then be released to flow back to the lower reservoir to produce electric power.	***Pros:*** • Mature technology operating at 100's MW/MWh scale. ***Cons:*** • Often have very large top-line project costs and long

	implementation timelines which can be perceived as a risk

Table 2: Brief overview of the storage technologies considered as in-scope for this paper. A more detailed description is provided in Appendix Section Technologies.

A comparison of each technology on the basis of maturity, cost, capability, efficiency, and expected lifecycle is presented in Table 3. Costs are "all-in" overnight system costs which include the storage device itself, the power converter, the remaining balance of system, and engineering, procurement, and construction (EPC) costs but not capital charges or cost escalations associated with rate-basing the investment. It is becoming increasingly common to provide all-in pricing in units of kWh instead of kW to highlight the impact of the storage element itself (kWh) rather than the power converter (kW) connecting the asset to the grid. Costs were assembled primarily on the basis of 3rd party resources (*e.g.,* Lazard, costs reported to utilities from consultants during IRP planning) rather than actual project costs due to availability; it is possible that a response to a request for proposals (RFP) would be outside of this range, particularly for less mature technologies whose costs may be rapidly declining with scale and experience. The scale (in MW / MWh) and expected construction year of emerging technologies is very important and contributes significantly to the wide range in capital costs; a bid for a large scale project to be completed in 2021 is likely to assume technology cost declines that would provide a savings compared to a smaller project previously completed in 2016.

	Maturity	Overnight System Cost ($/kWh)	Power (MW)	Discharge Duration	Round Trip Efficiency	Expected Life (Cycles)
Battery: Li-Ion	Deploy	370-900	1-10's	Hours	87-94	10,000
Battery: Flow	Demo	480-1000	1-10's	Hours	65-75	> 10,000
Flywheels	Demo	550-950	1-10's	Minutes	70-85	Indefinite
Pumped Hydro	Mature	200-300	100's	Hours-Days	80	Indefinite

Table 3: Comparison of typical costs associated with energy storage technologies. These are unsubsidized all-in overnight costs (storage device, power converter, remaining balance of system, EPC) which do not include capital charges.

The overnight system costs can be converted from units of $/kWh or $/kW to an annualized figure in units of $/kWh-year or $/kW-year by levelizing the total resource cost over its expected lifetime. This is typically augmented by the addition of a term for the fixed operations and maintenance (O&M) costs in $/kWh-year or $/kW-year to then describe the total fixed cost of owning and operating the resource per year. The purpose of levelizing resources is that, for example, a resource with a small overnight cost but short life may or may not be less expensive on a yearly basis when compared to a large resource levelized over a much longer lifespan. A determination of the time over which to levelize an investment should be made on the basis of the expected resource life, debt carrying charge, and confidence in figures for O&M if a plant is expected to operate over a duration where major components would need rehabilitation or replacement.

Finally, the value streams typically accessible to each technology are shown in Table 4. The results primarily reflect the turn-on and ramp time, discharge duration, and lifecycle characteristics typical to each technology and application. For example, pumped storage has the potential to deliver significant capacity and energy and could in some cases ease transmission congestion; however, it is not likely to be able to defer investment in the distribution system in particular given the high power capability and the need for specific geography. At the same time, while lithium-ion batteries degrade with cycling there have nevertheless been a number of deployments, often referred "Lithium Ion – Power" in contrast to

“Lithium Ion – Energy”, which do provide regulation on a day-to-day basis. The table provides general guidelines based on typical use cases.

	Energy	Capacity	Frequency Response	Regulation	Load Following	Contingency Reserves	Arbitrage	Volt/Var	Transmission Deferral	Distribution Deferral	Outage Mitigation
Battery: Li-Ion	-	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Battery: Flow	-	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Flywheels	-	✓	✓	✓	-	✓	-	✓	-	-	-
Pumped Hydro	-	✓	✓	✓	✓	✓	✓	✓	✓	-	-

Table 4: Description of the value streams typically accessible to a given technology.

U.S.-Wide and Northwest Regional Policy

Utility-scale energy storage developments in the last several years have been driven primarily by state level policies which encourage or mandate energy storage procurement and by wholesale market developments which provide pay-for-performance products for all resources in addition to capacity credits for energy storage specifically. Each of these areas are discussed in detail in the following subsections.

In addition to growth in utility-scale storage, it is also worth noting that additional market and policy factors have led to growth in behind-the-meter (*i.e.* residential and commercial and industrial (C&I)) storage across the country. Residential storage has been driven primarily by customers subject to high retail electricity rates without access to net metering structures who wish to self-supply their electricity both day and night with a combination of solar and storage. C&I storage has been driven primarily by peak shaving opportunities in areas with especially high demand charges[1].

Broad State-By-State Policy Overview

Thus far, three states have put forth energy storage mandates (CA, OR, MA), seven have invested in grid modernization programs that provide funding for projects which may include storage (CA, MA, WA, MN, IL, HI, NH), and four states have seen utilities proactively seeking storage through Request For Proposals (RFPs) / Request For Offers (RFOs) (AZ, NY, CT, HI) (Figure 3).

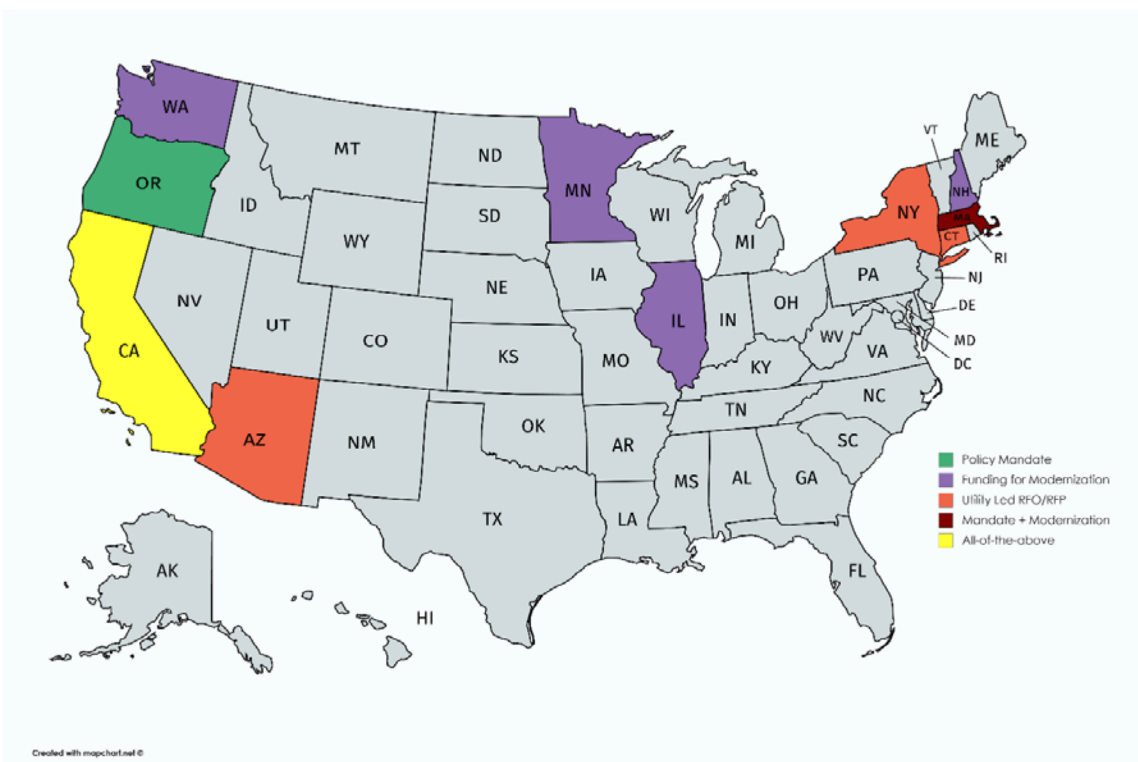

Figure 3: In the Northwest, Oregon has developed a storage mandate and Washington has provided grid modernization funding that has led to storage development. Idaho and Montana do not have formal storage related policy.

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[1] Demand charges refer to an extra tariff levied based on the single highest peak demand (in kW or MW) from a specific customer over a given billing cycle

Wholesale Market Policy and Regulation

Through their regulatory authority over interstate transmission and wholesale electricity markets (Figure 4), the Federal Energy Regulatory Commission (FERC) has issued key orders which have led to observable growth in energy storage in regions with an organized market. Unlike the power system in the Northwest where energy is primarily transacted through bilateral agreements, an organized market is facilitated by an independent system operator (ISO) which creates and manages an auction for generators and consumers to buy and sell energy, ancillary services, and potentially capacity as well depending on the region. This is a significant structural difference in that, for example, the cost of specific ancillary services in a wholesale market has an explicit transaction-based value whereas a utility operating in a region without a wholesale market may choose to provide ancillary services using their own assets without specifically calculating the implicit cost of doing so. Not having access to clear market signals can challenge a utility or regulator executing a least-cost comparative analysis during planning.

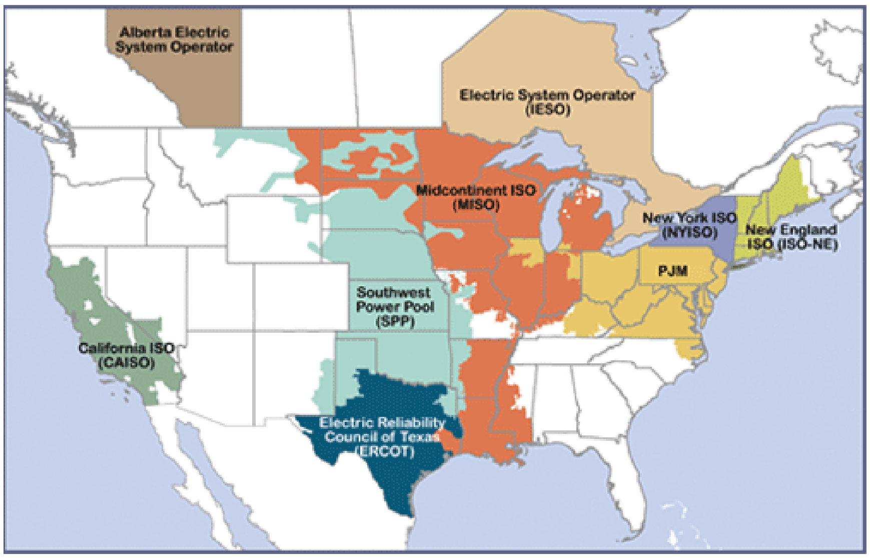


Figure 4: Regions of the country operating via a wholesale market under the jurisdiction of FERC. Image from www.ferc.gov.

In 1996, FERC issued Order 888 to established definitions for specific ancillary services across each ISO (discussed in detail in Appendix Section Value Streams). In a 2011 follow up, FERC issued Order 755 to require market operators to establish pay-for-performance rates for frequency regulation. The basis for this order was that faster responding units (typically measured in units of MW/second) inherently provide more regulation by better tracking the regulation command signal, and that some underlying practices prior to Order 755 could result in an economically inefficient dispatch of regulation resources through over commitment due to poor signal tracking.

The outcome of the order is that the Regional Transmission Operators (RTOs)/ISOs operating robust ancillary service markets have been able to reduce their regulation procurement on an hourly basis by taking advantage of the Order 755-derived development of fast and accurate generating resources such as energy storage. As an example, in the two years prior to implementing market rules to meet Order 755, PJM (the RTO which coordinates the sale and transfer of wholesale electricity for all or part of 13 mid-Atlantic states including Delaware, Pennsylvania, Maryland, Ohio, Virginia and the District of

Columbia) procured a yearly average of 884 MW per hour of frequency regulation. In the year immediately following, pay-for-performance allowed PJM to reliably operate the grid with 35% less hourly regulation procurement and freed 240 MW to provide capacity or other services. Many energy storage deployments in PJM following Order 755 have been developed specifically to participate in economic frequency regulation although this development has slowed drastically in the last several years. This is discussed in detail in the Overall Market Development Activity section.

A FERC proposal from November 2016 under dockets RM16-23-000 and AD16-20-000 may broaden the opportunity for storage to participate in organized markets. The proposal would order the development of wholesale market participation models to ensure that storage resources are eligible to provide all capacity, energy, and ancillary services that they are technically capable of. The proposal would also order that bidding parameters be developed to account for the physical and operational characteristics of electric storage resources and would establish a minimum size requirement not to exceed 100 kW. In combination, the FERC proposal would allow aggregated storage assets to better participate in the market and could allow utilities and other power producers to gain experience with dispatching small scale storage for purposes other than peak shaving or arbitrage before potentially making larger investments.

Northwest Regional Development and Policy

Regional Development

A list of all regional energy storage projects that have been commissioned and are still in operation are shown in Table 5.

State	Project Name	Owner	Technology	MW	MWh	In Service
Idaho	None currently commissioned and operating.					
Montana	Flathead Electric ViZn Z20	Flathead Electric Cooperative	Zinc Iron Flow Battery	0.08	0.16	2014
Oregon	Battelle Memorial Institute Pacific Northwest Smart Grid Demonstration (Salem Smart Power Center)	Portland General Electric	Lithium-ion Battery	5	1.25	2013
	EasyStreet Data Center VYCON Flywheels	EasyStreet Online Services, Inc.	Flywheel	0.8	Unknown	Unknown
Washington	John W. Keys III Pump-Generating Plant	Bonneville Power Administration	Open-loop Pumped Hydro Storage	314	25,120	1973
	SNOPUD MESA 1a Project	Snohomish County Public Utility District No. 1	Lithium-ion Battery	1	0.5	2015
	Benton PUD Battery Energy Storage	Public Utility District No. 1 of Benton County	Valve Regulated Lead-acid Battery	0.01	0.04	Unknown
	Clean Energy Storage: Advanced Energy Storage Research & Innovation Center	Clean Energy Storage Inc.	Lithium Iron Phosphate Battery	0.03	0.36	Unknown
	PSE Storage Innovation Project - Primus Power	Puget Sound Energy	Zinc Bromine Flow Battery	0.5	1	Unknown
	SNOPUD MESA 1b Project	Snohomish County Public	Lithium-ion Battery	1	0.5	2015

		Utility District No. 1				
	UET HQ BESS	UniEnergy Technologies	Vanadium Redox Flow Battery	0.6	1.8	Unknown
	1 MW Avista UET Flow Battery	Avista Utilities	Vanadium Redox Flow Battery	1	3.2	2015
	Clean Energy Storage: Steel Project	Confidential	Lithium Iron Phosphate Battery	0.005	0.02	Unknown
	Clean Energy Storage: Devinenini	Confidential	Lithium Iron Phosphate Battery	0.005	0.02	Unknown
	Clean Energy Storage: Centralia College	Confidential	Lithium Iron Phosphate Battery	0.005	0.04	Unknown
	Clean Energy Storage: Nagasawa	Confidential	Lithium Iron Phosphate Battery	0.005	0.025	Unknown
	Clean Energy Storage: Sun Buzz	Confidential	Lithium Iron Phosphate Battery	0.005	0.025	2014
	2 MW/ 4.4 MWh Puget Sound Energy - Glacier Battery Storage	Puget Sound Energy	Lithium-ion Battery	2	4.4	2015

Table 5: All active C&I and Utility-scale energy storage projects in the Northwest Region. Data obtained from US DOE's https://www.energystorageexchange.org/.

Oregon Policy

The Oregon legislature passed HB 2193 in 2015 to create an energy storage mandate for Oregon's two largest electric utilities, Portland General Electric (PGE) and PacifiCorp. The bill requires PGE and PacifiCorp to each procure a minimum of 5 MWh of new storage on or before January 1, 2020 with a maximum total capacity of up to one percent of their 2014 peak load (~40 MW or less per utility) to limit ratepayer-derived cost recovery. For comparison, the mandate in California requires their three major investor-owned utilities to procure a combined 1,325 MW of storage capacity by 2020[2].

The Oregon Public Utilities Commission (OPUC) issued a final order (Order No. 16-504) under Docket No. UM 1751 on December 28, 2016 directing PGE and PacifiCorp to submit proposals for several potential candidate storage projects by January 1, 2018. The commission will review these candidate projects and authorize those that are determined to be within the guidelines of the order, of reasonable value, and in the public interest. Those projects must then have contracts in place for engineering procurement and construction (EPC) by January 1, 2020.

On the path towards the final proposal submissions at the start of 2018, the commission directed staff to hold public workshops in the first quarter of 2017 to help the two utilities engage with stakeholders to work through key concepts, definitions, strategies, and expectations. OPUC Order No. 17-118 represents the outcome of these efforts in describing that utilities are to submit draft evaluations by July

[2] Pacific Gas and Electric (PG&E): 580 MW, Southern California Edison (SCE): 580 MW, San Diego Gas and Electric (SDG&E): 165 MW with additional details available at https://energy.gov/sites/prod/files/2014/06/f17/EACJune2014-3Charles.pdf

15, 2017, that the project horizon should be 10 years, and that the proposals will be evaluated on the basis of cost-effectiveness, diversity, location, and utility learning. The order included a list of use cases/value streams and advised that each should be evaluated for any proposed project. Draft evaluations can use generalized descriptions of benefits but final proposals must provide location-specific details including all-in cost estimates for the proposed solutions. Utilities engaged in the Energy Imbalance Market (EIM) should use market based rates to assign values to benefits and should use a next-best alternative avoided cost approach for values which do not have a clear market signal. Models used in evaluations must have the capability to do capture sub-hourly operation, ancillary services, and locational benefits on the T&D system. The model must be able to co-optimize the operation of the storage system to maximize the total net benefit of the system. A single base year may be used however it is noted that this limits the extent to which risk due to uncertainty in fuel costs, loads, market prices, and *etc.* is included.

Washington Policy

Following a review of the 2013 IRPs for the three investor-owned utilities in Washington, the Washington Utilities and Trade Commission (UTC) directed the state's IOUs to improve their analyses of energy storage resource options in their 2015 IRPs. This was not a mandate and was instead more similar to OPUC 2014 Order No. 14-415 which directed PGE to better consider storage in its IRP analysis.

Upon review of the 2015 IRPs from each of Washington's IOUs, the UTC concluded that more structured and formalized guidance was needed. A comparison of the 2013/2015/2017 IRPs is shown in Table 6.

	2013 IRP	**2015 IRP** **Progress towards better including storage (Docket UE-120416)**	**2017 IRP**
Puget Sound Energy	Omitted storage from IRP	Partnered with PNNL to study specific sites on its system where storage may be especially valuable	Not yet available for review. Expected in Q2 2017.
Avista	Omitted storage from IRP	Used "ADSS" full dispatch system model with arbitrage, regulation, load following, and reserves but no locational value.	Not yet available for review.
PacifiCorp	Contracted with HDR to evaluate storage costs, schedules, and operating and performance characteristics. Evaluated storage using models which accounted for reserves; not found to be economic.	Re-contracted with HDR to update storage data. Same basic approach as 2013 with updated costs. Augmented with an additional model run which assumed storage existed on system to evaluate generic system benefits. Storage again not found to be economic.	Contracted DNV-GL and Black & Veach to update data from HDR's previous storage studies. Results not yet available.

Table 6: A description of the way in which storage was evaluated by each of the investor-owned utilities in Washington.

Following their review, the UTC issued a whitepaper[3] in May 2015 where they describe that in their view,

1) Many of the challenges facing energy storage in the Northwest are on the account of the region not having an organized market to send clear price signals for various energy services.
2) Because the majority of recent storage pilot projects in Washington (7 announced in the two years preceding the white paper) were funded through one-time funds from outside sources, utilities may return to current (as of 2015) planning procedures that do not allow storage to fairly compete against other resources.
3) Arbitrage alone is a limited value in the Pacific Northwest where low-cost hydropower for load following limits daily price differentials, and where the lack of an organized market leads to little transparency in magnitude of those differentials.
4) While frequency response, voltage regulation, and energy imbalance management are critical to the electric grid, their values are more difficult to quantify and are unlikely to be large enough to offset an energy storage project at current prices.
5) Integrating renewable resources may be a path forward.

In describing the potential for the economics of storage to be enhanced through wind integration in particular, the UTC points out that the production tax credit (PTC) gives a credit of $23 per MWh for the first 10 years of a project. Many of the wind projects in Washington are approaching the 10 year mark and will no longer be able to rely on the PTC to help support the integration costs. In a 2014 Wind Integration Study[4], PacifiCorp found this cost to be $3.06 per MWh of wind.

Where storage can provide integration of wind, the $/MWh integration cost becomes an avoided cost. Compounding that, those resources that were previously held back for integration can be released to meet load or sell energy to the market, increasing revenue from those assets. Although the application is different, the potential result is similar to the result of FERC Order 755 affecting organized markets that enabled capacity held for frequency regulation to be freed to provide another service. Additionally, there is an avoided cost associated with further delaying future generation needs. Finally, a storage asset capable of providing additional stacked grid services provides additional benefits with value.

The UTC points out that holistic avoided cost and complete system benefit analyses for storage is well beyond the studies typically executed by utilities during IRP planning and may be a major factor in why storage is not chosen for development. This is distinct from developments taking place in organized markets where clear price signals can motivate economic development in lieu of detailed planning from a single utility and where a developer can lower costs during RFP/RFOs to provide a specific service at specific times (peak shaving for T&D deferral, for example) by independently participating in the wholesale market during the out-of-contract hours. This strategy improves the economics of a storage bid and eases the planning burden on a utility that may be focused on solving one specific problem economically without wanting to develop and implement detailed optimal dispatch schemes.

[3] Modeling Energy Storage: Challenges and Opportunities for Washington Utilities https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=3&year=2015&docketNumber=151069

[4] http://www.pacificorp.com/es/irp/wind_integration.html

The UTC notes that while orders from FERC only apply to wholesale markets, the underlying market principles are still germane to any utility operating its own balancing area, as is the case with the three IOUs in Washington. To this end, the UTC opened docket UE-151069 to evaluate the treatment of energy storage in IRP planning. In late 2016, this was combined with docket U-161024 that previously focused on revisions to IRP planning more broadly. An initial IRP rulemaking workshop was held on December 7, 2016 and draft rule language on storage policy and flexible modeling was released on March 6, 2017.

The draft policy statement from the UTC would be significant if implemented as written; a detailed evaluation of storage would need to be included in IRP modeling and a comparative analysis of storage would need to accompany a request for prudence for any acquisition of either a traditional generating resource or even an investment on the transmission and distribution system if that investment did not come specifically from regional planning processes. A net cost approach would be used where sub-hourly models calculate the benefits of storage and then calculate the net present value of those benefits and deduct that value from the resource's capital cost. Although not defined specifically, the draft does also state that the commission would be willing to consider rate design proposals for all customer classes that reflect the cost of serving customers during times of peak demand as well. It is noted that this could encourage investment in cost-effective behind-the-meter storage. In the interim, the commission is willing to consider rate basing storage procurements with the recognition that a traditional cost-benefit analysis may not capture all potential values.

Idaho Policy

In their 2015 IRP, Idaho Power used capacity ($/kW) and energy ($/MWh) costs from a 2014 Lazard study to create candidate portfolios which included vanadium batteries, pumped hydropower, and behind-the-meter thermal ice storage (out of scope for this paper). These portfolios were compared with other resource portfolios and ranked by least cost on the basis of capital plus variable costs. Aurora was used to calculate variable costs and no additional value streams were considered.

No storage-specific policy is currently in place or in development in Idaho by the legislature or commission. There are no energy storage projects in operation in Idaho; however, the Idaho National Laboratory did place on order for a 0.128 MW/0.32 MWh flow battery in mid-2016, though it has not yet been developed

Montana Policy

Montana does not have a storage mandate or modernization program that would encourage the development of energy storage; however, there is potential Montana-based pumped hydropower project, Gordon Butte[5], that FERC approved a final license for in late 2016. The 400 MW Gordon Butte project is under detailed engineering review by the developer and is targeted to seek capitalization for the project next year.

In their review of the NorthWestern Energy 2015 IRP (Docket No. N2015.11.91), the Montana Public Service Commission (PSC) instructed NorthWestern to specifically evaluate pumped hydropower as had been recommended by the NorthWestern advisory committee. The commission also encouraged NorthWestern to consider lessons learned from their two battery storage projects in operation today. Northwestern currently operates a solar plus storage pilot project serving 17 total customers in Deer

[5] http://www.gordonbuttepumpedstorage.com/

Lodge, Mt. as well as a small scale battery located on the distribution circuit near their district office in Helena. They had additionally evaluated thermal energy storage (off-peak ice to reduce on-peak cooling), however that did not proceed and is also outside of the scope of this paper.

The next IRP from NorthWestern is expected in 2018 and a preliminary evaluation of storage is not yet available.

Overall Market Development Activity

The 2013-2016 timeframe encompasses the majority of new storage development and reflects the impact that recent policy and technology changes have had on the market. In total, roughly 1,000 MW / 5,400 MWh of energy storage has been added at utility and C&I scale in ~240 projects across the country (Figure 5). For scale, in an average water year, the Federal Columbia River Power System has a sustained 2 hour peaking capability ranging between 15,500-18,500 MW for a total of 31,000–37,000 MWh depending on the time of year. In addition, a significant portion (541 MW / 400 MWh) of the 2013-2016 additions were the result of just three utility-scale molten salt thermal storage plants. The remaining new capacity was primarily in batteries at a much smaller average size of 2 MW / 2 MWh.

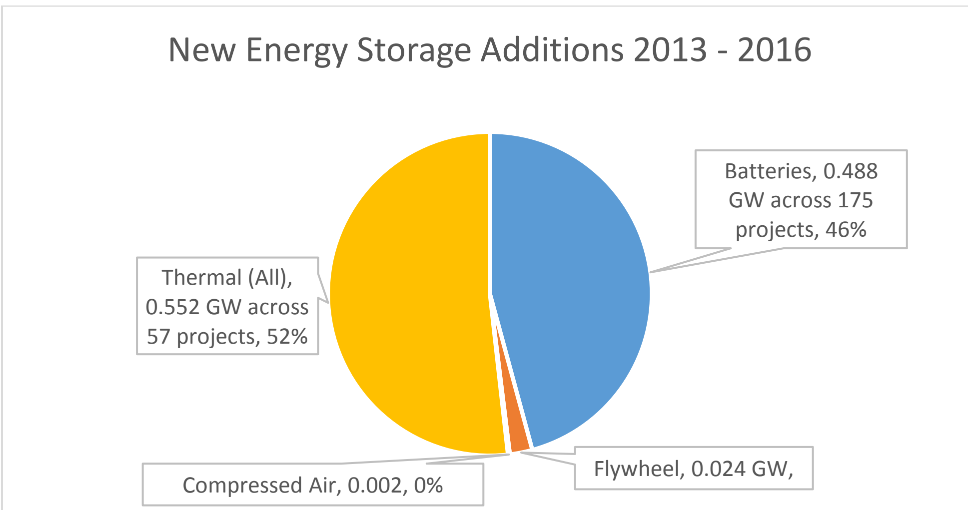
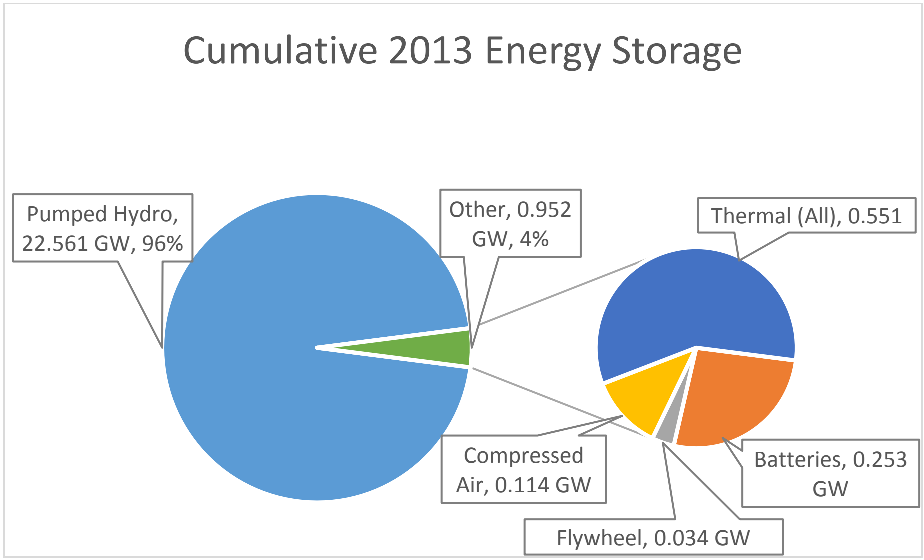


Figure 5: New storage developments at utility and C&I scale between 2013 and 2016. The majority of new projects were in batteries however thermal storage also added significant capacity owing mainly to 3 molten salt projects totaling 0.541 GW of the 0.552 GW of new Thermal storage.

The net effect of 2013-2016 development on the total composition of installed storage has been modest. A national look across all forms of storage technologies at utility and C&I scale shows that pumped hydropower accounted for nearly 96% of the total installed capacity in the United States in 2013 compared to 93% in 2016 (Figure 6). Pumped hydropower is a mature technology with a decade's long history of development at 10's-100's MW/1,000's MWh scale and an average capacity of 600 MW. The most recent new pumped hydropower project was in 2012 in California and the remaining operational projects were completed at least 20 years ago and primarily in the 1960-1970s.



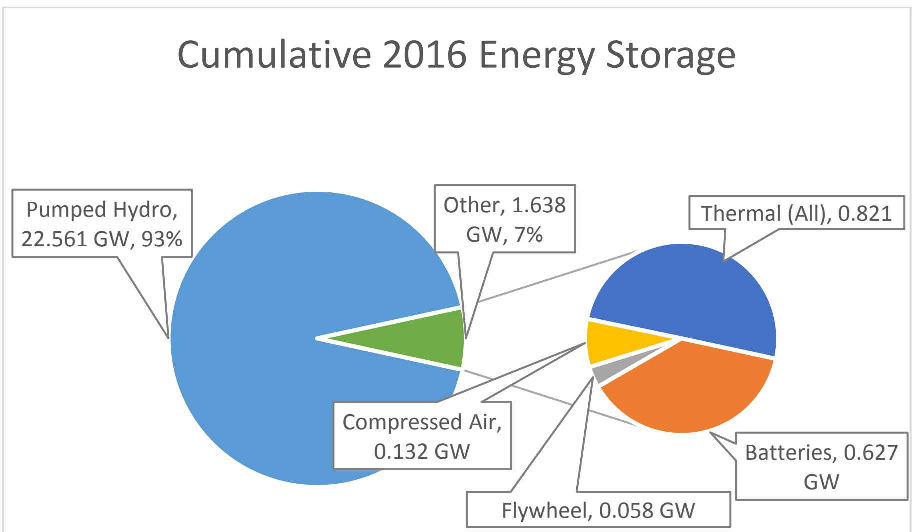


Figure 6: Comparison of installed storage composition from 2013 to 2016.

A regional breakdown of new utility and C&I storage development in 2012 – 2016 is shown by number of new projects (Figure 7) and by project size in MW (Figure 8). California and the PJM interconnection have been the two most active regions in this space, together accounting for a total of 113 projects totaling nearly 600 MW since 2012. Of note, three large molten salt storage facilities (280 MW / 1680 MWh in AZ in 2013, 110 MW / 1100 MWh in NV in 2016, and 150 MW / 1200 MWh in CA in 2016) highlight the impact of scale in a market composed primarily of small projects. A flurry of recent large scale battery deployments in California (10's of MW, 100's of MWh) in early 2017 are likely to re-center this distribution towards California in the future.

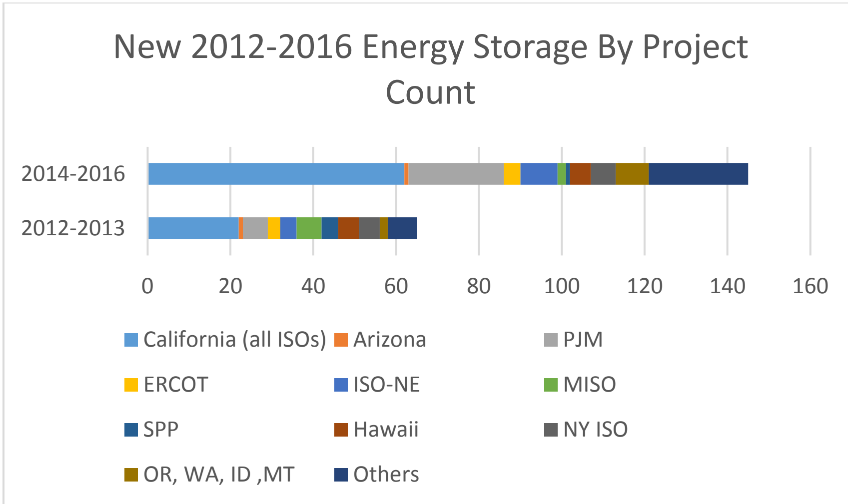


Figure 7: The majority of new project activity (by count) has taken place in California and the PJM interconnection where energy storage mandates and FERC orders have created market conditions which encourage storage development.

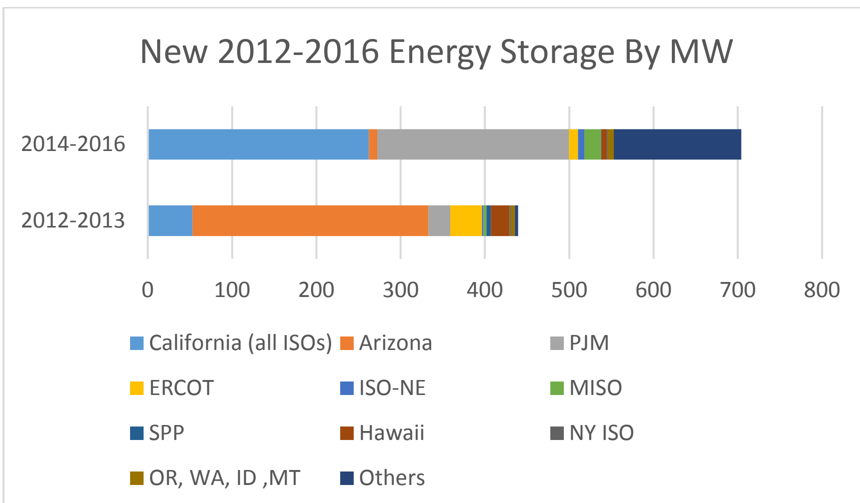


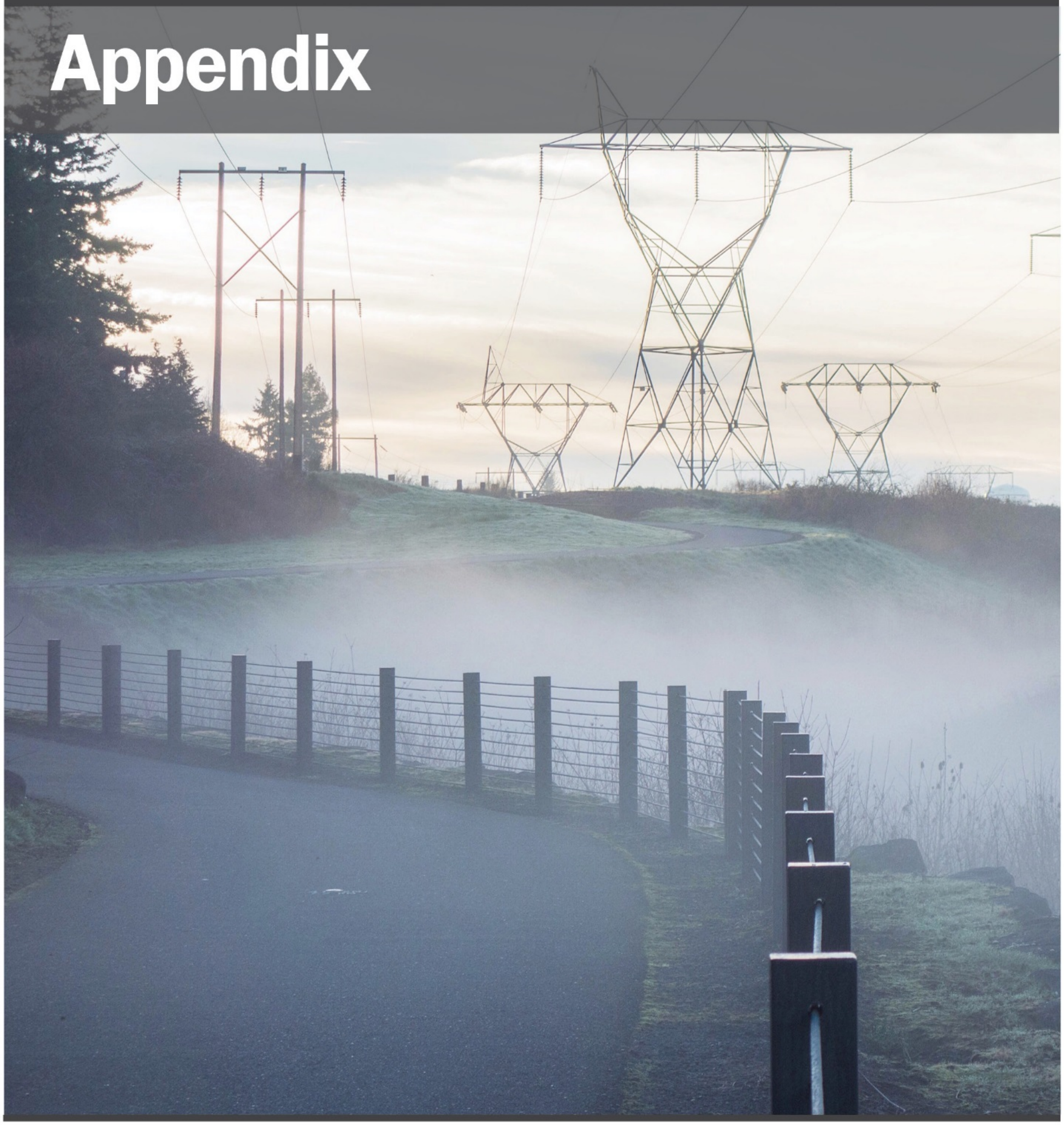
Figure 8: Three large molten salt projects (280 MW / 1680 MWh in AZ in 2013, 110 MW / 1100 MWh in NV, listed under "Others" in 2016, and 150 MW / 1200 MWh in CA in 2016) overshadow the small scale activity taking place in many other regions.

Trends from developments between 2012 and 2016 primarily represent changes in battery storage deployments specifically because of their strong representation in the market activity (> 90% by MW of all non-molten salt developments for nearly every quarter from 2013 – 2016). Discharge duration (in units of MWh) have trended upwards as battery storage costs have fallen. This has the effect of broadening the range of potentially economic value streams and increasing the importance of planning. However, it is important to note that some of the values of storage diminish as additional capacity is added to a single market. For example, the need for fast-responding regulation decreases as more and more fast responding units are added to the system.

The national picture for storage growth has been one of large percentages and relatively small magnitudes and a shift between growth in MW (tied strongly to the application of the project and the cost of the power converter) to growth in MWh (tied strongly to the application of the project and the cost of the storage device itself). For example, taking out molten salt storage projects, there was a total of just 40 MW of new utility and C&I storage commissioned in 2014. The rate of newly commissioned projects increased more than 300% in 2015, however that amounted to just 200 MW of new storage. Year-on-year increases in MWs deployed retracted slightly in 2016 as less than 200 MW of new storage was added. At the same time, falling costs for the storage device itself within the total storage system led to a significant increase of more than 100% in the total MWh deployed in 2016 *vs.* 2015. This could have the potential to broaden the value streams accessible to new storage developments.

White Paper on the Value of Energy Storage to the Future Power System

Appendix



November 2017
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Northwest **Power** and **Conservation** Council

Contents

Value Streams

System Reliability

At an operational level, system reliability refers to maintaining peaking capacity to meet peak demand, continually aligning generation and load, and quickly responding to deviations in frequency which could affect power quality and overall power system stability.

Peaking Capacity

New resource additions are most commonly driven by system resource adequacy requirements in place to ensure that sufficient capacity is available to meet the forecast peak demand within a given planning horizon.

Energy storage of a sufficient discharge duration could defer or replace investment in traditional resources by providing a portion of the expected flexible capacity need. As an energy limited capacity resource, planners and grid operators evaluating storage for this purpose have developed several strategies aimed at assigning a fair and appropriate “effective” capacity for storage. The effective capacity accounts for the fact that state-of-charge (*i.e.* battery charge level, pumped hydro reservoir level, *etc.*) directly determines the amount and duration of flexible capacity available at the time of system need.

Utilities within the region have used at least two strategies to characterize the effective capacity for storage (Figure 1):

1) Duration-Based Capacity: In this paradigm, the storage system must be able to meet a minimum duration of discharge to count towards resource adequacy requirements. As an example, CAISO established a 4 hour minimum duration which would mean that a 50 MW/4 MWh battery has capacity value of 50MW, whereas 50 MW/2MWh has capacity value of 25 MW. Importantly, this strategy assumes perfect knowledge of when the full capacity for discharge will be needed.
2) Electric Load Carrying Capability (ELCC): This strategy assumes that the magnitude of peak system demand is known day-ahead but that the timing of occurrence is somewhat uncertain. A utility can use an loss of load expectation (LOLE) calculated on a monthly basis and put the storage system on fixed schedule to discharge continuously for the period with the highest loss of load probability for each month. Data gathered from this can then be used to calculate the ELCC through a loss of load probability (LOLP) model.

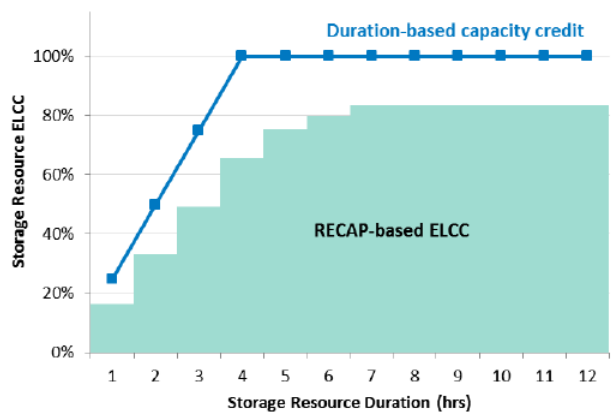

Figure 1: Effective capacity as calculated using duration-based and electric load carrying capability (ELCC). Representative results shown are from the Portland General Electric 2016 IRP.

Balancing

Balancing refers to the temporal management of supply and demand. In 1996, FERC Order 888 adopted four distinct ancillary services to meet system balancing needs,

- **Frequency Response and Regulation:** Encompasses all types of intra-hour energy delivery needed to maintain nominal grid frequency.
- **Energy Imbalance:** Accounts for hourly mismatches between schedule and load. According to Order 888, *"In contrast, Regulation and Frequency Response Service corrects for instantaneous variations between the customer's resources and load, even if over an hour these variations even out and require no net energy to be supplied."*
- **Operating Reserves – Spinning:** Generation that is online and operating at less than full load for immediate contingency response.
- **Operating Reserves – Supplemental:** Generation that is online but unloaded for delayed contingency response.

Unfortunately these definitions are not ubiquitous and can vary from region to region. The following forms of balancing are adopted for the purpose of this paper in lieu of the FERC definitions:

- **Frequency Response:** Autonomous generator action taken on the timescale of seconds to arrest grid destabilizing frequency excursions.
- **Regulation:** Coordinated dispatch of additional resources occurring on the timescale of 5 seconds to 5 minutes. Typically very expensive.
- **Load Following:** Economic dispatch of flexible resources on the timescale of 5 minutes to 1 hour.
- **Contingency Reserves:** Reserves available for contingency response.

These specific services have been chosen on the basis of their use within the IRPs of some regional utilities. FERC's energy imbalance is assumed to be met through sub-hourly economic dispatch.

Renewable Integration/Curtailment Mitigation

Fluctuations in the output of renewable generating resources increases the overall need for system flexibility and in particular the need for fast responding regulation and also load following services. At a system level, the cost of this increased flexibility can be determined as a $/MWh reduction in revenue from renewable generations. To the extent that energy storage can absorb and balance fluctuations from renewable generation, expenses formerly associated with their integrations become an avoided cost.

Economic Dispatch

Energy Time-Shifting/Arbitrage

Energy storage can take advantage of potential peak *vs.* off-peak electricity price differentials by storing energy when prices are low and re-delivering that energy when prices are higher. The margin of price differential between peak and off-peak drives the economic benefit of this value stream.

In the Northwest, peak *vs.* off-peak prices are typically not separated by a wide margin and the lack of a wholesale electricity market can further challenge power producers hoping to capture value from arbitrage alone.

Locational Value

Local Volt/Var Control

Voltage regulation, also commonly referred to as volt/var control, refers to investments and actions taken to maintain nominal grid voltage. This enhances the power carrying capacity of the transmission system and is an important metric of local power quality in the distribution system.

Grid voltage is strongly affected by reactive power, measured in units of var, such that fluctuations in voltage can be mitigated through reactive power management. While large scale generators are capable of providing reactive power, it is much more efficient to deliver reactive power locally to avoid using transmission capacity. Local reactive power has traditionally been delivered through capacitor banks shunted throughout the distribution system however it is also possible for distributed generating resources and energy storage assets to provide this service. Using smart inverters it can be possible, for example, to automatically stand up a falling voltage on a feeder while still providing energy or performing some other service. Providing this level of volt/var control consumes very little energy from the storage device and can improve power quality and defer other investments.

T&D Upgrade Deferral

Energy storage located along heavily loaded T&D paths can be dispatched during times of peak demand to reduce transmission needs from distant generating resources and ease substation transformer loading. This potential benefit is very location specific and would require that planners evaluate segments of their distribution system during resource planning. This level of system analysis is not currently executed by utilities within the region during integrated resource planning.

Local Outage Mitigation

Utilities can harden T&D corridors identified as being prone to unplanned outages by deploying energy storage resources along problematic circuits. An appropriately sized storage system can provide instantaneous back up power to downstream loads in the event of a system outage caused by storms, foliage, *etc.* Storage employed for this purpose must be managed to ensure that a pre-identified minimum state-of-charge is always maintained to ensure unplanned outages can be managed for an expected duration.

Technologies

Batteries

Lithium Ion

Lithium-Ion (Li-Ion) batteries are widely used in consumer electronics and electric vehicles and have likewise been an important part of energy storage projects developed within the last several year. Owing to more than two decades of research and development, Li-Ion batteries have a high energy density (*i.e.* energy per area) relative to other forms of grid storage and are manufactured through a reliable supply chain at commercial scale.

Grid scale Li-Ion batteries are typically a collection of tens of thousands of small batteries (approximately AA size) connected and packaged together to form a larger resource. Although the there are several flavors of detail level Li-Ion battery chemistries, the fundamental composition of each cell is several stacks of brittle thin film anode/cathode pairs separated by an electrolyte (Figure 2). During discharge, lithium ions migrate from the anode into the porous crystalline solid cathode to form a chemical bond which releases energy through a metal current collector to provide power to the grid.

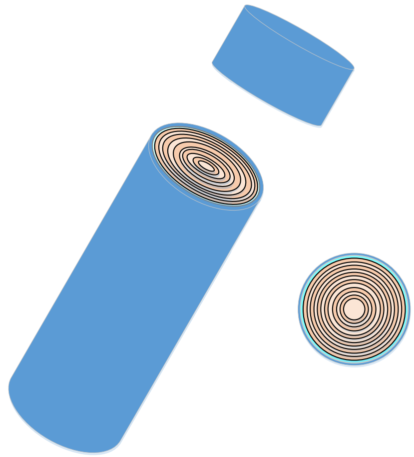

Figure 2: Cross-section of a representative Li-Ion cell. Thin-film anode-cathode pairs are stacked and rolled into a battery case. Insulating paper separates each anode-cathode pair. Thousands of these cells are combined to form a grid scale Li-Ion storage system.

Discharge and recharge cycles cause irreversible degradation to the crystalline lattice of the power producing cathode. This occurs with temperature dependence and worsens the performance of the battery over time. Battery manufacturers work to limit this degradation by limiting the depth of discharge (*i.e.* lowest amount of energy the battery can be discharged today), the amount of cycling, and the temperature of the battery system. Nevertheless, systems with guaranteed performance over 20 or even 10 years tend to be budgeted and built with extra room to add additional racks of batteries as the original cells degrade over time (Figure 3). Manufacturers do not publically share the expected degradation.

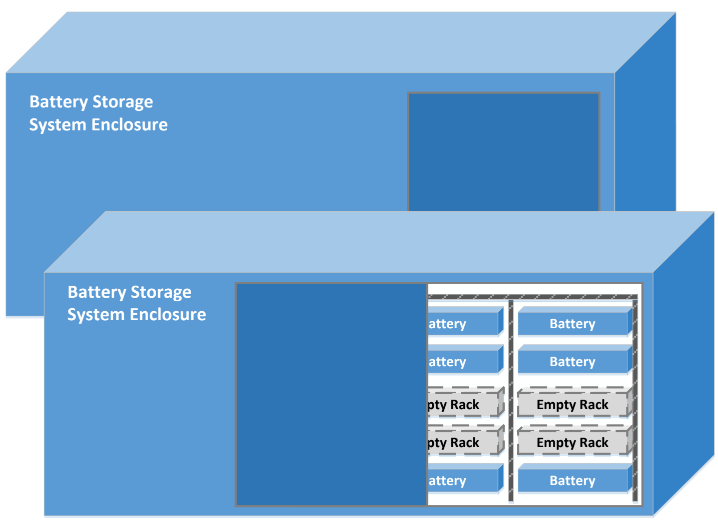

Figure 3: Battery cells are added in racks to a storage container. A developer may opt to leave empty racks to later add additional batter cells as the capacity of the overall unit degrades with cycling.

Flow

The fundamental operation of a flow battery is for two large tanks to separately store the key chemistries for the battery (Figure 4). Pumps are used to cycle the fluid from each tank through a common cell where a chemical reaction occurs to generate electricity. The fluids are separated in the cell by a membrane which prohibits them from mixing. Flow in one direction charges the battery whereas flow in the other direction discharges the battery. The amount of energy (in MWh) stored in flow battery systems is proportional to the size of the tank, and the amount of power (in MW) produced by the battery is proportional the number of cells. In most cases, the tank size and the number of cells in the cell stack can be specified independent of one another.

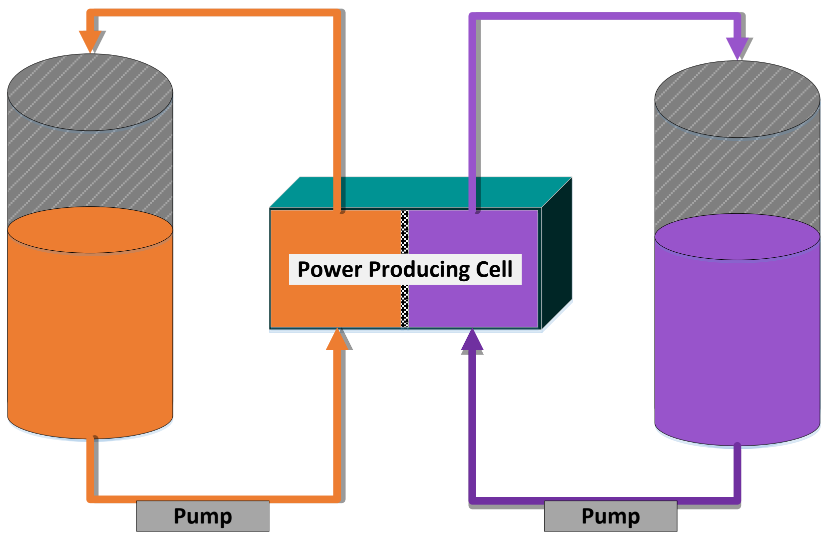

Figure 4: Overview of a flow battery. Fluids within separate tanks are pumped into a fuel cell where charge transfer takes place. The size of the tanks determines the energy and the number of cells determines the power.

There are several flow chemistries in use or under development including vanadium redox and zinc bromide. In general, the energy density and round-trip efficiency of flow batteries is not as high as that of Li-Ion. However, flow batteries can typically be cycled significantly more frequently than Li-Ion without impacts to performance.

Compressed Air

The general layout of a compressed air energy storage (CAES) plant is shown in Figure 5. Off-peak energy is used to power electric machines which compress ambient air and store it underground at pressure. When needed, the compressed air can be released back to the surface to flow through an expansion turbine where it is mixed with natural gas and combusted to generate electricity. The CAES turbine is very similar in principle to a conventional natural gas turbine except that the compression stage is already completed.

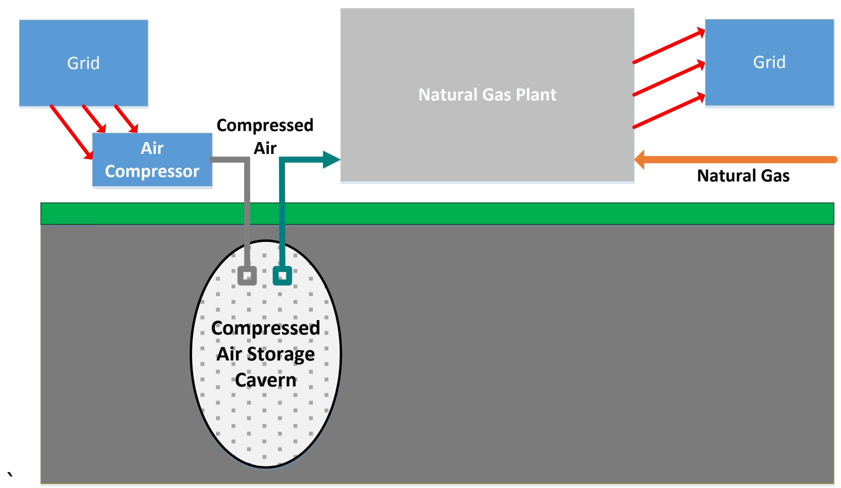

Figure 5: A typical CAES plant. An ambient air compressor is run when electricity prices are low. The high pressure air is stored underground. When prices are high, the compressed air is released back above ground where it mixes with natural gas inside of a turbine for combustion. This saves the compression stage of the gas turbine.

Compression is a very energy intensive process and typically consumes 60% of the turbine capacity in a traditional system. Thus, a CAES turbine where the air is already compressed can generate 3 times more energy using the same amount of natural gas for combustion. However, the overall system is still only 42-55% efficiency because a significant amount of natural gas is combusted specifically to re-heat the compressed air prior to expansion in the turbine. Future systems may reach efficiencies as high as 70% by better capturing and re-using the heat generated during initial compression which is otherwise dissipated via inter- and after-cooler before underground injection.

There are only two existing large scale CAES plants in the world; a 290 MW/580 MWh plant commissioned in 1978 in Huntorf, Germany and a 119 MW / 2860 MWh plant commissioned in 1991 in McIntosh, Alabama. Both of these plants store compressed air in underground salt caverns formed hundreds of feet below the surface by solution mining. These type of deposits are not common around the world and are not present in the Northwest. However, a study led by the Pacific Northwest National Lab in collaboration with the Bonneville Power Administration and other industry partners identified that underground porous and permeable rock structures located in Eastern Washington and Oregon may be suitable candidate CAES sites. Modeling studies indicate that two potential sites in particular could produce plants at ~230MW and ~100MW scale with continuous discharge durations on the order of 400 hours or more at potentially cost competitive rates.

Flywheels

Flywheel energy storage works by coupling an electric motor/generator to a large cylinder spinning in on a near frictionless bearing within a vacuum enclosed space. During off-peak hours, the electric machine acts as a motor and accelerates the spinning mass. Energy can later be withdrawn by decelerating the mass to convert mechanical energy back to electrical energy.

Flywheels are typically best suited for short duration power (rather than long duration energy) applications and can operate at up to 10MW with discharge times from seconds to potentially up to 15 minutes. Round-trip efficiency is typically in the range of 70-85% and is driven in large part by stand by energy loss due to friction while spinning in unloaded standby.

Pumped Hydropower

Pumped storage is the most mature and well represented storage technology around the world. A typical pumped hydro project is shown in Figure 6. Water is pumped from the lower reservoir to the upper reservoir during off peak hours by a turbine connected to an electric machine. When energy is needed, the water flows back through the turbine and spins the electric machine to generate electricity.

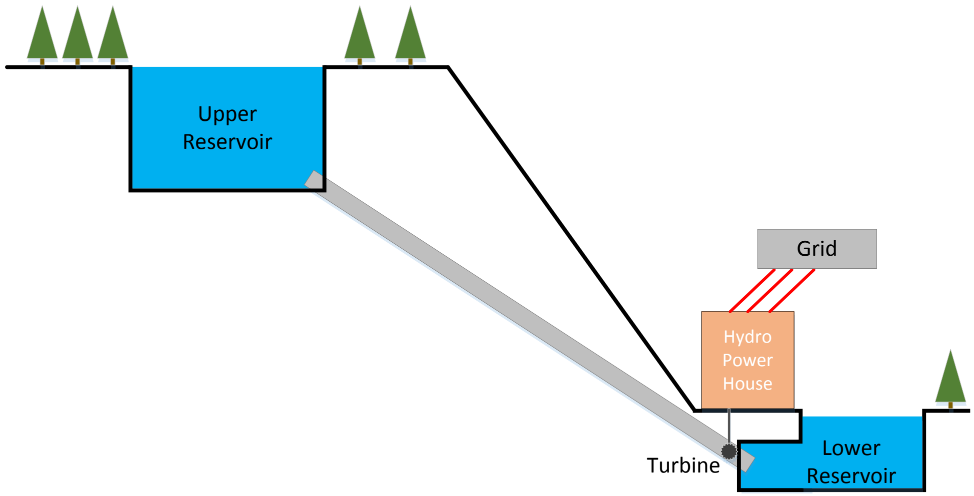

Figure 6: Pumped hydropower moves water between an upper and lower reservoir.

Pumped hydropower plants are available at all power and energy scales and typically operate near 80% efficiency. Variable speed motor/generators have the potential to increase efficiency by optimizing the operating speed for the turbine in pumping *vs.* generating mode. Units with a variable speed electric machine could also provide frequency response during pumping mode by slowing down and therefore decreasing pumping demand. Ternary pumped hydropower systems – available since 2009 - can offer flexibility even above and beyond variable speed units by stacking the pump and generator on a single shaft to allow for simultaneous pumping and generation and, therefore, very fast transitions across the full range of operating modes.

Detailed Northwest Regional Development and Planning Activity

A detailed description of the planning methodologies being executed by each utility and state is provided below.

Oregon

Portland General Electric

As a part of their draft 2016 IRP[1], PGE devoted a chapter to their analysis of energy storage and also submitted a request for information (RFI) from storage vendors to begin information gathering in preparation for their project proposal development to be submitted to the OPUC.

PGE's analysis utilized their Resource Optimization Model (ROM) to assess the potential benefits of storage within their system. Originally developed to quantify the operational challenges and costs

[1] https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning

associated with renewable integration, ROM extends beyond the energy and capacity only modeling tools typically used in IRP planning by executing optimal unit commitment and dispatch of the entire PGE resource fleet over multiple time horizons with forecast errors (*i.e.* day-ahead to real-time), ancillary service requirements, and sub-hour dispatch. According to PGE, ROM dispatches their full portfolio to minimize the net cost of meeting demand, is able to shift energy through charging and discharging cycles, and enables storage and other assets to provide contingency reserves (spinning and non-spinning), upward and downward regulation (for <5 minute fluctuations), and upward and downward load following (for 15 min to 1 hour fluctuations). Locational benefits such as transmission and distribution deferral were not studied.

System cost estimates similar to those presented in the original document's Technology subsection were provided to PGE by Black and Veatch. Pumped storage was not considered although PGE plans to incorporate it into future IRPs. A single test year of 2021 was used for simulation on the account of computational constraints. This has the effect of assuming factors effecting the utilization and overall economics of a storage asset are consistent year-to-year through the lifetime of the device.

The capacity contribution of the storage systems were scaled and simulated using the duration and Electric Load Carrying Capability (ELCC) methodologies described in the Appendix Section Value Streams. Using each method of capacity contribution, PGE compared the net cost impact of storage *vs.* a generic frame combustion turbine (GE 7FA.05). Net cost is the annual fixed cost net of the operational value provided to the system as calculated through ROM. Figure 7 shows an example comparison between a 50 MW, 2 hour battery and a 25 MW frame; the example resource with the lowest net cost impact (*i.e.* the frame) is most cost effective.

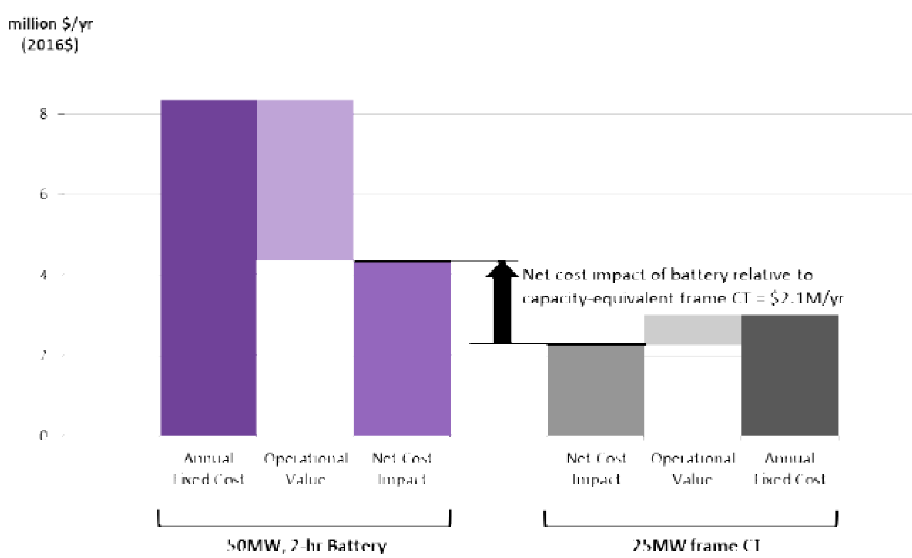

Figure 7: In this example, which assumes a duration based capacity credit, the economics of a 50MW, 2 hour battery are compared to that of a 25MW frame CT. The frame has a lower net cost impact and is therefore a better value than storage in this example. Image from Portland General Electric 2016 IRP.

PGE also presented their cost effectiveness analysis using an alternative but mathematically equivalent conceptual framework. In this framework, they attribute a capacity value to the battery system which is equal to the net cost avoided by displacing the capacity-equivalent default frame resource. The storage element would then be considered economic if the sum of its operational value, capacity value, and any additional identified values exceed the annual fixed cost of the battery system (Figure 8). Again, this is simply an additional conceptual framework; mathematically it is identical to their net cost impact comparison approach.

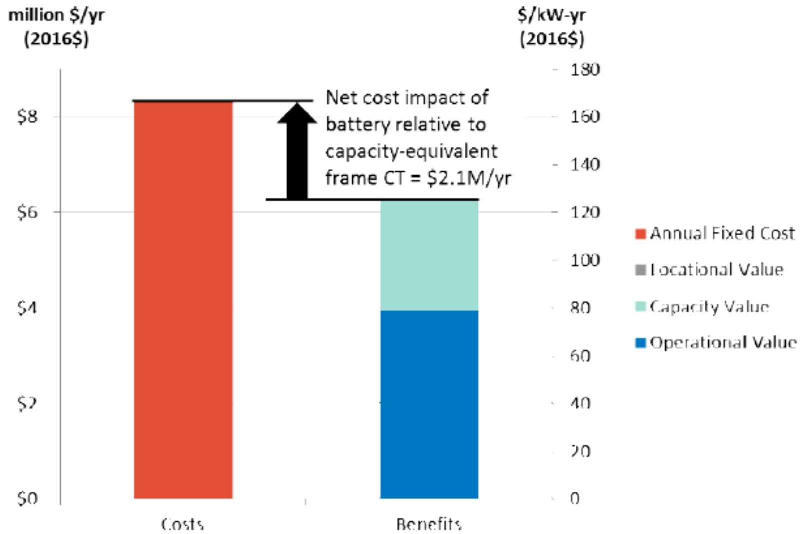

Figure 8: An alternative conceptual evaluation of the economics of storage vs. CT. The net capacity value of the CT is added to the operational value of the storage asset. Storage is economic if the sum of the values exceeds the cost. This is mathematically equivalent to the previously presented evaluation. Image from Portland General Electric 2016 IRP.

An example of the simulated dispatch behavior for summer (June) and winter (January) is shown in Figure 9 and Figure 10, respectively. During the summer, the battery tends to charge during the low load morning hours (shown as negative MW net schedule) and discharge during the on-peak period of the day (shown as positive MW net schedule). Reserves are provided above and below the net schedule based on the battery state of charge and economics of storage *vs.* other resources. Comparatively, in the winter the battery is primarily scheduled for reserve only and provides very little scheduled energy. Across the 2021 test year the storage asset is shown to consistently provide multiple services at the same time (Figure 11).

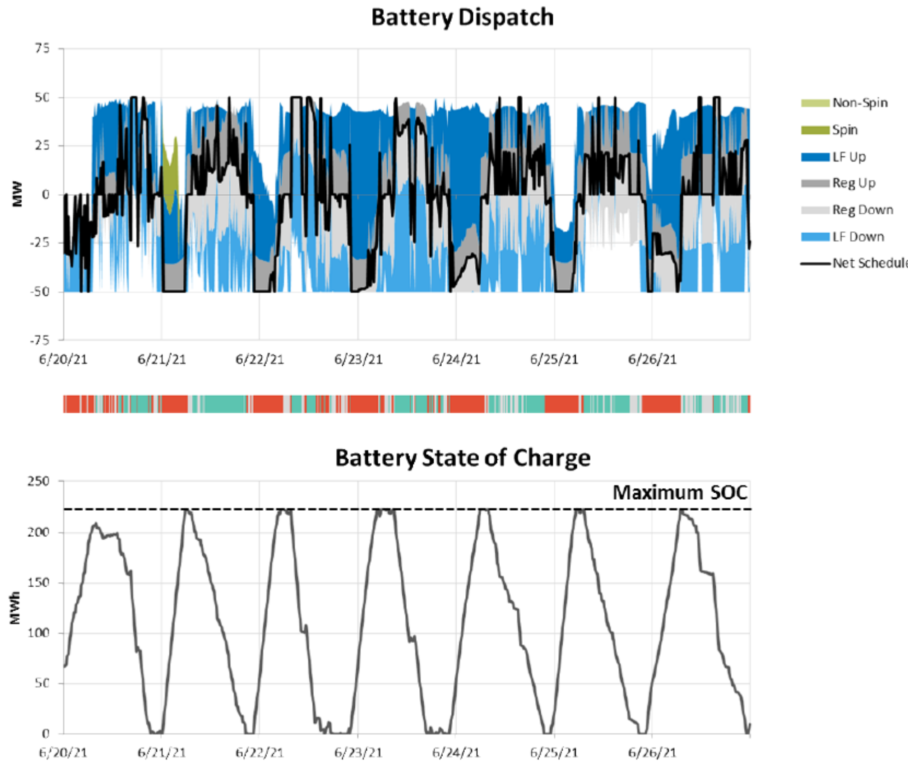

Figure 9: Storage dispatch in summer. Image from Portland General Electric 2016 IRP.

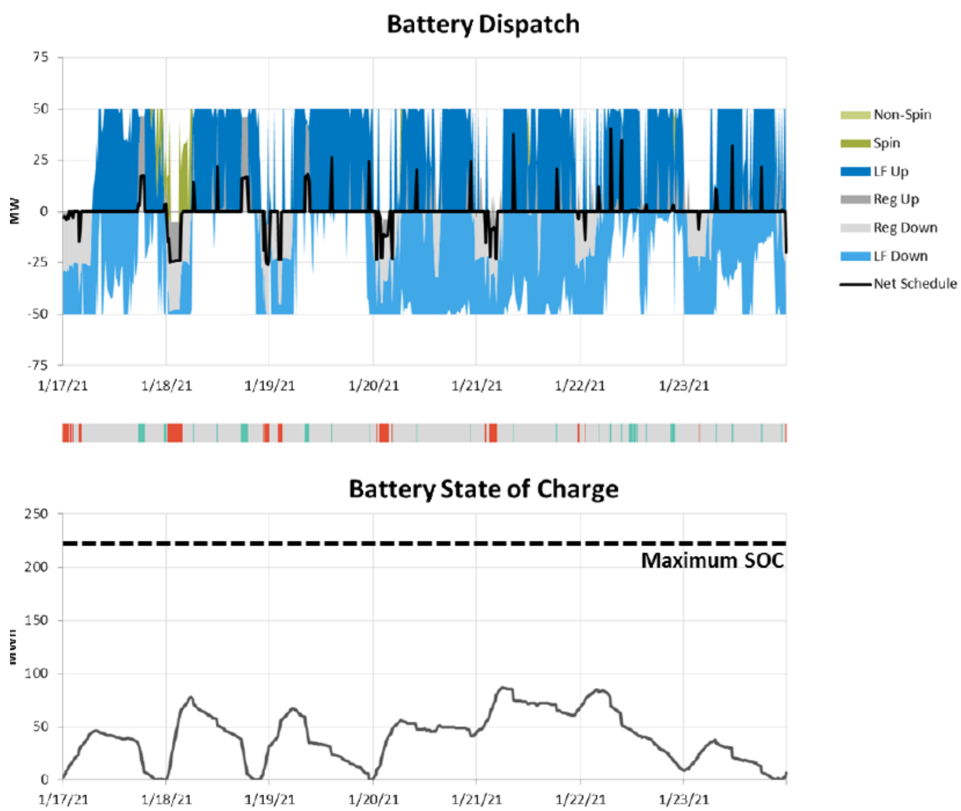

Figure 10: Storage Dispatch in winter. Image from Portland General Electric 2016 IRP.

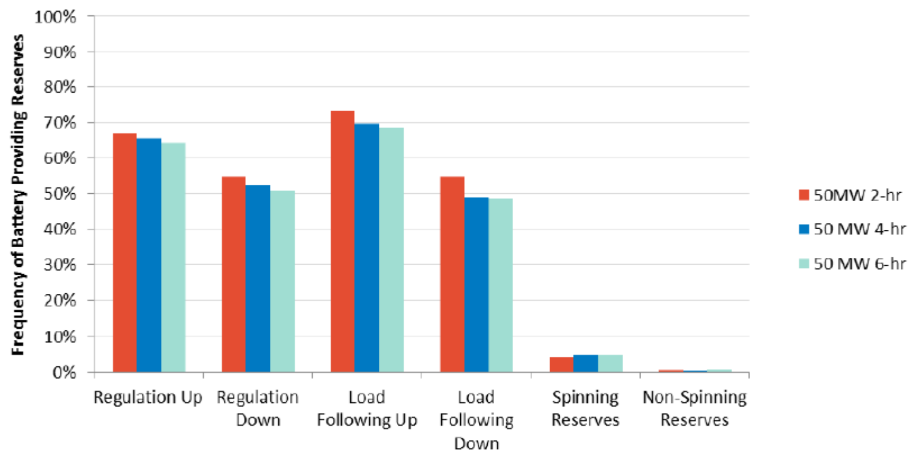

Figure 11: Year-end summary. The fact that the sum of the frequencies exceeds 100% indicates that the battery was commonly scheduled to provide multiple services simultaneously. As with conventional resources, this is possible if, for example, the battery is discharging at half capacity and could increase or decrease output if needed. Image from Portland General Electric 2016 IRP.

Concluding their analysis, PGE found that storage at multiple sizes and using both capacity evaluation strategies do not currently yield an economic net cost impact relative to a frame CT (Figure 12). A negative net cost impact would have indicated the value of storage (sum of operational value, capacity value, *etc.*) exceeded its costs.

Configuration	50 MW, 2-hr	50 MW, 4-hr	100 MW, 2-hr	100 MW, 4-hr
Fixed Costs (2016$/kW-yr)	$167	$371	$167	$371
Operational Value (2016$/kW-yr)	(79.5)	(84.2)	(64.4)	(67.6)
Capacity Value (2016$/kW-yr)	(30.4) – (45.8)	(60.1) – (91.6)	(30.4) – (45.8)	(60.1) – (91.6)
Locational Value (2016$/kW-yr)	(0)	(0)	(0)	(0)
Net Cost Impact (2016$/kW-yr)	41.4 – 56.8	195 - 227	56.5 - 71.9	212 - 243

Figure 12: This is the second conceptual framework where values are subtracted from costs. A positive net cost impact means costs exceeds value and it is not economic. Image from Portland General Electric 2016 IRP.

PacifiCorp

PacifiCorp has followed a very consistent approach to valuing energy storage throughout their 2013, 2015, and forthcoming 2017 IRPs [2]. PacifiCorp has contracted with industry firms (HDR, DNV-GL, Black & Veatch) to obtain cost, specification, and performance data based on a review of RFOs (when available), publicly shared data, and consultant experience. Additionally, PacifiCorp has had their contractors provide detailed information about several specific proposed pumped storage and compressed air energy storage projects.

[2] http://www.pacificorp.com/es/irp.html

PacifiCorp uses a System Optimizer model to optimize the present value revenue requirement (PVRR) through a 20 year horizon. The PVRR includes the net present value cost of existing contracts, spot market purchase costs, spot market sale revenues, generation cost (fuel, fixed, O&M, *etc.*), demand side management costs, and amortized capital costs for existing coal resources and other potential future resources. The goal of this least-cost dispatch tool is to maintain resource adequacy with a 13% planning reserve margin through optimized resource additions subject to costs and capacity constraint. The model uses a representative-week method where time-of-day hourly blocks are overlaid using a user-specified day-type pattern. Each month is developed using one representative week scaled to match the number of weeks in the month. Broad transmission flows are constrained and reserves are not included.

The System Optimizer treats energy storage as an energy limited conventional generator dispatched to optimize energy use subject to constraints including round-trip efficiency, daily balance of charge and discharge energy, *etc.* Typical characteristics including capital cost, size of storage and time to fill, heat rate (if fuel is used), O&M, and minimum and maximum capacities are used to determine the economics of dispatch.

PacifiCorp uses a second Planning and Risk (PaR) model to manage risk in its production cost estimates and to ensure adequate reserves are included and valued in the system. A stochastic dispatch of the portfolio from System Optimizer is simulated using a Monte Carlo[3] random sampling of load, wholesale electricity and natural gas prices, hydro generation, incremental reserve requirements associated with wind, *etc.* A week-ahead unit commitment model is used and operating resource requirements are accounted for.

PaR schedules storage to charge and discharge energy to minimize system cost by treating the value of energy used for charging as the marginal cost of generation for dispatch. In addition to the value of energy, PaR identifies the incremental operating reserve benefit of storage but does not include other values such as frequency or locational benefits.

In their 2015 IRP, PacifiCorp studied the potential impact on PVRR of a pumped and compressed air energy storage system. The results from PaR indicate that the projects would not be economic and therefore storage was not selected (Figure 13). Detailed dispatch profiles were not provided.

	Sensitivity Case S-06 (Pumped Storage)		
	Low Price Curve Scenario	Base Price Curve Scenario	High Price Curve Scenario
PVRR without Storage Resource Fixed Costs ($m)	($76)	($74)	($72)
PVRR of Storage Resource Fixed Costs ($m)	$511	$511	$511
Total PVRR ($m)	$435	$437	$439
	Sensitivity Case S-08 (CAES)		
	Low Price Curve Scenario	Base Price Curve Scenario	High Price Curve Scenario
PVRR without Storage Resource Fixed Costs ($m)	($87)	($80)	($76)
PVRR of Storage Resource Fixed Costs ($m)	$453	$453	$453
Total PVRR ($m)	$366	$373	$378

Figure 13: Results from PacifiCorp 2015 IRP showing results of PaR study evaluating cost effectiveness of storage.

[3] A Monte Carlo random sample runs a model multiple times using probabilistic simulation parameters to cover a range of suspected potential future conditions.

Washington, Idaho, Montana

A description of the storage related activities from utilities within Washington, Idaho, and Montana was provided in the original document that this appendix accompanies and is at a sufficient level of detail to describe the practices executed in each state thus far.