Energy Storage at the Frontier of Distribution System Planning

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Our Members

- manufacturers
- component suppliers
- system integrators
- developers
- independent generators
- electric utilities
- large end-users
- law, finance, consulting

Technologies represented

- battery storage
- thermal storage
- mechanical storage
- power-to-gas storage
U.S. grid battery storage now past the 1 GW mark

As of 2Q 2019:
1.3 GW (2.3 GWh) batteries online
35% of MW installed “behind-the-meter”

(SOURCE: WoodMackenzie)
Battery storage installed costs continue to drop

Bulk-scale 4-hour lithium-ion battery installed cost ($/kWh)

Historical

NREL ATB Forecasts

Annual Cost Decline Rates from 2018

<table>
<thead>
<tr>
<th></th>
<th>2025</th>
<th>2030</th>
<th>2040</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Cost</td>
<td>-10%</td>
<td>-9%</td>
<td>-6%</td>
</tr>
<tr>
<td>Mid Cost</td>
<td>-6%</td>
<td>-5%</td>
<td>-3%</td>
</tr>
<tr>
<td>High Cost</td>
<td>-1%</td>
<td>-1%</td>
<td>-1%</td>
</tr>
</tbody>
</table>

Source: Bloomberg New Energy Finance (2018) and NREL (2019b) with Brattle analysis.

Notes: Historical estimate assumes Bloomberg NEF battery pack cost estimate plus a constant non-pack cost estimate of approximately $170/kWh. NREL costs are for a 4-hour, utility-scale lithium ion battery.
U.S. market will reach 15.5 GWh in annual deployments by 2024

4-hour systems becoming the norm for front-of-the-meter systems; average BTM durations inch toward 3 hours

U.S. energy storage annual deployment forecast, 2012-2024E (MWh)

- The U.S. energy storage market will nearly triple between 2019 and 2020 as a significant number of FTM projects are set to come online. 2021 will follow a similar trajectory, as a massive amount of FTM capacity coming online will lead to another near tripling in total market size.
- Average discharge durations continue to increase as applications such as capacity and bulk energy-shifting rise in prominence.
Barriers to Deployment That Policy Can Address

**Cannot VALUE or compensate storage flexibility**

- Solutions
  - Deployment targets
  - Incentive programs
  - Tariff/rate design
  - Wholesale market products
  - Cost-benefit studies

**Unable to COMPETE in all grid planning and procurements**

- Solutions
  - Long-term resource planning
  - Distribution planning
  - Transmission planning
  - GHG/renewables standards
  - Wholesale market rules
  - Resource adequacy rules

**Cannot ACCESS grid or constrained to narrow use**

- Solutions
  - Interconnection processes
  - Multiple-use frameworks
  - Ownership rules
Storage Targets/Goals

California: 1,325 MW x 2020 + extra 500 MW

Oregon: Min of 10 MWh and max 1% of peak load per utility

Massachusetts: Target of 1,000 MWh x 2025

New York: 1,500 MW x 2025 target and 3,000 x 2030

New Jersey: Study plus 600 MW x 2021 and 2,000 MW x 2030 goal

Arizona: 3,000 MW (proposed)

Nevada: Study determined 1,000 MW by 2030 is in the public interest

Maine: 100 MW (proposed)

Virginia: Study determined 1,000 MW by 2030 as economic

Target/goal in place
Under development
Storage Incentives

California: Self-Generation Incentive Program ($800MM)

Nevada: $10MM solar+storage program

Massachusetts: SMART incentive program for solar+storage; Clean Peak Standard program in development

New York: Bridge Incentive Program ($280MM) + NY-Sun program ($40MM)

Maryland: Onsite storage tax credit ($3MM)

Federal: Storage paired with solar eligible for 30% investment tax credit
Updating Planning for Storage

Washington:
Policy Statement and draft regulations call for sub-hourly modeling and mechanism to value flexibility
*Docket U-161024*

Arizona:
Regulators rejected utility IRPs, called for evaluation of storage, gas moratorium
*Case E-00000V-15-0094, Decision 76632*

Colorado:
PUC updated all planning rules to consider storage procurement
*Docket 18R-0623E, Decision C18-1124*

Minnesota:
Legislation requires IRPs to include storage modeling best practices
*HF 2*

Michigan:
PSC issued guidelines on consideration of storage in 2019 IRPs
*Cases U-15896, 18461, 18418*

New Mexico:
Revised IRP rules require consideration of energy storage
*Case 17-00022-UT*

32 states have planning requirements
Over 7,000 MW selected to date

NARUC: A November 2018 resolution (EL-4/ERE-1) calls for modeling “the full spectrum of services that energy storage and flexible resources are capable of providing.”

NARUC/NASEO: Task Force for Comprehensive Electricity Planning is a two-year project, working with 16 states on improving electric system modeling and planning methods
Storage enhances T&D capabilities

- Extend the life of existing electric infrastructure
- Enhance resilience of network & other critical infrastructures
- Increase hosting capacity to enable customer choice
- Adapt to uncertain futures: supply mix, load & DER forecasts
- Enable the demands of increasingly electrified economy
  - Transportation
  - Industrial processes
  - Ubiquitous computing/IoT
  - Heating? Desalination?
Examples of storage as electric infrastructure

• **APS (Arizona) projects**
  - 4 MW storage avoids transmission upgrade for rural communities (Punkin Center)
  - 2 MW storage at 2 substations to increase hosting capacity for customer solar

• **HECO (Hawaii) Aggregation**
  - 1 MW aggregation of customer-sited storage providing distribution system stability

• **National Grid (New York) Nantucket project**
  - 6 MW, 8-hr storage to avoid new undersea cable & island resilience

• **Eversource (New Hampshire) “bring-your-own-device” project**
  - Combination 1.7 MW substation battery + 0.7 MW customer peak demand reduction to avoid distribution upgrades

• **Duke Indiana projects**
  - 5 MW storage at 2 sites in development
    - Grid infrastructure deferral (Naab Battery Project – distribution sited)
    - Resilience (Camp Atterbury Project – customer-sited microgrid)
Benefit-cost analysis of DER storage in planning

- **Traditional benefit-cost analysis** examines storage as a wire—e.g., comparing a smartphone to a landline
  - Value side of the ledger remarkably expanded—e.g., not just the cost of making a phone call

- **Hosting capacity value enhancement**
  - Reduce interconnection burden for customers installing DERs
  - Contribute system-wide services when needed
  - Helps state meet public policy goals

- **Option value**
  - Storage can be quickly deployed in increments to meet reliability needs as they occur and change → manage risk of locking in unnecessary infrastructure capex
  - Storage can be re-deployed if conditions change to obviate reliability need → lower risk of stranded investment

- **Resilience value**
  - Either substation-sited or customer-sited

**ESA recommends the Maryland PC 44 Storage Working Group proposal filed at MD PSC**
Storage as resilience: an increasing trend

Solar-storage at Apollo Elementary in FL

Ameren microgrid w/ storage

Ft. Bliss microgrid w/ storage

Sterling MA substation storage

Irvine Ranch Water District storage

Puerto Rico Children’s Hospital w/ solar + storage
Options for moving toward a grid services market

• Utility programs can provide payments to storage (+ other DERs) to provide useful services, akin to a price signal
  • Utility “bring-your-own-device” programs provide payment in exchange for turning over dispatch control under certain conditions (e.g., GMP, Liberty, Eversource BYOD programs)
  • Daily / Targeted Dispatch program in Massachusetts provides payments for storage producing specific dispatch
  • Payments for certain DER functionality (e.g., ComEd $/kVAR incentive for enabling Volt-VAR support) or peak demand reductions

• RTO/ISO markets define specific services, which are then bid to establish clearing prices
  • Energy, ancillary services, and sometimes capacity services are defined discretely with price that changes with supply/demand and market conditions

• Value of DER (VDER) approaches as a partway step to market pricing
  • Administrative ease of utility program + proxy for market prices
  • Since value is long-term avoided costs, contract length should be set similar to utility asset lifetimes (e.g., 10 years)
## Components and Eligibility for the VDER Value Stack Phase Two

**Overall eligibility:** On-site DG >750 kW; Remote Not Metered and Community DG of any size, excludes CHP

**Effective 06/01/2019** for projects that qualified for Value Stack after 07/26/2018

<table>
<thead>
<tr>
<th>Definition</th>
<th>Description</th>
<th>Units</th>
<th>Eligibility</th>
</tr>
</thead>
<tbody>
<tr>
<td>LBMP</td>
<td>Location Based Marginal Pricing</td>
<td>Energy volumetric credit Day ahead LBMP</td>
<td>$/MWh</td>
</tr>
<tr>
<td>ICAP - Ait 1</td>
<td>Installed Capacity</td>
<td>Volumetric credit applied to production in all hours, equivalent to the value of avoided capacity levelized over expected PV production</td>
<td>$/kWh</td>
</tr>
<tr>
<td>ICAP - Ait 2</td>
<td>Installed Capacity</td>
<td>Volumetric credit concentrated during 240 or 245 weekday non-holiday summer afternoon hours, from 2 PM until 7 PM June 24 through August 31</td>
<td>$/kWh for 240 or 245 summer hours</td>
</tr>
<tr>
<td>ICAP - Ait 3</td>
<td>Installed Capacity</td>
<td>Volumetric credit based on exports of power coincident with prior summer NYCA peak load</td>
<td>$/kW-month coincident prior summer peak</td>
</tr>
<tr>
<td>REC</td>
<td>Renewable Energy Credit</td>
<td>Environmental Credit Higher of NYSERDA REC price or Social Cost of Carbon</td>
<td>$/kWh</td>
</tr>
<tr>
<td>DRV</td>
<td>Demand Reduction Value</td>
<td>Proxy for distribution value of DER based on avoided Marginal Cost of Service (MCOS) Available for export in 4 hour window during summer non-holiday weekdays between June 24 and September 15. Window assigned during interconnection.</td>
<td>$/kWh</td>
</tr>
<tr>
<td>CC</td>
<td>Community Credit</td>
<td>Designed to incentivize Community Distributed Generation</td>
<td>$/kWh</td>
</tr>
<tr>
<td>LSRV</td>
<td>Locational System Relief Value</td>
<td>Incentive for high value areas based on &quot;stretch&quot; of MCOS. Credited for minimum average hourly export during each event.</td>
<td>$/kW-event</td>
</tr>
</tbody>
</table>

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1. Qualification based on date of payment of at least 25% of interconnection costs, or date of executed interconnection agreement if payment is not required
2. Intermittent resources include: Solar (Photovoltaic), Wind, and Micro-hydroelectric
4. Eligibility for RECs for Biomass generation depends on the fuel source – please see NYSERDA Guidelines
Thank you.

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www.energystorage.org
Parking Lot
Example: Oakland Clean Energy Initiative

- Mix of substation storage and customer DERs used to address thermal overload risk
- Allows retirement of aging gas generation used for local reliability
- Found to be 15-25% of cost of traditional transmission solutions
Battery storage for grid stability: Voltage support

- EPRI 2012 study found batteries superior to SVC/STATCOM for voltage support in N-1 contingency with high dynamic loads
  - Faster replacement of active and reactive power injection
  - Including active power allows wider area of support
    - SVC only injects reactive power → still requires active power from remote sources thru weak transmission system, increasing stress conditions
    - SVC/STATCOM must be oversized relative to batteries in terms of MVA ratings
  - Efficiency of SVC declines with severe voltage dip
  - Batteries can sustain MW and Mvar injection for longer periods of time for voltage or overload issues in steady-state post-fault operating state
- Example: APS 2 MW / 2 MWh batteries on distribution feeders being used for voltage regulation, in addition to capacity deferral
  - Full 2 MVA capacity available for reactive power during peak shaving
Battery storage for grid stability: Fast frequency response

- **Batteries provide sub-second response at full output (”synthetic inertia”)**
  - Arrests frequency deviations faster → avoids lower nadir → reduces headroom reservations needed for primary frequency response

- **Batteries provide sub-minute response at full output (”primary frequency response”)**
  - Supports faster recovery → reduces headroom reservation for existing generators

- **UK Everoze study finds 360 MW batteries replaces inertia of 3,000 MW of CCGTs**

- **Value of fast frequency response increases as inertia decreases from greater wind/solar deployment**
  - ERCOT, UK have fast frequency response market products

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**Angamos BESS Response**
- Angamos BESS responds with rapid increase of output from 0MW to 20MW
- Autonomous response according to programmed profile
- Output sustained until stability restored

**Thermal Units**
- Thermal unit responds with 4MW burst, then output drops off
- Gradually ramps up in oscillating manner to 7MW output increase over 4 minutes
Fast frequency response as resilience

In Dominican Republic, battery storage remained online through Hurricane Irma in 2017 while generators and loads tripped offline.
Battery storage for grid stability: Fast frequency regulation

- Batteries meet 2-4 second signal more precisely than generators
- ~270 MW of storage in PJM fast frequency regulation (RegD) market
  - Includes BTM storage as demand response
- RegD reduced overall regulation reserve requirement by 30%

SOURCE: PJM
The Potential for Battery Energy Storage to Provide Peaking Capacity in the United States

(Source: NREL 2019)

Findings for 4-hr storage:
• 28 GW of capacity potential nationwide
• 2-8% of system peak across regions

Peaking capacity potential increases with more wind/solar
Storage Selected Economically in IRPs 2018-2019

- Over 7.6 GW of storage proposed in IRPs (not including TVA)
- Notable procurements include 690 MW from NVE and 500 MW from APS
- Some proposals are geared to piloting technology

<table>
<thead>
<tr>
<th>State</th>
<th>Utility</th>
<th>IRP Year</th>
<th>Storage Proposed</th>
<th>Timeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>IN</td>
<td>IPL</td>
<td>2016</td>
<td>833</td>
<td>over 20 years</td>
</tr>
<tr>
<td>HI</td>
<td>HECO</td>
<td>2016</td>
<td>535</td>
<td>2020</td>
</tr>
<tr>
<td>OR</td>
<td>PGE</td>
<td>2016</td>
<td>39.8</td>
<td>2020</td>
</tr>
<tr>
<td>KY</td>
<td>Kentucky Power</td>
<td>2016</td>
<td>10</td>
<td>over 10 years</td>
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<tr>
<td>CO</td>
<td>Xcel</td>
<td>2016 (2018 update)</td>
<td>275</td>
<td>2030</td>
</tr>
<tr>
<td>WA</td>
<td>Puget Sound</td>
<td>2017</td>
<td>75</td>
<td>2029</td>
</tr>
<tr>
<td>NC</td>
<td>Duke Carolinas</td>
<td>2017</td>
<td>75</td>
<td>2019-2021</td>
</tr>
<tr>
<td>AZ</td>
<td>UNS Energy Corp</td>
<td>2017</td>
<td>20</td>
<td>2028</td>
</tr>
<tr>
<td>WA</td>
<td>Avista</td>
<td>2017</td>
<td>5</td>
<td>2029</td>
</tr>
<tr>
<td>OR</td>
<td>PacifiCorp</td>
<td>2017</td>
<td>4</td>
<td>2020</td>
</tr>
<tr>
<td>MI</td>
<td>Consumers</td>
<td>2018</td>
<td>450</td>
<td>2040</td>
</tr>
<tr>
<td>NC</td>
<td>Duke Carolinas &amp; Duke Pro</td>
<td>2018</td>
<td>290</td>
<td>2026</td>
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<tr>
<td>NM</td>
<td>El Paso Electric</td>
<td>2018</td>
<td>115</td>
<td>2035</td>
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<tr>
<td>NV</td>
<td>NVE</td>
<td>2018</td>
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<td>2021</td>
</tr>
<tr>
<td>IN</td>
<td>NIPSCO</td>
<td>2018</td>
<td>92</td>
<td>2023</td>
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<tr>
<td>FL</td>
<td>FPL Energy</td>
<td>2018</td>
<td>50</td>
<td>2020</td>
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<tr>
<td>VA</td>
<td>Dominion</td>
<td>2018</td>
<td>30</td>
<td>2025</td>
</tr>
<tr>
<td>VA</td>
<td>Appalacian Power</td>
<td>2018</td>
<td>10</td>
<td>2025</td>
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<tr>
<td>NV</td>
<td>NVE</td>
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<td>590</td>
<td>2023</td>
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<tr>
<td>AZ</td>
<td>APS</td>
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<td>2025</td>
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</tr>
<tr>
<td>PNM</td>
<td>New Mexico</td>
<td>2019</td>
<td>130</td>
<td>2023</td>
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<tr>
<td>GA</td>
<td>Georgia Power</td>
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<td>OR</td>
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<td>2019</td>
<td>50</td>
<td>2028</td>
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<tr>
<td>Multi</td>
<td>PacifiCorp</td>
<td>2019</td>
<td>2,800</td>
<td>2038</td>
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<tr>
<td>Total</td>
<td></td>
<td></td>
<td><strong>7,658</strong></td>
<td></td>
</tr>
</tbody>
</table>

Note: Does not include TVA’s recent 2019 IRP (5,300 MW x 2038 in preferred plan)
Key recommendations:
• Use up-to-date cost estimates and forecasts
• Employ models with sub-hourly time intervals
• Use a net-cost analysis of capacity investment options
• Quantify system flexibility needs & consider value for risk management

Also inside:
• Catalogues 2016-2017 utility IRPs that consider storage, highlighting best practices
• Summarizes actions on storage in IRPs from state utility commissions

Find the report at energystorage.org/IRP