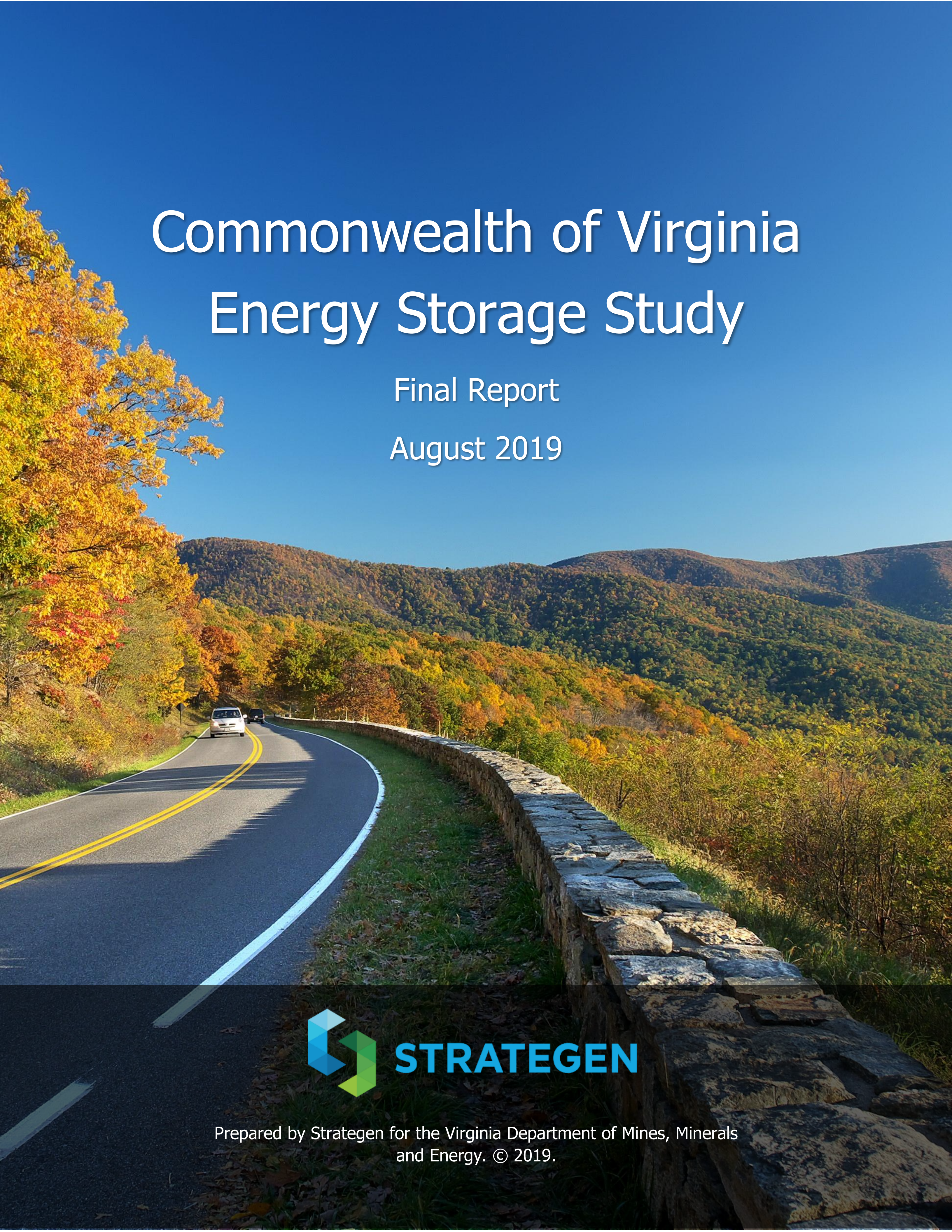

Commonwealth of Virginia Energy Storage Study

Final Report

August 2019

STRATEGEN

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Executive Summary

In recent years, the market for advanced energy storage technologies has grown substantially both globally and in the U.S., primarily due to state-led initiatives such as those in New York, New Jersey, and California. An overview of the current state of energy storage technologies and markets is provided in Chapter 1: Technology and Market Overview.

With the recent passage of the Grid Transformation and Security Act, Virginia is also poised to benefit from deployment of advanced energy storage technologies. To better inform policy decisions for the Commonwealth, Strategen conducted a review of potential energy storage value streams in Virginia (Chapter 2: Energy Storage Value Streams and Use Cases in Virginia) and performed an economic analysis of the total benefits that these value streams could provide to the Commonwealth under different levels of storage deployment (Chapter 3: Analysis of Energy Storage Potential in VA).

The results of the analysis show that the near-term economic potential for energy storage in Virginia ranges from 24-113 MW (4-hr duration or less) depending on the installation costs and duration. This would yield annual net benefits ranging from $3-9 million to the Virginia electricity system and its customers. Over the next decade, the potential grows to 329-1,123 MW, with annual net benefits ranging from $20-$58 million. A preliminary estimate suggests that this equates to a total estimated job impacts 1,212-4,132 job-years, resulting in a range of 114-387 $MM in labor income.

		1hr	2hrs	4hrs	10hrs
		2019			
Low Cost	Efficient Storage Level (MW)	110	113	84	0
	Annual Net Benefits ($M)	$ 4.99	$ 9.35	$ 6.36	$ -
High Cost	Efficient Storage Level (MW)	71	72	24	0
	Annual Net Benefits ($M)	$ 2.82	$ 5.28	$ 3.18	$ -
		2029			
Low Cost	Efficient Storage Level (MW)	961	1,123	970	356
	Annual Net Benefits ($M)	$ 29.93	$ 56.66	$ 58.04	$ 25.27
High Cost	Efficient Storage Level (MW)	397	396	329	9
	Annual Net Benefits ($M)	$ 19.93	$ 37.44	$ 25.30	$ (0.17)

Figure ES-1. Summary of estimated potential electricity system benefits from energy storage deployed in the Commonwealth of Virginia. Results are summarized by High-Cost and Low-Cost scenarios for storage deployment and by duration of storage resources

These results reflect only a portion of the potential value streams that storage may be capable of providing and should therefore be considered conservative in nature.

While there are meaningful benefits to energy storage deployment, there are also a variety of market barriers that may limit these benefits from being realized under today's conditions. One key market barrier is safety and permitting issues, which are addressed in detail in Chapter 4:

Safety & Permitting Issues. Other market barriers are identified in Chapter 5, which describes ten issues that could be addressed to promote more storage adoption in Virginia.

To overcome these, Strategen recommends the state consider a set of potential policy actions, which are briefly listed below and described in more detail in Chapter 6: Recommendations & Policy Actions. These recommendations were informed by Strategen's analysis in this report and the experiences of other states around the U.S. The recommendations are intended to encourage growth in Virginia's energy storage industry and enhance resiliency, while balancing costs and economic equity concerns. While some of these recommendations may require new legislation, some could be achieved under existing law through actions taken by state agencies (e.g. DMME, DEQ) or the State Corporation Commission (SCC).

Recommendations and Policy Actions:

State Level Strategic Actions:

1. Establish a statewide storage deployment requirement to complement Virginia's existing renewable energy goals under the Grid Transformation and Security Act (i.e. 5,000 MW of wind and solar). Based on the analysis conducted in this report (see Figure ES-1), a **storage deployment target of approximately 1,000 MW by year 2030** would be consistent with an approach that maximizes net benefits for the Commonwealth.[1] In several other states, setting a storage deployment target has been a critical step for accelerating the industry's development.
2. Convene a **statewide "storage issues forum"** on a regular basis to allow key stakeholders (including the significant number of federal entities in Virginia) to identify challenges and opportunities for the industry going forward.
3. Develop a statewide **strategic plan for accelerating microgrid deployment**, which would include a significant energy storage component. Part of this deployment could include various "make ready" provisions to provide enabling microgrid infrastructure and controls networks. This can be targeted towards Virginia's significant presence of Department of Defense facilities or other critical facilities at public institutions.

Utility Planning and Procurement:

4. Move beyond the pilot stage to implement **additional commercial scale deployments** of energy storage, in addition to the 40 MW already being considered. These deployments should leverage lessons learned from the broad array of existing pilot programs across the U.S. and can advance Virginia's storage industry through "learning by doing."
5. Adopt more advanced methods and best practices for considering storage in **utility resource planning processes** (e.g. within the SCC's resource planning process) as well as **utility procurement processes** (e.g. through competitive all-resource solicitations).
6. Develop a formal **process for identifying location-specific opportunities on the distribution system for storage** to provide value to utilities and their customers –

[1] Assumes the "low-cost" scenario could be achieved by through technological advances as well as pairing storage with renewables (thus providing federal tax incentives). Based on Strategen's final review of battery storage costs estimates just prior to the release of this report (i.e. August 2019), the "low-cost" scenario appears to be more representative of large-scale standalone energy storage systems installed in the near-term.

particularly through the use of storage as a Non-Wires Alternative (NWA). This could be accomplished through an enhanced Grid Transformation Plan process, or through a separate standalone process. The process should be informed by lessons learned from other states. The process should also provide a pathway for cost recovery of storage investments. Non-wires solutions should be prioritized in the near term and secondary consideration given to hosting capacity analysis due to VA's low penetration of DERs.

7. Explore ways to support economically distressed communities by **studying the viability** of new pumped hydro projects.

Retail Rates and Customer Programs:

8. Establish ratepayer funded **direct incentive programs** to accelerate storage deployment in Virginia. Incentives can be linked to specific program goals (e.g. safety, reliability, environmental benefits), or provided as a means of accelerating market transformation (e.g. cost reduction) of the local energy storage industry. Lessons from incentive programs in California and New York can help to maximize the benefits delivered.
9. Implement **reforms to retail rates** and expand or **enhance retail customer programs** to better reflect the potential grid benefits that storage can deliver.

Wholesale Markets:

10. Enable storage "value stacking" by providing regulatory certainty through the adoption of a **Multi-Use Application (MUA) framework**. This could provide a pathway for aggregating smaller distributed storage assets for wholesale participation under FERC Order 841.
11. Participate in PJM stakeholder processes to ensure that **wholesale market rules** are continually improved to maximize storage participation options and value creation. This could include sponsorship of additional technical analysis to more closely examine PJM's "10-hour duration" rule for storage capacity market value and identify cases where shorter duration storage resources can provide enhanced value.

Interconnection and Permitting:

12. Enact revisions to codes and standards that will help enhance and streamline **safety and permitting processes** for local jurisdictions.
13. **Update the interconnection process** for distributed energy resources (DER), including those at campuses, public facilities and military installations to ensure that greater visibility and situational awareness are provided to both the local utility and wholesale market operators for resources that are providing multiple services.

Competitive Provider Participation:

14. **Revise the definition of public utility to exclude storage,** to ensure that third-party developers can continue to advance and innovate energy storage throughout the state.

Research and Development:

15. **Provide Virginia's universities with additional resources** to pursue research and development of new energy storage technologies.

Chapter 1: Technology and Market Overview

1.1 Overview of Energy Storage Technologies

The term "energy storage" applies to a diverse set of technologies that can store energy at one time and make it available during another. Storage technologies range in size, modularity, application, electrical performance characteristics, cost, time to construct, locational flexibility, storage duration provided, grid services offered, and the way in which they operate.

Storage technologies generally fall into five different technology categories: (1) mechanical storage, (2) electrochemical storage, (3) thermal storage, (4) electrical storage, and (5) chemical storage (e.g. hydrogen). See Figure 1. Each of these categories is discussed further below, and this report focuses primarily on the first three of these categories.

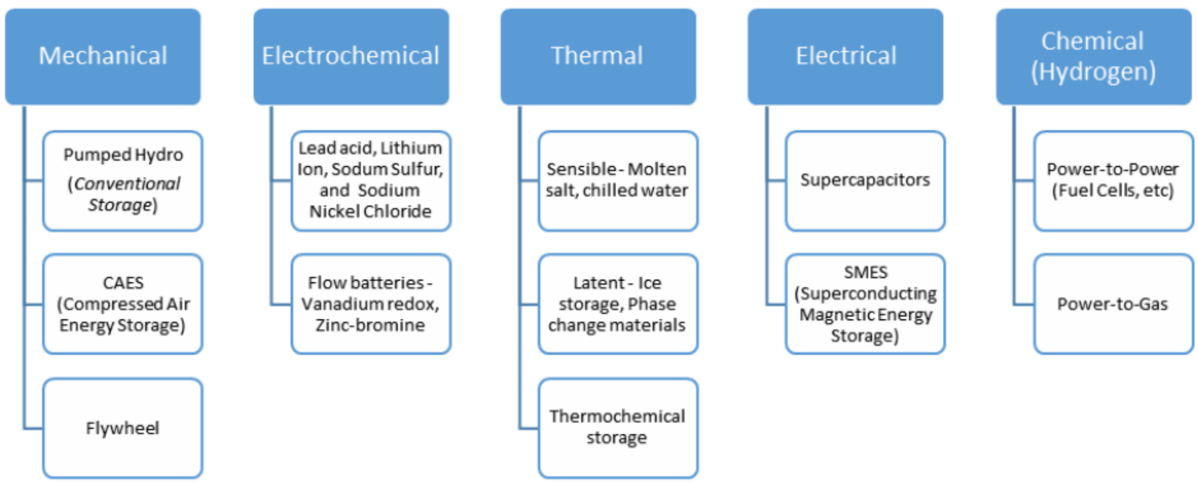


Figure 1. Energy Storage Technology Categories. This report focuses primarily on the first three of these categories.[2]

1.1.1 Mechanical Storage

Mechanical storage technologies store energy by converting electric energy to kinetic energy. Example technologies include flywheels, compressed air energy storage, and pumped hydroelectric storage.

Flywheels store electric energy as rotational energy by spinning a cylindrical rotor at very high speeds in a nearly frictionless enclosure. The flywheel's rotational speed is reduced in order to convert kinetic energy into electricity via a generator. Vacuum chambers and magnetic bearings are often used to reduce friction further. High tensile strength materials must be used. Flywheels are characterized by good efficiencies over short timescales, rapid start-up times (typically a few minutes), high cycling capabilities, high energy density, long lifetimes (typically 20 years), limited maintenance, minimal environmental impact, and modularity. They are typically used for power

[2] Source: Government of Massachusetts, *State of Charge*: Massachusetts Energy Storage Initiative Study, 2016

quality, management, and reliability including for reactive power support, spinning reserves, voltage regulation, frequency response, and for short duration ride-through applications. They have also been used to smooth the output power fluctuations of wind resources.[3]

Compressed air energy storage (CAES) systems compress and store gas (typically ambient air) under pressure in above-ground storage containers or in suitable underground geologic formations (e.g. underground salt caverns). Energy is extracted by expanding or decompressing the air through a turbine that drives a generator. Small-scale applications exist in industries like mining. Utility-scale applications are more limited and include deployments in Bremen, Germany and McIntosh, Alabama. CAES is site-specific and typically requires natural gas to operate.[4] CAES applications can be used for peak shaving; ancillary services, price arbitrage, and seasonal load shifting — among other applications. Capacity and discharge times are site-specific, and CAES systems are generally operated similarly to pumped hydroelectric storage systems.

Pumped hydroelectric storage systems store energy by pumping water against gravity from a reservoir at lower elevation to one at higher elevation. Energy is extracted by releasing stored water through a hydroelectric turbine to generate electricity. Systems are "open loop" if they connect to a natural body of water, and "closed loop" if they do not. Pumped hydro is a mature, highly efficient technology. It is the most common type of energy storage system in North America and the world. In fact, pumped hydro accounts for more than 90% of all utility-scale energy storage applications in the United States.[5] Pumped hydro systems can contribute valuable energy, capacity, and ancillary services, depending on a system's operational, environmental, and water resource constraints. Notably, the Bath County Pumped Storage Station in Bath County, Virginia, has been coined the "world's biggest battery."[6] Proposed systems are subject to rigorous environmental review and can take several years to site, permit and build. Small-scale installations have also been deployed. Depending on size, they are called "micro," "mini," "nano," or "pico" systems.

1.1.2 Electrochemical Storage

Electrochemical storage technologies include numerous battery technologies that vary in energy density, power performance, cost, and charging durations — among other attributes. The two main categories of batteries discussed below are: (1) solid state batteries and (2) flow batteries.

Solid state batteries are batteries in which chemical energy is stored in solid-based electrodes. Examples include lead acid batteries, lithium ion (Li-ion) batteries, sodium sulfur (NaS) batteries, and zinc-based batteries.

- Lead acid batteries are a well-established technology dating back to the 1800s. They are supplied by a large, worldwide base of suppliers, and are the world's most widely used rechargeable battery.[7] They are primarily used as automotive batteries and in the

[3] Source: EPRI, Energy Storage for Grid Connected Wind Generation Applications, December 2004
[4] Source: Sandia National Laboratories, Potential Hazards of Compressed Air Energy Storage in Depleted Natural Gas Reservoirs, 2011
[5] Source: U.S. Department of Energy, Pumped-Storage Hydropower
[6] Source: National Public Radio, "The World's Biggest Battery, 2018
[7] Source: Geoffrey J. May, Alistair Davidson, Boris Monahov, Lead batteries for utility energy storage: A review, 2018

industrial sector for standby applications. "Advanced lead acid batteries" and carbon composite lead materials continue to mature, allowing for greater depth of discharge and longer battery lifetimes in utility storage applications.[8]

- Lithium ion (Li-ion) batteries include a wide range of battery chemistries characterized by the transfer of lithium compounds between electrodes. They are used by the cell phone, consumer electronic, and electric vehicle industries, and represent the fastest growing chemical storage technology in the electric utility industry. Utilities are increasingly deploying Li-ion batteries in grid-scale applications for power management, capacity, arbitrage, and ancillary services. Over the last decade, Li-ion battery costs have declined substantially due to technological improvements, increased manufacturing capacity, and the growing demands of the electric vehicle industry. As of 2019, Bloomberg New Energy Finance estimates that Li-ion battery demand through 2030 will be driven primarily by passenger electric vehicles.[9]

  EVs predominantly use Li-ion battery technology and could be used to dynamically support the grid by modifying the rate and timing of charging and discharging (collectively called vehicle-grid integration or "VGI"). Unidirectional VGI ("V1G", or "smart charging") simply modulates charging activities so charging takes place in a manner consistent with efficient grid operations. Bidirectional VGI ("V2G") contemplates EV batteries discharging to the grid to act as a generation resource when needed but is currently restricted by the manufacturers' warrantee and performance characteristics; once those are established, such potential can be further explored. Electric vehicles are expected to constitute between 80-90% of the global demand for battery cells by 2030 and will have a significant impact on electrical system loads as the vehicle mix shifts towards EVs. Research and analytics firm IHS-Markit estimates that the share of EVs sold in the U.S. will increase to 2 percent of the market in 2020 and 7 percent of the market in 2025.[10] This growth will be fueled in part by the introduction of new EV models by nearly every major automaker by 2020. Uptake rate of EVs may vary significantly from one community to the next, so the impact of EVs on the distribution system is likely to vary in terms of timing.

- Sodium sulfur (NaS) batteries use metallic sodium and operate at high temperatures (300 to 350°C). They are characterized by high round trip efficiencies (90%), long discharge properties, and the potential for continuous peak load support. They have been deployed globally at more than 200 locations in order to shave peak, provide backup power, firm wind capacity, and provide ancillary services.

- Zinc-based batteries are a maturing technology that employ zinc (a readily abundant element) and other chemicals. For example, Zinc-air (Zn-air) batteries oxidize zinc with oxygen from the air using only one electrode. Zn-air batteries have very high energy densities but low charging/discharging efficiencies (~50%) because the electrolyte does not always deactivate during the recharging cycle. Zn-air batteries are low cost, light

[8] Ibid.
[9] Bloomberg New Energy Finance, A behind the scenes take on lithium-ion battery prices, March 5, 2019
[10] Source: IHS Markit, US Electric Vehicle Loyalty and Volumes Reach Record Highs, 2019

weight, and non-toxic. Deployments to-date have primarily focused on micro-grid applications.

Flow batteries are batteries in which separate tanks store fluid electrolytes that are pumped through a common chamber separated by a membrane that allows electrons to flow between the electrolytes. Examples of flow batteries include redox flow batteries, iron-chromium (ICB) flow batteries, vanadium redox (VRB) flow batteries, and zinc-bromine (ZNBR) flow batteries. These batteries can be reconditioned in-situ by replacement of the electrolyte to extend their life. Vanadium discharges reliably for thousands of cycles but is a rare and costly element. Organic compounds may offer an alternative to vanadium.

Batteries are an exceptionally flexible energy storage technology. Due to their scalability and modularity, batteries are being deployed in applications as diverse as kilowatt-scale household backup use through to gigawatt-scale bulk energy systems which support utility operations.

1.1.3 Thermal Energy Storage

Thermal energy storage stores energy by cooling or heating water or other mediums and releasing the stored energy at later times for heating, cooling, or power generation applications. Examples are numerous and include:

- Ice-based technologies – Ice is made, stored, and used later for cooling, industrial processes, or to cool inlet air for various purposes (e.g. for combustion turbines).
- Chilled-water thermal storage – Water is chilled, stored, and used later for cooling, industrial processes, or to cool inlet air for various purposes (e.g. for combustion turbines).
- Direct load control of electric heat pump water heaters or resistive electric water heaters – Water-heating loads are shifted to periods of time with low demand and energy prices.
- Pumped heat electrical storage – Similar to pumped hydro, but instead of pumping water uphill, heat is pumped from one thermal store to another using a reversible heat pump.
- Solar hot water storage – water from solar thermal water heaters is stored in a tank, similar to a standard water heater tank, for later use.
- Molten salt technologies – Molten salt is heated to high temperatures and circulated through a heat exchanger to create super-heated steam that powers a steam turbine. This technology has been coupled with solar in concentrated solar power applications.

Many of the above technologies[11] are utilized around the country at the industrial, commercial, or residential level, in places with time-differentiated rates and can be a cost-effective way to shape end use load for better grid outcomes.

[11] With the exception of molten salt, which has generally been deployed in utility scale applications.

1.1.4 Electrical Storage and Chemical Storage

Examples of electrical storage systems include supercapacitor (or double-layer capacitor) storage systems and superconducting magnetic energy storage (SMES) systems which modify electrical or magnetic fields to store electric energy.

Chemical energy storage systems produce hydrogen via water electrolysis. Once produced, the hydrogen can be stored and used later to generate electricity via fuel cells or internal combustion.

1.1.5 Technology Considerations

An important characteristic of the different energy storage technologies is their ability to hold different amounts of energy as well as how much of that energy can be released in a short time. Each technology has different electrical performance characteristics, which may make some technologies better suited to function in specific grid locations, to provide certain grid services, or to be better suited to customer-side applications.

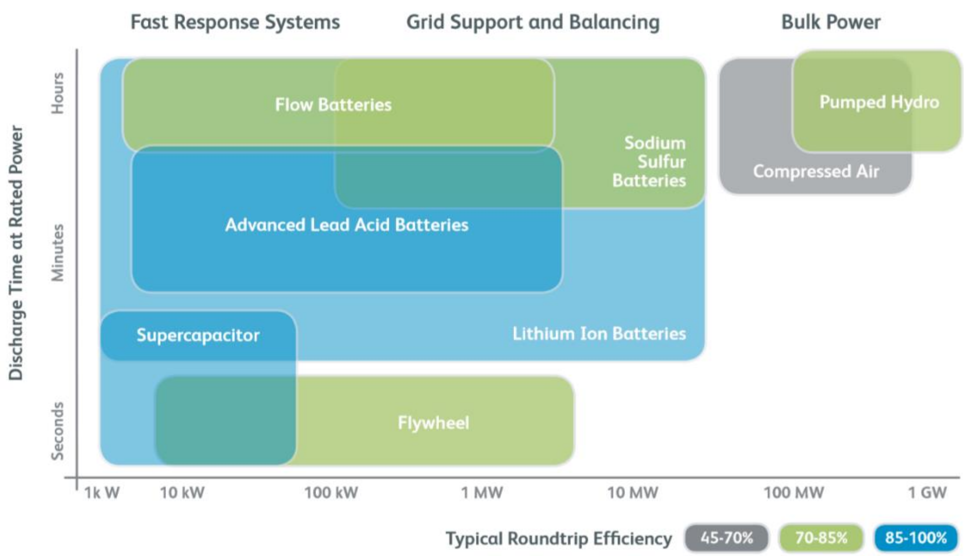


Figure 2. Typical size and duration of energy storage technologies[12]

Furthermore, energy storage technologies can be integrated in multiple locations across the entire energy value chain from generation to transmission, distribution, and customer applications.

[12] Source: AECOM, Energy Storage Study: Funding and Knowledge Sharing Priorities, 2015

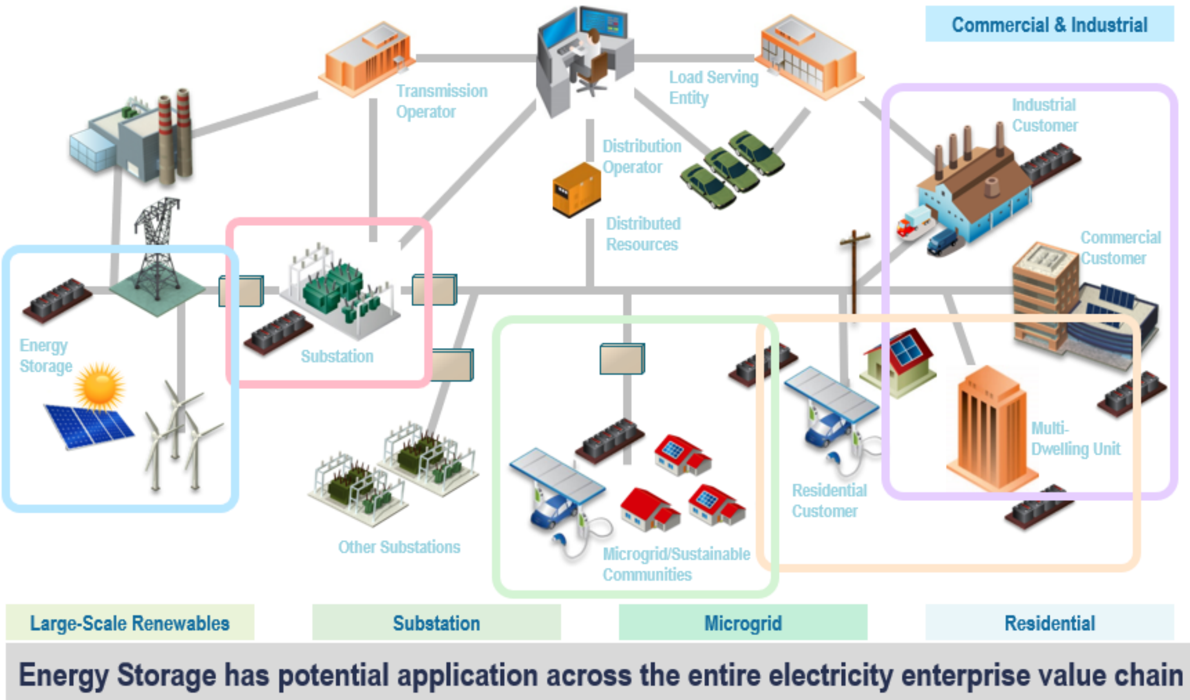


Figure 3. Applications of energy storage in the electric power system[13]

Energy storage can be used to provide a variety of grid services discussed more thoroughly in Chapter 2. These include improving grid reliability by providing ancillary services such as fast responding frequency regulation, spin and non-spin reserves, as well as acting as a system capacity resource. Bulk storage can also lower electricity generation costs by storing lower cost energy and later using it to reduce the need to dispatch higher cost generation resources. Storage can also act as an alternative transmission or distribution resource, acting as a peak reduction solution for managing circuit loading, and by providing volt/VAR support for enhanced system operations. In behind-the-meter contexts, energy storage can lower customer bills by enabling customers to manage demand charges and peak energy usage. It also can be used to provide enhanced community resilience when deployed in microgrid applications or as a resource that can "island" during outages. Storage technologies can be deployed as standalone grid resources or paired up with a diverse class of generation resources, enhancing the efficiency and flexibility of traditional generators, or firming the output of renewable generation such as solar and wind.

1.2 Global & U.S. Energy Storage Landscape

1.2.1 Global Energy Storage Market

As of 2019, the global operational storage power capacity is 172 GW, while another 5GW are under construction, contracted, or announced.[14] Pumped hydro is the technology with the highest installed capacity, followed by compressed air, lithium-ion batteries, flow batteries, and sodium-based batteries, for large scale applications. Historically, energy storage in the form of pumped

[13] Source: EPRI, 2015
[14] Source: DOE, Global Energy Storage Database, 2017

hydro was installed to enable baseload power plants to be more dispatchable and better able to match daily load patterns. Today, the daily load following rationale for energy storage remains, but various regions are also deploying storage to provide increased resilience, resource diversity, local capacity, system flexibility and as a tool for renewables integration. Figure 4 below is taken from the DOE Energy Storage Database, showing the number of non-residential storage installations by region.[15]

Figure 4. Non-residential storage installations around the world[16]

Recently, the deployment of storage technologies has been fueled by cost declines in the cost of storage technologies, particularly batteries. This has enabled economic deployment of storage in an increasing number of applications. These cost declines have been paired with regulatory changes and market design reforms that have enabled greater monetization of the services that energy storage can provide. In addition, the shifting generation mix within the U.S. (including Virginia) has created the need for additional system flexibility and diversity, services that storage is well-suited to provide.

Bloomberg NEF recently forecasted that by 2040 the energy storage market will produce 942 GW, representing 7% of the total power capacity installed in the world.[17] The countries that are expected to lead in storage deployment with more than two thirds of installed capacity are the U.S., China, Australia, France, Germany, India, Japan, South Korea, and the United Kingdom.

[15] Note: Red pins denote single energy storage installations in that region.
[16] Ibid.
[17] Source: Bloomberg NEF, Energy Storage is a $620 Billion Investment Opportunity to 2040, 2018

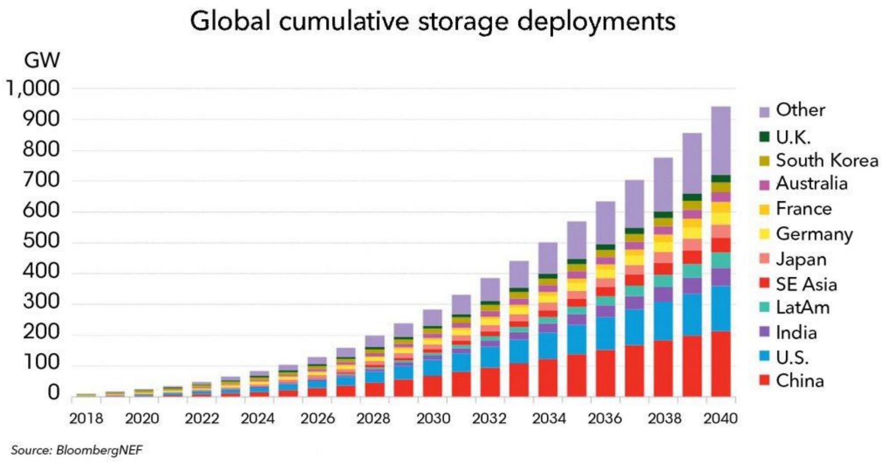


Figure 5. Global cumulative battery storage deployment[18]

1.2.2 U.S. Energy Storage Market

As of 2017, the U.S. energy storage capacity was approximately 24 GW (by rated power). The principal source of storage is pumped hydro with 93% of the total, composing the 7% thermal storage, compressed air, flywheel and batteries. This is shown below in Figure 6.

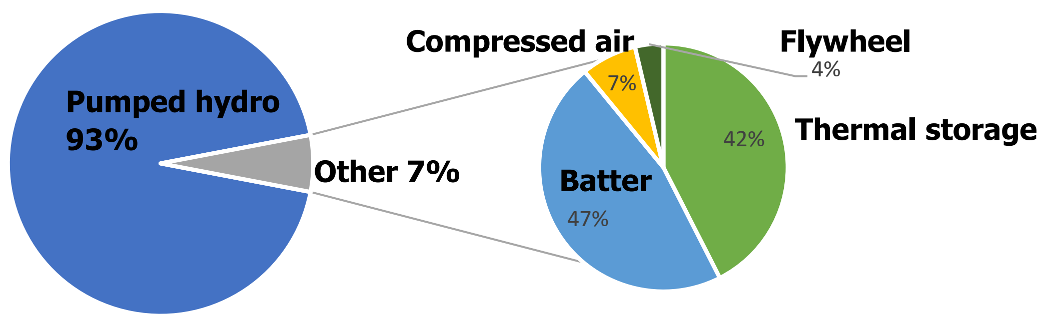


Figure 6. Energy Storage Capacity in the U.S.[19]

While energy storage technologies in general have grown briskly in the last decade, electro-chemical (battery) storage technologies have experienced the most rapid growth. The regions with the most newly installed storage between 2015-2017 are PJM, CAISO and ERCOT, as shown in Figure 7. At the end of 2017, the total battery storage capacity in operation (by energy rating) was 867 MWh.[20] At 86% of the total new deployments, lithium-ion batteries provide the largest amount of new battery storage capacity.[21]

[18] Ibid.
[19] Source: DOE Global Energy Storage Database, 2017
[20] Source: U.S. Energy Information Administration, U.S. Battery Storage Market Trends, 2018
[21] Source: U.S. Energy Information Administration, U.S. Battery Storage Market Trends, 2018 Idem, p. 9.

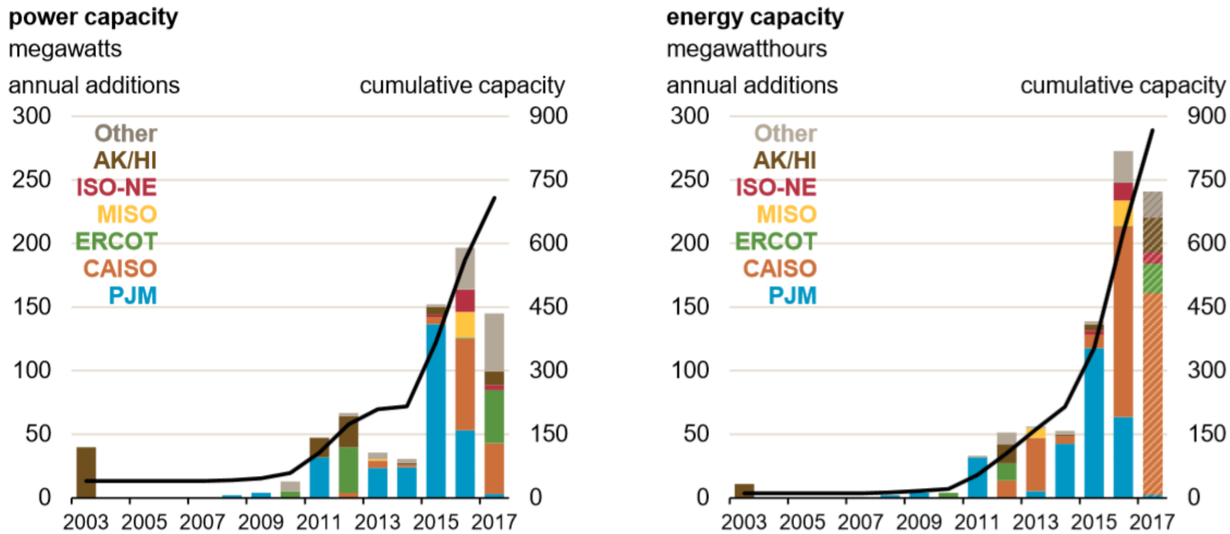


Figure 7. Deployments of Battery Energy Storage in the U.S, by power capacity & energy capacity[22,23]

Several states in addition to Virginia have recognized the value of storage technologies, such as Massachusetts, New York, New Jersey, Arizona, Hawaii and California. Many of these states have developed similar energy storage studies and have started to integrate the technology class into their planning processes, citing reasons such as economic resource optimization, for grid resiliency, system efficiency, system flexibility, renewables integration, and greenhouse gas reductions. Some of these states have established mandatory storage deployment targets, for example in 2018 New York passed legislation setting a statewide target of 1,500 MW by 2025 and the state's Public Service Commission subsequently adopted a requirement of 3,000 MW by 2030.[24] Similarly, in 2013, California adopted a mandate to deploy 1,325 MW by 2020, and subsequently increased the deployment target to 1,825 MW.

California Energy Storage Framework

California has three major investor-owned utilities (IOUs) – Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE). As the cost of storage has declined, all three are on track towards meeting their share of California's 1,325 MW energy storage procurement target by 2020. The state's focus on reducing regulatory barriers, enhancing wholesale market participation options, improving end use customer rate design, and enabling Multi-Use Applications (MUA) for storage have made good headway in **enabling energy storage technologies to participate on a level playing field with conventional resources** in the state, and have unlocked new applications for nontraditional technologies, such as distribution

[22] Source: U.S. Energy Information Administration, U.S. Battery Storage Market Trends, 2018
[23] Note the initial rise in deployment of battery energy storage in PJM starting in 2014 and subsequent decline in 2016. This was due to a rapid increase in storage deployment due to favorable treatment under a PJM market rule change establishing a market for fast frequency regulation ("RegD"). Subsequent rule changes limited storage's participation as a RegD resource, leading to the decline in later years. This is further explored in detail in Section 5.9 Wholesale Market Rules.
[24] Source: New York State (NYSERDA), New York State Energy Storage, 2019

deferral and power quality applications, that are helping the grid to operate more efficiently and reduce costs to California's energy consumers.

The primary application driving deployment of bulk storage in California is system/local capacity (also called resource adequacy), as fossil plant retirements continue to grow, and long-term capacity payments can be obtained in bilateral contracts with utilities. These contracts generally allow new storage facilities to provide other grid services on a merchant or contracted basis so long as they meet the market participation requirements established in their bilateral capacity contracts.

Storage has also been procured in California on an emergency basis due to localized grid constraints. An example of the latter was the 99.5 MW of energy storage procured and operational within 6 months to address reliability issues stemming from the Aliso Canyon gas storage facility leak, which severely curtailed natural gas import capacity into the Los Angeles basin.[25]

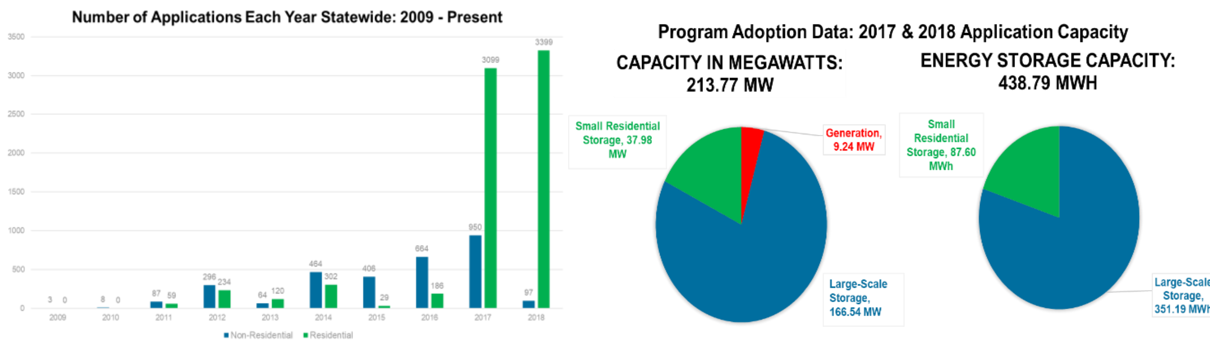


Figure 8. California storage deployment[26]

While California has been a first mover in many ways, other states have also begun adopting advanced frameworks for incorporating storage assets. For example, in addition to its deployment target, New York, under the umbrella of the NY-REV process, has adopted a robust distribution system planning process (DSIP) which has led the state's utilities to develop harmonized models for integration of DERs. Each utility is also required by the Public Service Commission to launch two ESS projects, with the intent to use these as models for additional Non Wires Alternatives. Competitive solicitations for NWA have been conducted and more are expected going forward as a means of addressing local system needs in lieu of traditional capital expenditures (e.g. reconductoring, substation upgrades, etc.).

1.2.3 Cost of Storage

Over the past decade, most energy storage technologies have shown differential cost declines, with lithium-ion technologies leading the way. BNEF has reported a 76% drop in cost of lithium ion cells since 2012[27], largely driven by increases in manufacturing capacity to serve the needs of consumer electronics, electric vehicles, and grid-connected stationary storage.

[25] CESA compilation of AB 2514 compliance filings and applications for approval

[26] Source: California Energy Storage Alliance, 2019

[27] Source: Bloomberg NEF, Battery Power's Latest Plunge in Costs Threatens Coal, Gas, 2019

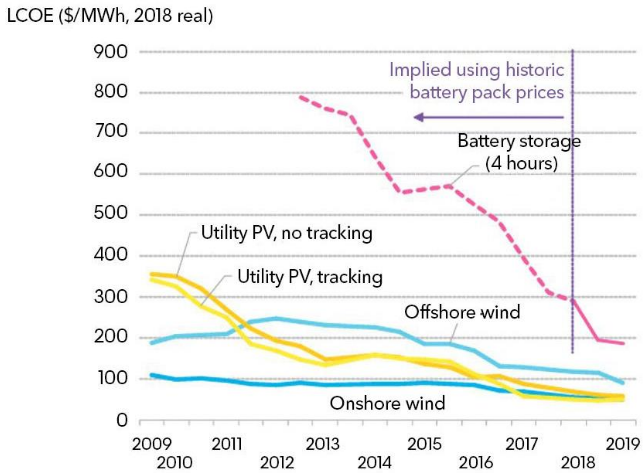


Figure 9. Technology cost benchmarks - Battery storage and renewables[28]

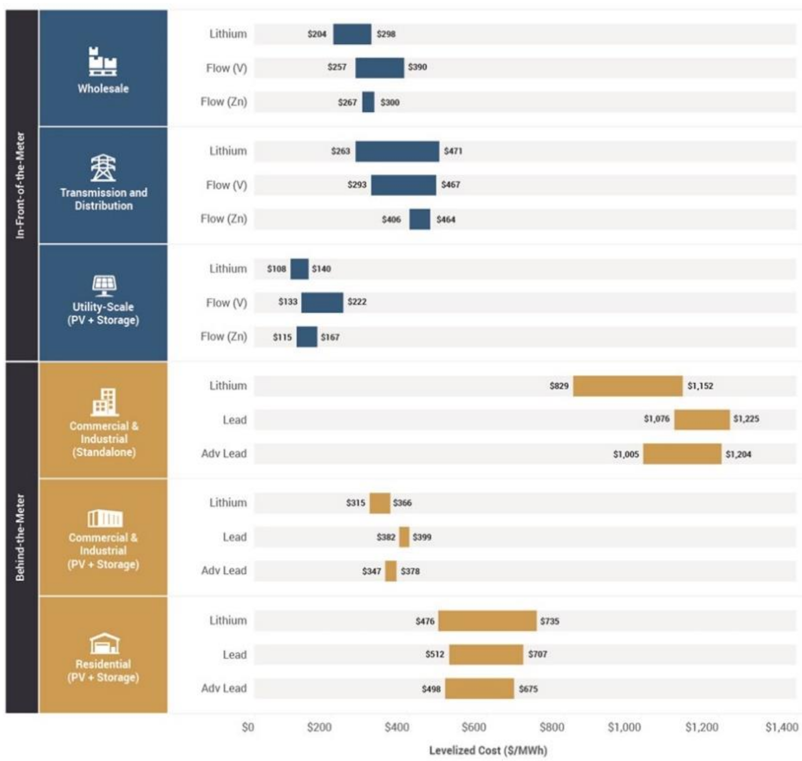
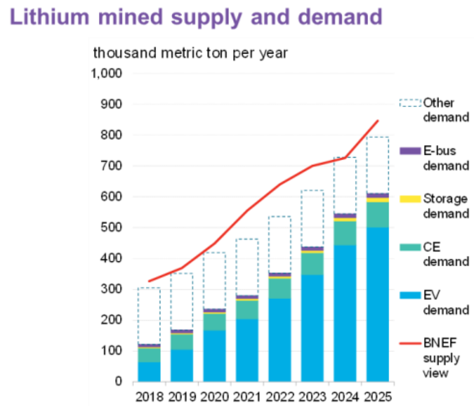


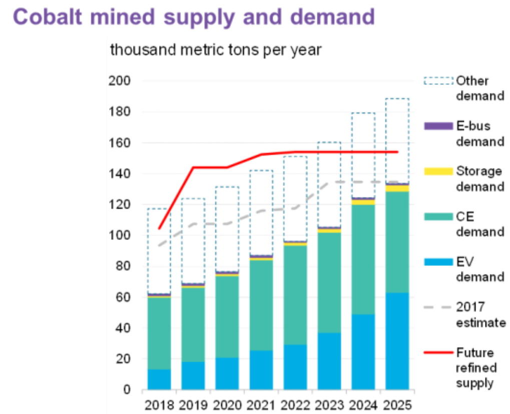
Figure 10. Levelized cost of storage in the U.S.[29]

Most analysts expect continued cost declines for lithium-ion technologies. Lazard's latest analysis revealed that lithium-ion storage systems deliveries may have some risk of cost volatility due to tight supplies of input commodities such as cobalt and lithium carbonate as shown in in Figure 11 below; cobalt demand is projected to outpace supply by 2023. This could limit the scale of the energy storage market with current technology.

[28] Source: Bloomberg NEF, Battery Power's Latest Plunge in Costs Threatens Coal, Gas, 2019
[29] Source: Lazard, Levelized Cost of Energy and Levelized Cost of Storage, 2018



Source: Bloomberg NEF, Avicenne, Deutsche Bank. Note: Lithium demand from batteries will require lithium to be mined 12 months earlier. Note: unit refers to lithium carbonate equivalent tons.



Source: Bloomberg New Energy Finance, Avicenne, Wealthdaily

Figure 11. Lithium and Cobalt mined supply and demand[30]

Cobalt is especially problematic, as the majority of it is sourced from the Democratic Republic of Congo (DRC), which has come under increased scrutiny for human rights violations and hazardous mining conditions.[31] Alternative sourcing could present an increased cost, but is possible; BMW has recently announced that it will be procuring cobalt from mines Australia and Morocco instead of the DRC.[32] The majority of cobalt refining also takes place in China, with over 50% of refining capacity located in the country.[33] This also introduces additional price volatility, as China has previously restricted its supply of other rare earth metals when it reduced export quotas by 35% in 2010.[34]

Despite this potential for price volatility, lithium-ion technologies have still been steadily declining in cost. Figure 12 below shows a summary of Lazard's analysis of capital cost for storage technologies, with lithium-ion showing an -8% CAGR, and finding that most of the barriers to lowering cost are with the non-battery systems (BOS, EPC, and inverter) costs.

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[30] Source: Bloomberg NEF, Lithium Market Overview, 2018
[31] Source: Source Intelligence. https://www.sourceintelligence.com/cobalt-new-conflict-mineral/
[32] Source: Bloomberg, "BMW to Source Cobalt Directly From Australia, Morocco Mines." https://www.bloomberg.com/news/articles/2019-04-24/bmw-to-source-cobalt-directly-from-mines-in-morocco-australia
[33] Source: McKinsey and Company, "Lithium and cobalt: a tale of two commodities," 2018.
[34] Source: Reuters, "China 2010 rare earth exports slip, value rockets," 2011. https://www.reuters.com/article/us-china-rareearths/china-2010-rare-earth-exports-slip-value-rockets-idUSTRE70I11T20110119

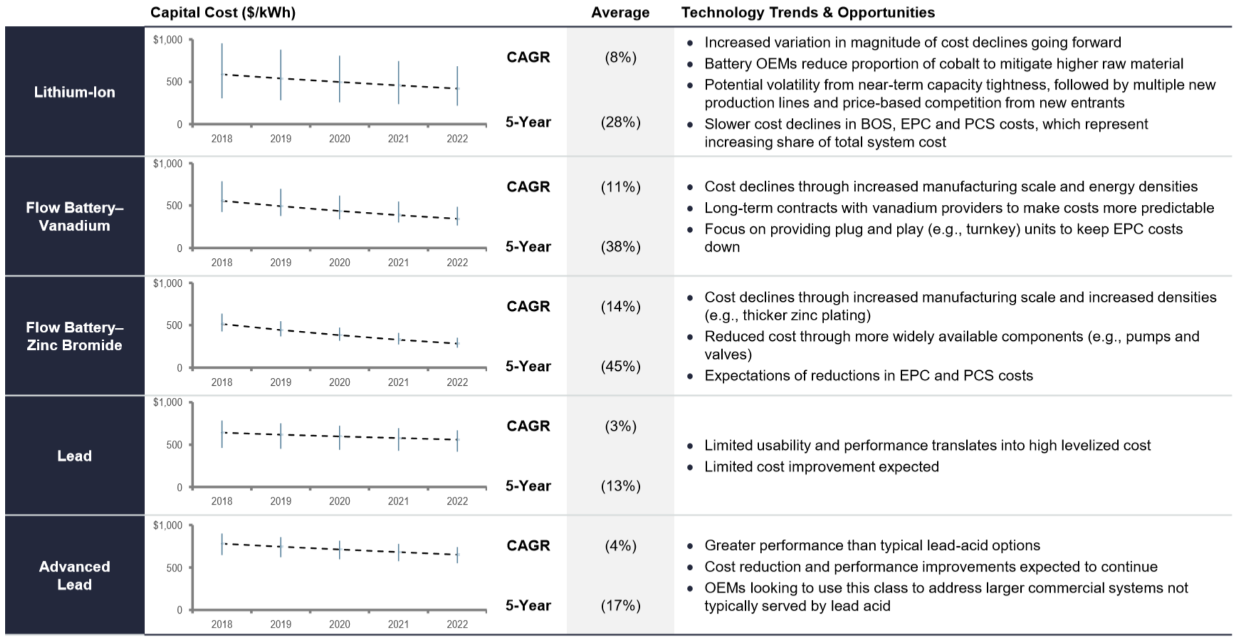

Figure 12. Capital Cost Outlook by Technology[35]

Manufacturers are also developing lithium-ion battery chemistry to be less reliant on rare earths such as cobalt, as shown in the following Figure 13. This figure from Bloomberg NEF shows the chemical proportions for two nickel-based lithium-ion batteries, nickel-manganese-cobalt (NMC) and nickel-cobalt-aluminum (NCA). NMC has the potential to be almost 80% nickel-based, while NCA technologies completely remove manganese and greatly reduce the proportion of cobalt, in some cases to 5% of total composition. This will reduce reliance on cobalt and remove some of the associated price volatility.

[35] Source: Lazard, Lazard's Levelized Cost of Storage Analysis, 2018. p. 14

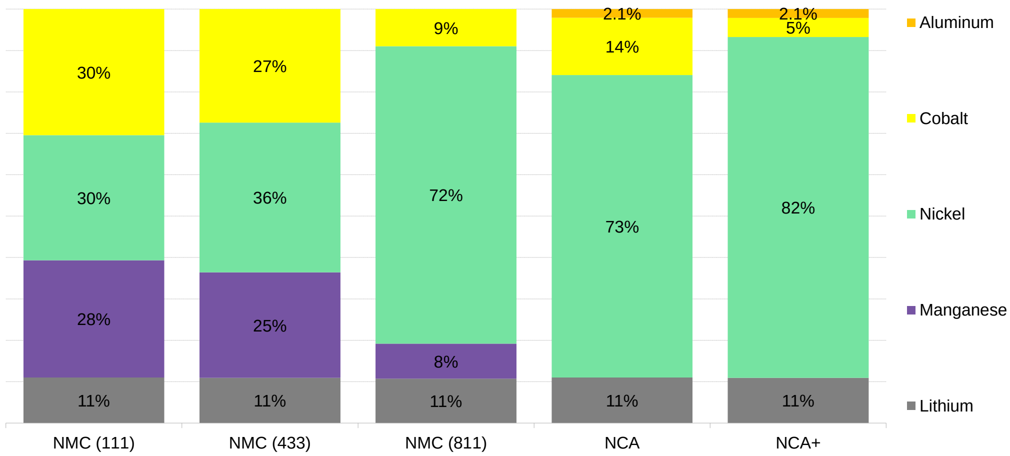

Figure 13. Battery cathode metal composition[36]

1.3 Overview of Virginia's Energy Landscape

1.3.1 Energy Resource Mix

Traditional resources such as coal, nuclear, and natural gas have historically been the primary providers of energy to Virginia's electricity mix. For example, Dominion Energy Virginia's energy portfolio in Virginia consists of 33.6% natural gas, 26.5% coal, 33.8% nuclear and 5.6% renewables.[37]

While renewables are still a small share, they have grown in recent years. Lazard's *Levelized Cost of Energy 2018* report indicates that new renewable generation is now the cheapest form of new-build capacity, and is on track to becoming cheaper than the marginal cost of existing conventional generation as shown below in Figure 14. Thus, the energy mix is expected to shift further towards renewables in the coming years. Moreover, many large customers, including technology companies like Microsoft and Apple, have facilities in Virginia and have expressed concerns about continued reliance on traditional fossil sources of energy.[38]

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[36] Source: Bloomberg NEF, Lithium Market Overview, 2018
[37] Source: Greentech Media, Virginia Regulator Asks Dominion Energy for More Accurate Resource Plan, 2018
[38] Source: CERES, VA Data Center IRP Letter-Spring, 2019

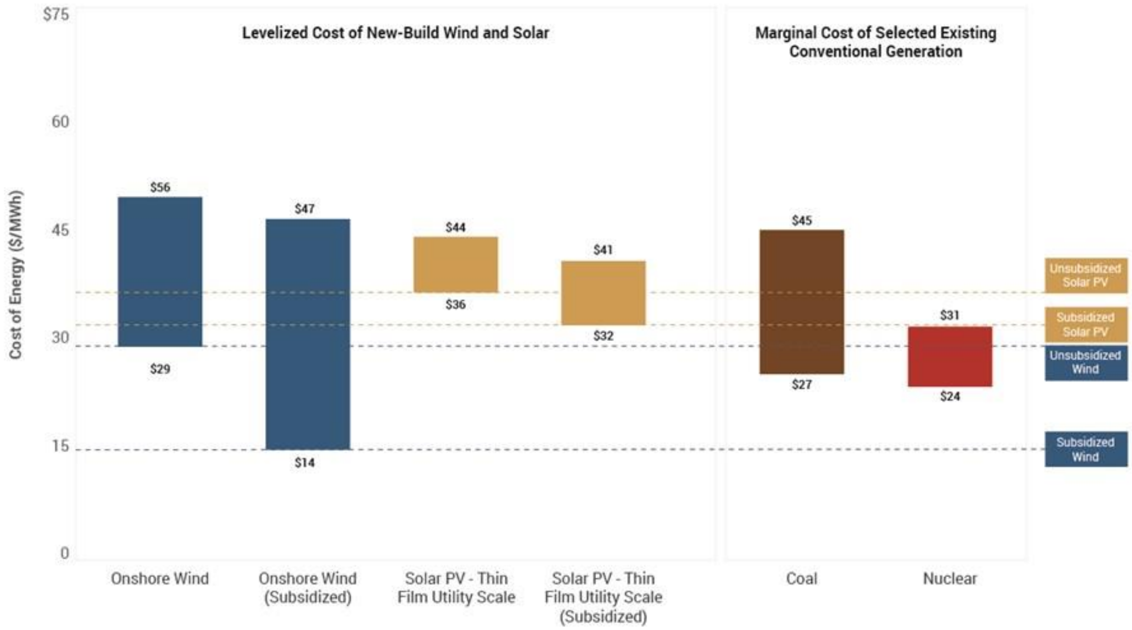

Figure 14. Levelized Cost of Energy, 2018[39]

In 2007 the General Assembly passed legislation that established the creation of a Renewable Energy Portfolio Standard program, in order to diversify Virginia's energy portfolio, which at the time contained large shares of coal and nuclear resources. This established a voluntary goal of 15% to come from eligible renewable energy sources by 2025.

Additional renewable resource additions are also expected in coming years due to the passage of SB 966 the Grid Transformation and Security Act (GTSA) which established that 5,000 MW of wind and solar was in the public interest, as well as 500 MW of distributed generation or offshore wind. The designation of these renewables as being in the public interest significantly increases the likelihood of them being approved for cost recovery by the SCC and the corresponding investments being made by Virginia's utilities.

1.3.2 Retail Electricity Providers

A large majority of Virginia's electricity customers are served by one of two large investor-owned utility distribution companies: Dominion Energy Virginia (DEV or Dominion) and Appalachian Power Company (APCo). Several smaller municipal and cooperative utilities serve the remaining customer load.

[39] Source: Lazard, Levelized Cost of Energy and Levelized Cost of Storage, 2018

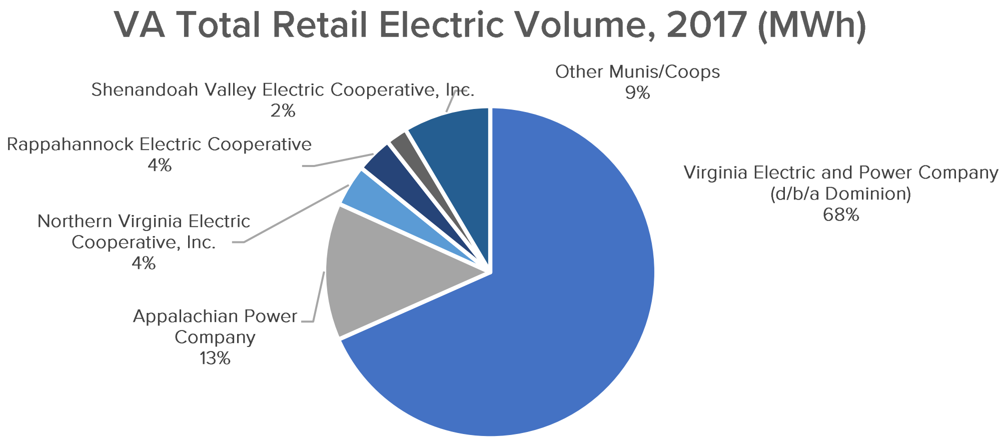

Figure 15. Virginia Electric Utilities by Retail Sales[40]

Both the investor-owned utilities and the coops are rate regulated by the State Corporation Commission (SCC). The 2007 General Assembly passed legislation (Senate Bill 1416 and House Bill 3068) re-establishing retail rate regulation for most of the electricity customers in the Commonwealth. As such, most retail rates are approved through the SCC's ratemaking process. Electricity customers with annual demands greater than five megawatts also have the option to shop for competitive electricity supply. In addition, retail customers may purchase electricity supply from 100 percent renewable sources from competitive suppliers if their local utility company does not include renewable energy as a source of generation.

As of November 2018, the average retail rate of electricity in Virginia was $0.094/kWh, which was below the U.S. national average of $0.104/kWh.[41] However, several retail tariff rates in Virginia also include either time-of-use energy charges or demand charges, which may be conducive to energy storage deployment for customer bill management. Demand charges in particular have been significant drivers of customer-sited energy storage deployment in certain U.S. markets (e.g. California).[42] While various rate designs are possible, demand charges are typically assigned every month based on a customer's highest instantaneous electricity usage with a specific interval. For example, Dominion (Virginia Electric and Power Company) offers a Large General Service tariff with a distribution demand charge of $2.037 per kW, an on-peak generation demand charge of $10.878 kW and a transmission demand charge of $2.277 per kW.[43] Customers that can reduce their peak instantaneous demand over the course of a month through load reduction (including through energy storage) thus may be able to realize significant bill savings.

[40] Source: U.S. Energy Information Administration, 2017
[41] Source: U.S. Energy Information Administration, 2018. The average retail rate is combined between residential and commercial/industrial customers.
[42] Note that demand charges are not typically included in residential customer tariff rates.
[43] Source: Dominion Energy, Large General Service Secondary Voltage, 2018

Tariff	Rate	Customer Peak Load (kW)	Total Demand Charges ($/kW)	Yearly MWh consumption
Dominion	1S	[44]	5.459	171,000
Dominion	GS-2T	30-500	10.874	8,184,000
Dominion	GS-3	>500	15.192	10,673,000
Dominion	GS-4	>500	14.055	2,419,000
APCo	M.G.S.	25-1000	3.12	29,000
APCo	L.G.S.	25-1000	11.22	171,000
APCo	L.P.S.	>1000	16.87	2,184,000

Table 1. Sample of VA Tariff Rates with Demand Charges[45]

1.3.3 Wholesale Markets in Virginia

Transmission owners that serve load in Virginia (e.g. Dominion Energy, APCo) are also members of the PJM Interconnection, a Regional Transmission Organization (RTO), that operates a competitive wholesale electricity market, and Independent System Operator (ISO) that manages the reliability of its transmission grid and performs long term transmission planning. As part of market operations, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM's organized wholesale markets include the Day-Ahead Energy Market, Real-Time Energy Market, a three-year forward capacity market known as the Reliability Pricing Model, and ancillary service markets.

Energy

PJM's energy markets ensure that adequate electricity is being generated to meet demand. The Day-Ahead Energy Market is a forward market in which supply-side resources specify the price level at which they are willing to generate electricity and demand-side resources specify the price level at which they are willing to consume electricity. The market clears taking into consideration the different bids, as well as other resource constraints. The hourly locational marginal prices for the next day reflect the cost of generating the electricity, as well as the congestion and losses that occur moving that electricity across the transmission system. PJM's Real-Time Energy Market similarly calculates locational marginal prices, but is a spot market, meaning that the electricity is procured for immediate delivery and prices are calculated at five-minute intervals based on real-time operating conditions. Resources that clear the day-ahead market receive a schedule and are committed to perform the following day, but because day-ahead load forecasts do not always accurately predict electricity demand the following day, and other changes can occur regarding the availability of generators transmission wires, the real-time market provides a means to reevaluate the system's needs and dispatch resources as cost-effectively as possible.

[44] Residential rate (referred to by Dominion as the "Demand TOU" rate).
[45] Source: Dominion, Appalachian Power Company tariffs; Dominion and APCo rate cases. Yearly kWh consumption rounded to the nearest million. Where applicable, demand charges are for primary voltage service. Demand Charges do not include rider charges.

Capacity

The capacity market is designed to ensure adequate electricity supply exists to meet forecasted peak demand plus a reserve margin over a longer time period. PJM accomplishes this by procuring these forecasted capacity requirements three years prior to the resources being required to deliver energy. These long-term price signals are intended to attract any needed power supply by helping to cover the capital costs of investing in new electricity generation. Resources that clear the capacity market must be operational entering their performance year (i.e. three years after they clear the capacity market) and must offer into the day-ahead energy market to ensure their availability. Additionally, under PJM's "pay-for-performance" model, resources that cleared the capacity market must deliver energy during system emergencies or owe a significant payment for non-performance.

Ancillary Services

The ancillary service markets help maintain a balance between supply and demand on the transmission system. Regulation and reserves are the two primary types of ancillary services. Regulation is the injection or withdrawal of real power by facilities capable of responding to the system operator's automatic generation control (AGC) signal and is used to keep system frequency within acceptable tolerances as small discrepancies between supply and demand occur. In its regulation market, PJM uses a traditional signal, called RegA, to dispatch slower, sustained-output resources such as steam and combustion resources and a faster signal, called RegD, to dispatch faster, dynamic resources, such as battery storage. PJM created these two signals in response to FERC Order 755 which required the RTOs/ISOs to pay regulation resources not only for the megawatt range over which they can move (their capacity), but also the amount that they move up and down in response to the AGC signal (their mileage). Since faster moving resources are better at following the AGC signal and do more work in the regulation market, these reforms helped ensure that those resources were being compensated for their superior performance.

Reserves is the operation of resources in standby mode such that they are able to be deployed within a specified timeframe to compensate for the loss of assets that have cleared the markets to provide energy. PJM operates a Synchronized Reserve Market, Non-Synchronized Reserve Market, and a Day-Ahead Scheduling Reserve Market. The Synchronized Reserve Market is for resources that are connected to the grid and can be deployed in ten minutes or less. The Synchronized Reserve Market is further divided into Tier 1 and Tier 2 resources, where Tier 1 resources are those that are already online and following economic dispatch but are not operating at full capacity and are able to increase their output. Tier 2 resources are all other resources that cleared the synchronized reserve market. Non-synchronized reserves are non-emergency energy resources that are not synchronized to the grid but are able to start up and provide energy within 10 minutes. The Day-ahead Scheduling Reserve Market is for resources that can provide energy within 30 minutes. Offline and online generation as well as economic demand response are eligible to provide day-ahead scheduling reserves.

In addition to the ancillary services that PJM procures through its organized markets, it also compensates resources for providing reactive power and blackstart service. Reactive power helps maintain voltages within acceptable limits and all resources with a PJM interconnection agreement are required to have reactive power capability and operate within a specified power factor range.

The costs of doing so are recovered through a cost-of-service rate in PJM's tariff. Blackstart resources are used to restore electricity to the grid in the event of an outage. PJM selects units to meet blackstart needs identified in transmission owner restoration plans through a request for proposal process. Storage can also provide many of these non-market services.

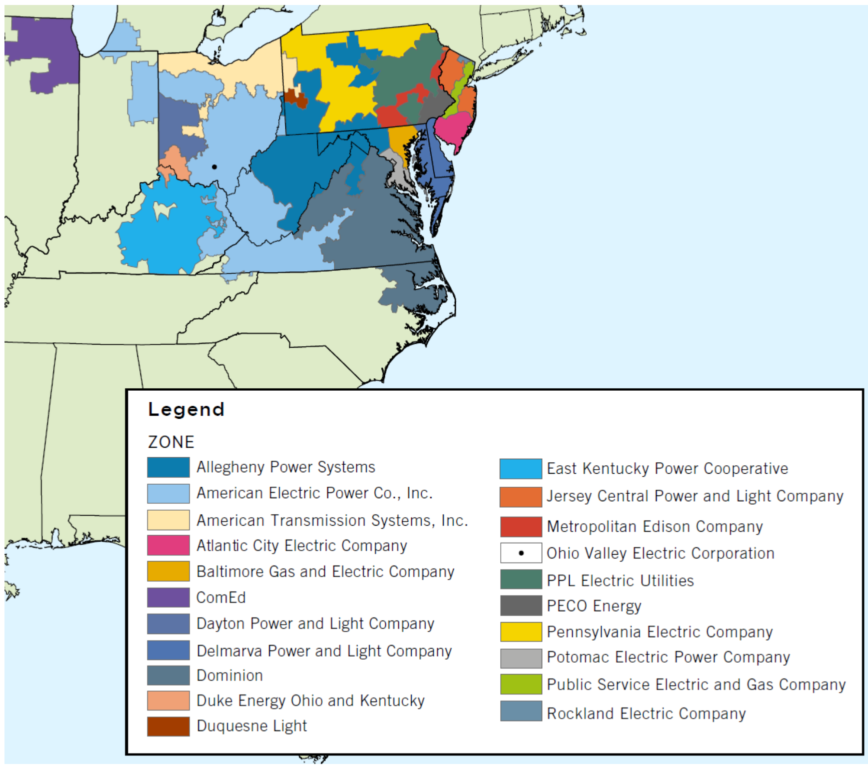

Figure 16. PJM Interconnection Transmission Zones[46]

1.3.4 Recent State Policy Developments (e.g. the Grid Transformation and Security Act)

In early 2018, Virginia Governor Ralph Northam signed Senate Bill 966, also known as the Grid Transformation and Security Act (GTSA), which enacted several major reforms to Virginia's energy policy. The law included several important provisions including significant reforms to Virginia's utility ratemaking process, expansion of renewable resources including 5,000 MW of new solar and wind energy, significant investments in energy efficiency and low-income energy assistance, and cost recovery structures for grid modernization and distributed energy resource integration.

As part of these reforms, the Virginia Department of Mines, Minerals and Energy (DMME) was also required to develop an Energy Plan, which was released in September 2018. This plan provides high-level and detailed recommendations to enable Virginia's grid modernization and other policy goals to be achieved over the coming decade. Some of these goals include expanding Virginia's existing solar and wind programs, developing new solar purchase options for corporate customers and small businesses, increasing energy efficiency financing opportunities, establishing

[46] Source: PJM, PJM Zones, 2019

electric vehicle targets, and working with stakeholders to evaluate energy storage options. More specifically, the plan also included a target of 16% renewable procurement target and a 20% energy efficiency target, with 3,000 MW of solar and onshore wind by 2022, 2,000 MW of offshore wind by 2028, and investments of $115 million per year in energy efficiency programs for Virginia's utilities.

Additionally, Virginia committed to conduct a study of energy storage potential and policy options to remove barriers (this study).

Prior to Senate Bill 966 there were no specific programs or policies to encourage deployment of energy storage systems in Virginia. However, the bill directed the state's major utilities to conduct pilot programs for the deployment of electric power storage batteries with capacity of up to 10 MW for APCo and 30 MW for Dominion Energy Virginia. Additionally, in defining a "public utility" for purposes of the Utility Facility Act, SB 966 excludes any company that provides storage of electricity that is not for sale to the public, provided the company is not organized as a public utility. The law also establishes a new rate adjustment clause category for expenses of electric distribution grid transformation projects, which include, among other things, certain energy storage systems and microgrids.

As part of its regular planning process, utilities in Virginia are required to develop an Integrated Resource Plan (IRP) every two years and submit this to the SCC for review and approval. An IRP provides a forecast of a utility's future energy needs and resources to meet those needs in a reliable and cost-efficient manner. In December 2018, the SCC rejected the Dominion Energy IRP proposed for the period 2019 to 2033, for a variety of reasons. In its Order, the SCC gave Dominion Energy Virginia 90 days to remodel and resubmit an updated IRP. A key stipulation of the order was that the updated plan must incorporate the 30 MW battery storage pilot program described in SB 966.

1.3.5 FERC Order 841

As the provision of wholesale services became a more attractive business model for energy storage, some RTOs/ISOs started to revise their tariffs to improve access for storage resources, but the wholesale markets still were not accommodating their full capabilities. Original RTO/ISO market constructs were designed for centralized thermal generation and one-way power flows, which can create barriers to the participation of storage resources, but even where rules for storage had started to emerge, they often placed limitations on the services that storage resources could provide, or were designed for the unique operating characteristics of specific storage technologies such as pumped-hydro. Opening the wholesale markets to emerging technologies so that they can compete on an equal basis with all other resources fosters competition in those markets, thereby helping to ensure efficient market outcomes and cost-effective rates for consumers. On this premise, and after evaluating the existing RTO/ISO market rules for energy storage, the Federal Energy Regulatory Commission (FERC) issued Order 841 in February 2018 to require the RTOs/ISOs to remove barriers to the participation of energy storage resources in their capacity, energy and ancillary service markets.

Order 841 required the RTOs/ISOs to create a participation model (*i.e.* a set of market rules) for all energy storage technologies that recognizes their physical and operational characteristics and facilitates their participation in the RTO/ISO markets. The final rule included five primary requirements related to the participation of storage resources. First, it **requires the RTOs/ISOs to ensure that a resource using the participation model for storage resources is eligible to provide all capacity, energy, and ancillary services**. While storage resources will still need to meet the minimum technical requirements of providing these services, this reform makes sure the storage resources have access to the markets and are not unnecessarily prohibited from selling certain services as was the case in multiple markets.

Second, the RTOs/ISOs are **required to ensure that a resource using the participation model for storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer**. This reform acknowledges the bidirectional characteristics of energy storage (i.e. its ability to charge from the grid, and discharge back to the grid). Consistent with the economic theory upon which they are built, the RTO/ISO markets generally put resources either on the supply side of the market (generators of electricity), or on the demand side of the market (consumers of electricity), but since energy storage can to do both, Order 841 ensured that it is able to participate as both supply and demand.

Third, Order 841 **requires the RTOs/ISOs to account for the physical and operational characteristics of electric storage resources in their participation models**. The energy limitations and bidirectional capabilities of storage resources make operating them unlike other energy assets. Making sure the resources are able to submit information about their physical constraints or operational limitations either as a dynamic part of their market offers or as a static characteristic of the resource ensures that it is being modeled and dispatched consistent with its capabilities. Order 841 established a list of 13 physical and operational characteristics that the RTOs/ISOs must account for and also provided them flexibility to propose other characteristics they think are necessary to operate storage resources. This list included characteristics like state of charge, maximum charge and discharge rates, minimum charge and discharge rates, maximum state of charge, and minimum state of charge. The list of characteristics was intended to be broad enough to acknowledge the potential constraints of all energy storage technologies, but submission of the information was not mandatory as some of the characteristics may not be relevant for a particular technology.

Fourth, because several RTOs/ISOs had size requirements that were creating a barrier to entry for small storage resources, Order 841 **requires that the RTOs/ISOs allow energy storage resources at least as small as 100 kilowatts to use their participation models for storage resources.** This was also consistent with the requirement that transmission-connected, distribution-connected and behind-the-meter storage resources be able to participate in the RTO/ISO markets, and the fact that many smaller storage resources are being developed today. However, the ability for greater participation also has the potential to complicate the interconnection, monitoring, and control of storage devices.

Lastly, Order 841 **requires each RTO/ISO to ensure that storage resources are able to pay the wholesale price for their charging energy**. This requirement extends to all resources that fall under the definition of electric storage resources in the Final Rule,[47] and not

[47] Order 841 defined an electric storage resource as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid.

just those that are using the participation model for storage resources. Because charging an electric storage resource to sell electricity back into the wholesale markets is not an end use of electricity, this qualifies as a wholesale transaction, and therefore the relevant wholesale rate is applicable. However, while wholesale rates are generally lower than retail rates thus potentially improve the competitiveness of storage resources in the markets, storage resources were not precluded from paying the retail rate for their charging energy, buying it bilaterally, or charging off a co-located generator.

1.3.6 PJM Market Reform

On December 3, 2018, PJM filed its proposal to comply with the requirements of Order 841. While PJM's existing tariff rules ostensibly permit the participation of storage resources in all of its markets, PJM did propose numerous reforms in its compliance filing that were required by Order 841 to further remove barriers to storage participation in its markets. Specifically, PJM's filing addresses the ability of storage resources to participate in all of its capacity, energy and ancillary service markets and proposes the changes that it believes are necessary to ensure that storage resources are able to provide all of the services they are capable of providing. However, PJM's proposed market reforms are not final until they have been accepted by FERC, and given the contention around some of PJM's proposals, it is likely that further changes will be required by FERC. Consequently, this report focuses on describing how PJM's proposal will affect the ability of energy storage resources to participate in its markets, and highlights some of the more controversial proposals that FERC may require PJM to amend.

To comply with 841, PJM proposed its Energy Storage Resource (ESR) Participation Model, which will allow storage resources to provide all capacity, energy and ancillary services in PJM's markets. Because PJM currently only allows ESRs to participate as market sellers, it revised its tariff to ensure that they will be able to also act as market buyers and be eligible to purchase energy or related services from the PJM Interchange Energy Market. To ensure that ESRs are able to pay the wholesale rate for charging energy, PJM is working on metering and accounting practices that will help storage resources distinguish charging energy that is resold back into the PJM markets from other charging energy and plans to implement these changes prior to the implementation deadline for their proposed market reforms on December 3, 2019. The minimum size for all resources in PJM was already 100 kilowatts, so it did not need to make any changes to the size requirements for ESRs.

In its energy market, PJM has proposed a construct that it states will allow ESRs to participate and be dispatched as supply and demand and set the wholesale clearing price as both in a way that accounts for the unique characteristics of storage. Specifically, PJM proposes to model ESRs as one continuous resource by accounting for their entire positive (discharging) to negative (charging) range over a given hour. PJM also proposes to allow ESRs to participate in the day-ahead and real-time energy markets under three different modes: (1) continuous mode; (2) charge mode; and (3) discharge mode. Continuous mode allows an ESR to be dispatched along their entire operating range, while charge mode only allows them to participate with a negative dispatchable range, and discharge mode only allows them to participate with a positive dispatchable range. PJM incorporated many of the required physical and operational characteristics into the modeling of ESRs in the energy markets, although it will not be managing the state of charge of ESRs or optimizing their output over time.

For its capacity market, PJM proposed to revise the definition of a "Capacity Storage Resource" to include all types of storage technologies. PJM also proposes that the installed capacity megawatt value of Capacity Storage Resources will be based on the level of continuous output that the resource can sustain over ten hours. However, this proposal faces significant opposition in the comments filed by industry, and it is possible that FERC may require a shorter duration requirement that better reflects the output duration of new storage technologies such as batteries and offers a more cost-effective approach for consumers.[48] Additionally, PJM clarified that it will not be changing its must-offer requirement for the day-ahead energy market or its capacity performance requirements for Capacity Storage Resources. It is also important to note that outside of the Order 841 proceeding, significant changes to PJM's capacity market are being contemplated. Most notably, FERC required PJM to revamp its buyer-side mitigation rules and develop a method to carve subsidized generation out of the capacity market on a unit-specific basis, but PJM is waiting on FERC to rule on its proposal.[49]

For reserves, PJM proposes that ESRs that are synchronized to the grid and operating in continuous, charge, or discharge mode may participate in the synchronized reserve market, and that they can do so without offering into the energy market and being co-optimized across energy and reserves. This provides some added flexibility in how ESRs can provide reserves and may improve competition in that market. Additionally, PJM clarifies that if an ESR is disconnected from the grid and is capable of providing energy within ten minutes then it may participate in the non-synchronized reserve market. PJM proposes that ESRs that want to participate in the day-ahead scheduling reserve market would need to inform PJM that it would like to be considered and would require an energy schedule.

For regulation service, PJM proposes that an ESR may elect to provide both energy and regulation or regulation only. When the resource is providing regulation and energy, it may be in continuous, charge or discharge mode, and its potential regulation capacity will be determined by the operational limits of the mode it is operating in. While these are relatively minor changes to the regulation market, it is worth noting that the Energy Storage Association and multiple storage owners/operators in PJM filed a complaint against changes that PJM made to its regulation market in 2017 and that the current market design is currently being contested in settlement procedures before FERC.[50] Lastly, PJM clarifies that ESRs are eligible to receive compensation for reactive power capability and dispatch and that they may participate in solicitations for blackstart service.

[48] See Section 2.1.2 for more background on PJM's treatment of storage as a capacity resource.
[49] Source: See PJM Capacity Market Reform Proceeding (Docket Nos. EL16-49-000, EL18-178-000, ER18-1314-000, ER18-1314-001).
[50] Source: Order Establishing Settlement Procedures and Postponing Technical Conference, 163 FERC ¶ 61,157, (May 2018)

1.4 Current State of Energy Storage in Virginia

1.4.1 Existing Energy Storage Resources in Virginia

As renewable energy adoption increases in Virginia there may be an increased need for energy storage to aid with integration challenges. However, Virginia already has made some strides in terms of energy storage resource deployment.

Pumped storage hydropower (PSH) already plays a significant role in the state's energy system. Virginia's first pumped storage project, "Smith Mountain Lake", was completed in the mid-1960s by Appalachian Power. In the early 1980s, Dominion Energy (Virginia Electric and Power Company at the time) built the Bath County Pumped Storage Station, which is considered the largest pumped storage in the world, with a capacity of 3,003 MW that can power around 750,000 homes.[51]

Dominion Energy declared its intentions of establishing a newer station in the coalfield region of Southwest Virginia.[52] The facility is intended to store energy from Virginia City Hybrid Energy Center, Dominion Energy Virginia's coal-fired facility, as well as from renewable sources. Senate Bill 1418 and House Bill 1760 approved the petition to build newer pumped hydro storage facilities when at least renewable energy resources are used to partly power the facilities.[53] Dominion Energy Virginia anticipates that it will invest approximately $1.0 billion over the next 5 years to cover the capital cost of the project.[54]

Bulk Mechanical Storage technologies have also been used in Virginia. For example, several flywheel energy storage systems have been deployed (e.g. in Alexandria, Ballston, and Arlington) to regulate sudden changes in supply and demand, also known as frequency regulation.

Additionally, PJM is actively studying the role of electric vehicles as an energy storage resource. For example, the University of Delaware has recently conducted a conceptual "vehicle-to-grid" (V2G) technology test.[55]

1.4.2 Energy Storage Companies Operating in Virginia

Several technology companies are also actively developing energy storage products in Virginia. For example, Tumalow is a software company working in the energy storage space and helps to pair batteries with cloud-based optimization software.[56] This work allows synchronization between the batteries and building's peak energy usage, so demand charges can be reduced, ensuring power quality and reliability. In 2018, Siemens and AES formed Fluence, a joint venture to provide energy storage solutions for grid scale storage systems.[57] Fluence's global headquarters are in Arlington, VA.

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[51] Source: Dominion Energy, Bath County Pumped Storage Station
[52] Dominion Energy is considering Tazewell County and Wise County to build the power station, with a proposed timeline of commercial operation date in 2028
[53] Source: Dominion Energy, Renewable Generation, Water
[54] Source: Dominion Energy, Investor Day, 2019
[55] Source: PJM's Advanced Technology Initiative, 2019
[56] http://tumalow.com/
[57] https://press.siemens.com/global/en/pressrelease/siemens-and-aes-join-forces-create-fluence-new-global-energy-storage-technology

Other storage companies with a prominent presence in Virginia include:

- Greensmith, a provider of grid-scale energy storage software and integration solutions;
- Trane/CALMAC, a provider of thermal energy storage solutions that, by their own estimates, has installed more than 160 MWhs of thermal energy storage across Virginia since 1984;
- Delorean Power, a utility-scale energy storage development company;[58]
- East Point Energy, a storage developer based in Charlottesville, Va., that is partnering with utilities, power producers and landowners.
- Apex Clean Energy, a Charlottesville, Va.-based company that develops, constructs, and operates utility-scale wind, solar and storage projects across the U.S.
- WGL Energy, also known as WGL Energy Services and WGL Energy Systems, offers a full spectrum of energy offerings, including electricity, natural gas, renewable energy, carbon reduction, distributed generation (including energy storage) and energy efficiency. The company announced in July it is selling the distributed generation part of its business.
- Wärtsilä, a Finnish company operating in 177 countries with offices in Virginia, helps build natural gas plants, hybrid solar power plants and energy storage plants.

Furthermore, Fermata Energy, based in Charlottesville, VA, commercializes technologies that enable electric vehicles to provide grid services.[59] Fermata is currently developing a bi-directional EV demonstration pilot project with Nissan, in Danville, VA.[60]

Finally, several smaller demonstration storage projects for thermal and flow-battery technologies have been deployed including the following:

- In 2006, a thermal energy storage tank was created by an internet service provider in Dulles, Virginia.[61] This tank was designed to provide back-up cooling for the central plant and specified to have capabilities of storing enough chilled water equal to the peak cooling load for the facility for a period of two hours. It is in current operation and has a rated power of 1,500 kW.[62]
- In 2015, Dominion Virginia Power and Randolph-Macon College completed the state's first integrated solar and battery storage project, by installing 265 rooftop solar panels and connecting them to a battery system in Ashland, VA.[63]

1.4.3 Proposed Energy Storage Pilot Projects

On August 2, 2019, Dominion Energy Virginia requested approval from the VA SCC for the deployment three new battery pilot projects with aggregate capacity of 16 MW.[64] These projects are being proposed pursuant to the Grid Transformation Security Act which requires Dominion Energy Virginia to propose a battery energy storage system pilot program of up to 30 MW. The

[58] https://www.deloreanpower.com/
[59] https://www.fermataenergy.com/
[60] Source: Fermata Energy, Nissan Taps Fermata Energy for Nissan Energy Share Pilot, 2018
[61] Source: DOE Global Energy Storage Database, Dulles TES Tank, 2017
[62] Source: DN Tanks, TES Tank for Internet Service Provider in Dulles, VA
[63] Source: DOE Global Energy Storage Database, Randolph-Macon College - Dominion Virginia Power, 2017
[64] Source: Dominion Energy Virginia's August 2, 2019 filing at the Virginia State Corporation Commission (VA SCC) for approval of three battery pilot projects, http://www.scc.virginia.gov/docketsearch/DOCS/4%244301!.PDF

three pilot programs address specific use cases which are described in more detail in section 2.2.4.

Chapter 2: Energy Storage Value Streams and Use Cases in Virginia

Energy Storage is a versatile resource than can be deployed to provide a diverse range of services for the modern grid due to the variety of operational modes and potential locations where the it can be sited. The services that energy storage can provide are dependent on grid location as well as whether the systems are being sited on the utility side of the meter (in-front-of-meter) or on the customer side of the meter (behind-the-meter). The ability of an energy storage system to meet a particular need is dependent on several parameters, including 1) minimum power and energy requirements, 2) location requirements, 3) frequency requirements, and 4) fungibility of the asset.[65]

The diagram below cites thirteen different general services that energy storage can provide the transmission grid and wholesale markets, distribution utilities and the systems they operate, and retail customers.

[65] Fungibility, in this context, refers to whether there are substitute resources that could be deployed if the energy storage is unavailable. This is particularly relevant in the case where storage is to be deployed as an alternative transmission or distribution solution.

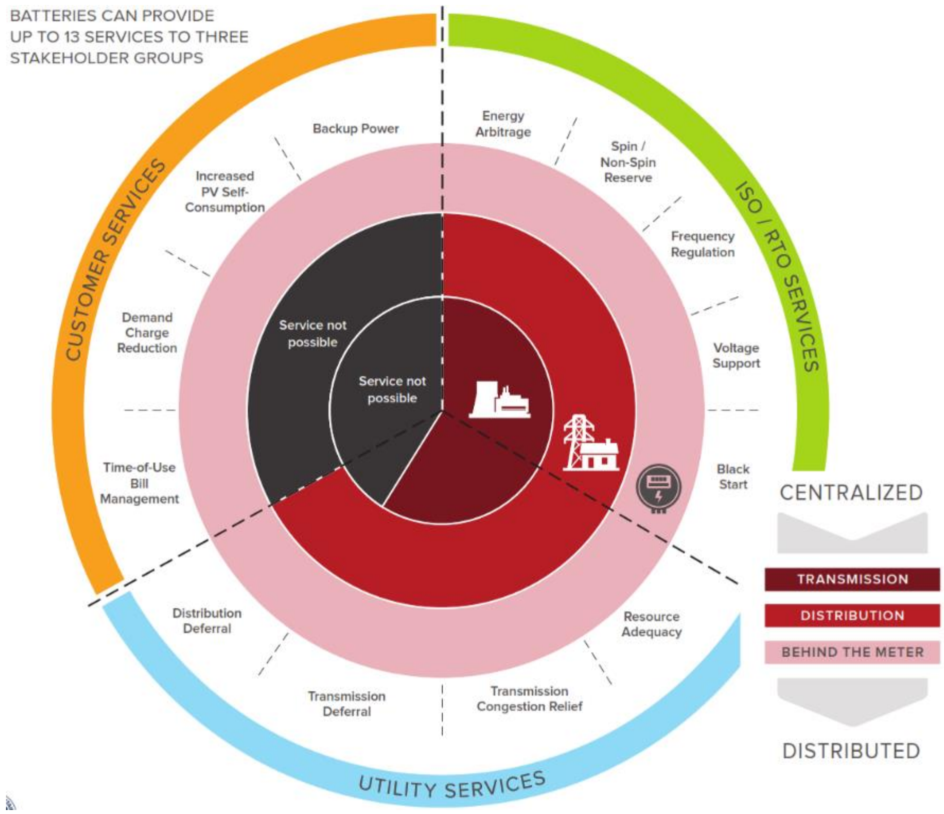

Figure 17. Energy Storage Services[66]

In order to remain consistent with the overview developed by RMI, descriptions of the above services are provided within the Virginian context below.

2.1 Wholesale Market Services

As described above, Virginia's utilities are members of PJM, which operates wholesale capacity, energy and ancillary service markets. Energy storage resources are able to participate in all of these markets, however due to the operational characteristics of storage and some elements of PJM's market design, there are relatively limited opportunities for energy storage resources, particularly new technologies like batteries, to depend on wholesale market revenues alone as a business model. PJM's filing to comply with the requirements of Order 841 will improve the ability of storage resources to participate in its markets, but the reforms as proposed will not immediately open new opportunities for storage resources, particularly given the lingering uncertainty regarding other market design changes in PJM's capacity and regulation markets. Additionally, while PJM is supposed to have its Order 841 market reforms implemented by December 2019, it is unclear if or when FERC will approve the proposed changes, and the compliance process could be iterative over the next several years. Nonetheless, opportunities do exist for energy storage resources to generate revenues in the wholesale markets.

[66] Source: The Economics of Battery Energy Storage, Rocky Mountain Institute, 2015

2.1.1 Energy Markets

PJM clears both day-ahead and real-time energy markets where the price for energy is determined by the cost of the last and most expensive resource needed to ensure that all of the demand on the system is met, subject to reliability and transmission constraints. Thus, as demand goes up, so does the price, both on an hourly basis in the day-ahead market and a five-minute basis in the real-time market. Significant price differences can therefore result between periods of relatively low demand and periods of relatively high demand, and because operating storage resources is premised on charging and discharging cycles, it is possible to time these cycles such that a resource is charging when the price is low (off-peak periods – generally during the night), and discharge when the price is high (peak periods – generally during the day). This is known as energy arbitrage and is profitable for storage resources if the price differential between peak and off-peak periods is adequate to make up for the efficiency losses experienced when cycling the storage asset.

Energy arbitrage has long been the business model for pumped-hydro resources in the U.S. and is the primary revenue stream for Dominion Energy Virginia's Bath Country Pumped Storage Station in Virginia, generally by taking advantage of daily peak and off-peak prices. However, new storage technologies like batteries are creating additional opportunities for arbitrage. They can easily be co-located with load, and therefore can serve as a hedge against the potential high congestion component of the locational marginal prices for energy when located in a load center where there is limited transmission capacity to bring generation into that load center during peak periods. In the past, this was only possible by purchasing financial transmission rights in PJM but using new storage technologies to reduce peak consumption in load pockets, allows load-serving entities to hedge against congestion costs by arbitraging energy for their customers, which creates more reliable predictions of congestion costs. Additionally, new storage technologies are able to move from charge to discharge mode faster than legacy pumped-hydro assets, so there is more opportunity to arbitrage prices in real time. As wholesale prices change in each five-minute increment, batteries are able to respond immediately as the price goes below what they are willing to pay for energy or above what they are willing to be paid.

While PJM's proposed continuous charge and discharge modes for ESRs and the new physical and operational parameters will make it easier to model and dispatch storage resources in PJM's energy markets, there will be limitations in fully capturing their value. PJM will not benefit from the same full-day optimization that it performs for its large pumped-hydro units, and it will be difficult for storage resources to account for their opportunity costs of discharging energy, primarily because PJM has not proposed to optimize ESRs over time and give them a day-ahead schedule (i.e. because storage resources have to stop and recharge - if they discharge energy during one hour, it limits their ability to do so in future hours when the price might be higher). Additionally, without a day-ahead schedule, ESRs will not know whether or when they will have wholesale market obligations or what their scheduled revenues are in advance. This is less problematic for storage resources whose business is predicated on wholesale market participation than it is for storage resources who may also want to sell services to a distribution utility or its customers.

2.1.2 Capacity Market (Reliability Pricing Model)

Large-energy storage resources can provide peak capacity when it is needed, the latter which is typically in the late afternoon and early evening during summer and/or winter months. Additionally, unlike traditional peaking units, energy storage resources can provide valuable grid services like ramping, voltage support, energy arbitrage, congestion relief, regulation and frequency response when they are not needed for peak capacity. Energy storage assets have low marginal costs for providing these services outside of peak hours because they would be charging with off-peak energy (arbitrage) and because they are always on and connected to the grid and do not have start-up and shut-down costs like thermal generation. To provide other services outside of their capacity obligations, system operators must identify the hours during which the resources must be available to fulfill their capacity obligations. However, system operators already engage in such behavior by identifying the times during which generators can be on a forced outage, or by forecasting peak demand periods months and years in advance. The California ISO (CAISO) has even limited the obligations of its flexible resource adequacy resources to certain times of certain days so that they do not need to be available around the clock.

PJM operates a three-year forward capacity market called its Reliability Pricing Model to ensure adequate supply is available to meet forecasted demand plus a reserve margin. While energy storage resources are eligible to participate in PJM's capacity market, and the large, long-duration pumped hydro units have been doing so successfully for years, there are several obstacles to newer, shorter duration technologies such as batteries being able to do so effectively. Under the existing construct, storage resources are required to have durations of six or ten hours (depending on how they register) and be available for capacity performance assessment hours which are of unknown times and durations. This means that storage resources must be available at all times for capacity performance and must be longer duration than most new storage technologies are generally designed for. Additionally, they are subject to day-ahead must-offer obligations for the entire operating day, which does not account for their energy limitations because they cannot possibly provide energy 24 hours per day at a reasonable power rating. Due to the long duration requirements, potential performance penalties, and must-offer obligations, there have not been any front-of-meter storage assets other than pumped hydro that have cleared the capacity market.

PJM's proposed Order 841 reforms for the participation of storage resources in the capacity market have not improved the market opportunity, and arguably have made it worse. **PJM maintained the same capacity performance and must-offer obligation rules and created a ten-hour duration requirement for the ESR participation model**. Because increasing the duration of new storage technologies like batteries can drastically increase their costs, it would be prohibitively expensive under current technology prices to design a system that can discharge for ten hours at its maximum output. PJM did clarify that ESRs may de-rate their capacity to meet the ten-hour requirement, which means that a 1MW/1MWH battery could offer 100 kW into the capacity market as that is the quantity that it is able to discharge for ten hours. However, this is only a fraction of the capability of the resources, and numerous arguments were made by commenters on PJM's filing that the ten-hour requirement goes well beyond what the operator needs to meet peak demand, is significantly longer than the capacity duration requirements in any of the other RTOs/ISOs,[67] is unnecessary and redundant due to the capacity performance requirements, and over-procures capacity which raises costs for consumers. Due to the significant pushback on PJM's capacity market proposal, and the other open capacity market proceedings described above, significant uncertainty exists regarding future opportunities in the capacity market for storage resource.

It is important to note that PJM establishes its market rules through a deliberative multi-party stakeholder process. States like Virginia are generally represented in these processes through groups like the Organization of PJM States, Inc. (OPSI). Moreover, the development PJM's Capacity Market rules are informed by its own analysis of operational data, including an effective load carrying capability analysis that is impacted by the specific suite of resources available within the PJM footprint. However, there are often differences of opinion among experts on how these technical analyses should be conducted and what conclusions should be drawn to inform market rules. For example, the Energy Storage Association recently solicited its own technical analysis which demonstrated that energy storage systems with durations shorter than 10 hours would be able to provide full capacity value up to a certain level of penetration.[68]

Non-market Resources

While the PJM capacity market is the primary means for ensuring resource adequacy in the state of Virginia, it may also be possible for Virginia utilities to use non-market resources (including energy storage) to serve their peak system needs. For example, Dominion Energy Virginia recently announced that it is planning to invest $500 million in "renewable-enabling" combustion turbines.[69] It's possible that this is a need that could also be equally met by energy storage resources instead. While storage resources may not be able to be offered into the PJM capacity market at their full capacity for the reason discussed above, Dominion Energy Virginia could use those resources to reduce its coincident peak load, thereby reducing its obligations in the capacity market, and also making those storage assets available for other balancing services necessary for effective renewable integration when they are not serving peak demand.

2.1.3 Ancillary Service Markets

As described above, PJM procures numerous ancillary services, with organized markets for regulation and reserves, as well as cost-of-service compensation for reactive power and blackstart. PJM's regulation market, and particularly its RegD signal described above are particularly well-suited for new storage technologies because faster moving resources which are inverter-based, such as batteries and flywheel systems, can very accurately follow AGC signals from PJM. Additionally, the pay-for-performance requirements of Order 755 that now also require compensation for mileage has made participation in the regulation market an attractive revenue stream for storage resources. However, PJM's regulation market design is currently being

[67] For example, the CAISO requires a 4-hour capacity duration to fulfill system resource adequacy requirements. Recently, NYISO had also proposed moving from a 4-hour duration requirement to a longer 8-hour duration requirement to receive full capacity credit. After further studies, the NYISO revised its proposal to arrive at a 6-hour duration for full capacity credit, and 90% credit for 4-hour duration.

[68] Source: Energy Storage Association, 2019 http://energystorage.org/system/files/resources/astrape_study_on_pjm_capacity_value_of_storage.pdf

[69] Source: Dominion Investor Presentation, 2019 (slide 41) Dominion Investor Presentation, March 2019 (slide 41)

disputed in settlement procedures at FERC because PJM changed its 15-minute neutral regulation signal to a 30 minute conditionally neutral signal.[70] The rationale for these changes relates to the fact that under the previous design, some RegD providers (including storage resources) were actually working against the needs of the grid.[71]

FERC also recently rejected a proposal by PJM on the basis that it did not appropriately use resources' mileage in determining their payments (ER18-87).

Energy storage resources are also eligible to provide synchronized reserves in PJM if they are connected to the grid and can provide energy in less than ten minutes, and they can provide non-synchronized reserves if they are not connected to the grid but are still capable of providing energy in less than ten minutes. While these are not highly valuable markets, storage resources that are offering energy will be co-optimized by PJM's market model and may be called upon to provide reserves if their state-of-charge provides adequate ability for them to do so. Additionally, PJM removed the requirement to have an energy schedule to provide synchronized reserves, so it is possible for storage resources to only offer synchronized reserves which gives them added flexibility in how they provide services. However, without an energy offer, they will not get compensated based on their opportunity cost of providing energy, which could further reduce prices in a market that already does not provide significant value outside of shortage events.

Energy storage systems located near areas where high reactance occurs can offset that reactance by generating or absorbing reactive power. All resources, including energy storage, are required to have reactive power capabilities as a condition of interconnection and can recover the capital costs of their reactive power capability through PJM's tariff. **However, it does not appear that the cost-of service methodology for calculating reactive power capability costs has ever been used for new inverter-based storage resources so precedent for this still needs to be established.** They are also eligible for opportunity cost compensation if they are dispatched to provide reactive power and must decrease their real power output to do so. Energy storage resources can also be used to re-start turbines after a blackout. This blackstart service is procured through a request for proposal process based on recovery schemes in PJM and storage resources are eligible to submit proposals in response to such solicitations.

Lastly, PJM, as the regional balancing authority, is responsible for complying with NERC requirements for maintaining adequate primary frequency response on its system.[72] Primary frequency response involves the rapid, automatic and autonomous actions of generating facilities to arrest and stabilize frequency deviations and allows the interconnected grid to maintain frequency within acceptable boundaries following the sudden loss of generation or load.[73] While

[70] Source: Order Establishing Settlement Procedures and Postponing Technical Conference, 163 FERC ¶ 61,157, (May 2018).

[71] More specifically, according to PJM participants they were working against controlling the Area Control Error (ACE) which is the measure used to maintain frequency within a specific control area.

[72] See NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting (Source: NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Settinghttps://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/BAL-003-1_clean_031213.pdf)

[73] Source: FERC Revised Requirements for Provision of Primary Frequency Response, 2018https://www.ferc.gov/media/news-releases/2018/2018-1/02-15-18-E-2.asp#.XJvxmPZFwYs

FERC has enabled market-based sales of primary frequency response,[74] it also later required all new facilities seeking interconnection service to install, maintain and operate a functioning governor or equivalent controls as a precondition of interconnection and created some accommodations for energy storage based on its energy limitations.[75] Due to the abundance of primary frequency response that the recent FERC order will result in, it seems unlikely that primary frequency response is a service that will be directly compensated in Virginia, but nonetheless it is an essential service that large energy storage resources will now provide to help maintain reliability of the bulk power system.

2.2 Distribution Utility Services

In addition to direct participation in the wholesale markets, energy storage resources can also be used by utilities in lieu of traditional investments in infrastructure and should be considered in planning processes for the cost-saving and operational benefits that they can provide. However, obstacles remain for effectively integrating energy storage into utility planning. Emerging storage technologies are not familiar investment options for utility planners, so the initial obstacle is to ensure that they are being considered on an equal basis with all other potential solutions. Storage should be considered as an alternative to traditional capital investments based on the latest assumptions for its cost and capabilities, particularly for those investments that are being developed to serve peak demand. Adopting this approach in Virginia could leverage lessons learned from other states with non-wires solutions frameworks such as California and New York.

Due to the rapidly declining cost of storage technologies, any assumptions made during planning analyses need to be updated on a frequent basis. Additionally, any planning analyses conducted should reflect the full capabilities of storage devices, including the bidirectional capabilities and fast response times of inverter-based technologies. Lastly, utilities with traditional regulated cost-of-service revenue models need to be incentivized to look at storage as an alternative to other more expensive investments. Storage is often capable of deferring or completely substituting for investments in more traditional wires infrastructure, but unless utilities are required to evaluate all options and to select the solution with the highest benefit-cost ratio inclusive of multi-use applications, then it is generally in the utility's interest to opt for more expensive conventional projects as they offer greater returns to their investors.

2.2.1 Transmission Congestion Relief

The cost for distribution utilities to serve their customer load goes up during peak hours partly because the transfer capabilities of the transmission system can be pushed to its limits, thereby causing the congestion component of wholesale energy prices to escalate. However, these costs can be mitigated by relieving congestion on transmission lines that serve urban areas or other parts of the grid with limited transmission capacity. Mitigating congestion can be a form of energy

[74] See FERC Order No. 819 – Third-Party Provision of Primary Frequency Response Service (Source: FERC Order No. 819 – Third-Party Provision of Primary Frequency Response Servicehttps://www.ferc.gov/whats-new/comm-meet/2015/111915/E-1.pdf?csrt=15550587718537652574)

[75] See FERC Order No. 842 - Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response (Source: FERC Order No. 842 - Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Responsehttps://www.ferc.gov/whats-new/comm-meet/2018/021518/E-2.pdf?csrt=15550587718537652574)

arbitrage for the downstream purchaser of energy, as discussed in Section 2.1.1 Energy Markets. Alternatively, it could be part of a planning approach that helps ensure a utility is able to effectively serve load, while hedging price risk. Operationally, it is accomplished the same way – the storage asset is co-located with load, charged when energy demand is low (with accordingly lower prices) and the transmission system is not congested, and then discharged when energy demand is high (higher prices) and the transmission lines serving the co-located load are congested. Moving energy into the load pocket with storage during times when the system is not stressed can significantly reduce the cost of serving load during peak demand. The small footprint, short development timelines, and minimal environmental impact of storage also allows it to be deployed quickly and very close to load which can be particularly advantageous for any near-term reliability concerns emerging from line congestion. This is more likely to occur in more congested urban areas such as northern Virginia, Richmond, or the Virginia beach areas.

While congestion relief has a clear economic valuation at the transmission level as described above, congestion also exists at the distribution level as well. The following section describes how distribution system costs can be avoided which could include those related to relieving congestion.

2.2.2 Transmission or Distribution Cost Avoidance (Non-Wires Solutions)

For transmission and distribution infrastructure that is persistently congested, aging, or otherwise experiencing voltage problems or thermal overloads, the most common mitigation strategy is to either upgrade or replace those components of the grid. However, upgrading or replacing utility infrastructure can require expensive capital investments. As such, deferring those investments, or completely avoiding them can reduce overall costs for the utility and its customers, especially if other value streams can be monetized when the resource isn't functioning as a grid reliability resource. These cost saving strategies can present a viable business case for energy storage investments and the major reason why it needs to be considered on an equal basis with all other potential investment in transmission and distribution infrastructure, especially that which is only needed to serve extreme peaks in demand. By placing storage downstream of transmission or distribution wires and operating it for congestion relief, as described above, it can reduce loading on wires and remove the need to upgrade their capacity or replace aging infrastructure. Additionally, storage can be located at substations or along transmission corridors to help maintain frequency and voltage on the system, reducing the need for capacitors, synchronous condensers, or other substation upgrades and helping generators on the system run more efficiently as they are relied on less for such services.

Despite these opportunities, significant challenges exist. In general, distribution utilities operating under a cost-of-service model have an inherent incentive to pursue additional capital investments, which these non-wires solutions would be displacing. This is described more thoroughly in Section 5.4 Limitations in Utility Procurement and Cost Recovery.

Transmission Services

Deferral services are possible on both the transmission system and distribution system, however there are some key differences between the applications. The high-voltage transmission system is FERC jurisdictional, so using storage for transmission deferral or avoidance will require a resource to be selected in a local or possibly regional transmission planning process and be subject to FERC approval and associated transmission rates. At the transmission level, there are both regional transmission planning processes, conducted by public utility transmission providers such as PJM, as well as local transmission planning processes that are conducted by the transmission owners such as Dominion Energy and AEP.

The regional processes are geared toward identifying transmission or non-transmission alternative projects that provide benefits to the region and having their costs allocated commensurately. FERC Order 1000 also aimed to create more competition in this space by removing barriers to the participation of non-incumbent transmission providers in regional planning processes and requiring that projects be chosen on a non-discriminatory basis to provide the most efficient and cost-effective outcomes for the region. While, as discussed further below, there are some barriers to effectively selecting energy storage as transmission or non-transmission alternatives, the framework exists for these types of projects to be proposed and selected to serve regional transmission needs.

At the local level, transmission owners such as Dominion Energy and AEP identify the necessary transmission investment for their system, include them in their local transmission planning processes, and ultimately file those plans with FERC for approval. While it is possible for energy storage to be proposed in these local plans as well, there are no requirements for competition from non-incumbents, no requirements to consider non-transmission alternatives, and limited consideration of alternative technologies like energy storage. Thus, while some utilities are considering energy storage and distributed energy resources as alternatives to expensive transmission investment, such as Con Edison's Brooklyn-Queens Demand Management program in New York, regulatory changes at the federal and state level may be necessary to promote the use of energy storage as a transmission asset.

Additionally, transmission costs in PJM are allocated based on Network Integration Transmission Service, which is the mechanism by which transmission owners recover their annual transmission costs, and Transmission Enhancement Charges, which are how the cost for regional transmission projects are recovered. These costs are generally assessed to PJM network customers based on their load coincident with the annual peak load of the transmission zone that they are located within. Because these charges are assessed based on coincident peak, it is possible for network customers to reduce their transmission charges by dispatching storage resources during their coincident peak, thereby reducing their need for transmission service.

Distribution Services

If a non-wires project is distribution connected, then it would not need to be selected in a federally jurisdictional transmission planning process and would instead likely be filed as part of a plan before state regulators (e.g. integrated resource plan, grid transformation plan, etc.). Utilities have different accounts for different types of assets that determine the rate of return that they will receive, and to be counted as an infrastructure project, energy storage would have to be proposed and approved as a distribution system upgrade to receive such regulatory treatment.

In New York, utilities are procuring non-wires alternatives directly as part of their REV Connect program.[76] These projects allow utilities to defer or avoid conventional infrastructure investments

[76] See: Source: REV Connect, Non-Wires Alternatives, 2019, https://nyrevconnect.com/non-wires-alternatives/

by procuring distributed energy resources such as energy storage that lower costs and emissions while maintaining or improving system reliability. Utility demand response programs that target particular circuits or distribution feeders are another effective means of using energy storage to avoid infrastructure investments. Additionally, while these types of resources avoid investments in infrastructure, they also reduce peak electricity demand for distribution utilities, and such energy benefits should be factored into their evaluation. However, while storage resources can in theory be a more cost-effective alternative to major distribution infrastructure investments, utilities may not pursue lower cost options due to the incentive to increase overall capital expenditures under cost of service regulation. **As such, an incentive or requirement for utilities to invest in these alternatives may be needed, which may necessitate regulatory or legislative reforms.**

It should be noted that one of the three pilot projects proposed by Dominion Energy Virginia on August 2, 2019 is a non-wires alternative use case.[77]

2.2.3. Generation Cost Avoidance

In addition to avoided PJM wholesale capacity costs, Virginia utilities are also planning to invest in new generation resources. The costs of these resources are generally recovered through a rider mechanism on retail customer bills. For example, Dominion Energy Virginia is planning to invest in eight new simple-cycle combustion turbines capable of producing up to 3,664 megawatts of electricity.[78] Combustion turbines are generally designed to operate for a very limited subset of peak hours during the year and have fast ramping times that can help address fluctuations in generation associated with renewable resource variability. Similarly, advanced energy storage systems can provide energy during a limited number of peak hours and can have near-instantaneous ramping capability, which can aid with renewable resource integration. To the extent that energy storage could provide a similar capability to or nearly equivalent capabilities to a combustion turbine, it could be considered as an alternative to new CT generation additions. Additional evaluation may be helpful to determine the suitability of storage as an alternative in terms of its capabilities and cost-effectiveness.

2.2.4 Solar and Wind Integration

The Grid Transformation and Security Act established that up to 5,000 MW of new solar or wind generation constructed or purchased by a utility before 2024 is deemed to be "in the public interest."[79] Additionally, up to 500 MW of rooftop solar or offshore wind is also deemed in the public interest. Accordingly, Virginia utilities are planning to pursue significant additions of new solar and wind in the coming years. The variability of wind and solar output poses new challenges while the advanced capabilities of inverter-based generation create new opportunities for enhancing grid reliability. Some of these challenges and opportunities must be addressed by fast-acting energy storage. At the transmission level, it is expected that PJM's ample supply of

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[77] Source: Dominion Energy Virginia's August 2, 2019 filing at the Virginia State Corporation Commission (VA SCC) for approval of three battery pilot projects, http://www.scc.virginia.gov/docketsearch/DOCS/4%244301!.PDF

[78] Based on information in Dominion Energy Virginia's 2018 Integrated Resource Plan. Note that these are planned and not approved resources. Construction of any large-scale generation resource would be subject to consideration by the VA SCC.

[79] SB 966 Electric utility regulation; grid modernization, energy efficiency, https://lis.virginia.gov/cgi-bin/legp604.exe?181+sum+SB966

regulation and operating reserves should be able to accommodate this variability for the foreseeable future. **However, to the extent that solar resources are interconnected at the distribution level, different challenges might arise**. Two of these are described below. Additionally, coupling storage with renewable resources can provide certain benefits which are also described below.

Reverse Power Flow

Certain locations on the transmission and distribution system were originally designed for power to flow only in one direction – that is from central power plants to the high voltage transmission, and ultimately stepped down to lower voltage substations and feeders. With the advent of distributed generation, such as solar PV, there is now the possibility that power would flow in the "reverse" direction. While much of the underlying infrastructure can accommodate this reverse flow, there may be instances where this is not the case. For example, special protection schemes installed at substations transformers may not be equipped to handle reverse power flow conditions that could occur on high solar penetration feeders. As such the protection scheme would need to be upgraded or the conditions mitigated through other means, such as with energy storage). Generally, these conditions have been rare to date, even in higher penetration states as the amount of energy injected by solar PV typically does not exceed load at higher voltage levels. However, there is an increased likelihood this could occur at large solar installations located in more remote areas where there is little to no load. As much higher solar and DER penetration levels are reached in Virginia, a dynamic hosting capacity analysis (DHCA) can be conducted to identify locations on the distribution system where limits are being approached more quickly than others.

It should be noted that one of the three pilot projects proposed by Dominion Energy Virginia on August 2, 2019 is intended to address solar generation backfeeding.[80]

Voltage Regulation

The addition of distributed resources can also increase the frequency of voltage fluctuations. Thus, as distributed solar penetration increases, its variable output could increase the usage of distribution system equipment such as load tap changers, switching capacitor banks, and line voltage regulators. Recent studies of high penetrations of PV in California have indicated that these devices can support high penetrations of PV on many feeders without voltage violations. However, increased switching needs could cause these devices to wear more quickly and lead to higher distribution system maintenance costs. It is not anticipated that these costs will be very large - recent studies of a 100% penetration solar PV scenario in California have indicated that the increase in annual utility operations and maintenance costs due these fluctuations would be on the order of 0.01%.[81] However, to the extent these costs do exist, they could be mitigated with storage. As inverter-based resources, battery storage is generally capable of providing reactive power and voltage regulation services.

[80] Source: Dominion Energy Virginia's August 2, 2019 filing at the Virginia State Corporation Commission (VA SCC) for approval of three battery pilot projects, http://www.scc.virginia.gov/docketsearch/DOCS/4%244301!.PDF
[81] Source: Energy Institute at Haas, Economic Effects of Distributed PV Generation on California's Distribution System, 2015http://ei.haas.berkeley.edu/research/papers/wp260.pdf

Regarding the role of storage for integration of distributed energy resources such as solar PV, it is worth noting that the level of DER penetration is very small in Virginia to date, and thus has not yet been a demonstrable concern. For example, the SCC recently issued an order rejecting the majority of Dominion Energy Virginia's proposed Grid Transformation Plan. As part of its rationale the Commission stated the following:

> In this regard, the record reflects that (i) DER penetration levels (customer-sited and utility-scale solar) are less than 1% of peak load and fewer than 1% of all customers have DERs, and (ii) the Company has not experienced any documented instances of the intermittent output of DER causing voltage stability or reliability problems for the Company's system.[82]

Benefits of Coupled Resources

In addition to these challenges, the anticipated deployment of solar creates an opportunity for investments in paired, "hybrid" resources. This can be advantageous for a few reasons. First, storage resources that are directly coupled and charged by renewable energy can take advantage of the federal investment tax credit (with certain limitations). Second, there may be cost advantages to collocating these resources due to shared power conversion systems. Finally, for paired resources that are DC-coupled, energy that would otherwise be "clipped" due to inverter limits can be stored for later use, thus increasing the facility's output by a small amount.

It should be noted that one of the three pilot projects proposed by Dominion Energy Virginia on August 2, 2019 is a solar plus storage use case.[83]

2.2.5 Storage for Resilience and Other Utility Services

Energy storage can provide enhanced service to certain types of customers by providing improved power quality and backup power. The function of providing backup power could an especially important consideration for certain critical load facilities (e.g. hospitals, schools) under emergency conditions. In particular, energy storage could assist with emergency preparedness by pairing solar plus storage on police, fire stations and buildings that serve as emergency shelters, as well as for community centers and other buildings that serve as "resiliency hubs" within neighborhoods serving vulnerable communities with few other options such as those areas susceptible to storm damage, such as from hurricanes.

In addition to those services described above storage may have other potential benefits for distribution utilities. For example, with the advent of electric vehicles, there may be substantially increased loads in locations with a high penetration of EV chargers. To the extent this increases peak demand on the distribution system, it could necessitate certain equipment upgrades. Energy storage could be added near high-penetration EV charger locations to help defer the need for

[82] Source: Virginia SCC, Case No. PUR-2018-00100, Final Order at 12.
[83] Source: Dominion Energy Virginia's August 2, 2019 filing at the Virginia State Corporation Commission (VA SCC) for approval of three battery pilot projects, http://www.scc.virginia.gov/docketsearch/DOCS/4%244301!.PDF

these additional upgrades. There are now several utilities across the U.S. that have begun to implement transportation electrification plans, which can provide a variety of lessons learned.[84]

In Virginia these services would be provided by distribution-connected energy storage. PJM maintains frequency and voltage on the bulk power system and has control over the resources that are interconnected to it but does not have visibility into the distribution system or the ability to control distributed energy resources that are not transacting in the PJM markets. Therefore, these services would be contracted with the local utility on an as-needed basis to keep the distribution system within acceptable tolerances and storage would need to be considered in the utilities planning processes for these services as an alternative to more traditional resources like capacitors, synchronous condensers, and local generation.

2.3 Customer Services

2.3.1 Time-of-Use Bill Management

The price of the wholesale energy that utilities must buy to serve their customers increases as total demand on the system increases relative to supply. This creates an incentive for utilities to reduce their total consumption during peak demand; serving as a hedge against wholesale price exposure. Time-of-use (TOU) tariffs are retail billing plans that allow customers to manage their bills by offering different rates based on the time of day, day of the week, and/or season of the year, with higher prices for customers corresponding to when the utility's cost of serving its load are highest. By offering a rate structure that is reflective of the utility's costs, they encourage efficiency amongst their customers during periods of peak consumption. Similar to arbitraging wholesale energy prices, as discussed above, customers on time-of-use tariffs can deploy energy storage to charge and store energy during off-peak periods when the price of electricity is low and discharge it when the price of electricity is high, thus reducing grid consumption during peak periods and reducing a customer's electricity bill. Customers would need to consider the difference between peak and off-peak prices, as well as the efficiency of the storage system and its expected useful life to determine whether shifting their consumption from peak to off-peak periods with energy storage would be economic.

Appalachian Power has "Time-of-Day" rates for residential and large general service customers that provide different peak and off-peak prices, as well as advanced time-of-day rates that offer four different price segments for customers with a normal maximum electrical capacity of 5,000 kW.[85] Dominion Energy Virginia has options for its residential customers for demand-based time-of-use rates (with varying $/kW charges), and energy-based time-of-use charges (with varying $/kWh rates).[86] Dominion Energy Virginia also has time-of-use rates for churches and

[84] For example, LADWP's challenges in electrifying its public transportation sector may be worth reviewing in greater detail.

[85] Source: VIRGINIA S.C.C. TARIFF NO. 25 APPALACHIAN POWER COMPANY, 2019 VIRGINIA S.C.C. TARIFF NO. 25 APPALACHIAN POWER COMPANY, Accessed at: https://www.appalachianpower.com/global/utilities/lib/docs/ratesandtariffs/Virginia/Tariff25April-1-2019UnbundledStandard.pdf on April 13, 2019.

[86] Dominion Energy Residential Rate Tariff, Schedule 1S – Demand TOU, and Schedule 1T – Energy TOU (accessed at Source: Dominion Energy Residential Rate Tariff, Schedule 1S – Demand TOU, and Schedule 1T – Energy TOU,

intermediate customers (30-500kW of demand) that have both demand and energy components to them.[87] The differences between the peak and off-peak rates in some of these programs are significant, but the value proposition for storage would depend on the cost of the system, its round-trip efficiency, and how often it would be cycled to arbitrage the rates.

2.3.2 Demand Charge Reduction

Demand charges are typically based on the maximum instantaneous demand of a customer at any given point during a billing cycle. Retail demand charges are generally calculated by taking the highest level of usage at every 15-minute interval during a billing period. Some demand-based tariffs limit demand charges to the maximum demand during peak-use periods. If managed improperly, demand charges can significantly drive up customer bills. Energy storage can help mitigate these charges by discharging electricity during periods of high customer demand and storing electricity during periods of low demand.

In Virginia, demand charges are generally limited to large commercial and industrial customers and can account for a major portion of a customer's bill. For example, in Virginia, Dominion Energy Virginia charges its large general service customers $10.689/kW for its on-peak generation demand charge, $2.277/kW for its on-peak transmission demand charge, and $1.992/kW for its distribution demand charge (among other charges).[88] Under this pricing structure, a storage resource that can reduce a large customer's peak consumption by one megawatt could create savings of over $15,000 per month.

2.3.3 Demand Response Programs

Demand response programs pay electric customers to reduce their consumption, generally during peak times when energy consumption and wholesale prices are high, and the grid is under significant stress. Because there is a need to balance supply and demand on the grid, decreasing consumption can be just as, if not more valuable than increasing generation because it helps bring the system back to equilibrium without having to start up additional peak generation facilities which often run on oil or gas. Providing incentives to participate in demand response programs therefore provides economic and environmental benefits for all stakeholders.

Demand response is generally measured as the difference between metered consumption during a demand response event and a customer's baseline consumption during comparable hours when they were not called on to reduce consumption. The customer is then compensated based on the reduction in consumption below their baseline. **While real-time reduction in electricity consumption is one way to participate in demand response programs, demand**

2019https://www.dominionenergy.com/home-and-small-business/rates-and-regulation/residential-rates on April 13, 2019)

[87] Dominion Energy Business Rate Tariff, Schedule 5P – TOU Church Rate, Schedule GS-2T – TOU Intermediate General Service (accessed at Source: Dominion Energy Business Rate Tariff, Schedule 5P – TOU Church Rate, Schedule GS-2T – TOU Intermediate General Service, 2019https://www.dominionenergy.com/large-business/rates-and-tariffs/business-rates on April 13, 2019).

[88] Virginia Electric and Power Company, Schedule GS-3, Large General Service Secondary Voltage (Source: Virginia Electric and Power Company, Schedule GS-3, Large General Service Secondary Voltagehttps://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/business-rates/virginia/schedule-gs3.pdf?la=en).

reductions can also be effectuated by behind-the-meter energy storage which shifts a customer's consumption to off-peak hours (i.e. the customer charges the energy storage resource during off-peak hours, and then discharges it to serve its co-located load during peak hours, reducing that customers metered load).

Several demand response opportunities exist in the Commonwealth of Virginia, and energy storage should be considered a viable load reduction technology for all of them. Virginia has a demand response program managed by CPower for all state agencies and public localities who are willing and able to reduce electrical load when grid reliability is threatened.[89] Additionally, Dominion Energy Virginia offers a non-residential distributed generation program where participating customers receive an incentive to use their on-site backup generation to reduce consumption of electricity when electrical demand is high.[90] Dominion Energy Virginia has also proposed additional demand-side management programs, although these are generally energy efficiency programs for which energy storage resources would not be eligible.[91]

The best opportunities for demand response participation in Virginia are in the PJM wholesale markets. In PJM end-use electricity customers can be compensated by curtailment service providers that aggregate retail customers and offer their combined load reductions into the PJM markets. PJM has an economic demand response program where curtailment service providers can participate in the day-ahead or real-time markets on behalf of the customers they represent. Curtailment service providers are also able to participate in the capacity market as a capacity performance resource if they can reduce their load during capacity performance events throughout the entire year. PJM also enables demand resources to participate and submit bids for reductions in the Synchronized Reserve, Regulation and Day-Ahead Scheduling Reserves markets.[92] Appalachian Power serves as a curtailment service provider for its customers and has Peak Shaving and Emergency Demand Response, Demand Response Service – RTO Capacity, and Demand Response Service options under its Tariff.[93]

2.3.4 PV Self-Consumption

To save money on their utility bills and generate clean, local electricity, an increasing number of retail customers are electing to install their own solar PV generation. In addition to the federal Solar Investment Tax Credit (ITC),[94] Virginia customers may also be eligible for net-metering

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89 See: Source: Virginia Demand Response Programshttps://www.dmme.virginia.gov/DE/DemandResponseContract.shtml

90 See: Source: Dominion Energy Virginia, Non-Residential Distributed Generation Programhttps://www.virginiaenergysense.org/incentives/residentialincentives/dominion-energy-virginia-non-residential-distributed-generation-program/ Note:. Participants in this program are not also allowed to participate in the PJM markets.

91 Source: Virginia SCC See: http://www.scc.virginia.gov/docketsearch#/caseDetails/139129

92 PJM Demand Response Summary, See: Source: PJM Demand Response Summaryhttps://learn.pjm.com/three-priorities/buying-and-selling-energy/markets-faqs/~/media/BD49AF2D60314BECA9FAAB4026E12B1A.ashx

93 VIRGINIA S.C.C. TARIFF NO. 25 APPALACHIAN POWER COMPANY, Accessed at: Source: VIRGINIA S.C.C. TARIFF NO. 25 APPALACHIAN POWER COMPANY, 2019https://www.appalachianpower.com/global/utilities/lib/docs/ratesandtariffs/Virginia/Tariff25April-1-2019UnbundledStandard.pdf on April 13, 2019.

94 A tax credit is a dollar-for-dollar reduction in the income taxes that would otherwise be paid to the federal government. For owners of solar projects, the ITC is equal to 30 percent of investment for projects which have

tariffs,[95] solar purchase programs,[96] and solar property tax exemptions[97] that decrease the cost of installing solar generation. Pairing behind-the-meter energy storage systems such as lithium ion batteries with PV generation can allow a customer to consume more of the energy that their PV system is generating by shifting that generation to the times when the customer needs it, possibly offsetting higher time-of-use rates.

By pairing the solar and storage systems, the entire hybrid system becomes eligible for the federal investment tax credit, but the customer also becomes less reliant on the utility for their energy. In some cases, customers can rely upon this hybrid system for backup power, provided that UL 1741 SA restrictions do not preclude the system from operating when there is an outage. However, even when the grid is functioning normally, there can be benefits to greater self-consumption. Depending on the how utility net-metering and solar purchase tariffs are structured, it may be more economical for customers to consume the PV energy they are generating when they need it rather than send any of the electricity back to the grid. However, according to local distributed energy providers, current net metering and solar purchase programs in Virginia have not historically provided a strong incentivize for solar self-consumption. If so, the value derived from this service would depend on the customer's interest in reducing their reliance on utility service and having a clean back-up source of energy.

2.3.5 Backup Power (Customer Resiliency)

Outages can be caused by weather and equipment failures, or human caused factors (e.g. vandalism or terrorism) among other factors. Outages can negatively impact critical loads, such as hospitals, schools and military bases, or cause financial losses to customers with a high need for reliability. Energy storage can provide backup power to customers during outages, reducing loss of critical loads and/or avoiding financial losses to customers. It can also provide power to emergency response centers and first responders. Because the value associated with this service can vary widely, back-up power energy storage systems are designed not only based on anticipated outages on a particular utility's system but are also tailored such that the back-up power capability corresponds to individual customers' reliability needs.

Backup power can also be provided within the context of a multi-customer microgrid. Microgrids are local energy grids with the option of operating autonomously by disconnecting from the main grid with on-site/local energy generation. Typically paired with distributed renewable or diesel generation, energy storage in a microgrid application can enable the capability to "island" and operate without grid connectivity for extended periods of time. This use case is related to the 'backup power' service, but is typically deployed in a more complex, integrated environment.

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commenced construction through 2019, 26 percent for projects beginning in 2020, and 22 percent for projects beginning in 2021. After 2021, the ITC will drop to 10 percent indefinitely.

[95] Source: Dominion Energy, Traditional Net Metering See, e.g., https://www.dominionenergy.com/large-business/renewable-energy-programs/traditional-net-metering; http://programs.dsireusa.org/system/program/detail/40

[96] Source: Dominion Energy, Solar Purchase Program See, e.g., https://www.dominionenergy.com/large-business/renewable-energy-programs/solar-purchase-program; https://www.tva.com/Energy/Valley-Renewable-Energy/Green-Power-Providers

[97] See: Source: DSIRE, Residential Property Tax for Solarhttp://programs.dsireusa.org/system/program/detail/85

Some cities have also recently explored programs for deploying storage or solar plus storage facilities at critical load facilities like hospitals or schools. This can provide a clean source of backup power in case of a natural disaster (e.g. hurricane), while also still offering some ability to offset customer load and reduce costs. An example is the City of San Francisco's recent Solar Resilient program.[98]

2.3.6 Wholesale Market Participation

Customer-sited energy storage resources are also able to participate in the PJM markets, either on a standalone basis or aggregated with other resources to meet the minimum size requirements. Currently, those storage resources are required to participate as demand response and make their largest contribution in the regulation market. Batteries provided 65% of demand response participation in the regulation market in 2018, and grid-integrated electrical water heaters (i.e. thermal storage) contributed the remaining 35%. Although their participation has been limited thus far, these storage resources that are registered as economic demand response are also eligible to participate in PJM's capacity, energy and reserve markets.

While PJM's demand response constructs are currently the only means for customer-sited energy storage to reach the wholesale markets, PJM is in the process of developing a participation model for DER aggregations that could improve the ability of BTM storage to combine its capabilities with other assets like rooftop solar and offer services into PJM's capacity, energy and ancillary service markets. FERC is also considering broader market reforms for DER aggregations, but as currently framed, PJM's model for DER aggregations would allow a group of DERs to be joined virtually into a single resource as long as all of the DERs are within one utility's service territory and the aggregate resource is less than 1 megawatt. However, this would not be limited to BTM resources, as PJM defines a distributed energy resource as any generation or electric energy storage resource connected to the distribution system and/or behind a load meter. PJM is also working on a metering and accounting framework as part of implementing the requirements of Order 841 that will help distinguish between wholesale and retail actions for distributed storage resources.

2.4 Potential Use Cases in Virginia

2.4.1 Merchant Wholesale

Merchant resources are those that are financed and built completely based on their anticipated revenues from PJM's capacity, energy, and ancillary service markets. PJM thus far has the largest market in the world for merchant standalone energy storage projects. In 2013, When PJM redesigned its regulation market to comply with FERC Order 755, it began paying regulations resources for their performance and created its "RegD" signal for faster resources like battery storage and flywheels. Hundreds of megawatts of energy storage projects were financed and built based on this new construct. However, the large influx of storage resources and flexible natural gas generation have lowered regulation prices and some fundamental changes to the

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[98] Source: SF Environment, Solar and Energy Storage for Resiliency https://sfenvironment.org/solar-energy-storage-for-resiliency

market design have made it less economic for short duration storage resources to compete. As a result, no additional merchant storage resources have been built in recent years.

Additionally, there are pumped hydro resources in PJM that are reliant on merchant revenues, but those assets have long enough durations to qualify their full capacity for PJM's capacity market and are arbitraging energy and providing ancillary services as well. Outside of the regulation market, the opportunities for merchant revenue for shorter duration energy storage are somewhat limited. The duration requirements in the capacity market limit the ability of storage resources like batteries to participate at their full rated capacity, and price convergence and decreased volatility in the energy markets have made arbitrage opportunities a relatively unreliable source of revenue for new projects.

However, there are emerging opportunities to pair energy storage with generation resources in the markets. Co-locating energy storage with solar and/or wind installations can assist with renewable integration by better aligning renewable output with load. This is effectively a form of arbitrage and improves earnings for developers by absorbing the clean energy in real time and then selling it into the markets during peak hours when the price for energy is the highest. By controlling the output of these hybrid assets, it is also possible to mitigate intermittency and improve local power quality issues that can arise due to fluctuations in renewable output. While it is possible to offer these resources into the market as a merchant asset, it is more likely for them to be contracted with a utility on a long-term basis as a clean energy asset and/or as an alternative to peak generation units.

Energy storage can also be paired with thermal generation to improve its operational efficiency. Generators often must maintain headroom (i.e. the ability to increase output), to provide load-following and ancillary services, which can result in sub-optimal operation of the generator. If energy storage assets co-located with the generator are dispatched to follow load and provide ancillary services, then generators can operate at a constant, optimal output which reduces wear and tear, outages, operating and maintenance costs, and emissions. Although this use-case is discussed in the merchant section, it is also possible for the storage asset to be used to improve the efficiency of thermal generation on a portfolio basis through integrated planning processes.

2.4.2 Customer-Sited (Behind-the-Meter)

Commercial and Industrial

Storage owners can realize significant energy management benefits when they install energy storage either by itself or paired with generation assets. As discussed above, by using energy storage to reduce their peak demand, C&I customers can reduce retail demand charges associated with their instantaneous peak demand and manage their energy costs when they are on time of use (TOU) rates by charging during off-peak periods and discharging during peak periods. At the same time, C&I customers can use energy storage to improve power quality for their facility if they have more precise frequency or voltage tolerances than the grid can provide, and they can use it to provide back-up power during outages.

Additionally, for customers on time-of-use rates pairing energy storage with on-site renewable generation can reduce the consumption of expensive grid power during periods of peak demand. Storage can also be paired with Combined Heat and Power (CHP) systems and used to increase their efficiency by reducing the need to vary the energy output of the CHP system to match the real time changes in the energy demand. By smoothing the demand peaks, a smaller CHP system can be installed and operated more efficiently, reducing costs and emissions. Adding storage to onsite generation can also make the facility more resilient, reducing the possibility of the generators shutting down during grid outages, and providing back-up power if the generator is not available.

Not only do C&I use cases provide benefits to the customer, but they can also reduce production costs for the system, because they reduce peak requirements in terms of both the amount of energy that has to be generated and the transmission and distribution infrastructure needed to transport it. Reducing system peaks can also reduce ramping needs and system variability which can reduce ancillary service requirements. Monetizing full system benefits should be considered in utility rates for customers with energy storage.

Residential

For residential owners of energy storage, the standalone use case is limited to back-up power and energy bill management if the customer is on a time-of-use rate. The system could also be paired with behind-the-meter generation such as rooftop PV to increase solar self-consumption. Utility net metering rates in Virginia do not currently incentivize such behavior, but these combined systems are eligible for the solar investment tax credit. Pairing with solar could further reduce metered consumption and costs during peak periods for customers on time-of-use rates, but in the absence of demand charges, the financial benefits to residential customers for these applications are relatively modest. However, energy storage can provide the same system benefits as the C&I use cases by reducing peak demand. It would be prudent for Virginia policy makers to continue to ensure that retail rates, including any time-of-use or net-metering components are representative of the value that can be provided by energy storage resources to the grid.

Opportunities for residential and C&I customers to partially defray the costs of storage systems are also emerging as PJM considers ways to better integrate these resources into their markets. There are already aggregations of grid-integrated water heaters and vehicle-to-grid systems participating in the PJM markets, and they are also considering new models for distributed energy resource aggregations. As market opportunities emerge for customer-sited assets, these revenue streams can help reduce the cost of ownership of these systems, making them attractive to customers that did not assign sufficiently high value on back-up power or solar self-consumption to invest in them. Additionally, it is possible for utilities to create customer programs to dispatch behind-the-meter storage resources to reduce their peak requirements, just as has already been done in Green Mountain Power in Vermont[99] and Liberty Utilities in New Hampshire.[100]

2.4.3 Utility (Front-of-Meter)

Energy storage resources deployed on a utility's distribution system can provide a flexible tool to provide multiple services including managing peak demand, integrating renewable energy, providing voltage regulation, and mitigating power outages among other capabilities. One of the

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[99] See: Source: Green Mountain Power, Powerwallhttps://greenmountainpower.com/product/powerwall/
[100] Source: Liberty Utilities, Liberty Utilities Home Battery Storage Pilot Approved See: https://new-hampshire.libertyutilities.com/alstead/liberty-utilities-home-battery-storage-pilot-approved-.html

primary applications for a utility is siting energy storage downstream of congested infrastructure, generally at a substation, to defer or avoid investments in system upgrades. This can be accomplished through both a utility owned storage resources or a contracted storage resource owned by a third party. Storage resources can be deployed more easily and more rapidly on an incremental basis, which can mitigate the uncertainty of supply and demand forecasting and help avoid major investments in infrastructure.

As renewable energy grows in Virginia, utilities can also use storage to manage the intermittent output of distributed solar and avoid reverse power flows at the substation. Additionally, energy storage can be critical in serving peak load, and shifting renewable generation to peak hours, thereby eliminating the need for seldom used peaking plants and better integrating renewables. And because this is a peak load service, these benefits can often be realized using the same resources that are providing T&D investment deferral/avoidance because their operational profiles are similar. As renewable generation increases, designing portfolios of utility storage assets that can be aggregated and dispatched to absorb renewable generation and discharged to displace peak capacity requirements will prove increasingly valuable.

There may also be opportunities to offer excess storage capacity into the PJM markets, but this is somewhat dependent on how the utility procures the asset. While FERC made clear that it is possible for storage resources that are receiving cost of service rates to also participate in the wholesale markets, there are concerns about over-recovery of costs and the operation of the asset. PJM has not created any official market rules for such assets, and limited precedent exists, so it is unclear how such hybrid cost-based and market-based cost recovery would work. **Obtaining clarity from FERC and PJM on this issue could help add value to utility-owned storage assets.**

While limited utility investment in advanced energy storage has occurred, the Virginia legislature authorized a 30 MW pilot for Dominion Energy Virginia and 10 MW pilot for APCo in the recently passed Grid Transformation & Security Act of 2018. More specifically, in summer 2019, Dominion Energy Virginia asked regulators for permission to build four battery storage facilities as pilots to test the technology's functionality: two 2-megawatt/4-megawatt-hour batteries at substations to study batteries as an alternative to expensive grid infrastructure upgrades and as a voltage and power-quality tool, and a different pair of batteries totaling 12 megawatts/48 megawatt-hours to play a renewables integration role at the Scott solar plant in Powhatan County. One will be DC-coupled and the other will be AC-coupled, to isolate the performance of those different power electronics architectures. After expected completion in 2020, Dominion will study the operations for five years.[101]

Additional legislation that encourages or requires additional utility deployment of energy storage as a means of integrating renewables or as an alternative to future peaking power requirements could be helpful for realizing the value of storage in Virginia.

[101] Source: https://www.greentechmedia.com/articles/read/dominion-energy-plans-to-build-four-storage-pilots-and-study-them-for-five-#gs.yjyq65

2.4.4 Competitive Service Providers

Competitive Service Providers, which are also commonly known as load-serving entities, purchase energy and transmission service from the wholesale market and compete for business to serve retail loads. In Virginia, Competitive Service Providers must be licensed by the State Corporation Commission and they are then able to offer competitive service to retail load or aggregations of retail load.[102] In Appalachian Power and Dominion Energy Virginia service territories, non-residential customers may select competitive service providers whose generation source is not 100% renewable energy (Appalachian Power and Dominion Energy Virginia are required to provide 100% renewable energy tariffs to large customers). Only non-residential customers with at least a 5 MW of load can choose a Competitive Service Provider individually. All other smaller non-residential customers must aggregate their load to meet the minimum 5 MW threshold to choose a Competitive Service Provider.[103] Additionally, residential customers seeking electricity from 100% renewable energy sources may purchase energy from a Competitive Service Provider if the local utility does not provide this option.

It is possible for a Competitive Service Provider to purchase energy during off-peak hours and store it to provide to its customers during peak hours. This arbitrage could be useful as a hedge against wholesale price volatility and transmission charges that are based on peak consumption for any Competitive Service Providers that have to purchase some of their portfolio from the PJM markets. Energy storage could also be used by Competitive Service Providers that own or purchase renewable generation and want to be able to offer time-matched clean peak energy to their customers. With the increasing growth of the tech industry in Virginia and the growing demand for clean energy tariffs that track real-time consumption profiles, this could be an increasingly attractive use case for storage resources. This type of application could further be encouraged by state policies that further enhance retail competition and encourage the consumption of clean energy, particularly during peak hours or coincident with a customers' consumption.

2.4.5 Microgrids

A microgrid is a collection of generation assets and other distributed energy resources and loads within a defined boundary that can operate in grid connected mode or separate, or "island", from the broader electricity grid. Energy storage is a critical part of any microgrid that is reliant on non-dispatchable renewable generation as it gives the operator flexibly to manage its generation and load. Additionally, storage can provide benefits when the microgrid is connected to the grid. When the microgrid is connected to the "macrogrid" the storage asset is operated much like a utility would operate a traditional energy storage asset. It can provide infrastructure support, reducing peak requirements, mitigate impacts of intermittency of renewable generation, and provide services back to the macrogrid. When the microgrid is islanded, the storage asset is relied on for its balancing services in a smaller local area, helping to maintain frequency and voltage on

[102] Source: Virginia State Corporation Commission, Energy Regulation in Virginia http://www.scc.virginia.gov/power/compsup.aspx

[103] Source: Appalachian Power, Customer Choice in Virginia See: https://www.appalachianpower.com/account/service/choice/default.aspx

the system, charging during times of excess generation, and discharging during times of generation deficits.

Resilience is a key benefit of a microgrid. Many cities and municipalities across the country are also implementing solar plus storage resources and/or microgrids to provide a resiliency functionality to critical infrastructure. The costs of power outages can be high to commercial and industrial customers, and maintaining power supply to first responders, hospitals, universities, military installations and other critical infrastructure is particularly important during natural disasters and emergencies (e.g. severe storms and hurricanes). As the costs of microgrids are coming down and capabilities going up, Virginia should not only ensure that there are adequate incentives in place to protect its critical infrastructure, but also to fully value the capabilities of microgrids when they are connected to the grid and able to provide services to the wholesale markets as well.

Virginia is also home to some of the country's largest military installations and Department of Defense (DoD) facilities that could benefit from the use of microgrids as a means of improving energy security. There are a number of initiatives in DoD to look at the details of DoD microgrid siting, including concepts such as "microgrid as a service" or "resiliency as a service" products being offered by third party implementers. These implementers could potentially also seek value by using microgrid assets to participate in wholesale markets as an additional revenue sources to the core function of enhancing energy security. Local utilities may also be able to participate by installing "make ready" infrastructure such as controls and switchgear to enable microgrid functionality for participating locations.

Multi-Use Application Framework

Multiple-use application for energy storage resources generally describe business models where the resource provides more than one service, thereby increasing the overall value of the asset. These services can include any incremental benefits provided to the wholesale market, distribution grid, transmission system, and customers. While the versatility of energy storage resources and the software that controls them enable such applications, there are often regulatory obstacles that can limit their potential. As a result of these barriers, energy storage cannot realize its full economic. Therefore, it is necessary for policy makers to develop rules and guidance related to multiple-use applications that allow storage to deliver multiple services in multiple domains. These types of applications will not only enhance the economic viability and cost-effectiveness of storage but will also enhance reliability and reduce production costs for the power system.

California is the only state that has thus far done a comprehensive analysis of multiple-use applications for energy storage. The California Public Utilities Commission established five service domains for storage (customer, distribution, transmission, wholesale, and resource adequacy), and defined reliability and non-reliability services that storage could provide in each domain. They also established a set of rules that determine what resources are able to provide what services and what service must be prioritized over other services (e.g. resources interconnected in the customer domain can provide services in in any domain, reliability services must always have priority, and storage resources must not contract for multiple reliability services if one of them could render the resource unable to perform the other). While several related implementation issues are now being discussed in a working group, this initial rule provides a useful framework for the realization of multiple use applications in California as well as a starting point for policy makers in other states to start exploring the barriers to fully unlocking the value of energy storage in their states.

Domain	Reliability Services	Non-Reliability Services
Customer	None	TOU bill management; Demand charge management; Increased self-consumption of on-site generation; Back-up power; Supporting customer participation in DR programs
Distribution[7]	Distribution capacity deferral; Reliability (back-tie) services; Voltage support; Resiliency/microgrid/islanding	None
Transmission	Transmission deferral; Inertia*; Primary frequency response*; Voltage support*; Black start	None
Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves; Flexible ramping product	Energy
Resource Adequacy	Local capacity; Flexible capacity; System capacity	None
*Voltage support, inertia, and primary frequency response have traditionally been obtained as inherent characteristics of conventional generators, and are not today procured as distinct services. We include them here as placeholders for services that could be defined and procured in the future by the CAISO.		

Figure 18. Domains, Reliability Services and Non-Reliability Services

Multi-Use Application Framework (con't)

Below are the rules adopted by the California Public Utilities Commission in conjunction with the Multi-Use Application Framework.

ADOPTED RULES

These are interim rules, which may be further refined through the working group process.

- Rule 1. Resources interconnected in the customer domain may provide services in any domain.
- Rule 2. Resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources, per Ordering Paragraph 11 of D.17-04-039.
- Rule 3. Resources interconnected in the transmission domain may provide services in all domains except the customer or distribution domains.
- Rule 4. Resources interconnected in any grid domain may provide resource adequacy, transmission and wholesale market services.
- Rule 5. If one of the services provided by a storage resource is a reliability service, then that service must have priority.
- Rule 6. Priority means that a single storage resource must not enter into two or more reliability service obligation(s) such that the performance of one obligation renders the resource from being unable to perform the other obligation(s). New agreements for such obligations, including contracts and tariffs, must specify terms to ensure resource availability, which may include, but should not be limited to, financial penalties.
- Rule 7. If using different portions of capacity to perform services, storage providers must clearly demonstrate, when contracting for services, the total capacity of the resource, with a guarantee that a certain, distinct capacity be dedicated and available to the capacity-differentiated reliability services.
- Rule 8. For each service, the program rules, contract or tariff relevant to the domain in which the service is provided, must specify enforcement of these rules, including any penalties for non-performance.
- Rule 9. In response to a utility request for offer, the storage provider is required to list any additional services it currently provides outside of the solicitation. In the event that a storage resource is enlisted to provide additional services at a later date, the storage provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this Rule is to provide transparency in the energy storage market.
- Rule 10. For all services, the storage resource must comply with availability and performance requirements specified in its contract with the relevant authority.
- Rule 11. In paying for performance of services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

As illustrated in this chapter there are a wide variety of services and use cases for energy storage in the Virginia context. The following chapters will provide a more detailed analysis of the potential for several use cases, as well as specific market barriers and policy recommendations that could enable beneficial storage deployment.

Chapter 3: Analysis of Energy Storage Potential in VA

3.1 Overview & Approach

While there are many potential beneficial use cases for energy storage in Virginia, it can be useful to quantify what the overall potential value of these use cases may be. This section attempts to develop a reasonable Virginia-specific estimate for what the value of energy storage could be to the Commonwealth by comparing the potential benefits to the costs of deploying storage under different scenarios.

3.1.1 Benefit-Cost Analysis

In any value assessment or benefit-cost analysis of the energy system, there are multiple perspectives that can be considered. For the purposes of this analysis two primary perspectives were considered: 1) system value and 2) customer value.

System Value

For this portion of the analysis, we attempt to quantify the overall value that storage could provide to Virginia's energy system, including both bulk energy system benefits (e.g. energy, capacity and ancillary services) and distribution utility benefits (e.g. distribution deferral). These categories also reflect costs and values ultimately borne by all end-use customers through retail electricity bills. The portion of these system benefits associated with the bulk energy system could theoretically be realized by storage sited anywhere on the power system, including at the transmission level. Meanwhile, the distribution level benefits would likely only be realized by storage resources sited directly on the distribution system or at the customer level. Detailed methodology and results for the system value analysis are described below in Section 3.2 System Benefits Analysis.

Customer Value

For this portion of the analysis, we attempt to quantify the overall value that storage could provide to end use customers if it is sited at the customer's premises (i.e. behind the meter). Today, this value is driven primarily by utility bill savings under prevailing retail rates. However, it is anticipated that this could increasingly include revenue from other sources such as utility customer programs that target specific system benefits, direct access to the wholesale market (e.g. through aggregation), or incentive programs. In addition to (or in lieu of) these approaches, retail rates could also be reformed to provide better alignment with system-level benefits. For the purposes of this analysis, we examined customer benefits under prevailing retail rates, as well as a hypothetical utility demand response program offering targeting distribution system benefits. Detailed methodology and results for the system value analysis are described below in Section 3.3 Customer Benefits Analysis.

3.1.2 Storage Cost Assumptions

Although the study is technology agnostic, the modeling exercise assumes storage assets that have characteristics similar to Li-ion batteries, one of the dominant storage technologies being deployed today. Operational characteristics include a lifetime of 15 years and a round trip efficiency of 90%. Cost assumptions are based on Lazard's levelized cost of storage report.[104] Lithium battery costs have fallen substantially in recent years and are expected to continue their decline in coming years. As such there is some uncertainty around what the true installed costs will be. To account for this, we included both a low case and a high case for storage costs.

The cost components and their values are summarized below, assuming an annual cost decline of 5% (CAGR).

	2019		2029	
	Low	High	Low	High
Storage Module ($/kWh)	$205	$350	$123	$210
Balance of System ($/kWh)	$27	$48	$16	$29
Power Conversion System ($/kW)	$49	$61	$29	$37
Engineering, Procurement & Construction (%)	16.7%	16.7%	16.7%	16.7%
Annual O&M				
O&M (% of Storage Module and BoS Equipment)	1.3%			
O&M (% of Power Conversion System)	1.7%			
Warranty (% of Storage Module and BoS Equipment)	1.5%			
Warranty (% of Power Conversion System)	2.0%			
Augmentation (% of Storage Module and BoS Equipment)	4.2%			

Figure 19. Storage Cost Assumptions

3.1.3 Accounting for Multiple Value Streams

A perennial challenge for energy storage is the fact that it can provide a variety of value streams simultaneously, yet none of these is generally sufficient on its own to justify the cost. However, if these values are combined or "stacked", then the value is more likely to exceed the cost.

For the purposes of this analysis, we combined several major value streams in the system benefits analysis including energy, ancillary services, capacity, and distribution deferral. This may not reflect all the potentially stackable values from a single storage resource but reflects what we believe are the most significant and broad-based categories and thus reflects a reasonable approximation for many storage resources.

[104] Source: Lazard, Levelized Cost of Storage Analysis https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf . Capital Costs are based on Key Assumptions presented in page 28 of Lazard's report for Li-ion batteries under the "Wholesale" use case. More specifically, Lazard's report assumes DC-system capital costs ranging from $232/kWh to $398/kWh and AC-system costs ranging from $49/kW to $61/kW. O&M and warranty costs are set using Lazard's assumptions as a percent of initial capital costs. O&M costs are assumed to increase annually by 2%. Warranty and augmentation costs start after the third year of operations. Lazard's estimates are based on a 20-year lifetime for installation sizes of 100 MW/400 MWh. Costs were annualized assuming a 6.3% WACC. Recycling costs were not included in the estimates.

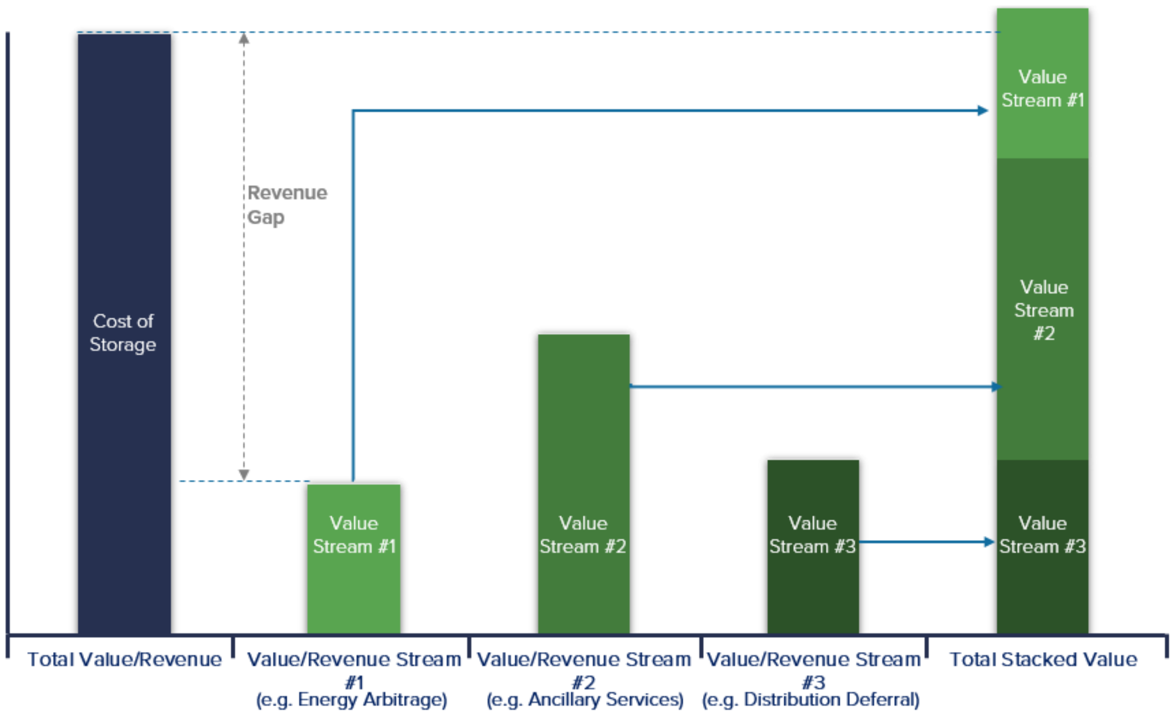

Figure 20. Illustration of Cost and Potential "Value Stacking" of Energy Storage[105]

We are also cognizant that today's market mechanisms may not fully compensate storage resources for all the potential value streams. To the extent that there are insufficient revenue streams to incent beneficial storage deployment, additional policies, programs, or incentives may be needed to account for the gap between the cost and full value of storage.

3.1.4 Limitations

While the analysis presented provides a reasonable initial estimate of storage's value potential to the Commonwealth, we also advise caution on the use of the analysis as a preliminary starting point due to a variety of limitations as described below. As the stakeholder process moves forward, some of these limitations can be further addressed and the analysis can be updated accordingly.

Future Uncertainty

The analysis contains certain key assumptions about the future of the Virginia energy system that contain substantial uncertainty (e.g. natural gas commodity prices, load forecasts, etc.). While reasonable projections of these future values were used, there is a strong possibility that these assumptions may ultimately be incorrect. Market dynamics also may have a large effect on certain projections. For example, if the proposed Southwest Virginia pumped hydro project is completed, it could have a significant impact on energy market prices in the region going forward.

[105] Source: Lazard, Levelized Cost of Storage Analysis

Data Availability

Due to limited data availability, certain portions of the analysis were either simplified or generic approximations were used that may not specific to Virginia circumstances. These assumptions should be updated as further analysis is conducted.

Unquantified Benefits

Several benefit categories are more difficult to quantify and were not included within the limited scope of this analysis. However, they may warrant further investigation. Some of these include:

- Reliability improvements
- Resiliency
- Voltage Control
- Avoided transmission costs
- Avoided criteria pollutants

Multiple-Use Applications ("Value Stacking")

Where possible, considerations were made to ensure that multiple uses did not conflict with one another. For example, storage dispatch was co-optimized for the day-ahead energy, real-time energy and ancillary services markets when evaluating bulk energy system benefits. However, in some instances there may be value categories that cannot be simultaneously delivered due to conflicting requirements. For example, a storage device dispatched for distribution deferral might or might not exactly match bulk system capacity resource requirements. In other cases, benefits may not necessarily be additive and could lead to double counting. For example, retail energy rates should (in theory) be inclusive of wholesale energy costs even if the retail rates have less temporal granularity. While Virginia has not yet established a multiple-use application framework for storage, any dual participation limits that arise from such a framework would constrain the overall amount of benefits that a single storage resource can deliver.

3.2 System Benefits Analysis

An analysis was conducted of several of the major value streams that storage could address in Virginia. This analysis comprised two general categories of values: 1) Bulk Electric System benefits, and 2) Distribution System benefits. Together these categories were used to estimate the total value potential that storage could provide to Virginia's electricity system.

3.2.1 Bulk Electric System

The Bulk Electric System was analyzed using a simplified representation of the Virginia power system. This analysis focused on the Dominion Energy Virginia (DOM) and APCo (AEP) areas within PJM and included generation and load assumptions consistent with those areas. The model used in the study simulates a least-cost economic dispatch of the DOM and APCo generators with a simplified representation of the transmission system. Within the context of this study, the system simulation approximates the day ahead operations.

Model results for the deployment of the first storage MW were cross referenced with the output of a price taking model for the DOM and AEP zones for 2017[106] in the Day Ahead market. To better represent the volatility of the real time market and fully capture the value of storage in a system with uncertain generation, transmission, and load, a much more complicated stochastic version of the model would be necessary. Instead, the production benefits were scaled up to better reflect the energy cost savings that storage can bring in the system based on the historical differences of the day ahead and real time markets as those calculated in the price taking model.

Energy Arbitrage

As previously discussed, energy storage resources can provide value through energy arbitrage either by directly participating in PJM's wholesale energy markets, indirectly participating by responding to utility dispatch instructions, or by responding to retail time-of-use prices. In any case, the storage project investor earns a revenue stream (or reduces their costs) while at the same time reducing the cost of the overall system to meet the load. To better understand the energy arbitrage potential within the Virginia context, we first looked at historical energy prices. Figure 21 and Figure 22 below show the average hourly Locational Marginal Price (LMP) for the Dominion Energy Virginia zone within PJM for both the Day Ahead and Real Time energy markets in 2017.

Hour of the day	January	February	March	April	May	June	July	August	September	October	November	December
0	26	23	26	22	23	21	23	21	22	23	24	32
1	26	22	26	22	22	20	21	20	21	22	23	32
2	26	22	25	21	21	18	20	19	20	22	23	31
3	26	22	26	21	21	17	19	19	20	21	23	31
4	27	23	27	22	21	17	19	19	20	22	24	33
5	30	25	31	23	23	19	20	20	21	24	29	37
6	39	34	43	29	27	20	21	21	25	31	40	48
7	41	35	47	30	29	22	22	22	26	32	41	54
8	38	32	41	32	30	24	24	24	27	31	38	50
9	37	31	39	33	32	26	27	25	30	32	36	46
10	36	30	37	34	34	28	31	28	33	34	35	43
11	34	28	35	34	35	31	35	31	36	34	33	39
12	32	27	33	35	37	34	38	34	39	35	31	36
13	30	26	32	36	38	35	40	36	43	36	30	34
14	29	25	30	36	40	38	43	38	48	37	29	33
15	29	25	29	35	42	40	47	40	51	37	29	34
16	31	25	29	37	44	44	50	42	55	39	32	40
17	42	30	30	36	43	42	49	40	50	38	43	57
18	42	35	35	34	38	37	42	36	42	41	41	53
19	39	33	41	36	35	34	38	33	40	44	38	51
20	36	30	40	42	39	32	35	33	38	37	36	48
21	33	28	34	34	35	30	33	29	32	31	32	44
22	29	25	29	26	27	25	27	25	27	26	27	38
23	26	23	26	24	24	23	25	23	24	24	24	33

Figure 21. Dominion Energy Virginia average hourly price ($/MWh) per month in the Day Ahead Market, 2017

[106] In early 2018, Virginia experienced a cold snap, which resulted in very elevated prices for January 2018, so 2017 is a more representative year.

Hour of the day	January	February	March	April	May	June	July	August	September	October	November	December
0	26	22	25	22	22	20	22	21	21	23	23	39
1	27	22	26	22	22	20	22	21	21	23	23	36
2	26	22	25	20	21	18	20	19	20	21	22	34
3	25	22	26	21	21	17	19	19	19	21	23	35
4	29	23	26	21	22	17	20	19	20	22	23	41
5	34	25	28	22	23	18	21	20	22	25	33	35
6	45	35	45	30	27	19	21	21	26	32	46	42
7	40	37	43	27	30	22	22	21	25	29	42	46
8	36	31	38	28	29	23	24	23	25	31	33	50
9	38	28	36	30	30	25	27	25	29	31	32	46
10	34	28	38	30	35	28	36	27	30	32	32	46
11	37	27	37	31	34	31	35	30	31	31	31	45
12	37	25	32	31	39	33	43	37	36	35	31	39
13	31	25	32	33	37	34	40	34	43	33	31	38
14	29	24	28	34	39	35	44	37	67	35	27	40
15	28	23	27	37	40	38	48	38	53	42	27	36
16	30	24	27	36	45	41	53	42	65	42	30	42
17	41	27	29	38	46	42	52	40	50	47	42	66
18	41	36	32	29	41	36	43	34	34	40	34	44
19	39	30	43	34	34	32	39	31	39	50	30	43
20	37	28	44	44	39	30	34	32	35	32	31	44
21	36	26	33	32	42	29	34	28	28	29	28	45
22	27	23	29	26	27	24	26	23	24	25	25	39
23	26	22	26	23	24	22	24	22	23	23	23	48

Figure 22. Dominion Energy Virginia average hourly price ($/MWh) per month in the Real Time Market, 2017

Virginia has both a winter and a summer peak. As easily seen in the heatmap, high prices are observed in the afternoon during summer, and the morning and evening during winter. The pattern of high and low prices is very similar in the Day Ahead and the Real Time markets and remains the same for both DOM and AEP.

Prices in the Day Ahead and Real Time markets might deviate in any given hour but remain close on average. However, these hourly deviations can significantly increase the revenue potential of a storage asset. The graph below shows the annual average value for the maximum difference between any two prices during a day. The results presented in the graph are based on historical prices and reflect the maximum difference between the highest and lowest priced hour in every day during a year. A storage asset with a single hour duration, could theoretically have an average daily revenue equal to this difference per MW (de-rated by efficiency losses). A longer duration asset could capture additional value, although such value would be diminishing as remaining price differences during the day are lower.

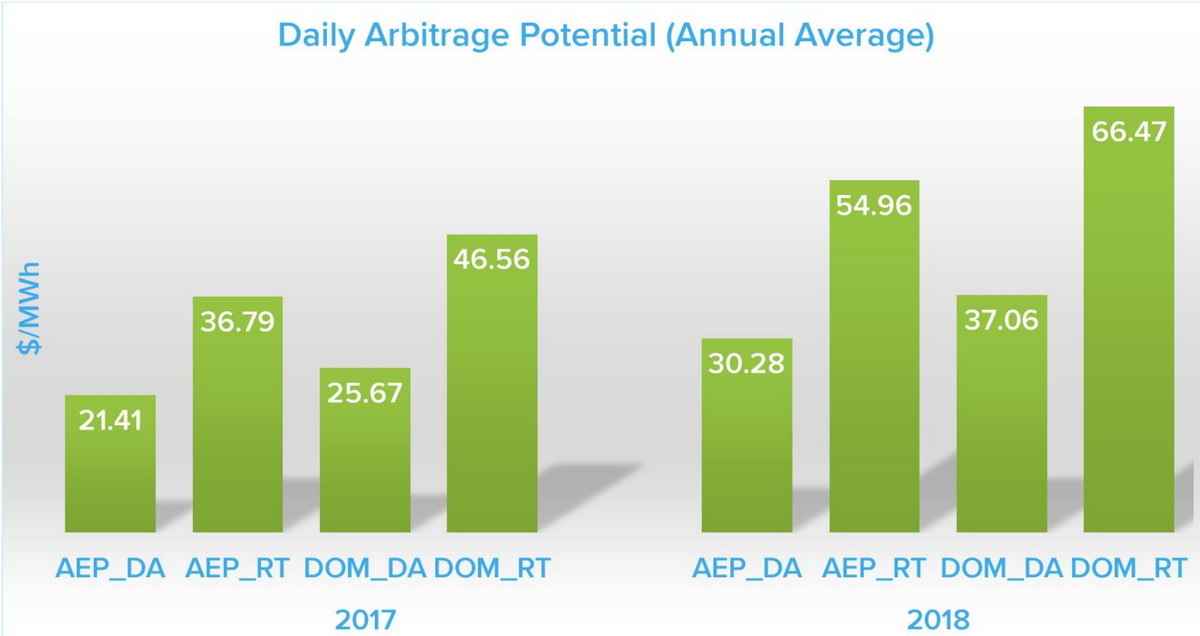

Figure 23. Energy arbitrage potential based on 2017 and 2018 historical day ahead (DA) and real time (RT) prices in the Dominion Energy Virginia (DOM) and APCo (AEP) load zones (average daily maximum)

To estimate the energy savings associated with Virginia's energy and ancillary service needs, first we estimated the minimum cost of serving Virginia's load with the current and future system. By simulating the operations of the system in 2019 and 2029 without any additional storage, we are taking two snapshots that later serve as the baseline scenarios against which we compare additional simulations of the system containing storage. By increasing the level of storage deployment in the system, we estimate the reduction in the production cost and, thus, the amount of energy savings that correspond to each storage deployment level. The marginal energy benefit of storage is decreasing both with the duration of storage, as well as with the level of deployment of storage assets in the Commonwealth as the highest value opportunities are explored first. At some level of deployment, the load curve would be flat with all opportunities for arbitrage explored and no value for additional storage.

The representation of the system including supply, cost, and load data was informed by data available from the S&P Market Intelligence Platform. The future system was informed by DOM's and APCo's IRPs. Strategen only modeled the operations of the system without making any evaluation of the proposed capacity additions. More specifically, the APCo IRP[107] includes 455MW of solar, 1,545MW of wind additions, 10MW of battery storage resources, and 14MW of additional CHP. The preferred plan also includes the retirement of Clinch River Units 1 and 2 in 2026. Load is assumed to grow 1% on average annually. On the other hand, Dominion Energy Virginia refrains from recommending a Preferred Plan and presents a range of options (the "Alternative Plans") representing plausible future paths for meeting the electric needs of Dominion Energy Virginia customers. For this study, the Dominion Energy Virginia system in 2029 assumes the adoption of Plan A, which includes solar additions of six CT plants (2748 MW), 5000MW of solar,

[107] Source: Integrated Resource Planning Report to the Commonwealth of Virginia State Corporation Commission, May 2017

12MW of offshore wind, 1,585 MW of CC natural gas, and retirements of many generating units (some initially placed into cold reserves).

Both Dominion Energy Virginia and APCo serve load and have generation located out of Virginia. In this study all APCo and Dominion Energy Virginia resources and load were modeled; results were scaled down to represent only their share within the Commonwealth.

Ancillary Services

Ancillary services help balance the transmission system as it moves electricity from generating sources to retail consumers. As already mentioned, PJM operates markets to procure two important ancillary services: regulation and reserves.

Reserves help to recover system balance by making up for generation deficiencies if there is loss of a large generator. As already mentioned, reserves are not high value markets and their impact in the value modeling exercise was minimal. Average prices for Synchronized and Non-Synchronized reserves in 2017 were below two and one dollars respectively for both the MAD and RTO regions.

On the other hand, regulation is used to control small mismatches between load and generation. The market for regulation is lucrative, although shallow and thus, it can quickly saturate. A storage asset can bid in the regulation market in consecutive hours, which is the reason that a storage asset participating in both energy and ancillary services markets might choose to forego high arbitrage opportunities to maintain its state of charge and be active in the regulation market. PJM has a regulation requirement of 525MW during non-ramp hours and 800MW during ramp hours, which consist of both RegA and RegD. Energy storage can provide dynamic regulation (RegD), but as of 2018 PJM seems to have enough qualified storage MW to satisfy the requirements.[108] Nevertheless, regulation prices are high, and the market remains attractive for more investment in storage.

The optimal revenue that a storage asset with one-hour duration participating in the PJM ancillary services market providing dynamic regulation in 2017 could get was over $100 per kW for the year. This number is calculated based on optimal bidding in both the energy and ancillary services markets[109] and informs the study's marginal regulation benefit that the first deployed MW of storage can capture in Virginia. Although the battery can bid in both energy and ancillary services markets, it is much more profitable to only bid in the regulation market and only shift energy during extreme price spikes. However, that revenue could quickly disappear as more storage comes online. And as regulation is being procured at a PJM-wide level, Virginia assets will be competing with resources from other states. At the same time Virginia assets could be offering regulation exceeding the needs of the VA load. For that reason and although the VA load represents less than 15% of the PJM load, within this study it is assumed that the marginal

[108] Source: PJM, Regulation Update, 2018 https://www.pjm.com/-/media/committees-groups/committees/oc/20180206/20180206-item-18-regulation-update.ashx
[109] Storage revenue in the regulation market was modelled according to: Byrne et al, Estimating Potential Revenue from Electrical Energy Storage in PJM

regulation benefit approaches zero when additional storage within Virginia reaches 25% of the PJM requirement.

In addition to other factors, the amount of regulation required by the PJM system is highly dependent upon the amount of variable resource (e.g. wind and solar) production at that time. According to a recent renewable integration study[110] it was recommended that PJM develop a method to determine regulation requirements based on forecasted levels of wind and solar production. The study's main conclusion is that the PJM system could operate reliably under this higher renewable energy scenario if up to additional 1,500 MW of regulation reserves are also included. Similarly, the study assumes that 25% of those could be captured by Virginia assets.

Capacity

PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand three years in the future. Storage can participate in the capacity market, but its valuation is limited by PJM's proposal that a minimum of 10-hour duration should be maintained to participate in the capacity market.[111]

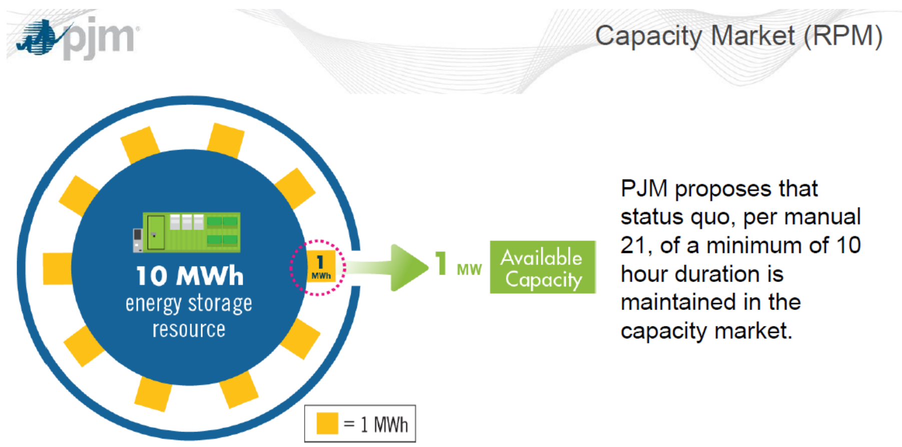

Figure 24. PJM Proposed Capacity Market Credit for Energy Storage Resources / Source: Electric Storage Participation Straw Proposal[112]

Additionally, it is worth noting that the Appalachian Company in its 2017 IRP assumed that a 10MW, 30MWh battery would provide a capacity value of 5MW, thus suggesting that a minimum of 6 hours of duration is needed to provide full capacity value.[113]

In a recent study on the Capacity Value of Energy Storage in PJM,[114] Astrapé Consulting simulated the entire PJM electric system plus those of its direct neighbors and found that energy storage

[110] Source: PJM, Renewable Integration Study Reportshttps://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx
[111] Source: PJM, Updated Electric Storage Participation Straw Proposal, 2018
[112] Source: PJM, Updated Electric Storage Participation Straw Proposal, 2018
[113] Source: APCo 2017 IRP, p 99: "The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 10MW and 30MWh, with a round trip efficiency of 87%. For Capacity Performance considerations the assumed PJM capacity rating that was modeled was 5MW."
[114] Source: Capacity Value of Energy Storage in PJM

systems with duration capability of 4 hours can provide up to 4,000 MW of capacity of equivalent reliability value to that supplied by conventional resources. Storage systems with 6-hour duration can provide up to 8,000 MW of capacity of equivalent reliability value to conventional resources. Within these limits, storage can replace traditional generation MW-for-MW with no reduction in system reliability.

Thus, a 4-hour duration requirement would correctly represent the capacity value of storage under current market conditions and would remain accurate until the amount of installed storage in PJM increases by two orders of magnitude. The study shows no justification for longer duration requirements, and that, at current levels of penetration, duration requirements longer than 4 hours reduce the capacity value of storage to well below the amount of traditional capacity it provides equivalent service as. The conclusion of the study was incorporated as a sensitivity analysis in this report and leads to significantly higher storage deployment.

In both the main, and the reduced required duration analysis, capacity savings are quantified by multiplying the capacity value of storage with forecasted capacity costs and are assumed to be constant for any level of storage deployment within Virginia. The capacity value of a storage system is equal to 10% of the total energy it can store if its duration is shorter than 10 hours and equal to the power rating if the asset has a duration longer than 10 hours. Capacity prices are based on the forecast included in Dominion Energy Viginia's IRP,[115] and are shown in the following graph:

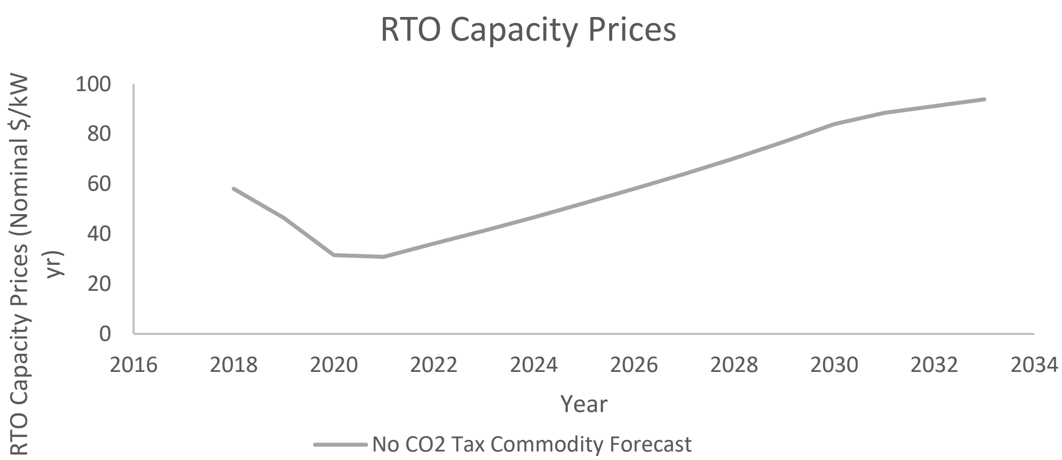

Figure 25. PJM Capacity Price Forecast, Source: Dominion Energy Virginia 2018 IRP

3.2.2 Distribution System

A major potential category of benefit to the Virginia power system that storage could help realize is the avoidance or deferral of distribution system upgrades. As customer load on the distribution system grows, certain facilities (e.g. substation transformers, feeder lines, etc.) will need to be upgraded to accommodate the higher network peak demands. If storage resources installed on

[115] Source: Dominion IRP, Appendix 4A – ICF Commodity Price, pg 200: Forecasts for Virginia Electric and Power Company, Forecast 2017

the distribution system are dispatched to reduce peak demand, they could potentially reduce the need to make these upgrades. These demand-related distribution upgrades can be represented in terms of the average marginal cost to serve an additional MW increase in customer load. Both Dominion Energy Virginia and APCo were unable to provide the marginal cost of service for their respective distribution systems. However, an approximation of these costs in Virginia was developed from publicly available information that was provided.

In recently released investor materials, Dominion Energy Virginia projected a need to invest $1.7 billion through 2023 to accommodate customer growth in Virginia.[116] Meanwhile, the utility projects its peak load to grow by approximately 645 MW over 2018 levels.[117] In addition to demand-related distribution system costs, additional costs are related to customer interconnections which may also be able to be minimized through behind-the-meter storage. Moreover there may be growth in demand related to economic expansion in addition to customer growth. Strategen estimates that this could equate to a marginal distribution system upgrade capital cost of approximately $1,054/kW, or about $73/kW-yr on an annualized basis.[118]

To fully capture the upgrade deferral value a minimum of six hours of duration was assumed to be required (storage assets of shorter duration only partially capture this value). Furthermore, the value is assumed to diminish as storage is deployed reflecting the notion that the highest value deferral opportunities would be exploited first.

3.2.3 Key Findings

Figures 26 and 27 summarize 2019 and 2029 total annual costs and benefits of storage across all key value drivers for different deployment levels. Energy cost reduction and ancillary services market participation seem to be the highest value driver for both 2019 and 2029. Significant part of this value comes from participation in the regulation market, which is contingent on both PJM rules and storage deployment in other states. Thus, the potential could significantly change if a major change in either of the two factors occurs. On the other hand, PJM's 10-hour capacity value restriction significantly limits a value driver that has been reported to be the most valuable one in other regions. The value of storage is higher in 2029 as all savings categories increase. More specifically, with higher renewable penetration, storage can play an even more important role both shifting energy from hours of high renewable resource to hours with lower resource, as well as help stabilize a system with increased frequency regulation needs.

[116] Source: Dominion Energy, Investor Day General Sessionhttps://s2.q4cdn.com/510812146/files/doc_presentations/2019/03/2019-03-25-DE-IR-investor-meeting-general-session-vTC-website-version.pdf

[117] Source:See March 7, 2019 compliance filing in Docket No. PUR-2018-00065

[118] Assumes 40% of customer growth expenditures are demand related or could otherwise be deferred through storage; distribution system asset life of 40 years, and 6.31% Weighted Average Cost of Capital.

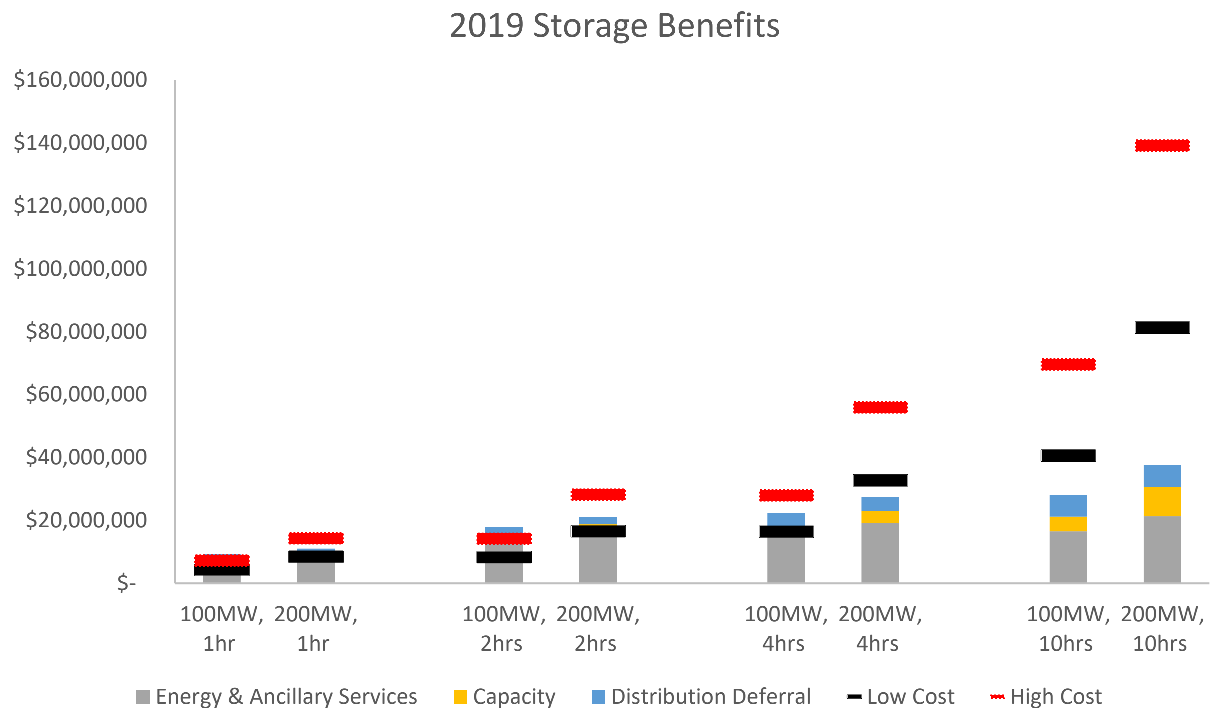

Figure 26. Benefits and Costs of Storage Deployment in 2019

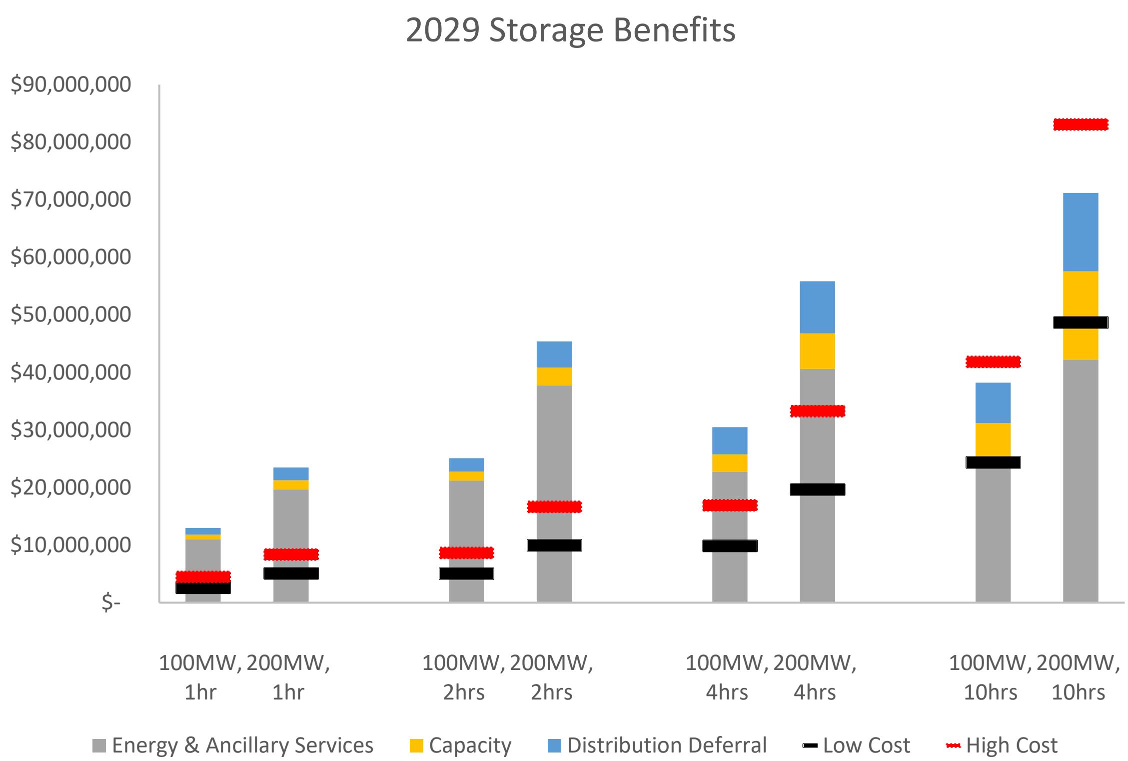

Figure 27. Benefits and Costs of Storage Deployment in 2029

To estimate the storage potential in the Commonwealth, we first quantify the marginal benefit of different levels of storage deployment and compares them with cost projections. When studying different value drivers and stacking revenues, we restrict double utilization of the same resource which would result in an overestimation of the potential. More specifically, when stacking energy and ancillary services benefits, only the highest of the two values is accounted for. Following the same reasoning, when including distribution deferral benefits, storage assets prioritize this service over other potential revenues. To this end, the storage in the modeling exercise was considered unavailable for any other service during the 120 highest load hours.

The cost-efficient level of storage within the Commonwealth is the one that maximizes total net benefits and can be determined as the level at which the marginal cost of the last deployed MW is equal to its marginal benefit. Storage deployment below that level would still be profitable but leaves value opportunities unexplored. On the other hand, storage above the cost-efficient level indicates overinvestment and lower net benefits, assuming all benefit streams are appropriately captured in the analysis. The graph below shows the marginal cost and marginal benefit curves of batteries with assumed four hours of duration:

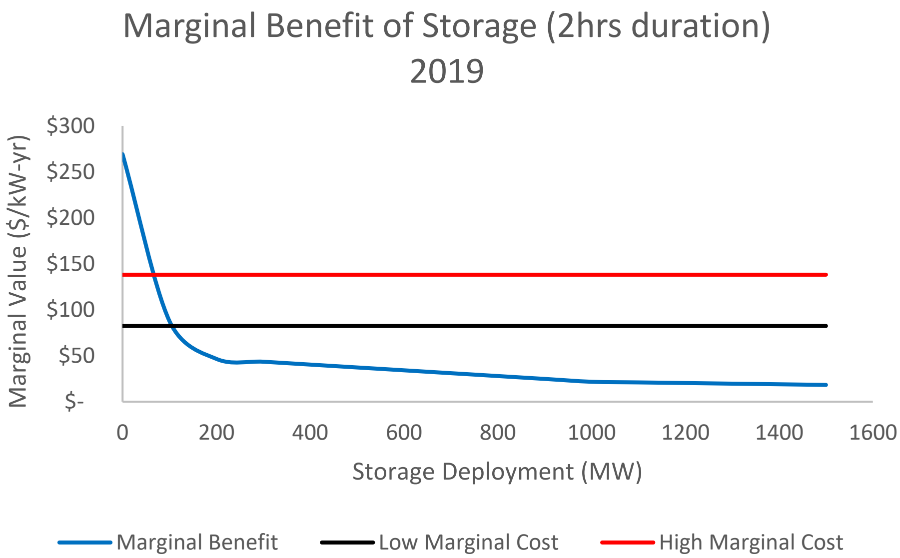

Figure 28. Marginal Benefit and Cost of Storage in 2019

According to the graph, the storage potential in Virginia assuming batteries of 4 hours is between 80 and 140MW in 2019, depending on the realized cost.

We also examine batteries of different duration and estimated the efficient level of deployment for each of them. These are summarized in the table below:

		1hr	2hrs	4hrs	10hrs
		2019			
Low Cost	Efficient Storage Level (MW)	110	113	84	0
Low Cost	Annual Net Benefits ($M)	$ 4.99	$ 9.35	$ 6.36	$ -
High Cost	Efficient Storage Level (MW)	71	72	24	0
High Cost	Annual Net Benefits ($M)	$ 2.82	$ 5.28	$ 3.18	$ -
		2029			
Low Cost	Efficient Storage Level (MW)	961	1,123	970	356
Low Cost	Annual Net Benefits ($M)	$ 29.93	$ 56.66	$ 58.04	$ 25.27
High Cost	Efficient Storage Level (MW)	397	396	329	9
High Cost	Annual Net Benefits ($M)	$ 19.93	$ 37.44	$ 25.30	$ (0.17)

Figure 29. Summary of estimated potential electricity system benefits from energy storage deployed in the Commonwealth of Virginia

Batteries of duration between two and four hours seem to be more cost effective, indicating that diminishing returns to scale exist not only on the total MW deployed, but also the duration of the installed storage. For example, batteries of long duration allow the full deferral of a distribution upgrade when this is needed to accommodate peaks of a few hours. However, increasing the duration beyond those needed hours (assumed to be six in the study) increases the cost without adding more value to storage from that category. Participation in the ancillary services market also exhibits strong diminishing returns, as during any hour an asset bids in the reserves or regulation market, its bid is restricted by its power rating; energy stored beyond a single hour output does not generate additional revenue.

In addition to the main analysis results, two more sensitivity scenarios were run to determine the optimal amount of storage: in the first case, no distribution benefits were included in the analysis, while in the second, the duration requirement for capacity accreditation of a storage system in PJM was assumed significantly lower than 10 hours.

The efficient levels of deployment for each battery duration in the case of zero distribution benefits are summarized below:

		1hr	2hrs	4hrs	10hrs
		2019			
Low Cost	Efficient Storage Level (MW)	90	91	59	0
Low Cost	Annual Net Benefits ($M)	$ 3.88	$ 7.27	$ 2.99	$ -
High Cost	Efficient Storage Level (MW)	58	60	0	0
High Cost	Annual Net Benefits ($M)	$ 1.65	$ 3.02	$ -	$ -
		2029			
Low Cost	Efficient Storage Level (MW)	469	495	386	218
Low Cost	Annual Net Benefits ($M)	$ 23.02	$ 43.64	$ 34.76	$ 8.45
High Cost	Efficient Storage Level (MW)	360	358	252	0
High Cost	Annual Net Benefits ($M)	$ 15.61	$ 29.00	$ 12.95	$ -

Figure 30. Summary of estimated potential electricity system benefits from energy storage deployed in the Commonwealth of Virginia assuming zero distribution benefits

Finally, as mentioned earlier, PJM has proposed that a minimum of 10-hour duration should be maintained to participate in the capacity market. This requirement is considered conservative and might undervalue storage capacity. In a recent study, Astrapé Consulting found that a 4-hour duration requirement would correctly represent the capacity value of storage under current market conditions and would remain accurate until the amount of installed storage in PJM increases by two orders of magnitude (exceeds 4,000 MW). Given the significant difference of these duration requirements, another sensitivity was run assuming a midpoint required duration for capacity accreditation (i.e. 7 hours). The efficient levels of deployment for each battery duration in the case of zero distribution benefits are summarized below:

		1hr	2hrs	4hrs	10hrs
		2019			
Low Cost	Efficient Storage Level (MW)	119	122	88	0
	Annual Net Benefits ($M)	$ 5.15	$ 9.75	$ 6.97	$ -
High Cost	Efficient Storage Level (MW)	73	74	28	0
	Annual Net Benefits ($M)	$ 3.01	$ 5.82	$ 3.28	$ -
		2029			
Low Cost	Efficient Storage Level (MW)	1,287	1,388	1,234	356
	Annual Net Benefits ($M)	$ 32.10	$ 61.70	$ 64.98	$ 25.27
High Cost	Efficient Storage Level (MW)	422	429	355	9
	Annual Net Benefits ($M)	$ 21.24	$ 40.03	$ 29.53	$ (0.17)

Figure 31. Summary of estimated potential electricity system benefits from energy storage deployed in the Commonwealth of Virginia assuming 7 hours of storage duration for capacity accreditation.

As expected, the efficient levels under a shorter required duration are significantly higher, as the increased capacity value results in higher benefits. The levels would be even higher under the assumption of a 4-hour required duration.

3.3 Customer Benefits Analysis

Behind-the-meter (BTM) energy storage systems are those that are deployed at a utility ratepayer's site – "behind" the meter from the perspective of the utility – in order to achieve savings on the ratepayer's utility bills via the controlled dispatch of the BTM system. These monthly bills result from charges applied to the electricity usage as measured at the utility meter according to the utility's tariff electrical rates, which may charge based on total energy (kWh) consumption, peak power (kW) consumption, and other quantities, within the month.

In addition to monthly bill savings, customers can also obtain revenues from demand response programs that reflect broader system benefits such as wholesale energy or capacity. For example, Dominion Energy Virginia currently offers a form of demand response through its Non-Residential Distributed Generation program, which provides a revenue stream for customers who are able to reduce consumption during peak times through the use of backup generation. In principle, additional demand response programs could be developed to target other system benefits such as reducing local system peaks to avoid distribution system upgrades. To reflect this possibility, we examined two scenarios:[119]

- Scenario 1: "Status Quo"
    - Includes customer bill savings from energy and demand charge reduction
- Scenario 2: Enhanced DR

[119] Additional system benefits may be achievable by customer-sited storage systems but were not quantified. Some of these are explored in Section 3.3.4.

- o Includes customer bill savings from energy and demand charge reduction
- o Includes demand response revenues based on existing programs
- o Includes hypothetical revenue from a new customer program targeting distribution deferral.

Our analysis evaluates additional potential capacity in kW that would result from each scenario, and the difference in additional potential capacity between the two scenarios, in order to determine the system-wide effects of including the additional revenue streams in the Enhanced DR scenario.

3.3.1 Overview of Methodology

Strategen used a proprietary BTM storage model to analyze the BTM storage potential in the state of Virginia. This model calculates the optimal dispatch (charge and discharge) of the BTM storage in order to minimize the resulting utility bill. The BTM storage model was used to analyze the effects of different storage sizes for large customers on existing tariff rates for both Dominion Energy Virginia and Appalachian Power Company. Bill savings were used to determine a payback period for storage investments and estimate a potential market share for both a high case and a low case for the installed costs of storage. A flowchart of the modelling process is provided below in Figure 32.

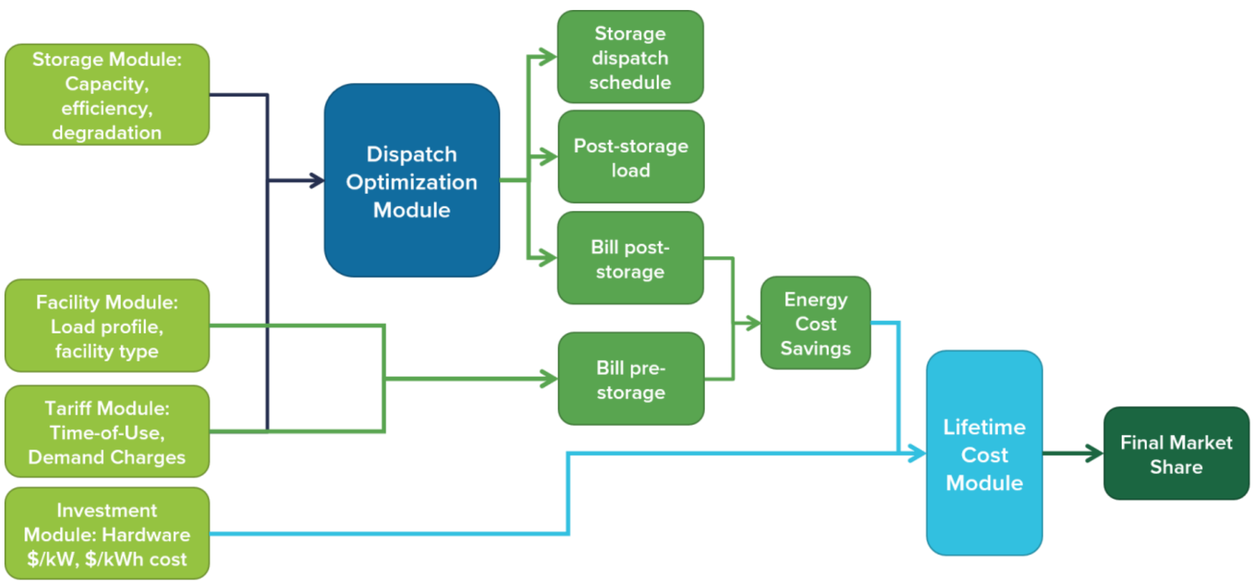

Figure 32. Behind-the-meter model structure

The model output demonstrates the effect of the optimized BTM system dispatch on the facility load. The new load shows reduced peak load demand during on-peak demand charge times and increased load charging during off-peak hours. Figure 33. Sample BTM model output on the Appalachian Power Company LPS tariff rate. Arrow indicates the demand reduction resulting from energy storage shows a sample of model output representing several days' worth of load with different storage system sizes. This figure shows the flattening of peaks from the base load to the load with storage, as storage optimally charges and discharges against those peaks. The green arrow highlights the >200kW reduction in peak demand between the base load and the load with a 1400kW, 2-hour BTM storage system.

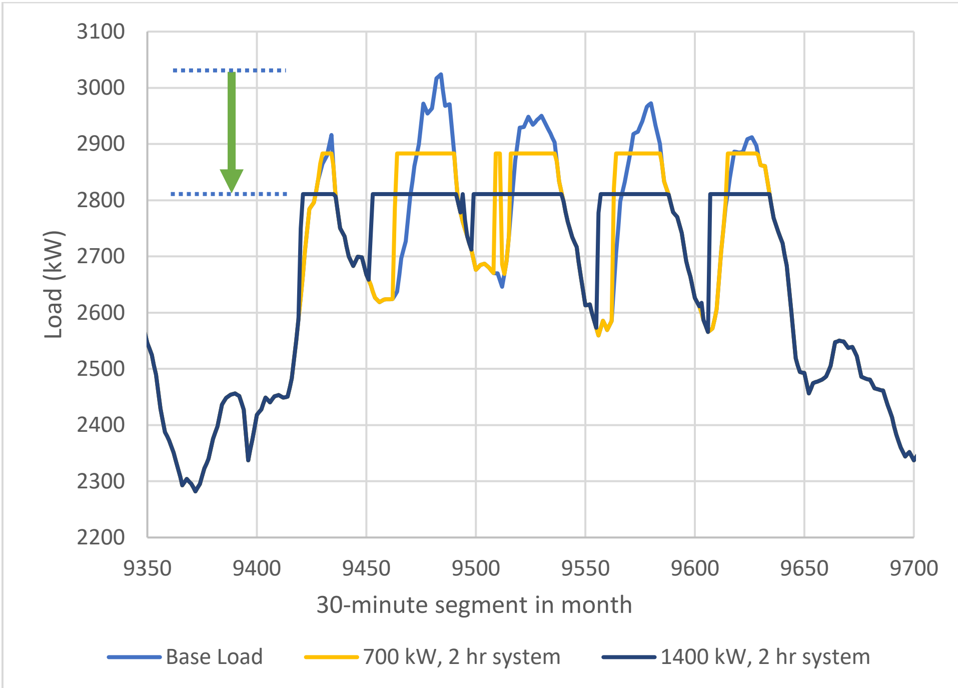

Figure 33. Sample BTM model output on the Appalachian Power Company LPS tariff rate. Arrow indicates the demand reduction resulting from energy storage

The BTM model optimization and analysis was conducted on three loads from two different sources: First, each tariff (Dominion Energy Virginia and Appalachian Power Company) was evaluated on two simulated loads selected from the Department of Energy (DOE) Commercial Reference Buildings dataset. These two loads were evaluated to compare differences between the tariffs across different load shapes and the results are presented in Section 3.3.2.

Additionally, Dominion Energy Virginia and Appalachian Power Company supplied proxy loads representing the average load within a given tariff rate. These loads were evaluated as a realistic assessment of savings, benefits, and potential value of BTM storage in these two tariffs, and the results are presented in Section 3.3.3.

A detailed presentation of model implementation and results can be found in Appendix A.

Solar PV + Storage

The analysis provided in this report focuses on standalone energy storage systems. However, it should be recognized that many customers in Virginia are exploring and implementing solar PV plus storage systems as a means to take advantage of the federal solar investment tax credit as it steps down from 30% in 2019 to 10% in 2022 for commercial systems. While these coupled systems generally are focused on retail bill savings (versus other grid benefits) there may be future opportunities to provide other grid services at both wholesale and distribution grid level.

3.3.2 Key Inputs and Assumptions

In order to evaluate general trends within the tariff rates, simulated loads from the DOE Commercial Reference Buildings dataset were analyzed using the BTM model. While these are not fully representative of actual customer loads within each tariff rate, the analysis of these loads allows for general trends and comparisons between different tariffs, loads, and system costs.

Facility Load Profile

As the utility bill is charged based on electricity consumption, the facility load profile is highly influential on the bill. Figure 34 below shows the percentage bill savings on the Dominion Energy Virginia GS-3 tariff for two different load profiles. The difference is due to the shape of the load profile; the load with greater percentage bill savings had steeper peaks, increasing the demand charges as well as the opportunity for energy storage to reduce those peaks. These differences in savings greatly impacted final market share, with around 10x reduction in final market share between the two loads.

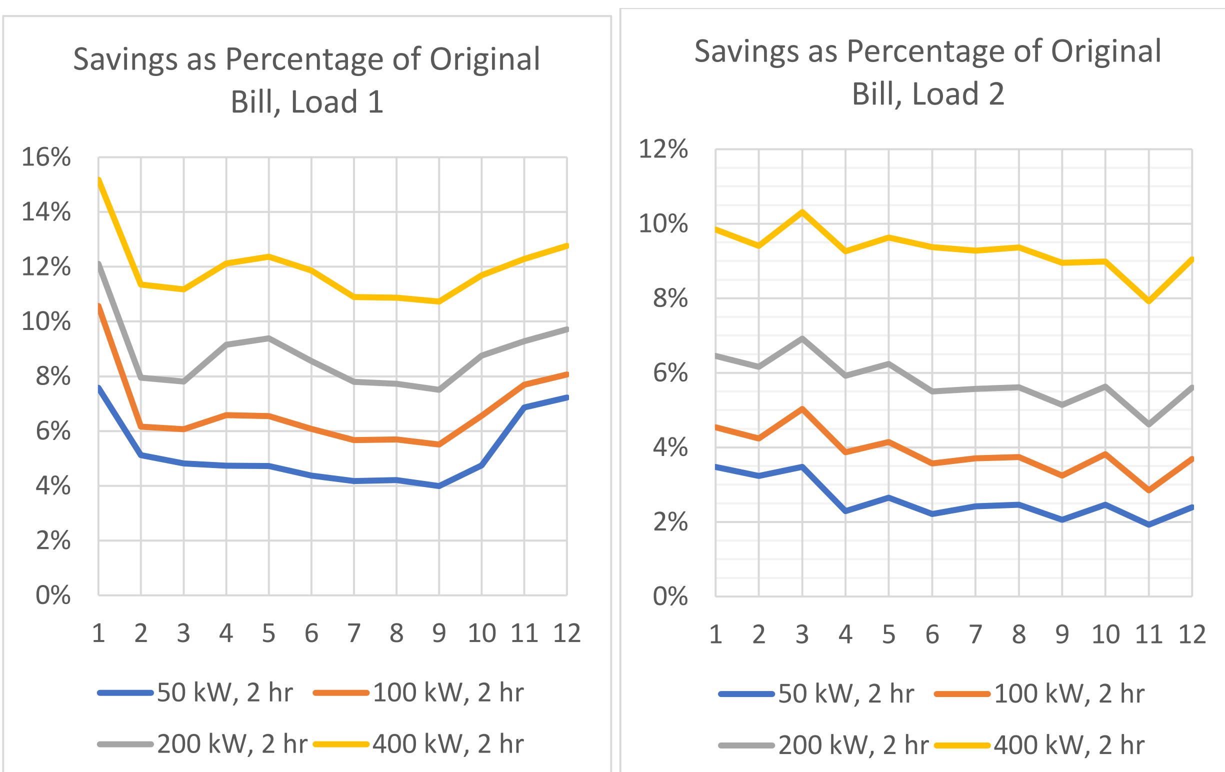

Figure 34. Percentage bill savings for two different loads on the same tariff

Tariff Rate Structure

As the other main component of the bill, the rate structure itself is also highly influential on how BTM storage systems are dispatched. The analysis focused primarily on two different tariff rates that were identified as potentially the most favorable for storage due to high demand charges: Dominion Energy Virginia GS-3 and Appalachian Power Company L.P.S. Figure 35 below shows the modeled share of bill savings by component for these two tariffs. The L.P.S. bill savings is almost exclusively due to demand charge reduction, as there are no time-of-use energy charges on the tariff rate. In contrast, the GS-3 tariff rate includes such charges, and they are reflected as non-demand, energy charge savings in the bill.

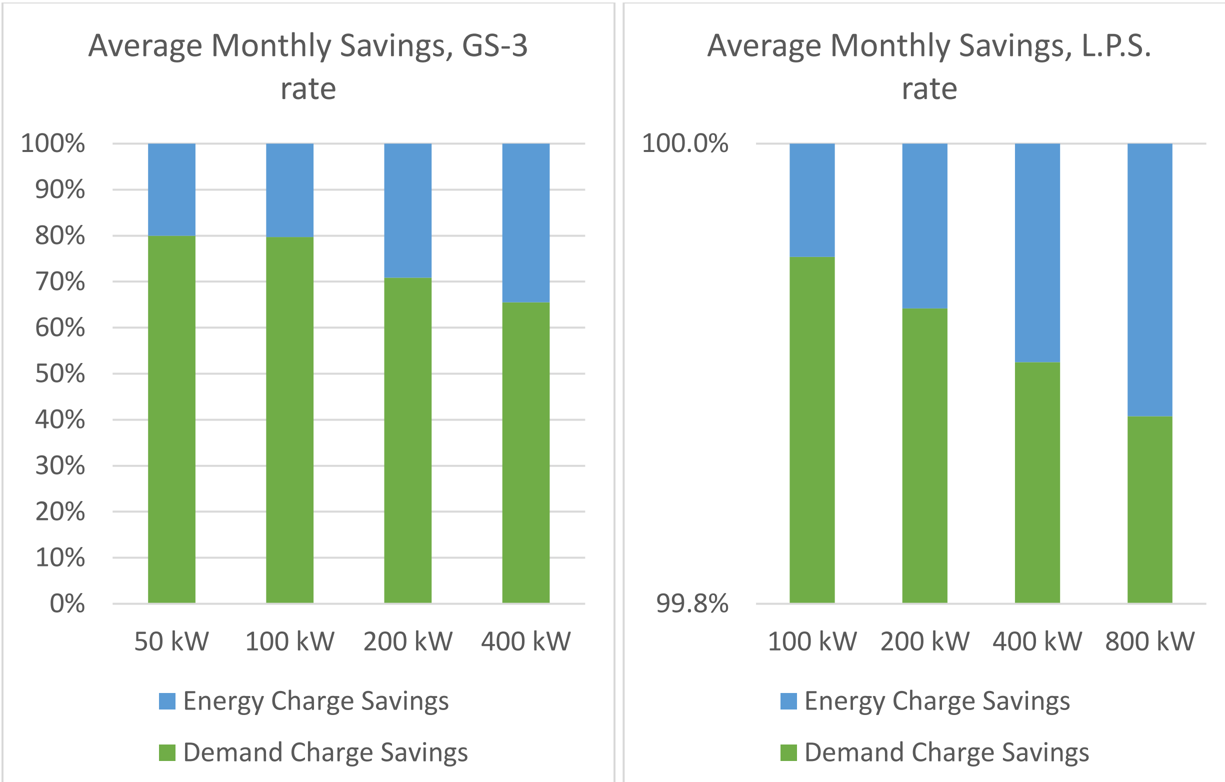

Figure 35. Average monthly savings broken down by energy charge and demand charge savings, for the same load on two different tariffs

Installed System Cost

For a given system size, the bill savings were compared to a high-cost scenario and low-cost scenario to calculate the payback period and resulting final market share, or the percentage of customers under the tariff rate that would eventually adopt the system given the payback period of the system. The high- and low-cost scenarios were derived from Lazard's Levelized Cost of Storage Analysis Version 4.0, which lists a cost range for the \$/kW and \$/kWh of a commercial/industrial, standalone BTM storage system.[120] The system cost had considerable influence on the final market share as shown in Figure 36 below.

[120] Source: Lazard, Levelized Cost of Storagehttps://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

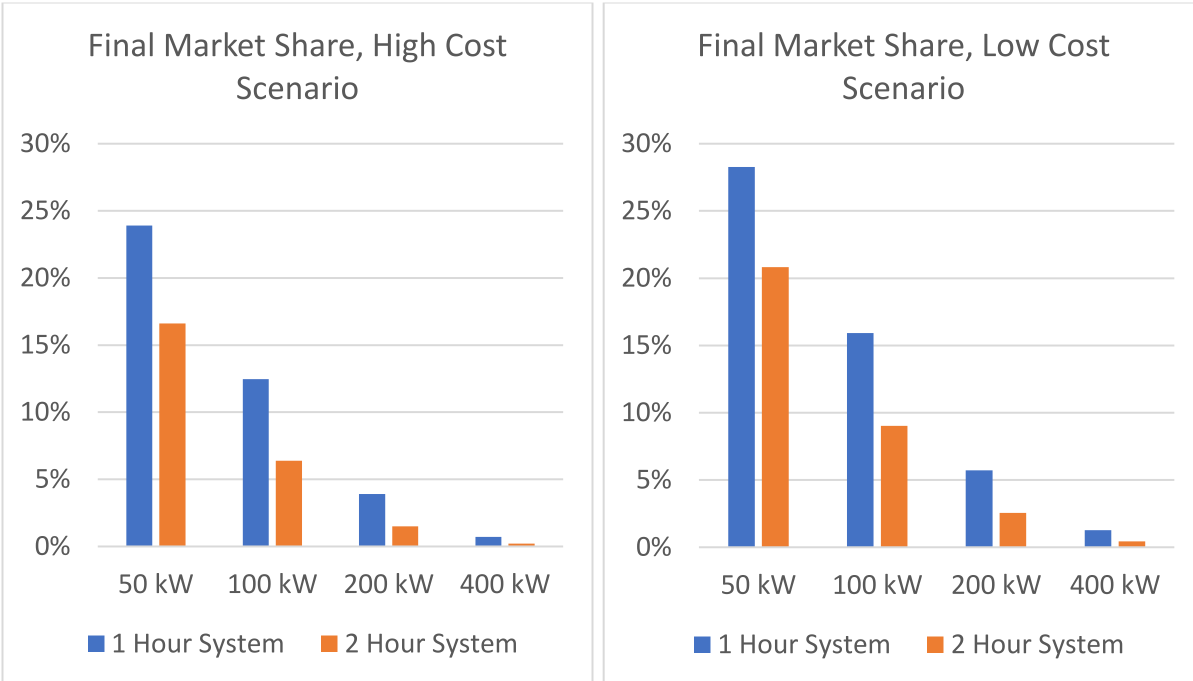

Figure 36. Final market share percentages for the same load and tariff rate, for high-cost and low-cost scenarios

Demand Response Revenues

Demand response (DR) programs are also currently available in the Dominion Energy Virginia and Appalachian Power Company tariffs. This analysis models the Non-Residential Distributed Generation program for Dominion Energy Virginia,[121] and the "D.R.S. - RTO Capacity" demand response rider for Appalachian Power Company.[122] Both include a $/kW capacity payment, and the Dominion Energy Virginia program includes additional energy-based ($/MWh) incentives as well.

Details of the demand response model implementation can be found in Appendix A.

3.3.3 Key Findings

In order to evaluate realistic, quantitative benefits for storage, proxy loads were then analyzed using the BTM model. Proxy loads are an average of the load within a tariff rate. For this section, Dominion Energy Virginia and Appalachian Power Company each sent one proxy load for the Dominion GS-3 (GS-3) and APCo Large Power Service (LPS) tariff rate, respectively. For the analysis, four system kW sizes were chosen for each load, based on the peak demand, and three storage durations: 1, 2, and 4-hour systems. These loads and system sizes were evaluated using the BTM model, and the results are presented below.

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[121] Source: Dominion Energy, Distributed Generationhttps://www.dominionenergy.com/large-business/energy-conservation-programs/distributed-generation/distributed-generation-faqs
[122] Source: Appalachian Power, Virginia SCC Tariff No 25https://www.appalachianpower.com/global/utilities/lib/docs/ratesandtariffs/Virginia/Tariff%2025%20April%201,%202019%20MASTER-Tax,%20RPS%20and%20Tax%20Riders-clean.pdf

3.3.3.1 Example Bill Savings & Revenues – Scenario 1 ("Status Quo")

The analysis of the tariff rates on the proxy loads begins with establishing a status quo in Scenario 1, evaluating all current benefits available for BTM system owners due to demand charge and energy charge management.

Figure 37 below shows a summary of the reduction in monthly electricity bill averaged over the year, for different system sizes under GS-3 and LPS tariff rates with their respective proxy loads.

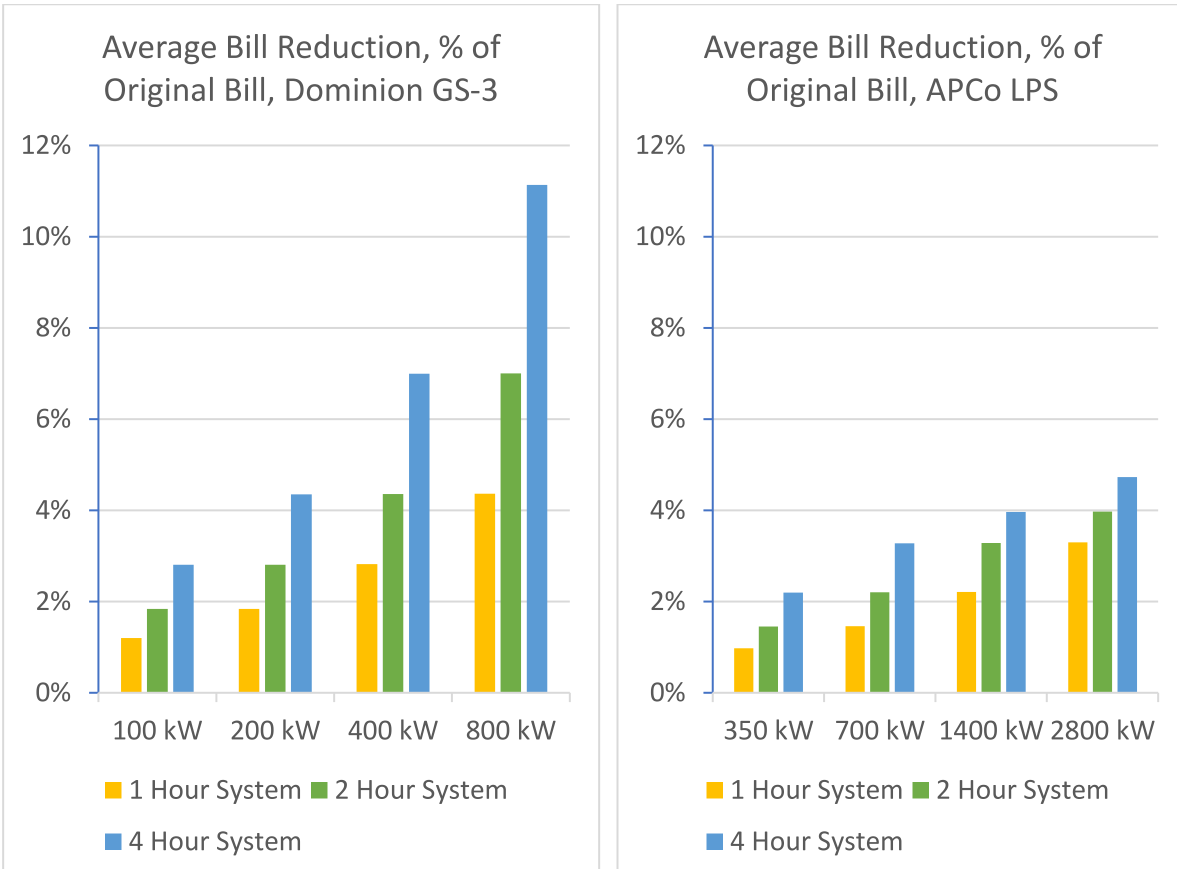

Figure 37. Comparison of monthly bill reduction averaged yearly, between GS-3 and LPS tariff rates.

While LPS bill savings are roughly double those of the GS-3, the LPS storage has been scaled appropriately with the peak demand to 3.5x of the GS-3 storage size. This diminished effect of storage on the LPS proxy load and tariff rate can be seen in the average percentage reduction of the electricity bill across the two different rates. On the GS-3 rate, this bill reduction ranges between 1.2%-11.13% of the original bill, compared to only 0.98%-4.73% on the LPS rate.

The limited value of storage on the LPS tariff rate affects the adoption rate of BTM storage on that rate. Our analysis calculates both the final market share (i.e. % of customers within the tariff rate that will invest in a BTM system) and final added BTM capacity in kW, for each system size on each tariff rate. Table 2 and Table 3 show the results for the Dominion Energy Virginia GS-3 and Appalachian Power Company LPS tariff rates, respectively. For many system sizes on the LPS tariff rate, the savings is not enough to justify the system cost, and so the final added BTM capacity is zero.

Power (kW)	1-hour system	2-hour system	4-hour system
100	0.3 – 4.2	0.1 – 2.9	0 – 1.3
200	0 – 2.6	0 – 1.6	0 – 0.6
400	0 – 1.2	0 – 0.8	0 – 0.4
800	0	0	0

Table 2. Final Added BTM Capacity, in MW, for the Dominion Energy Virginia GS-3 tariff rate

Power (kW)	1-hour system	2-hour system	4-hour system
350	0 – 0.7	0 – 0.35	0
700	0	0	0
1400	0	0	0
2800	0	0	0

Table 3. Final Added BTM Capacity, in MW, for the Appalachian Power Company LPS tariff rate

The existing DR programs do not present significant influence on the final added capacity, with a slight increase in capacity for the GS-3 rate and a slight decrease in capacity for the LPS rate.[123] This is due to the low capacity credit of about $5/kW for both DR programs.

This is explained by analyzing the difference in bill between dispatching to reduce demand and energy charges and dispatching for DR program signals. This is shown below in Figure 38.

[123] Detailed results of this analysis are included in Appendix A.

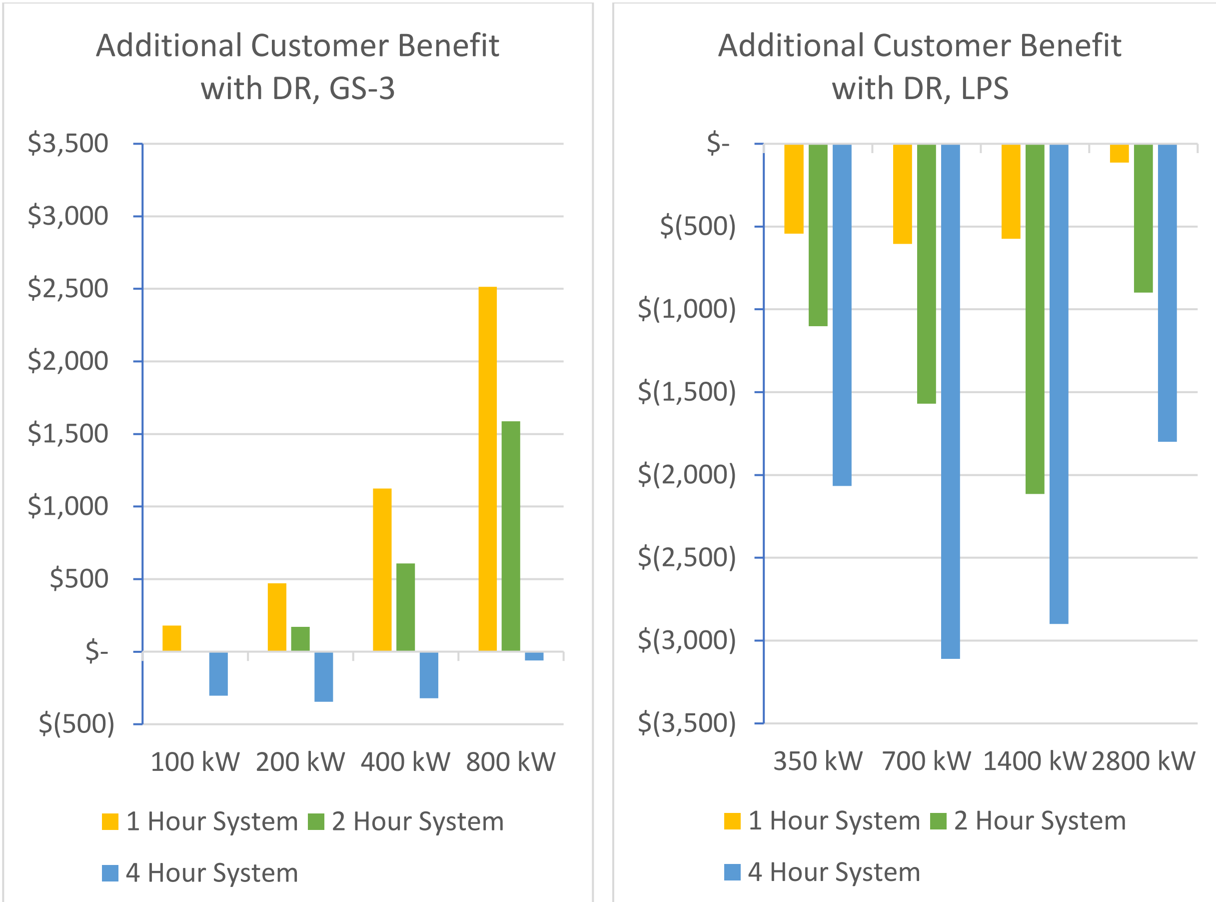

Figure 38. Additional customer benefit with DR participation for GS-3 and LPS tariff rates. Positive values indicate a lower bill with DR participation, as compared to the bill optimized to reduce demand/energy charges

For the GS-3 rate, the DR dispatch increased the bill savings for most system sizes, as the DR program credit outweighed the increased demand and energy charges. For the LPS rate, DR participation uniformly led to reduced bill savings compared to dispatching on demand charge reduction, since the DR program was not sufficient to cover the increased demand and energy charges.

3.3.3.2 Example Bill Savings & Revenues – Scenario 2 ("Enhanced DR")

At present, the current value and potential of BTM storage is small, roughly 5MW in the best-case scenario. However, proper valuation of BTM storage, as well as declining storage equipment and hardware costs, can make BTM storage a more attractive investment for customers and increase the potential for BTM storage in the state.

The following tables (Table 4 and Table 5) provide similar data to that in the previous section, of final added BTM capacity in the Dominion Energy Virginia GS-3 and Appalachian Power Company LPS tariff rates, for a further analysis including additional value streams and future high/low cost scenarios for storage systems. This includes revenues from existing DR programs and revenues from a hypothetical distribution deferral program, as well as a 5-year forecast cost of BTM system hardware.[124] This creates a "best-case" scenario for BTM storage system additions within these tariff rates.

Power (kW)	1-hour system	2-hour system	4-hour system
100	8.0 – 29.6	3.7 – 19.1	1.1 – 9.8
200	8.6 – 41.2	3.0 – 22.6	0.6 – 9.6
400	8.8 – 55.2	2.4 – 26.0	0.4 – 9.6
800	8.8 – 74.4	1.6 – 30.4	0 – 8.8

Table 4. Final Added BTM Capacity, in kW, for the Dominion Energy Virginia GS-3 tariff rate, in best-case scenario

Power (kW)	1-hour system	2-hour system	4-hour system
350	1.05 – 42.2	.35 – 2.45	0 – 1.05
700	0.7 – 5.6	0 – 2.8	0 – 0.7
1400	1.4 – 7.0	0 – 2.8	0
2800	0 – 8.4	0	0

Table 5. Final Added BTM Capacity, in kW, for the Appalachian Power Company LPS tariff rate, in best case scenario

In the best-case scenario, as much as 74.4 MW of BTM capacity could be added within the GS-3 rate, and 8.4 MW in the LPS rate.

3.3.4 BTM Storage Considerations and Recommendations

The analysis in the previous section above demonstrates that between current-day and best-case scenarios for BTM storage, a 16x increase in potential BTM capacity is possible. Along with the additional value streams captured in the hypothetical best-case scenario, further recommendations are included within this section.

As installed systems cost decline, the payback period and resulting market share will increase. For example, reducing the current cost of a 100kW, 1-hour system on the GS-3 tariff by 66% would reduce the payback period from 21 years to 7 years. As such, steps taken to reduce soft costs, or streamline permitting processes and interconnections could play a role in greater adoption of BTM storage.

While this current analysis uses proxy loads with two separate tariff rates, it does not represent the total number of potential non-residential customers who might consider adopting storage. Both rates examined have a relatively small numbers of customers, with approximately 1950 customers in GS-3 and 105 customers in LPS.[125] Further analysis could include more facility loads and additional tariff rates and identify loads with high potential for BTM savings to analyze with the BTM model.

The results of the analysis show that in general, increasing the storage size and duration increases the payback period and thus reduces the final market share. This is due to the focus on mainly

[124] Details of this analysis are included in Appendix A.
[125] Estimated from rate cases, which present the total yearly kWh in each rate, and the yearly kWh consumption in each proxy load.

capturing demand charges, which do not require a large amount of power or energy to effect a large change in bill savings, and result in diminishing returns with larger storage systems. However, even with a decline in final market share for larger systems, the size of each storage system can still lead to a net increase in additional BTM capacity, as is shown for both rates in the best-case scenario.

Additional value streams would influence the model to properly utilize and value larger storage systems. In particular, the addition of co-located solar photovoltaics (PV) could incentivize longer-duration (higher energy) storage. This solar-plus-storage system could generate energy during the day to meet facility load, with the excess stored in the battery to be dispatched at night. Incentive programs similar to California's Self Generation Incentive Program (SGIP)[126] could encourage both the purchase of larger BTM storage systems as well as their usage in tandem with solar PV. Rate design that allows these additional value streams to be captured as system benefits will incentivize customers to invest in BTM storage systems.

Finally, the valuation of BTM systems as local sources of backup power also needs to be taken into account, including both the customer-led value of system reliability in outages, as well as the environmental and societal benefits of replacing diesel backup generators. The value of BTM as a backup power resource, though difficult to quantify in financial terms, cannot be understated, as backup power is often one of the main reasons that customers choose to invest in BTM storage.

3.4 Virginia Energy Storage Market Potential

As the results of the System Benefits analysis show, the near-term economic potential for storage in Virginia (<4-hr duration) ranges from 28-116 MW, and would yield annual net benefits ranging from $3-10 million, depending on the installation costs and duration. Over the next decade, the potential grows to 338-1152 MW, with annual net benefits ranging from $20-$62 million.

Only a fraction of this potential can be realized from wholesale benefits alone due to modest arbitrage values, PJM market rules limiting capacity value, and a shallow market for ancillary services. However, the potential grows substantially if systems are deployed to provide both wholesale and distribution system benefits. This could include systems that are directly connected to the utility's distribution system, or customer-sited systems providing distribution system benefits.

Under the retail rates examined, customer-sited storage appears to have relatively limited potential today, totaling approximately 5 MW statewide. However, if additional customer program enhancements are made to deliver additional value streams from BTM storage (i.e. similar to Scenario 2 of the BTM analysis), then we estimate that 83 MW of BTM storage could be deployed economically for the large commercial and industrial sector. This amount could also grow over time as additional market segments become more cost-effective in conjunction with evolving program offerings, customer loads, and rate options.

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126 Source: CPUC, SGIP. http://www.cpuc.ca.gov/sgip/

3.4.1 Job Impacts

The economic potential for storage installations, if realized, will create a robust battery storage industry in the state, spurring job creation and employment within this new industry. These impacts are estimated based on a previous study of the energy storage potential in the state of Massachusetts.[127] These estimates are scaled for the low-high potential installed energy storage MW range stated above. A summary of the estimated job impacts is shown below in Table 6 and Table 7 for the low and high potential stated above, respectively.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
New Storage (MW)	38	75	93	123								329
Job Years	205	369	290	237	16	15	15	15	15	17	17	1212
Labor Income ($Millions)	19	34	27	23	1	1	1	1	1	2	2	114

Table 6. Estimated job impacts, low-potential case

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
New Storage (MW)	130	254	318	420								1123
Job Years	700	1261	989	809	53	53	52	52	51	56	56	4132
Labor Income ($Millions)	64	116	93	77	5	5	5	5	5	6	6	387

Table 7. Estimated job impacts, high-potential case

Given the range of 329-1,123 MW of storage potential, the total estimated job impacts are 1,212-4,132 job-years, resulting in a range of 114-387 $MM in labor income.[128]

Chapter 4: Safety & Permitting Issues

Government, private, and non-profit sector entities have established a solid foundation of energy storage safety principles and guidelines over the last decade. Efforts have largely focused on advanced battery energy storage, with specific emphasis on lithium-ion and other emerging battery chemistries. Whereas traditional lead acid batteries often sat idle and only provided backup power when grid power was unavailable, new battery chemistries facilitate novel use cases that cycle regularly and interact with the grid. These new chemistries and grid-connected

[127] Massachusetts Energy Storage Initiative, State of Charge report. https://www.mass.gov/files/2017-07/state-of-charge-report.pdf

[128] Further studies, such as the potential rate impact on customers, could be undertaken by the DMME or SCC.

use cases necessitated the update of safety and permitting guidelines for advanced battery energy storage.

Leveraging the groundwork developed through a decade of stakeholder collaboration, several states have accelerated adoption of advanced energy storage systems by focusing on four primary safety related areas:

1. Adopting safety codes
2. Adopting interconnection standards
3. Educating and training relevant stakeholders
4. Facilitating uniform permitting processes

States leading the development of energy storage include California, Hawaii and New York, which have each produced resources and best practices tailored to their unique grid, jurisdictional authorities, and customer safety considerations. Stakeholders can readily adapt and promulgate appropriate parts of these existing resources to enable the safe integration of energy storage at residential, commercial, and utility facilities in their state. This chapter provides an overview of the four areas, cites examples of state actions, and offers relevant references for further information.

4.1 Adopting Safety Codes

Building code development and adoption is a notoriously long process, typically requiring three years for development and then multiple years for states and municipalities to amend and adopt. The length of this process can be a barrier to the deployment of emerging energy technologies, such as advanced battery storage. For example, the National Fire Protection Association (NFPA) 70A: National Electrical Code (NEC) contained guidance only regarding traditional lead-acid batteries until the 2017 version, at which time NEC Article 706 was formally published to address energy storage systems (ESS) more broadly.

The latest code versions, including the 2017 NEC and the 2018 International Code Council International Fire Code, contain ESS provisions that reflect safety considerations and best practices from recent battery research and testing. Furthermore, these codes also require installed products to adhere to the latest energy storage component and system safety standards, such as UL9540, so both products and installations meet consensus-built safety benchmarks. There are now model codes and standards that address battery energy storage components, systems, installation, and the built environment, as shown in Figure 39 below.

Additionally, the National Electrical Safety Code (IEEE/ANSI C2) is the current safety standard for electric supply stations under the exclusive control of the utility and is developing requirements for ESS installations.

Energy Storage System Components	• **IEEE P1679.1** Guide for the Characterization and Evaluation of Lithium-Based Batteries in Stationary Applications • **IEEE P1679.2** Guide for the Characterization and Evaluation of Sodium-Beta Batteries in Stationary Applications • **IEEE P1679.3** Guide for the Characterization and Evaluation of Flow Batteries in Stationary Applications • **UL 1973** Batteries for Use in Light Electric Rail and Stationary Applications • **UL 1974** Evaluation for Repurposing Batteries • **UL 810A** Electrochemical Capacitors
Complete Energy Storage Systems	• **UL 9540** Energy Storage Systems and Equipment • **ASME TES-1** Safety Standard for Thermal Energy Storage Systems
Installation of Energy Storage Systems	• **NFPA 855** Standard for the Installation of Stationary Energy Storage Systems • **NECA 416** Recommended Practice for Installing Stored Energy Systems • **FM Global Property Loss Prevention Data Sheet # 5-33** Electrical Energy Storage Systems
Safety of the Built Environment	• **NFPA 1** Fire Code • **NFPA 70-** National Electrical Code [NEC] • **IFC** International Fire Code • **IRC** International Residential Code • **DNVGL-RP-0043** Safety, Operation and Performance of Grid-connected Energy Storage Systems • **IEEE C2** National Electric Safety Code [NESC]

Figure 39. U.S. Standards and model codes addressing energy storage technology safety[129]

Adopting the most recent building and fire codes, or at least those sections that relate to energy storage, is the foundational step that States and municipalities can take to minimize the safety risks that ESS pose to commercial and residential customers. Not only does it immediately establish a safety baseline, it also ensures that authorities having jurisdiction (AHJs) across the state are working with a common reference and vocabulary when evaluating installation permit requests. This action results in increased safety and confidence for ESS customers, accountability and assurance for AHJs, and certainty for vendors who otherwise must navigate conflicting code compliance requirements across multiple jurisdictions.

For many states, codes and standards are adopted at the local level due the state's "home rule" status. In contrast, Virginia is not a home rule state - it administers building codes and standards at the state level through its Uniform Statewide Building Code. As such the state has a unique role to play in ensuring successful codes and standards are adopted to reduce barriers to energy storage deployment.

State Examples

NFPA produces maps to demonstrate which version of the NEC is in effect in each state and which states are in the process of adopting the 2017 version (see Figure 40 and Figure 41 below).

[129] Source: Sandia National Laboratories, Energy Storage System Safety, Development and Adoption of Codes and Standards

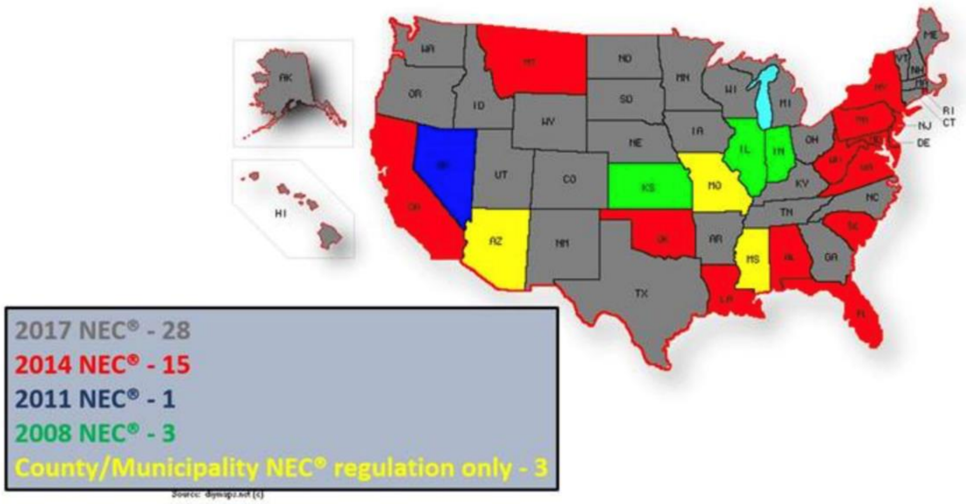

Figure 40. NFPA 70A: National Electrical Code version in effect by state as of 4/1/2019[130]

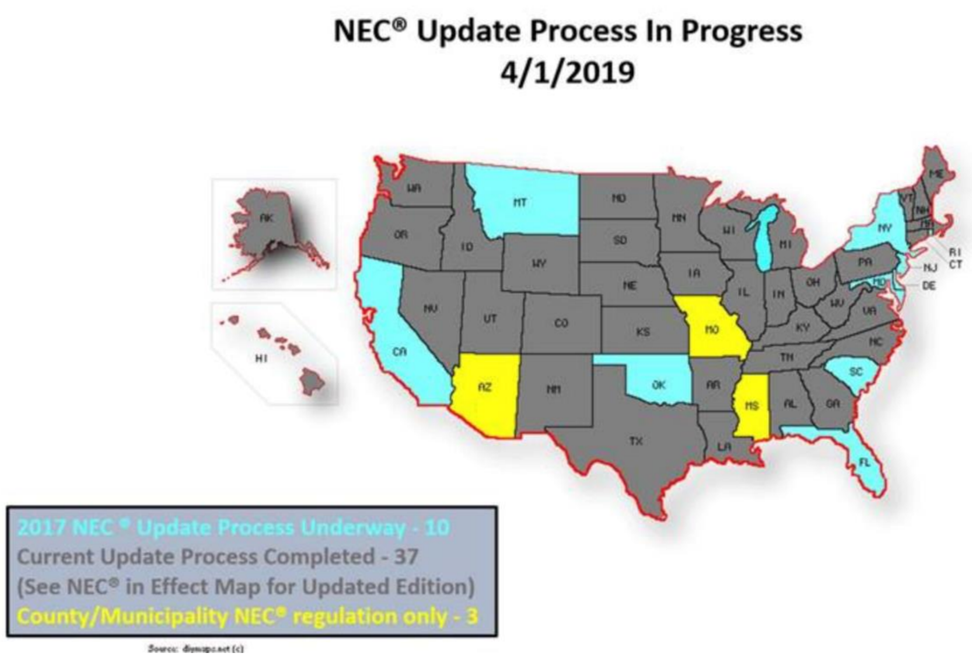

Figure 41. NFPA 70A: National Electrical Code update process in progress by state as of 4/1/2019[131]

Resources and References

Organization	Resource/Reference	Description	Link
Sandia/PNNL	Energy Storage System Safety, Development and Adoption of Codes and Standards	Short introduction to energy storage codes and standards and the processes for development and adoption.	PDF
PNNL	Codes 101: Overview of Development and Deployment of	Acquaints stakeholders involved in the development and deployment of ESS	PDF

[130] Source: NFPA, NEC Adoption Maps
[131] Source: NFPA, NEC Adoption Maps

	Codes, Standards and Regulations Affecting Energy Storage System Safety in the United States	with the subject of safety codes, standards and regulations (CSR) that can impact their activities.	
Sandia	Inventory of Safety-related Codes and Standards for Energy Storage Systems	Identifies laws, rules, codes, standards, regulations (CSR) and associated requirements related to safety that could apply to stationary ESS, as well as describe experiences to date securing approval of ESS from those who have adopted and are applying CSR.	PDF
CSA Group	*Ryan Franks*	Manager, Global Energy Storage	Email
PNNL	*David Conover*	Senior Technical Advisor	Email
NFPA	*Rich Bielen*	Director of Fire Protection Systems	Email

4.2 Interconnection Standards

Advanced energy storage systems are frequently used in grid-interactive scenarios that require advanced inverters to operate in conjunction with the utility service. There may be situations where a utility tariff or ancillary service market could enable a customer-sited ESS to provide value to the customer and/or the grid, but the utility must still approve the interconnection of that device to its grid. Whereas building and fire codes seek to protect the ESS host customer and their neighbors, interconnection standards seek to protect the grid from safety and reliability issues that distributed energy resources may pose.

Overly burdensome interconnection requirements can pose a significant hurdle to customer-sited, distributed energy resources, including energy storage resources. Therefore, regulators in many states have taken proactive roles in addressing interconnection issues by establishing fair and transparent regulations and standards.

In 2018, the National Renewable Energy Laboratory identified several emerging focus areas for regulators of energy storage interconnections:

- Planned operational capacity and behavior
- Exporting versus non-exporting systems and associated control systems testing
- Engineering reviews and technical screening procedures
- Impact on load
- Collocation with on-site generation (e.g., solar plus storage)[132]

State Example

While several states have undertaken revisions or comprehensive reforms, California presents a thorough example of how energy storage interconnection issues and regulations have evolved over time. The California Public Utilities Commission (CPUC) established "Rule 21" in 1982 to govern the interconnection of distributed generation to the utility distribution system. It has undergone several updates since then to allow solar, energy storage, and other distributed energy

[132] Source: National Renewable Energy Laboratory (2018). Emerging Practices for Energy Storage Interconnection. Source: National Renewable Energy Laboratory (2018). *Emerging Practices for Energy Storage Interconnection.* Blog Post. Accessed 4/14/2019. https://www.nrel.gov/dgic/interconnection-insights-2018-11.html

resources to support the grid. Working diligently with stakeholders through the decision-making process, the CPUC has sought to establish a "timely, non-discriminatory, cost-effective, and transparent interconnection" through the following best practices:

- Two-track interconnection study process: 1) "Fast Track" streamlined process for small and non-exporting systems, and 2) "Detailed Study" for more complicated systems
- Smart inverter requirements
- Cost-certainty envelope for interconnections that trigger a distribution system upgrade
- Incorporation of Integration Capacity Analysis into siting decision and Fast Track applications (based on distribution system capacity and distributed resource planning)[133]

This ongoing stakeholder process has resulted in fair, technically rigorous, and consensus-built interconnection frameworks that all customer-sited generators and energy storage must adhere to. This uniform standard enables manufacturers and vendors to obtain a single certification through a third-party testing laboratory to interconnect their technologies anywhere in California. Furthermore, it includes provisions related to dispute resolution which provide project developers a clear, timely process to address interconnection disputes with the utility.

Resources and References

Organization	Resource/Reference	Description	Link
CPUC	*Rule 21 Interconnection Website*	Overview of history, rulemaking, disputes, implementation, and links to utility tariffs and Rule 21 websites.	Link
Hawaiian Electric Company	*Rule 14H*	Customer sited generation interconnection standard for Hawaiian Electric Company.	PDF
Energy Storage Association	*Updating Distribution Interconnection Procedures to Incorporate Energy Storage*	Overview of the types of distributed energy storage systems customers, main interconnection hurdles facing ESS, and proposed recommendations to address interconnection challenges.	Link
National Renewable Energy Laboratory (NREL)	*Emerging Practices for Energy Storage Interconnection*	Reviews specific state regulatory actions to reform interconnection processes and categorizes common areas of focus.	Link
Federal Energy Regulatory Commission	*Pro forma Small Generator Interconnection Agreements and Procedures*	Discussion and framework for pro forma small generator interconnection agreements and considerations.	PDF

133 Source: CPUC, Rule 21 Interconnection website for a complete history and relevant Decisions and Orders See the CPUC Rule 21 Interconnection website for a complete history and relevant Decisions and Orders: http://www.cpuc.ca.gov/Rule21

California Energy Storage Alliance	*Jin Noh*	Policy Manager	Email
CPUC	*Reese Rogers*	Public Utilities Regulatory Analyst	Email
NREL	*Zachary Peterson*	Technical Project Manager	Email

It should be noted that there is currently an interconnection rulemaking underway at the Virginia State Corporation Commission (VA SCC) in Case No. PUR-2018-00107. This process has been managed for several months by the VA SCC Staff who has held stakeholder workgroup meetings and accepted comments to inform draft revised interconnection standards to be developed for review and consideration by the Commission.

4.3 Stakeholder Education and Training

When developers seek to deploy ESS in a new market, they often first undertake an extensive education campaign to educate local AHJs, fire officials, and utilities about the safety of these technologies and that these systems will not destabilize the grid. The process of adopting appropriate building codes and interconnection standards is the first step in this stakeholder education. However, even after code updates are in progress or complete, the inherently risk-averse nature of AHJs, first responders, and utility stakeholders often necessitates additional education.

The type of education necessary will vary by audience, but may include ESS technologies, use cases, codes and standards, interconnection issues, and permitting and safety considerations. Additional hazard- and emergency-specific training and education is warranted for the first responder community, and NFPA has several free resources available (see Resources and References). States can support this education by sponsoring training programs in different areas, by developing guidebooks, by providing ongoing technical assistance, and by establishing working groups of relevant stakeholders to identify issues, barriers and opportunities.

Utility education on energy storage technologies and use cases is an excellent example of coordinated training activities and resources. The utility industry has several dedicated organizations, including Edison Electric Institute and Electric Power Research Institute (EPRI), that offer educational materials, training seminars and conferences, reports with results from research and testing results, opportunities for pilot project collaboration, and other resources to increase utility stakeholder understanding of energy storage systems and related opportunities. EPRI's Energy Storage Integration Council has a dedicated working group that develops and promulgates best practices for energy storage evaluation, procurement, testing, commission, and safety (see Figure 42 below).

Figure 42. Energy Storage Safety for utility projects[134]

State Example

Developers can also benefit from education about regulations and opportunities in new markets. In 2018, the New York Public Service Commission directed NYSERDA to educate out-of-state developers about New York market opportunities in order to ensure there was sufficient market competition and that customers were receiving low-cost systems.[135] One output of NYSERDA's efforts is a permitting and interconnection guide for developers who are trying to deploy projects. Figure 43 below presents an example process for permitting and interconnection of a small outdoor ESS in New York City.

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[134] Source: EPRI Guide to Safety in Utility Integration of Energy Storage Systems
[135] Source: New York Public Service Commission, 2018, Order Establishing Energy Storage Goal and Deployment Policy New York Public Service Commission (2018). Order Establishing Energy Storage Goal and Deployment Policy. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bFDE2C318-277F-4701-B7D6-C70FCE0C6266%7d

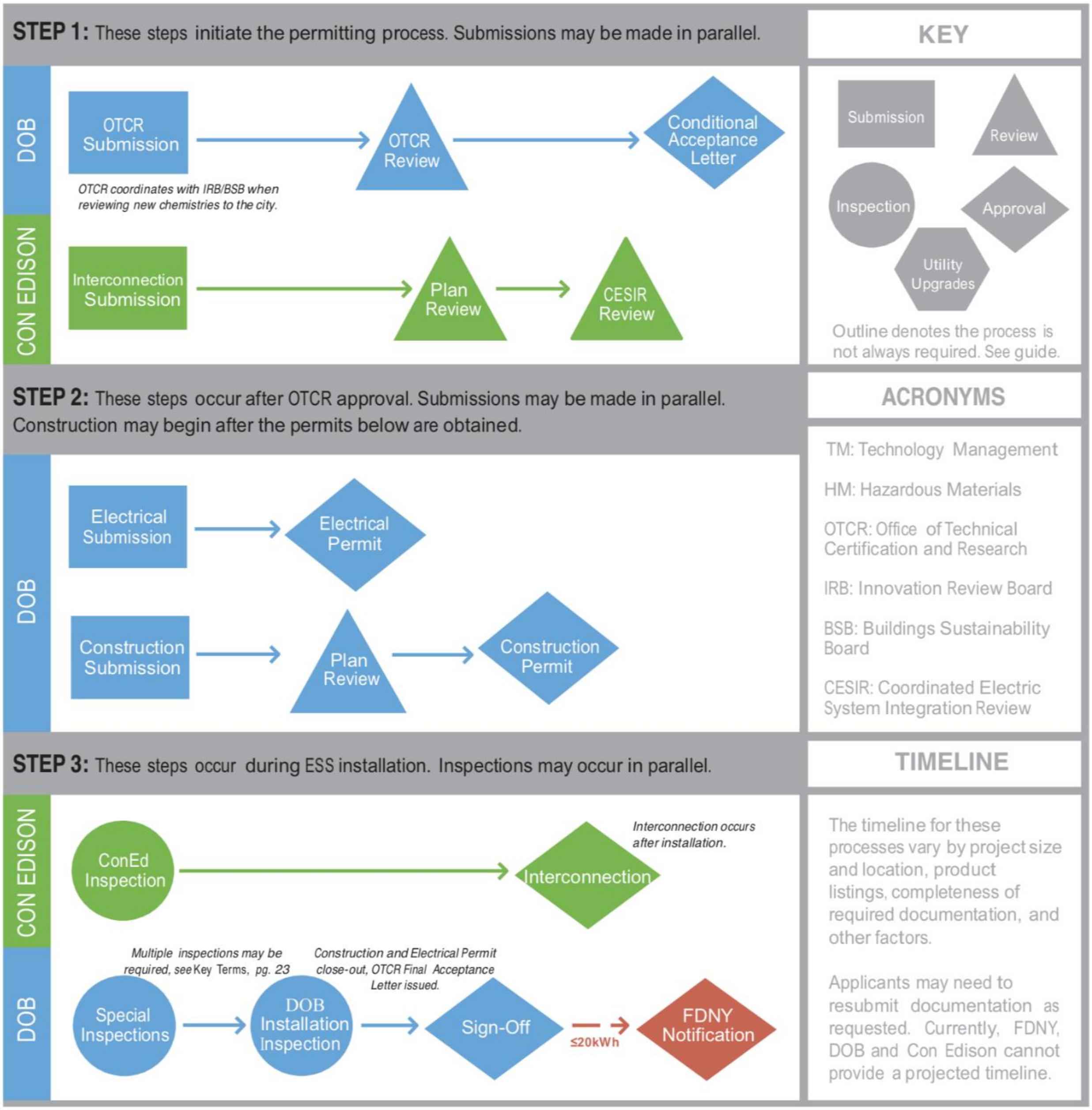

Figure 43. NYC Permitting and Interconnection Process for Small Systems (<20 kWh) (DOB means "Department of Buildings")[136]

The guide also includes larger systems that require the review and approval of the fire department (see Figure 44).

[136] Source: NYSERDA - Permitting and Interconnection Process Guide For New York City Lithium-Ion Outdoor Systems

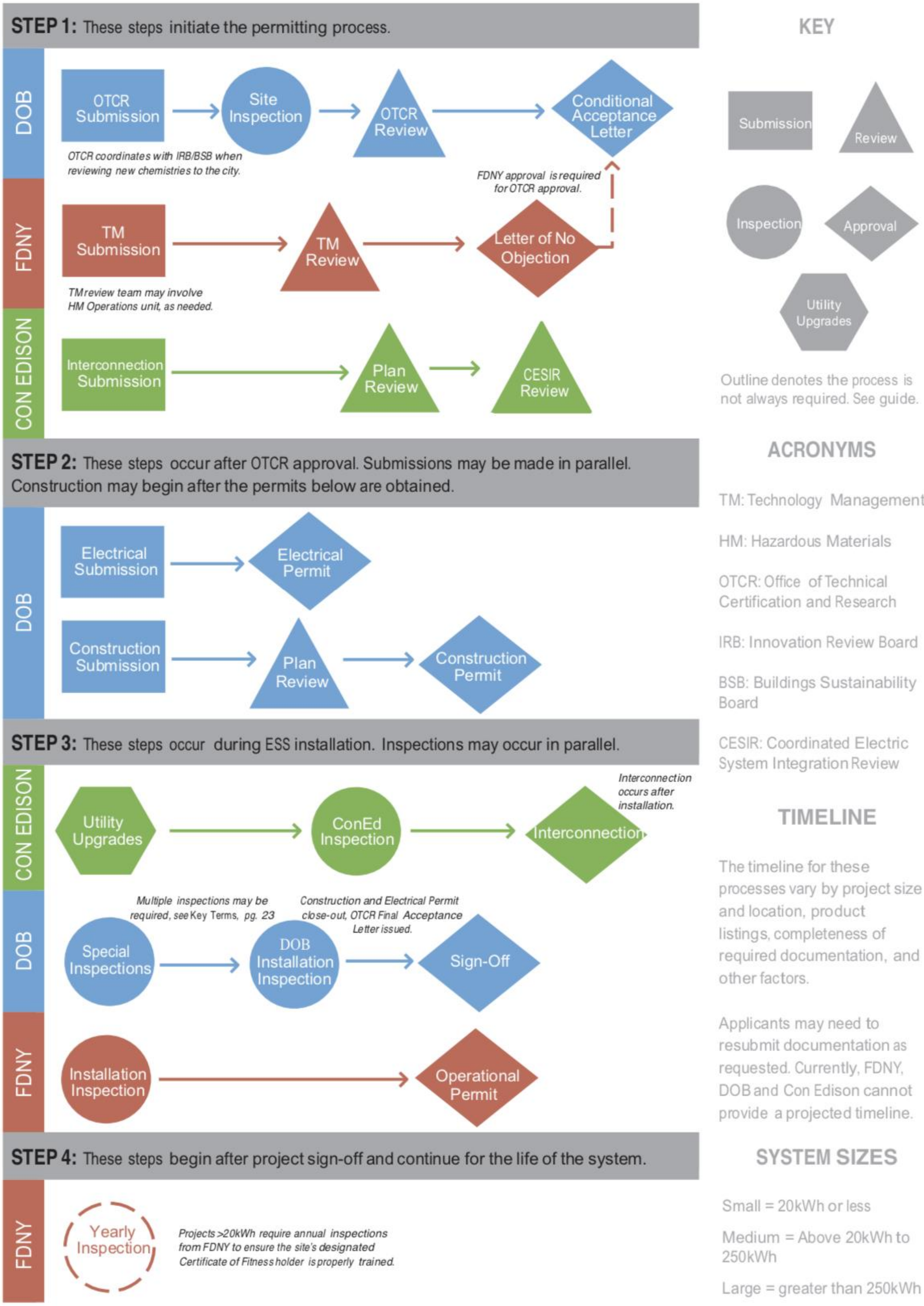

Figure 44. NYC Permitting and Interconnection Process for Medium ESS (>20 kWh - <250 kWh)[137]

These resources effectively prepare developers for what to expect from the development process, thereby reducing risk and, ideally, reducing the system costs by ensuring all the appropriate safety approvals are expediently obtained.

Resources and References

Organization	Resource/Reference	Description	Link
NFPA	*Energy Storage and Solar Systems Safety Training*	Online (free) and classroom (at-cost) training program focused on fire fighter training for ESS.	Link
NFPA	*Battery ESS Quick Reference Guide for First Responders*	Two-page reference sheet for ESS emergency response procedures.	PDF
Electric Power Research Institute	*Energy Storage Integration Council website*	Collection of resources for utilities including RFP guide, technical specification template, test manual, and commissioning guide.	Link
Sandia	*Energy Storage Safety Collaborative website*	National working group for ESS safety, includes regular email updates on codes and standards, workshops, and many related resource links.	Link
Sandia	*Fact Sheet for Code Officials*	Short overview of energy storage technologies, codes and standards, and research and development for code officials.	PDF
Sandia	*Fact Sheet for Fire Service*	Short overview of energy storage technologies, codes and standards, and research and development for fire officials.	PDF
NYSERDA	*Energy Storage Permitting and Interconnection Process Guide for New York City: Lithium-Ion Outdoor Systems Guide*	Guide for developers wanting to interconnect and install projects in New York.	PDF
Energy Response Solutions	*Matthew Paiss*	President	Email
NFPA	*Michael Gorin*	Program Manager, Emerging Technologies	Email
EPRI	*Ben Kaun*	Program Manager, Energy Storage	Email
Sandia	*Summer Ferreira*	Principle Member of the Technical Staff	Email

4.4 Uniform Permitting Processes

The decentralization and relative autonomy of permitting authorities can result in variable permitting processes across a state. Some jurisdictions, such as New York City, require over a dozen steps from application to approval, whereas some areas may not require an ESS to obtain any permits at all. This variability presents challenges for AHJs, project developers, and customers.

When AHJs with no existing permit process are presented with an unfamiliar technology, they may either let it pass unchecked, take an arbitrary amount of time to check its safety without any standardized approach, or disallow it entirely. Each scenario is undesirable and prevents the safe development of energy storage systems and the advancement of the energy storage market.

Project developers who trying to offer customers the lowest cost project with reasonable installation times must build permitting costs and timelines into their financial and project development models. An uncertain permit process results in uncertainty and risk, which will consequently increase the cost of the project for the customer. The New York Public Service Commission (PSC) found that so-called *soft costs* (i.e., permitting, interconnection, and customer acquisition) can account for up to 20% of total system costs.[138]

Customers rely on the AHJ to provide an objective assessment of a project's safety in order to purchase with confidence. If an AHJ is unfamiliar with a technology and has not established a comprehensive permitting process and inspection checklist, the AHJ cannot be certain that a project – and the customer - is safe.

States seeking to address this uncertainty should ensure that appropriate (but not unreasonably onerous) permitting processes are developed by AHJs before significant energy storage deployment is expected. Outreach regarding permitting processes can be accomplished in conjunction with AHJ stakeholder education on technologies, use cases, and safety considerations. Some states, such as California and New York, have developed guidebooks specifically for municipal AHJs to utilize in developing their own processes. The likelihood of rapid consideration and adoption of guidebooks, model permits, and inspection checklist templates by AHJs is increased if it is paired with 1) AHJ group training sessions that introduce and explain the developed tools held in different regions, and 2) AHJ technical support services provided by the state or hired experts.

State Example

New York has a unique, safety-oriented market because of the plethora of high-rise buildings, as well as the technical expertise and engagement of the Fire Department of New York (FDNY) in evaluating emerging technologies and risks. To build consensus around ESS safety best practices, the New York State Energy Research and Development Authority (NYSERDA) supported large scale ESS fire testing (with guidance from FDNY and ConEdison), developed a suite of permitting resources, and spent millions of dollars in grants to reduce energy storage soft costs.

Although FDNY is still working with stakeholders to develop rules for indoor ESS in NYC, NYSERDA's effort led to the recent announcement of a 1,500 MW energy storage target by 2025 based on an Energy Storage Roadmap. The roadmap recommendations were launched through a PSC Order, and included directions for NYSERDA to develop model procedures and permitting guides. These resources are now available (See *Resources and References*) and are intended to support AHJs from municipalities across New York State to develop their own processes based on best practices and safety considerations stemming from NYSERDA's work.

Resources and References

Organization	Resource/Reference	Description	Link

[138] Source: New York Public Service Commission, 2018 Order Establishing Energy Storage Goal and Deployment Policy Source: New York Public Service Commission (2018). Order Establishing Energy Storage Goal and Deployment Policy. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bFDE2C318-277F-4701-B7D6-C70FCE0C6266%7d

NYSERDA	*New York State Battery Energy Storage System Guidebook*	Collection of resources for AHJs and municipalities, including editable model ESS law, inspection checklist, and permit.	Link
California Governor's Office of Planning and Research	*Solar Permitting Guidebook*	Resource for AHJs to develop more efficient processes for solar permitting while still ensuring safety (energy storage guidebook is in development).	PDF
PNNL	*ESS Safety: Plan Review and Inspection Checklist*	Model inspection checklist based on Sandia/PNNL Energy Storage System Guide for Compliance with Safety Codes and Standards	PDF
NYSERDA	*Jason Doling*	Program Manager, Energy Storage	Email

4.5 End-of-life Disposal and Environmental Considerations

In addition to safety considerations during operation, many types of energy storage technologies – particularly batteries -- also contain hazardous chemicals that must be safely disposed of or recycled at their end of life to avoid environmental contamination. To date, the overall deployment of grid-tied battery storage facilities remains small and recent. As such there has been relatively little experience with end-of-life disposal issues within the industry. However there are efforts under way to address these concerns and develop best practices.

For example, in March 2019 the Energy Storage Association launched the Energy Storage Responsibility Initiative, through which many of the industry's leading corporations and institutions became signatories to a Corporate Responsibility Pledge.[139] Among the activities of this initiative are a Task Force designed for participants to establish best practices in the areas of potential operational hazards, end-of-life and recycling, and responsible supply chain practices.

As mentioned previously, Li-ion is one of the fastest growing technologies in the energy storage industry. According to the National Academy of Sciences (NAE), "Lithium-ion batteries are generally significantly less toxic compared to lead-acid and nickel-cadmium batteries (Pistoia et al. 2001), but they are nonetheless associated with environmental impacts. These include resource depletion (Notter et al. 2010), energy waste, and risks of land and groundwater pollution leading to ecotoxicity and human health impacts (Kang 2012)."[140]

Options for Li-ion batteries at end-of-life include reuse, remanufacturing or refurbishment, refunctionalization, recycling and recovery of materials, and ultimately disposal. A review of these options and their viability under different circumstances can be found in the NAE's report, "Lifecycles of Lithium-Ion Batteries: Understanding Impacts from Material Extraction to End of Life."[141]

[139] Source: ESA http://energystorage.org/energy-storage/energy-storage-corporate-responsibility-initiative
[140] Source: National Academy of Sciences 2018 https://www.nae.edu/181102/Lifecycles-of-LithiumIon-Batteries-Understanding-Impacts-from-Material-Extraction-to-End-of-Life
[141] Ibid.

4.6 SCC and DEQ Jurisdictional Issues

Currently, there is a lack of clarity over whether the siting of battery storage projects would require explicit approval from either the SCC, or the Department of Environmental Quality (DEQ), or both. Under the SCC, all Generating Facilities greater than 5MW in capacity are required to obtain a Certificate of Public Convenience and Necessity (CPCN),[142] which could apply to utility-scale storage facilities. The DEQ is required to develop regulations that use a Permit by Rule (PBR) for small renewable energy projects less than or equal to 150MW in capacity, which would apply to almost all energy storage facilities (including residential projects).[143] **However, no such DEQ PBR for energy storage currently exists.**

Additional clarification on the necessary documentation and approval by the SCC and DEQ for energy storage installations is needed. Given the current scope of the CPCN and DEQ, these may differ for large-scale, utility-owned projects versus third-party, distributed but aggregated projects. This is a threshold issue for enabling robust project deployment going forward.

However, the current regulatory processes may be able accommodate for these issues. For example, energy storage may potentially be added to the PBR process during the revisions to rules occurring in late 2019.

Chapter 5: Market Barriers to Energy Storage Deployment in Virginia

While the analysis presented in Chapter 3 identifies the potential for energy storage in Virginia, this does not mean that the benefits will be necessarily be realized within today's market environment. A variety of market barriers exist that may prevent the full amount of cost-effective storage from being deployed in the Commonwealth. Below are a few of the potential market barriers to greater storage deployment in Virginia. Chapter 6 discusses some potential solutions that correspond to each of these barriers.

5.1 Limited Local Industry Experience to Date

Aside from pumped hydro and a few small demonstration projects, there has been limited deployment of advanced energy storage technologies in Virginia. Any time an emerging technology such as advanced energy storage attempts to enter a new market, there are often hurdles that are non-technical in nature simply due to lack of overall experience among relevant stakeholders who include developers, financiers, utilities, system operators, regulators, and ratepayers. Overcoming barriers to achieve market transformation can often be more easily resolved through "learning by doing" as well as a careful analysis of what has worked, and more importantly, what has been challenging in other states. Potential solutions to this are discussed below in Chapter 6.

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142 Source: Virginia Administrative Code at 20VAC5-302-10.
143 Source: Department of Environmental Quality. https://www.deq.virginia.gov/Programs/RenewableEnergy.aspx.

5.2 Limited Renewable Energy Resource Requirements to Date

From a policy level, a major motivation for pursuing energy storage in many jurisdictions has been the notion that it will help advance a transition to a cleaner energy system. That is, storage is seen as an enabler of other clean energy technologies such as wind and solar. As such, clean energy policies themselves have served as an indirect driver for energy storage deployment.

States like California, New York, Massachusetts, New Jersey and Oregon, have established or proposed ambitious clean energy targets, which has provided a foundation for robust energy storage investment as well as complementary storage policies.

Currently, Virginia has in place a ***voluntary*** renewable portfolio standard (RPS) to encourage investor-owned utilities to procure a portion of the electricity sold in Virginia from renewable energy resources. The RPS goal is for 15% of base year 2007 sales to come from eligible renewable energy sources by 2025. However, this target is voluntary and is weak compared to other states, several of which have implemented 100 percent clean energy objectives in the last year. As such, Virginia's clean energy policies historically have not served a significant factor in advancing additional storage deployment, and under the current structure, and not anticipated to advance progress without significant changes.

More recently, SB 966 established that 5,000 MW of utility wind and solar was in the public interest, and Dominion Energy Virginia's 2018 IRP included up to 6,400 MW of clean energy resource by 2033 in most of the scenarios it modeled as part of its resource plan. Additionally, technology companies moving to Virginia are further driving demand for clean energy resources. For example, Amazon Web Services has contracted for 260 MW of solar in Virginia by the end of 2017, and Microsoft announced plans for a 500 MW project in March of 2018.

Between state policies and customer interests, there is increasing demand for clean energy resource deployment in Virginia. In many instances, wind and solar are now more economic than other forms of generation, while at the same time eliminating concerns of long-term fuel price volatility and preventing adverse environmental impacts. Moreover, the preponderance of resources proposed for development Virginia's interconnection queue are wind and solar. To the extent these resources will require additional integration capabilities, additional energy storage resources may be needed. One potential solution to this would be to establish new or modified clean energy requirements, including those for storage. This is discussed below in Section 6.2.

5.3 Lack of Robust Evaluation Tools & Processes

In general, modern storage technologies have not played a major part in traditional approaches to evaluating the needs for new generation, transmission, and distribution infrastructure. Many new technologies such as storage can serve the same needs as traditional grid assets. Therefore, it is important to ensure they are being given due consideration in planning processes, and that they are chosen by utilities where they do represent more efficient and cost-effective solutions. In some cases, the traditional approaches of value quantification offer an incomplete assessment of the value streams and potential use cases for storage. This means that new tools, methodologies, and processes may need to be developed or implemented to properly evaluate storage for grid planning purposes. This pertains to storage resources considered for both distribution system benefits (e.g. through grid transformation planning) as well as on the generation side (e.g. integrated resource planning). Solutions to these challenges are discussed below in Sections 6.5 Enhance the Generation Resource Planning and Procurementand 6.6 Enhance the Distribution Planning and Procurement Processes to Ensure Thorough Consideration of Storage Options

5.4 Limitations in Utility Procurement and Cost Recovery

In general, distribution utilities have a disincentive to seek solutions (including storage as a non-wires alternatives) that may lead to lower overall capital expenditures. This is due to the fact that cost-of-service regulation inherently provides an opportunity for utilities to earn a stable rate of return on any incremental new capital investments. As such, a utility may not be motivated to pursue storage options even if they are lower in cost than traditional solutions.

Alternatively, utilities may have an incentive to pursue incremental investments on the distribution system (including storage) for which they are able to take an ownership stake and earn a return on capital.

In either case, there is no specific framework in Virginia for determining when certain storage investments are beneficial and in the public interest and should be authorized (i.e. by the SCC) for procurement and/or cost recovery.

SB 966 has provided a pathway for utility deployment 40 MW of storage in the form of pilot programs, but beyond these there is no clear path. Moreover, while SB 966 has determined that a certain amount of renewable energy is "in the public interest", it is silent on the potential procurement of energy storage in conjunction with these renewables. Such procurement could provide synergies in terms of reducing the ultimate costs of storage deployment within the Commonwealth. Potential solutions to these challenge are discussed in Sections 6.3 and 6.6 below.

5.5 Lack of Retail Customer Programs Tied to Grid Services

As discussed previously, there are a variety of grid services – both at the wholesale level and at the distribution level -- that could be provided by behind the meter storage assets but lack a clear pathway for doing so. At the wholesale level these likely require some mechanism for aggregation (e.g. through FERC Order 841) either by the distribution utility or a third party. While options like Dominion Energy Virginia's Non-Residential Distributed Generation program do exist, they are limited in nature and are not specifically tailored to storage. For distribution level services, the provisions of Order 841 do not apply and thus there is no incentive or ability for customers to provide these services in a meaningful way even through aggregation. Solutions to these challenges are discussed below in Section 6.6.

5.6 Lack of Retail Rate Options that are Clearly Tied to Grid Benefits

Retail choice laws in Virginia significantly limit what a competitive service provider is allowed to offer, and who it can offer to. Competitive supply is only available for non-residential customers, it requires aggregation if those customers are less than 5 MW, and competitive suppliers can only offer 100% clean energy if a utility does not do so. These limitations act as a barrier to entry for new service providers and for customers seeking more sophisticated rate options that can yield both bill savings and reduce grid costs. Limited retail choices also inhibit opportunities for competitive service providers that may be able to offer peak shaving opportunities and tailored product offerings that could benefit storage.

Even in the absence of more retail choice options, the prevailing retail rates in Virginia do not necessarily reflect a robust representation of grid cost drivers – and as a corollary, the benefits associated with avoiding these costs. More sophisticated retail rate options that capture these costs and benefits could facilitate more storage and are discussed below in Section 6.9 Enact Retail Rate Reforms and Implement Utility Customer Programs.

5.7 Lack of Clarity on Regulatory Treatment for Multiple Uses

In Virginia there are multiple jurisdictional and service domains that energy storage resources need to navigate. It is possible for energy storage resources to simultaneously[144] provide services in the PJM markets, to the high-voltage transmission system, to the distribution system and the utilities that own and operate it, and to end-use customers. Thus, storage devices can function as a wholesale asset and be subject to federal jurisdiction or as a retail asset and be subject to state jurisdiction. Additionally, there are different interconnection requirements depending on where the resource is located and what it intends to do.

As energy storage technologies and the control systems that manage them evolve, they are demonstrating increased abilities to provide multiple services both within individual domains and across multiple domains. Such multi-use applications are critical to unlocking the value of storage assets and maximizing their cost-saving potential for Virginia ratepayers.

Overly cautious approaches to market access can place unnecessary limitations on a resource's ability to provide multiple services. Sometimes these limitations are necessary to preserve system reliability, prevent distortions in the markets, and to ensure resources are not receiving conflicting dispatch signals. However, sometimes these limitations are not needed.

5.8 Local Permitting & Interconnection

Cumbersome permitting and interconnection processes are a perennial barrier for distributed energy resource deployment and storage is no exception. These issues are discussed more thoroughly in Chapter 4 and solutions are recommended in Section 6.11 Seek Wholesale Market Improvements Through Participation in PJM Stakeholder Processes.

5.9 Wholesale Market Rules

Reforms to wholesale market rules, such as PJM's, fall under the jurisdiction of the FERC. Although Virginia has no direct control over the decisions made by FERC and PJM, the state may be able

[144] "Simultaneously" in this case refers to the ability to perform multiple functions over several intervals of time. It is not always possible for storage to perform multiple functions at the same instant (though in some cases this may be possible).

to play an influential role in shaping these decisions. As such it's important to recognize what wholesale market barriers exist currently. Virginia's role in shaping these matters is discussed below in Section 6.11 .

5.9.1 Regulation

Although the regulation market that PJM implemented after FERC Order 755 was heralded as a success, the market has since been flooded with energy storage resources, which has driven down regulation prices, but has also led to some operational challenges and ongoing reconfigurations of the market design. The regulation market now represents a highly competitive market with persistent regulatory uncertainty as FERC and PJM decide on a reasonable path forward in an ongoing settlement proceeding.[145] Additionally, PJM determines whether it needs to propose new settlement procedures for regulation resources after FERC rejected its previous attempt, which focused on the relative benefits of faster regulation resources and not the amount of work they were doing.[146] Given these ongoing proceedings, the uncertainty associated with the eventual design for the regulation market creates the biggest barrier to further participation by energy storage. However, PJM has indicated its interests in moving the market towards a direction that requires longer durations for energy storage and assigns less value to their faster response times. While this will adversely affect the value of storage resources that are already in the market, it also makes it unlikely that new energy storage resources will be deployed with any significant reliance on regulation revenues until these issues are resolved.

5.9.2 Reserves

PJM's compliance proposal for Order 841 was designed to improve the ability of storage resources to provide reserves as they no longer need an energy schedule to do so, but it still requires them to go through an exception process to be a Tier 1 synchronized reserve resource. Similarly, storage resources must seek an exception to participate in the day-ahead scheduling reserve market, although this is the lowest value reserve product, and it is unlikely that storage resources would benefit from participating in this market.

PJM recently proposed to revise its reserve pricing to account for increasing variability on its system, especially when weather conditions or deviations from load forecasts require additional resources to meet demand.[147] While the filing may create a better pricing regime by consolidating and better aligning reserve products, and by implementing a demand curve for them that better supports the system needs, the increased penalty factors could create a disincentive for energy-limited resources like storage to provide reserve. Additionally, PJM's proposal was not supported by its stakeholders, making it unclear whether it will be approved by FERC, thereby creating uncertainty in the reserve market for any storage resources.

[145] Source: Order on Complaints and Establishing Technical Conference, March 30, 2018; 162 FERC ¶ 61,296.
[146] Source: Order Rejecting Tariff Revisions, March 30, 2018; 162 FERC ¶ 61,295
[147] Source: PJM Reserve Pricing Proposal, filed March 29, 2019; Docket No. EL19-58-000.

5.9.3 Capacity

As noted earlier, PJM's existing and proposed duration requirements in its capacity market create a barrier to storage technologies like batteries from being able to participate in the capacity market at their full rated capacity. While PJM received numerous comments opposing this proposal, and FERC has requested additional information regarding how the proposal recognizes the unique characteristics of storage resources,[148] it remains uncertain whether FERC will have sufficient evidence to reject the proposal based on the requirements of Order 841. If FERC is unable to do so, this will stand as a major barrier for the participation of storage resources in the capacity market.

5.9.4 Hybrid Storage + Generation Assets

An increasingly common application for storage resources, particularly large-scale batteries, is pairing them with renewable generation. Most common amongst these hybrid resources are solar plus storage facilities because, as described earlier, they are eligible for the investment tax credit if the storage asset charges via exclusive use of the solar production. Notably however, the federal investment tax credit is set to phase down from 30% in 2019 to 10% in 2022 and beyond for commercial systems.

Combining storage with wind or with solar and wind can also offer attractive operational advantages over traditional intermittent generation assets. Most of these hybrid resources to date have been contracted to sell their output directly to utilities to provide dispatchable clean energy that is available to serve system peak.[149] The declining costs in these technologies and their ability to be dispatched during periods of high wholesale prices are making their business case as a participant in PJM's markets increasingly attractive.

A weakness in PJM's markets, however, is the lack of a participation model for these hybrid assets. Rules for intermittent generation exist in PJM's markets, and the rules for storage are evolving under Order 841, but there remains a structural gap in the market for how these hybrid assets can participate. The uncertainty created by this lack of rules creates a barrier to these hybrid resources entering the market as it is unclear whether the rules for intermittent generation, all other generation, or for energy storage will apply to them. An example of this is capacity accreditation, where PJM allows wind and solar resources to define their capacity levels by reference to the resource's output during four summer-peak afternoon hours because they are incapable of being dispatched to a specific MW level of sustained output. In contrast, PJM has proposed to treat energy storage like fossil or nuclear generation because they can be dispatched to a specific output for a sustained amount of time. Hybrid storage-plus assets, while more dispatchable than traditional wind and solar, are still reliant on the availability of the wind and the sun, therefore making it unclear whether their installed capacity values will be established like intermittent generation, traditional generation, or somewhere in between.

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[148] Source: FERC Letter to PJM Requesting Additional Information, April 1, 2019, Docket ER19-469-000.

[149] See e.g. NV Energy Application Seeking Approval for Renewable Energy and Energy Storage Procurement, pp 68-75; Source: NV Energy Application Seeking Approval for Renewable Energy and Energy Storage Procurement,http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-6/30452.pdf; See also: Solar + storage projects to drive utility-scale deployment of batteries: Navigant

In addition to determining the capacity value of hybrid storage-plus resources, uncertainty also remains with respect to the participation model that applies to them, what types of physical and operational characteristics need to be considered in PJM's modeling and dispatch software, what ancillary services they are eligible to provide and how they will provide them, and what interconnection rules apply to these resources.[150] In addition to the fundamental rules regarding access to the grid and the wholesale markets, PJM must determine the applicability of market mitigation schemes and offer obligations, transmission charges, metering and telemetry, settlement, and all other rules that will be necessary to facilitate market participation. Moreover, these rules may need to account for the configuration of the assets as well. It is possible for hybrid assets that share a point of interconnection to be tightly coupled so that the storage can only charge off the generation it is paired with and loosely coupled so that the storage is also able to charge off the grid, and market operators will need to consider both. As these resources continue to gain a foothold in the markets, lack of clarity on these issues will continue to constrain their participation in the wholesale markets.

5.9.5 Storage as Transmission

In addition to participating in the organized markets, energy storage is also able to provide infrastructure services to transmission and distribution systems. FERC has approved the use of energy storage as a transmission asset in the past,[151] as well as issued a policy statement that clarified the ability of energy storage resources that are chosen as a transmission asset and are receiving cost-based rates to also receive market-based compensation.[152] Additionally, the Energy Policy Act of 2005 included energy storage technologies in its definition of "advanced transmission technologies" and encouraged their use to enhance the reliability, operational flexibility, and power-carrying capability of transmission and distribution systems.[153] FERC also required public utility transmission providers to consider non-transmission alternatives as part of their regional transmission planning processes as part of Order 1000.[154]

While policies exist that encourage the use of storage resources as transmission assets and non-transmission alternatives, these policies lack effective implementation thus far. To be considered a transmission asset or a non-transmission alternative, storage resources must be chosen in a transmission planning process, but it is unclear what services a storage asset must provide to be considered a transmission asset, and there are no existing cost allocation and recovery processes for non-transmission alternatives. Additionally, while the regional (PJM) planning process must select most efficient and cost-effective projects, there are no such requirements in local transmission planning processes. This may cause lower cost storage solutions to be overlooked,

[150] Noting that approval of PJM's compliance filing with FERC order 845 will help clarify some of the interconnection rules for hybrid assets. PJM's proposal is due on May 22.
[151] Source: Western Grid Dev., LLC, 130 FERC ¶ 61,056 (Western Grid), reh'g denied, 133 FERC ¶ 61,029, (2010).
[152] Source: Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, January 19, 2017; 158 FERC ¶ 61,051
[153] Energy Policy Act of 2005; PUBLIC LAW 109–58—AUG. 8, 2005; See SEC. 1223. ADVANCED TRANSMISSION TECHNOLOGIES and SEC. 925. ELECTRIC TRANSMISSION AND DISTRIBUTION PROGRAMS. Source: Energy Policy Act of 2005; PUBLIC LAW 109–58—AUG. 8, 2005; See SEC. 1223. ADVANCED TRANSMISSION TECHNOLOGIES and SEC. 925. ELECTRIC TRANSMISSION AND DISTRIBUTION PROGRAMS.https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf
[154] Source: Order No. 1000 requires that regional processes must give "comparable consideration of transmission and non-transmission alternatives...." (P 155).

which may be further exacerbated by a lack of requirements to consider storage in those local processes in the first place.

Without clear rules for when storage is transmission and when it is a non-transmission alternative, without due consideration in planning processes, and without cost-allocation for non-transmission alternatives, it will remain difficult for storage assets to be chosen to fulfill infrastructure planning needs. These represent the primary obstacles, but once they are resolved, implementation of FERCs policy statement on utilizing storage for multiple services will even further unlock the potential value of these resources.

5.9.6 DER Aggregation

Creating clear paths for potential sellers to participate in as many markets as possible fosters competition and enhances market liquidity. As the distributed energy resources proliferate on the grid, market access is critical to maximizing their value. Small distributed storage and generation assets have the same capabilities as their utility-scale counterparts, but RTO/ISO modeling and dispatch software becomes constrained and cannot reach timely solutions if the number of resources it needs to optimize becomes too large. To reduce the number of market participants, but still create opportunities for distributed resources to participate in the RTO/ISO markets, wholesale market operators must establish clear rules for DER aggregations. Such frameworks will enable the participation of resources that cannot by themselves meet the minimum size and/or performance requirements to participate in the PJM markets.

While FERC has proposed a rule that would facilitate the participation of DER aggregations in the PJM markets,[155] and PJM has also developed a framework for DER participation with its stakeholders, FERC has not issued a final rule and PJM has not filed its proposed framework for approval. Thus, participation of aggregated DERs in the PJM markets is still limited to demand response which can place limitations on the type, configuration, and location of DER that are able to participate. However, California has an existing framework for DER aggregations,[156] and a DER aggregation cleared the ISO New England capacity market for the first time this year,[157] which demonstrates that participation models for these types of resources are emerging around the country. Wholesale market revenue streams will become more available as the penetration of DERs increases in Virginia and in the PJM region, and as the rules regarding their participation in the wholesale markets are formalized.

5.10 Pumped Hydro Barriers

Pumped hydro facilities make up a large share of the grid-connected energy storage in existence today. Pumped hydro has been one of the predominate forms of energy storage over many

[155] Source: FERC Notice of Proposed Rulemaking; *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (2016).
[156] California ISO Distributed Energy Resource Provider Framework. See: Source: California ISO Distributed Energy Resource Provider Framework.http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx
[157] See e.g., Source: Utility Dive, Residential Solar Storage Breaks New Groundhttps://www.utilitydive.com/news/residential-solarstorage-breaks-new-ground-as-sunrun-wins-iso-ne-capacity/547966/

decades, and Virginia is no exception with the existence of the Bath County Pumped Storage Station.

However, the development of new pumped hydro is increasingly uncommon due to the limited number of suitable locations, environmental review processes, long development timeframes to other resources, and changing regulatory paradigms for cost recovery. Despite this, one proposed location for a new pumped hydro project is in Southeast Virginia. While the general concept of a new pumped hydro project in the region has been under consideration for some time, new details about a specific project proposal came to light as this report was being drafted and after the primary analysis was completed.

More specifically, Dominion Energy has narrowed the location of its proposed pumped hydro project to a site in Bluefield, Virginia (Tazewell County). It has also been estimated that the project's construction costs will be approximately $2 billion,[158] the development timeline is estimated to be approximately 10 years after approval (pushing commissioning to at least 2029 if not later), and the final project will provide about 850 MW of storage capacity.[159]

At the time this report was drafted, it was unclear how feasible a new pumped hydro facility in Virginia would be. As such the primary focus was on the fastest growing segment of today's energy storage market – i.e. batteries.

A more complete analysis of the cost and value of this pumped hydro project was not possible within the limited time and budget available for this report. However, due to the significant size and cost of this proposal, Strategen recommends that such an analysis could be part of a supplemental study to be completed in the near future.

At a high level, it is worth noting that the estimated Tazewell County project cost equates to about $2,353/kW in capital costs, with an assumed in-service date of 2029.

For comparison, the range of capital costs included in our analysis for a 10-hr lithium ion battery storage facility entering service in 2029 is about $1,656-2,832/kW.[160] This range reflects a high and low cost scenario, as well as anticipated cost declines in battery technology over the coming decade.

However, there are significant differences that make a simple "apples to apples" comparison between the cost and value of these resources difficult without further analysis:

- **Storage Duration**: Generally speaking, pumped hydro projects have a much long duration (typically 8 to 10 hours of capacity). While it is possible to construct long-duration battery systems, these are not as typical as shorter-duration systems, and would increase the overall project cost.
- **Project Lifetime**: Hydroelectric facilities are long-lived assets that are likely to remain for many decades (e.g. >40 years). Recent grid tied battery storage projects generally have estimated projects lives the 10-20-year range. It is conceivable that such a project

[158]https://www.bdtonline.com/news/massive-economic-benefits-bluefield-va-formally-endorses-dominion-energy-hydroelectric/article_2ba7beae-a377-11e9-a6fb-0b4d4b2c864d.html
[159]https://www.bdtonline.com/news/a-huge-step-forward-tazewell-county-only-site-in-consideration/article_906f249a-9237-11e9-afab-7bdee1f11a0e.html
[160] Based on the High and Low CapEx scenarios included in Figure 18.

will have a longer lifetime, but would likely need to include additional battery replacement costs to account for degradation over time.

- **Environmental Impacts**: Pumped hydro facilities have a significantly greater adverse local environmental footprint in terms of land use and water. Meanwhile, batteries may have an impact in terms of raw materials needed including certain rare metals.
- **Project Development Cycle**: As mentioned previously, the estimated development timeline for a major new pumped hydro project is about 10 years. This contrasts with battery projects which have much shorter development cycles and, in some cases, can be installed in under 1 year. This means that the benefits and costs that accrue from each type of storage facility may occur over very different timelines.
- **Locational Value**: The proposed pumped hydro project is relatively remote from the largest centers of electricity demand in Virginia. Thus, while it would contribute value to the overall power system, it is unlikely to be able to provide many of the location-specific grid benefits described in this report (e.g. distribution system deferral). In contrast, smaller distributed energy storage projects, which could include battery storage, may be able to provide enhanced locational value.

Chapter 6: Recommendations & Policy Actions

Creating a robust policy environment that fosters energy storage investment and integration can be done in many different ways. Policies and programs that target energy storage resources specifically can help foster the industry, but it is a higher priority to make sure those initiatives are taken in a way that complements the Commonwealth's other clean energy policies and long-term energy objectives. New storage technologies are fast-responding and highly controllable assets that are quite versatile in the services they can provide. As such, they not only offer performance enhancements over traditional assets, which can make the power system operate more reliably and at lower cost, but they also can serve as a precision tool that enables other energy policies such as clean energy integration, grid modernization, enhanced resilience and reliability, better utilization of existing resources, or lower costs for consumers. Crafting policies for energy storage that fit within Virginia's vision for its energy sector will help transform the power system into one that is efficient and cost effective for customers large and small, and that helps continue to attract jobs and businesses to the Commonwealth.

State Level Strategic Actions

6.1 Establish a Storage Procurement Goal or Target

One option for accelerating the market for advanced storage systems is to establish a required procurement goal or target. Several states have recently taken this approach. For example, California required its investor-owned utilities to procure 1,325 MW of energy storage by 2020 and has since expanded that by another 500 MW. New York established a statewide target for 3,000 MW of storage deployment by 2030 and have adopted a variety of complementary policies to achieve this. Similarly, Oregon, Massachusetts and New Jersey both have energy storage procurement goals.

Storage procurement requirements and targets, especially coupled with other state and federal incentives,[161] have been key factors in the rapid commercialization and growth of the storage market in other jurisdictions. They create certainty of demand for energy storage technology providers and developers and help to drive down costs of the technology and maximize its value as it reaches full commercial scale.

If Virginia's goals include the acceleration of the local energy storage industry, then establishing a numerical procurement target would be an effective policy step towards that goal. Ideally the specific numerical target would be linked to an amount of storage determined to cost effective or in the public interest. Based on the analysis conducted in Chapter 3, a minimum **storage deployment target of at least 1,000 MW by year 2030** would be consistent with an approach that maximizes net benefits for the Commonwealth.[162]

[161] For example, direct state incentive programs, like the California Self Generation Incentive Program, and federal incentives like the federal ITC for coupled solar plus storage systems.
[162] Assumes the "low-cost" scenario could be achieved by pairing storage with renewables (thus providing federal tax incentives) as well as through technological advances.

Of the scenarios analyzed, Strategen believes there is a strong likelihood that the "low-cost" scenario could be achieved by pairing storage with renewable (thus providing federal tax incentives) as well as through technological advances. Under this scenario, storage deployments ranging from 961 MW (1hr duration) to 1,123 MW (2hr duration) were found to maximize net benefits in the year 2029. We estimate that the lower end of this range could exceed 1,000 MW by 2030 due to additional cost declines.

Establishing a numerical target would be similar in many ways to the recent legislation (SB 966) establishing that 5,000 MW of renewable energy resources is in the public interest.

In addition to setting an overall target, the state should also include other parameters to ensure that the storage being deployed covers a broad range of market segments and that the projects deployed are selected to maximize benefits to the Commonwealth.

This would likely include a process for thoughtful selection of locations and applications for storage projects as well as a methodology to evaluate benefits to utilities and their ratepayers. These decisions can also be made incrementally, with the amount of investment ramped up over time. Moreover, it is possible to rely on the utilities, who know their systems better than the regulators, to perform locational analysis, so that storage deployment can be done more strategically. As part of this strategic deployment process, the overall storage target can be divided into sub-categories, whether by point of interconnection, application, or both. Creating sub-categories by application (e.g. non-wires alternatives, storage-as-transmission, peaking capacity, peak demand reduction), rather than by point of interconnection, could further target the state-specific key areas of value and need for the Commonwealth. These concepts are further addressed below in Section 6.4.

In addition to providing some prescriptive guidance on the locations and applications for storage, regulators must also consider potential ownership models and how they may be linked to any obligations under the target (e.g. which portion of the goal should be utility-owned and operated versus third-party owned and operated).

Finally, establishing a storage procurement target could also effectively be accomplished through modifications to existing statewide goals. For example, through the implementation of Virginia's existing 5,000 MW renewable energy goal, a certain portion could be further required to deliver energy during hours of peak energy demand. Placing a time value on clean energy could in turn promote coupled renewable plus storage projects designed to shift wind energy generated over night or solar energy generated midday to the morning and evening peaks. In doing so, it would ensure that renewable generation is reducing the need for generation to meet peak loads, which can often be more expensive, less efficient, and contribute greater environmental impacts. While the wholesale markets already put a time value on energy, they do not value the environmental attributes of energy, nor do they value the additional benefits to the distribution system by avoiding peak demand.

6.2 Convene a Statewide "Storage Issues Forum"

Not only is Virginia home to new and established storage companies (e.g. Fluence), but is also home to a number of important federal agencies (e.g. DoD), national trade associations (e.g. EEI, NRECA), and other interest groups that may have unique insight and visibility into a wide range of issues likely to emerge as the industry evolves. As such, it is recommended that the state convene a "Storage Issues Forum" on a regular basis to allow key stakeholders to identify challenges and opportunities for the storage industry going forward, both within Virginia's own economy, but also more broadly across the U.S. and internationally.

This Storage Issues Forum could be used as an opportunity to revise and update the analyses presented in this study, as technologies evolve and system needs change. For example, one technology-specific question is whether policies could increase the demand for longer-duration storage options, which could be fulfilled by thermal storage or flow batteries as those technologies mature, among other options.

6.3 Develop a Strategic Plan for Accelerating Microgrid Deployment to Enhance Resilience at Critical Facilities

Two key factors make Virginia a prime area for microgrid development. One is the significant presence of Department of Defense (DoD) facilities. Microgrids can advance DoD's interests by enhancing the energy security and resiliency of mission-critical facilities. Second, as a coastal state, Virginia is susceptible to major catastrophic storms and hurricanes. Microgrids can help provide resiliency and a means of backup power in the event that there are significant outages, especially for critical infrastructure and emergency services (police and fire departments; hospitals and shelters) within vulnerable communities. Due to these and other factors, it may be beneficial for Virginia to accelerate the development of microgrid functionality for critical facilities. We recommend that Virginia develop a statewide **strategic plan for accelerating microgrid deployment**, which would necessarily include a significant energy storage component. Part of this strategy could include various "make ready" provisions, whereby utilities could make investments to enable microgrid-specific infrastructure (e.g. interconnection requirements, controls network architecture, grid disconnection protocol) and facilitate microgrid development.

Part of this strategic plan would be the identification of critical facilities where storage can help provide resilience benefits. Another key aspect would be providing tools and best practices to local jurisdictions that could develop their own microgrid capabilities. For example, many cities are now implementing storage or solar plus storage in government buildings as a means to prepare for natural disasters such as earthquakes, wildfires, and storms.

Utility Planning and Procurement

6.4 Move Beyond Pilot Projects Towards Larger Commercial Scale Project Deployments

Aside from the Bath County Pumped Storage Station, Virginia is in the early stages of energy storage adoption. This suggests that the approach to integrating energy storage, particularly the newer technologies like large scale batteries, should be measured both in terms of experience and appetite for the technology, but also in terms of its overall maturity and the lessons that can be learned from other states and countries that have greater experience with the technology and policies for its adoption. Because Virginia has limited experience, incubation programs that provide education and grants for studies and analyses are a useful first step. However, there are a significant number of pilot and demonstration projects implemented throughout the U.S. that Virginia could learn from. As such, it may be appropriate to bypass more preliminary deployments and focus on more commercial scale projects that leverage lessons learned from existing pilots deployed elsewhere.

While Virginia and potential adopters of energy storage in the Commonwealth are in early stages, new energy storage technologies have reached commercialization in other jurisdictions and are being deployed as cost-effective and reliable grid assets. Education and technology demonstration programs are important but given the state of the industry establishing additional programs that will help deploy energy storage at scale will also ensure that Virginia is able to enjoy the benefits that storage resources can provide. As discussed further below, this type of program can include procurement targets and/or mandates for storage, grid modernization and other regulatory reform that ensure that Virginia is deploying these assets in a meaningful way that will help create jobs and improve the energy sector in the state, but also that set an example for the rest of the country and the world on how to effectively design policies for energy storage integration.

Providing funding for a comprehensive meta-analysis of nationwide energy storage and demonstration projects is an excellent means to catalyze storage investment in Virginia. It allows potential adopters to determine what use cases may work best for them and how to optimize an asset for their purposes. Additionally, funding for pilot and demonstration projects also provides valuable experience related to owning and operating storage assets. By making the projects more affordable for early adopters, the investment becomes less daunting, the investors can learn how to utilize the resource by actively managing it, and they are able to validate and improve upon various energy storage applications for future projects. Moreover, demonstration projects engage investors in the sector, facilitate energy storage development experience, and help to identify and resolve any barriers that may exist to storage deployment on Virginia by facilitating engagement on projects.

The Grid Transformation and Security Act of 2018 established requirements for the utilities to propose new pilot programs, of up to 40 MWs of energy storage, however they are only applicable to Dominion Energy Virginia and Appalachian Power. It should be noted that Dominion Energy Virginia proposed on August 2, 2019 to implement three new pilot programs totaling 16 MW.[163] Enabling pilot projects with the IOUs is a sensible initial step, however additional deployments are likely needed to allow residential, commercial and industrial customers, municipal and rural cooperative utilities, as well as independent power producers and distributed energy resource aggregators to investigate and invest in projects to further prove the technology will help accelerate education and adoption. These deployments could target specific use cases for projects, including retail applications such as demand charge reduction and time-of-use bill management for large retail customers. Additionally, other models can be explored such as aggregations of customers for demand response and/or non-wires alternatives, and community resiliency that can be enabled by solar self-consumption and backup power. These demonstration

[163] Source: Dominion Energy Virginia's August 2, 2019 filing at the Virginia State Corporation Commission (VA SCC) for approval of three battery pilot projects, http://www.scc.virginia.gov/docketsearch/DOCS/4%244301!.PDF

projects can also help test various ownership and procurement models for storage, while also benefiting from lessons learned via other existing demonstration projects.

Establishing clear program goals, requiring some customer or third-party cost share, and providing sufficient funding are all critical to the success of additional commercial deployments. In addition to direct investment in energy storage projects, programs can also include related economic development funding such as improved investment in and tax incentives for energy storage companies, workforce development grants for the industry, and university funding for related programs and activities. Performance-based incentives are also a useful tool as they help bolster program success over time, and effective tracking mechanisms both in term of direct performance and incidental performance are also recommended. Energy storage projects bring a lot of value in terms of the services and use-cases described in this report, but energy storage also offers numerous incidental benefits such as reduced outages, job creation, reduced land use, fewer utility service calls, and others that can be experienced with well-designed programs and well-coordinated strategies.

6.5 Enhance the Generation Resource Planning and Procurement Processes to Ensure Thorough Consideration of Storage Options

6.5.1 Integrated Resource Planning

Virginia's utilities are required by statute to file an Integrated Resource Plan (IRP) with the State Corporation Commission (SCC) every three years. The IRP provides the utility's plan of which generation and other resources will be used to provide reliable service to its customers over the next 15 years. Notably, the SCC recently rejected Dominion Energy Virginia's 2018 IRP, in part because it did not include the 30 MW battery pilot project that was required by SB 966, the Grid Transformation and Security Act.

Going forward, it will be critical to ensure that storage is included and properly modeled in any future resource plans developed by Virginia utilities. Prudency determination rules at the Commission could be revised to ensure that when investments are proposed, there is an adequate showing of alternatives analysis. Specifically, storage should be able to compete on a level playing field with other resources when being considered for selection in an IRP. Since energy storage is an emerging technology, many legacy tools used for IRP analysis do not have robust methods for evaluating storage. As such, these tools may need to be updated or supplemented. For example, future IRP scenarios should be required to run their model (PLEXOS) using sub-hourly modeling data. This would further highlight the value for battery storage that is not represented when modeling at hourly intervals.

Furthermore, since costs of storage are rapidly declining, it will be important for any future IRP process to include assumptions regarding storage costs that are as up to date as possible. To address this, the SCC could issue guidance or amend its rules on Integrated Resource Planning to ensure that storage is appropriately treated in the resource planning process. In addition to this study report additional training and education on energy storage is recommended for the SCC Staff, in time for the staff to appropriately evaluate the next IRPs in May 2020.

6.5.2 Resource Procurement

In states where utilities are vertically integrated and own their generation, there can be a tendency to bias towards traditional generation investments. As such, state regulators should consider whether storage could be a feasible, and less costly alternative to any conventional resource being proposed. Any analysis conducted in this regard should also consider the potential for storage to provide multiple values or revenue streams, which can help to offset the initial cost.

Additionally, another approach to help level the playing field between storage and other resources is to ensure that any solicitations held for new resources are "all source" solicitations, meaning that several types of technologies can effectively compete to provide the identified system need, regardless of what that need is. This is particularly relevant for proposed new resources that may have capabilities similar to large scale storage system, such as new natural gas peakers.

6.5.3 Renewable Energy and Hybrid Resource Procurement

As described in this report, energy storage offers many complementary characteristics to renewable generation, so one way to further encourage energy storage investment and to benefit from energy storage projects is to increase clean energy objectives for the Commonwealth. Virginia's current 15% voluntary renewable portfolio standard is very modest, and it does not identify a quantity of renewable generation that is cost effective for the state or that is even being developed in the state. Interconnection queues in Virginia are full of wind and solar resources and the GTSA has identified up to 5,000 MW of wind and solar in the public interest. One option for increasing storage deployment would be to increase the state's RPS or clean energy goals and enable storage to be procured in tandem with this deployment.

Another option for Virginia would be to include storage as part of the 5,000 MW target that the GTSA identifies for wind and solar. Many states and utilities have taken this approach with large renewable procurements. For example, Florida Power and Light recently announced the deployment of a 409 MW battery project that is being used to complement its 30 million solar panels by 2030 project. Similarly, in 2018, NV energy announced plans to procure 1,000 MW of solar and 100 MW/400MWh of storage as part of their clean energy objectives. When the solar is coupled directly with the storage these projects are eligible to receive the federal ITC, but they will be an operational necessity, whether co-located or not, as renewable penetration increases. To start planning for this high renewable future, Virginia could start setting aside part of its clean energy programs for storage plus renewable projects.

Finally, not only renewable resources are capable of being hybridized with storage. Existing natural gas generators can be retrofitted to include a hybrid battery storage component. This was recently accomplished at two plants in California and has led to significant operational improvements and efficiencies at the plants as well as reduced emission.[164]

[164] https://www.powermag.com/two-sce-gas-battery-hybrid-projects-revolutionize-peaker-performance/

6.6 Enhance the Distribution Planning and Procurement Processes to Ensure Thorough Consideration of Storage Options

Due to the significant potential for distribution system benefits of storage, it is recommended that the state establish a process, overseen by the SCC, for identifying and implementing these opportunities. This could occur through enhancements to an existing process such as the Grid Transformation Plans (discussed below in 6.4.1) or through a newly established grid planning process. This section describes some of the elements that could form the basis of a distribution system planning and procurement process that enables storage deployment. Two primary areas of focus within the broader distribution planning paradigm could include non-wires alternatives (described below in 6.4.2) and hosting capacity analysis (described below in 6.4.3). In either case, once the best opportunities are identified, corresponding procurement and cost recovery mechanisms would also be needed (described below in 6.4.4).

6.6.1 Grid Transformation Plans

Grid transformation is a term that can encompass a variety of meanings, but in general refers to investments made in distribution system technologies that provide enhanced capabilities to utilities and their customers.

In Virginia's case, the GTSA of 2018 acknowledged the potential benefits of "grid transformation projects" and deemed these to be in the public interest (though subject to review by the SCC). These projects are defined to include a variety of technologies, including certain energy storage systems and microgrids as well as advanced metering infrastructure, intelligent grid devices, automated control systems for electric distribution circuits and substations, communications networks for service meters, certain distribution system hardening projects, physical security measures at key distribution substations, cyber security measures, electrical facilities and infrastructure for electric vehicle charging systems, LED street light conversions, and new customer information platforms.

Under SB 966, Virginia also adopted a requirement for Dominion Energy Virginia and APCo to develop "plans for electric distribution grid transformation projects." The plans are intended to both facilitate integration of distributed energy resources and enhance grid reliability and security.

The GTSA also provides some incentives for Virginia utilities to make these investments. Namely, it allows Appalachian Power and Dominion Energy Virginia to file rate adjustment clauses for cost recovery of grid transformation projects and for the SCC to act on those filings within six months of the filing. Alternatively, the GTSA allows utilities to reinvest any overcollection of revenues into solar, wind or grid transformation projects instead of crediting them back to their ratepayers. Lastly, it requires them to consider grid transformation projects in their IRPs with the objective of reducing customers' bills. Thus, through the Grid Transformation Plan process, SB 966 provides a general framework for deployment of grid transformation projects, which could include energy storage. However, the GTSA did not establish a detailed process for how Virginia and its utilities should select grid transformation projects, nor did it specify the appropriate role of storage within these plans.

Notably, in early 2019 the SCC rejected most of Dominion Energy Virginia's proposed Grid Transformation Plan, stating that the cost to customers was too high, that the plan lacked sufficient detail, and that many of the investments proposed were not cost effective. **Importantly, storage was not a focus of Dominion Energy Virginia's proposed plan.** As a way to both improve the Grid Transformation Planning process and encourage energy storage, the state should consider providing additional guidance on the incorporation of energy storage resources within future plans. Ideally, this would include a robust process for identifying needs that storage could address, identifying locations that would best address these needs, and a cost-benefit evaluation of particular project or program proposals. Figure 45 below illustrates an example of the potential elements in an idealized distribution system planning process.

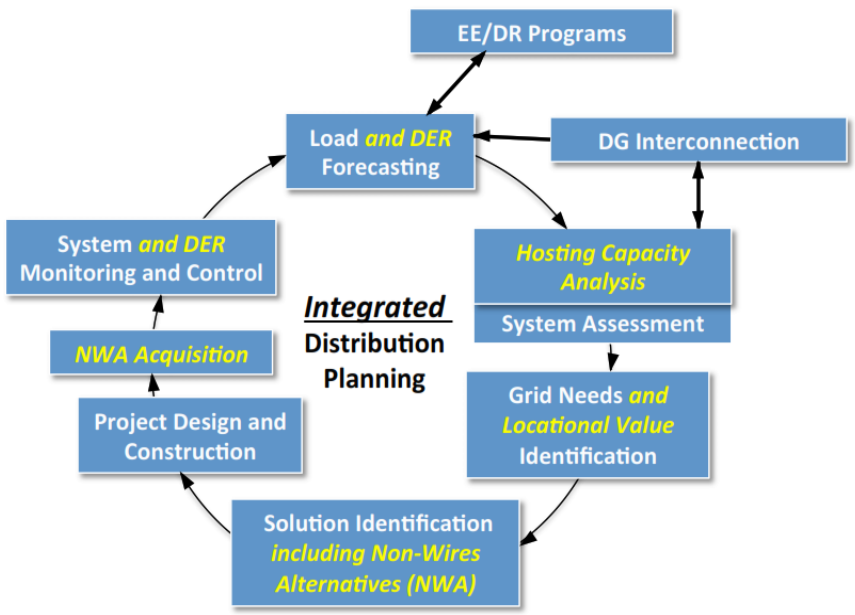

Figure 45. Integrated Distribution System Planning[165]

Some examples of potential needs in Virginia that might be considered for storage under future grid modernization plans might include:

- Distribution system deferral (i.e. non-wires solutions), which are discussed below in Section 6.4.2
- Avoidance of special protection scheme upgrades to accommodate remote, large-scale solar PV (see discussion in Section 2.2.4 Solar and Wind Integration)
- Avoidance of distribution system upgrades to accommodate distributed energy resources (i.e. hosting capacity)
- Backup power and improved power quality for critical customer loads

6.6.2 Non-wires Alternatives

As discussed, storage can provide benefits by deferring or avoiding distribution system upgrades thus providing a "Non-Wires Alternative." However, several steps are needed to ensure successful

[165] Source: Curt Volkmann, New Energy Advisors, 2018

procurement of Non-wires Alternatives (NWA). Virginia could consider adopting some or all of these steps as a means of achieving distribution system benefits via storage as an NWA:

(a) develop and implement a distribution system planning process (e.g. through Grid Transformation Plans) that enhances the transparency of distribution planning,
(b) improve information and transparency around locational net benefits on the grid,
(c) implement screening criteria for the consideration of non-wires alternatives;
(d) adopt protocols for solicitation and evaluation or NWA projects; and
(e) approval of standard offer contracts for the procurement of third-party owned NWA.

It is important to note that holistic distribution system planning is generally a requirement of effective NWA procurement because NWA cannot generally be procured in the reactive manner that, for example, replacing conduit or a transformer, can be.

As examples of best practices, Pacific Northwest National Laboratories recently compared several distribution system planning modernization initiatives in sixteen states throughout the country.[166] Three states were identified as leaders in the development of protocols for NWAs to address distribution system requirements: Rhode Island, New York and California. Roughly half of the states reviewed currently have proceedings underway, thus the final approaches had not yet been finalized as of the date of publication. Several states' approaches included protocols utilities to develop planning documents that identify opportunities within their service territories to defer traditional investments with NWA using both technical and practical (time, dollar value, etc.) screening criteria. Additional incentive programs have also been considered to ensure that utilities can be rewarded for selecting the most cost-efficient outcome for consumers, regardless of ownership structure. For example, California proposed a pilot that would provide an incentive to utilities that are able to "cost-effectively displace or defer traditional distribution system investments" through third-party DER providers.[167]

6.6.3 Hosting Capacity Analysis

Another component of a robust distribution planning process that could identify opportunities for storage is a hosting capacity analysis. Development of dynamic hosting capacity maps can provide public information to developers about the locational value of storage and other DER deployments. This has been especially important in locations that have high penetrations of rooftop solar PV, such as Hawaii and California, and where there have been limitations on the ability of the distribution sytsem to accommodate additional solar systems. This is likely less of a priority for Virginia since there has been very limited rooftop solar PV installed to date. However, it could be an important consideration if the penetration of distributed solar increases over time.

6.6.4 Procurement and Cost Recovery

Even if opportunities for beneficial storage are identified in the distribution planning process, they are unlikely to be implemented unless there is a clear mechanism for procurement and cost recovery. For example, utilities may not wish to pursue non-wires solutions over traditional distribution investments if this reduces the overall capital expenditures (and thus reduces

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[166] See: Source: PNNL, Distribution System Planning https://epe.pnnl.gov/pdfs/DSP_State_Examples-PNNL-27366.pdf
[167] https://www.cpuc.ca.gov/General.aspx?id=10710

investment opportunity for the utility). As such, an incentive or requirement for utilities to invest in these alternatives may be needed, which may necessitate regulatory or legislative reforms. One option would be to establish a requirement to pursue non-wires solutions that are found to be cost-beneficial.

For example, in New York, distribution utilities have conducted competitive solicitations for non-wires solutions (including storage) to a subset of distribution upgrades identified as part of their distribution system plannign process. Virginia could take a similar approach by requiring utilities to issue a Request for Proposals for non-wires solution opportunities that meet certain criteria.

Procurement of storage solutions for distribution benefits also necessitates a cost recovery mechanism. For example, the SCC could consider preauthorizing costs of non-wires solutions that meet certain criteria, regardless of whether the underlying asset is owned by the utility itself or procured through a contract with a third party provider.

6.6.5. Data Limitations

We recognize that for most locations on the distribution grid in Virginia, very limited data collection currently takes place (if any) of system loads. As such, there are inherent challenges to successfully identifying and deploying storage as a non-wires solution. However, there are still options worth considering and pursuing despite these limitation:

- Identify what voltage levels load data exists for and target deferal opportunities towards the lowest possible level where such data is collected.
- Identify locations with significant numbers of completed or requested distributed generation interconnections. These may be more likely targets for storage as a means to increase hosting capacity.
- Identify locations that require new or upgraded distribution equipment due to load growth.
- Consider deferral opportunities that could be unlocked if other data collection devices are deployed such as advanced metering infrastructure (AMI) or advanced distribution management system (ADMS)

6.7 Explore Ways to Support Economically Distressed Communities by Studying the Viability of New Pumped Hydro Projects

Historically, the Southwestern region of VA has been heavily reliant on coal as a major component of the local economy. In today's energy markets, the economic competitiveness of coal has deteriorated significantly due to the advent of low-cost natural gas, and as such, the coal economy in Southwest VA faces a very uncertain future. As the use of coal declines, many states have begun to explore policies to provide a just and equitable transition that would support affected communities. These policies have frequently included actions to spur investment in clean energy resources as a means of creating jobs and economic stimulus to communities who have supported to the Virginia economy for many decades. The opportunity to develop large pumped hydro projects in Southwest VA could serve as a core component of any transition package developed by the Commonwealth. This support could include direct financial assistance for these projects, as well as training and relocation services for project construction workers and plant operators.

However, as discussed in Section 5.10, additional analysis is warranted in the first place to better assess the relative cost and value of large pumped storage projects when compared to other energy storage and clean energy alternatives. Additional study work is warranted to better understand the relative economic value of such a resource including both the potential benefits it could provide both to the power system and to local communities, as well as the potential costs to Virginia electricity customers and the local environment.

Retail Rates and Customer Programs

6.8 Establish a Direct Incentive Program for Storage Projects

Several other states have established direct incentive programs to help achieve market transformation for energy storage technologies and accelerate cost reductions. These programs also are intended to reward early adopters for providing a variety of hard-to-quantify benefits, such as enhanced grid resilience, and can vastly accelerate broad market acceptance.

One possible option for providing an incentive is to establish a statewide tax abatement for storage projects.

Alternatively, funding for an incentive program could be collected from all utility ratepayers through a bill surcharge or rider. Direct incentive programs can also be structured in a variety of ways. For example, a simple upfront incentive can be provided simply as a way to accelerate market transformation and drive down technology costs. Alternatively, the incentive could be tied to specific performance or system benefit being provided.

Examples of direct incentive programs include California's Self-Generation Incentive Program (SGIP), which is a ratepayer-funded rebate program available to customers of the four California investor-owned utilities that supports existing, new, and emerging distributed energy resources.[168] New Jersey has the Renewable Electric Storage Program that provides financial incentives for electric energy storage systems that are integrated with renewable energy projects installed behind-the-meter at non-residential customer sites.[169] Maryland has its Game Changer competitive grant program that provides funding to energy storage projects that demonstrate a quantifiable reliability or resiliency benefit, an innovative application, and drive economic development.[170] Massachusetts also has its ACES (Advancing Commonwealth Energy Storage) program that awards projects that are aimed at piloting innovative, broadly replicable energy storage use cases/business models with multiple value streams in order to prime Massachusetts for increased commercialization and deployment of storage technologies.[171]

Key best practices from similar programs include establishing clarity of program goals and objectives, requiring customer or third-party cost share, and providing sufficient funding so the program can help achieve market transformation. Utilizing performance-based incentives and

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[168] Source: CPUC, SGIP See: http://www.cpuc.ca.gov/sgip/
[169] Source: NJ Clean Energy, Storage See: http://www.njcleanenergy.com/storage
[170] See: Source: Maryland Energy, Incentiveshttps://energy.maryland.gov/business/Pages/incentives/gamechanger.aspx
[171] See: Source: Massachusetts Clean Energy Center, Advancing Commonwealth Energy Storagehttps://www.masscec.com/advancing-commonwealth-energy-storage-aces

ensuring program certainty over time, both in terms of per project incentive amounts and program funding and duration are also recommended.

Key to the success of any incentive program is to establish clarity of program goals and objectives and ensure that program be modified or suspended if it fails to reach these objectives. For example, evaluation of California SGIP program revealed that the program was not achieving its intended goals for GHG emissions reduction and may actually be leading to increased emissions.[172] Additional program reforms have been considered and implemented since then to improve program performance.

It is recommended that programs include a customer cost share while also including sufficient funding so the program can help achieve market transformation. Importantly, an incentive program should be designed to be temporary in nature and would wind down over time as the market matures. Additional elements can also be incorporated such as specialized incentives for low-income residents.

6.9 Enact Retail Rate Reforms and Implement Utility Customer Programs

Creating a robust market for BTM storage deployment primarily depends on ensuring that retail customers are exposed to price signals that reflect the values that storage can provide to the energy system. Implementing reforms to retail rate designs and/or utility customer programs may be an avenue to encouraging greater adoption of customer-sited, distributed energy storage.

6.9.1 Retail Rate Reforms

Other than customers with loads greater than 5 MW, electricity customers in Virginia have no ability to choose between retail energy providers. As such, the prevailing retail rate options for customers of the major utilities (i.e. Dominion Energy Virginia and APCo) will have a significant influence on customer adoption of energy storage. Moreover, the specific design of these rates is critical to ensuring that the operation of BTM storage is aligned with broader grid benefits. There are two main components of typical retail rate designs that are particularly well-suited to encouraging storage deployment and beneficial charging/dispatch behavior:

- Time-of-use (TOU) volumetric $/kWh energy rates
- Time-varying $/kW demand charges

Deployment of BTM storage in other jurisdictions (e.g. California) has been largely driven by high demand charges that are offset by storage used to reduce consumption during peak hours. In both cases, the rates must be designed in a manner that is sufficiently targeted toward peak demand hours, and that it provides an incentive for customer adoption. In contrast, if for example, a TOU rate has insufficient differential between on and off-peak hours, it will be much less likely to incentivize storage.

172 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/2016-2017_Self-Generation_Incentive_Program_Impact_Evaluation.pdf

As illustrated in Chapter 3, Virginia utilities already offer large customer rates (e.g. GS-3 for Dominion Energy Virginia and LPS for APCo) that have significant demand charges. However, even these rate structures may be limited in terms of encouraging deployment of storage at scale. Additional modification of these rates, or incorporation of stronger time-varying price signals (beyond what is currently in place) into other rate classes may be beneficial for encouraging more energy storage. To accomplish this, the SCC to open an investigation into more advanced time-of-use rates and require that pilot rates be implemented if they are found beneficial.[173]

These energy storage rates (TOU, demand charge, and advanced rates) can also complicate customer's electric utility bills to the point of unintentional obfuscation. Therefore, along with these energy storage rates, a clear billing design is recommended. Utility bills should be itemized, with line-by-line breakdowns of all of the various demand and energy charges that customers are paying for. A supplemental page on each utility bill, with more detailed explanations of the various charges, the way that they are assessed, and their purpose would be greatly beneficial for customer transparency and understanding.

6.9.2 Expanded Utility Customer Programs

In addition to bill savings linked to retail rate design, utility customer programs can provide an additional source of revenue to reward customers who provide value to the grid by installing and dispatching storage devices.

Virginia utilities already offer some limited demand response programs to their customers, such as the Dominion Non-Residential Distributed Generation program. However not all customers may be able to participate in these programs, and the ability for storage resources to participate is unclear. Furthermore, the program's authorization is limited to five years. As such, existing program like these could be expanded or modified to better incorporate storage resources.

Additionally, these existing programs focus primarily on delivering wholesale energy and capacity benefits to the wholesale market. There are a variety of other potential system benefits that could be delivered by BTM storage devices for which additional customer programs could be developed, or existing programs could be modified to allow. This was illustrated in the analysis presented in Section 3.3. Scenario 2 examined a hypothetical case in which a new demand response program was offered to target local distribution system deferral benefits. Other utilities, such as ConEd in New York offer similar types of programs, in which customers can participate in simultaneously with other demand response programs focused on wholesale grid benefits. In principle programs like these could be offered by distribution utilities for customers who provide services in accordance with these needs.

[173] It should be noted that a broad multi-party stakeholder process facilitated by HB 2547 (2019) is currently under way that is intended to inform additional time-differentiated pricing options for Dominion Energy Virginia's residential customers.

Wholesale Markets

6.10 Adopt a Multiple-Use Application Framework

Like other modular or distributed resources, storage can function within many domains and under various ownership structures. For example, storage can function as a utility-owned grid infrastructure asset akin to transmission or distribution. It can also provide grid functions through third-party contracting mechanisms. Storage can also serve as a generation asset similar to demand response. Finally, it can serve as a load modifier, particularly for customer-owned deployments. As such, it may be important for state regulators clarify the regulatory treatment of storage under different use cases and deployment scenarios.

As discussed throughout this report, a major potential barrier to storage deployment is related to uncertainty regarding the ability of storage resources to benefit from multiple value streams both at the retail and wholesale levels. In more advanced storage markets (e.g. California), concerted efforts have been made to establish a framework for multiple-use applications. These frameworks can help provide clarity to storage providers about which value streams are able to be delivered at different grid interfaces, when certain value streams can be delivered simultaneously, when conflicts may arise, and what jurisdictions apply to certain capabilities. It will likely be important for Virginia to establish a similar framework to provide greater market certainty.

6.11 Seek Wholesale Market Improvements Through Participation in PJM Stakeholder Processes

PJM has a two-tiered governance structure that includes the PJM board of directors and the members committee. The board includes nine independent members who vote on final decisions regarding market changes and new programs before they are filed for regulatory approval. Each member of PJM has one representative on the members committee, which votes on issues and provides advice to the board.[174] The committee is made up of five sectors representing Generation Owners, Transmission Owners, Electric Distributors, Other Suppliers and End Use Customers. In addition to the member committee, PJM also has a number of permanent committees, user groups, subcommittees, and task forces that make decisions on individual issues and provide their recommendations to the members committee.[175]

Virginia and the SCC are part of the Organization of PJM States, Inc. (OPSI), providing a unique relationship to the PJM stakeholder process. This does not make Virginia or the SCC members of PJM, but does give them the right to participate, deliberate, give input, and engage at all levels of the PJM stakeholder process. Since they are not members, they do not get a vote, but they may individually elect to become a member and obtain voting rights.[176] Hence, for issues that may be important for the state, there are numerous ways for it to get involved in the PJM

[174] Source: PJM, Governance See: https://learn.pjm.com/pjm-structure/governance.aspx
[175] Source: PJM, Committees and Groups See: https://www.pjm.com/committees-and-groups
[176] PJM Manual 34, Section 4.4, Revision 07, Effective May 19, 2016 (Source: PJM Manual 34, Section 4.4, Revision 07, Effective May 19, 2016 See: https://www.pjm.com/-/media/documents/manuals/m34.ashx?la=en)

stakeholder process, all the way from early stage issue formation to later stage voting and approval of changes.

Regarding energy storage, most of the stakeholder work has recently occurred in response to Order 841. PJM staff developed the proposal (because it was required by FERC and not initiated *sua sponte*), but they did present the proposal to the Market Implementation Committee, Distributed Energy Resources Subcommittee, Operating Committee, Planning Committee, Markets and Reliability Committee, and the Members Committee. However, if Virginia, the SCC, or any other stakeholders want to be involved in the ongoing 841 compliance process, they will have to file any comments at FERC because PJM has already submitted their filing under Docket Number ER19-469-000.[177] This may allow stakeholders to participate in the ongoing debate over PJM's proposed 10 hour duration requirement, but for any other issues regarding energy storage in the wholesale markets, Virginia and its stakeholders should go directly to the relevant subcommittees, task forces, or general OPSI and PJM stakeholder meetings. The most relevant subcommittee is currently the Distributed Energy Resources subcommittee where PJM continues to deliberate issues related to some of the opportunities and barriers for distribution-connected and behind-the-meter energy storage resources discussed in this report.

An issue of primary concern that Virginia may want to provide input on is the PJM-proposed 10-hour storage duration criteria for capacity market valuation. For example, New York ISO recently proposed implementing a longer duration criterion for storage to receive full capacity market credit. This proposal was later revised, and full credit is likely to be given to shorter duration resources up to a certain level of penetration. This revision was made in part due to additional technical analysis conducted after the original proposal. Virginia could similarly support additional technical analysis and seek adoption market rules that provide greater opportunities for shorter duration (e.g. 2-hr, 4-hr, etc.) storage resources to participate in PJM's capacity market.

Most recently, FERC has rejected PJM's market rule for the capacity market, which requires that eligible facilities provide capacity on a year-round, 24/7 basis.[178] This market rule would have biased the market against summer renewable resources such as wind and solar, and limits energy storage activity. This rejection marks an important step towards market rules that are more tailored to seasonal and peak loads for establishing capacity needs.

Interconnection and Permitting

6.12 Streamline Permitting Both Statewide and for Local Jurisdictions

As detailed in Chapter 4: Safety & Permitting Issues, there are many steps that can be taken at the state level to facilitate the local safety and permitting processes associated with energy storage deployment. Additionally, there is a growing body of best practices and resources from other states' experience that Virginia could adopt. These include the following:

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[177] To track the ongoing stakeholder process, go to https://elibrary.ferc.gov and search for ER19-469. Interested stakeholders may also submit comments by using FERC's eFiling system. The eFiling system requires that you have an unrestricted eRegister account.

[178] Source: Utility Dive, "FERC rejects PJM tariff proposal to require year-round demand response resources". https://www.utilitydive.com/news/ferc-rejects-pjm-tariff-revision-requires-year-round-demand-resources/557958/

- Amend and adopt a model permit and checklist system, such as that developed by New York. These can be distributed to AHJs and ultimately used to educate AHJs through a special stakeholder session.
- Conduct Fire Official education courses through NFPA.
- Ensure the State Corporation Commission has developed sound interconnection rules that do not pose undue barriers to customer storage adoption
- Immediately adopt the 2017 National Electric Code. Alternatively, the state could adopt just article 706 of the 2017 NEC Code, which pertains to ESS and let the current code adoption process continue as is.
- Ensure any utility procurement of storage systems include relevant product safety standards, and that these be demonstrated as part of any competitive solicitation process.

In addition, to local permitting issues, Chapter 4 discusses the fact that there is lack of clarity regarding whether SCC or DEQ must provide siting approval. Guidance from these agencies is needed regarding whether storage projects must secure a Certificate of Public Convenience and Necessity (CPCN) via the SCC or Permit By Rule via the DEQ.

6.13 Update the Interconnection Process for Distributed Energy Resources

Currently, the interconnection process for distributed energy resources does not include any specific consideration of monitoring and controls that might be beneficial or even necessary in certain cases for energy storage facilities.

As increasing levels of distributed energy storage facilities are deployed, greater visibility and situational awareness will become increasingly important for both the local utility and wholesale market operators in cases where resources that are providing multiple services across both domains. However, it is also important that interconnection requirements are not overly burdensome or include excessive costs for communications and control features that can be bypassed or achieved through other means. Virginia should institute a process to update the interconnection process and rules to ensure that these storage-specific issues are adequately addressed.

As mentioned above, Virginia has an ongoing rulemaking underway at the Virginia State Corporation Commission in Case No. PUR-2018-00107. This may be an appropriate venue to address and include best practices for interconnection that pertain to energy storage.

Competitive Provider Participation

6.14 Revise the Definition of Public Utility to Ensure Third-Party Development is Possible

In SB 966, the Virginia Grid Transformation and Security Act, the definition “public utility” was amended to include "storage" in the definition.[179] By adding this one word, the amendment could restrict deployment of energy storage to incumbent utilities only. Unless this provision is eliminated it could limit the ability of competitive third-party providers to implement storage solutions storage, thereby reducing the potential cost savings and technology benefits of competition. This will also create a barrier to the development of advanced microgrids in Virginia. This is therefore a threshold issue for third-party development that should be resolved, in order to ensure that such development is possible.

Research and Development

6.15 Provide Virginia’s Universities with Additional Resources to Pursue Research and Development of New Energy Storage Technologies.

As described in Chapter 1, there are a variety of energy storage technologies that are continually evolving as the industry’s technical knowledge improves and manufacturing capabilities scale up. Virginia’s education and research institutions could play a key role in advancing the state of knowledge around core technologies (e.g. battery chemistry). Demonstration projects could also serve as a learning opportunity for students and faculty to prepare them for careers in the storage industry. Additional funding and other resources could be allocated towards this effort to help position Virginia as a center for learning and research in energy storage.

[179] See VA Code Ann. sec. 56-265.1(b)

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Glossary of Acronyms

AEP – American Electric Power (owner of APCo); or AEP zone within PJM

AGC – Automatic Generation Control

AHJ – Authorities Having Jurisdiction

APCo – Appalachian Power Company (subsidiary of AEP)

ATM – Above the Meter

BTM – Behind the Meter/Below the Meter

CAES – Compressed Air Energy Storage

CAISO – California Independent System Operator

CapEx – Capital Expenditures

CC – Combined Cycle

CHP – Combined Heat and Power

C&I – Commercial and Industrial

CPCN – Certificate of Public Convenience and Necessity

CPUC – California Public Utilities Commission

CT – Combustion Turbine

DA – Day Ahead

DEQ – Department of Environmental Quality

DER – Distributed Energy Resource

DoD – Department of Defense

DOE – Department of Energy

DEV – Dominion Energy Virginia

DHCA – Dynamic Hosting Capacity Analysis

DMME – Department of Mines Minerals and Energy

DOM – Dominion zone within PJM

DR – Demand Response

EPRI – Electric Power Research Institute

EV – Electric Vehicle

ESR – Energy Storage Resource

ESS – Energy Storage System

FERC – Federal Energy Regulatory Commission

GTSA – Grid Transformation and Security Act

GW – Gigawatt

ICA – Integration Capacity Analysis

ICB – Iron Chromium Battery

IOU – Investor Owned Utility

IRP – Integrated Resource Plan

ISO – Independent System Operator

ITC – Investment Tax Credit

Li-ion – Lithium-ion

LNBA – Locational Net Benefits Analysis

MUA – Multiple Use Application

MW - Megawatt

NaS – Sodium Sulfur

NEC – National Electric Code

NERC – North American Electric Reliability Corporation

NFPA – National Fire Protection Association

NPV – Net Present Value

NREL – National Renewable Energy Laboratory

NWA – Non-wires Alternatives

NYSERDA – New York State Energy Research and Development Authority

O&M – Operations and Maintenance

PBR – Permit by Rule

PJM – PJM Interconnection (Virginia's regional transmission organization and wholesale market operator)

PSH – Pumped Storage Hydropower

PV – Photovoltaic

RPS – Renewable Portfolio Standard

RT – Real Time

RTO – Regional Transmission Organization

T&D – Transmission and Distribution

TOU – Time of Use

SCC – State Corporation Commission

SGIP – Self Generation Incentive Program

VGI – Vehicle Grid Integration

V1G – Unidirectional VGI

V2G – Bidirectional VGI

VRB – Vanadium Redox Battery

ZNBR - Zinc-bromine

Appendix A – BTM Analysis Methodology and Detailed Results

Introduction

The analysis of energy storage potential for behind-the-meter (BTM) applications focuses on the benefits to BTM system owners. As utility customers, these BTM system owners can achieve savings on their utility bills from the controlled dispatch of the BTM system.

Utility bills are generally divided into three sections: a "base" rate, a flat charge which effectively acts as an electricity access rate; demand charges, which incur costs based on the peak power (kW) consumption measured by the utility meter during the billing period, and energy charges, which incur costs based on the total energy (kWh) during the billing period. Additionally, demand and energy charges can be applied during "on-peak" and "off-peak" periods during the day. For example, a utility may enforce a demand charge of $10/kW during the on-peak hours of 10am-7pm, meaning a peak demand of 50 kW measured at a customer's utility meter during this period applies a $500 charge to the customer's utility bill. The billing period is usually defined as one month. For Virginia utilities, customer load data is represented for each 30-minute period in the month.

By selectively charging and discharging the battery, the BTM system can reduce both the demand charges and energy charges by adjusting the electricity required from the utility as measured by the utility meter.

As part of the analysis for energy storage potential, the BTM analysis focused on storage-only systems. The tariff rates within the Dominion and Appalachian Power Company (APCo) utilities, and two rates with particularly high demand charges were chosen for further analysis: Dominion GS-3 and APCo L.P.S. Both rates apply to large, commercial/industrial utility customers, with minimum peak loads between 500-1000kW. Both rates also represent the largest component of the yearly energy consumption among the different tariff rates, for each utility. Both utilities supplied proxy load data for the rate, representing an average or "typical" customer in the rate, along with a sample bill by month over an entire year for the proxy load.

A summary table of the utility rates is below in Table A1.

Tariff	Dominion	Appalachian Power Company
Rate	GS-3	Large Power Service (L.P.S.)[180]
Minimum On-Peak Demand	500 kW	1000 kW
Total On-Peak Demand Charge	15.51 $/kW	21.00 $/kW
Total Off-Peak Demand Charge	0.63 $/kW	2.08 $/kW
Total On-Peak Energy Charge	0.3882 c/kWh	0.552 c/kWh[181]
Total Off-Peak Energy Charge	0.2613 c/kWh	

[180] Numbers presented for the Primary Voltage service rate.
[181] Energy is charged at a flat rate, i.e. no TOU charges for energy.

Yearly kWh Consumption	10,672,642,909	2,183,796,913
Number of Customers[182]	1950	100

Table A1. Summary of Dominion GS-3 and APCo LPS rates

Model Framework and Optimization

In order to properly analyze BTM potential within the two tariff rates, Strategen has created a BTM model written in Python which includes an optimization framework to minimize the electric utility bill.[183] Given a yearly load profile, tariff rate, and BTM system size in power (kW) and duration (hours), the BTM model models the optimal dispatch of the BTM system over the monthly billing period, and is repeated for all 12 months of one year.

The model output includes the resulting dispatch profile, peak load, and bill for each month, stored as CSV files. A flowchart of the modelling process is provided below in Figure A1.

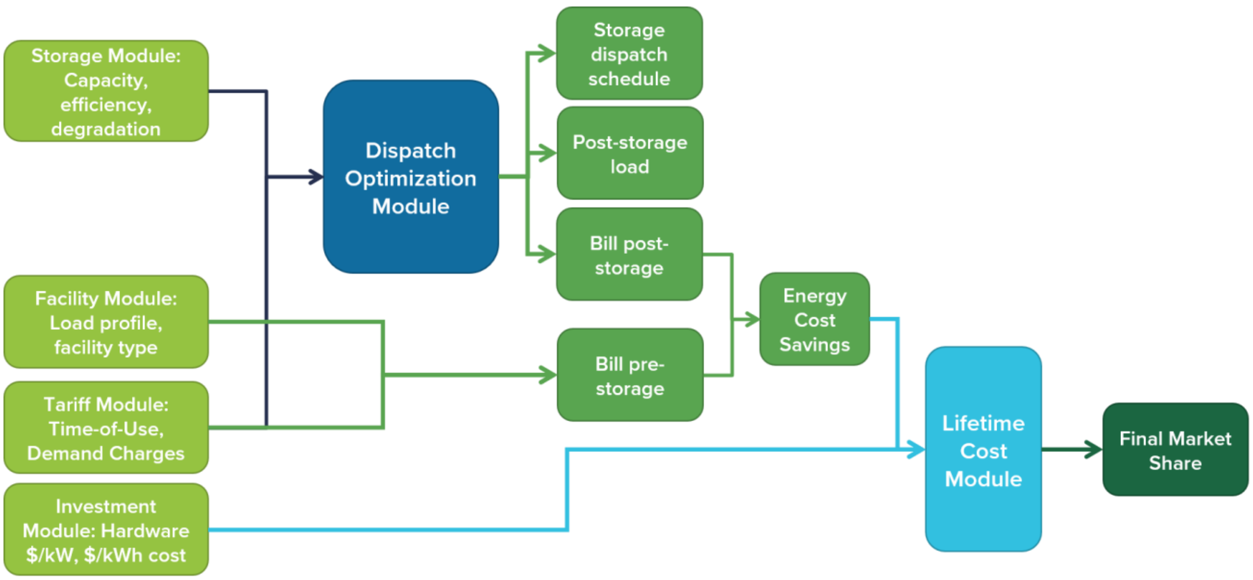

Figure A1. Behind-the-meter model structure

The model output shows the effect of the optimized BTM system dispatch on the facility load. The new load shows reduced peak load demand during on-peak demand charge times, and increased load charging during off-peak hours. Figure A2 below shows a sample of model output representing two days' worth of load with different storage system sizes. This figure shows the flattening of peaks in the load profile as storage optimally charges and discharges against those peaks.

182 Estimated from proxy loads; see section on Model Assumptions.

183 The optimization is constructed using Pyomo, and the GNU linear programming kit *glpk* was used for the as the optimization solver.

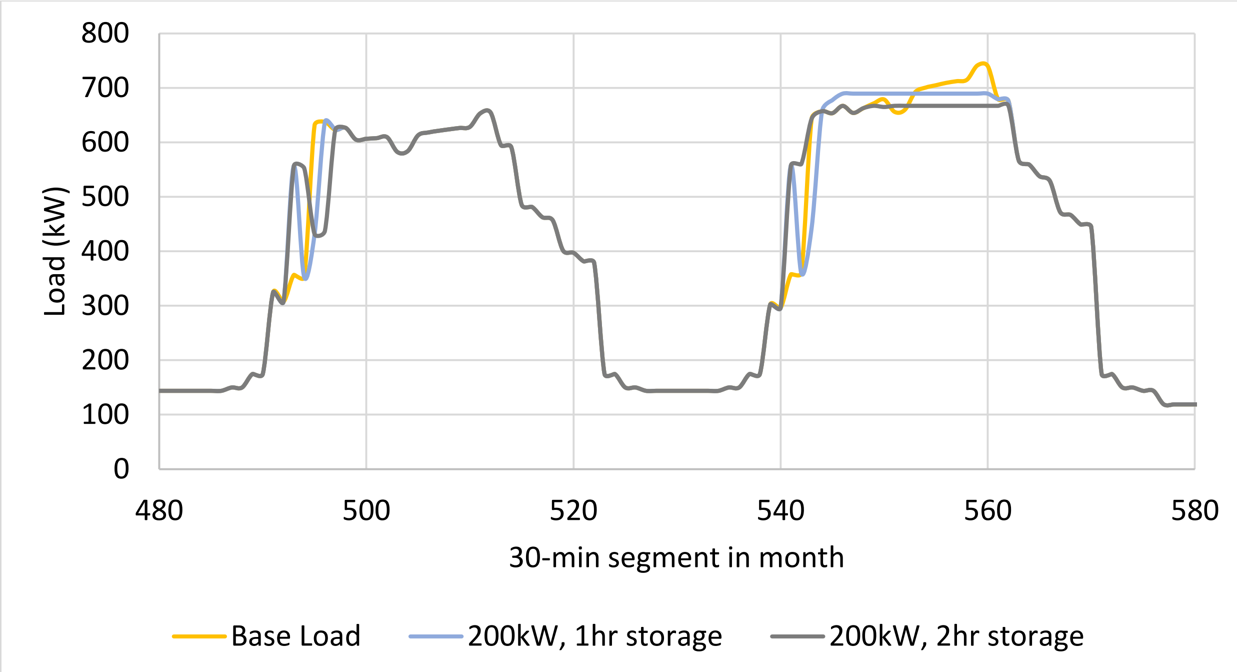

Figure A2. Sample BTM model output on the Dominion GS-3 tariff rate

Economic Analysis

Within each tariff rate, the resulting utility bills are compared to the utility bill without the BTM system to produce a yearly bill savings for each system size. The yearly bill savings are then de-rated by 90% to account for imperfect forecasting in real system performance. The cost of each system size is also calculated using commercial/industrial, standalone, lithium-ion battery system cost data, as reported by Lazard in their levelized cost of storage (LCOS) report.[184] As the Lazard report uses a range of numbers for both system $/kW and $/kWh cost, a "high" cost scenario and "low" cost scenario were created using the upper and lower bounds (respectively) of the ranges. Using the yearly bill savings and the system cost, the payback period is calculated for each system size across these two scenarios.

Finally, the final market share for each system size is calculated from the payback period within each scenario. The final market share is defined as the percentage of the available market within each tariff rate that will eventually invest in a given BTM system. The conversion from payback period to final market share is adapted from existing studies on residential PV adoption.[185] This final market share can then be converted to an additional BTM (kW) capacity by multiplying this percentage by the total number of customers in the rate and the system kW size.

In the "best case" scenario, modifications were made to both the yearly system savings as well as the initial system cost. The Lazard report also mentions a -8% CAGR for the cost of lithium-ion battery systems, which is applied over 5 years to get to a reduced high/low cost scenario.

[184] Source: Lazard, Levelized Cost of Storage, https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf
[185] Source: PACE, Value of Solar, https://appsrv.pace.edu/VOSCOE/?do=viewFullResource&resID=J8PAM033116121012

The distribution deferral amount of $70/kW-yr was estimated from information supplied by Dominion on their distribution network and was applied to the yearly savings amount.

Model Assumptions

In order to simplify the model to present a high-level analysis, assumptions were considered for the model and optimization framework.

First, the optimization is heavily dependent on not only the tariff rate data, which dictates the framework for costs applied to the bill, but also the load data. In order to properly evaluate the effects of load on BTM system performance, simulated load profile data was available and taken from the DOE Commercial Reference Buildings dataset.[186] This dataset includes simulated building load data, which uses weather TMY3 data to construct the load demand.

The simulated load data used in the model was taken from the Baltimore dataset and includes the "LargeOfficeNew2004" and "HospitalNew2004" building datasets, both of which satisfied the minimum 500kW demand requirement in the Dominion GS-3 tariff. As no load data in the dataset satisfied the minimum 1000kW demand requirement in the APCo L.P.S. tariff, both loads were doubled and used in the model for the L.P.S. tariff.

The model assumes that off-peak demand charges do not apply, and these charges are not accounted for in the model. This is due to optimization constraints with the linear optimization used in the model. The off-peak demand charges for each tariff rate are described in relation to the on-peak demand; for example, the GS-3 rate off-peak demand charge only applies if the off-peak demand is within 90% of the on-peak demand. As both off-peak and on-peak demand change with the dispatch of the BTM system, they are both variables in the optimization, and therefore this relationship between the two variables no longer satisfies the constraints required for linear optimization.

Within this model simplification, the optimization produces a reasonable result given that the off-peak demand is much less than the on-peak demand. Such load profiles represent loads that are stronger candidates for BTM storage systems; there is greater potential for savings, since on-peak demand charges are much larger than off-peak demand charges.

The number of customers in each rate was estimated by using the proxy loads supplied by each utility and understanding that these were average or "typical" customer loads for the rate. From these proxy loads, an average customer yearly kWh consumption was calculated. The total yearly kWh consumption for each rate was divided by this to produce the estimate of number of customers for each rate.

Demand response (DR) program participation is also simplified in this model. The BTM system dispatches at 1/6th of its rated kW capacity over 6 hours from 1p-7p for all working days in the month of July. This replaces the dispatch optimized for demand and energy charges for this month. The bill is then recalculated accounting for the demand response dispatch for this month.

[186] Source: Energy.gov, Commercial Reference Buildings, https://www.energy.gov/eere/buildings/commercial-reference-buildings

This analysis models the Non-Residential Distributed Generation program for Dominion,[187] and the "D.R.S. - RTO Capacity" demand response rider for Appalachian Power Company.[188] The Dominion program Load Curtailment Capability Payment, in $/kW, is given in 2013 dollars, and so this is escalated with inflation to 2019 dollars. Similarly, the Fuel payment is taken at July 2018 prices.

The hypothetical distribution deferral program is assumed a value of $70/kW-yr, based on Strategen's analysis of the marginal distribution system upgrade capital cost.[189] It is applied to the demand response dispatch power (i.e. 1/6th of rated kW capacity) and added to the yearly savings of the BTM system in the best-case scenario.

Finally, the model aims to capture the value of energy storage dispatch, rather than a full simulation of system performance. As further simplification, the efficiency of the energy storage system is set as 100% and the storage is allowed full depth-of-discharge. Furthermore, the battery degradation is not considered for yearly savings and is assumed to operate optimally at full rated capacity throughout the payback period.

Detailed Model Results

Added BTM Capacity with Current DR programs

The impacts of the currently existing demand response programs in Dominion and APCo are below in Table A2 and Table A3 respectively, showing the final added BTM capacity with the existing DR program value included.

Power (kW)	1-hour system	2-hour system	4-hour system
100	400 – 4900	100 – 2900	0 – 1100
200	200 – 3600	0 – 1800	0 – 600
400	0 – 2000	0 – 800	0 – 400
800	0	0	0

Table A2. Final Added BTM Capacity, in kW, for the Dominion GS-3 tariff rate, with existing DR program

Power (kW)	1-hour system	2-hour system	4-hour system
350	0 – 350	0 – 350	0
700	0	0	0
1400	0	0	0
2800	0	0	0

Table A3. Final Added BTM Capacity, in kW, for the Appalachian Power Company LPS tariff rate, with existing DR program

[187] Source: Dominion Energy, Distributed Generation, https://www.dominionenergy.com/large-business/energy-conservation-programs/distributed-generation/distributed-generation-faqs

[188] Source: Appalachian Power, Virginia SCC Tariff No. 25. https://www.appalachianpower.com/global/utilities/lib/docs/ratesandtariffs/Virginia/Tariff%2025%20April%201,%202019%20MASTER-Tax,%20RPS%20and%20Tax%20Riders-clean.pdf

[189] See report section 3.2.2.

Appendix B – Storage as an Alternative to New Natural Gas-fired Peaker Plants in Virginia

In several places around the U.S., battery storage has been proposed or selected as an alternative to new natural gas peaking power plants. For example, in Oxnard, California, battery storage was recently selected by Southern California Edison through a competitive solicitation as part of the suite of alternatives to provide local capacity in lieu of a previously proposed gas peaker plant.[190] New York recently completed an energy storage roadmap that analyzed the role of storage in replacing aging peaker plants.[191]

In Virginia, Dominion has proposed a significant addition of new natural gas-fired peaking combustion turbines (CTs) over the next decade. According to their revised IRP from March 7, 2019, each of the Alternative Plans (A through F) includes over 900 MW of new combustion turbine additions by 2023, and over 2,200 MW by 2030 (Plan A). Assuming an initial capital costs ranging from $476/kW (frame CT) to $1680/kW (aero CT), this represents an investment ranging from $1.0 billion to $3.7 billion, not including financing costs, fuel, or O&M.

In its March 25th investor presentation, Dominion further characterized its planned investments in combustion turbines as "renewable enabling."[192] Moreover, Dominion's 2018 IRP describes the Aero-derivative class of combustion turbines as follows: "This is a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatch, renewable resources, such as solar and wind."[193]

As renewable resources are added to the system, there may be an increased need for resources that are can provide flexible ramping capabilities to accommodate the variability and uncertainty of wind and solar. The exact magnitude and timing of these flexibility needs likely requires further study. This is also complicated by the fact that Dominion operates within PJM, which already provides flexibility through its participation in real-time energy and ancillary services markets.

As these issues are studied, it is worth considering what technologies are capable of providing "renewable enabling" grid services. In addition to aero-derivative combustion turbines, several technologies are capable of providing fast ramping capabilities that could complement variable wind and solar. For instance, inverter-based resources, such as battery storage, are particular well suited to this function since they have near instantaneous ramping capability and can respond quickly to variations in renewable resource availability by providing frequency regulation and load following services. Additionally, energy storage can provide peaking power for a limited duration that can serve as a complement to wind and solar resource that may contribute only a fraction of their nameplate capacity at times of peak demand. Due to their relatively inefficiency versus

[190]https://www.greentechmedia.com/articles/read/sce-picks-major-battery-portfolio-in-place-of-puente-gas-plant#gs.u1iotm

[191]http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b2A1BFBC9-85B4-4DAE-BCAE-164B21B0DC3D%7d

[192] https://s2.q4cdn.com/510812146/files/doc_presentations/2019/03/2019-03-25-DE-IR-investor-meeting-general-session-vTCII-website-version.pdf

[193] See p 72: https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf

mid-merit units (e.g. combined cycle), peaker plants also tend to operate only a few hours at a time.

As such, limited duration energy storage systems may be well equipped to provide an alternative. In addition to providing similar functionalities, battery storage technologies are also increasingly competitive with peaker plants in terms of costs. Below is an illustrative comparison of the estimated net cost (i.e. capital and O&M, net of energy and ancillary service revenues) for a new gas-fired combustion turbine plant in Virginia versus a 4-hr duration battery storage system.

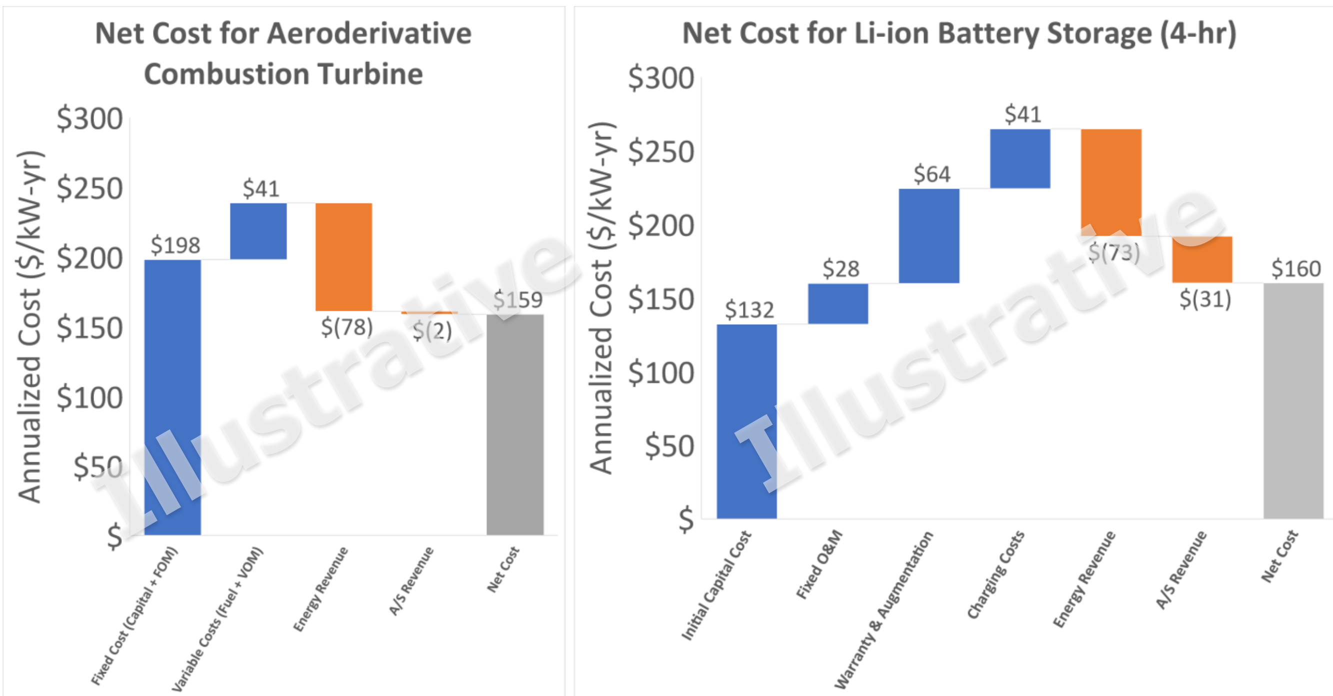

Figure 46.Comparison of the net cost for a new aeroderivative combustion turbine (left) and an equivalent-MW (4-hr duration) new battery storage system (right). Assumptions are described in

While further analysis is necessary to more precisely determine specific resource needs, capabilities, and costs, this preliminary analysis suggests that the net cost of the two resources may similar. As such, it may be worthwhile to evaluate battery storage as an option for renewable enablement in addition to new natural gas-fired combustion turbines.

Table 8. Assumptions for peaker and storage cost comparison.

Peaker Assumptions (Aero CT)[194]	Values	Source
Fixed Cost	$198/kW-yr	Dominion 2018 IRP, Appendix 5B
Book Life	36 years	Dominion 2018 IRP, Appendix 5B
Variable Cost	$59/MWh	Dominion 2018 IRP, Appendix 5B
Storage Assumptions	**Values**	**Source**
Capital cost (4-hr duration)	$1,477/kW	Lazard Levelized Cost of Energy Storage 2018 (midpoint of high/low for Li-ion)
Weighted Average Cost of Capital	6.31%	Dominion 2018 IRP, p 114
Warranty + Augmentation Costs	$64.19/kW-yr	5.7% of initial cost (starting after year 3)
O&M Costs	$16.25/kW-yr	1.1% of initial cost (escalated at 2%)
Book Life	20 years	
Other Assumptions	**Values**	**Source**
Energy Prices (charging/discharging)	8760 Hourly Day Ahead LMPs for Dominion Hub	S&P Global (from PJM)
Ancillary Service Prices	$5.39/MW Spinning Reserve $0.29/MW Non-Spinning Reserve	PJM 2018 State of the Market Report p 447-448

[194] Aero-derivative CT was selected as the "RE Integration" resource due to its more flexible performance versus a standard Frame CT.

Appendix C – Stakeholder Feedback

The following is a list of stakeholders who provided written feedback to the Interim Report distributed in April 2019. Additional feedback was also provided at the Stakeholder Meeting held by DMME on July 11, 2019. To the extent possible, Strategen considered and incorporated this feedback into this final report.

- Dominion Energy
- East Point Energy
- Energy Storage Association
- Ivy Main, Publisher Power for the People Virginia
- Natural Resources Defense Council
- Secure Futures
- Sierra Club Virginia Chapter
- Southern Environmental Law Center
- Trane Commercial North America
- Virginia Solar