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ADVANCED ENERGY STORAGE IN INTEGRATED RESOURCE PLANNING (IRP)

2018 Update • Energy Storage Association

EXECUTIVE SUMMARY

Energy storage deployments are increasing across the U.S., contributing to a more efficient, resilient, sustainable, and affordable grid. To continue this progress, it is imperative that utility integrated resource planning be updated to consider advanced energy storage as a viable option for system capacity. Energy storage costs are declining rapidly, and large-scale storage deployments are increasing. With electric utilities planning to invest billions of dollars in new and replacement capacity over the next several years, the time is now to include storage in resource planning to ensure least-cost solutions for ratepayers and prudent long-term investments for reliability.

In this June 2018 update to ESA's primer on *Advanced Energy Storage in Integrated Resource Planning*, we provide an overview on how to appropriately include advanced storage in long-term utility resource planning processes with examples from utilities already doing so. In addition, the report includes a set of up-to-date cost inputs from publicly available sources, a summary of utility IRPs from 2016-2017 that examine energy storage, and a list of recent state regulatory decisions on including storage in IRPs.

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I. LEAST-COST UTILITY PLANNING MUST CONSIDER ADVANCED ENERGY STORAGE AS A CAPACITY RESOURCE

Utilities prepare integrated resource plans (IRPs) to determine the combination of resources that will enable them to meet forecasted annual peak and energy demand, plus an established reserve margin, over a specified future period (usually 10-20 years). Those IRPs then inform utilities' subsequent decisions on what kind of resources to build/own or to procure from other parties through long-term contracts.

While many utilities have demonstrated an interest in recent years to understand the costs and benefits of advanced energy storage in the context of IRPs, informational barriers remain: many models continue to use inaccurate or out-of-date storage cost information; planning models are not granular enough to fully capture the operations of advanced storage; and analyses of model results overlook forthcoming system needs for flexibility. Planners are thus missing the opportunity to analyze, evaluate, and procure advanced storage as a cost-effective capacity resource, risking imprudent investments.

Utilities and utility commissions have begun to address these barriers. Advanced energy storage is now commercially contracted—and procured competitively against traditional resources—at project scales of 100 megawatts (MW), on par with natural gas-fired power plants. Storage cost estimates are available in public sources, many of which are updated annually or quarterly to support understanding of current trends. Several validated commercial planning models in use today capture intra-hourly operations of storage and other resource options. Additionally, these newer models can quantify system needs for flexibility, as well as capacity. A range of utilities have recently demonstrated new analytical insights from models that include storage, which other utilities can learn from and build on. If utilities and the commissions that regulate them update their approaches to storage in IRPs, choosing storage as a capacity resource can be made on an economic basis today, avoiding costs and risks to ratepayers.

This document provides information on modeling storage and a framework for evaluation of benefits of storage resources in IRP analyses. Additionally, this document offers public sources of current and forecasted costs and benefits of advanced energy storage.

Key Takeaways:

- Planners who use up-to-date cost estimates and forecasts in their models can more accurately identify the near- and long-term prudence of energy storage;
- Models that use sub-hourly intervals can quantify the value of both capacity and flexibility benefits provided by advanced energy storage;
- By using a “net-cost” analysis—subtracting flexibility benefits from the cost of storage—planners can more accurately compare advanced energy storage with traditional capacity resources;
- Models that examine system flexibility needs and employ risk management techniques are more likely to reduce costs to ratepayers, especially through the use of storage; and
- Commissions can require regulated utilities to consider advanced storage in IRPs under their existing authority, either through policy statements, rate cases, or rulemakings.

II. HOW TO EFFECTIVELY INCLUDE ENERGY STORAGE IN IRPs

IRPs and other long-term utility planning methods proceed through a series of steps to transform inputs and assumptions into outputs that guide long-term capital investment decisions.

1. INCLUDE STORAGE AS AN INVESTMENT OPTION

Following the calculation of load forecasts, every IRP lists the supply resources that are included as possible options for

planning models to use in meeting load forecasts—also known as a “resource screen.” Even today, as a result of using outdated technology types for the proposed application or outdated cost data, many IRPs dismiss storage technologies during the resource screen as either too costly or not technologically mature. IRPs also occasionally don’t source a citation to support the dismissal, and in some cases, energy storage is not even mentioned.

Simply put, any resource screen that excludes advanced storage puts ratepayers at greater risk of imprudent investments. More than 800 MW of advanced storage has been deployed in the U.S., with over one third of that capacity installed in 2017. Multiple IRPs in 2016 and 2017 have concluded that storage is a viable investment option in the resource screen, eventually selecting storage on economic grounds (see Section III). Additionally, multiple open utility procurements have resulted in storage being selected as more economic than traditional generation and infrastructure options. Since technological maturity and costs are relatively consistent across U.S. utility regions, it is incorrect to categorically assert that storage maturity and cost disqualify it from consideration.¹

To ensure prudence to ratepayers, therefore, commissions should require their regulated utilities to include energy storage as an investment option in the resource screen of their IRPs.

Additionally, energy storage should be considered as an explicit part of demand resources screening.

DEMAND RESOURCES AS SUPPLY

All IRPs begin with a load forecast over the next 10-20 years. These load forecasts represent the anticipated needs that a supply portfolio must satisfy. While most utilities have engaged in demand-side management strategies for years, the results of those efforts most commonly have been factored into load forecasts, rather than treated as a capacity resource. Similarly, customer-sited generation is forecast and then factored into load forecasts. As a result, demand-side resources are not treated as options for a capital investment plan. This approach can produce sub-optimal investment results for utilities, precluding customer-sited energy storage investments for system capacity.

Customer-sited energy storage offers an innovative way to deploy demand resources as capacity. Customer-sited storage is highly controllable, can be dispatched quickly and precisely, and importantly, can be measured directly by utilities for system operations. Aggregations of customer-sited storage are already being used by utilities to meet capacity needs, such as in Arizona and New York.

Instead of factoring demand resources into load forecasts, utilities can separately analyze controllable customer-sited resources such as energy storage as a potential supply option. For example, in its 2017 IRP, the utility Arizona Public Service (APS) examined a range of customer resources—energy efficiency, traditional demand response, rooftop solar, and energy storage—as separate supply options from its load forecast. APS ultimately selected demand response and microgrids, energy efficiency, and distributed generation as part of its portfolio.¹ APS is procuring those resources in part through innovative measures like the Demand Response, Energy Storage and Load Management Program, which proposes the first-in-the-nation “reverse demand response” program that would pay customers for load-shifting with energy storage.



¹ While lithium-ion batteries are the dominant advanced storage technology, storage technologies using alternative chemistries or other means of storage (i.e., thermal or mechanical) may be at varying stages of maturity and cost curves. For the purposes of IRP resource screening, ESA recommends that utilities be clear and specific on the range of storage technologies under examination.

Note also that installed costs may vary slightly by utility territory based on non-technology costs, like labor, permitting, and taxes.

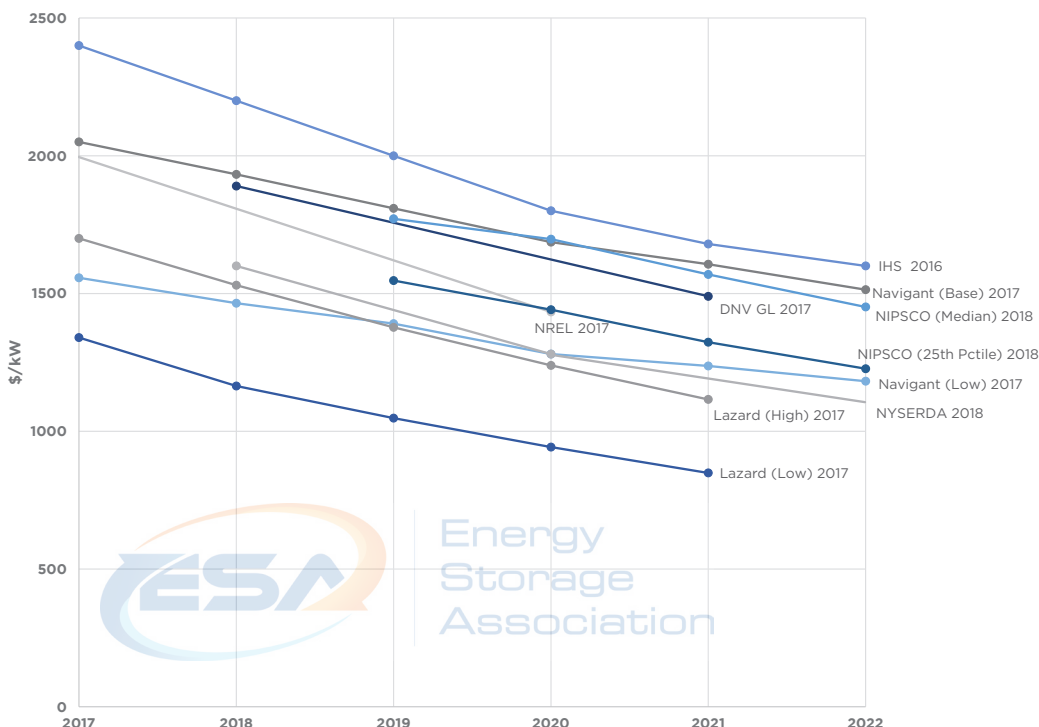
2. USE ACCURATE DATA ON COST AND PERFORMANCE

Planners should, at minimum, annually update their cost estimates of advanced storage. Numerous sources report the installed cost of advanced energy storage has declined significantly in recent years, generally faster than market expectations.² While estimates of the rate of reduction vary, cost declines of 8-15 percent year-on-year are projected.³ Considering this rapid and recent technical progress, it is critical that planners use up-to-date advanced storage cost estimates and forecasts for IRP model inputs. Not doing so risks basing investment decisions on outdated assumptions.

Planners should also use a declining cost curve when projecting the future cost of storage. Utility IRPs typically assume the cost of conventional supply technologies increase over time, based on inflation, since combustion turbines and other traditional generation technologies are no longer experiencing significant cost declines. Advanced storage is different because the rapidly increasing scale of manufacturing capacity and deployment has resulted in significant unit cost reductions. This trend is expected to continue within current IRP planning windows, typically 10 to 20 years.

Figure 1: Installed Costs of Large-Format Lithium-Ion Battery Energy Storage, 4-Hour System⁵

While advanced energy storage technologies are diverse, lithium-ion battery storage is the most common technology being deployed today. Figure 1 presents a range of recent, publicly-sourced estimates of the installed cost of a large-scale (10+ MW) lithium-ion energy storage facility with 4-hour duration.ⁱⁱ Note that total installed costs are described as a capacity value (\$/kW) to make them readily comparable to traditional capacity options.⁴ Total costs include batteries, balance of systems, financing costs, and O&M. Note that these costs will vary for battery storage facilities of different sizes and do not scale linearly as duration is increased.ⁱⁱⁱ



Additionally, IRPs should use the most recent vintage sources available for performance data on storage, such as round-trip efficiency and cycle life.

ⁱⁱ4 hours of duration is considered sufficient to contribute meaningfully to system resource adequacy in a variety of states and wholesale markets. At time of writing, over 300 MW of 4-hour or longer battery storage is deployed or in development at bulk scale across 7 states.

ⁱⁱⁱMany sources report storage capital costs as a function of duration at rated capacity (\$/kWh) so as to make their figures applicable to range of project durations. This is a flawed approach, however, as only the battery costs scale with duration; power controls and other balance of system costs do not vary significantly with battery duration. The result is to overstate the cost of longer-duration storage, when PCS/BOS costs are a smaller proportion of total cost, and understate the cost of shorter-duration storage, when PCS/BOS costs are a larger proportion of total cost. For this reason, ESA recommends that estimates for varying durations (e.g., 30-minutes, 2-hour, 8-hour) of battery storage facilities use capital cost figures (\$/kW) specifically estimated for those project durations.

3. EMPLOY GRANULAR RESOURCE MODELING

With a growing number of exceptions, most IRPs still use methods that do not adequately model energy storage. Typical IRP models use three inputs—forecasted demand, the capital cost of available technologies, and those technologies’ operating profiles—to calculate long-term economic options for system capacity. These models tend to be simplistic because they only capture the uncomplicated operations of traditional generation units providing capacity.

In contrast, current-day advanced energy storage provides high value grid flexibility services, like frequency regulation or ramping support, in addition to capacity. A large-scale energy storage resource dedicated to providing peak capacity when needed—typically a four-hour period in the afternoon and early evening—can also provide grid services for the many hours when its peak capacity is not needed. Storage resources can do this because they are “always on” and available for service, in contrast to traditional generation units that need to be started up and shut down to provide peak capacity and other services. As a result, planners do not often have updated tools on hand to estimate the full benefits of storage resources.

For this reason, it is important to update the methods used in IRPs to accurately model advanced storage. Models that use sub-hourly intervals can capture the flexibility of storage operations to provide both capacity and grid services. Several validated commercial models are available that can calculate economic resource options including intra-hourly dynamics, such as PLEXOS,⁶ SERVM,⁷ and E3 REFLEX.⁸ If sub-hourly modeling is not possible, then at minimum an hourly chronological production cost model should be used, rather than sampling from a small set of hours from each season.

TIME INTERVALS IN IRP MODELING

Typical production cost models are relatively simple and calculate economic options by modeling generator operations to meet expected load for *each hour chronologically* over a period of many years. The main shortcoming of this type of model is that advanced storage can provide grid flexibility services on an *intra-hourly* basis, and there is no way to capture that service in an hourly model.

Some models are even more rudimentary and extrapolate from a small *sample of hours* for each season to simulate load and generator dispatch patterns for all hours over a period of many years. The main shortcoming of this type of model is that advanced storage provides services, like system ramping for renewables, that are only captured by a full chronological series of hourly or sub-hourly intervals *over the course of a full day*. Thus, using a small number of sample hours will exclude significant storage services and result in inaccurate extrapolation for long-term planning.

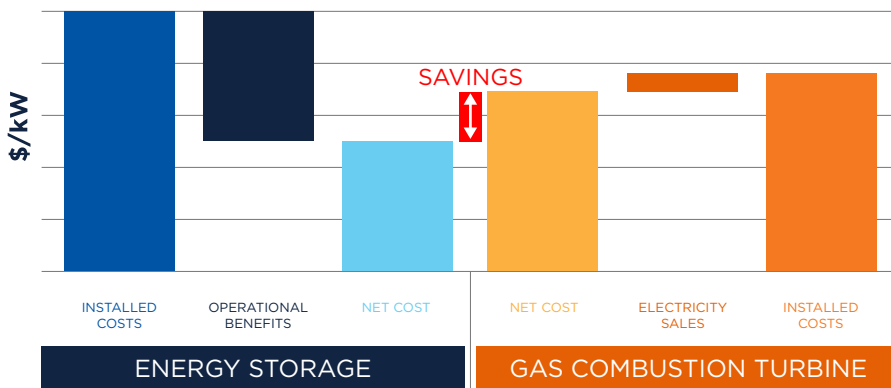


4. COMPARE OPTIONS ON A NET-COST BASIS

The flexibility benefits of advanced storage operations are significant and represent a substantial addition to the capacity value of storage. The most straightforward method to incorporate such storage benefits into IRPs is to use a *net-cost-of-capacity* approach, as pioneered by Portland General Electric in their 2016 IRP.⁹ This concept is illustrated in Figure 2:

$$\text{Net cost of capacity} = \text{Total installed cost} - \text{Operational benefits (flexibility operations \& avoided costs)}$$

Figure 2: Example of Net Cost of Capacity Calculation



Some of the operational benefits of storage are grid flexibility services directly provided by the individual unit in question. Among these benefits are (1) regulation, (2) load following, and (3) contingency reserves. When these additional services of storage are modeled, they can equal or even exceed the capacity value of storage. For example, preliminary findings from Portland General Electric’s 2016 IRP found that operational benefits of storage (~\$90/kW-yr) were expected to be approximately two times larger than the capacity value (~\$40/kW-yr).¹⁰

Other operational benefits of storage accrue to the entire system as avoided costs (see Table 1).

Table 1: Avoided System Costs from Use of Energy Storage

AVOIDED COST	EXPLANATION
1. Reduced operating reserves requirements	Fast-responding energy storage is ideally suited to manage grid stability, allowing reliability to be maintained with fewer total megawatts of regulation and spinning reserves
2. Reduced start-up and shut-down costs of generating fleet	Energy storage either (i) ramps up to capture short-term peaks, thereby allowing generators to remain offline rather than start-up for short duration service; or (ii) ramps down to absorb energy, thereby allowing generators to remain online that would otherwise go below minimum set points
3. Improved heat-rate of thermal plants and consequently reduced emissions	Energy storage ramps up and down repeatedly to enable generators to avoid cycling, allowing them to remain their most efficient heat-rates, lowering emissions
4. Reduced uneconomic dispatch decisions	Energy storage can supply electricity for shorter-duration intervals, avoiding uplift or revenue sufficiency guarantee payments to generators whose ramp rate limitations would require them to stay online to be available in future intervals
5. Reduced curtailment of renewable resources	Energy storage charging can absorb electricity, allowing variable renewable generation to continue in oversupply conditions and be re-delivered at future intervals
6. Reduced risk of exposure to fuel price volatility	As energy storage provides functions that fueled thermal generators provide, diversification reduces impact of fuel price changes on overall grid costs
7. Reduced local emissions and lack of service interruption from environmental restrictions	Energy storage has no direct air emissions, avoiding NO _x , SO _x , and particulate matter, and can continue to operate even during non-attainment conditions that would shut down generators

Such avoided costs can be significant. As an example, a 2016 Massachusetts state-commissioned study of large-scale energy storage deployment found that the total value of these system benefits was greater than the value of the direct, compensated services of storage.¹¹ Indeed, because these benefits increase the efficiency of the overall grid, they must be accounted for at a system level, rather than at the level of an individual storage resource.

U.S. National Laboratories and others have sought to quantify the avoided costs of energy storage using commercially available production cost models.¹² For example, NREL’s 2013 study of California market estimated storage will result in avoided costs from other generators as \$35.70 – \$58.50/kW-yr.¹³ The conclusion of these studies is that the avoided cost and grid flexibility benefits of advanced storage are significant and should be captured in a net cost of capacity approach.

Recognizing that utilities use the models currently available to them and that those models may not be capable of capturing flexibility benefits and avoided costs of storage, values can be estimated from other studies until such modeling is instituted. While it is beyond the scope of this document to quantify all the previously discussed operational benefits of storage or provide a methodology to do so, an illustrative table of benefits is provided in Table 2 to guide commissions and utilities that seek to account for these benefits when including storage in IRPs.

Table 2: Examples of Operational Benefits of Storage in Addition to Capacity Value

BENEFIT	ILLUSTRATIVE VALUE	INCLUDED IN IRPs	INCLUDED IN SUB-HOURLY MODELS
Avoided capacity values			
Avoided generator start-up/shut-down	\$20.10-\$46.70/kW-yr ¹ 10% system reduction ²	Sometimes	Yes
Avoided generator fuel and O&M costs	\$11.90-\$61.00/kW-yr ¹ 0.5% system reduction ²	Yes	Yes
Reduced reserve requirements	30% regulating reserve reduction ³	No	Yes
Sub-hourly operational values			
Regulation reserve	\$35-41/kW-yr ¹	No	Yes
Load-following	\$75-90/kW-yr for ancillary services ⁴	No	Yes
Spinning reserve		No	Yes
Other system values			
Reduced wholesale prices	\$0.19-0.29/MWh ⁵	Yes	Yes
Fuel hedging value	\$21/kW-yr for doubling of gas prices ²	Yes	Yes
Environmental values			
Avoided NO _x	60-70 g/MWh ⁶	Sometimes	Yes
Avoided CO ₂	600 MTCO ₂ e/MW ⁵ 0.1-0.3 MTCO ₂ e/MWh ⁶	Sometimes	Yes

¹ NREL (2015) *Operational Benefits of Meeting California’s Energy Storage Targets*

² NREL (2013) *The Value of Energy Storage for Grid Applications*

³ PJM (2013) *Performance Based Regulation: Year One Analysis*

⁴ PGE (2016) *Portland General Electric 2016 Draft Integrated Resources Plan*

⁵ MA DOER (2016) *State of Charge: Massachusetts Energy Storage Initiative Study*

⁶ Energy Policy 96 (2016) *A framework for siting and dispatch of emerging energy resources to realize environmental and health benefits: Case study on peaker power plant displacement*

5. INCORPORATE GRID FLEXIBILITY REQUIREMENTS INTO RELIABILITY METRICS

IRPs model the ability of different resources to meet resource adequacy in an electric service territory. Resource adequacy traditionally focuses on meeting the single greatest hour of demand in the planning horizon and defining an acceptable level of risk of not meeting that demand, called the Loss of Load Expectation (LOLE). The LOLE is typically based on a “1-in-10” standard — that is, available capacity will fail to meet system demand only once in 10 years. IRP modeling combines that LOLE standard with load forecasts and the attributes of existing resources to calculate the extra capacity (“planning reserve margin”) needed in the system—which informs new capital investments.

The LOLE convention does not adequately capture the evolving needs for system flexibility. As a higher share of supply comes from variable renewable generation, utilities will be faced with periods of significant ramps in electric supply over short intervals. Yet, these fast and sudden changes in supply are not captured in the LOLE convention, which focuses only on evaluating risks to meet peak demands. Addressing this outdated approach is not only important to accurately quantify the benefits of storage in IRPs, but is also good practice to ensure prudent investment of ratepayer funds.

A method to incorporate flexibility into the resource adequacy of IRPs is to use a LOLE measure geared toward peak *rates of change* in supply, not simply peak periods themselves. This concept was pioneered by the New Mexico utility, PNM, in their 2017 IRP,¹⁴ which used two complementary measures: $LOLE_{CAP}$, the conventional reliability standard for events caused by insufficient resource capacity to meet peak demands, and $LOLE_{FLEX}$, a new reliability standard for events caused by insufficient resources to respond quickly to meet the volatile nature of renewable resources. Since New Mexico’s utilities are required to meet a Renewable Portfolio Standard, PNM modeled the reliability contributions of various capacity options under scenarios with higher renewable shares in generation, using both $LOLE_{CAP}$ and $LOLE_{FLEX}$. Illustrative results from PNM’s analysis are reproduced in Figure 3.

Figure 3: Reliability Contributions of Resources Using $LOLE_{CAP}$ and $LOLE_{FLEX}$ Metrics in PNM 2017 IRP

	RENEWABLE GENERATION	RENEWABLE SUPPLY	LF TARGET	RENEWABLE CURTAILMENT		$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM BALANCE AREA COSTS
	GWh	% of Load		%	MWh	Events Per Year		\$ millions
Base Case	5,493	38%	14%	11.46%	634,370	0.04	0.13	520.07
Base Case and 2 LM6000 (80 MW)	5,493	38%	14%	11.55%	638,933	0.02	0.13	517.14
Base Case and 100 MW 2-hour storage	5,493	38%	14%	8.72%	482,265	0.01	0.13	503.79
Base Case and 100 MW 4-hour storage	5,493	38%	14%	8.18%	452,470	0	0.12	500.73
Base Case and 100 MW 6-hour storage	5,493	38%	14%	8.07%	446,422	0.01	0.1	500.6

III. NOTABLE IRPs INCLUDING STORAGE IN 2016-2017

In 2016 and 2017, increasing numbers of utilities meaningfully incorporated energy storage into their IRPs, and several utilities selected storage as an economic resource for future procurement. This section briefly identifies and discusses the promising actions of utilities considering storage within those IRPs.

Portland General Electric (PGE) (2016)¹⁵

PGE was the first utility to undertake sub-hourly modeling of energy storage and utilize a net-cost approach in comparing it to other capacity options. PGE modeled the year 2021 in 15-minute increments, accounting for the variability of expected wind resources in its system. From there, PGE modeled the cost and benefit of different resources—namely, battery energy storage and gas-fired combustion turbines—for meeting the frequency regulation, load-following, and contingency reserves needs identified by the sub-hourly modeling. PGE then compared those two supply options using a net-cost approach, where the flexibility value of each asset was subtracted from its overall capital costs to arrive at a capacity value for comparison.

From this analysis, PGE's 2016 IRP ultimately concluded that energy storage was less cost-effective than a gas CT. However, after updating the cost estimates and cost forecasts of energy storage, in 2017 PGE selected 39 MW of storage projects.

[Hawaiian Electric Company \(HECO\) \(2016\)¹⁶](#)

In their December 2016 update to their Power Supply Improvement Plan, HECO employed sub-hourly modeling of their system and found that energy storage would be an economic resource for a variety of applications, particularly for grid flexibility services like frequency regulation. HECO's analysis also examined storage on a declining cost curve under a variety of project sizes. HECO's updated plan selected 225 MW of energy storage as economic through 2020, as well as 535 MW over the 15-year window of its IRP.

[Kentucky Power \(2016\)¹⁷](#)

KY Power found that "the modeling of Battery Storage as a peaking resource option is becoming a more common occurrence in IRPs" and selected 10 MW of energy storage within its 10-year window.

[Indianapolis Power & Light \(IPL\) \(2016\)¹⁸](#)

IPL modeled energy storage under three different sizes of projects each suited to peaking capacity, transmission support, and frequency regulation. Additionally, IPL used a declining cost curve of up to 10% per year, based on developer cost estimates of storage systems. IPL's base case ultimately selected 500 MW of standalone energy storage in its 20-year window, as well as 50 MW of customer-sited storage and 283 of "hybrid" energy storage co-located with generation.

[Arizona Public Service \(APS\) \(2017\)¹⁹](#)

APS selected 503 MW of additional energy storage as economic over the 15-year window of its IRP. Moreover, APS modeled sensitivities to battery energy storage costs and produced a scenario that found 1,107 MW of storage economic.

Additionally, APS used a novel method for modeling demand resources. As mentioned in Section II.1 of this paper, APS identified customer-sited energy resources as an investment option, rather than integrate projections of customer-sited resources into its load forecast. In doing so, APS then examined the role that customer-sited resources, including storage, could play in providing resource adequacy, as well as mechanisms like programs and tariffs to yield such resources. APS selected 420 MW of demand resources in its IRP, though without reference to the expected proportion from energy storage.

[Tucson Electric Power \(TEP\) \(2017\)²⁰](#)

TEP selected 200 MW of additional energy storage as economic through 2031, with 100 MW planned by 2021. TEP specifically selected storage as a grid balancing resource, defined as resources "that are fast ramping and flexible, as needed to maintain grid reliability," which are defined as a separate resource need intended to complement load-serving renewable generation. TEP's approach unbundles a variety of grid balancing services—ramping, frequency regulation, voltage support, and frequency response—from its load-serving capacity, which allows it to take particular advantage of fast-responding storage for savings to ratepayers. In addition, TEP explored adjustments to its reference case where energy storage provides load-serving capacity, in addition to grid balancing, with significant 4-hour storage procured by 2025.

[PNM \(2017\)²¹](#)

In its IRP plans, PNM announced that it will use a Request For Information (RFI) to obtain cost and performance data on energy storage from developers to inform future IRPs. PNM also used a novel analysis of LOLE. As described in previously in Section II.5, PNM examined an LOLE for the greatest change in net load in a single interval, in addition to an LOLE for the greatest level of net load in a single interval. In doing so, PNM determined conditions under which energy storage may be more economical than conventional generation.



Puget Sound Energy (PSE) (2017)²²

PSE selected 50 MW of energy storage as economic through 2023, with an additional 25 MW by 2027. Of note, PSE specifically chose flow battery technologies rather than lithium-ion technologies to be best suited for its capacity needs. Additionally, PSE found other advantages to using energy storage for capacity: “While batteries are more expensive than peakers on a dollars per kW basis, batteries are more scalable, so they fit well in a portfolio with a small, flat need ... Also, batteries provide more sub-hourly flexibility value than peakers, and this value is reflected in the IRP forecast.”

Avista (2017)²³

Avista selected 5 MW of energy storage as economic for capacity, finding that “energy storage costs are significantly lower than the last IRP which for the first time makes the technology operationally attractive in meeting energy needs in the 20-year timeframe of the 2017 IRP.” Of note, Avista specifically examined energy storage for deferring or avoiding distribution system upgrades, quantifying the value stream for storage providing that functionality, in addition to system-wide capacity and ancillary services. Avista notes its next IRP will use sub-hourly modeling to better capture the latter values for storage.

Duke Carolinas (2017)²⁴

In a revision to its previous year’s IRP, Duke plans for up to 75 MW of battery storage in the 2019-2021 time period, as well as upgrades to pumped hydro units totaling 184 MW over the 2021-2024 timeframe.^{iv}

Pacificorp (2017)²⁵

Pacificorp’s IRP examined a set of energy storage technologies. While Pacificorp did not use up-to-date cost estimates and did not select any storage, the IRP does use a declining cost curve for storage in future years. Costs decline continuously with the annual rate of decline increasing—from a 10% reduction in 2017-2018 to a 5% reduction in 2022-2023. Additionally, Pacificorp models scenarios where several storage technologies are included in resource portfolios.

Florida Power & Light (FPL) (2017)²⁶

Following four smaller pilot projects, FPL plans to deploy 50 MW of energy storage by 2020. While 24 MW of storage are planned for specific curtailment avoidance and distribution deferral functions, FPL notes it is still selecting applications for another 26 MW of storage. FPL considers the storage assets as part of a “pilot,” but it is noteworthy that the 50 MW capacity still positions FPL as forward-leaning in comparison with those who have yet to consider storage as an option.

^{iv}In addition, Duke has recently agreed to increase storage deployments to 300 MW by 2026 in its grid modernization plans, separate from its IRP. See *Duke Energy Carolinas, LLC’s Proposed Stipulations and Settlement Agreements Docket No. E-7, Sub 1146*, 1 June 2018, available at <http://starw1.ncuc.net/NCUC/ViewFile.aspx?id=d6757e5f-91f2-4c5d-81b1-e253d08f9f2a>

IV. RECENT POLICY STATEMENTS ON STORAGE IN IRPs

In addition to the initiative taken by an increasing number of utilities, state policymakers have also begun to issue guidance on including energy storage in IRPs. Since the first version of this IRP document was released, 15 states have taken regulatory or legislative action to encourage consideration of storage in long-term planning.

In the past year, the utility commissions of Washington, New Mexico, Michigan, and Arizona each released policy guidance on storage in IRPs, and their actions are summarized here.



Washington Utilities and Transportation Commission (UTC): In Docket U-161024, the Washington UTC issued a *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition*.²⁷ In the report, the UTC updated its rules to ensure that utility planning and procurement activities adapt to changes in utility needs through three policy principles: changing planning paradigms, providing modeling guidelines, and identifying principles for regulatory treatment of energy storage investments.

The UTC changes the planning paradigm by connecting utility planning requirements to the prudent use of ratepayer funds. The UTC Policy Statement reads:

*“At its core, the IRP process is the basis for utilities to plan for and procure resources to meet system load. To that end, **utilities must be able to demonstrate in any prudence determination for a new resource acquisition that their analysis of resource options included a storage alternative.** In such analyses, utilities must demonstrate that they have reasonably considered all of the costs and benefits of each option, to allow for comparison on similar terms and planning assumptions. **This policy applies to investments in generation and distribution projects, as well as transmission projects** that have not been selected for regional cost allocation through a regional transmission planning process pursuant to the Federal Energy Regulatory Commission’s Order 1000. While we provide this exemption for regional lines, we note that regional planning processes are guided by utilities, and we expect that Washington utilities will encourage the analysis of storage and other non-wires alternatives where feasible in such processes.”*

By creating a prudence requirement, Washington’s UTC has stated that cost-recovery for new utility investments will be incumbent upon a demonstration that storage was duly considered as an investment option. Moreover, that prudence requirement extends beyond generation—the traditional subject of IRPs—to also distribution and certain transmission infrastructure.



New Mexico Public Regulation Commission (PRC): In Case No. 17-00022-UT, the New Mexico PRC initiated a rulemaking leading to a decision to amend the Commission Rule on Integrated Resource Plans for Electric Utilities in the New Mexico Administrative Code.²⁸ The amendments made several changes to the code, key among them: (1) updating definitions to include energy storage resources as “a commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter delivering the energy,” and (2) requiring identification and evaluation of energy storage options along with feasible supply-side and demand-side resources. The PRC explicitly noted that it also did not want utilities to consider energy storage only as part of demand-side resources.



Michigan Public Service Commission (PSC): In Case No. U-15896 and U018461, the Michigan PSC amended its rule on IRPs.²⁹ The amendments include: (1) requiring that IRP resource screens examine “new energy integration of storage technology and operating assumptions” and “new energy storage development costs” as a part of new build resources; (2) requiring consideration of energy storage as a part of distributed generation resource options, which are modeled separately from load forecasts; (3) requiring documentation of cost data and estimates used in the resource screening process to evaluate each electric resource, including energy storage; and (4) evaluate the costs of combinations of resources, such as solar power plus battery storage, in addition to individual resource options.

Additionally, in Case No. 18418, the Michigan PSC updated its Michigan Integrated Resource Planning Parameters document, which outlines modeling and future scenario guidelines for utility IRPs.³⁰ Changes include: (1) incorporation of energy storage in the emerging technologies future scenario and specifying “technology costs for energy storage resources decline over time, particularly battery technologies and others which can enable supply- and demand-side resources;” recommending recent sources of storage cost estimates to be used for IRP modeling input assumptions; and stating that “IRPs should consider, to the extent possible, the net cost of capacity additions, that is, the capital costs adjusted by the operational and other system benefits that a given resource can provide.”



ARIZONA CORPORATION COMMISSION
Powering Arizona's Future

Arizona Corporation Commission: In Docket No. E-0000V-15-0094, the Arizona Corporation Commission found that Arizona utilities’ integrated resource plans did not meet the requirements of Commission Resource Planning and Procurement rules,³¹ based on a variety of factors including insufficient consideration of energy storage technologies for meeting

future capacity needs. As a part of its decision, the Commission ordered that Arizona utilities “shall include a storage alternative as a resource option in future Integrated Resource Plans, and shall include an analysis of storage alternatives into their respective processes when considering upgrades to transmission or distribution systems, or when considering new build or capacity upgrades for existing generation resource.” Additionally, the Commission ordered Arizona utilities to include in their next IRPs at least one portfolio that includes the lesser of 1000 MW of energy storage capacity or an amount of energy storage capacity equivalent to 20% of system demand.

V. THE TIME TO INCLUDE ENERGY STORAGE IN PLANNING IS NOW

With billions of dollars of new capacity additions planned over the next several years, and with storage costs continuing to decline rapidly while deployments increase, the time is now to include energy storage in long-term planning for a more efficient, resilient, sustainable and affordable grid. As many systems are planning for higher levels of variable generation sources, flexibility of supply will be a critical requirement. Evaluating storage as a flexible resource choice for future capacity needs is thus an issue of urgent prudence in utility decisions.

Right now, utility commissions generally have the authority to require utilities to adequately consider energy storage as a capacity resource in their IRPs. And utilities are increasingly including storage as a resource choice in their plans. Those that do not are stranding future value that can be returned to ratepayers. ESA and its member companies, including electric utilities, energy service companies, independent power producers, financiers, insurers, law firms, installers, manufacturers, component suppliers and integrators, developers, and manufacturers welcome the opportunity to work with resource planners and commissions to include storage in their IRPs.

ABOUT ESA

The Energy Storage Association (ESA) is the national trade association dedicated to energy storage, working toward a more resilient, efficient, sustainable and affordable electricity grid – as is uniquely enabled by energy storage. With more than 160 members, ESA represents a diverse group of companies, including independent power producers, electric utilities, energy service companies, financiers, insurers, law firms, installers, manufacturers, component suppliers and integrators involved in deploying energy storage systems around the globe.

More information is available at: www.energystorage.org.

END NOTES

¹ See APS, *2017 Integrated Resource Plan*, April 2017, available at <https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf>

² See discussion of price declines exceeding forecasts at B. Nykvist & M. Nilsson, "Rapidly falling costs of battery packs for electric vehicles," *Nature Climate Change* 5, 329–332 (2015), doi:10.1038/nclimate2564, available at <http://www.nature.com/nclimate/journal/v5/n4/full/nclimate2564.html>. Additionally, several resources describe a 50% decline in energy storage costs in recent years; see IHS, *Future of Grid Connected Energy Storage*, Nov 2015, available at <https://technology.ihs.com/512285/grid-connected-energy-storage-report-2015>; see also

³ See GTM Research, *U.S. Front-of-the-Meter Energy Storage System Prices 2018-2022*, Feb 2018, available at <https://www.greentechmedia.com/research/report/us-front-of-the-meter-energy-storage-system-prices-2018-2022>. See also Lazard, *Levelized Cost of Storage Analysis—Version 3.0*, Nov 2017, available at <https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf>. See also Navigant, "Storage in the Northwest," presentation at the Northwest Demand Response and Energy Storage Summit, 28 Sep, 2017, available at https://www.navigantresearch.com/wp-assets/uploads/2017/10/Storage-in-the-Northwest_Jay-Paidipati.pdf.

⁴ Since storage provides flexibility services that are not valued by volume of output, a capacity cost metric (\$/kW) is more appropriate than a levelized cost of energy metric (\$/kWh), which best applies to resources that simply supply electricity.

⁵ Sources available as follows:

- IHS 2016 case for 50 MW Load Shifting BESS without AFUDC and interconnection costs in real dollars: https://cca.hawaii.gov/dca/files/2016/12/dkt_2014_0183_20161223_companies_PSIP_update_report_3_of_4.pdf#16
- NREL 2017 midpoint estimate and includes O&M costs: https://www.ferc.gov/CalendarFiles/20170627130026-FERC_storage_presentation.pdf
- DNV GL 2017 battery, power control system, balance of systems, and installation costs combined: <http://edocs.puc.state.or.us/efdocs/HAA/haa165931.pdf#30>
- Lazard 2017 peaker replacement configuration: <https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf>
- Navigant 2017 case for 5 MW battery: https://www.navigantresearch.com/wp-assets/uploads/2017/10/Storage-in-the-Northwest_Jay-Paidipati.pdf
- NYSERDA 2018 blended cost of technologies and sources including Lazard, GTM Research, Bloomberg, Navigant Research, and storage developers: <https://www.nyscrda.ny.gov/-/media/Files/Programs/Energy-Storage/2018-03-09-Energy-Storage-Roadmap-base-case-webinar.pptx>
- NIPSCO 2018 stochastic forecast from samples based on multiple sources: <https://www.nipsco.com/docs/default-source/about-nipsco-docs/irp-public-advisory-meeting.pdf#61>

⁶ See Energy Exemplar website: <https://energyexemplar.com/software/plexos-desktop-edition/>

⁷ See Astrape Consulting website: <http://www.astrape.com/servm/>

⁸ See E3 website: <https://www.ethree.com/tools/reflex-renewable-energy-flexibility-model/>

⁹ See Chapter 8 in *Portland General Electric 2016 Integrated Resources Plan*, issued 15 Nov 2016, available at <https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning>

¹⁰ See Chapter 8 in *Portland General Electric 2016 Integrated Resources Plan*.

¹¹ See Massachusetts Department of Energy Resources, *State of Charge: Massachusetts Energy Storage Initiative Study*, Sep 2016, available at <http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf>

¹² 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>

END NOTES

- ¹³ See National Renewable Energy Laboratory, *The Value of Energy Storage for Grid Applications*, May 2013, available at <http://www.nrel.gov/docs/fy13osti/58465.pdf>
- ¹⁴ See pages 121-127 in *PNM 2017-2036 Integrated Resources Plan*, issued 13 July 2017, available at <https://www.pnm.com/irp>
- ¹⁵ Available at <https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf>
- ¹⁶ Available at https://cca.hawaii.gov/dca/files/2016/12/dkt_2014_0183_20161223_companies_PSIP_update_report_1_of_4.pdf
- ¹⁷ Available at https://psc.ky.gov/pscecf/2016-00413/jkrosquist@aep.com/12202016110531/KPCO_2016_IRP_Volume_A_Public_Version.pdf
- ¹⁸ Available at <https://www.iplpower.com/IRP/?terms=irp>
- ¹⁹ Available at <https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf>
- ²⁰ Available at <https://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource-FINAL-Low-Resolution.pdf>
- ²¹ Available at <https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/eae4efd7-3de5-47b4-b686-1ab37641b4ed>
- ²² Available at https://www.pse.com/aboutpse/EnergySupply/Documents/01_IRP17_CH1_110117b.pdf
- ²³ Available at <https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2017-electric-irp-final.pdf?la=en>
- ²⁴ Available at <https://dms.psc.sc.gov/Attachments/Matter/557f78d7-4533-438e-a106-b3a8f6fa1885>
- ²⁵ Available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_Volume1_IRP_Final.pdf
- ²⁶ Available at <https://www.fpl.com/company/pdf/10-year-site-plan.pdf>
- ²⁷ See Washington Utilities and Transportation Commission Docket U-161024, *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition*, 11 Oct 2017, available at https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CasItem.aspx?item=document&id=236&year=2016&docketNumber=161024&resultSource=&page=&query=&refiners=&isModal=&omItem=false&dolItem=false
- ²⁸ See New Mexico Public Regulation Commission Case 17-00022-UT, *Final Order Amending Integrated Resource Planning Rules 17.7.3 NMAC to Include Energy Storage Resources*, 2 Aug 2017, available at <http://164.64.85.108/infodocs/2017/8/PRS20243548DOC.PDF>
- ²⁹ See Michigan Public Service Commission, Case No. U-15896, *Opinion and Order In the matter, on the Commission's own motion, to implement the provisions of Section 6s of 2016 PA 341*, and Case No. U-18461, *Opinion and Order In the matter, on the Commission's own motion, to implement the provisions of Section 6t of 2016 PA 341*, 20 Dec 2017, available at <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001X2Co>
- ³⁰ See Michigan Public Service Commission, Case No. U-18418, *Order In the matter, on the Commission's own motion to implement the provisions of Section 6t(1) of 2016 PA 341*, 21 Nov 2017, available at <https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UYSyAAO?casenum=18418&submit.x=0&submit.y=0>
- ³¹ See Arizona Corporation Commission, Docket No. E- 0000V-15-0094, Decision 76632, *Resource Planning and Procurement in 2015 and 2016*, 29 Mar 2018, available at <http://images.edocket.azcc.gov/docketpdf/0000186964.pdf>