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November 15, 2017

Members of the Vermont General Assembly
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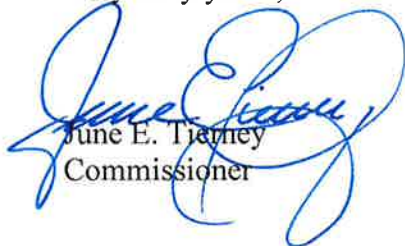
Re: Energy Storage Report Pursuant to Act 53 of 2017

Dear Senators and Representatives:

I am pleased to submit a report on the issue of deploying energy storage on the Vermont electric transmission and distribution system, conducted pursuant to Sec. 22 of Act 53. This report explores the benefits and costs of, challenges to, and opportunities for energy storage in Vermont, and provides potential recommendations for further consideration.

If you have any questions or concerns upon reading this report please do not hesitate to contact me or Ed McNamara, Director of Energy Policy and Planning here at the Department.

Very truly yours,



June E. Tierney
Commissioner



Act 53 Report:

A Report to the Vermont General Assembly on the Issue
of Deploying Storage on the Vermont Electric
Transmission and Distribution System

Final Report – November 15, 2017

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Agency of Agriculture, Food & Markets, Agency of Natural Resources, BayCorp Holdings, Bennington County Regional Commission, Burlington Electric Department, Catamount Solar, Clean Energy States Alliance and Clean Energy Group, Dynamic Organics, Dynapower, Encore Renewable Energy, Grassroots Solar, Green Mountain Power, Independent System Operator – New England, Key Capture Energy, Northern Power Systems, Northern Reliability, Peck Electric, Renewable Energy Vermont, Billy Scully, Stowe Electric Department, Suncommon, Sunrun, Sunverge Energy, U.S. Department of Energy – Office of Electricity, Vermont Electric Cooperative, Vermont Electric Power Company, Vermont Emergency Management, Vermont Energy Investment Corporation, Vermont Public Interest Research Group, Vermont Public Power Supply Authority, Vermont Solar Farmers, Vermonters for a Clean Environment, Washington Electric Cooperative, and the Windham Regional Commission.

Introduction

Act 53 of the 2016-2017 legislative session directed the Department of Public Service (Department) to “submit a report on the issue of deploying energy storage on the Vermont electric transmission and distribution system.”¹ This report offers a snapshot of the current state of energy storage in the state and beyond², provides some insight into the challenges and opportunities it poses, and proposes reasonable next steps to further our collective understanding of the role storage could and should play in the state in the near- and longer-term. Vermont’s size may constrain our ability to devote substantial financial resources to testing and advancing storage use cases and technologies, but it also allows individuals and entities exploring storage to easily convene and pool knowledge to arrive at solutions to sensibly advance grid transformation efforts that promote the public good.

Vermont’s grid has changed considerably over a brief time: peak electric use now occurs after dark rather than in the middle of a summer afternoon; there are thousands of net-metered (mostly solar) systems in the state; and constraints on the distribution and transmission systems are now a result of excess generation during certain times, rather than load growth. In the context of these changes, Vermont must reinvigorate and modify existing tools (such as load management and demand response) and look to new tools such as storage.

As Vermont moves forward, it is important that we do not focus attention on only one solution but instead provide a measured evaluation of all options and deploy those that are most cost-effective in the long term. Storage has several potential benefits, which are described in this report; however, it is only one tool of many, and one that is just starting to become cost-effective in certain use cases. Indeed, the relatively sudden interest in storage systems in the nation and region can in part be attributed to the improving performance and precipitous declines in the costs of certain technologies. In particular, the significant decline in the cost of lithium-ion storage batteries is expected to continue at an annual pace that parallels the declines in solar costs, due in large part to the economies of scale in the manufacturing process. Consequently, through this report, the Department recommends an approach that acknowledges the potential benefits of storage technologies without going “all in” before better information is available.

In preparing the report, the Department reached out to many stakeholders, including electric transmission and distribution utilities, renewable energy and storage project developers, nonprofits, land use planners, neighboring states, and the regional transmission organization. We are grateful to all who took the time to engage in discussion with us and send comments on this topic; your comments and suggestions have been incorporated into this report as much as possible, and we look forward to the continued discussion.

State energy policy and the changing grid

Vermont’s state energy policy, as set forth in 30 V.S.A. § 202a, is focused on three sometimes competing goals: affordability, reliability, and environmental responsibility. This policy is further defined by the

¹ The relevant text of Act 53 is included as Appendix A.

² A snapshot of storage in the nation and region, and detailed descriptions of VT storage activities and projects, can be found in Appendix B.

least-cost planning requirements contained in 30 V.S.A. § 218c, which requires utilities to develop plans to meet safety, reliability, and environmental goals in the most cost-effective manner.

The 2016 Vermont Comprehensive Energy Plan (CEP) describes “power sector transformation” – characterized as grid transformation in other venues – as “a strategy by which states, utilities, and other partners seek to capture the value of distributed energy resources (DER) for the benefit of consumers through lower costs, cleaner generation, and better system reliability.” The CEP goes on to discuss how power sector transformation not only affects distribution utilities (DUs) but also “leverages them to facilitate change in ways that encourage greater customer participation and entry of new market players into the business of supplying electricity services,” mainly through regulatory interventions and oversight. “Distributed energy resources such as solar and wind, combined with distributed storage, flexible loads (such as electric vehicles and controllable devices), and a centrally managed platform, offer great potential for improving the grid’s performance,” the CEP states. The CEP makes one overarching – and still relevant, recommendation on this issue: “Utilities, the DPS [Department], and the PSB [now PUC] should each use their roles in regulatory proceedings to advance the further alignment of utility actions with power sector transformation that advances the general good of the state. The DPS and [PUC] should be especially cognizant of the need for public engagement and transparency in these aspects of each proceeding.”

Storage technologies and applications

Generally, energy storage is defined as any technology that absorbs energy, stores it, and then releases it on demand.³ The energy can be stored in various forms, including mechanical (flywheels, pumped hydro), electrochemical (batteries), thermal (water tanks, molten salt, ice storage), electrical (supercapacitors), and chemical (hydrogen). Each form of energy storage contains multiple formulations; for example, battery storage can be broken down into a number of types, from market-leading lithium-ion and its subchemistries to longer-established lead-acid and sodium sulfur to newly emerging redox flow batteries. Technology and subtype choice depend on costs, uses cases, and risk tolerance of entities deploying storage projects.⁴

The best-established and most mature form of energy storage is pumped hydro⁵; however, most state energy storage policy is targeted at newer, “advanced” energy storage technologies that can be more easily scaled and deployed and which serve more varied applications. The National Governors Association report *State Strategies for Advancing the use of Energy Storage* calls out batteries (primarily lithium-ion), compressed air, thermal storage, and flywheels as advanced energy storage technologies, noting that “Recent advances in battery technologies, declines in battery storage costs and state and

³ Act 53 defined storage – for the purposes of this report and in 30 V.S.A. § 8015 – as, “a system that uses mechanical, chemical, or thermal processes to store energy for later use.”

⁴ Colthorpe, Andy. “California, Hawaii Drive US to Busiest Ever Quarter for behind-the-Meter Energy Storage.” *Energy Storage News*, 7 Sept. 2017, www.energy-storage.news/news/california-hawaii-drive-us-to-busiest-ever-quarter-for-behind-the-meter-ene.

⁵ Discounting low-tech thermal storage technologies, such as hot water tanks, which are ubiquitous but not generally used as a form of electricity storage.

federal policy incentives have combined to help spur a surge in advanced energy storage installations (with annual deployments of advanced energy storage capacity more than tripling from 2014 to 2015).⁶

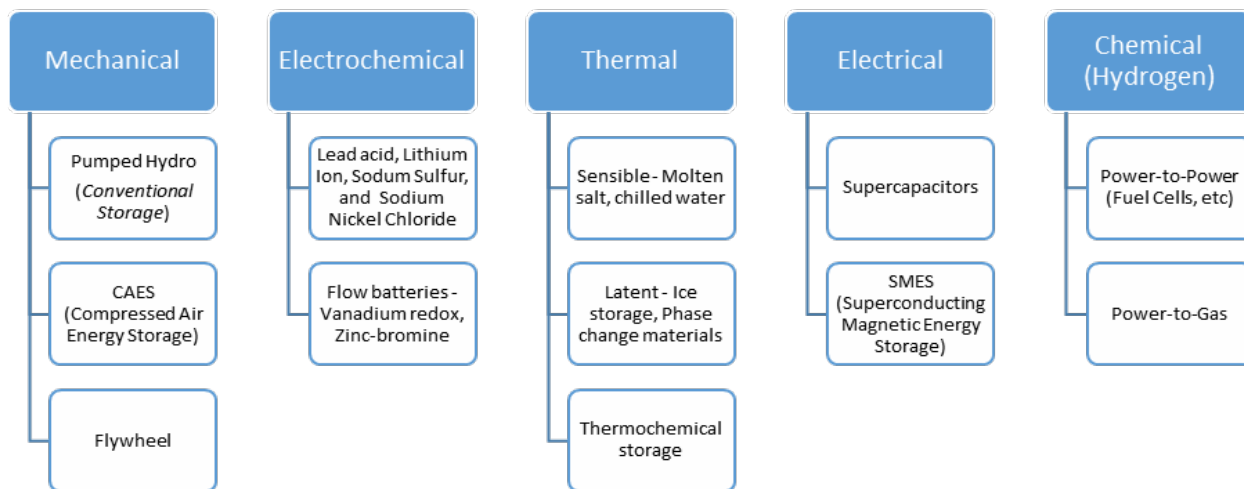


Figure 1: Classification of Energy Storage Technologies (courtesy Massachusetts Department of Energy Resources, from “State of Charge”⁷)

The size and capabilities of various forms of storage are usually described in terms of “power” (kilowatts or megawatts), indicating how much power can theoretically flow into or out of a system in a given instant, and “energy” (kilowatt-hours or megawatt-hours), indicating how much electricity can be delivered or stored over the course of an hour. A 4 megawatt-hour (MWh) battery system might have a power rating of 4 megawatts (MW) and an energy rating of 1 hour, or (more realistically) 1 MW and 4 hours; in the latter example, it can supply 1 MW of power for 4 hours (or 0.5 MW of energy for 8 hours, etc.). Storage technologies are generally selected based on power or energy ratings as needed to serve different use cases; high power ratings are generally preferred for frequent charging and discharging over short durations (such as for frequency regulation), while higher energy ratings are called for when long durations are needed (such as for peak shifting or backup power). Technology developments have started to help bridge the power versus energy dichotomy; advanced lithium-ion batteries, for example, are now useful across a spectrum of power- and energy-intensive applications.

⁶ J. Rackley. *State Strategies for Advancing the Use of Energy Storage* (Washington, D.C.: National Governors Association Center for Best Practices, October 21, 2016).

⁷ Massachusetts Department of Energy Resources. *State of Charge: Massachusetts Energy Storage Initiative Study*. September 27, 2016. <http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf>.

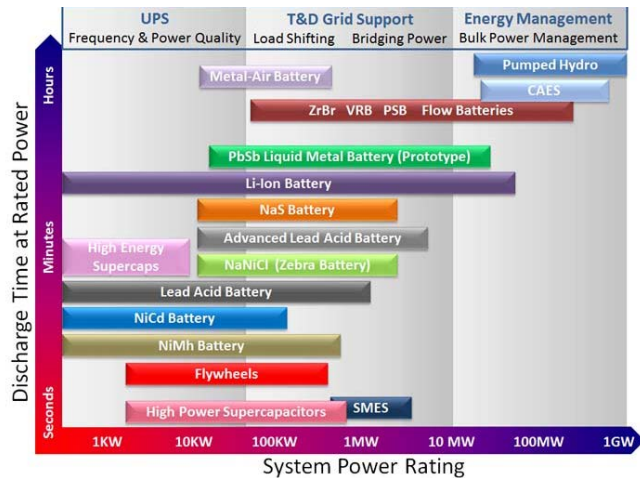


Figure 2: Grid energy storage technologies and applications⁸

Depending on type, storage projects are usually tied to the grid with power electronics, including inverters, that can add to the grid functionality of a storage project. A battery storage project tied to the grid with an advanced inverter might be able to simultaneously provide frequency regulation to the New England region while maintaining power quality (voltage) on a local distribution circuit.

Storage in the context of flexible and managed loads

Grid operators, such as those at the Independent System Operator of New England (ISO-NE), need to balance changes in electricity consumption and generation on an instantaneous basis.⁹ As power transformation occurs, the grid is evolving from a paradigm of one-way flow of electricity from large, central generators to businesses and residences, toward one of two-way power flows from a more diverse assortment of smaller, distributed generators located throughout the grid, including at businesses and residences. Many of these generators are renewably powered and generate when the wind is blowing, the sun is shining, or the water is flowing. Distribution and transmission grid operators need to plan for the variability of these resources while they also factor in power supplies from long-term contracts and short-term purchases (and associated costs) to supply customer loads, evolving customer load profiles from net metering systems, heat pumps, and electric vehicles, and spikes in customer demand based on weather, all while maintaining power quality and reliability.

Energy storage essentially captures energy produced at one time for use at another time, with associated conversion losses. It is one tool in utility and grid operators' "smart grid" toolbox of flexible and controllable resources to match demand with supply, which also contains controllable appliances, electric vehicles, heat storage such as in grid-interactive hot water heaters, rate design, and load-shedding. Thoughtful deployment of the suite of resources listed above can help maximize the efficiency of the grid while minimizing costs to consumers.

Declining costs and technology advances mean storage is on course to becoming a cost-effective tool to help maximize the efficiency of the grid while addressing many of the growing pains of power sector

⁸ Source: Electropaedia, http://www.mpoweruk.com/grid_storage.htm

⁹ ISO-NE, "Running the Electric Power Grid," January 2016. <https://www.iso-ne.com/static-assets/documents/2016/01/running-the-electric-power-grid.pdf>

transformation. Rather than building out infrastructure to accommodate peak usage (much like building enough lanes in a highway to accommodate free flow of rush-hour traffic), storage can be deployed to charge when the system has excess capacity and low prices, and discharge when the grid is stressed by high loads and prices spike. According to ISO-NE, regional electricity peaks – which are a major cost driver for our DUs and thus ratepayers – are growing more slowly due to energy efficiency and distributed solar (slowing the growth of the summer peak to 0.3% annually and overall demand to -0.2% annually), but increasing deployment of solar is changing the demand curve¹⁰, increasing the need for fast and flexible generation.¹¹ Storage can also help to buffer stresses on a grid that wasn't built for distributed energy resources, but which can become greener and more efficient as such resources become more prevalent. For example, it can address high penetration of solar on a distribution circuit causing two-way power flows at the transformer and stressing that infrastructure by better aligning local demand with local supply, as well as clouds passing over solar arrays by micro-managing fluctuations in power output and quality.

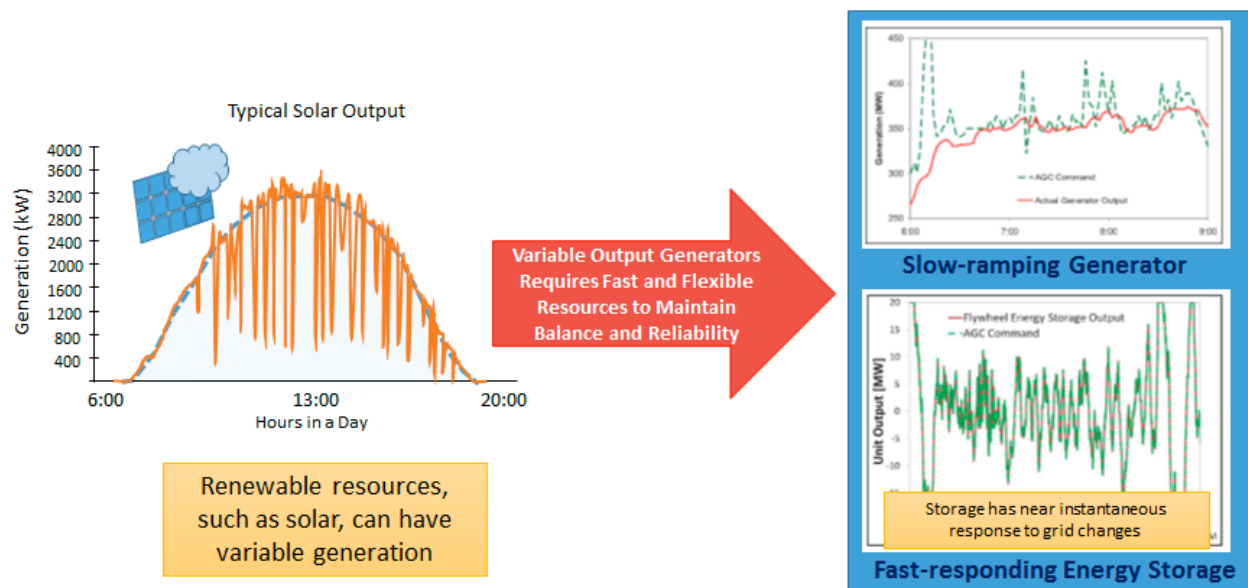


Figure 3: Energy storage can respond quickly to smooth output and provide frequency regulation (courtesy Massachusetts Department of Energy Resources, from “State of Charge”¹²)

Not only can storage maintain grid stability and power quality, while facilitating the integration of renewables, but if managed and wired to do so, it can provide power during outages to customers and critical facilities. Ideally, storage resources will be deployed to meet all three objectives (power cost

¹⁰ Solar reduces electricity demand that grid operators “see” in the middle of the day (net load). When solar starts producing in the morning and drops off in the evening, grid operators are faced with “ramps” down and up, respectively, for electricity. The more solar is deployed, the steeper and more challenging the ramps are to meet with traditional sources of generation. Grid stability can also be challenged when solar production drops the load in the middle of the day below the amount of available generation.

¹¹ ISO-NE, “State of the Grid,” January 2017. https://www.iso-ne.com/static-assets/documents/2017/01/20170130_stateofgrid2017_presentation_pr.pdf

¹² State of Charge at viii.

reduction, integration of renewables, and resiliency), though optimizing for each of the three objectives may not yet be possible. Through careful analysis of proposed investments and strategic planning work with stakeholders, Vermont can ensure that storage projects increase energy affordability for consumers, facilitate integration of distributed generation to maximize return on utility and consumer investments in renewables, and increase grid resiliency for the welfare and convenience of consumers and communities. Policies and programs addressing storage can promote these outcomes while also providing the opportunity for diverse types of entities – individuals, businesses, utilities, and communities – to reap the rewards of storage sector expansion.

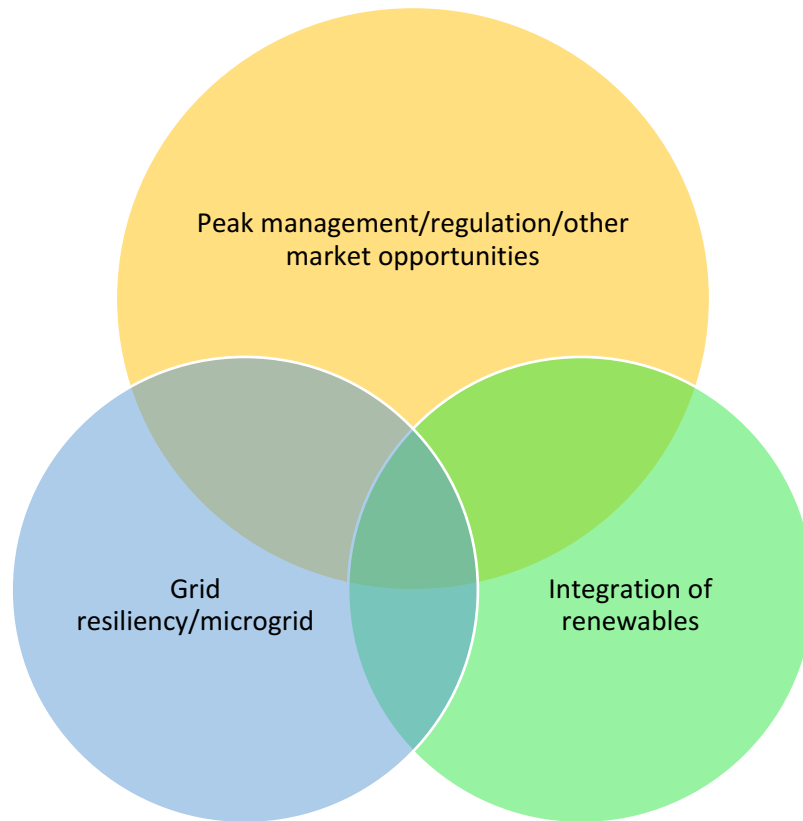


Figure 4: Storage resources can manage any one of the functions above; ideally, they will achieve and optimize all three, although at this point, only peak management and market opportunities (the larger, yellow circle) provide monetary value to the project. Integration of renewables and especially grid resiliency benefits are more site-specific in nature as well as harder to quantify. Storage resources may also not be able to optimize all three objectives – there will likely be tradeoffs.

Benefits and Costs of Storage Systems in Vermont

Storage of electric energy has the potential to improve resilience¹³, shave peaks, integrate renewables, and to expand available electricity market services. Though storage may not currently be the most cost-effective way to perform these functions, as costs come down and players realize how to capitalize on these revenue streams, storage may become more prevalent.

Rapid declines in price may drive greater adoption of storage. Similar to the early days of renewable technology, energy storage systems are finding their way into the mainstream utility plans and portfolios as well as those of private facilities, such as large industrial energy users, healthcare facilities, and even residences. As costs for storage come down, there is increasing interest in demonstrating the potential of storage and gaining familiarity with the value propositions for these systems.

Benefits

There is no clear-cut way to evaluate the benefits of storage writ large. Storage systems vary in their applications and capabilities. Any evaluation of the benefits of storage should take into consideration the particular problem – or more likely, problems – being solved. A battery system located at a residence might simultaneously help a utility shave its peak demand, provide frequency regulation to the grid, and be available for backup power to the residence in the case of an outage; a utility-scale battery might shave peaks, provide frequency regulation, defer transmission upgrades, and help island part of the grid. Most storage systems are providing more than one benefit.

Analysts generally refer to this “value stack” when discussing the costs and benefits of a storage project, meaning how many benefits can be layered together by one asset. What matters is not necessarily the comparison of costs with another resource that can perform any *one* of the functions in isolation, but whether the combined expected lifetime values from the storage asset exceed the lifetime costs of the storage investment.¹⁴ Many storage resources can be operated to change their function on an hourly basis. Storage costs and benefits also vary across technologies and scales, and can be influenced by any number of factors (including capital, balance-of-system, operations & maintenance, charging, etc. costs, as well as power, energy, and response rate benefits).

¹³ Resilience pertains to maintaining electric service during a grid outage, as, say, from backup, resource optimization for economic benefit (fuel, wind, PV), resource integration (solar PV, wind) that allows the system to effectively use the energy, stability (frequency, voltage), and load management (leveling and shifting) to match the character of load requirements.

¹⁴ Lazard, Lazard’s Levelized Cost of Storage – Version 2.0, December 2016.
<https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf>

ENERGY STORAGE VALUE PROPOSITION

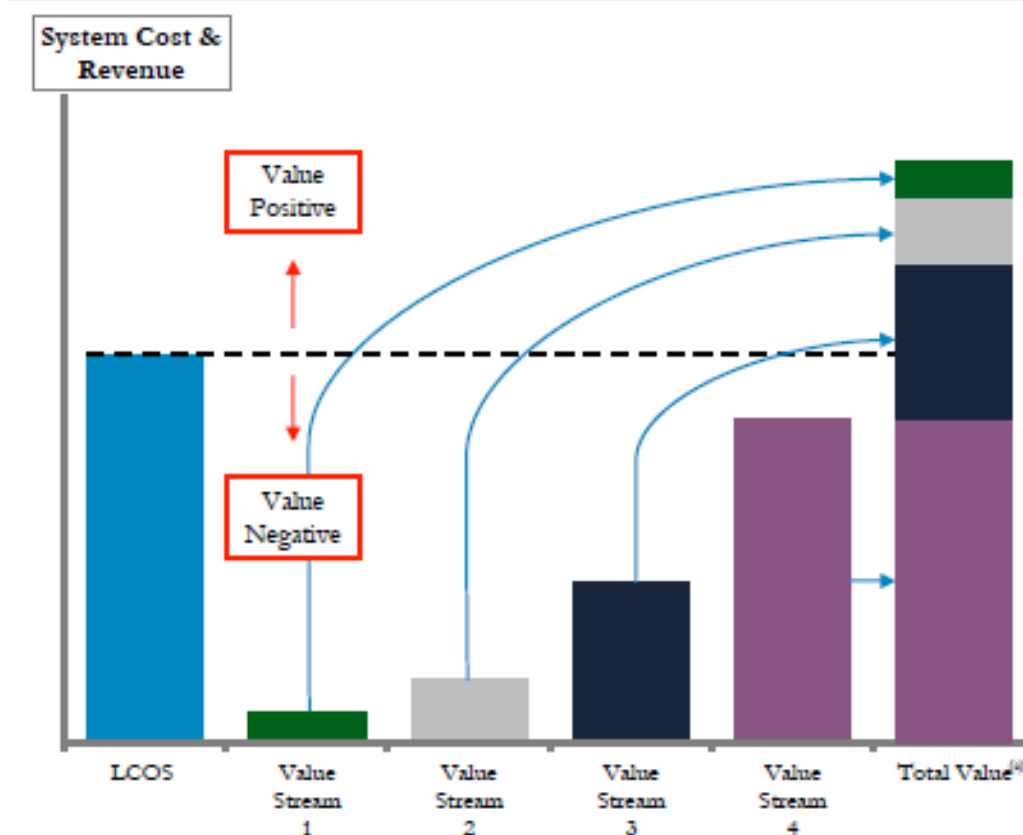


Figure 5: The sum of all potential value streams of storage project will determine the maximum economically viable cost for that system – however, not all potential use cases are compatible. (Source: Lazard’s Levelized Cost of Storage – Version 2.0)¹⁵

There are many benefits or “value streams” that storage can provide. Many battery systems include advanced power electronics, which can boost the ability of the grid to respond to changes in voltage, and all storage can serve as both a load (analogous to use of electricity) and a source of electricity (analogous to generation). Energy storage is sometimes referred to as the Swiss army knife of energy systems.¹⁶ Value streams include those that are readily monetized through the sale of services, as well as those that are not readily monetized (e.g., resilience).¹⁷

Monetized benefit streams

Forward Capacity Market

The Independent System Operator New England (ISO-NE) Forward Capacity Market (FCM) is regulated by the Federal Energy Regulatory Commission (FERC) and is intended to ensure that there are sufficient resources to meet load requirements. Utilities incur obligations to provide, or pay for their share of,

¹⁵ Ibid

¹⁶ Trabish, Herman K. What’s the Value of Energy Storage? It’s Complicated. *Utility Dive*, October 20, 2015, <https://www.utilitydive.com/news/whats-the-value-of-energy-storage-its-complicated/407498/>.

¹⁷ “Green Mountain Power (GMP): Significant Revenues from Energy Storage,” (Sandia National Laboratories, May 2017). Retrieved from: www.sandia.gov/ess/publications/SAND2017-6164.pdf

capacity requirements in New England. ISO-NE determines what each utility's share is based on the one hour each year with the highest electric load in the region; that calculation is based on the utility's portion of energy use at the hour of the annual system peak in the prior year. Utilities may directly reduce these bills by correctly predicting the peak hour and then discharging batteries during that hour. Given that anticipating the peak load is an art, the utility will need to reserve several hours in the month to ensure that a storage asset discharges during the peak hour(s). As several commenters noted, predicting peak is becoming more difficult with distributed renewable generation on the grid. Alternatively, for either utility or merchant facilities, types of storage with sufficient duration to meet capacity supply obligations may bid into the ISO-NE forward capacity market to receive revenue.

As can be seen in the graph below, there are a small number of hours (during the hottest days of the year) that require a significant amount of resources. Storage and other load management devices can reduce the very highest of peaks, but at some point, there are diminishing returns – as the peak flattens, it becomes increasingly difficult to further reduce the peak. This phenomenon is demonstrated by the gradual slope of the load duration curve in Figure 6. Below about 17,500 MW of demand, storage is not a likely candidate to reduce peaks because there are many hours each year where demand is around 17,500 MW. Storage cannot generally “last” through so many hours (with the exception of pumped storage). Comments submitted in response to the draft report emphasized that storage will have diminishing marginal returns with the benefits to peak occurring for the first number of projects, but subsequent projects adding little value for peak-shaving. The Department agrees with this observation. The more storage that is deployed, the less value that next MWh offers for peak-shaving.

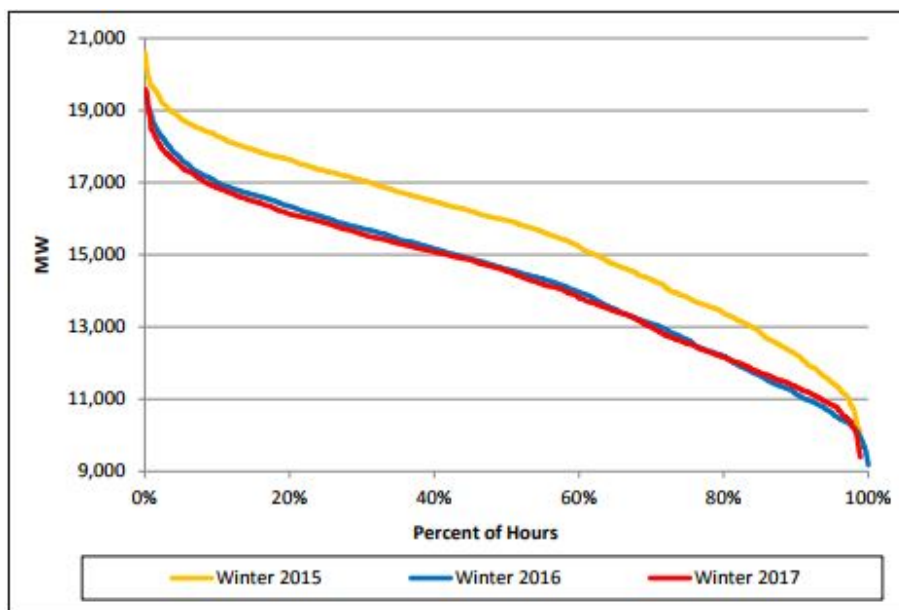


Figure 6: Load duration curves for ISO-NE for winters 2015, 2016, and 2017. A load duration curve sorts all the hourly load values from highest to lowest for any given period. There are very few hours (in this graph, fewer than 5% of hours) when storage could serve as a meaningful capacity resource. (from ISO-NE's Internal Market Monitor Winter 2017 Quarterly Markets Report.¹⁸)

¹⁸ Available at <https://www.iso-ne.com/static-assets/documents/2017/05/2017-winter-quarterly-markets-report.pdf>.

The graph below (provided in comments submitted in response to the draft of this report), shows Vermont’s load profile for a day. Notice that during mid-day, load hovers around 800 MW. In this example, about 50 MW of battery storage, discharging for about 5 hours (250 MWh) could meaningfully reduce evening peak and provide societal benefits. Any more storage than this would not meaningfully reduce costs related to peaks (including FCM and RNS costs).

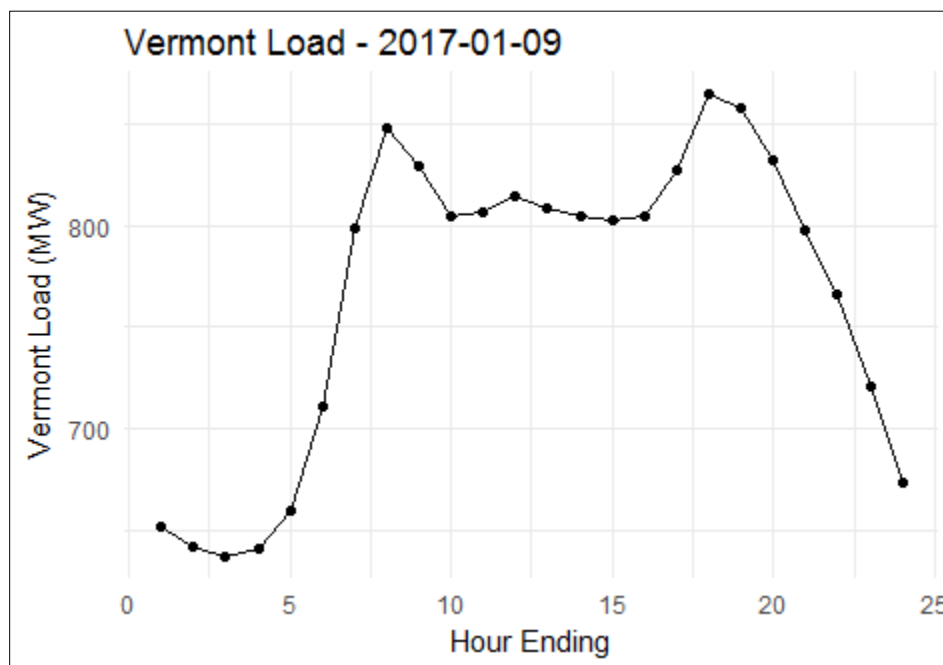


Figure 7: Vermont Load Profile – 2017-01-09. This chart was provided by the Burlington Electric Department and the Vermont Public Power Supply Authority in their response comments to the draft report. It comes from ISO-NE and is available at https://www.iso-ne.com/static-assets/documents/2017/02/2017_smd_hourly.xlsx on the VT Tab, RT Demand Column

Regional Network Service

Utilities pay for the use of the regional transmission grid. Those bills are determined by each utility’s demand during regional monthly peak loads (the electric use at the maximum use hour each month). By reducing monthly coincident peaks, utilities can reduce their own transmission charges, but will essentially be shifting those charges to other utilities and ratepayers in New England. If storage helps to avoid significant investment in the transmission grid, there will be “real” societal cost savings associated with the use of storage. If, however, storage is merely being deployed to shift around costs among utilities, the value stream offered by reducing monthly peaks will diminish rapidly. While utilities may reduce their bills in the short-term, if many utilities begin using this strategy, RNS rates will likely rise, wiping out bill savings (since a fixed amount of revenue must be raised to pay for the grid). Long-term cost-benefit analysis should recognize that RNS savings will likely not continue at a high rate for the lifetime of a project. Monthly peaks are difficult to predict, particularly given weather-dependent generation. Any consideration of the value streams of storage should explicitly acknowledge, in the form

of an appropriate calculation, that storage devices will not always be discharged to coincide with all FCM and RNS peaks. In fact, it is *likely* that they will not, because peaks can be difficult to predict.

Frequency regulation

To operate at a consistent frequency, the grid requires resources that can adjust their intake or output very accurately to keep the grid running at 60 hertz/second. This is a very small market relative to the size of other markets (an average day requires about 60 MW), but the revenue available through it can be substantial in some hours.¹⁹ However, as the volume of battery storage in the region increases, revenues are expected to decline significantly. This revenue stream will not likely be available at current levels for the lifetime of most assets.

Other ancillary services

While storage can already provide ancillary services such as black start and reserves, the ISO is implementing rule changes that will enhance the ability for storage to participate.

Energy arbitrage

Utilities and private developers may earn revenue through purchasing energy when it is relatively cheap, storing it, and then selling it back during high-priced hours. Energy prices are currently at a historic low, so this revenue stream is comparatively minor.

Demand charges

Commercial and industrial customers typically have a demand charge component on their electric bill. These charges reflect the fact that the customer's peak load is significantly higher than its average load, and therefore the utility incurs additional cost to serve that customer at the customer's peak time. The demand charge is usually a per-kW charge based on the *customer's* highest peak over the prior year. Some industrial or large commercial users are discharging batteries during their own annual peaks to reduce demand charges that they incur on their electric bill. Over time if many users choose to do this, demand charge rates may rise, reducing the total bill savings consumers can realize.

We need to align price signals from the ISO to utilities to customers—James Gibbons, BED

Demand charges in Vermont are generally set based on the customer's individual *non-coincident* peak, not on the customer's *coincident* peak. If customers are reducing their *non-coincident* peaks, there are only very marginal, if any, savings to the utility over the short-term as a result because the utility may or may not save anything in the RNS or FCM portions of their expenses. Because utilities will collect less revenue from demand charges, that revenue will need to be collected from some source. It may be in the form of increased *rates* for demand charges or through a cost-shift to other customers. Utilities may also consider altering their demand charges such that they would instead be based on the customer's

¹⁹ There were some technical barriers to small batteries participating in this market, which were recently removed by ISO-NE.

share of *coincident* peak; this would align the savings to the customer and the utility and provide real benefit to the system.

Reliability

In some cases, where grid equipment needs to be replaced or upgraded to maintain reliability or power quality, a battery may be the “least-cost” option for solving that grid issue. In these instances, the costs avoided by using a storage solution rather than a traditional “poles and wires” solution can be viewed as a benefit. There have been some studies which seek to quantify the financial impact of outages, so to the extent that batteries are used to power small areas of the grid during an outage, there are real benefits to the wider economy and to people’s quality of life.

Non-monetary benefit streams

Renewable integration

Storage can be deployed to capture excess renewable energy in hours of the day when production exceeds demand and cannot be exported due to grid constraints. This could potentially allow more renewable generators on a given circuit and more closely coordinate demand and supply. For example, storage could time-shift generation in the northern Vermont Sheffield-Highgate Exchange Interface (SHEI) to reduce the economic impact (generation curtailment) of that transmission constraint.²⁰

On a more local scale, energy storage can buffer the effects of over-generation on a distribution circuit with high penetration of, for instance, solar. In a reverse flow situation, generation exceeds load on a circuit and must be exported. This can be problematic if the grid is not sufficiently robust to export energy. Storage can ease the reverse flow problem caused by distributed renewable generation. Storage, and associated power electronics, can also help maintain power quality (as in provide consistent voltage support).

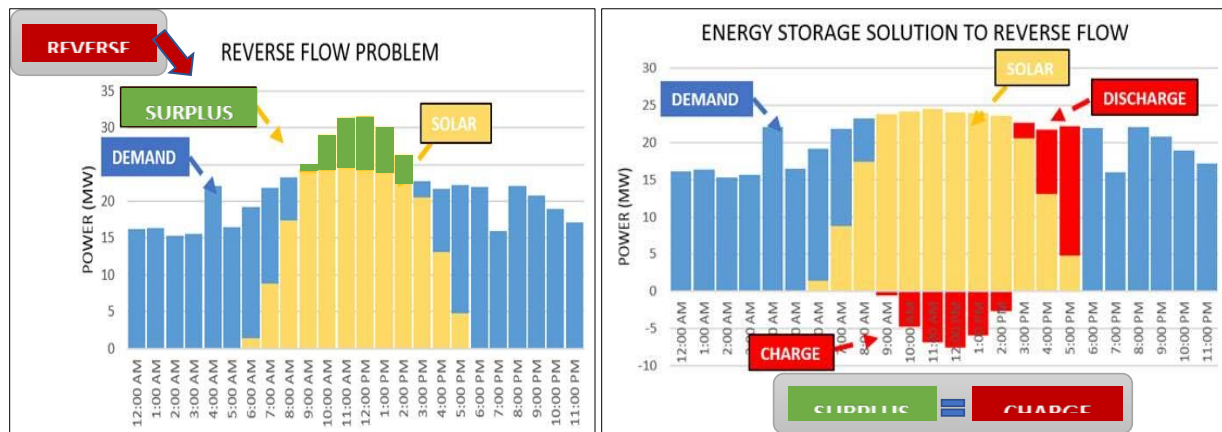


Figure 8: Storage can avoid reverse power flows with PV (courtesy MA DOER, from *State of Charge*)

²⁰Ettori, Frank.” Sheffield-Highgate Export Interface.” Vermont Systems Planning Committee Quarterly Meeting, July 12, 2017. Retrieved from: http://static1.1.sqspcdn.com/static/f/424754/27621837/1499801489777/20170712_VELCO_SHEI_ToVSPC.pdf?to ken=W%2FA9nW071ysolPsSzcpcDNA8ngMY%3D

The state should be thoughtful and strategic regarding where, whether, and how to upgrade specific circuits to accommodate renewables. Storage is not always the “least-cost” solution.

In Vermont, at the *distribution* level, if an individual circuit is saturated with renewable energy, the developer of the *next* renewable facility on that circuit must pay for the grid upgrades so that excess power can be exported from that circuit to the rest of the grid. These upgrades are extremely expensive, and in many cases, once a circuit is saturated, it is functionally closed to additional renewable facilities.

While storage could allow more renewable generation on a given circuit or in a transmission constrained area, utilities and the state should be thoughtful and strategic regarding where, whether, and how to upgrade specific circuits to accommodate renewables using storage. Using utility-developed storage to integrate renewables has the effect of *socializing* the costs of grid upgrades related to renewable development. While this may be an effective solution, it would be a significant shift in policy from “cost-causer-pays” model of funding grid upgrades to sharing costs across ratepayers. Furthermore, storage may not always be the most cost-effective solution to renewable saturation. It must be compared to alternatives.

At the project level, storage could be integrated with individual renewable projects to smooth or time-shift production and coordinate the timing of supply and demand. This is more likely to happen as the costs of storage come down and as pricing signals to renewable generators make the use of storage economical. For example, one commenter on the draft of this report noted that net-metered systems could be paired with storage set to a particular charge/discharge schedule to allow for more systems on a saturated circuit. As net-metering rates and costs for storage fall, it may become economical for net-metering customers to install storage to shift more of their net-metering production to “self-supply.”

Balancing intermittent renewable distributed renewable generation resources will require changing the current grid structure from a supply-side management framework where generation is dispatched to follow loads, to a demand-side management framework where load and storage are dispatched to follow and firm production—Dynamic Organics and Baycorp Holdings

As one commenter pointed out, the use of storage to address long-duration outage and renewable time-shifting needs (such as over multiple days) is more complicated, and requires a sophisticated understanding of the electrical system.

Resilience and Microgrids

Storage can provide power in the event of an outage, but only for as long as the storage lasts and usually with grid upgrades. Pairing storage and local generation can extend the duration of the outage ride-through.

Storage can potentially be used to “island” areas of the grid in the event of an outage, meaning that buildings in the microgrid area – including critical services such as emergency dispatch, shelters, and municipal water and sewer systems – continue to have access to electricity from a smaller “local” grid during the outage. However, there are some limitations. Usually, storage must be paired with specific grid upgrades to facilitate safe islanding.

These upgrades may be costly. Furthermore, the

duration of outage ride-through is limited by the size of the battery. For example, a 1 MW/4 MWh battery could sustain a 1 MW load for 4 hours before it needed to be recharged, though it could be recharged with local generation, whether fossil or renewable. A 2 MW/3.9 MWh battery paired with a 2.4 MW solar array in Sterling, MA is expected to be able to “island” from the grid during a power outage and provide at least 12 days of resilient backup power to the town’s police station and emergency dispatch center.²¹ Although creating islandable sections of the grid with storage and generation assets can be quite expensive, the Center for American Progress reported that every \$1 invested in community resiliency efforts saves \$4 in disaster recovery costs.²²

When distributed storage is implemented as part of a microgrid, it supports vital public health and safety functions for high-risk communities and can provide significant cost savings for those communities and ratepayers statewide--VPIRG

Tradeoffs

Batteries can’t do everything *at once*. Software that optimizes across these competing revenue streams is needed. There are several software products available to do this, though they are early in the learning curve.

There are *tradeoffs* between these different revenue streams and engineering applications. For example, if a battery is participating in the regulation market in a given hour, it cannot also be discharging at full capacity to reduce peak. In another example, to receive the federal tax credit, batteries must charge 75% of the time from a renewable resource to receive 100% of the credit²³. This charging regime likely eliminates the

²¹ This system was installed by the Sterling Municipal Light Department.

²² Kelly, Cathleen and Miranda Peterson. *U.S. Communities Clobbered by \$53 billion in extreme weather and climate disasters in 2016* (Center for American Progress, January 19, 2017. Retrieved from: <https://www.americanprogress.org/issues/green/news/2017/01/19/296860/u-s-communities-clobbered-by-53-billion-in-extreme-weather-and-climate-disasters-in-2016/>)

²³ The ITC may be pro-rated if the battery is charged less than 75% of the time from the renewable source.

opportunity to gain revenues from energy arbitrage. Users (and often automated algorithms) decide what a storage device is doing in any given hour based on what the user is trying to accomplish with that resource, whether it is power quality, riding through an outage, reducing a demand charge, or reducing peaks. These different applications are called “use cases.” Some commenters pointed out that tradeoffs between applications extend beyond hourly decisions about what a system should be doing. Systems which are cycling daily (charging and discharging every day) slowly lose their duration. Batteries which have been participating in markets for several years, and therefore cycling frequently, will have diminished capability to provide power during outages.

Use cases

The term “use cases” refers to a particular scenario in which an asset will be used. For many generation assets, the use case is straightforward. However, storage systems are capable of a wide variety of applications and uses, which can vary widely depending on the size of the system and sector (and even utility) in which they are being deployed. Often, determining the benefits of a system, and comparing those benefits to the costs, requires understanding how the user, or owner, will deploy the battery.

Use cases can be differentiated into grid-scale applications (both merchant and utility), industrial, commercial, and residential applications. Small (residential and commercial) systems can be aggregated for delivery of grid-scale services. In each use case, there is potential for multiple value streams or a stacking order of benefits that can be captured through a wide range of business models.²⁴

It is important to note that the strict separation of behind-the-meter systems vs. utility systems is rapidly becoming an outdated concept. Already, utilities including GMP, are offering contracts to customers who have batteries behind-the-meter, whether owned by GMP or by the customer, which GMP can draw on to provide the same type of capacity and transmission cost shifting or cost savings it obtains by dispatching its own grid-scale batteries. As utilities and third-party aggregators gain the ability to remotely dispatch customer-sited systems, this type of arrangement may become more common. This type of aggregated, distributed system is sometimes referred to as a “virtual power plant.”

End-use customers should receive a fair portion of the value of the system benefits they are creating through use of storage—VEIC

Residential Use Cases

For most residential customers, storage systems provide a source of backup power for outage ride-through, but also offer the potential to shift loads within the household for additional value through time-varying retail rates. Some homeowners are pairing solar and storage to ride through outages for longer or even to avoid connecting to the grid entirely. There may be some opportunities for multifamily

²⁴ Lazard at 6.

housing units that have a shared meter for common charges to use behind-the-meter storage to reduce demand charges on that meter.

Commercial and Industrial Use Cases

In the commercial/industrial sector, behind-the-meter storage is largely driven by two applications: resilience (the ability to provide backup power in case of a grid outage), and demand charge management (the ability to reduce spikes in the user's demand for electricity and thereby control bills related to utility-imposed demand charges).

Resiliency is highly valued by a specific subset of commercial customers for whom even momentary power interruptions are costly. These include data centers, financial institutions, medical facilities and the like. Generally, the costs of power outages are difficult to quantify, and having the ability to ride through power outages without loss of electrical service is clearly of value. For certain customers, the potential losses related to even a brief power outage are substantial. These customers may opt to install solar paired with storage systems behind the meter as a form of operational insurance. For other batteries, and their associated sophisticated power electronics, can provide assurance of superior power quality. Some manufacturers are sensitive to even minute variations in voltage. Batteries could protect such industrial users from power quality issues. It is important that the cost of building storage systems for industrial users to maintain power quality is not shifted to other ratepayers, but is borne fully by industrial customer.

For most commercial customers, however, some monetizeable benefit is necessary to justify investment in an energy storage system. By far the most widespread and valuable service currently provided by behind-the-meter battery systems is demand charge management. Generally, at current prices, commercial customers paying more than \$15/kW in demand charges can expect an energy storage system to pay for itself in demand charge reductions.

Current demand charge rates in GMP's service territory in Vermont are at approximately \$14.30 - \$14.67, just below the \$15/kW threshold, meaning that behind-the-meter energy storage systems could quickly become cost effective for demand charge management alone.²⁵ If demand charges rise slightly, or battery costs fall, the use of storage to reduce demand charges will become economical. In response the draft of this report, one commenter correctly noted that commercial users seeking to reduce their demand charges may simply be shifting costs to other customers. Unless utilities see an equivalent reduction in *actual* costs, the use of storage in the commercial and industrial sector to reduce demand charges could potentially shift costs to others. The key to avoiding such cost shifts, as other commenters noted, is accurate rate designs in which demand charges represent actual costs.

²⁵ "Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges," (Clean Energy Group and National Renewable Energy Laboratory, August 24, 2017). Retrieved from: <https://www.nrel.gov/docs/fy17osti/68963.pdf>.

Community Use Cases

Energy storage can provide benefits to “clusters” of customers, including office and industrial parks, neighborhoods, downtowns, and municipalities. Where a community is composed of adjacent buildings, particularly if they can be islanded as a group, an energy storage system can provide any number of the benefits discussed above. Such systems could be deployed independently of a utility, but would likely gain access to more benefit streams if deployed in partnership with a utility (allowing the utility to access the system to lower peaks, but retaining the community’s ability to access the system for resiliency and even renewables integration).

Economic development

Neighboring states including Massachusetts and New York are aggressively pursuing energy storage (and broader clean energy) economic development opportunities. The New York Battery and Energy Storage Technology Consortium (NY-BEST) was established in 2010 with funding from the New York State Energy Research and Development Authority (NYSERDA) “to position New



Source: American Electric Power (AEP)

York State as a global leader in energy storage technology, including applications in transportation, grid storage, and power electronics.”²⁶ Massachusetts has developed an Energy Storage Initiative, with planned and proposed funding for storage activities along the technology development curve.²⁷ In the Commonwealth’s State of Charge study, an economic development impact study using the IMPLAN model was performed and found that up to 1,766 MW of energy storage through 2020 would yield a value of \$3.4 billion to the state (\$2.3 billion in system benefits, or cost savings to ratepayers, and \$1.1 billion in market revenue to system owners).²⁸

Costs

The costs for storage have come down significantly in recent years due to increasing economies of scale. Many analysts project that costs will come down further. Lithium-ion batteries in particular have become much more affordable; however, many systems are not cost effective strictly on a monetary cost-benefit calculation. The non-monetary benefits may, in some cases, make these projects sound investments nonetheless.

²⁶ New York Battery and Energy Storage Technology Consortium(NY-BEST). *About Us*. https://www.ny-best.org/About_NY-BEST

²⁷ Massachusetts Department of Energy Resources. *Energy Storage Initiative*. <https://www.mass.gov/energy-storage-initiative>

²⁸ Massachusetts Department of Energy Resources. *Energy Storage Study*. <https://www.mass.gov/service-details/energy-storage-study>

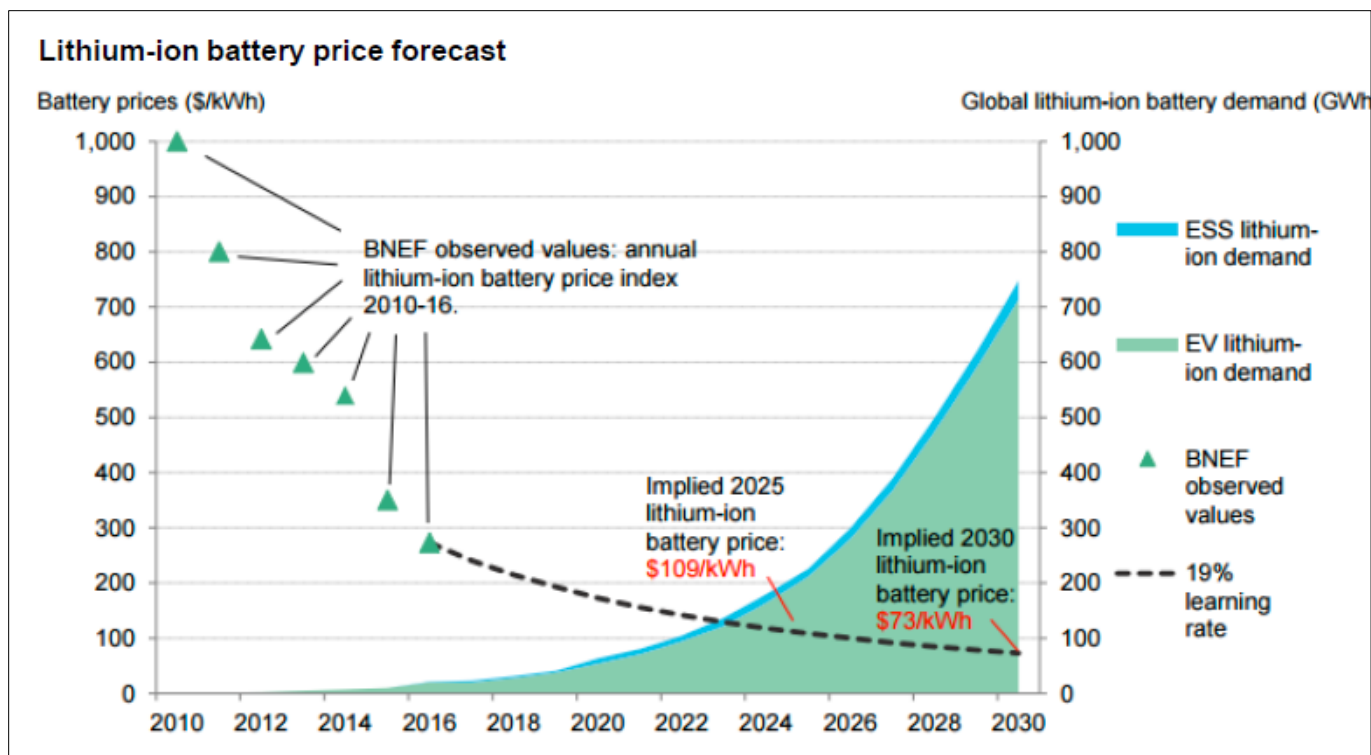


Figure 9: Lithium-ion prices fell 73% from 2010-2016, and are forecast to drop another 75% by 2030²⁹

Furthermore, as one of the commenters on the draft report pointed out, used lithium-ion batteries from electric vehicles could be aggregated into more-affordable battery systems for use on the electric grid.

As noted above, there are a wide variety of storage technologies with widely different performance characteristics. The costs of these systems also vary widely. The figure below provides a recent sampling of the varying costs of storage systems. Even while the costs of storage in different use cases can vary widely, the costs of the respective systems can be reduced by extracting value from many value streams. GMP, for example, offers its customers a resilience service with the Tesla Powerwall, but it also relies on these batteries to provide grid services such as peak reduction. GMP uses a software platform to optimize use of the Powerwall for the grid, subject to the constraints that are associated with the homeowner's use requirements defined in the service or tariff offering.

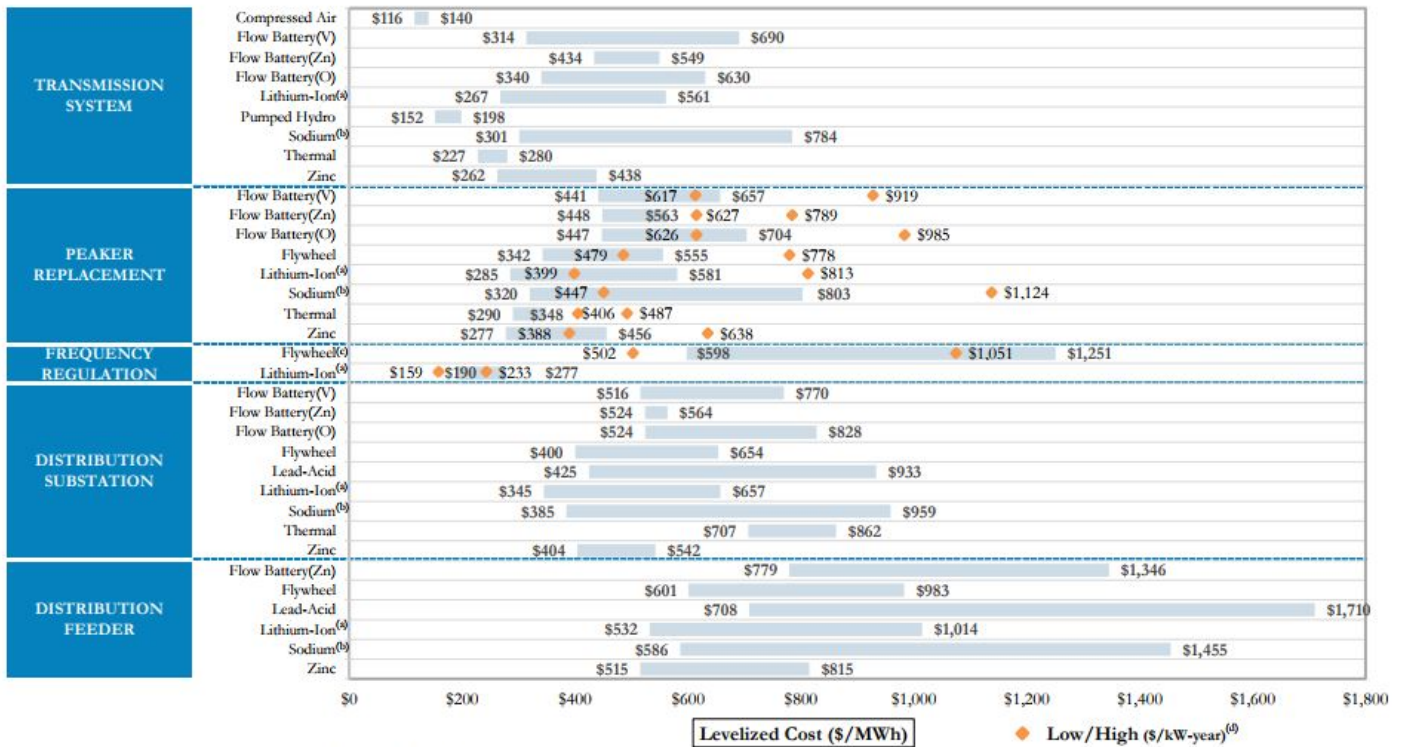
As noted earlier, even while residential storage may be among the most expensive to provide, multiple value streams could potentially be captured and aggregated to deliver grid-level services that may reduce the costs to the residential home owners and other ratepayers alike.

The costs of technologies in the charts below may represent relatively expensive options when compared with the use of flexible loads that are increasingly in homes and businesses in the form of

²⁹ Liebreich, Michael. Bloomberg New Energy Finance Summit, April 25, 2017. Retrieved from: <https://data.bloombergfp.com/bnef/sites/14/2017/04/2017-04-25-Michael-Liebreich-BNEFSummit-Keynote.pdf>.

thermal hot water, heating, and cooling systems, and electric vehicles that are parked and available to deliver services for most hours of the day. But as noted, storage can offer multiple value streams that may not be feasible with other individual load management measures, and so should be compared with that added flexibility in mind.

Unsubsidized Levelized Cost of Storage Comparison

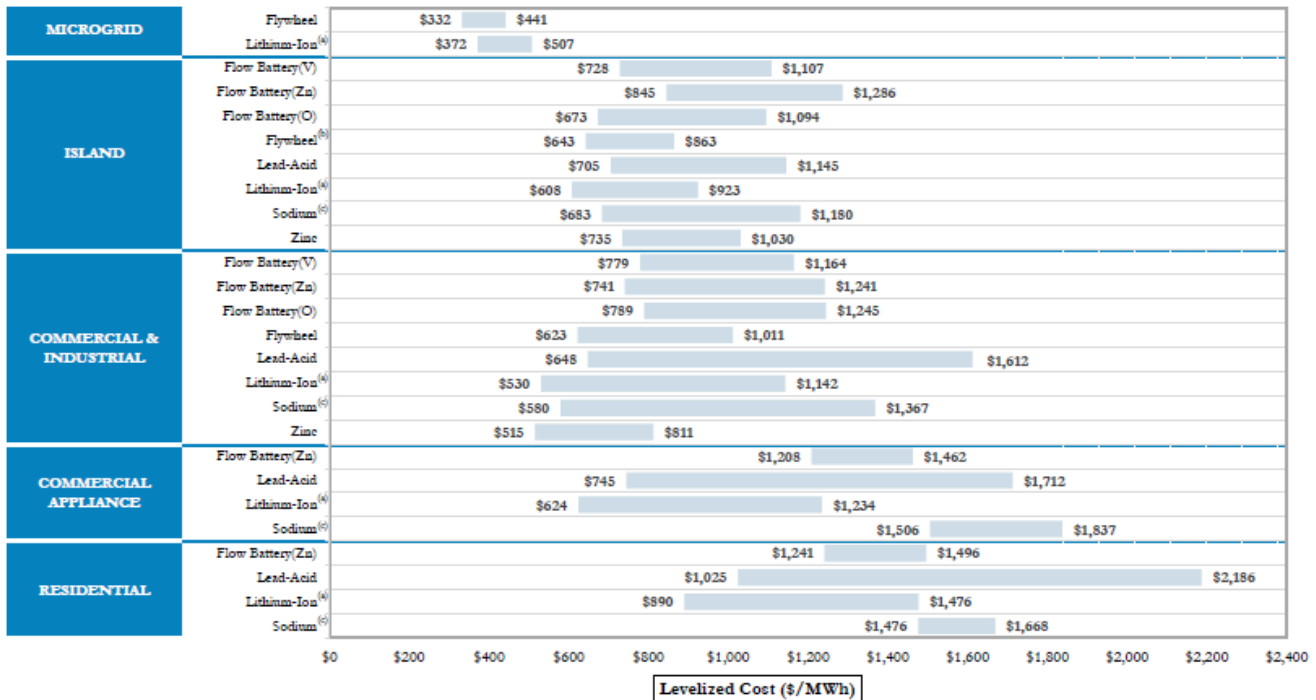


Source: Lazard and Enovation Partners estimates.

Note: Flow Battery(V) represents Vanadium Flow Batteries; Flow Battery(Zn) represents Zinc-Bromine Flow Batteries; Flow Battery(O) represents Other Flow Batteries. Lazard's LCOS v1.0 study did not separately analyze each of these distinct technologies within Flow Battery.

- (a) Lithium-Ion-Power technology used in the Frequency Regulation and Microgrid Use Cases due to low duration/high power requirements. Lithium-Ion-Energy systems are used in all other Use Cases that include Lithium-Ion technology.
- (b) Sodium-Low Temperature systems are used in Commercial Appliance and Residential Use Cases. Sodium-High Temperature systems are used in all other Use Cases that utilize Sodium technology.
- (c) Flywheel storage in the Frequency Regulation Use Case represents short-duration storage. Flywheel storage in all other Use Cases represents long-duration storage.
- (d) Reflects conversion of LCOS figure (\$/MWh) by multiplying by total annual energy throughput (MWh) and dividing by capacity (kW).

Unsubsidized Levelized Cost of Storage Comparison (cont'd)



Sources: Lazard and Envision Partners estimates.

Note: Flow Battery(V) represents Vanadium Flow Batteries; Flow Battery(Zn) represents Zinc-Bromine Flow Batteries; Flow Battery(O) represents Other Flow Batteries. Lazard's LCOS v1.0 study did not separately analyze each of these distinct technologies within Flow Battery.

(a) Lithium-Ion-Power technology used in the Frequency Regulation and Microgrid Use Cases due to low duration/high power requirements. Lithium-Ion-Energy systems are used in all other Use Cases that include Lithium-Ion technology.

(b) Flywheel storage in the Frequency Regulation Use Case represents short-duration storage. Flywheel storage in all other Use Cases represents long-duration storage.

(c) Sodium-Low Temperature systems are used in Commercial Appliance and Residential Use Cases. Sodium-High Temperature systems are used in all other Use Cases that utilize Sodium technology.

Figure 10: The levelized cost of storage (LCOS) is an approach that determines the levelized price per kWh at which benefits and costs are equal over time. The costs include up-front costs, charging, and operations and maintenance costs, plus usable lifetime energy, residual value, and financing costs. It is a way to compare storage systems for particular use cases in an “apples-to-apples” fashion.³⁰

Potential costs to the system

Several commenters noted that inappropriate, too rapid, or thoughtless deployment of storage could lead to cost *increases* to the system. If, for example, large batteries owned by commercial and industrial interests are charged during peak times, or if the charging and discharging of batteries is disconnected from the dynamic circumstances on the grid, there will likely be an overall increase in costs. For example, if the grid must be built out to accommodate the additional load batteries represent, or if commercial and industrial users use batteries to reduce their own peaks, uncoordinated with utility peaks, costs will increase for all.

³⁰ Lazard at 11.

Environmental and social costs

In addition to the financial costs of battery systems, there are environmental and social costs that must be considered. Particularly for lithium-ion batteries, which contain nickel and cobalt, there are environmental impacts associated with mining, transport, manufacturing, charging regimes, and recycling practices that determine the overall impact of storage systems. Which materials are used, how they are assembled, and whether batteries are charged from a renewable grid, and how they are recycled has implications for the environmental and human health impact of these systems. The level of greenhouse gas emissions, toxic pollution, and human health are all implicated by battery manufacture, use, and disposal. In 2013, the EPA released a report regarding the environmental impacts of lithium-ion batteries, which concluded that changes to the material and processes used to create batteries could improve the environmental performance of these assets.³¹ Siting impacts should also be considered. More study in this area is certainly warranted, and a consistent method for evaluating the environmental impact of various systems is needed.

What are the full costs of different technologies, including negative externalities and social/environmental concerns, associated with the storage technology life cycle (from mining to manufacturing to installation/operation to disposal)?—Windham Regional Commission

Emissions

It is important to better understand the lifecycle greenhouse (GHG) emission impacts of storage technologies, particularly (but not exclusively) at the utility scale. The Vermont Agency of Natural Resources currently understands utility-scale battery storage to have the potential for reducing overall GHG emissions, but depending upon how a system is operated, it could result in increased emissions. The specific charging regime also impacts the lifecycle GHG impact of a facility. For example, if a system charges when renewables are not operating, and drives up load to an extent that additional fossil generating units must be turned on in the region, the battery has not reduced emissions. However, if the battery charges when renewable output is high, perhaps the emissions impact of that system is a net positive environmental benefit. If a region is in a “duck curve” situation, and the battery system is used to store ample renewable energy during the day and then discharged during the evening ramping (when the sun goes down, but load is high and growing), the battery likely avoids significant emissions because ramping up fossil units is emissions-intensive.

Given that alternative use cases can result in reduced or increased GHG emissions over Vermont’s baseline, a review of what use cases are probable, their respective lifecycle GHG emissions, and how those impacts are reviewed through the regulatory process is important.

³¹ U.S. Environmental Protection Agency. *Application of LifeCycle Assessment to Nanoscale Technology: Lithium-ion Batteries for Electric Vehicles*. (Washington, DC, Abt Associates, April 24, 2013). Available at https://www.epa.gov/sites/production/files/2014-01/documents/lithium_batteries_lca.pdf

It is also important to understand the potential benefits of reduced emissions of other air pollutants that may result from storage technology displacement of traditional backup power sources, such as diesel generators. The expense to install a battery storage system likely exceeds the cost of a traditional diesel generator, but the long-term benefits related to emissions of particulates and other air pollutants could be substantial. These relative costs and benefits should be further explored.

Finally, it is important to understand the emissions implications of siting storage, again with a focus on batteries. Since batteries could in theory be sited at any location with a grid connection, whether there are optimal beneficial locations from an emissions standpoint should be examined (e.g. near existing load, integrated with renewable generation, near substations, etc.). And given the construction practices necessary to install and the chemical makeup of battery storage technology, it is important to evaluate whether there are there locations that have outsized risks or costs to the natural environment and thus should be avoided.

Ownership Options and Delivery Pathways for Promoting Storage

Energy storage – much like generation – can be owned and managed, in a vertically integrated state³² such as Vermont, by utilities, customers, and third parties.³³ While each ownership or management arrangement comes with pros and cons, the ability of a wide variety of actors to participate in Vermont’s energy storage deployment is important to ensuring the benefits of storage accrue to all consumers. One comment received suggested that control of storage should perhaps be determined by its primary or most significant value streams, with storage deployed to relieve grid constraints best controlled by utilities, storage leveraging regional wholesale markets controlled by the utility or another party (provided it doesn’t cause negative grid impacts), and storage deployed primarily for reliability best controlled by the customer. Control and ownership need not be mutually exclusive, either, and are explored further below.

Utility ownership

When a utility deploys a storage asset, it can control for variables such as size, technology, location, and cost. The utility can oversee the interconnection and testing of the storage asset, connect it to its controls, design the operational regime, register it in the necessary markets if desired, and manage deployment to maximize value to the utility and its ratepayers. It can determine when to schedule maintenance and, if the system is designed to provide resiliency, when to forgo market revenues in order to instead maintain charge before severe weather events. Owning and controlling a storage asset also allows the utility to test, learn from, and gain experience with such highly complex systems with diverse value streams.

In Vermont, utilities are exploring ownership of storage assets at both the “utility” or “grid” scale, as well as at smaller assets that can be aggregated to provide some of the same functional values as a single, larger-scale asset. For the purposes of this report, “grid-scale” storage refers to storage assets that are located on the distribution grid, “in front of” any end-use customer’s meter (at this point in time, these assets are nearly all batteries, from hundreds of kW to multiple MW in capacity). The largest utility-owned, grid-scale energy storage project in Vermont is Green Mountain Power’s 2 MW, 3.4 MWh Stafford Hill storage project in Rutland, described in Appendix B.

Distributed, or “behind-the-meter” storage, usually refers to batteries (but can also encompass thermal storage resources, such as ice storage) located behind the utility customer’s billing meter. These systems are usually sized to provide backup power for a home or business, and therefore can range in size from a

³² A vertically integrated utility can own transmission, distribution, and generation assets, and provides electricity to customers within a monopoly service territory. Vermont is one of 36 states in the U.S. to retain a structure of vertically integrated utilities. Other states, including all others in the Northeast, have restructured, replacing monopoly utilities with competing sellers of electricity (as well as transmission & distribution). Vertical integration is the reason why the utility in whose service territory you are located is the only entity that can “sell” electricity to you.

³³ In a vertically integrated state, any entity that is not the utility or its customer is a third party. Examples include merchant generators from whom utilities purchase electricity through a Power Purchase Agreement, and owners of group net metering generators who provide net metering service to a customer through a lease or net metering credit purchase agreement structure.

few to hundreds of kW. Utilities in Vermont are exploring deployment of distributed storage for utility-owned facility backup power, to lower customer demand charges (and, commensurately, utility demand and associated charges), and as aggregated units that can be controlled to function much like a single, grid-scale battery – to lower utility peak-related charges – but which can also provide backup power for the residences in which they’re located (see Appendix B for details and project descriptions).

Customer and third-party ownership

Distributed storage systems such as those described above – aggregated to provide value to a utility, such as in GMP’s Tesla pilots – can be owned by the utility (with customers making a monthly payment to access backup power functionality), or they can be owned by the customer, either with utility access for aggregation purposes (which brings down the up-front cost) or without.

A third-party or intermediary could also own and aggregate distributed storage assets, given the opportunity to share costs and benefits with the customer and the utility. In order for this to happen, control platforms and communications protocols must be developed and deployed to enable utilities to derive value from the storage assets by either controlling when they charge and discharge or sending signals to the aggregator or device to schedule or trigger charging and discharging. Savings to the utility from reducing load at peak hours, or revenues from participating in wholesale markets, could then be shared with the aggregator and/or customer. Customers could then “stack” this value on top of what they are willing to pay for the backup power value of the storage asset, and the sum of utility- and customer-derived value would ultimately determine the cost-effectiveness of such an investment to customers and third parties.

Some customers may place such a high value on resiliency that sharing operability with and deriving additional value from a utility or third party is unnecessary to their investment decision. This category includes entities for whom unplanned or extended interruptions in business operations would be extremely costly (e.g., manufacturers whose production runs of expensive electronics would be ruined by a disruption to the production process) as well as entities whose services are considered critical in the event of a natural or civil disaster (e.g. government offices, emergency shelters, first responders, hospitals, wastewater treatment facilities, communications infrastructure, fuel suppliers transportation hubs, supermarkets, etc.).

However, many entities in the latter category – including state and local governmental entities and communities – may not be able to bear the up-front investment in adding a backup power to a critical service facility or area, or at least not the incremental investment required to invest in battery backup rather than a traditional solution such as a backup generator. Such entities would benefit from being able to piggyback onto a utility or merchant storage asset investment being deployed to reduce load or provide market revenue streams, however, if the utility or merchant were willing or incented to locate such assets alongside high-value critical services. If generation assets (particularly those with local fuel security and reliability across seasons – such as a combination of solar and hydropower) also existed in the vicinity of the storage asset and the critical service, and could be wired to island as a discrete portion of the grid during an extended power outage, then the community would gain the resiliency benefit of a microgrid.

There are other scenarios that encourage customers to deploy their own storage. For instance, commercial and industrial customers subject to utility demand charges may find sufficient value in

deploying storage to reduce their peak demand and defray their demand charges (even if the storage asset is insufficient to provide backup power to the facility during outages).³⁴ Additionally, off-grid buildings, and grid-tied utility customers, with renewable generation resources such as solar, may deploy a storage resource to maximize utilization of that renewable generation. Off-grid customers need to “bank” solar power generated in the daytime for use at night; grid-tied customers may want to maximize their use of self-generated power.

At this point in time, most utility customers – like utilities – are choosing batteries as their preferred method of energy storage. However, other customer-owned devices can provide storage value, albeit value that flows to the customer from utilities or third parties accessing these devices and aggregating them to reduce load during certain hours. The devices include appliances that “time-shift” energy usage, such as cold-climate heat pumps and hot water heaters. In the case of the latter, water heaters can be programmed to “charge up” or heat hot water during times of low grid demand/prices and retain the heat for when customers need hot water, and also be shut off during periods of grid stress.³⁵

Electric vehicles hold promise for similar reasons – with charging coordinated by utilities or through rate structures – with the added benefit of a battery that has the potential to provide backup power to a home during outages, and to discharge to the grid to provide system-wide benefits, such as frequency regulation.³⁶ Such vehicles could include light-duty passenger or fleet cars as well as heavy-duty vehicles such as electric school buses. Issues remain, however, around maintaining battery depth-of-charge so vehicles are available when owners need them, and minimizing battery cycling to avoid shortening the lifespan of the batteries or voiding their warranties.³⁷

The role of aggregators

Aggregators of load and demand response resources may play a key role in coordinating and bidding into markets not only traditional demand response resources such as interruptible loads but also the emerging suite of flexible distributed energy resources (water heaters and heat pumps, storage, and renewables paired with storage). New models are emerging, particularly in populous areas with large concentrations of potential participants. The ability of aggregators to work in this space is directly related to their ability to receive and translate signals from utilities or even the regional grid operator to dispatch responsive resources, and to capture value from the utilities or grid operator for successful demand response.³⁸

³⁴ See note at 24.

³⁵ St. John, Jeff. “Green Mountain Power’s Latest Distributed Energy Plan: Smart Water Heaters for 99 Cents a Month.” (Greentech Media, June 15, 2017). Retrieved from: www.greentechmedia.com/articles/read/green-mountain-powers-latest-distributed-energy-play-grid-smart-water-heate.

³⁶ National Renewable Energy Laboratory, Transportation Research. *Electric Vehicle Grid Integration*. www.nrel.gov/transportation/project-ev-grid-integration.html.

³⁷ Glitman, Karen and Stephanie Morse. *Electric Vehicles as Grid Resources in ISO-NE and Vermont*. (Burlington, VT: Efficiency Vermont, May 2014). Retrieved from: www.veic.org/documents/default-source/resources/reports/evt-rd-electric-vehicles-grid-resource-final-report.pdf.

³⁸ Kolo, Elta. *U.S. Wholesale DER Aggregation: Q2 2016*. Greentech Media, July 2016. Retrieved from: www.greentechmedia.com/research/report/us-wholesale-der-aggregation-q2-2016

Select National Demand Response Aggregators Registered Within ISO/RTO Territories



Figure 11: Traditionally controlled behind-the-meter resources include load control, thermal storage and on-site generators. However, growing interest in aggregation services is pushing players, independent system operators (ISOs) and regional transmission organization (RTOs) to look beyond traditional behind-the-meter management. New approaches will unlock value streams for up-and-coming technologies such as distributed generation, electric vehicles and battery storage (from GTM Research, *U.S. Wholesale DER Aggregation: Q2, 2016*: <https://www.greentechmedia.com/research/report/us-wholesale-der-aggregation-q2-2016>).

Stakeholder considerations

The Department solicited input from many energy storage stakeholders, including utilities and storage project developers, that highlight some of the considerations when it comes to ownership structures. In general, Vermont utilities are looking for simplicity, control, and value to customers when evaluating storage investments, but are not insistent on owning storage assets outright.

The primary objective should be to lower the total cost of constructing and operating the grid so that all electric utility customers (not only those who participate in battery storage projects) save money—Green Mountain Power

Storage project developers are very interested in developing utility-scale batteries for Vermont utilities (either as the contractor or third-party owner with a PPA agreement), and would also like to fulfill residential and commercial customer requests to install storage (often concurrent with installation of a solar project in order to access the ITC, and in many instances spurred by Green Mountain Power's residential Tesla Powerwall offering). These developers would like to be able to install Tesla or other

storage technologies to customers, but are not presently able to perform Tesla installations or otherwise make these projects cost-effective without being able to share access and value with utilities. As with other projects that rely on outside sources of capital, developers are looking for contractual structures that offer a fixed revenue stream over a number of years (5+).

It is important that all stakeholders – electricity end users, storage project owners, ratepayers, and utilities (on a transparent and competitive procurement basis) have access to realizing the benefits of energy storage—Renewable Energy Vermont

Other Considerations

Federal and state jurisdictional issues regarding deployment of energy storage

The Federal Power Act grants the Federal Energy Regulatory Commission (FERC) authority over transmission and wholesale sales of electricity in interstate commerce. There is very little dispute with respect to FERC's authority over transmission – it establishes interconnection standards and ensures that any rates charged for use of the transmission system are just and reasonable. A project interconnected to VELCO's transmission system will be required to follow the ISO-NE interconnection requirements (which are subject to FERC jurisdiction). A project interconnected to the system of one of the Vermont electric distribution utilities will be subject to that utility's interconnection review (which is subject to PUC Rule 5.500).

In recent years, issues related to wholesale sales in interstate commerce (for example, the sale of electricity from a power plant in New Hampshire to an electric utility in Vermont) have been increasingly litigated. Generally, wholesale sales in interstate commerce are regulated by FERC, while retail sales (sales from the electric utility to the end-use customer) are regulated at the state level. However, given the interrelated nature of the electric grid, actions taken at the federal level have consequences for state decisions, and vice versa. In 2016, the U.S. Supreme Court clarified that FERC has the authority to regulate practices that directly affect wholesale prices even if those practices are also subject to state jurisdiction.³⁹ In that particular case, the Supreme Court found that FERC had authority to issue rules regarding the participation of demand response in wholesale electricity markets, despite the fact that demand response occurs at the retail level and is subject to state jurisdiction. The Court found that “the practices at issue in the Rule – market operators’ payments for demand response commitments – directly affect wholesale rates.”⁴⁰ The phrase “directly affect” is likely to be the subject of litigation for some time.

The charge and discharge of storage projects is likely to be subject to disputes over state and federal jurisdiction. Not only can storage act as either load or generation but also it can participate in the regional wholesale electricity market, or it can be used to reduce a distribution utility's load obligations at ISO-NE.⁴¹ In the former case, a resource would be considered “in front of” the ISO-NE meter, where the actions taken by the storage resource follow the ISO-NE market rules. To the extent that a resource is “behind” the ISO-NE meter, it is reducing market obligations but not participating in the ISO-NE market. The underlying assumption regarding value streams for storage is that resources would be able to maximize value both within and outside the wholesale market construct for the same resource – for example, a project could participate in ISO-NE's frequency regulation market (and be in front of the ISO-NE meter) but also reduce transmission and capacity costs by reducing the utility's load during the peak times (and be behind the ISO-NE meter). At this time, there is no barrier for a storage resource to

³⁹ *FERC v. Electric Power Supply Ass'n*, 136 S. Ct. 760, 774 (2016). (Commonly referred to as the EPSA decision.)

⁴⁰ *EPSA*, 136 S. Ct. at 773.

⁴¹ Generally, a generation project larger than 5 MW must participate in the ISO-NE wholesale electricity markets; projects under this size can participate if they so choose and small projects can be aggregated and bid into a market collectively.

participate directly in one wholesale market but reduce obligations indirectly through actions outside the wholesale market. However, the market rules can, and likely will, change over the life of a storage resource and these changes will likely be influenced by additional clarity over the line between state and federal jurisdiction over these resources.

In November 2016, FERC issued a Notice of Proposed Rulemaking that would require regional entities such as ISO-NE to establish market rules that accommodate storage resources and also allow aggregations of distributed storage resources to participate in the wholesale electricity markets. A number of entities filed comments on the proposed rule, with several explicitly noting that additional clarity over state versus federal authority over storage is needed. FERC has yet to finalize rules in that docket; however, it's unlikely that the promulgated rules will resolve all jurisdictional issues regarding storage going forward.

Safety training for first responders

Because some battery technologies require specific fire-fighting techniques, it is essential that first responders be made aware of the battery chemistry before attempting to fight a battery fire. Developers of storage projects should place appropriate signage in the vicinity of the battery storage facilities and should also, immediately upon completion of construction of the facility, inform local first responders of the nature of the facility.

Sales and property tax treatment

Stakeholders have suggested that storage, in particular storage + solar, should be treated akin to solar for the purposes of sales and property taxes. With respect to the latter, the Department of Taxes has established a protocol for the state and municipalities to assess property taxes on a solar plant.⁴² Such a protocol may need to be developed for solar + storage – or standalone storage – assets, and deserves further exploration

Software platforms

The development of software platforms to control the dispatch of storage and other distributed energy resources by utilities – either based on programmed dispatch or in real time – is still in its infancy. These platforms consist of algorithms that determine optimal dispatch of charging and discharging of storage systems for capturing the best value at any given time from one of more value streams, while recognizing the operating limitations of the storage (e.g., depth of charge and degradation). Green Mountain Power is using Tesla's platform, GridLogic, to control its residential Tesla Powerwall fleet and hopes to use it for any utility-scale Tesla Powerpack batteries it deploys.

Ultimately, it is important these platforms evolve to a point where they can dispatch and optimize around many storage and other distributed energy resourced systems, many value streams, and multiple providers of storage – including different storage technologies made by different manufacturers, either behind or in front of the meter, and under different ownership structures (utility, customer, and third party), to ensure no single technology or application monopolizes the marketplace, and consumers benefit from maximum choice and value.

⁴² Vermont Department of Taxes. *Solar Valuation*. <http://tax.vermont.gov/municipal-officials/solar-valuation>

With a reliable, secure, open architecture smart grid framework capable of sending price signals and reliably accounting for flexible demand response and storage performance, Vermont can unlock smart grid innovation across the state—Dynamic Organics and Baycorp Holdings

Enabling technologies

Essential to the operation of any given software platform is the availability of telecommunications infrastructure (smart meters, fiber connections, and wifi) to enable the utility to communicate (ideally within seconds) with the storage device and tell it to charge or discharge. Any weak link in the ability to securely, instantaneously signal storage assets will limit the values to the utility (and any customers or third parties involved in the transaction). Vermont’s telecommunications infrastructure is not evenly robust throughout the state and can differ markedly utility-by-utility, and thus should be considered a near-term limiting factor to optimal deployment of storage throughout the state.

Potential Programs and Policies to Encourage Storage in Vermont

There are a number of approaches Vermont could take to encourage sound storage capabilities in Vermont. These span a continuum from removing barriers, to regulatory and financial incentives, to mandates. Each option or suite of options comes with its own set of costs, benefits, and tradeoffs. This section describes some potential approaches, including those suggested by stakeholders, and lays out pros and cons.

Utility planning exercises

Every three years, utilities in Vermont conduct long-range planning exercises to identify future needs for energy and power, renewability, and grid upgrades in advance, and to identify the “least-cost” way of meeting those needs. This is known as an “Integrated Resource Plan” (IRP).⁴³ The Department periodically issues a guidance document which lays out a framework and set of issues that the Department would like utilities to address in their plans. As the industry evolves, the guidance document has been periodically amended to focus attention on emerging issues. In 2016, the Department released new guidance that encouraged utilities to consider storage in a variety of ways:⁴⁴

⁴³ The requirements for IRPs are outlined in 30 V.S.A. § 218c.

⁴⁴ The most recent version of this IRP Guidance document can be found at this link (storage is referenced on pages 5, 11-13, and 24):
http://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/State_Plans/Comp_Energy_Plan/2015/Appendix%20B.pdf

1. The potential adoption of customer-sited storage (including industrial, commercial, and residential). Customer-sited storage may impact the shape and timing of load, revenue collections, and net-metering accounting.
2. The value-proposition of storage for utility-scale systems
3. The potential of utility-scale storage to meet transmission, distribution, and power quality needs
4. The utility's role and potential tools in shaping and managing load
5. The potential of storage to disrupt traditional utility business models

Because these guidelines are new, many utilities have yet to complete an IRP that considers storage in these ways. However, several utilities *have* already begun to plan for storage in the IRP process. Both Washington Electric Cooperative and Burlington Electric Department used recent IRPs to look at potential applications for utility-owned storage and to develop ways to evaluate the value proposition for storage. As storage technology becomes more affordable and more prevalent, the Department expects that utilities will include storage as a potential solution to power supply and grid issues, but also the effect of customer-sited storage on utility operations and financing.

Rate design, tariffs, and distinct pricing of storage-related services

Perhaps the biggest challenge to achieving more storage deployment is the lack of clear market mechanisms to transfer some portion of the system benefits created to end users and the third-party developers.⁴⁵ Well-formed price signals sent to end users, the pricing of individual services from storage systems and other emerging advanced capabilities can help to address the gap. By “price” we mean to include the price signal that end users or third-party storage providers see, or the price of services or incentives received in exchange for yielding some measure of control or delivering services to the network system.

The New England grid has been built to meet peak load. Peak load is typically a few hours during the warmest period of the summer or the coldest in the winter. Most of the time, the unused capacity can be viewed as storage capacity sized to deliver on peak energy demand, but capable of delivering on loads below it. Energy is delivered to end users in an instant regardless of the varying loads and production at the consumer's location. The immediate response is made possible by a utility system that is built, and potentially overbuilt, to deliver energy up to that peak. Leveling the load over the daily and seasonal cycle provides an opportunity to reduce the costs of supply, which are typically higher during times of peak load. What holds for the regional transmission system also holds at the subtransmission and distribution system.

With respect to distributed generation, at local peak production periods, distributed generation has the potential to saturate local loads and push the flow of electricity back toward upstream networks (i.e., back-flow). The system could be designed or reconfigured to accommodate, but to date, the distribution utility equipment was not designed to manage significant back-flow of electricity. Addressing back-flow requires either upgrades to the equipment or setting limitations on the amount of variable generation

⁴⁵ State of Charge at xiii.

produced. In Vermont, this has materialized as distribution circuits that are now constrained, or a large region of the state that is export constrained.⁴⁶

One important contributing factor is the price signals that end users see. Prices are (largely) currently set on the basis of a uniform usage rate or price per kWh.⁴⁷ The price that end users see as either consumers of electricity or producers (with, say, rooftop systems) does not differentiate by time of day or geographic location. In effect, there is no incentive to manage load, even where such a shift would be beneficial to the system and ratepayers generally. This feature of pricing makes sense in an environment in which consumers, their agents, or their utility have little ability or interest in managing their loads. In the emerging era of low-cost storage, distributed generation, communications, automation, and consumers empowered by smart phones and new business models, price may have a larger role to play.

Third-party Aggregators and Developers

The direct motivation for price signals would be to motivate responses from end-users, perhaps in the form of changing usage patterns or investments in enabling technologies like Nest thermostats that accomplish much the same. For most consumers, however, active management of their loads is a distraction from the flow of normal patterns. Electricity bills represent only a small portion of their overall cost of living and anguishing over the particulars of their time-of-use patterns may be of little interest to many, or most, customers. Rate design and/or the monetization of storage-enabled grid services can also help foster new business models for businesses to intervene, by offering technology options that deliver grid services. Given the burgeoning array of enabling technologies that include storage and advanced inverters, fostering new pathways to finding value for customers may have some merit.

Traditional Time-of-Use Pricing

Options for price include innovations around options already available. The price signals that are available to most customers are fairly muted – modest peak versus off-peak pricing. Price signals could be expanded, and customers could be empowered with more and better information about their own load characteristics as well as with technologies on smart phones that help to remotely control certain flexible loads (e.g., water heaters, cold-climate heat pumps, and electric vehicles). Even if end users resisted the complexity, new business models might emerge for customer or utility agents to manage loads in ways that serve both the customer and the utility.

End-use Time-of-Use Rates

Options include reliance on a form of time-of-use pricing that is end-use specific. A variation on this might allow an end-use-specific price signal. Mitigating against this is the high cost of separate meters. However, sub-metering options are available that are low-cost and could render this feasible. In

⁴⁶ The GMP Solar Map shows constraints on the system that limit interconnection absent an upgrade to the system. Current practice requires customer payment for upgrades to allow more interconnection.

<http://gmp.maps.arcgis.com/apps/Viewer/index.html?appid=546100cc60c34e8eb659023ea8ae03f3>

⁴⁷ We ignore the customer charge, demand charge, inclining block rates and even the optional time-of-use rates that exist in for most distribution customers. The latter is seldom marketed, unpopular with customers, and requires a deeper knowledge of household loads and value than most customers possess.

response to a time-varying price signal, loads could be managed by the customer, a third party, or the utility itself.

Other Forms of Time-Varying Rates

There are a wide range of additional time-sensitive rates that fall into the category of dynamic rates. These may be regarded as overly complex by the vast majority of customers, but may be well within the capacity of a third-party agent, acting on behalf of customers or the utility, to manage. The utility itself, either alone or with empowered agents, could be contracted by the customer to help manage its loads to capture the value of dynamic pricing arrangements.

Controlled Loads

The utility could just jump ahead and strike arrangements directly with customers through controlled loads. For decades, utilities in Vermont have offered rented water heaters controlled by the utilities through either ripple-controlled systems or systems that were clock controlled. In exchange for some measure of control over the operation of the water heater, customers were given a credit on their monthly bill. In effect, this type of arrangement is already taking hold on a pilot basis in GMP's service territory. Larger Vermont customers also control loads for snow-making and manufacturing in exchange for a lower rate or incentive. The value of this framework is that the utility is well positioned to identify and capture one or more value streams from the loads. The framework can also exist with some reliance on third-party agents or aggregators. Utilities in New England have experience with demand-response providers like Comverge and Enernoc, which are now global providers of these same services.

Time-of-Use Rates for Net Metering

As noted above, there is little incentive for customers to manage the time or location of generation, either during operation or in relation to siting. The product of current pricing is that customers have every incentive to rely on the electric utility system as battery storage and generate electricity in ways that require little or no storage. The surge of generation in certain parts of the state has the effect of limiting future customer generation in those same areas. The net metered arrangements going forward could be restructured for new customers to encourage them to manage loads through effective use of storage or load shifts. This could include a combination of time-varying pricing and two-directional price signals. The combination of signals would send consumers the signal to consume power when it is most valuable for the consumer and the utility for customers to self-deliver, and to provide electricity to the system when that is most efficient.

Separately Price Distinct Services

Storage is sometimes referred to as the Swiss Army Knife of electricity delivery. There are a wide variety of services that can be provided through a combination of storage and smart inverters. Frequency regulation services are provided in the PJM region using controlled water heater loads. Smart inverters can improve power quality and deliver ancillary services.⁴⁸ Storage systems can provide ancillary services, ramping capability, energy arbitrage, and add to customer and grid resilience. These services can be actively managed by the grid, but new business models and practices may emerge in an environment in which these services are distinctly priced and managed by either the utility or third-

⁴⁸ "Advanced Inverter Functions to Support High Levels of Distributed Solar: Policy and Regulatory Considerations," (National Renewable Energy Laboratory, November 2014). Retrieved from: www.nrel.gov/docs/fy15osti/62612.pdf

party agents acting on behalf of the utility or their customers, perhaps compensating customers through reduced rates or credits on the monthly bill in exchange for services.

Other Options

Many other pricing options exist. One suggestion made by a stakeholder is to rely on statutory or regulatory targets for renewables that are time- or location-differentiated. Under such a framework, renewable energy credits could be priced differently by time of day. The oversaturation of credits during periods of intense solar energy would motivate some customers or their agents to build storage or manage load so as to capture value of higher resulting prices.

In summary, the new ways of pricing electricity service to either retail customers or to third-party agents working in concert with the customer or the utility offers considerable promise for the timely advancement of technologies like storage, smart inverters, and controlled loads.

Energy assurance efforts

Vermont's Energy Assurance Plan (EAP) discusses microgrids as one way to "keep the lights on" when utility power is lost to a circuit (or a portion of a circuit). The current EAP (completed in 2013) contemplates microgrids using generation units, and not energy storage; however, energy storage has become technologically feasible as well, and might complement generation in a microgrid setting. Since utility-scale batteries may only last for a few hours, batteries could be effective during short-term power outages, but perhaps not long-term outages (depending on the loads), which would necessitate the use of some sort of generation.⁴⁹

Some stakeholders have suggested including storage in the 2018 revisions to the State Hazard Mitigation Plan and the State Emergency Management Plan (SEMP), in order for the state to be eligible for FEMA funding in the event of a natural disaster. In discussions with Vermont Emergency Management (VEM), it became clear that the suggestion would not yield the desired result, and that the Energy Assurance Plan would be the more appropriate home for any storage language. In order to be eligible for funding after a disaster, an asset would need to be publicly owned (rendering infrastructure owned by an investor-owned utility ineligible, for instance). Additionally, reimbursement would only be made for the particular infrastructure that was damaged – not for replacement with different or additional infrastructure such as storage. Finally, in terms of mitigation funding, at this time FEMA is only funding traditional backup generators and does not recognize storage as a funding-eligible infrastructure type. That being said, the Department and VEM are enthusiastic about the potential for storage in energy assurance efforts, and we offer several suggestions for consideration in the Recommendations section below.

Another area for consideration, which would not require a microgrid, is for each home or building to have its own battery to get through a short-term outage (hours or one day, depending on use). Batteries deployed to provide backup power can also be used for day-to-day functions such as maintaining reliability and/or power quality on a circuit, or even wholesale power benefits such as peak shaving if

⁴⁹ The Sterling Municipal Light Department in Sterling, MA, has implemented a microgrid project with 2 MW/3.9 MWh of lithium-ion batteries and 2.4 MW of solar; the battery alone can run the police station and emergency dispatch center for two weeks, longer with solar. <http://www.cleangroup.org/ceg-projects/resilient-power-project/featured-installations/sterling/>.

deployed in the aggregate – though availability for resilience purposes would need to take precedence, limiting the batteries’ availability for other services in some instances.

Regulatory review process and criteria

Title 30 provides the regulatory framework for the Vermont Public Utility Commission’s (the “Commission”) review of applications for electric *generation* or *transmission* facilities in order to issue, or not, a certificate of public good. Currently, Section 248 of Title 30 does not explicitly address storage. Without further statutory and regulatory guidance, storage is left to proceed unregulated, particularly small-scale storage installations. Storage’s resemblance to generation means many of the same issues regarding ratepayer and system-wide benefits and costs may arise and require regulatory review. Section 248, which is used for review of larger generation projects, could be used (or modified) to accommodate larger storage projects, while a review process more akin to Title 30 Section 8010, used for review of smaller, net metering projects, might be more appropriate for use in review of smaller, behind-the-meter storage projects (as well as projects paired with net metering systems). Using § 8010 as a model, the Legislature would be able to tailor the engineering, economic, safety, and environmental considerations that come from this report and other storage studies. The Legislature would also be able to use a § 8010-like statute to articulate the appropriate cost allocation – in terms of credits, system implications and benefits, and Commission rulemaking – as well as how to evaluate non-monetizable benefits, such as integration of renewables and community and residential resiliency. Regardless of the statutory approach, the Commission will also need to change its rules in order to refine storage review, and it will likely require guidance from the legislative process in order to effectuate those changes. In many instances, this may require only modest changes to existing rules (such as the newly established Rule 5.900, which addresses system decommissioning). Stakeholders have additionally suggested that storage projects under certain conditions (size, location, type) should not be subject to state agency review fees, which would best be considered in the context of periodic comprehensive legislative review of agency fees.

Interconnection standards

All forms of electric storage would use the existing Public Utility Commission (PUC) interconnection rule (Rule 5.500). The currently adopted version of this rule does not explicitly include storage, but the rule is applicable to storage (Green Mountain Power used the existing Rule 5.500 to determine the system impacts of its proposed Panton battery project). The existing PUC Rule 5.500 is applicable to electric generation and transmission, and electric storage can provide the functionality of both generation and transmission. The currently proposed revision to Rule 5.500 explicitly includes storage, and this rule is expected to be finalized in 2018. In practice, the interconnection requirements of electric storage are very similar to those of inverter-based distributed generation.

Some stakeholders have broadly suggested that interconnection standards in general should include standards and procedures for non-exporting systems, special standards for exporting systems, methods for determination of storage system capacity, and inverter and communication control standards. Others have suggested that the pending rule should be reviewed for impacts on energy storage projects, and should allow projects co-located at existing points of interconnection to have expedited review or exemption from utility requests for supplemental review if there is no increase in electricity injection from the project. While the rule under consideration does not necessarily go in to this type of detail or nuance, it does proactively incorporate storage and does not appear to present an apparent barrier to

deployment of storage projects. Storage systems that would be “behind the meter” and not export to the grid would be exempt from the Rule 5.500 and the Section 248 processes. Storage systems that would export to the grid would each be studied pursuant to Rule 5.500 on a case-by-case basis according to its particular circumstances.

With respect to stakeholder comments regarding the need for accurate representation of and assumptions about the electric system in the interconnection application context, as well as policy frameworks to consider storage options to allow additional generation where saturated distribution circuits exist, the Department agrees these are areas worthy of further consideration but feels they may be better housed within a comprehensive discussion of distribution system planning, which is beyond the scope of this report.

Procurement targets

Several stakeholders suggested Vermont should consider setting energy storage procurement targets – either mandatory (as in California) or aspirational (as in Massachusetts) to spur the development of storage in the state (other states adopting targets include Oregon, New York, Nevada, and Maryland). Utilities, on the other hand, argue that Vermont is not in the position of needing to mandate or even incentivize its distribution utilities to consider storage in their resource planning initiatives. Based on input to this report and the extensive list of projects under consideration or development in Appendix B, it is apparent that Vermont’s distribution utilities are deploying or actively considering storage, but each has a different calculus in terms of determining costs, benefits, and timing. In addition, the efforts by one utility in particular to deploy and promote storage – Green Mountain Power – have led to customer demand for similar opportunities with other utilities and from non-utility entities. The key from the perspective of utilities is to deploy storage where it makes sense and will displace an alternative – not deploying a specified amount of storage in a certain timeframe. From the perspective of third-party storage providers, setting targets would spur market development and private investment, and – if predicated on cost-effectiveness – benefit ratepayers.

Modification of existing or development of new programs and incentives

Vermont offers a number of different programs and incentives for renewable energy programs that could be modified to explicitly include or encourage energy storage. These include the Clean Energy Development Fund, the Standard Offer Program, the Net Metering Program, and the Renewable Energy Standard.

Clean Energy Development Fund

In their *State of Charge* report, the Massachusetts Department of Energy Resources recommended providing incentives totaling \$10 million for demonstrations to jump-start the market; and the state is proposing over \$50 million in total for programs that could include storage. The funding would come from an existing fund of Alternative Compliance Payments (ACPs) made by utilities failing to meeting state Renewable Portfolio Standard (RPS) requirements. While Massachusetts’s RPS began in 2002, Vermont is only in the first year of its RPS and as of yet has not collected any ACPs. In the event a Vermont DU is unable to meet its RPS obligations, it would pay an ACP into the Clean Energy Development Fund (CEDF), which could then be used for any of the expenditures the Fund is authorized to make (including storage). The CEDF does not currently have any funding source, other than repayments from loans and repurposed funds from programs that are not fully obligated. At this time, the CEDF’s fund balance is fully budgeted; however, that does include \$50K for a storage project in FY18.

The RFP for that funding will be based on recommendations from this report for the most impactful way to deploy those modest funds.

Standard Offer Program

The Standard Offer program (30 V.S.A. 8005a), designed to procure 127.5 MW of cumulative renewable energy capacity through 2022, has been modified many times since its creation in 2009. The program has procured 83 MW of capacity to date, and the most recent annual RFP – for 7.5 MW of capacity – attempts to balance multiple objectives including price competition, technology diversity, preferred locations, and provider vs. developer allocations.⁵⁰ Several stakeholders have suggested that a renewable energy + storage pilot initiative should be implemented in 2019 and 2020. Energy storage could supplement any of the resources bid into the various categories, but the objectives for doing so would need to be clearly defined and avoided price caps would need to be developed in order to fairly evaluate bids. There is a broader conversation to be had about whether a program trying to achieve so many objectives can achieve any single one of them well, and discussion of any additional program modifications involving storage – such as a solar + storage pilot – should be had in that context.

Net metering program

Vermont's net metering program (30 V.S.A. 8010), designed to allow utility customers to generate electricity up to their annual consumption, has seen a similar evolution through time. When the program first started in 2002, it was open to farmers only, for systems up to 100 kW. The program gradually expanded to encompass all customer types, to allow for projects up to 500 kW (and for a time, up to 1 MW, if it benefitted municipalities), and to allow for group and virtual net metering. Caps of cumulative capacity in relation to utility peak that once existed were met and expanded, and a program that was initially based on "spinning your meter backwards" gave way to two-way power flow valuation, with exports receiving an adder (supplanting up-front incentives for systems from the Clean Energy Fund). In 2014, the legislature directed the Public Service Board (now Public Utilities Commission) to revise the program to accomplish a number of objectives, including advancing state energy goals, achieving a level of deployment consistent with the Comprehensive Energy Plan, avoiding cost-shifting, accounting for costs and benefits, ensuring the ability of customers to participate, balancing deployment with rate impacts, accounting for the changing cost of technology, and allowing customers to retain Renewable Energy Credits (or give them to their utility). The new net metering program took effect in January 2017 and provides adjustors to projects based on size, preferred location, and treatment of renewable energy credits. The program also has a built-in adjustor review on a biennial basis, with the first slated for 2018.

It may be worthwhile to start to examine if and how energy storage should be incorporated into the net metering program, either in terms of the goals articulated in the governing statute or more directly through potential amendments to the rule and/or adjustors. However, after several years of program stops, starts, and redesign, it may be prudent to allow the program to operate for a year or so to better understand the "new normal" pace and pattern of deployment, before attempting any amendments. In the meantime, stakeholders could begin to consider whether and how storage could be addressed in the 2018 adjustor review.

⁵⁰ VEPP, Inc. *Standard Offer Program*. www.vermontstandardoffer.com.

Renewable Energy Standard

Vermont's Renewable Energy Standard (RES) contains three tiers.⁵¹ Tier I requires utilities procure 55% of their sales from renewables by 2017, and 75% by 2032, from renewables of any size or provenance. Tier II requires utilities to procure 1% of their sales from new distributed generation by 2017, and 10% by 2032. Tier III requires either new Tier II resources or fossil fuel savings through energy transformation projects, equivalent to 2% of sales in 2017 and 12% of sales in 2032. Act 56 of 2016⁵², which created the RES, includes "infrastructure for the storage of renewable energy on the grid" as an example of an eligible energy transformation project; however, utilities to date have not proposed storage in their Tier III plans, primarily because other types of eligible projects – including weatherization and support for electric vehicles – offer much more clear-cut fossil fuel savings.

Some stakeholders have suggested that the RES be modified by creating a storage-specific expansion to the Tier III program; others have suggested that the Department could more explicitly support storage as a Tier III solution by adopting a lifecycle evaluation framework for energy storage fossil fuel reductions and comparisons with other measures (e.g., expanding distribution infrastructure).

EEU Activities

The Massachusetts *State of Charge* report discussed the potential need for changes to cost-benefit test methodology guidelines in order to accommodate storage in utility demand reduction programs. In Massachusetts, utility efficiency programs are administered by an entity called MassSave, a collaborative of gas and electric utilities and efficiency providers, and have a new focus on peak demand savings. Vermont has created a separate entity to run statewide efficiency programs – Efficiency Vermont (Burlington Electric Department and Vermont Gas each run their own efficiency programs). Several stakeholders suggested authorizing these three Energy Efficiency Utilities (EEUs) to lower peak demand with storage in a similar fashion. The electric efficiency measures implemented by Efficiency Vermont and Burlington Electric Department are funded from the Energy Efficiency Charge collected on ratepayers' electric bills, and both have traditionally focused these funds on electric efficiency measures. Some stakeholders have suggested that EEUs be empowered to take a "total energy" approach that can include storage (this concept is being explored in a separate report pursuant to Act 77), and also that the EEUs' focus be expanded to include measures that actively reduce peaks.

Cross-Programmatic Concepts

Various stakeholders have made suggestions that span multiple programs. These include providing an up-front incentive or other financial motivator (without reducing existing incentives for other technologies), offering in-state technology providers an additional incentive (e.g., 20% such as in California) and considering a cap on any particular technology for incentive programs, to prevent a monopoly at the hardware level.

⁵¹ Public Utilities Commission. *Renewable Energy Standard*. <http://puc.vermont.gov/electric/renewable-energy-standard>

⁵² An act relating to establishing a renewable energy standard, <http://legislature.vermont.gov/assets/Documents/2016/Docs/ACTS/ACT056/ACT056%20As%20Enacted.pdf>

Several stakeholders have suggested moving to a framework of incentivizing peak load reduction, rather than renewable energy production. One way of accomplishing this is tying compensation for production and or load reduction to peak coincidence, including through time-of-use rates (discussed above). In their report *Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future*,” Strategen Consulting recommends awarding additional value to renewables that are available during peak demand periods, thus encouraging the use of storage paired with renewables.⁵³

Demonstration projects and R&D

At this point, it would be fair to characterize nearly all – if not all – storage projects deployed in Vermont as demonstration projects, as they are all enabling utility, customer, third-party, and regulator learning about different storage technologies, use cases, costs, and benefits. Projects that provide ratepayer savings while simultaneously facilitating the integration of renewables and providing meaningful resiliency benefits – to residences, communities, and/or critical facilities – are the “holy grail” of storage deployments in Vermont, which should offer a guidepost for those working in the storage space. However, in the near term, projects may need to sacrifice renewables integration and resiliency benefits in favor of savings to ratepayers, or conversely, will need to make the case that these “non-monetizable benefits” should outweigh any marginal cost-benefit to ratepayers. Massachusetts has devoted \$10 million to soliciting storage demonstration projects (and over \$50 million for programs that could include storage), but in the absence of comparable resources, Vermont will need to find other ways to encourage exploration of diverse use cases and sensible deployment opportunities.⁵⁴

⁵³ Fishman, Zoe. “Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future.” (Strategen Consulting, December 1, 2016). Retrieved from: www.strategen.com/new-blog/2016/12/1/evolving-the-rps-a-clean-peak-standard-for-a-smarter-renewable-future

⁵⁴ Massachusetts Department of Energy Resources. *ESI Demonstration Program Advancing Commonwealth Energy Storage (ESI ACES)*. www.mass.gov/service-details/esi-demonstration-program-advancing-commonwealth-energy-storage-esi-aces

Recommendations

The Department offers the following recommendations in the context of the costs and benefits of, challenges to, and opportunities for prudent deployment of storage in Vermont. As discussed in the report, we view energy storage as a means to an end – rather than an end in and of itself – and thus many of our recommendations focus on pursuit of storage within the broader pursuit of a clean, efficient, reliable, and resilient grid in the most cost-effective manner for ratepayers. To achieve this end will require flexible demand and generation, brought about not only through technologies such as storage but also by other means of controlling and orchestrating electric loads and production and through deeper insight into distribution-level infrastructure and dynamics. We are cognizant of the economic opportunities rendered possible by the technological innovations and falling costs of advanced energy storage in the last few years, and see potential for consumers, utilities, and third parties alike to share in the rewards of early deployment. However, we also believe it is important to proceed with some amount of caution to ensure ratepayers will achieve the greatest benefit possible through careful, thoughtful deployment of the technology, and that energy storage is evaluated for its specific benefits in specific use cases against other potential solutions. We anticipate continued conversation with stakeholders and the legislature about the best path forward, and are grateful for having had the opportunity to spend time exploring the topic with many others over the last few months.

Utility planning exercises

Utility Integrated Resource Planning

Utility Integrated Resource Planning offers a unique opportunity for utilities to do deep thinking about the most effective and least-cost methods to meet customer needs for energy, capacity, renewability, and a reliable grid. There are several roles that storage could potentially play as utilities plan to meet customer needs. As some commenters noted, the amount of storage needed to address local distribution grid issues is likely to be discrete and case-specific, but in some cases may offer real financial advantages over traditional poles-and-wires solutions.

Short-term

Utilities should include analysis of storage alongside other options for meeting those needs where appropriate. Where utilities include storage, they should compare storage to other options and perform a quantitative analysis of the different options that considers the costs and benefits of each option. With regards to storage being deployed primarily for the power supply benefits (e.g. peak-shaving and market participation), utilities should maximize the benefits of storage by finding locations that offer resilience or micro-grid benefits in addition to power supply benefits. In the action plan section of their IRP's, utilities which plan to deploy storage should include a description of their planned deployment, with specific reference to any studies the utility plans to conduct and/or the location and magnitude of planned projects.

Longer-term

In the next iteration of the Guidance for Integrated Resource Planning, the Department should discuss

relevant methods for cost-benefit analysis for storage compared with other options and provide a more concrete framework for utilities to consider storage.

Distribution-system mapping, modeling, and planning is likely to become increasingly important in some service territories as distributed generation and controllable loads (including storage) are being deployed. Utilities which see storage as becoming more relevant for them and their customers or members should consider advanced methods for distribution circuit mapping and modeling in their IRP process. Utilities should prepare by building expertise and methods in this new planning area.

Distributed Energy Management Systems

It is very likely that private, merchant and third-party providers will continue to develop storage for various purposes (for example, reducing demand charges, power quality, bidding into ISO-NE markets, and resilience). If the charging and discharging of batteries is not timed to coincide with pertinent circumstances on the grid, it is possible, even likely, that the addition of these resources could cause additional costs to the utility's other customers (as noted in comments on the draft report). If charging and discharging are well-timed, storage has the potential to reduce or hold flat costs for everyone.

Short-term

Utilities should explore methods for coordinating the charging and discharging of both utility-owned and privately owned storage to optimize operation of the grid. There are several options for accomplishing this including demand charges or time-of-use rates that coincide with system and/or regional peaks, Distributed Energy Resource Management Systems (DERMS) software solutions, and direct load-control technology.

Longer-term

Utilities that expect the deployment of private storage, particularly at the commercial and industrial level, should explore and deploy options for efficient integration of storage including the above-mentioned options. Any DERMS deployed should be non-discriminatory and provide open access to both customers and third parties so that these stakeholders can actively participate in grid choreography through real-time signals. Open and affordable access should be a core principle of any software solutions deployed.

Power quality

Short-term

In areas of the distribution grid where power quality issues are arising because of high levels of distributed generation or other reasons, there may be an appropriate application for storage. Utilities working to solve power quality issues should consider battery storage and/or stand-alone advanced power electronics alongside traditional solutions and should conduct a quantitative cost-benefit analysis which gives appropriate value to the various value streams associated with the solutions presented.

[Rate design, tariffs, and distinct pricing of storage-related services](#)

Short term

In the near term, the Department recommends taking exploratory steps toward eventual implementation of time-of-use rates for net metering customers and/or time-of-generation for net metering systems, which – while designed to better align load and generation – would have a side effect of encouraging use of storage in some instances.

Some stakeholders have also suggested implementation of a virtual curtailable load rider; the Department is supportive of exploring this concept in more detail, although there are significant concerns with linking such a mechanism to demand charges. The Department does not support the companion recommendation to allow aggregation across utility service territories; there is already a mechanism available to aggregate resources, including storage, across service territories and bid into various ISO-NE markets, which would not burden Vermont distribution utilities with the administrative costs of accounting for shares of load reduction.

The Department is also in the early stages of exploring innovations in rate design and utility regulation with the ultimate goal of creating transparent pricing incentives – including variations on time- and location-specific pricing for both consumption and generation – that would likely result in new opportunities for customers and third parties to deploy energy storage and other solutions to align load and generation. These conversations, which could eventually become more formalized, have the potential to address the desire expressed by stakeholders for a valuation framework for storage, without duplicating resource-intensive endeavors and without creating a product that will almost immediately become outdated, given the pace of change in storage technologies and costs.

Longer term

Beyond rate design, unlocking locational value will entail achieving a level of insight into the distribution system far greater than possible today. The required planning work, and ensuing rate designs tailored to addressing time- and location-specific needs, will require substantial process and time to achieve. The resulting tariffs and granular pricing mechanisms should unlock opportunities for customers and third parties, including aggregators, to deploy storage and other solutions. Exploring possibilities through optional pilots along the way will help the Department, utilities, customers, third parties, and other stakeholders to better understand the opportunities and challenges posed by rate design and other regulatory innovations in achieving a transactive energy ecosystem in Vermont.

Energy assurance efforts

Short term

State Energy Assurance Plan: The Department is the lead on the EAP and anticipates issuing an update to the 2013 plan in 2018. We anticipate inclusion of storage in the discussion of microgrids and will be reaching out to stakeholders to begin this discussion in early 2018. This process could be used to assist municipalities in exploring options for storage, and may result in the revised EAP providing guidance on this topic.

Hazard Mitigation Plans: VEM anticipates including a section on methods of assessing vulnerabilities – including to the grid – in the next update of the State Hazard Mitigation Plan. In developing their local plans, municipalities will be able to reference these methods and include their own vulnerability assessments. When VEM crafts the next State Hazard Mitigation Plan, they will consider inclusion of a grid failure gap analysis, which can again be used as a template for local plans.

Vermont Threat and Hazard Identification and Risk Assessment (THIRA): Every year, VEM updates the State's THIRA, which is an analysis of vulnerabilities and capabilities based on discussion with subject matter experts. In the next update of the THIRA, VEM anticipates including an analysis on a statewide electrical grid failure.

Utilities Conference: VEM hosts a utilities conference on an annual basis, and are considering inclusion of grid resilience, microgrids, and storage as a topic for their 2018 conference.

Longer term

Microgrid Opportunity Study: Depending on funding availability and the interest of stakeholders including municipalities, regional planning commissions, and utilities, it may be useful to conduct a study to identify high-value microgrid opportunities. These might exist where concentrations of critical infrastructure (emergency shelters, first responders, water and wastewater facilities, gas stations, etc.) exist on a distribution feeder containing generation (renewable and otherwise). Vermont Emergency Management (a division of the Department of Public Safety) is in the process of revising the template for Local Emergency Operations Plans (LEOPs), which includes a place for municipalities to note the locations of critical infrastructure.

Resilience Project Assessment: It is important to continually assess the success of community microgrid projects (such as the Stafford Hill solar + storage project) and residential backup initiatives (such as the Tesla Powerwall pilots) to understand whether the objective of resilience during grid outages is achieved to the extent represented in initial proposals. Such assessments will help all stakeholders understand the challenges and opportunities associated with storage for grid resilience and help in the design of future microgrid and residential backup projects and initiatives.

Regulatory review process and criteria

The Department recommends that the Legislature make revisions to Title 30 to explicitly subject grid-exporting energy storage to PUC jurisdiction in a manner that acknowledges both its similarities as well as its differences from electric generation. In this vein, legislative changes may involve establishing or refining the definitions of “storage” and “electric storage installation” or “electric storage facility.”⁵⁵ It may also entail adding storage alongside mention of electric generation in Section 248, by making modifications to at least: § 248(a)(1)(B), § 248(a)(2) and (a)(2)(A), (a)(4)(F)(i), (a)(4)(J), (a)(7); or otherwise defining electric generation to include grid-exporting storage for the purposes of Section 248, at the beginning of the section.

The Department also recommends that the Legislature address smaller storage akin so electric generation of similar capacity. This may mean making revisions to § 8010 to incorporate storage; however, it may be more straightforward to instead implement an § 8010-like statute for storage installations, using a net-metering-like categorization of storage for the purpose of defining the scope of review.⁵⁶ For residential and small-scale storage,⁵⁷ the Department proposes a registration-like filing

⁵⁵ These definitions should be placed in 30 V.S.A. § 201 and, perhaps, § 8002.

⁵⁶ The categories of review described below would apply to stand-alone storage installations. When storage is coupled with generation, the combined application should meet the minimum requirements for the generation component of the project, and the storage should be independently justified under the same criteria as the generation project, regardless of the size of the storage component. *See, e.g., Petition of Green Mountain Power Corporation for a Certificate of Public Good, Pursuant to 30 V.S.A. § 248, Authorizing the Construction and Operation of a 2.5 MW DC Solar Electric Generation Facility, Known as the Stafford Hill Solar Farm, to Be Located on Gleason Road in the City of Rutland, Vermont, Docket No. 8098, 2014 WL 3557104 (Vt. P.S.B. July 14, 2014).*

⁵⁷ The Department considers storage less than 15 kW “residential.”

with a short timeframe for review and objection, and which is otherwise deemed approved if no comments are received by the prescribed deadline.⁵⁸ For storage systems greater than 15 kW, but less than 1 MW, the Department recommends an application-like procedure similar to that found in Commission Rule 5.107. For storage installations greater than or equal to 1 MW, however, the Department recommends a full § 248 review, with the possibility that, in certain cases, an applicant may petition for § 248(j) review. The applicable § 248 criteria are likely to differ in some regards from those considered in § 8010, and should be flexible enough to address looming challenges and opportunities including aggregated storage and electric vehicles capable of exporting to the grid. Additionally, in any future revisions to § 8010, the Legislature should take into consideration the likelihood that storage may be proposed in conjunction with a net metering generation system.

Finally, the Department urges the Legislature to incorporate the recent changes requiring decommissioning plans in the § 248 context to its statutory revisions for storage, particularly because storage technology often presents significant environmental risk when it comes to disposal. On August 15, 2017, the Commission adopted final rules related to decommissioning (Commission Rule 5.900) for facilities subject to its jurisdiction under 30 V.S.A. § 248. The adopted rules took effect for new requests for a certificate of public good filed on or after September 1, 2017. Commission Rule 5.900 does not apply explicitly to storage:

This rule applies to all electric generation, electric transmission, and natural gas facilities that are or become subject to the jurisdiction of the Vermont Public Utility Commission pursuant to 30 V.S.A. § 248. This includes net-metering facilities permitted under the procedures authorized by 30 V.S.A. § 8010. This rule shall apply to all facilities for which a petition or application for a certificate of public good under 30 V.S.A. § 248 is submitted after the effective date of this rule.

Although, the recommendations above that would include storage in the § 248 certificate of public process may carry with them the application of Rule 5.900, the Department believes the applicability should be made clear by amending the first sentence above to read: “This rule applies to all electric generation, electric transmission, *storage*, and natural gas facilities that are or become subject to the jurisdiction of the Vermont Public Utility Commission pursuant to 30 V.S.A. § 248.” Further, Rule 5.904 should be revised to include an equivalent section for storage installations. At a minimum, for storage installations of all sizes, the Department recommends a provision for the proper disposal of the device(s) consistent with environmental regulatory parameters. For larger installations, the decommissioning requirements of Rule 5.904 should apply to stand-alone or integrated storage.

Interconnection standards

The Department does not recommend any changes to the pending interconnection standards (Rule 5.500) at this time, as the pending rule language explicitly addresses – and does not appear to present a barrier to – energy storage projects. If stakeholders have experience with the specific existing or pending rule language indicating it has or would potentially present a barrier to storage – along with

⁵⁸ See Commission Rule 5.105.

specific language remedies for these concerns – the Department would be open to further discussion of the matter.⁵⁹

Modification of existing or development of new programs and incentives

Short term

Clean Energy Development Fund

In Fiscal Year 2018, the Department and Clean Energy Development Fund will be working to identify the best use for \$50,000 that has been set aside for energy storage. This is a one-time availability of funds from a source for which other remaining funds are fully encumbered and/or budgeted, with no replenishing funding source. While the exercise of creating this report, and the valuable feedback from stakeholders, have helped spur ideas for the best use of those funds, the Department feels additional conversation with the Clean Energy Development Board, legislature, and stakeholders is warranted before further narrowing down the scope of any proposal for use of that funding.

Standard Offer Program

Several stakeholders recommended development of a pilot within the Standard Offer program for solar (or other generation)-plus-storage. The Department, however, feels that the Standard Offer program is not the best mechanism for incentivizing the development of storage – or more accurately, achieving the goals that storage might be able to serve, such as firming renewables or providing renewables on peak. The Department’s primary concerns with using the Standard Offer program for storage is (1) it does not contain the locational considerations that are necessary for optimal deployment of storage; and (2) there is currently no mechanism to ensure that the charge and discharge of a storage device is timed in a manner that ensures a benefit to ratepayers. We are, however, open to having discussions about the best way to achieve these objectives, including through the potential development of new programs designed to achieve deployment of beneficial time- and location-specific generation.

Longer term

Net Metering

As discussed under the “Rate design” recommendations, the Department believes eventual modifications to the Net Metering program to move net metering customers to time-of-use rates, and/or adjust system production based on time-of-generation, should be considered. We are cognizant, however, of the recent significant changes the Net Metering program has undergone, and therefore are not recommending any immediate changes to the program, though conversations about potential changes should likely begin soon.

Renewable Energy Standard

Several stakeholders suggested making changes to the Renewable Energy Standard – particularly Tier III, which focuses on energy transformation – that would create more opportunities for storage. Among these, the Department finds merit in the concept of a clear framework for evaluating energy storage fossil fuel reductions. The Department suggests that as a first step, the distribution utilities work together to come up with a strawman proposal for further discussion.

⁵⁹ The pending interconnection rule can be found at <http://puc.vermont.gov/about-us/statutes-and-rules/proposed-changes-rule-5500>.

EEU Activities

Given the need to maximize the use of efficiency funds, the Department does not believe that these funds should be used for storage resources. Additionally, including Efficiency Vermont in the storage planning process creates an overlap with electric utilities' current responsibilities for grid planning, thereby duplicating efforts and increasing costs to ratepayers.

Procurement targets

The Department does not believe it is prudent to adopt utility storage procurement targets at this time. Many of Vermont's distribution utilities are already actively deploying – or exploring near-term deployment of – energy storage projects, either under utility ownership or in partnership with customers and third parties. Under Vermont's least-cost planning framework, utilities are required to look at the most cost-effective solution to their needs; imposing a storage-specific target would presuppose that storage is the right solution to a particular need, without allowing for full consideration of other, potentially more cost-effective alternatives such as load control and rate design. If after a period of time there is little to show for the very active current discussion around utility adoption of storage, it may be appropriate to re-evaluate the concept of procurement targets. However, any such future targets should allow for flexibility in implementation and should be predicated on cost-effectiveness of investments to ratepayers.

Other

Regional Participation

Vermont intends to continue participating in relevant regional discussions aimed at removing barriers and ensuring a level playing field for energy storage.

Utility Storage Initiatives

In their comments to the draft report, one utility recommended that the State should encourage utilities to continue with pilot programs to demonstrate the use of storage for grid stability, reliability, and lowering costs for all consumers; and also to work with battery retailers to facilitate deployment of systems where they provide the greatest grid value to customers, with commensurate compensation. The Department remains supportive of utilities' ability to innovate while keeping costs low for consumers, and recognizes the leadership of several Vermont utilities in the storage arena. We also believe it is important to keep in mind that stakeholders beyond utilities – including customers and third parties – are also eager to innovate and thrive in the storage arena, and would encourage initiatives that create opportunities for all sectors. Green Mountain Power noted in comments that they are developing a “bring-your-own-device” storage offering, which, along with innovations in rate design, has the potential to create an environment in which a diversity of storage technologies, applications, and ownership structures might thrive. Other stakeholder comments have suggested requiring the use of open, non-proprietary specifications and standards for utilities and energy storage providers (e.g., <http://mesastandards.org/>), the creation of an energy storage information clearinghouse, and the provision of information on the availability of non-utility storage products in services in any utility communication to customers. These are all suggestions that have the potential to lead to a thriving storage ecosystem in Vermont, and are worthy of further consideration, keeping in mind that these suggestions also require the commitment of scarce resources.

Locational Storage Value Study

Some stakeholders have suggested that Vermont seek funding to commission an analysis similar to that conducted in Massachusetts, looking at the optimal amount of and locations for storage to maximize benefits to ratepayers. Funding question aside, the Department would encourage a more holistic approach in which utilities have the opportunity to look comprehensively at distribution system needs and solutions, which may or may not be storage-based. Such an analysis falls under the broad umbrella of “distribution system planning,” a significant undertaking that Vermont’s distribution utilities and the Department are just beginning to explore. There is a potential nexus with the study of the locational value of storage from a resiliency perspective, discussed under the Energy Assurance recommendations above.

Appendix A: Act 53 Storage Report Language

No. 53
2017

Page 1 of 26

No. 53. An act relating to the Public Service Board, energy, and telecommunications.

See Revision note at end of Act

(S.52)

It is hereby enacted by the General Assembly of the State of Vermont:

* * * Preapplication Submittals; Energy Facilities * * *

Sec. 1. 30 V.S.A. § 248(f) is amended to read:

(f) However, plans for the construction of such a facility within the State must be submitted by the petitioner to the municipal and regional planning commissions no less than 45 days prior to application for a certificate of public good under this section, unless the municipal and regional planning commissions shall waive such requirement.

(1) ~~Such~~ The municipal or regional planning commission may take one or more of the following actions:

(A) ~~hold~~ Hold a public hearing on the proposed plans. The planning commission may request that the petitioner or the Department of Public Service, or both, attend the hearing. The petitioner and the Department each shall have an obligation to comply with such a request. The Department shall consider the comments made and information obtained at the hearing in making recommendations to the Board on the application and in determining whether to retain additional personnel under subdivision (1)(B) of this subsection.

(3) the estimated capital costs of providing such access; and

(4) the estimated operating costs for hosting and connecting.

* * * Citizen Access to Public Service Board; Implementation Report * * *

Sec. 15. REPORT; IMPLEMENTATION OF WORKING GROUP

RECOMMENDATIONS

On or before December 15, 2017, the Public Utility Commission shall submit to the House Committee on Energy and Technology and the Senate Committees on Finance and on Natural Resources and Energy a report on the progress made in implementing the recommendations of the Access to Public Service Board Working Group created by 2016 Acts and Resolves No. 174, Sec. 15, including those recommendations that the Group identified as not requiring statutory change.

Secs. 16–21. [Deleted.]

* * * Energy Storage * * *

Sec. 22. ENERGY STORAGE; REPORT

(a) Definitions. As used in this section, “energy storage” means a system that uses mechanical, chemical, or thermal processes to store energy for later use.

(b) Report. On or before November 15, 2017, the Commissioner of Public Service shall submit a report on the issue of deploying energy storage on the Vermont electric transmission and distribution system.

(1) The Commissioner shall submit the report to the House Committee on Energy and Technology and the Senate Committees on Finance and on Natural Resources and Energy.

(2) The Commissioner shall provide an opportunity for the public and Vermont electric transmission and distribution companies to submit information relevant to the preparation of the report.

(3) The report shall:

(A) summarize existing state, regional, and national actions or initiatives affecting deployment of energy storage;

(B) identify and summarize federal and state jurisdictional issues regarding deployment of energy storage;

(C) identify the opportunities for, the benefits of, and the barriers to deploying energy storage;

(D) identify and evaluate regulatory options and structures available to foster energy storage, including potential cost impacts to ratepayers; and

(E) assess the potential methods for fostering the development of cost-effective solutions for energy storage in Vermont and the potential benefits and cost impacts of each method for ratepayers.

(4) The report shall identify the challenges and opportunities for fostering energy storage in Vermont.

Appendix B: Energy storage in the state, region, and nation

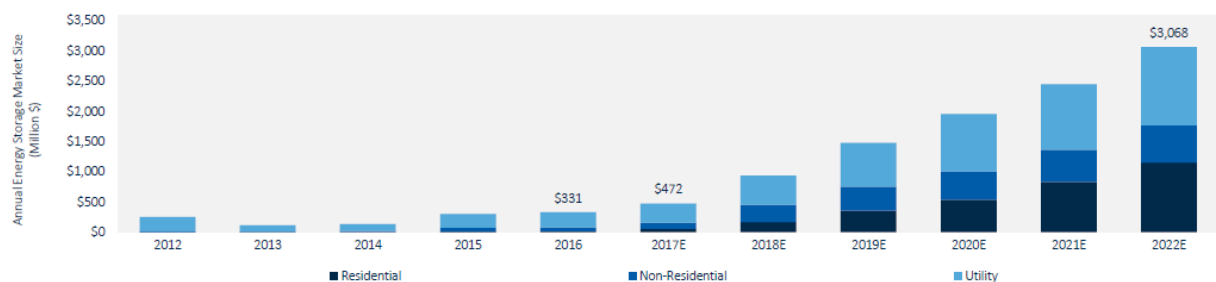
National storage landscape

Support for storage at the national level spans R&D efforts at the U.S. Department of Energy (DOE) and national laboratories, several market-opening orders from the Federal Energy Regulatory Commission, the DOE Office of Electricity's energy storage deployment program, and tax incentives including accelerated depreciation and the Investment Tax Credit (ITC), which can be taken for storage if it is charged from eligible renewable resources.⁶⁰ There are also a number of states actively developing energy storage policy and/or programs. California has set a storage procurement target for investor-owned utilities and has included storage in the Self Generation Incentive Program (SGIP), while Massachusetts has set an aspirational target for utility-procured storage, is soliciting proposals for storage use-case demonstration projects, and is proposing to add storage to its solar incentive program.

Apart from these state efforts, the national storage landscape has been largely defined by regional markets. Storage deployment has been highest where electricity and ancillary service prices are high; where wholesale electricity markets are open to distributed and non-generator resources; where penetration of renewable generation has reached relatively high levels; where resilient power is valued, usually due to experience with natural disasters that have disabled the electric grid; where utilities pay high prices for capacity and transmission services; and where commercial customers pay high demand charges.

Energy storage deployment is increasing rapidly, and this trend is projected to continue; but to date, high deployment levels have been concentrated in a few states.

U.S. Annual Energy Storage Market Size, 2012-2022E (Million \$)



Source: GTM Research

- By 2022, the U.S. energy storage market is expected to be worth \$3.1 billion, a ninefold increase from 2016 and a sixfold increase from this year. Revenues in 2017 will grow by 43% over 2016. Cumulative 2017-2022 storage market revenues will be \$10.4 billion.
- Residential segment revenues contributed only 4% in 2016, but by 2022, the residential segment alone will be a \$1.2 billion market. The utility segment accounted for \$252 million and 76% in 2016, and will continue to be the largest segment by 2022 at \$1.3 billion and 42%.

Figure 11: Energy storage deployments 2012-2016 and expected deployments through 2022 (from GTM quarterly report)

⁶⁰ The investment tax credit of 30% steps down starting in 2019 until it reaches 10% from 2022 on (see www.nrel.gov/docs/fy17osti/67558.pdf for details). Storage must be charged by renewables 75% of the time to receive the full 30%.

Research and development

Most (95%) installed storage capacity is still in the form of pumped hydro, but battery installations are growing quickly as lithium-ion prices drop and as solar installers partner with battery vendors to produce plug-and-play solar + storage packages. Lead acid batteries, an older technology, retains significant market share, and research is underway to bring advanced lead acid batteries to market (these would be more competitive with higher-performing lithium batteries). Other battery technologies, notably flow batteries, are beginning to make their way into the field with demonstration projects, but are still not fully commercialized.

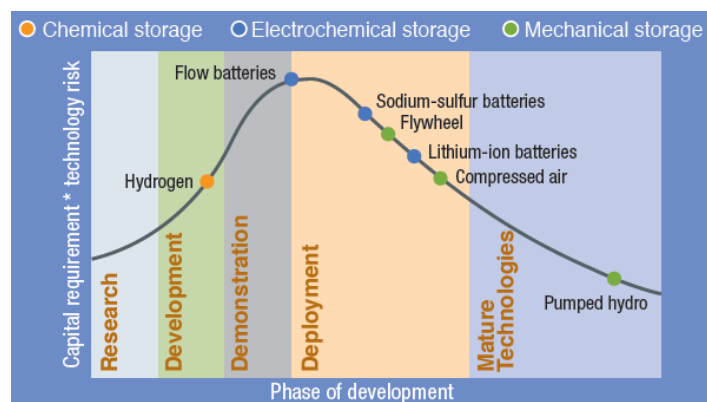


Figure 12: Energy storage technology development curve (from E Source, “Making Sense of Grid Energy Storage Technologies in 2016”)

Federal Energy Regulatory Commission (FERC) orders

A number of recent FERC rulings have opened ancillary services markets in ISO/RTO territories to energy storage and other non-generator resources, such as demand response. These orders required eligible resources to be equitably paid for the benefits they provide, and lowered barriers that might have barred energy storage from participating in regulated wholesale energy markets.

The orders above have been implemented to different degrees by the various ISOs. PJM was the first to fully implement FERC Order 755 (dubbed “Pay for Performance”), and this created a lucrative market for energy storage providing frequency regulation in PJM. That market is now saturated; however, as energy storage continues to develop, and new markets continue to open, new monetizable applications for storage will continue to emerge.⁶¹

States focusing on storage

California

To integrate more solar PV, address generator ramping issues, and support the development of new markets, California has put in place two significant energy storage policies: A utility procurement mandate of 1.325 GW of energy storage by 2020, which includes carve-outs for behind-the-meter

⁶¹ Mullendore, Seth. “Energy Storage and Electricity Markets,” (Clean Energy Group, August 2015). Retrieved from: www.cleanenergygroup.org/wp-content/uploads/Energy-Storage-And-Electricity-Markets-August-2015.pdf

(customer sited) systems in each utility territory; and the Self-Generation Incentive Program (SGIP), which was recently recapitalized and focused almost entirely on providing support for behind the meter energy storage projects.

The utility mandate for behind-the-meter systems has been clarified and expanded several times by the California PUC. For instance, in its February order, the CPUC stated that, “proposed programs and investments should prioritize distributed energy storage systems to public sector and low-income customers, and should demonstrate ratepayer benefits, seek to minimize overall costs and maximize overall benefits, reduce dependence on petroleum, meet air quality standards, and reduce greenhouse gas emissions while not unreasonably limiting or impairing the ability of nonutility enterprises to market and deploy energy storage systems.”

The SGIP incentive program has also been highly successful in stimulating customer-sited storage deployment. In this regard, it is worth noting the immense scale of the California energy storage incentives. The SGIP budget through 2019 is approximately \$566,692,308. Of this amount, 79% is reserved for energy storage projects, with the balance going to support renewable generation. Recently, an initial \$50 million offering (SGIP Step 1) was almost fully subscribed within 24 hours; the California Solar Energy Industries Association estimates that SGIP Step 1 will support 340 large-scale battery systems and 1,400 residential systems. This is in addition to approximately 380 non-residential behind-the-meter storage systems already installed in CA through SGIP. Most non-residential systems are likely providing demand charge management, which offers significant cost savings due to high demand charge rates in California. Currently, the CPUC is considering a proposal that would reserve 20% of the SGIP budget for projects in disadvantaged communities.⁶²

Massachusetts

In 2016, the Massachusetts Energy Storage Initiative released its *State of Charge* report, on energy storage in the Commonwealth. The report analyzed the opportunities for energy storage on the Massachusetts grid, estimated the optimal level of storage deployment, and recommended policy and program development to help the state obtain greater storage capacity. The report’s recommendations focused on (1) the growth of cost-effective storage deployment on the MA grid; and (2) the growth of storage companies as part of Massachusetts’ robust clean tech economy. These recommendations included:

- Providing grant and rebate programs
- Including storage in the state’s alternative energy portfolio standard
- Establishing/clarifying regulatory treatment of utility storage (as a restructured state, it was unclear whether utilities could own storage)
- Developing options that include statutory change to enable storage as part of clean energy procurements
- Other changes, such as easing interconnection, safety and performance codes, and customer marketing and education

⁶²Rulemaking 12-11-005, ORDER. By Commissioner Rechtschaffen, June 2, 2017; pg 5. Retrieved from: <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M189/K136/189136189.PDF>

The report concluded that the optimal amount of energy storage that should be deployed on the state grid by 2020 was 1,766 MW, which would result in up to \$2.3 billion in benefits to the state; and the report recommended that state policy and programs should be scaled to result in the deployment of 600 MW of new, advanced energy storage by 2025, which was expected to result in over \$800 million in cost savings to ratepayers and approximately 350,000 metric tons reduction in GHG emissions over a 10 year period.

In addition to the report, the state legislature took a number of important steps through its Energy Diversity Act. These included allowing utilities to own energy storage in Massachusetts, and directing the state Department of Energy Resources (DOER) to determine whether a utility procurement target was desirable and, if so, to set a target for utility procurement by 2020. This target is to be revisited every three years. In 2017, DOER set a 200 MWh “aspirational” utility procurement target. DOER and MassCEC have also announced \$14.5 million in energy storage project grants, and many of the recommended rebate and incentive programs are under development. The first of these, the proposed SMART solar incentive program with storage adders, is due to take effect in 2018.

Regional storage landscape (ISO New England)

There are a number of trends that are increasing the amount of energy storage in ISO-NE markets:

- Generation retirements: As legacy generators retire, portions of the retired capacity could eventually be replaced with renewables and storage. Energy storage is modular, can be deployed quickly, and can be located close to load centers to improve efficiency and reduce the need for additional transmission capacity.
- Renewable Portfolio Standards: the increasing penetration of renewables makes storage and other load management tools more valuable. Already, the California “duck curve” shows signs of appearing in New England (see figures below).
- Wholesale energy markets: Energy storage has already proven it is faster and more accurate than gas peaker plants at providing frequency regulation services in PJM. Regulatory changes continue to enhance how storage participates in New England.
- High and rising capacity and transmission costs: these costs provide an economic basis for utilities to install storage in New England.

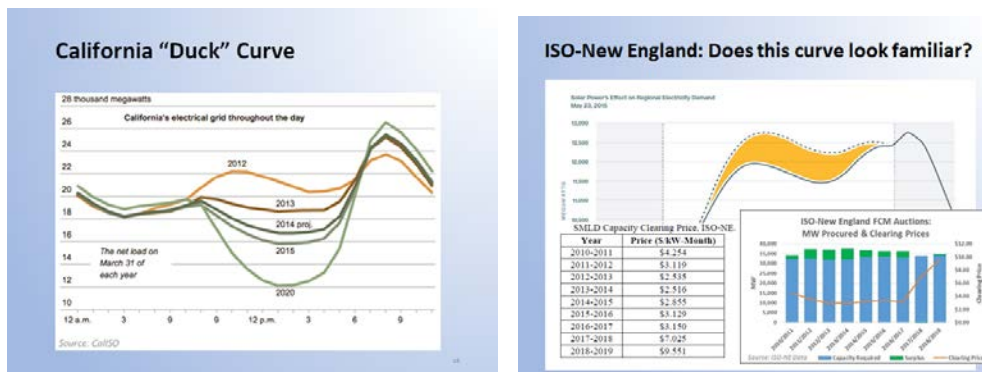
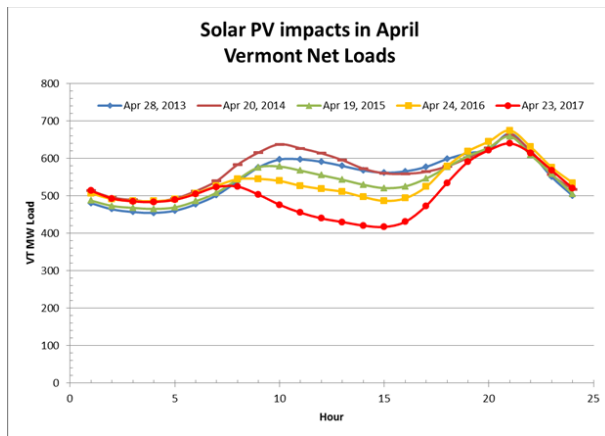


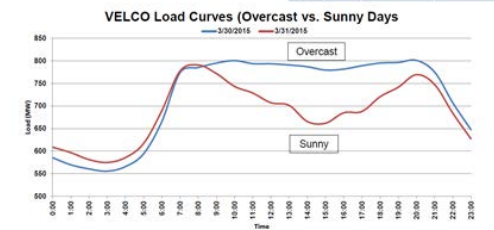
Figure 13: The demand curves in California (left) and New England (right), showing the effects of solar generation on demand in the middle of the day (from Clean Energy Group).



VELCO Load Curve Study Case #1

Increase of solar generation "behind the meter" is offsetting VELCO demand curve

	3/30/2015	3/31/2015
Cloud Cover	Overcast	Sunny
High/Low (°F)	41/26	42/24
Max Radiation (w/m ²)	241	965



VELCO Vermont Weather Analytics Center - VTWAC# 1

DO NOT DISTRIBUTE—Contains Critical Energy Infrastructure Information

Figure 14: Left: evolving demand curve on a sunny Vermont April day. The midday (net) load has now dropped below load in the middle of the night. Right: net load on an overcast vs. a sunny day (when solar is producing) in VT (courtesy VELCO).

Energy storage is not new to New England. Pumped hydro has provided grid-scale storage in New England for the past 40 years; two facilities built in 1970s can supply 1800 MW, within 10 minutes, for 7 hours (ISO-NE, State of the Grid 2017). However, due to the difficulties of siting large pumped hydro facilities, the majority of additional storage capacity in the region is expected to be in the form of batteries.

ISO-NE, like the other ISOs and RTOs, has taken steps to implement FERC orders related to storage (discussed above), and have been working to review market rules to ensure they do not create a barrier to storage participation in regional markets, as well as to provide educational resources to potential storage market participants.

In 2008, ISO-NE developed a category of resources called "Alternative Technology Regulating Resources," which enabled storage resources to participate in the regulation market (ensuring grid stability), on a pilot basis. The minimum size of a participating resource must be 1 MW, but that 1 MW can be composed of an aggregated set of < 1 MW resources. As a result of their experience working with early ATRR storage resources, including Green Mountain Power's Stafford Hill batteries, ISO-NE has modified implementation of rules governing this market that were presenting a barrier for smaller resource participation. Starting in late 2018, ATRR resources will also be able to bid into the day-ahead and real-time markets as either generation or dispatchable asset-related demand (demand that can be modified on the basis of the physical load's ability to respond to remote dispatch instructions from ISO-NE).

ISO-NE is also working to fully integrate demand response (which can include storage) into wholesale markets, including day-ahead, real-time, operating reserves, and forward capacity, and to receive obligations and compensation in the Forward Capacity Market (FCM) comparable to dispatchable resources. These changes are due to take effect June 1, 2018.

As of September 2017, ISO-NE had two storage systems participating in its wholesale markets, a 16.2 MW, 8.1 MWh lithium-ion battery storage system operated by NextEra Energy in Maine's Casco Bay and a 500 kW, 3 MWh advanced lead-acid battery system operated by Convergent Energy + Power in

Maine's Boothbay Harbor (which also deferred an \$18 million transmission project).⁶³ Green Mountain Power's Stafford Hill project (discussed below) participates only in the regulation market at this point (as does the Casco Bay project).⁶⁴ Of the 13,350 MW of proposed new resources in ISO-NE's August 2017 interconnection queue, about 79 MW – or less than 1% - were batteries. Notably, many of these are proposed in conjunction with generation resources, wind in particular.⁶⁵

According to ISO-NE's *State of the Grid 2017* report, "As more non-gas generators retire, there may not be sufficient resources to generate electricity when natural gas plants aren't available. Eventually, renewable resources may be the solution. They key to long-term independence from fossil fuels is renewable energy backed up by widespread, grid-scale storage. But storage will be needed at a level that won't be economically or technically feasible for many years."⁶⁶

While the ISO does not anticipate that a sufficient volume of energy storage will develop in time to compensate for upcoming generator retirements, it believes that storage's presence in the region will continue to grow. The ISO is working to remove barriers to and clarify rules for the participation of storage in regional markets and to recognize and value storage's unique capabilities, some of which will only become apparent as more storage resources participate in the New England wholesale markets under the existing framework and the new framework to be in effect in 2018. ISO has created several resources designed to provide information to stakeholders, including the white paper *How Energy Storage Can Participate in New England's Wholesale Electricity Markets*⁶⁷, and the webinar *Energy Storage Market Participation*.⁶⁸

Vermont storage landscape

Even in the absence of mandates or incentives to deploy energy storage, Vermont is punching above its weight in storage development. Green Mountain Power (GMP) installed 2 MW of storage in 2016, earning it a rank of 10th in the nation for amount of storage deployed by a utility in 2016 (and 9th in watts per customer).⁶⁹ And while GMP has plans to develop even more storage projects, so do many of the state's other electric distribution utilities, as well as many businesses (for themselves or on behalf of customers).

⁶³ U.S Department of Energy, DOE Global Energy Storage Database, GridSolar Boothbay Pilot Project, May 12, 2015; www.energystorageexchange.org/projects/1419

⁶⁴ "An energy storage milestone: two batteries join ISO-NE Regulation Market" (ISO-NE, April 18, 2017). Retrieved from: <http://isonewswire.com/updates/2017/4/18/an-energy-storage-milestone-two-batteries-join-iso-ne-regula.html>

⁶⁵ ISO-NE, Interconnection Request Queue 08-16-16; <https://irtt.iso-ne.com/tacgw/Customization/disc.cshml>

⁶⁶ ISO-NE, *State of the Grid – 2017*, January 30, 2017; www.iso-ne.com/static-assets/documents/2017/01/20170130_stateofgrid2017_remarks_pr.pdf

⁶⁷ ISO-NE, *How Energy Storage Can Participate in New England's Wholesale Electricity Markets*, March 2016; www.iso-ne.com/static-assets/documents/2016/01/final_storage_letter_cover_paper.pdf

⁶⁸ Peet, Tim. "ISO-NE, Energy Storage Market Participation." Webinar, April 11, 2017. Retrieved from: www.iso-ne.com/static-assets/documents/2017/04/20170411-webinar-energy-storage.pdf

⁶⁹ Green Mountain Power. (2017). *GMP ranked Number 10 for most energy storage installed in nation* [Press release]. Retrieved from: www.vermontbiz.com/news/april/gmp-ranked-number-10-most-energy-storage-installed-nation

Utility storage activities

The summaries below were compiled from conversations with Vermont’s distribution utilities and transmission operator in preparation of this report and represent the Department’s current understanding of the utility storage landscape in Vermont.

Burlington Electric Department

Burlington Electric Department (BED), referencing their recent Integrated Resource Plan (IRP), does not see a clear business case for storage at present, though they do see potential for one in the future depending on markets, costs, and specific use cases. However, they are exploring several pilot microgrid projects as part of their work to modernize their distribution system and learn about storage’s capabilities, and they will evaluate storage as an option if they determine there is a need for a distribution upgrade on their system.

BED has issued a Request for Proposals for a microgrid with storage at the Burlington Airport (1 MW, 4 MWh lithium-ion or flow battery), either as a service (implementable immediately) or possibly as an owned asset (FY 19 or later). BED owns a 500 kW (AC) solar array at the airport, and the airport itself has numerous traditional backup generators for emergency purposes, which enhance the facility’s ability to island critical loads for a long duration.

The utility is also evaluating the potential for a microgrid at their offices on Pine St. in conjunction with the adjacent Department of Public Works (100-200 kW/400-800 kWh lithium-ion or flow battery). BED’s offices have a 107 kW solar array (and are also the city’s emergency site), while the Department of Public Works is proposing an array this year. BED has funding budgeted in its 2018 capital budget for this



King St. Youth Center storage project

project, and anticipates leveraging responses from the airport storage RFP to develop a similar, if smaller, project.

BED also plans to test a 2.5 KW/12 kWh advanced lead acid battery storage project, on loan from Northern Reliability, in conjunction with solar in order to develop experience. They also intend to test the ability of the Packetized Energy Control devices to be used for battery storage (in addition to a Packetized Energy water heater load control device project, which would allow hot water to serve as the energy storage medium in real-time

response to market events).

A BED customer, the King St. Youth Center, has deployed an integrated solar/storage/building control system. BED has met with the Center and the developer – Northern Reliability – to understand the system’s capability and potential effects on the utility of additional, similar deployments.

Finally, BED is exploring the potential for a microgrid in the Burlington Town Center.

Green Mountain Power

In 2015, Green Mountain Power (GMP) deployed a 2 MW, 3.4 MWh storage project (1 MWh of lithium-ion plus 2.4 MWh of lead-acid batteries) in conjunction with its 2 MW AC/2.5 MW DC solar project on a

closed landfill in Rutland, with the potential to island an area of the distribution grid to create a microgrid encompassing the adjacent high school, a designated emergency shelter. The batteries and solar are behind a common inverter, which allows for discrete control of each component (lithium-ion batteries, lead acid batteries, and solar) and can also enable batteries to be charged from excess DC solar rather than clipping that excess production through the 2 MW inverter that limits the whole project's AC output to 2 MW. The project is owned by GMP and was assisted with funding from the U.S. Department of Energy and Vermont Clean Energy Development Fund, and technical assistance from Sandia National Laboratories. GMP uses the project for peak reduction (regional peak-based capacity charges and Vermont peak-based transmission charges), solar smoothing, energy arbitrage, frequency regulation service for ISO-NE, and islanding. In 2016, the project reduced system load by nearly 2 MW during the one-hour regional, annual system peak, saving nearly \$200,000 in capacity charges.⁷⁰ GMP reports that through June 2017, the project has produced over \$300,000 of value for customers (annual and monthly peak savings plus regulation market revenue).



Stafford Hill solar + storage project in Rutland. Batteries are in the shipping containers in the upper right. Credit: GMP

GMP is pursuing additional standalone or solar + storage deployments, some as potential microgrids. The company has proposed a 1 MW, 4 MWh Tesla Powerpack project in Panton (currently an active docket before the Public Utilities Commission, Docket. No. 17-2813-PET), and included proposed additional microgrid projects in their most recent rate case. GMP has indicated that it intends to install storage alongside solar, through a joint venture framework, and follow certain rules related to charging batteries from the solar to be able to access the 30% federal solar investment tax credit (available until 2021, with step-downs through 2023). These batteries would all be used for capacity, transmission, energy arbitrage, and possibly frequency regulation.

GMP was also involved in an early project with a number of partners⁷¹ to deploy customer-sited batteries at the McKnight Lane project in Waltham, where Vermod energy efficient modular homes were deployed in a redeveloped mobile home park, each containing a 6 or 8 kWh Sonnenbatterie system paired with rooftop solar to provide power during outages. GMP is also using the batteries to provide grid benefits during times of peak demand, through their Virtual Peaker energy management platform.

GMP has embarked on a series of pilots (now in the second iteration) to test distributed, customer-sited energy storage in the form of Tesla Powerwall



Vermod
Sonnenbatterie

⁷⁰ "Green Mountain Power (GMP): Significant Revenues from Energy Storage," (Sandia National Laboratories, May 2017). Retrieved from: www.sandia.gov/ess/publications/SAND2017-6164.pdf

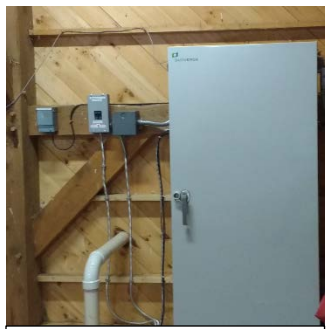
⁷¹ Clean Energy States Alliance, Vermont Energy Investment Corporation, High Meadows Fund, et al.

units (5.5 kW, 13.5 kWh lithium-ion batteries). The utility offers customers the option to purchase the unit outright, with or without sharing access with GMP; or to lease the system for \$15/month (\$37.50/month in the first iteration) with shared access for 10 years. Shared access means GMP can access the battery and use it (aggregated with others) to reduce peak demand and perform energy arbitrage; providing other grid services such as ISO-NE operating reserves and frequency regulation is on the horizon. GMP anticipates deploying up to 2,000 such units, with an aggregate capacity of 10 MW. The batteries otherwise serve to back up the home during outages for an advertised period of up to 12 hours. GMP is using Tesla's GridLogic software platform to dispatch the batteries based on inputs such as weather and load data, fed through algorithms designed to optimize value streams.



GMP Tesla Powerwall install

GMP has also been involved in two projects providing either backup or off-grid power for camps and parks. The utility worked with Farm & Wilderness Camp in Plymouth, to install an 8 kWh Sunverge lithium-ion battery in the dairy barn to provide backup power for the pasteurization process, as well as several smaller building loads. GMP can use the battery to provide grid services, and the camp uses it as an educational tool.



Sunverge in Plymouth

In East Dorset, GMP worked with the State to take Emerald Lake State Park off-grid with 10 kW of solar and 82 kWh of lithium iron phosphate batteries from Simpliphi, allowing GMP to retire the mile-long, difficult-to-access electric line previously serving the park. The system will run the park independently, and for up to two days in



Simpliphi system at Emerald Lake

the event of complete cloud cover.

GMP also represents that it is developing a “bring your own device” storage offering that will “encourage customer-owned storage devices to participate in GMP programs that enable those customers to share in the value their batteries offer to the grid and lowering costs for all GMP customers.”

On the customer side, GMP has also been involved on the thermal/demand response end of the storage spectrum. Their existing controllable hot water heater program involves over 15,000 customers with water heaters controlled through smart meters. This program has existed for a few decades and is used as a simple demand reduction resource. In addition, GMP recently rolled out a new water heater control program that leverages their custom distributed energy resource management control system, known as “Virtual Peaker,” which offers more dynamic control of the water heaters in addition to a customer override feature in the event the water temperature drops below a certain level. The utility has also experimented with deployment of ice storage on site of several commercial customers in Rutland.

Vermont Public Power Supply Authority

Vermont Public Power Supply Authority (VPPSA) is evaluating opportunities for storage to assist in the

coordination and valuation of customer demand response programs. They applied for but did not receive grant funding from the Northern Border Regional Commission to deploy a 100 kW, four-hour battery in conjunction with Northern Reliability either at a substation or at a hydro site (where it would replace old combustion turbines). Some of their member utilities are also evaluating the potential for batteries for individual, large customers.

Vermont Electric Cooperative

Vermont Electric Cooperative (VEC) has created a storage pilot committee and is looking at proposals from developers to install utility-scale storage in time to reduce the anticipated peak in summer 2018. According to VEC, the optimal approach for them would be to enter into a lease or Power Purchase Agreement (PPA) rather than owning storage infrastructure outright. VEC is also testing an Aquion battery at its Johnson facility, and expects to deploy a small storage project by the end of August 2017 at a commercial customer location to mitigate both customer and utility peak. Finally, VEC is looking into a funding opportunity from the National Rural Electric Cooperatives Association (NRECA) and the U.S. Department of Energy (DOE) to optimize distribution feeder performance, including assessing how storage technology can interact with distributed generation.

Washington Electric Cooperative

Washington Electric Cooperative's (WEC's) Integrated Resource Plan (IRP) discusses exploring utility-scale battery storage to help reduce load during times when the region's load is peaking, and the utility reports they are exploring storage and if cost effective and feasible could implement some form of storage within the next five years. The drivers for WEC would be reducing capacity and transmission charges from ISO-NE, VELCO, and GMP, particularly in light of other DUs installing storage (Vermont's transmission charges are based on each utility's monthly peak; utilities that deploy storage to reduce their peaks would reduce their transmission charges but shift them in part to those utilities whose peaks remain unaltered).

Vermont Electric Power Company

Vermont Electric Power Company (VELCO), the state's transmission operator, has evaluated the economics of deploying storage to reduce generation curtailment. VELCO is currently evaluating options for deploying storage to alleviate overall generation export constraints in the northern part of Vermont, the so-called Sheffield-Highgate Export Interface (SHEI) area. The preliminary results indicate that a storage device of the desired size, placed in the right location, can be a viable alternative from a technical perspective to reduce generation curtailment in two ways: 1) absorb generation that would have been curtailed, and 2) increase the system capability by providing additional voltage support via robust inverters. Further analysis will need to be performed by the affected generation owners to determine the amount of energy that would need to be stored, how frequently the device would be expected to absorb and inject generation, and what market mechanism would be necessary to make the storage device cost-effective.

Vermont System Planning Committee

In Hinesburg, the VSPC has considered a battery storage solution to solve reliability issues on a specific circuit. In that instance, GMP analyzed a number of possible solutions to address a long-term reliability need: a new GMP substation; a new jointly owned substation with the Vermont Electric Cooperative (VEC); installation of distance relaying; distributed generation; energy efficiency; and battery energy storage. Based on the analysis, GMP plans to install a battery energy storage system while participating

with VEC in a new substation. This type of “least-cost” analysis, where battery storage is considered alongside traditional solutions, presents a good model of how to integrate the consideration of storage with Vermont’s traditional “least-cost” grid planning.

Non-utility storage activities

Vermont possesses a rich ecosystem of non-utility storage developers and innovators working with utilities as well as customers to install and operator storage projects. The summaries below were compiled from conversations with Vermont’s energy and storage development community and represent the Department’s current understanding of non-utility storage projects that have been developed in Vermont. They do not reflect the increasing number of entities considering storage or in the early stages of developing projects.

Dynapower

Dynapower of South Burlington makes power electronics for energy storage systems; they have integrated 375 MW of storage at 250 project sites worldwide. They will work with many battery manufacturers, from sodium-sulfur to lithium-ion, and have an on-site 1.5 MW battery (plus a 100 kW wind turbine and a 101 kW solar project) used for testing their power electronics (and which they’re



exploring using for grid services in conjunction with GMP, and using during peak energy demand times), as well as an outdoor pad for battery manufacturers to test their products. Notably, Dynapower provided the controls for GMP’s Stafford Hill project, enabling integration of the solar, storage, and inverters.



Bill Laberge of Grassroots Solar with a Sonnenbatterie

Grassroots Solar

Grassroots Solar installs solar and solar + storage systems for residential customers; they have installed 185 kWh of storage for customers in the last two years. This year, they expect over half of their installations will include storage. This is partly in response to publicity around GMP’s Tesla Powerwall offering; Grassroots Solar is in partnership with Sonnenbatterie, however, and deploys a system that includes customer controls to prioritize self-generation (from solar, usually) or backup power (to stay charged in preparation for a power outage).

Northern Reliability

Northern Reliability has installed a number of mostly off-grid storage projects, from backup for mountaintop radar projects in Maine to creating solar + storage microgrids for resorts in the Caribbean. In Vermont, they have worked with Green Mountain Power to deploy a

1.6 kW solar + 12 kWh lead acid battery to provide uninterrupted power to a residence in Rutland, which they tested under various rate structure scenarios. They have installed ten 2.6 kW solar + 24 kWh lead acid battery systems across the state for the Vermont Telecommunications Authority, which can provide up to 3.5 days of system autonomy in the event of a grid outage (or longer, depending on solar availability). Another system – designed as a microgrid with 8.6 kW of solar + a 1,000 kWh battery bank + a 20 kW propane generator – supports VELCO infrastructure in Barnet and is designed to function continuously year-round with limited maintenance and refueling. And they have installed one small battery storage project at the King St. Youth Center in Burlington to help reduce that customer’s demand charges, and have two facilities for R&D and backup power at their offices in Waitsfield, one of which is being loaned to Burlington Electric for testing.



VTA solar + storage in Rochester



Tesla Powerwall unit installed by Peck Electric in S. Burlington.

Peck Electric

Peck Electric installed Tesla Powerwalls for GMP during their first pilot, all over the state from Rutland to St. Albans.

Power Guru

PowerGuru of North Bennington installs solar and battery backup systems for customers. Installations include an



PowerGuru 32 kWh battery install in Pownal

11.4 kW solar + 24 kWh Aquion saltwater grid-tied backup system in Pownal, and a 16.6 kW solar + 32 kWh Outback Power grid-tied backup system in the same town.

In addition to the companies actively working on domestic and international storage projects described above, many of Vermont’s renewable energy developers – such as Catamount Solar and Suncommon – routinely work with customers to install off-grid solar + storage systems. Others such as Vermont Solar Farmers and Great Bay Hydro are exploring development of larger storage assets for commercial customers or utilities, under structures where the customer or developer would own and operate the storage project and enter into a power purchase-like agreement with the utility