CHAPTER 24
ENERGY STORAGE POLICY AND ANALYSIS

William McNamara, Sandia National Laboratories

Abstract

The need for sound energy policies has become even more critical since the dawn of the 21st century because the energy sector is in the midst of a technological revolution. Emerging technologies that support an increased use of distributed energy resources including energy storage, renewable energies, and energy efficiency are influencing the priorities of policymakers in the United States as the nation attempts to migrate to a modern electricity grid.

Policymakers are beginning to see the potential for energy storage to help achieve ambitious clean energy goals to address climate change, particularly in states that are adopting plans to achieve 100 percent renewables or carbon-free energy infrastructures within the coming decades. Grid operators, federal and state policymakers, utilities and other stakeholders are presently working together to create the right economic and market conditions to ensure that energy storage continues to play a significant role in the broader decarbonization efforts in the power sector.

Policy initiatives that impact the energy storage sector can emerge from legislative or regulatory bodies, or directly from the governors in individual states. The Sandia Policy & Outreach team engages directly with state and federal policymakers to obtain and share perspectives on best practices in energy storage policymaking. We do not advocate specific policies; in fact, we are prohibited from taking any positions on specific policy measures. Rather, our mission is to provide independent, objective, and neutral analysis on industry best practices, lessons learned from specific regulatory and legislative proceedings, and cross-state comparisons. By providing this information, we support regulators and legislators as they continue to define policy for the emerging energy storage sector.

Key Terms

California Energy Commission (CEC), distributed energy resource (DER), Federal Energy Regulatory Commission (FERC), generators, independent systems operator (ISO), markets, New York State Energy Research and Development Authority (NYSERDA), North American Electric Reliability Corporation (NERC), policy, regional transmission organization (RTO), regulatory, transmission and distribution (T&D), utilities

1. Introduction

According to Meriam-Webster's definition, the word policy means "a high-level overall plan embracing the general goals and acceptable procedures, especially of a governmental body."

Policy that is specific to the U.S. energy industry over the last several decades has focused on three major goals: 1) ensuring a secure supply of energy; 2) keeping energy costs low; and 3) protecting the environment. In pursuit of those goals, government policies at both the federal and individual state levels have been developed to improve the efficiency with which energy is utilized, to promote the domestic production of conventional energy sources, and to develop new energy sources, particularly renewable resources [1].

The need for sound energy policies has become even more critical since the dawn of the 21st century because the energy sector is in the midst of a technological revolution. Emerging technologies that support an increased use of distributed energy resources (DERs) including energy storage, renewable energies, and energy efficiency are influencing the priorities of policymakers in the U.S. as the nation attempts to migrate to a modern electricity grid.

In the absence of a federal mandate that would require a specified amount of electricity generation that will come from renewable resources, a number of states are developing their own independent initiatives, some with goals to become 100-percent renewables or clean-energy based in the coming decades. It is likely that public commitments to non-carbon producing forms of energy such as solar and wind will continue given public demand and the fact that prices for alternative form of energy are now reaching parity with traditional forms of generation.

Along with the anticipated continued growth of renewables, as 2020 comes to a close it is widely accepted that, with its potential to fundamentally change the way society generates and uses energy, the widespread deployment of energy storage represents the dawn of a new era for the electricity grid [2]. The U.S. energy storage market is expected to hit the $5billion mark by 2024.

However, while energy storage technologies are becoming more advanced and providing a viable and long-term alternative to traditional generation sources with a host of operational benefits—not to mention the ever-increasing public demand for cleaner, more reliable energy resources—unfortunately there remains, at both the state and federal levels, an inherent lack of uniform policies that allow renewable energy and energy storage to connect to the utility grid and have equal opportunities to compete against conventional fossil-fuel resources.

A significant amount of regulatory work remains to be done to ensure that market growth forecasts for energy storage come to fruition. The electric system of the United States was designed long before cost-effective energy storage became widely available as an alternative to traditional forms of power generation. Moreover, technologies within the DERs sector appear to be developing more rapidly than the energy industry—which historically has been resistant to change and slow to adopt new business models—is prepared to accommodate. What this means in practice is that the functional capabilities of storage have been limited and possibly precluded under historic market rules and other policies. In addition, in most regions across the U.S. energy storage faces persistent barriers to adoption that are attributable, in part, to existing, legacy market rules and a confusing array of options for how to define storage assets, how to use storage, and how to value and capture the myriad benefits of deploying storage [2].

A major barrier to energy storage deployment regardless of jurisdiction is outdated regulations. Potential storage owners are reluctant to consider the deployment of resources until they can be assured and have clear evidence that barriers within a specific region no longer exist, enabling market access and a predictable revenue stream. Other regulatory issues that present barriers to the deployment of energy storage include complexity and lack of clarity surrounding the functional classification of energy storage and its multiple-use applications [3]. There are numerous non-technical issues plaguing the technology as well. These include storage valuation and market design issues, regulatory treatment of storage or lack thereof; significant risk and uncertainty associated with storage deployment and limited support for the technology [4].

The lack of uniform policies that allow renewables, DERs and energy storage specifically to participate fairly in market transactions at both the wholesale and retail levels remains a barrier that continues to cause challenges for energy storage developers, utilities that want to reduce their reliance on fossil fuels, and end-use customers that want to explore options for greater energy independence. Although manufacturing costs, roundtrip efficiency, and other technical characteristics are often cited as the major barriers to energy storage adoption, the promise of energy storage cannot be realized through technology alone. Well-designed, enabling policies for energy storage are also necessary in order to make the promise of energy storage a reality.

Policymakers are beginning to see the potential for energy storage to help achieve ambitious clean energy goals to address climate change. Grid operators, federal and state policymakers, utilities and other stakeholders are presently working together to create the right economic and market conditions to ensure that energy storage continues to play a significant role in the broader decarbonization efforts in the power sector.

Moreover, the rapid growth of energy storage and DERs requires that new policies and regulations be developed. Numerous regulatory, market design, and interconnection pre-requisites must be in place in order for energy storage to reach its full market potential and function as a realistic alternative to conventional generation resources.

Taken altogether, favorable policies, combined with falling costs and an increased appreciation of the advantages of electric storage suggest a fast-growing market and increased range of applications. Nevertheless, there is still considerable uncertainty with regards to which market design and regulation may actually provide the best framework that will enable energy storage to adequately develop and thus achieve its potential to significantly contribute to the migration toward a renewables-based, low-carbon electricity system.

Policymakers see storage as a potential solution to the challenges that stem from the intermittency of certain renewable resources. Storage systems are therefore considered key to hastening the clean energy revolution, and at the nexus of energy and climate change policy.

As policymakers start to rely more heavily on energy storage systems (ESSs) to achieve clean energy goals and other improvements to the grid, it is helpful to first understand the ways that the current regulatory and policy landscape fails to reward storage systems [5]. Additionally, as individual states seek "best practices" and "lessons learned" from other states that have taken steps to develop energy storage policy, it is important to review policies that have emerged at both the federal and state levels.

Energy policy is germane and applicable to a number of different stakeholders organized within a structure based on roles and participation within the E&U infrastructure. This assumes that different participants have different policy objectives and particulate in the policymaking process in different ways. The stakeholders listed below, which is not an exhaustive list, have different functions and possibly different perspectives and responsibilities with regard to policy considerations.

1. *Engineering companies whose function is to design and build an energy storage system (ESS).* Their interest in policy would be mostly what policy and regulations must be considered to build an ESS facility.
2. *Power providers (utilities, municipalities, rural electric cooperatives, etc.)* would be mainly focused on what policy and regulations must be followed to operate an ESS facility on the grid.

3. *Power distribution and transmission organizations* whose main interests lie with policy and regulation considerations only in what power is delivered to the grid and not the actual means of power generation.
4. *Governmental bodies* whose main interests are making sure that proposed new ESS installations and capability conform to existing policy and regulations, as well as possible improvements implemented by other organizations.
5. Finally*, end-use consumers* who would have an interest in policymaking to ensure that their usage of ESSs is not in violation of existing policy.

It also seems that physical location might be an important factor to consider as it seems that policy is quite diverse across many jurisdictional boundaries (not just physical borders). This can largely be determined by a physical location's placement within a restructured electric market or vertically integrated jurisdiction.

This chapter provides a summary of relevant historical policy initiatives at both the federal (i.e., wholesale) and state (i.e., retail) levels that have created a foundation and path forward for energy storage to develop. Current as of the end of 2019, this chapter seeks to summarize the policy landscape for energy storage that will continue into the next decade.

2. BACKGROUND/HISTORICAL CONTEXT

The market structures and regulations governing the electricity system were historically designed around large generating power plants, largely passive demand patterns, and little choice or control over energy resources among end-use customers. However, over the last two decades, the energy industry has been in a constant state of transformation, catalyzed by dramatic increases in clean energy and a multitude of technology innovations [6]. The increasing integration of DERs into T&D networks presents new challenges for utilities and grid operators as conventional grids have not been designed to handle bidirectional energy flow and the intermittent generating characteristics of DERs [7]. A section addressing changes that impact the market rules pertaining to energy storage within Independent Systems Operators (ISOs) and Regional Transmission Organizations (RTOs) is included in this chapter.

Moreover, end-use customers historically have not had much control over the components of their energy usage and did not seek this out as an option. The emergence of renewable energy and DERs, which has gained momentum particularly over the last decade, has fundamentally changed the energy equation and the systems that are needed to keep it in balance.

The energy industry has been undergoing a transformative process of decentralization over the last few decades. Along with a dismantling of the monopoly system that was the foundation of the industry for well over a century, the core of electricity systems is moving from the traditional structure of large, central generating stations to distributed generation often controlled by end-use customers (i.e., prosumers). Within this transformation, large and small consumers are taking over electricity generation while a single control area is being replaced by a web of interconnected, smaller control areas. All of this is moving the industry toward a more decentralized system in which DERs, energy storage, and the smart grid play ever-more-prominent roles.

Despite the ever-increasingly available technologies, the shift to cleaner energy will not occur at the same pace in every U.S. state or region. Regulation of the energy industry has remained regional for the most part, and it is expected that this will remain even more so as the use of DERs continues. This is due largely to the fact that each state operates in a unique regulatory environment and faces constraints regarding available generation resource options. Consequently, both the path and the end point of the transformation are likely to be specific to every locale. Policies need to address the actual needs of an individual system to be effective [8].

Indeed, the complexity created by the multiple system linkages, different technologies, legacy systems, and even weather conditions means generic solutions offered to the marketplace will not be particularly relevant or useful [8]. At a regional (i.e., location specific) level, targeted attention is being paid to the identification and removal of technical barriers and the revision of regulatory and market structures that are proving obsolete in the industry evolution.

Although still evolving to address modern issues and technologies, regulatory policy has always had a direct impact on the ways in which energy storage can participate in the energy and utility industry. For instance, regulatory policy has traditionally classified utility assets as either generation, transmission or distribution, which in turn has determined how costs associated with those assets can be recovered (i.e., either through market transactions or recovery through rate base). This approach creates an inherent problem for energy storage, as energy storage has characteristics of, and the ability to support, all three classifications. However, whether it is deemed to be a product of the market or a regulated asset, neither approach has thus far offered a treatment that fully values energy storage.

Removing existing market entry barriers, rather than adding new regulations, appears to be an essential step in enabling the transition to a renewables-based, clean energy future. At the same time, it is clear that energy storage policies cannot be considered independently from a wider energy policy context. The development of energy storage, and the policies that will enable it to reach its full potential, will not occur in a silo, but rather need to be considered against more holistic federal and state policies.

Deregulated electricity markets arguably offer the best potential for developing energy storage services. In a regulated market, opportunities for energy storage may be limited to one-dimensional services such as load balancing or peak shaving within a regulated utility's service territory. This, by definition, restricts the opportunities for energy storage to provide the full value of services of which it is capable, such as frequency regulation and voltage support that are available in competitive markets. Opportunities to develop energy storage solutions for transmission and distribution utilities may be limited, as energy storage devices deployed as transmission and distribution assets are not currently able to transact in wholesale markets, eliminating an important revenue source [3].

In the United States, there are several entities at the federal and state levels that either drive energy policy or have a direct effect on policy development, policy oversight, and policy compliance within the electric power T&D industry [9].

2.1. Policymaking at the Federal Level

Federal energy legislative policy developments are promulgated in Congress via three committees (Official House Natural Resources Committee, Official House Energy and Commerce Committee, and the Official Senate Energy Committee). At the federal level, the execution of policy enacted through legislation along with independently developed regulations is led by the following organizations:

- Department of Energy (DOE): The mission of the Energy Department is to ensure America's security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions. In the modern day, the DOE is focused on grid modernization and grid resilience.
- Department of Agriculture (DOA): Focused on the needs of the nation's nearly 1000 electric cooperatives.
- The Environmental Protection Agency (EPA): Focused on environmental concerns.
- The Federal Communications Commission (FCC): Focused on the regulation of interstate communications by radio, television, wire, satellite, and cable.
- The North American Electric Reliability Corporation (NERC): Focused on the effective and efficient reduction of risks to the reliability and security of the grid; and
- The Federal Energy Regulatory Commission (FERC): As an independent federal agency situated within the DOE, FERC is focused on the regulation of the transmission and wholesale sale of electricity and natural gas and the transportation of oil by pipeline in interstate commerce.

2.1.1. Role and Responsibilities of FERC

FERC is an independent agency tasked with overseeing the transmission and wholesale sales of electricity, natural gas and oil in interstate commerce. Its origins date back to 1920 with the creation of the Federal Power Commission, which was renamed FERC in 1977.

FERC's responsibilities are as follows:

- Regulation of wholesale sales of electricity and transmission of electricity in interstate commerce
- Regulation of the transmission networks of the nation's interconnected regions
- Oversight of mandatory reliability standards for the bulk power system
- Promotion of strong national energy infrastructure, including adequate transmission facilities
- Regulation of jurisdictional issuances of stock and debt securities, assumptions of obligations and liabilities, and mergers

FERC has an important role in achieving efficient price signals in the wholesale markets. The Federal Power Act (FPA) directs FERC to ensure that rates and rules are "just and reasonable" and are not unduly discriminatory or preferential. Therefore, ensuring that the ISO/RTO tariffs, relevant price formation mechanisms, and other payment mechanisms such as performance payments provide accurate compensation, and that these tariffs do not hinder the efficiency of the markets by insufficiently compensating an energy resource or by preventing an energy resource from being compensated at all, is FERC's main responsibility.

With regard to energy storage specifically, FERC has been developing policy for several years. The issue dates back to 2016, when FERC opened a docket (AD16-20) to review the role of storage for grid operators — independent system operators (ISOs) and regional transmission organizations (RTOs). After a technical conference and comments from market participants, in February 2018

FERC issued Order 841, asking the RTOs/ISOs to revise their tariffs so that battery storage could participate in all markets — energy, capacity and ancillary services.

2.1.2. Organization of Wholesale Markets

A wholesale market refers to the buying and selling of power between the generators and resellers. Resellers include electricity utility companies, competitive power providers and electricity marketers. For most regions within the United States, the operation of and transactions in the wholesale market are regulated by FERC.

The wholesale market begins with generators, which, after securing the necessary approval, connect to the grid and generate electricity. The electricity produced by generators is bought by an entity that will often, in turn, resell that power at the distribution level to meet end-user demand. These resale entities will generally buy electricity through markets or through contracts between individual buyers or sellers. In some cases, utilities may own generation and sell directly to end-use customers.

The price for wholesale electricity can be predetermined by a buyer and seller through a bilateral contract (a contract in which a mutual agreement has been made between the parties) or it can be set by organized wholesale markets managed by RTOs/ISOs. The clearing price for electricity in these wholesale markets is determined by an auction in which generation resources are offered in a price at which they can supply a specific number of megawatt-hours of power.

If a resource submits a successful bid and will therefore be contributing its generation to meet demand, it is said to "clear" the market. The cheapest resource will "clear" the market first, followed by the next cheapest option and so forth until demand is met. When supply matches demand, the market is "cleared," and the price of the last resource to offer in (plus other market operation charges) becomes the wholesale price of power.

Wholesale markets are typically comprised of three sub-market types that enable management of the grid over time scales ranging from cycles (one cycle = 1/60th of one second) to several years in advance of real-time dispatch. The three sub-markets typically associated with wholesale market operations are:

- Ancillary services markets
- Energy markets (Day Ahead and Real-Time)
- Capacity markets

Ancillary services allow a wholesale market to maintain a portfolio of backup generation in case of unexpectedly high demand or if contingencies, such as generator outages, arise on the system. There are many different types of ancillary services, corresponding to the speed with which the backup generation needs to be dispatched. "Reserves" represent capacity that can be synchronized with the grid and brought to some operating level within 60, 30, or 15 minutes. "Regulation" represents capacity that can change its level of output within a few seconds in response to fluctuations in the system frequency. Ancillary services are increasingly important tools that enable the integration of renewable energy and energy storage.

Energy markets are forward markets that are used within wholesale market structures to ensure that enough generation capacity is online and able to produce energy on a day-ahead (24-hour ahead) to one-hour-ahead basis. Wholesale markets generally organize Energy Markets into two sub-areas:

- "Day ahead markets," in which generators are scheduled to operate during each hour of the following day (and at what level of output), based on a projection of electricity demand the following day; and
- "Real-time markets," which are used to adjust which generators are scheduled to run on an hour-ahead basis. A better term for the real-time market (which is used in some cases) would be "adjustment market" or "balancing market" since supplies for this so-called real-time market are actually procured one day in advance (but after supplies are procured through the day-ahead market).

Capacity markets are generally forward markets that are intended to ensure that adequate levels of generation capacity are online and ready to produce electricity at least one year ahead of time. Capacity markets are meant to provide financial incentives for suppliers to keep generation assets online and to induce new investment in generation. Capacity markets are thought to be necessary because prices in wholesale markets are not always sufficiently high to keep existing generation from shutting down or to entice new generators to enter the market. Not all wholesale markets in the U.S. have forward capacity markets. Texas, for example, does not operate a capacity market.

2.1.3. Role and Responsibilities of ISOs/RTOs

In the late 1990s and 2000s, FERC took steps to create a level playing field for competitive markets, ensuring equal access to transmission grids and encouraging states to require utilities to sell off power plants and gradually eliminate regulator-set rates in favor of prices determined by the markets. The voluntary creation of ISOs and RTOs was initiated by FERC Order No. 2000, issued on December 20, 1999.

ISOs and RTOs are organizations formed with the approval of FERC to coordinate, control and monitor the use of the electric transmission system by utilities, generators and marketers. The FERC created ISOs to oversee restructuring on a regional basis. These ISOs were given responsibility for ensuring reliability and establishing and overseeing competitive wholesale electricity markets. Typically, neither ISOs nor RTOs are allowed to own generating assets.

An ISO is a non-profit organization that combines the transmission facilities of several transmission owners into a single transmission system. This consolidation enables the grid operator to move energy over long distances at a single lower price than the combined charges of each utility that may be located between the buyer and seller. The ISO provides non-discriminatory service and must be independent of the transmission owners and the customers who use its system. In the areas where an ISO is established, it coordinates, controls, and monitors the operation of the electrical power system, usually within a single U.S. state, but sometimes encompassing multiple states.

An RTO in the United States is an electric power transmission system operator (TSO) that coordinates, controls, and monitors a multi-state electric grid. The transfer of electricity between states is considered interstate commerce, and electric grids spanning multiple states are therefore regulated by FERC. RTOs also provide non-discriminatory access to the transmission network; however, they are required to meet specific FERC regulations that deal with transmission planning and expansion for an entire region. RTOs offer regional wholesale electric transmission services under one tariff. Put simply, RTOs typically perform the same functions as ISOs but cover a larger geographic area.

ISOs/RTOs are independent, federally regulated non-profit organizations that ensure reliability and optimize supply and demand bids for wholesale power. They are intended to be technology neutral and must ensure that market rules do not unfairly preclude any resource from participating in wholesale market transactions, as enforced and regulated by FERC. As of December 2019, many existing market rules created by the ISOs/RTOs may not take into account the unique operating parameters and physical constraints of energy storage as both a consumer and provider of electricity.

At present, ISOs/RTOs integrate ESSs into their organized wholesale markets in different ways. Some markets already allow certain storage technologies to provide ancillary services. However, these rules were designed with traditional generators in mind and lack the flexibility to recognize unique characteristics of ESSs. Some aspects of these market rules, such as performing penalties that penalize storage systems for not providing certain services while charging, create disincentives for ESSs.

For an ISO/RTO trying to fit energy storage into its system, one of the hardest tasks is how to characterize storage. It is both supply and load, but ISO/RTO rules generally take a binary approach to power system resources. It has to be one or the other but not both. In addition, existing regulations were not set up to handle distribution-connected storage devices that can also supply the wholesale market, which precludes energy storage from delivering all of the services it is capable of providing.

RTO/ISO markets must also address how they will manage the following complexities that are associated with energy storage:

- Avoiding conflicting dispatch instructions: How will the market ensure that an energy storage resource is not asked to both charge and discharge in the same interval.
- Provide storage make-whole payments: How will the market re-pay storage resources for transmission access charges accrued when the grid operator requires the resource to charge?
- Participation in ancillary services without offering energy services: Can a resource provide services such as frequency regulation without also submitting an energy schedule?
- Minimum run time: What will the market require as the minimum consecutive run time to offer forward capacity?

There are presently seven RTOs/ISOs that are operating in the United States.

1. <u>California Independent System Operator (CA-ISO)</u>

The California Legislature created the California Independent System Operator (CA-ISO) in 1998 as part of the state's restructuring of electricity markets. CA-ISO operates only in California, but it is under FERC's jurisdiction because the state's transmission grid is interconnected with the rest of the Western U.S. Some public power utilities in the state have chosen not to turn over operational control of their transmission facilities to the CA-ISO, but all public power utilities are impacted by CA-ISO's energy market prices and provision of transmission service due to the array of business relationships among market participants in the state [10].

The CA-ISO is one of the largest ISOs in the world, delivering 300 million megawatt-hours of electricity each year and managing about 80 percent of California's electric flow.

The CA-ISO does not operate a capacity market, and in 2018, FERC rejected a complaint issued by generators requesting the creation of a capacity market in CA-ISO. FERC responded that it does not impose a capacity market on a region, but rather only approves capacity market proposals brought to it by stakeholders in regions [10]. Recently CA changed its capacity procurement from one year to three years and made some other significant changes under its Resource Adequacy Proceedings, but it still has no capacity market.

2. ***Midwest Independent System Operator (MISO)***

The Midwest Independent System Operator (MISO) was established in 1998 as an ISO and was approved as the nation's first RTO by FERC in 2001. MISO is an independent and member-based non-profit organization. Its members include 51 transmission owners with more than 65,800 miles of transmission lines. Members include IOUs, public power utilities, and cooperatives. MISO operates in all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, Wisconsin, and Manitoba, Canada.

This open market began on April 1, 2005 and provides financially binding day-ahead and real-time pricing of energy. MISO Markets include a Financial Transmission Rights Market, a Day-Ahead Market, a Real-Time Market, and a market for operating reserves and regulation. They are operated and settled separately, providing a clear look at day-to-day price changes.

MISO has seen both defections by transmission-owning utilities—First Energy and Duke Energy left MISO to join the PJM Interconnection in 2011 and 2012 respectively—and a significant expansion of its territory at the end of 2013 to include what is known as MISO South. Many industry observers believe the former MISO utilities that joined PJM did so to receive lucrative capacity market payments not available from MISO, while MISO's revisions to its capacity market were an incentive for the southern expansion. In 2012, FERC approved a voluntary locational capacity market for MISO, but ruled against mandatory participation or a minimum offer price rule in that market. MISO filed a proposal in 2016 to create a mandatory capacity auction in those regions where there is retail choice and the utilities are not responsible for supplying power to their customers, which was later rejected by FERC [11].

MISO has a stored energy resource category that can offer regulation reserves.

3. ***Independent System Operator of New England (ISO-NE)***

Created in 1997, the Independent System Operator of New England (ISO-NE) is the independent, not-for-profit corporation responsible for the reliable operation of New England's electric power generation and transmission system, overseeing and ensuring the fair administration of the region's wholesale electricity markets, and managing comprehensive regional electric power planning. ISO-NE was created in 1997 by FERC as a replacement for the New England Power Pool (NEPOOL), which was created in 1971.

ISO-NE operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. ISO-NE oversees the operation of New England's bulk electric power system and transmission lines, generated and transmitted by its member utilities. ISO-NE operates a mandatory capacity market, called the forward capacity market, which procures capacity three years in advance.

The region is facing numerous challenges from growing reliance on natural gas without a corresponding increase in natural gas pipeline capacity, retirements of nuclear and coal plants, and rising energy and capacity prices [11].

4. New York Independent System Operator (NYISO)

The creation of the New York Independent System Operator (NYISO) was authorized by FERC in 1998. In November 1999, New York State's competitive wholesale electricity markets were opened to utility and non-utility suppliers and consumers as the NYISO began its management of the bulk electricity grid. The formal transfer of the grid operation responsibilities from the New York Power Pool to the NYISO took place on December 1, 1999.

The NYISO monitors a network of 10,892 miles of high-voltage transmission lines and serves approximately 400 market participants. Through the end of 2009, NYISO market transactions totaled more than $75 billion.

NYISO operates only in New York but is regulated by FERC because the state's transmission grid is interconnected with the rest of the region. New York City is a very transmission-constrained area within NYISO, which requires substantial mitigation of the power sales into that area. The NYISO operates a shorter-term capacity market than in PJM and ISO-NE, but it is only mandatory within the New York City and Lower Hudson Valley zones [11].

NYISO allows energy storage to provide regulation, capacity and ancillary services.

5. The PJM Interconnection (PJM)

Started in 1927, the pool was renamed the Pennsylvania-New Jersey-Maryland Interconnection (PJM) in 1956. The organization continues to integrate additional utility transmission systems into its operations. More than 1,000 companies are members of PJM, which serves 65 million customers and has 180 gigawatts of generating capacity. With 1,376 generation sources, 84,236 miles (135,560 km) of transmission lines and 6,038 transmission substations, PJM delivered 807 terawatt-hours of electricity in 2018 [11].

PJM operates in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

PJM operates a three-year forward mandatory capacity market, called the reliability pricing model. In 2018, FERC found that the capacity market rules in PJM are not just and reasonable because they do not prevent reductions from capacity prices due to state efforts to procure renewable resources or prevent nuclear plants from retiring. An investigation was opened by FERC into PJM's capacity market rules [11].

6. Southwest Power Pool (SPP)

The Southwest Power Pool (SPP) was incorporated as a nonprofit corporation in 1994 and was approved as an RTO by FERC in 2004.

The SPP region lies within the Eastern Interconnection, in the central Southern United States, serving all of the states of Kansas and Oklahoma, and portions of New Mexico, Texas, Arkansas, Louisiana, Missouri, South Dakota, North Dakota, Montana, Minnesota, Iowa, Wyoming, and Nebraska. SPP members include investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, and power marketers.

SPP has many of the high voltage direct current (DC) ties which connect the Eastern interconnection to the Western Interconnection and both of the DC ties to ERCOT Texas Interconnection.

SPP has roughly 67,000 miles of transmission lines. Its all-time peak load was 50,622 MW in the summer of 2016 and its nameplate generating capacity is 89,999 MW as of January 1, 2019. SPP sources most of its power from coal, with wind and natural gas coming in second and third, respectively. SPP also has the highest wind penetration of any ISO, with a wind penetration record of 66.5 percent on April 21, 2019 [11].

7. <u>ERCOT</u>

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power on the Texas Interconnection that supplies power to more than 25 million Texas customers – representing 90 percent of the state's electric load. ERCOT works with the Texas Reliability Entity (TRE), one of eight regional entities within the North American Electric Reliability Corporation (NERC) that coordinate to improve reliability of the bulk power grid. As the ISO for the region, ERCOT dispatches power on an electric grid that connects more than 46,500 miles of transmission lines and more than 550 generation units. ERCOT also performs financial settlements for the competitive wholesale bulk-power market and administers retail switching for 7 million premises in competitive choice areas [11].

Because ERCOT does not extend beyond the borders of Texas and is therefore considered an intra-state regional operator, ERCOT is not regulated by FERC. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas (PUCT) and the Texas Legislature.

ERCOT does have one market product that is suitable for limited duration resources, such as batteries, which is called the "fast responding regulation service."

2.2. Policymaking at the State Level

At the state level, 50 state-level public utility commissions (PUCs) and a District of Columbia commission are in place to oversee and regulate energy-related distribution services at the retail level. State commissions are united as members of the National Association of Regulatory Utility Commissioners (NARUC).

There are three types of electric utilities that may be regulated at the state level: investor-owned utilities, municipal (public power utilities), and electric cooperatives. Each of the three types of electric utilities also have trade associations that provide policy development and act as congressional liaisons for their members. The most important of these at the national level include the Edison Electric Institute (for IOUs); the American Public Power Association (APPA) for public power utilities, including federal power agencies; and the National Rural Electric Cooperative Association (NRECA) for electric cooperatives [9].

State policymakers and the utilities they regulate are increasingly looking to advanced energy storage to reduce the costs of electric service, enhance electric system reliability, and integrate more renewable resources onto the grid. However, storage is still considered new and experimental in most states, and the majority of states have yet to develop substantive energy storage policy.

The challenge of creating energy storage policy often has roots in the legacy policies within a given state. In fact, existing state rules and processes, or the lack thereof, inadvertently have created biases against or exclude energy storage as an investment option, in comparison to conventional investments in generation, transmission, distribution, and demand management [12]. This creates a number of barriers for energy storage to develop behind the meter or provide services at the distribution level.

These barriers involve:

- How energy storage is classified as an asset and who can own it
- How energy storage is or is not included in utility planning processes
- Whether energy storage has equal access to grid interconnection
- How energy storage is valued in the marketplace

In recent years, a number of states have introduced policies related to the support and development of energy storage markets. The approaches that states have taken include mandating specific levels of storage procurement, incentivizing storage through subsidies and tax credits, or requiring that utilities consider energy storage alternatives in their long-term resource planning.

According to the Energy Storage Association (ESA), public regulatory commissions (and the utilities that they regulate) across the U.S. generally fall into four categories when assessing the current status of their energy storage policy development. It should be noted that these four categories often overlap or repeat as state's examine multiple policy issues related to energy storage. These four categories are as follows:

- **Investigating**–States that have demonstrated an interest in storage through general investigations, workshops, or briefings.
- **Clarifying**–States that are clarifying existing rules as they apply to energy storage, through revising interconnection, net metering, fire and building codes, and other state standards as applicable.
- **Energizing**–States that are encouraging energy storage market growth through procurement targets, pilot/demonstration project funding, or other mandates or incentives that are specific to energy storage.
- **Planning**–States are that are addressing energy storage within a broader context when planning for the energy future through long-term resource planning, resource valuation efforts, grid modernization or distribution system planning.

A fifth category could be used for those states that are presently inactive, with no apparent activity toward the development of energy storage policy.

Accordingly, energy storage deployment policies at the state level range in both the type of policy mechanism and the level of ambition [2]. States are in different stages of deploying energy storage. Some are commissioning studies to understand the potential of energy storage, while others have already taken this step and are advancing to more sophisticated policies and/or project deployments.

2.2.1. Role and Responsibility of State Regulatory Commissions

While the task of eliminating inefficient wholesale market rules and barriers primarily falls under FERC's responsibilities, individual U.S. states also have the responsibility to implement policies for the efficient deployment of ESSs at the distribution level [5]. State governments have the authority to regulate utilities within their borders and to implement state-wide policies, such as storage infrastructure requirements and net-metering programs, which can influence the incentives for energy storage development. States also have an important in creating accurate price signals. While FERC is responsible for ensuring efficient price signals for transactions in the wholesale markets, states bear the same responsibility in the retail markets

Creating a framework in which energy storage can be compensated based on all the values it brings—even when installed locally behind the meter—is crucial to building a robust market for energy storage at the state level. Moreover, it is the responsibility of state regulatory commissions to coordinate with ISOs/RTOs to ensure that ESSs are not receiving double compensation from both the retail and wholesale markets for provision of the same service [5].

State policymakers and regulators play a significant role in laying the groundwork for energy storage to compete through a variety of means: regulatory changes that remove barriers for and/or open markets to energy storage; providing incentives to jumpstart the local market for storage; and approving utility demonstration projects or cost recovery for wide-scale deployments.

State agencies have the opportunity to develop rules and policies to not only monitor energy storage operations but also evaluate cost-of-service rates that will enable owners of storage assets to secure revenue streams and access to capital. ISOs/RTOs, through coordination with FERC, have the opportunity to enhance the market participation of energy storage by creating interconnection standards and compensation schemes on a much wider scale.

2.2.2. State Legislation

State legislation can have a direct impact on energy policy in numerous ways, including taxes, land use controls, regulation of energy utilities, and energy subsidies. In fact, states may establish environmental standards stricter than those set by the federal government. Along with public utility commissions that directly impact the opportunities for energy storage to participate at the distribution level, legislation at the state level also has a direct role in shaping new policies for the energy storage sector. For instance, procurement mandates for energy storage development at the state level have often been codified through legislation (examples of this are Massachusetts and New Jersey, both of which have procurement targets for energy storage that have been enacted through legislation). In particular, California's AB2514 is a good example. Since its passage in 2010 and then implementation by 2013, California has met its targets two years ahead of its target year. The legislation created assured market which has had a cascading impact on larger scale projects, encouraging manufacturers, bringing down costs and enabled financing.

In fact, the policy landscape for energy storage has matured dramatically over the past year in no small part due to the work of state legislatures, nine of which passed 17 measures aimed at supporting the emerging technologies. In all, 17 state legislatures considered more than 80 measures on energy storage—up from around a dozen such bills just three years ago. In addition, states have passed bills to provide tax credits for energy storage projects, commission studies, fund demonstration projects and require utilities to consider storage in resource planning [13].

Along with developing legislation that is specific to energy storage, more than a handful of states have also passed laws that mandate a transition to become 100-percent carbon free and/or renewables-based at a designated point in the future. As one example, California's Senate Bill 100 mandates that the state's grid be 100 percent carbon free by 2045 [6].

2.2.3. Other State Policymakers

A relatively new phenomenon in political elections is the increase of gubernatorial candidates who have campaigned and won their elections on platforms advocating for renewables and commitments to clean energy. Examples of this include the state of Colorado and its current governor Jared Polis (D). Building on momentum established by his predecessor (former Governor John Hickenlooper), who approved a new law that codified a citizen's right to install energy storage technology without discrimination from their utility provider, Polis campaigned on a platform that included 100 percent renewable energy by 2040. (His Republican opponent opposed the plan as being too expensive and increasing costs for Colorado customers). Upon his election in the fall of 2018, Governor Polis has issued a number of executive directives that call for increased use of clean energy technologies in Colorado, along an ambitious roadmap outlining Colorado's path toward achieving 100-percent renewable energy by 2040 [12].

Another example comes from Illinois, as Governor J.B. Pritzker (D) campaigned and was elected in 2018 based largely on a clean-energy platform. During his first month in office, Gov. Pritzker joined governors in Michigan, Minnesota and Wisconsin in backing the U.S. Climate Alliance, a coalition of states committed to the terms of the Paris climate accord. Pritzker has said that the approach toward developing clean energy policy in Illinois will be "gradual," with an emphasis placed on bringing jobs back to coal-mining communities that are already seeing reductions in workforce due to the move toward non-carbon resources [12].

Along with directives from governors, policymaking for energy storage at the state level can also emerge from state agencies formed within an executive administration. Agencies such as the California Energy Commission (CEC) in California and the New York State Energy Research and Development Authority (NYSERDA) in New York are two examples of state agencies that are directly involved with policy development for energy storage and often serve as the source of funding for energy storage deployment projects that are used to stimulate market growth.

2.3. Federal Energy Policy Set Through Legislation

2.3.1. Overview

There is a long history of federal legislation that has shaped energy industry policy. It is important to have a sense of this history as, despite the fact that widespread use of energy storage technologies is a relatively new phenomenon, federal legislation has often designated a path forward for energy storage even when the technology was not specifically identified. The evolution of federal legislation has broken down the monopolistic structure of the utility sector and created new wholesale market rules that have created opportunities for renewables and DERS (including energy storage) that otherwise might not have existed.

As of December 2019, there are reportedly five energy storage bills that are being considered by the U.S. House Energy and Resources Committee, that would create a research, development and demonstration program for "highly flexible, long-duration and seasonal (energy storage) systems [14]. Current legislation that is intended to create new opportunities specific to energy storage build upon a foundation of federal legislative policy that dates back to the 1970s.

2.3.2. Federal Legislation

2.3.2.1. PURPA

Congress enacted the Public Utility Regulatory Policies Act (PURPA) in the 1970s to address the national energy crisis. PURPA was intended to encourage the development of small power producers and co-generators, which were designed within the law as "qualifying facilities," to reduce the country's demand for traditional fossil fuels, which were considered to be in short supply. PURPA laid the foundation for subsequent policy enacted by FERC addressing open access transmission policies and the competitive wholesale power markets that are in place today.

PURPA required utilities to buy power from qualifying facilities (typically small cogeneration and renewable power plants) at the full avoided cost of replacing that power with other generation. Independent power producers typically lack the economies of scale and cheaper production costs enjoyed by large utilities, and prior to PURPA, utilities had little incentive to purchase from these producers.

Moreover, through the passage of PURPA, for the first-time small power producers—many of whom were pioneering renewable energy technologies—were given more equitable access to the grid. Through PURPA, the federal government opened the door to generation market competition in the electricity sector.

2.3.2.2. National Energy Policy Act of 1992 (EPAct 1992)

The National Energy Policy Act of 1992 (EPAct 1992) continued the efforts initiated by PURPA to reduce barriers to grid-access for independent power producers. In addition to exempting these small-scale producers from onerous securities regulations, EPAct 1992 also authorized FERC to require transmission-owning utilities to transmit ("wheel") wholesale power across their transmission systems. Although FERC was prohibited from ordering retail-level transmission access, EPAct 1992 enabled FERC to require "virtually any transmission owning entity in the U.S. to wheel power for wholesale transactions at the request of a broad range of potential applicants involved in wholesale power transactions" [15].

EPAct 1992 was intended to enhance competition in the energy industry by lifting legal barriers in generation markets. As an example of an expanded governmental role, EPAct 1992 provides tax incentives and other subsidies to generation technologies that are environmentally clean and potentially cost efficient. These provisions in the Act reflect a general public policy shift toward energy efficient and environmentally benign technologies that, in many states, started about a decade ago [15].

FERC subsequently implemented EPAct 1992 through orders 888 and 889, which further promoted market competition among power producers, and set the stage for restructuring of the entire generation sector in many parts of the country.

2.3.2.3. Energy Policy Act of 2005 (EPACT 2005)

The Energy Policy Act of 2005 (EPAct 2005) signed by President George W. Bush on August 8, 2005, was the first omnibus energy legislation enacted in more than a decade. Spurred by rising energy prices and growing dependence on foreign oil, the new energy law was shaped by competing concerns about energy security, environmental quality, and economic growth.

EPAct 2005 granted FERC new responsibilities and significant new authority to discharge these responsibilities by modifying the Federal Power Act, the Natural Gas Act and PURPA. FERC's expanded responsibilities include:

- Overseeing the reliability of the nation's electricity transmission grid
- Implementing new tools, including penalty authority, to prevent market manipulation
- Providing rate incentives to promote electric transmission investment
- Supplementing state transmission siting efforts in national interest electric transmission corridors
- Reviewing certain holding company mergers and acquisitions involving electric utility facilities, as well as certain public utility acquisitions of generating facilities

Along with expanding FERC's responsibilities, EPAct 2005 included the following provisions:

- Energy-related tax incentives totaling roughly $14.5 billion from 2005 to 2016, including $1.3 billion in tax incentives for energy efficiency and conservation; approximately $4.5 billion in incentives for renewable energy; $2.6 billion in incentives for oil and gas production and transmission; almost $3.0 billion for coal production; and around $3.0 billion in incentives for electricity generation and transmission.
- Increased oil and natural gas production, more electric transmission lines, and more gas pipelines on federally owned land.
- Offers tax benefits to individuals who increase energy efficiency in existing homes, buy or lease hybrid/alternative vehicles.
- Required all public utilities to offer net metering on request.
- Encourages more domestic energy production.
- FERC was authorized to certify national electric reliability organizations to enforce mandatory reliability standards for the bulk-power system.

2.3.2.4. Energy Independence and Security Act 9 (2007)

Signed on December 19, 2007 by President George W. Bush, the Energy Independence and Security Act of 2007 (EISA) aims to:

- Move the United States toward greater energy independence and security
- Increase the production of clean renewable fuels
- Protect consumers
- Increase the efficiency of products, buildings, and vehicles
- Promote research on and deploy greenhouse gas capture and storage options
- Improve the energy performance of the Federal Government
- Increase U.S. energy security, develop renewable fuel production, and improve vehicle fuel economy

EISA reinforces the energy reduction goals for federal agencies put forth in Executive Order 13423, as well as introduces more aggressive requirements. The three key provisions enacted are the Corporate Average Fuel Economy Standards, the Renewable Fuel Standard, and the appliance/lighting efficiency standards.

3. Energy Storage Regulatory Policymaking (Federal)

3.1. FERC Orders

Over the last two decades, FERC has issued a number of landmark orders that have either addressed energy storage specifically or do so in a tangential manner that nevertheless has created new policy on how energy storage can participate within the wholesale marketplaces that FERC regulates.

3.1.1. Order 888 (1996)

Based upon an acknowledgement that barriers to competitive wholesale markets may exist and that those barriers must be removed, in 1996 FERC issued Order 888, which was intended to create a foundation upon which building a transmission system aimed at opening the wholesale energy industry to competition could be pursued.

Although the issuance of Order 888 preceded current-day realizations about the benefits that energy storage can provide, it nevertheless created a path forward for energy storage to participate in wholesale transactions and be recognized for the multiple services it can provide.

Specifically Order 888 required all public utilities that own, operate or control interstate transmission facilities to:

- Offer network and point to point transmission service and ancillary service to all eligible wholesale buyers and sellers
- Unbundle generation functions
- Functionally separate transmission and power marketing functions
- Provide open access to their transmission facilities
- Adopt an electronic transmission system information network
- Have an Open Access Transmission Tariff on file with FERC

Order 888 played an instrumental role in opening up the U.S. electricity system to generator competition and wider transmission access. The Order and the concept of "open access" have since become deeply engrained in the regulatory framework. Furthermore, Order 888 encouraged the creation of ISOs and RTOs—entities that now manage most of the power transfers in the eastern interconnection and California.

3.1.2. Order 2000 (1999)

In 1999 FERC issued Order 2000, which was intended to advance the "voluntary" formation of RTOs. Each public utility that owned, operated or controlled facilities for the transmission of electric energy in interstate commerce was directed to make certain filings with respect to forming and participating in an RTO. The goal of the order was to promote efficiency in wholesale electricity markets and ensure that electric consumers pay the lowest price possible for reliable service.

Within the context of Order 888, FERC recognized that, like ISOs, RTOs encourage competitive generation markets by bringing all transmission control under independent entity's management. However, in the Order 2000 rulemaking, FERC wanted to correct some of the design faults inherent in the ISO structure. FERC realized that while "ISOs had the potential to provide significant benefits, a less intrusive functional unbundling approach"—and a shift toward regional cooperation—would better serve the end open access goals of Order 888.

3.1.3. Order 890 (2007)

Issued in 2007, Order 890 is relevant to the energy storage sector because it was intended to allow participation by non-generator resources in the RTO/ISO ancillary services market, including regulation, and prohibit undue discrimination and preference in transmission services.

Order 890 was intended to expand "nondiscriminatory access" to the transmission grid, increase customer access to new generating resources, facilitate the increased use of renewable energy (in part, by including "conditional firm" transmission service that responds to the needs of renewable energy generators), and enhance overall access to the grid by requiring transmission providers to calculate, in a uniform and transparent manner, the amount of capability available in the transmission network to accommodate additional requests for transmission services.

Order 890 appears to have also had impacts beyond those expressly contemplated by FERC. For example, as more transmission capacity becomes available to independent generators, short- and medium-term needs for additional generation may decrease. In addition, expanded access to the transmission grid may result in increased costs for owners of intermittent generation resources, which in turn creates greater incentives to incorporate energy storage as a means to defer more-capital intensive generation resources and further enable intermittent resources such as renewables.

3.1.4. Order 755 (2011)

Issued in 2011, Order 755 is directly relevant to energy storage because it requires ISO/RTO markets to provide compensation to resources having the ability to provide fast-ramping frequency regulation. The order applies only to secondary frequency response, or regulation, which is a fast-acting service provided by generators to address system imbalances. FERC cited evidence showing that regulation markets do not compensate resources providing differing amounts of regulation service based on the amount of service provided, only on a capacity bid. As a result, FERC found that exiting market rules for compensation were "unjust, unreasonable and unduly discriminatory" to faster acting resources such as energy storage [3].

Order 755 requires a two-part payment for frequency regulation service: a capacity payment and a performance payment. The capacity payment must be based on a uniform market-clearing price, while the performance payment must reflect the accuracy of the performance of a device providing frequency response service and must be market based. The final rule requires that all markets with centrally procured frequency regulation services must provide compensation for cross product and inter-temporal opportunity costs [3].

3.1.5. Order 784 (2013)

Historically, FERC policy restricted public utility transmission providers from procuring ancillary services from third parties. Issued in 2013, Order 784 reformed this policy, enabling third parties to sell ancillary services. Moreover, Order 784 revises regulations governing sales of frequency regulation services, thereby increasing the opportunities for energy storage projects in the ancillary services market. Frequency regulation, an ancillary service, facilitates grid stabilization by enabling supply-demand balance. It has been provided by slow-responding, fossil-fuel centered gas turbines and coal-powered generators until the emergence of energy storage technologies.

Order 784 expands the pay-for-performance requirements established by FERC Order 755 issued in 2011, which required the adoption of a two-part market-based compensation method for frequency regulation services – a capacity payment reflecting opportunity costs and a market-based performance payment. These changes were intended to reward faster-ramping resources, such as batteries and flywheels.

In practice, Order 784 requires public utility transmission providers to consider two additional parameters – speed and accuracy – while assessing regulation resources. ESSs are inherently fast-responding resources that excel in speed, accuracy, and ramping ability. Additionally, it would increase competitiveness in the market and improve efficiency of the transmission system, resulting in cost reductions for consumers in wholesale electric markets.

3.1.6. Order 841 (2018)

Issued in February 2018, Order 841 is perhaps the most significant policy issued by FERC that is related to energy storage, as it is intended to lift barriers to electric storage resources' participation in the wholesale power markets. In fact, Order 841 is considered a crucial step toward removing regulatory barriers that have prevented the efficient deployment of energy storage resources around the country [5].

Order 841 addressed the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by wholesale power markets (i.e., RTOS/ISOs) to more effectively integrate electric storage resources, enhance competition and help ensure that those markets produce just and reasonable rates. In practical terms, Order 841 required grid operators to treat electricity that derives from energy storage in the same manner as if it were from other generation sources.

FERC Order 841 requires RTOs/ISOs to adjust their individual market rules as may be necessary to accommodate and fairly compensate battery energy storage resources on their systems, which may include new products specifically designed for batteries. Specifically, Order 841 requires each of the RTOS/ISOs (CAISO, MISO, ISO-NE, NYISO, PJM, and SPP; ERCOT is not under the jurisdiction of FERC) to revise its tariff to establish a participation model consisting of market rules that going forward will recognize the physical and operational characteristics of energy storage and create a level playing field for energy storage to participate in those markets.

FERC asked each grid operator to provide details about various aspects of energy storage market participation in their unique regions, including size requirements, state of charge management, and how energy storage resources can participate as both buyers and sellers in wholesale markets. Through Order 841, FERC directed the RTOs/ISOs to develop participation rules that:

- Ensure that an energy storage resource can provide the market with all the capacity, energy and ancillary services that it is technically capable of providing
- Ensure that an energy storage resource can be dispatched and can set market prices for buyers and sellers consistent with existing rules
- Account for the physical and operational characteristics of the energy storage resource
- Establish a minimum size requirement for participating energy storage resources that does not exceed 100 kW

In addition, FERC asked the ISOs/RTOs to revise their tariffs to accommodate the participation of ESRs based on their physical and operational characteristics, and their capability to provide energy, capacity, and ancillary services. For example, FERC proposed new bidding parameters such as charge and discharge time and rate, which can give ISOs/RTOs information about the characteristics about ESSs, and hence the services they can provide [5].

Also, under Order 841, ISOs/RTOs must create a participation model that allows energy storage resources to receive compensation based on their physical and operational characteristics, including: state of charge, minimum and maximum states of charge, minimum and maximum charge limits, minimum discharge limit, discharge ramp rate, and charge ramp rate. FERC declined to require ISOs/RTOs to make each of these characteristics an individual bidding parameter but explained that they must demonstrate how their market rules account for each of these characteristics [5].

In subsequent clarifications, FERC explained that Order 841 does not require an RTO or ISO to create and provide a capacity product it does not otherwise offer. FERC further clarified that grid operators have flexibility with respect to how they account for the physical and operational characteristics of storage resources, including what is known as the “state of charge”—the equivalent of a fuel gauge for the battery pack [16].

Order 841 set a December 3, 2019, deadline for grid operators to implement approved tariff changes. However, that deadline was not met due to delays to FERC’s approvals of compliance plans and concerns about how quickly grid operators can then update and modify their market software. Several of the RTOs/ISOs have required extensions for the implementation deadlines.

While FERC has denied rehearing requests for Order 841, the Order is presently being challenged in the U.S. Court of Appeals. Citing a collusion of state and federal policy, EEI and other utility groups have sued FERC over Order 841 and the NARUC also has filed a separate lawsuit against FERC, claiming that Order 841 denies states the ability to fully manage energy storage connected to the distribution grid.

Alternatively, you could say that “As of February 2020, two years since its release, Order 841 has still not been finalized. FERC continues to review the filings that the Order has required from the RTOs/ISOS, including new tariffs for energy storage market participation as well as new power market prices for energy storage developers to participate as both a purchaser and seller of energy.

Order 841 does not specifically identify the energy storage technologies that will be subject to the participation rules, beyond the requirement that a covered energy storage resource must be capable of receiving energy from the grid for storage and later reinjecting that energy back into the grid. The energy storage resources that will be subject to the RTO/ISO compliance with Order 841 can provide energy, capacity, and ancillary services for the grid. Order 841 makes no distinction regarding the location of the resources on the grid.

Finally, FERC also required that each RTO/ISO specify that sales to and from energy storage resources must be priced at locational marginal price which reflects the value of the energy at a particular place and time.

As of December 2019, FERC’s Order 841 is not fully implemented as compliance filings submitted by the ISOs/RTOs are still being reviewed by FERC. The plans submitted by PJM and SPP have received preliminary approval from FERC, subject to additional clarifications that FERC has requested (see next section).

3.1.7. Order 845 (2019)

On February 21, 2019, FERC issued Order 845, granting in part and denying in part various requests for rehearing and clarification of its determinations in Order No. 845. In Order No. 845, FERC revised its interconnection rules for large generators, i.e., generators with capacities greater than 20 MW. Although the requests for rehearing asked FERC to reconsider all but one of the Order No. 845 reforms, Order No. 845-A effectively leaves the major reforms intact and focuses in large part on explaining FERC's intentions as to how the new rules should work.

In the order, FERC issued specific reforms and explained the revisions sought to improve certainty for interconnection customers, promote more informed decisions, and enhance the interconnection process. FERC addressed: 1) the interconnection customer's option to build; 2) contingent facilities; 3) study models and assumptions; 4) congestion and curtailment information; 5) the pro forma definition of "Generating Facility"; 6) interconnection study deadlines; 7) requesting service below generating facility capacity; 8) surplus interconnection service; 9) material modifications and the incorporation of advanced technology; 10) general process concerns; 11) interconnection request withdrawals; and 12) wholesale distribution tariffs.

3.2. ISO/RTO Compliance with FERC Order 841

In December 2018, the six major ISOs/RTOs in the U.S. (CAISO, MISO, ISO-NE, NYISO, PJM, and SPP) filed their plans for creating new market rules and opportunities for energy storage, in compliance with Order 841. Order 841 was not applicable to ERCOT, which is not under FERC's jurisdiction. The rules will take at least a year to go into effect and the plans submitted by the ISOs/RTOs is considered just an initial step. As of December 2019, Order 841 has not been officially finalized and FERC continues to evaluate the filings submitted by the ISOs/RTOs.

In the public comment period, which was open to parties in addition to the ISOs/RTOs, several high-level provisions of Order 841 were criticized. For instance, performance requirements, such as minimum run-times, are allowed to remain in ISO/RTO market rules. Some commenters on the proposed version of FERC's Order 841 argued that these limitations, as well as requirements like "must offer" rules, can limit the ability of some storage systems to provide value to the grid that they are technically not capable of providing [5]. Further, FERC has not ordered ISOs/RTOs to remove any requirements that resources providing ancillary services must also have an energy schedule, meaning all resources must be online and running at the time they are called upon to provide ancillary services. Some of the commenters in the Order 841 proceedings pointed out that this requirement excludes energy storage resources that are able to start and ramp-up more quickly than traditional resources and are therefore technically capable of providing ancillary services despite not already being online. In response, FERC has encouraged the ISOs/RTOs to consider how to allow energy storage resources to provide ancillary services without participating in the energy market [5].

In December 2018, the RTOs and ISOs filed their responses, providing details on a wide range of tariff changes. However, the details were viewed by FERC as insufficient and on April 1, 2019, FERC asked for more detail from each operator, giving deficiency letters to all RTOs and ISOs under its jurisdiction. The letters ask for more information on "physical and operational characteristics, charging requirements and metering" as well as "the ability of storage to participate in both load and generation in wholesale markets."

3.2.1. California Independent System Operator

In its compliance filing, CA-ISO told FERC that its non-generator resource participation model established in 2012 already accounts for the unique characteristics of storage as mandated by Order 841 [17].

Among other changes, CA-ISO proposed to let scheduling coordinators submit end-of-hour state-of-charge (SOC) parameters for resources in the real-time market to manage optimal use of the resource throughout the day. CA-ISO also outlined three options to create default energy bids to apply market power mitigation to energy storage resources [17].

FERC accepted the filing from CA-ISO but ordered further compliance clarifications to address some areas that the commission determined were not fully in line with Order 841's directives. Modifications directed by FERC include accounting for the 10 physical and operational characteristics of storage identified in Order 841 such as state of charge, run time, and charge and discharge limits through bidding parameters or other means in the tariff, rather than in a business practice manual. CA-ISO was also ordered to change the proposed 500 kW minimum size requirement for storage to participate as regulation, spinning reserves, or non-spinning reserves to a figure not exceeding 100 kW [6].

Other revisions required of CA-ISO included steps to eliminate the potential for duplicative retail and wholesale billing for charging by electric storage resources that later resell that charging energy back to the wholesale markets, FERC told CA-ISO to revise its tariff to explicitly provide that, if the host utility is unable or unwilling to net out any energy purchases associated with an electric storage resource's wholesale charging activities from the host customer's retail rate, then CA-ISO would be prevented from charging that resource wholesale rates for the charging energy for which it is already paying retail rates [6].

Although CA-ISO's filing was limited due to the fact that the state already has policy in place to enable energy storage, the reduction to its minimum size requirement from 500 kW to 100 kW represents a significant change for the region.

3.2.2. Independent System Operator of New England

ISO-NE proposed a process that allows suppliers to dispatch energy storage resources in the Real-time Market, ensuring recognition of their operational ability to transition from charging and discharging states quickly. The changes would, according to ISO-NE, allow resources to participate in the energy, reserves, and regulation markets. The region also proposed a definition for "Electric Storage Facility" as a well as a requirement that such facilities be registered as either a "binary" or "continuous storage facility." A binary storage facility is one that has traditional pumped-storage hydroelectric resources. A continuous storage facility is able to transition between maximum output and maximum consumption in 10 minutes or less [18].

The heart of ISO-NE's proposal is that a new section that defines the term "Energy Storage Facility" and provided that such a facility must be registered as either a binary or continuous storage facility.

One important innovation in ISO-NE's proposal is the idea of allowing batteries to provide frequency regulation services at the same time they're charging or discharging for other purposes. To do this, it proposes modeling continuous storage facilities as both energy market resources and "alternative technology regulation resources" for regulation services. That will allow ISO-NE to send dispatches that combine regulation signals with energy market dispatch signals, as well as to allow a storage facility to partition its energy and regulation capabilities as it sees fit [18].

ISO-NE was directed to include a similar provision in its tariff to prevent double payment for charging at the retail and wholesale levels. FERC also found that the ISO-NE compliance filing needs to be better account for the state of charge in its day-ahead market. It directed modifications to the storage resource participation model of the ISO-NE's compliance plan to ensure feasible scheduling and avoid instances where resources are called upon but cannot physically withdraw or inject based on their state of charge [8].

Most of the ISO-NE storage proposal will go into effect December 3, 2019, as directed by Order 841. FERC granted ISO-NE's request to move up the effective date on tariff revisions tied to transmission charges to December 1, 2019, to avoid difficult issues that arise with implementing system changes after the first day of the month [8].

FERC also permitted ISO-NE to delay to January 1, 2024, the effective date of its proposal authorizing pumped storage hydroelectric unit and other resources that cannot seamlessly switch from charging to discharging nor operate continuously across their negative and positive MW ranges to provide regulation services while consuming or withdrawing energy.

However, ISO-NE was directed to include a similar provision in its tariff to prevent double payment for charging at the retail and wholesale levels. FERC also found that the ISO-NE compliance filing must better account for state of charge in the day-ahead market. It directed modifications to the storage resource participation model to ensure feasible scheduling and avoid instances where resources are called upon but cannot physically withdraw or inject based on their state of charge [18].

3.2.3. Midwest Independent System Operator

MISO petitioned to FERC to postpone the effective date for its Order 841 tariff changes beyond the December 3, 2019, deadline after revising the proposal in response to the deficiency letter. FERC has yet to approve the updated tariff revisions [19].

MISO submitted tariff changes to create and refine a new resource category called Stored Energy Resource—Type II. The compliance filing that MISO submitted allows SER-Type II resources to be eligible for up/down ramp capability, MISO proposed the usage of eight "commitment statuses," and four additional statuses (emergency discharge, emergency charge, available, and not participating). Any electric storage withdrawals from the grid will be treated as negative generation, with categorization as wholesale electric storage withdrawals [18].

Further, MISO has proposed that capacity of an energy storage resource be gauged on two measurements: power (MW) and energy (MWh). The dual storage measurement is designed to give more latitude for the projects to participate in both capacity and energy markets [18].

MISO's proposal is technology neutral and includes all technologies and/or storage mediums, including but not limited to batteries, flywheels, compressed air and pumped-hydro.

In response, FERC directed MISO to explain its categorical exclusion of electric storage resources from qualifying as fast start resources and justify how that complies with the Order 841 requirement that storage be allowed to provide all services it is technically capable of providing. MISO must also remove proposed tariff revisions that would have established a phased approach to market entry for very small electric storage resources. FERC said the proposal to allow just 50 very small resources in the first year of implementation and 150 in the second year was inconsistent with the 100-kW minimum size requirement in Order 841 [8].

The order on MISO told the grid operator to explain its categorical exclusion of electric storage resources from qualifying as fast start resources and justify how that complies with the Order 841 requirement that storage to be allowed to provide all services it is technically capable of providing [20].

MISO must also remove proposed tariff revisions that would have established a phased approach to market entry for very small electric storage resources. FERC said MISO's approval to allow just 50 very small resources in the first year of implementation and 150 in the second year was inconsistent with the 100-kW minimum size requirement set by Order 841 [20].

FERC also rejected MISO's proposal to assess transmission charges to storage resources dispatched to provide a downward ramping service. FERC said it was not persuaded by MISO's arguments that this dispatch is not providing a service, or that exempting storage from charges in this situation would suggest that load participating as price responsive demand should also be exempt from transmission charges [8].

Lastly, FERC granted MISO's request to defer implementation of the Order 841 requirements until June 6, 2022, to accommodate other major market and reliability enhancements, namely the creation of a short-term reserve market product [8].

3.2.4. New York Independent System Operator

The NYISO submitted its most recent filing in response to FERC's Order 841 in May 2019, regarding storage in wholesale markets and submitted a separate filing in June regarding the treatment of DERS in its markets. Its proposal establishes new terms to facilitate the compensation of DERS for the megawatts of capacity they provide commensurate with their expected contribution to meeting New York's resource adequacy requirements [21].

NYISO proposed the usage of four modes: ISO-committed fixed, ISO—committed flexible, self-committed fixed, and self-committed flexible. Within ISO-committed modes, NYISO would determine optimal dispatch times for suppliers' resources. Within the flexible mode, NYISO would dispatch resources in the Real-Time Market based on locational marginal pricing. Within the fixed mode, NYISO would schedule resources in the Day-Ahead market and dispatch at a frequency of no more than every 15 minutes in the Real-Time market. With the self-committed modes, it would be the responsibility of the supplier to determine dispatch times and frequency. NYISO also proposed a minimum offer size of 100 kW for energy storage resources to participate in the NYISO market [18].

The NYISO has proposed that aggregations of resources—which could include storage, solar and more—that are at least 100 kW in combined size could participate in energy, capacity, and ancillary services markets depending on their capabilities. An important issue to be clarified is due participation or "value stacking." While the NYISO and the state both have announced plans to clarify dual participation, questions remain regarding how such resources will be operated and remunerated for each unique service provided [2].

FERC's response to NYISO seeks clarity on when those resources would have to bid energy in the day-ahead market: during all hours of the day-ahead market or only during the peak load window, a period that varies seasonally during which the overwhelming majority of resource adequacy concerns arise [21].

As of December 2019, the NYISO is currently waiting for the FERC's response to its Order 841 compliance filing.

3.2.5. The PJM Interconnection

PJM filed its Order 841 tariff changes to FERC in December 2018. In its filing, PJM's plan is to implement an accounting system to separate wholesale and retail transactions. However, its lack of state-of-charge parameters and requirement of a 10-hour capacity duration in PJM's filing exemplify the barriers PJM proposed to erect rather than remove in its filing [18].

PJM proposed the usage of three modes: continuous, charge, or discharge. In continuous mode, resources can both charge and discharge, and there would be no limitations on start-ups or ramp rates. A 10-hour discharge requirement for storage to participate in the region's capacity market has also been proposed [18].

FERC found that PJM's compliance filing complies with the requirements of Order 841 regarding the price paid for an electric storage resource's charging energy. Specifically, PJM's tariff provides that the price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly locational marginal price (LMP) at each load and generation bus [18].

In its filing, PJM proposed a 10-hour duration requirement for capacity qualification and market participation that has been contested as it assumes 20 percent penetration of storage, which would amount to 30 GW [20].

In the fall of 2019, FERC cleared the compliance filing from PJM Interconnection but sought further compliance filings on the grid operator's rules and practices for resource adequacy and capacity minimum run-time requirements. FERC also launched a paper hearing to investigate PJM's 10-hour discharge requirement for storage to participate in its capacity market [18].

In October 2019, FERC issued an order that PJM must place rules regarding the capacity qualification of energy storage resources in its tariff. In addition, FERC opened a new proceeding to determine whether PJM's proposed 10-hour duration requirement to qualify energy storage capacity is unjust, unreasonable, unduly discriminatory or preferential.

FERC asked PJM to submit further compliance filings within 60 days, finding that PJM's minimum run-time requirements for resource adequacy and capacity. FERC has initiated proceedings to address this issue and has directed PJM to submit tariff provisions regarding rules and practices for resource adequacy and capacity minimum run-time requirements for all resource types [19].

In addition, FERC established hearing procedures to examine PJM's minimum run-time rules and procedures for capacity storage resources.

3.2.6. Southwest Power Pool

Until its compliance filing, SPP had no formalized model for energy storage participation. Existing storage resources must participate in markets in a limited capacity, as either a generator or a load. Under the Market Storage Resource registration option included in SPP's Order 841 compliance filing, ESR's will have the ability to provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve services, provided they are capable of providing those services [18].

Changes that were included in SPP's compliance filing included:

- A definition of a new type of resource (an energy storage resource) that may register as a market storage resource subject to certain category-specific limitations
- Additional definitions such as maximum and minimum charge and discharge limits
- A reduction in an energy storage's must-offer obligation for such a resource that is self-charging during the maximum reported load hour [18]

SPP has created a registration type of "Market Storage Resources", which is distinct from Electric Storage Resources (ESRs). SPP will allow its storage resources the opportunity to continue utilizing the existing model as an ESR or participate in the model as a registered MSR.

SPP also has proposed the use of aggregation of energy storage, limited to the nodal delivery point, to accommodate generation that is less than 100 kW.

On October 17, 2019, FERC approved the compliance filing from SPP. However, despite approving the filing, FERC asked SPP to submit further compliance filings within 60 days, finding that SPP's market tariff contained minimum run-time requirements for resource adequacy and capacity. As a result, FERC initiated proceedings under Section 206 of the Federal Power Act to address those issues and directed SPP to submit tariff provisions regarding rules and practices for resource adequacy and capacity minimum run-time requirements for all resource types [19].

FERC concluded that both SPP's and PJM's proposals appropriately recognize the unique physical and operational characteristics of energy storage resources; generally enable energy storage resources to provide all services they are capable of providing; and allow energy storage resources to be compensated for those services in the same manner as other resources are compensated [18].

3.2.7. ERCOT

ERCOT is not under the jurisdiction of FERC and therefore was not required to submit a compliance filing for FERC's Order 841. However, ERCOT is monitoring the changes being considered and implemented by the other ISOs/RTOs to help inform its own future processes related to the integration of electric storage resources.

4. State Energy Storage Policymaking

4.1. Overview

Over the next decade it is expected that policymaking for energy storage will continue at the state level. Given that only about 15 states have formally enacted at least one substantive legislative or regulatory policy intended to remove barriers for energy storage, it is likely that we will continue to see the balance of states opening regulatory dockets, developing legislation, or responding to executive directives that address energy storage objectives.

While policymaking for energy storage remains a nascent concept and is still evolving, as of the end of 2019, there has been enough activity at the state level to begin to draw conclusions about trends and best practices. While the majority of states still have yet to enact any substantive policy on energy storage, those states that have taken action provide indications of how the potential markets for energy storage services are being structured.

In practice, many states have combined one or more policy instruments to spur storage deployment [2]. Storage investigations and proceedings can identify state-specific policy and market barriers that limit realization of the full value of energy storage. As of December 2019, California has introduced the greatest number of energy storage policy initiatives. These initiatives include setting a mandate for energy storage procurement and a subsidy program that provides financial incentives for installing customer-sited distributed generation. A good example of this is, again, California. A February 21, 2020, CPUC Proposed Decision in its integrated resource planning (IRP) proceedings has specifically asked for several thousand MW of energy storage, including some long-duration storage procurement, by year 2030. It is likely to be approved by CPUC in its March 26, 2020, Business Meeting. This is a significant development in California policymaking.

Along with California, the Northeastern U.S. is another region that is witnessing substantial growth of energy storage on both sides of the meter. This region of the U.S. is unique in the sense that it offers a robust wholesale market with multiple avenues for energy storage to participate attracting solar + storage developers that can earn additional income through participate in the nearby PJM, NYISO or ISO-NE wholesale markets.

4.2. Energy Storage Policy Issues Being Considered by State PUCs

4.2.1. Overview

Energy storage policymaking that has occurred at the state level to date has been focused on a set of specific policy issues. Considerations of procurement mandates and evaluations of how energy storage will factor into utility long-term resource plans appear to be the dominant approaches undertaken by those states that have developed policy on energy storage at the close of 2019. Considerations of these issues will continue into the next decade as additional states go on record with publicly adopted energy storage policies. In fact, it is anticipated that each of the 50 U.S. states (plus territories) will need to develop policy on any number of inter-related energy storage issues and, to one extent or another, will need to consider the following topics:

- Procurement mandates
- Incentives / tax credits
- Utility ownership
- Inclusion of storage in utility IRPs
- Changes to net metering policies
- Changes to RPS programs
- Multiple use applications
- Cost / benefit analysis
- Distribution system modeling
- Rate design specific to BTM storage

4.2.2. Changes to interconnection standards

These topics have been identified based on policymaking activity specific to energy storage that has taken place at the state level to date.

4.2.3. Summaries of key energy storage policy issues at state level

4.2.3.1. Procurement Mandates

Procurement targets are mandates set by a state that require regulated utilities to acquire a specified quantity of energy storage by a designated deadline. The fundamental purpose of a procurement mandate is to provide more opportunities for energy storage and stimulate market growth in a specific state.

In fact, a major pathway for energy storage to become an integral player across the electricity grid is through procurements made by utility companies. Sometimes these are voluntary procurements based on an economic analysis conducted independently by the utility to justify investments in energy storage compared to more traditional forms of generation. Other times, procurements of energy storage are enacted through regulatory or legislative mandates codified by a state to accelerate the development of energy storage, which is what would fall under the category of a procurement mandate.

In either approach, since energy storage is a resource that can act as both generation and load, while also being interconnected at various interconnection points across transmission and distribution networks, developing a consistent and clear procurement process for energy storage can be quite daunting. This is especially the case when energy storage is in a competitive position compared against traditional generation resources.

Some of the more high-profile actions on storage policy at the state level have come from regulatory commissions (or, in some cases, state legislatures) that have enacted a mandated procurement target for energy storage deployment by a specified date. These mandates typically have been placed upon utilities that are under the regulatory jurisdiction of a state commission.

Those states that develop procurement targets for energy storage likely have concluded that mandates can jump-start market creation, instill a "learning by doing" approach, and force the creation of a regulatory framework that is specifically geared toward energy storage.

However, various "pros" and "cons" for energy storage procurement targets have been identified:

PROS	CONS
• Used to stimulate market development • Provides cost recovery certainty for utilities • Storage targets are "in the public's best interest" • A mandatory approach for storage is compatible with most RPS policies	• Uncertainties about how to determine appropriate procurement levels & benefits • Mandates allow the government to pick "winners" rather than the marketplace. • Current resource planning is sufficient; 100% renewables will drive storage growth anyway

California was the first state to adopt an energy storage target in 2010 and has subsequently increased the target to 1,325 MW by 2020, with an additional requirement of 500 MW of distributed (behind the meter) storage aimed at serving the public sector and low-income customers [2].

While California was the first state to set procurement mandates for energy storage, other states have followed suit. As of December 2019, the following procurement mandates have been adopted at the state level:

- California (2013): Adopted mandate through legislation in which IOUs in the state must procure 1,325 MW of energy storage across their transmission, distribution and customer sectors by 2020. Subsequent regulatory action required the IOUs to procure up to an additional 500 MW of distributed energy storage, resulting in a total mandate of 1,835 MW.
- Massachusetts (June 2018): Through legislation, Massachusetts established a target of 200 MW by 2020.
- New Jersey (2018): Through legislation, New Jersey established a target of 600 MW by 2021 and 2,000 MW by 2030.
- New York (January 2018): New York's governor, regulatory commission and legislation worked collaboratively to develop a target of 1,500 MW by 2025 and 3,000 MW by 2030.
- Oregon (2015): Set through legislation, Oregon has a procurement target of 5 MW by 2020.

As other states contemplate the appropriateness and/or necessity to implement procurement targets for energy storage, a Needs Assessment is oftentimes the first step in the creation of a procurement mandate to address the fundamental drivers for the procurement mandate. A Needs Assessment is useful because it forces clarification of what is driving the energy storage procurement by asking questions such as: Is the procurement being pursued to meet a regulatory deadline? Is the procurement intended to add capacity (e.g., resource adequacy)? Is the procurement intended to offer distribution deferral benefits?

Moreover, there are a number of considerations that should be addressed when a state considers procurement mandates for energy storage:

- Can procurement mandates be effective if other legal or regulatory hurdles to energy storage remain unaddressed?
- What is the best approach toward determining appropriate and realistic mandates?
- Should the mandates be state-wide or utility-specific?
- Should the mandates apply to IOUs only or municipalities and cooperatives as well?
- What steps can be taken to ensure that ratepayers do not incur increased costs for arbitrary procurement levels, or face increased costs without associated benefits?
- What other state policies will need to be revised as a result of the procurement mandate (e.g., interconnection requirements, rates and tariffs, or other market rules?

Other key considerations in setting a storage procurement mandate include whether the procurement target provides a long-term policy signal, whether it is binding, what technologies qualify, and whether the mandate ensures a competitive framework for multiple applications and ownership structures. To consider equity, policymakers can include carve-out or set-asides specifying that some portions of the target should be met with projects that are designed to benefit underserved communities directly through reduced air pollution or improved resiliency [2].

4.2.3.2. Financial Incentives, Subsidies, and Tax Credits

Regulatory frameworks typically prevent utilities and end-use customers from being able to monetize the value of ESS. Consequently, incentives provided at the state level can serve as a bridge to jumpstart a market while regulatory policies are finalized. In fact, the prevailing industry perception is that the cost of batteries at the end of 2019 is still too high for most grid applications to be viable, other than where local regulations provide incentives for deployment [22].

In particular, investment tax credits (ITCs) can be used to limit exposure to technological and capital risk that is associated with an emerging technology such as energy storage. An ITC can be used at either the federal or state level to enhance widespread deployment of energy storage by bolstering market demand and promoting the cost-competitiveness of energy storage when compared against conventional resources.

Once such incentive program, the federal Business Energy Investment Tax Credit ITC, has been a major driver of solar deployment over the last decade. The federal subsidy allows project developers to request a tax rebate of 30 percent on any investment in eligible renewable energy technology. It is important to note however that the energy storage currently qualifies for the federal ITC only when paired with solar projects. At the federal level, there are pending congressional bills aimed at creating a stand-alone tax credit for energy storage. For instance, the bipartisan "Energy Storage Tax Incentive and Deployment Act" introduced by Rep. Mike Doyle (D-PA) and Sen. Martin Heinrich (D-NM) would provide a federal investment tax credit for ESSs [7].

Incentives at the state level in the form of rebates, grants, or various tax incentives, can provide a bridge to scalable deployment for energy storage to accomplish broader efficiency, resilience, and renewable energy goals as system costs continue to decline and policies and markets evolve. Incentives are typically designed to decline over time until storage values are more easily monetized in market rules. In addition, financial incentives can be applied to both utility-scale and distributed storage facilities.

However, various "pros" and "cons" for financial incentives that are created for energy storage have been identified:

PROS	CONS
• Pay-for-performance metrics that incentivize utilities to improve the utilization of existing assets can be very effective in deferring infrastructure investments. • Customer incentives can be tied to the economic value that is brought to the grid.	• Providing subsidies to ES can quickly become complicated---e.g., determining if the battery is charged by renewable energy or grid electricity. • Undefined parameters create a gap allowing parties to "double dip."

California is one example of how energy storage deployment can be supported through incentives, as evidenced by the state's Self Generation Incentive Program (SGIP) for DERs. The program includes an equity component that directs 25 percent of funding for distributed energy storage toward "low income households and environmentally burdened communities throughout the state [2]. The SGIP was the first program to spur BTM storage with $400 million in investment, which was later extended by five years (with $166 million/year). California's SGIP provides rebates for emerging renewable technologies including energy storage. Since 2001, the SGIP has been the state's primary means of encouraging residential installations of both solar and energy storage solutions. However, the state found that energy storage projects funded by the SGIP actually increased statewide greenhouse gas emissions in 2016. The reason for this is that the SGIP was not originally correlated with market price signals and restrictions against charging energy storage (typically batteries) with fossil-fuel sources. The state is presently working to resolve these issues.

Massachusetts, through legislation approved by its governor, launched the Solar Massachusetts Renewable Target (SMART) incentive, which pays solar customers for each kilowatt-hour produced and adds a premium for solar that is paired with energy storage. The SMART program pays a fixed tariff, based on kWh of solar production, to solar facilities under 5 MW across the residential, commercial, community solar, and qualifying facility industry sectors [7].

Maryland is currently the only U.S. state that has adopted its own ITC for storage, which has driven modest investments in residential systems in the past two years. The Maryland program has been criticized for not allowing third-party ownership of storage facilities to take advantage of the ITC, and the fact that the program has not offered additional incentives to drive investment of energy storage in underserved communities [2].

4.2.3.3. Utility Ownership of Energy Storage Assets

Given that storage is typically classified as a generation asset, a question that has persisted across various regulatory jurisdictions is whether or not utilities be allowed to own storage assets in deregulated markets. The debate is marked by strong opinions on both sides with advocates for ownership arguing that it will enable a larger market for DERS technologies in the most valuable locations across the nation's grid, and opponents of utility ownership arguing that it could undermine competition and innovation.

However, various "pros" and "cons" for utility ownership of energy storage assets that have been identified:

PROS	CONS
• Opportunity for long-range, system-wide planning • Opportunity to optimize the distribution system • Enhanced flexibility to use cost-effective resources • Enhanced economies of scale (i.e., prices drop with larger projects)	• Market power concerns • Utilities would have an advantage over 3rd parties, creating an unlevel playing field • Uncertainties about utility cost recovery and equitable rate treatment among customers

New York is one state that has relatively clearly restricted the right of utilities to own energy storage assets, within the context of the state's Reforming the Energy Vision (REV) policy. In the first order adopted under REV, New York's Public Service Commission disallowed utilities from owning behind-the-meter distributed energy resources, stating market power concerns outweigh most benefits of utility ownership and citing three issues: conflict with the REV's purpose of animating private investment (supported by proven interest from third-party installers); branding advantages and the appearance of impropriety for incumbent utilities; and conflicts with new utility platform management functions. However, the REV does acknowledge the unique potential for storage, allowing utilities to own and operate distributed storage under limited conditions.

4.2.3.4. Inclusion of Energy Storage in Utility Integrated Resource Plans

In 25 states, regulated utilities are required to submit integrated resource plans (IRPs) to justify future investments in power supplies and infrastructure. Many states require utilities under their regulatory jurisdiction to produce integrated resource plans (IRPs) that demonstrate the utility's ability to meet long-term demand projections using a combination of generation, transmission and energy efficiency investments. In many states, utility commissions must approve these plans. In most jurisdictions, regulators are typically required to consider only cost and reliability factors, so legislation within the state may be needed to require regulators and utilities specifically to evaluate the unique characteristics and additional aspects of storage deployment [23]. Unfortunately, because traditional IRP models do not consider many of the services that energy storage can provide, the technology does not fit neatly into IRP planning processes.

While historically regulators have not required utilities to include energy storage in their IRPs due to the immaturity of the technology, this is changing as energy storage costs decline and utilities explore the option of incorporating energy storage into their long-range planning as an alternative to more capital-intensive investments. However, incorporating energy storage into IRPs can be a challenge because energy storage is inherently different from conventional generation and other demand-side resources.

A growing number of state regulatory commissions are concluding that, at a minimum, IRPs should consider energy storage as a resource and ensure that the services storage offers are included and valued in the analysis. In addition, to help ensure equitable outcomes, some states may require utilities to evaluate storage in specific applications—including as a potential replacement for peakers and other fossil fuel power plants—to avoid costly transmission and distribution infrastructure development and upgrades, and to understand local resource needs [23].

However, various "pros" and "cons" for mandating the inclusion of energy storage in utility IRPs have been identified:

PROS	CONS
• Provides certainty around the role that ES will play going forward • Thermal and electrochemical ES are competitive with natural gas peaker plants in some cases and should be considered as an alternative. • Long-term consideration of ES addresses other policy requirements (e.g., for renewables or clean energy)	• Lack of reliable cost data and "best practices" makes including energy storage in an IRP difficult. • Lack of tools or protocols for analyzing storage • Would only apply to vertically integrated utilities that are still responsible for generation resource plans (not restructured markets) • Most IRPs do not address local values and flexibility of storage.

Nevertheless, some states have begun to require utilities to include energy storage in IRPs. These states include Arizona, California, Connecticut, Colorado, Florida, Indiana, Kentucky, Massachusetts, New Mexico, North Carolina, Oregon, Utah, Virginia, and Washington.

Best practices for inclusion of energy storage in IRPs are ensuring storage is included as an eligible technology; using latest cost and performance data; matching resource need with resource selection; using sub-hourly modeling; ensuring net cost of capacity (stacked benefits) are considered; and incorporating load-sited storage options as a potential resource.

The Energy Storage Association recommends the following approaches for those states attempting to incorporate energy storage into IRPs [24]:

- Use up-to-date storage cost estimates and cost forecasts to better identify near- and long-term prudency of storage
- Employ sub-hourly intervals in modeling to quantify the value of both capacity and flexibility benefits provided by energy storage
- Institute a "net cost" analysis of capacity investment options to more accurately compare energy storage with traditional capacity resources
- Incorporate system flexibility needs into reliability metrics to better account for the characteristics of the future supply mix
- Analyze demand resources as distinct resource options separate from load forecasts to seek the widest range of cost-effective resources [24]

4.2.3.5. Changes to Net Energy Metering Policies

Net energy metering (NEM) is a state-level program that is intended to promote direct customer investment in renewable energy by compensating the customer for excess energy that is generated at the customer's location but sold back to the utility at current retail rates. NEM programs can vary greatly state to state, and typical variations across states may include the types of technologies that are eligible to participate in the state's NEM, the customer classes that can participate, and the total aggregate generation capacity of the participating system.

Pairing solar-plus-storage with NEM has received minimal policy attention to-date due to low level deployments of energy storage in most states. However, the issue is emerging as pairing energy storage with solar energy systems becomes more economical.

It could be said that the nationwide fight over NEM began in Arizona. In 2013, the Arizona Corporation Commission became the first regulatory body in a major solar market to allow a utility (Arizona Public Service) to impose a discriminatory charge on photovoltaic (PV) system owners, which appears to have inspired utilities across the country to seek similar charges.

However, various "pros" and "cons" for allowing energy storage to be eligible for utility NEM programs have been identified:

PROS	CONS
• NEM programs help to: • Create a strong market signal would be achieved if certifiably solar-powered batteries could get paid through NEM. • Address the issue of states (e.g., California) reducing the value of traditional solar through TOU rates. • Help to ensure that residential solar projects "pencil out"	• Utilities don't want to pay net metering (retail) rates to batteries charged by grid power • Adding energy storage to a solar project adds a layer of complexity

At least 17 states have authorized aggregated net metering, including Arkansas, California, Colorado, Connecticut, Delaware, Maine, Maryland, Minnesota, Nevada, New Jersey, New York, Oregon, Pennsylvania, Rhode Island, Utah, Washington and West Virginia.

4.2.3.6. Changes to Renewable Portfolio Standard Programs

A state renewable portfolio standard (RPS) has arguably been the single most important state policy mechanism for advancing clean energy over the last two decades. In fact, in the absence of a federal mandate for renewable generation, RPS programs are among the most prominent clean energy policies in the U.S. today.

This is due to the objective that is inherent in any RPS program, which is to provide assistance for technologies that have great potential for transitioning the United States to clean energy but which are not yet able to compete against conventional forms of generation due to immature supply chains or proven operational efficiencies, which keep their costs high in comparison. The creation of a statewide mandate for renewables sends a market signal that there will be ample opportunities for renewables to develop in a particular state.

The policy issue at hand that has been considered by a handful of states is whether or not an RPS should allow ESSs to be eligible to "count" toward the RPS, or if objectives for energy storage be addressed separately from renewables.

For background, Iowa was the first state to establish an RPS in 1983, and since then more than half of U.S. states have established renewable energy targets. As of December 2019, 29 U.S. states, Washington, D.C., and three territories have adopted an RPS, while eight states and one territory have set renewable energy goals. In recent years, 12 states plus the District of Columbia have established 100-percent clean energy goals, sometimes within an RPS and sometimes separate from it. Furthermore, a handful of states have adopted procurement targets for energy storage as separate from RPS requirements. The extent to which states carve out specific energy storage requirements within an RPS, or simply allow energy storage to be eligible for RPS credit, remain policy issues that individual states continue to address [20].

However, various "pros" and "cons" for allowing energy storage to be eligible for state RPS programs have been identified:

PROS	CONS
• Integrate intermittent renewable energy • Help shift renewable generation to more closely match peak loads • Provide generation and load balancing services • Reduce the need for peaking and backup generators on the grid • Reduce customer demand charges	• Uncertain if regulators need to encourage storage specifically. Encouraging renewables may be enough to stimulate storage • Once an RPS is reopened, opponents of renewable energy could take the opportunity to revise, weaken or revoke the state's obligations

While most state targets are between 10 percent and 45 percent, 13 states—California, Colorado, Hawaii, Maine, Maryland, Massachusetts, Nevada, New Mexico, New Jersey, New York, Oregon, Vermont, Washington, as well as Washington, D.C. Puerto Rico and the Virgin Islands—have requirements of 50 percent or greater [20].

4.2.3.7. Multiple Use Applications

One of the more commonly cited barriers to the deployment of energy storage is the inability to quantify and capture the multiple value streams that energy storage can provide to the grid. Before the advent of restructured markets, valuation of storage usually only considered the ability of storage to provide two basic classes of services: firm capacity and "load leveling" (i.e., charging storage with low-cost off-peak generation and displacing high cost on-peak energy). Other benefits such as ancillary services were rarely valued [4].

The unique characteristics of ES (both load and supply) create flexibility to provide multiple uses or applications, sometimes simultaneously, and therefore layer on more than one revenue stream. Unfortunately, the array of potential services for which energy store is ideally suited is not well understood at the present time. Some of the applications that could be envisioned may not be suitable for all storage technologies, and the potential to develop these applications may be restricted by geographic location, specific site locations, or other technical characteristics.

Nevertheless, limitations on multiple use applications for energy storage have a direct impact on revenue potential. This is due to the fact that when revenue potential is based on only one category of benefits the currently high upfront investment that is needed for energy storage often cannot be justified.

Various "pros" and "cons" for conducting formal explorations of the potential, multiple use applications for energy storage have been identified:

PROS	CONS
• Consideration of multiple uses allow ES to achieve its full economic potential. • Composite forms of compensation can combine energy, capacity, environmental, location and temporally specific demand relief value.	• Most energy storage installations today consist of either behind-the-meter or grid-tied applications, but not both. • Some uses may have high priority than others (e.g., reliability), which may create conflicts in the marketplace.

While this is an emerging area for policymaking in multiple jurisdictions, there are some trends. The following multiple use applications, organized by industry segment, have emerged to create some "universal thinking" proposals about the potential uses of energy storage technologies:

Bulk Energy Services	Ancillary Services	Transmission Infrastructure Services	Distribution Infrastructure Services	Customer Energy Management Services
Electric energy time shift (arbitrage)	Regulation	Transmission upgrade deferral	Distribution upgrade deferral	Power quality
Electric supply capacity	Spinning, Non-Spinning & Supplemental Reserves	Transmission congestion relief	Voltage support	Power reliability
	Voltage Support			Retail electric energy time-shift
	Black Start			Demand charge management

California and New York lead the way on the development of multiple-use applications for energy storage. In addition, Maryland has passed through legislation an energy storage pilot program to investigate multiple use applications and multiple ownership models for energy storage.

4.2.3.8. Cost-Benefit Analysis (Valuation)

The deployment of energy storage is dependent on the economic benefits that can be obtained either in a traditionally regulated or restructured market. Unfortunately, current market structures and policies lack clear mechanisms to identify and capture the full value of ESS.

The purpose of a cost-benefit analysis is to understand whether or not a specific investment is desirable. The net benefits of each alternative resource, whether it is DERs or a traditional generator resource, can be represented using a common metric of dollars. As long as all the cost and benefit categories, including the external costs and benefits, are consistently calculated for each resource, comparing the net benefits of each alternative and choosing the one that yields the highest net benefit to society will ensure that only socially beneficial ESSs are installed [5]

As noted elsewhere in this chapter, due to the inherent diversity of its physical and electrical characteristics, energy storage can be utilized in many different locations across the electric power system (or completely off the grid). Typical configurations of energy storage are commonly classified as located as follows:

- Distribution-sited: Refers to projects physically interconnected to a utility's distribution system and regulated by a state regulatory commission
- Transmission-sited: Refers to projects physically interconnected to a transmission system and regulated by FERC (in those regions that fall under FERC's jurisdiction)
- Customer-sited: Refers to projects physically located at a customer site, which may or may not be used to support distribution or transmission operations

Each of these classifications and locations can have unique needs, offered services, jurisdictional authorities, operating systems, and approaches for valuation and compensation. Typically, customer services are monetized by helping customers save on their retail bills. Transmission-sited services (i.e., wholesale market services) are typically monetized through participating in wholesale markets where opportunities for energy storage to offer market services exist. Distribution-sited services are usually compensated through rate design driven cost recovery for the utility, which has presumably justified and received approval for the expense before its regulatory commission.

Consequently, at the state level the existence of a comprehensive reliable cost-benefit analysis for energy storage would help to support the assessment of both appropriate utility investments that should be recoverable and the myriad of benefits that energy storage can provide to the distribution grid. Both the costs and benefits for energy storage directly impact end-use customers, either through increased electricity rates (a cost) or improved electric service (a benefit).

Unfortunately, there still remains a gap within the industry in the sense that there is not a comprehensive and reliable cost-benefit analysis methodology for energy storage that is universally accepted as of today. This is largely due to the fact that energy storage is still an immature technology and many questions remains about its long-term use and value. Further, comprehensive cost/benefit analysis for energy storage is not easy because it depends on the rating of the ESS device (e.g., MW, MWh), its location on the network, and the kind of services provided. Traditional metrics like LCOE do not reflect the operational parameters or value proposition of energy storage.

Various "pros" and "cons" for conducting cost-benefit analyses for energy storage have been identified:

PROS	CONS
• Cost-effectiveness is one of two tests that must be met to establish any energy storage procurement target. • Accurate cost and benefit modeling will help justify utility cost recovery applications. • Market participants need to identify and prioritize customers for whom storage is profitable.	• Currently there is no universal approach toward defining costs and benefits of energy storage. • Assessing the viability of ES is a challenge given that technologies vary in stages of development from traditional to advanced systems. • Wide range of performance create variances in efficiencies & costs.

Revenue compensation mechanisms in different market environments present a barrier to the further deployment of energy storage resources. These mechanisms are oriented toward the evaluation of traditional power system technologies and may not appropriately compensate energy storage resources for the services they are capable of providing. Unfortunately, limited knowledge amongst power system stakeholders and the lack of modeling capabilities for energy storage resources prevent many stakeholders from conducting a thorough evaluation of energy storage technologies for deployment [3].

Massachusetts, New York, Nevada and Carolina have completed cost-benefit studies with robust modeling, while Virginia, New Jersey and Colorado have ongoing studies. Several states, including Maryland, Massachusetts, and North Carolina, have required cost-benefit analysis for energy storage, which have explicitly called for the evaluation of the potential to deploy energy storage in a specific area and quantify the benefits that energy storage can provide in specific categories (e.g., environmental, economic, resilience, etc.) [2]. However, these analyses developed by individual states are likely very regionally focused and thus the applicability to other states is questionable.

Groups like the Electric Power Research Institute (EPRI) are developing tools to quantify available revenue streams and help developers determine if it is economical to build an energy storage project in a given market. EPRI's publicly available Storage Valuation Estimation Tool is useful for determining the shape and profitability of a potential value stack, but at present it only incorporates regulatory assumptions for the CA-ISO market.

4.2.3.9. Distribution System Modeling

As previously noted, due to the inherent diversity of its physical and electrical characteristics, energy storage can be utilized in many different locations across the electric power system (or completely off the grid). Typical configurations of energy storage are commonly classified as located as follows:

- Distribution-sited: Refers to projects physically interconnected to a utility's distribution system and regulated by a state regulatory commission
- Transmission-sited: Refers to projects physically interconnected to a transmission system and regulated by FERC (in those regions that fall under FERC's jurisdiction)

- Customer-sited: Refers to projects physically located at a customer site, which may or may not be used to support distribution or transmission operations

Much of new storage that is expected to come online over the next decade is expected to be connected to distribution feeders. In addition, the increasing adoption of all forms of DERS is altering load nature and profile on distribution grids and stretching the hosting capacity among certain distribution lines. However, distribution planners presently lack tools and methods to assess storage impact on distribution system capacity, reliability, and power quality. The result is that up to this point there has been little visibility into utility distribution system planning.

Various "pros" and "cons" for distribution system modeling specific for energy storage deployment have been identified:

PROS	CONS
• Effective distribution system modeling supports optimal ESS sizing, placement, and operation are studied. • Distribution modeling provides location power quality improvements, mitigation of voltage deviation, frequency regulation, load shifting, etc.	• Energy storage modeling requires sequential-time simulation, as opposed to more traditional static power flow calculations. • Misusing or mislocating ESSs in distribution networks can degrade power quality and reduce reliability as well as load control.

Therefore, ES becomes a necessity for its ability to bridge the gap between the dynamically changing supply and demand in addition to other ancillary services it can provide.

Distribution planning for energy storage typically includes assessment of hosting capacity, forecasting and locational benefits of specific distribution lines. A good example of this is once again California, which through regulatory directives requires the regulated utilities to file distribution resources plan proposals. According to the California Code, these plan proposals will "identify optimal locations for the deployment of distributed resources." It defines "distributed energy resources" as "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."

4.2.3.10. Changes to Interconnection Standards

Interconnection procedures are the rules of the road for the electric distribution grid. Without common rules and predictable processes, gridlock and costly projects can result. However, interconnection standards that were developed without consideration of widespread renewables and/or energy storage are likely in need of significant revision. This creates a barrier for energy storage deployment, as without permission to interconnect an ESS has no access to the market.

Interconnection standards vary widely from state to state, but generally consist of: 1) the administrative procedures and technical standards used to evaluate potential impacts associated with interconnecting a generation resource to the electric power system; and 2) contractual agreements stipulating operational and cost responsibilities between the electric utility and the generation resource owner. As a starting point, many states prefer to use model interconnection standards developed by the International Renewable Energy Council (IREC), FERC, the Mid-Atlantic Distributed Resources Initiative, or rules established by specific states like California.

Interconnection standards for distributed generation were historically formulated based on a definition of "generating facilities" that is no longer appropriate as it does not address the unique operating characteristics of energy storage. The inadequacy of these historic interconnection standards has created a barrier for energy storage simply due to the fact that it has created uncertainty about how energy storage should be treated at a localized level, thus resulting in market inertia and delays in permitting.

Various "pros" and "cons" for distribution system modeling specific for energy storage deployment have been identified:

PROS	CONS
• Interconnection is a critical step for any resource that operates while connected to a utility's grid. • Interconnection standards can be integrated with other policies covering net metering, distribution planning, integrated resource planning, and energy efficiency to support a comprehensive clean energy plan.	• ES technology is so nascent that interconnection standards can still not envision the full potential of services and benefits that storage can bring to the grid. • Integration of large amounts of DERS can negatively affect the reliability and operational stability of power system.

A growing number of states are updating their outdated interconnection standards to more proactively address energy storage. Other states that have never had statewide standards are now beginning to examine and adopt interconnection rules.

A number of states have announced their intentions to revise legacy interconnection standards to address energy storage specifically by expanding the definition of "generating facilities." These states include South Carolina, Minnesota and Nevada. Other states have opted to go beyond revisions to existing standards in favor of a more holistic change to interconnection procedures. For example, New York and California have taken steps in this direction by developing application processes and review procedures specifically for storage systems. For example, California has proposed an expedited review process for stand-alone, non-exporting storage systems because of the lower risk that these systems pose to the grid [2].

Statewide interconnection standards (i.e., rules that apply to all regulated utilities) that reflect well-vetted best practices can provide greater consistency across the utilities and help streamline the grid connection process for all involved stakeholders. Interconnection rules are designed to handle the current and anticipated growth of DERS, while also enabling cost-effective and efficiency clean energy projects.

States and utilities that control distribution lines can call upon what are existing and voluntary standards applicable industry wide. For instance, the adoption of IEEE Standard 1547 in 2018 is considered a national standard for how DERS will interact with and function on the grid. The Standard requires DERS to be capable of providing specific grid support functionalities related to voltage, frequency, communications and controls.

Arizona, Nevada, California, New York and Hawaii have all revised their distribution interconnection rules to better reflect the characteristics of ESS. Michigan, Maryland, Minnesota, North Carolina, and Colorado have ongoing stakeholder working groups to review potential changes to their interconnection standards.

5. Best Practices in State Energy Storage Policymaking

5.1. Summary

As of December 2019, there are approximately 15 U.S. states that have developed substantive policy on energy storage. Without question, these various states have pursued stand-alone policies based on the unique market characteristics and existing regulatory framework within the given state. This is likely the way that energy storage policymaking at the state level will continue to evolve into the new decade, and this is arguably the most appropriate approach. Attempting to define a comprehensive set of policies intended to be uniformly applicable to all states would be misguided if not impossible due to the variances across states with regard to renewables penetration, historic generation mix, the T&D infrastructure that is in place, and the commitment to a clean energy future within the state that signals a strong marketplace for energy storage in the years to come. In addition, while energy storage policymaking for the most part will fall to public utility commissions that regulate utilities, it is unlikely that independent PUCs will develop energy storage policies in the same way. Regulatory dynamics that include revenue models, operational requirements, and subsidies offered to energy storage developers will all impact the scope and depth of energy storage policy at the state level.

The following case studies of unique state experiences in developing energy storage policies reflect the unique approaches that states are taking. While a uniform approach toward energy storage policy is unrealistic given the importance of locational applications, the activity of states to date do provide a suite of "best practices" on specific policy issues that can be adopted and modified by other jurisdictions.

5.2. Case Studies of States

The following summaries of individual state activity are provided for the following ten (10 states. These states were selected for analysis due to their positions as "policy leaders" within the context of energy storage:

- Arizona
- California
- Hawaii
- Illinois
- Massachusetts
- Nevada
- New Mexico
- New York
- Oregon
- Texas

5.2.1. Arizona

Among the group of approximately 15 states that have witnessed a significant growth in energy storage development and/or created energy storage policies at either the state legislature or public regulatory commission, Arizona remains unique in that its energy storage marketplace has been advanced primarily due to utility initiatives as opposed to policy directives. In all other states, it can be argued that policy has driven market development, either through outright mandates for energy storage (e.g., California, New York) or advantageous incentives that have subsidized the exploration of storage technologies. Not so in Arizona. The state's energy storage marketplace has continued to develop in spite of a near-total absence of policy guidelines; and despite this absence of policy directives, growth to date of energy storage initiatives in Arizona has been noteworthy and its potential for future growth is massive.

Storage technologies and utility-driven storage deployments continue to gain momentum in Arizona, while policymakers play "catch up" to develop appropriate rules and regulations. This approach has been thwarted at times due to conflicts among the state's policymakers and disagreements regarding which state agency (the governor's office, the legislature, or the Arizona Corporation Commission) should take the lead role in defining energy storage policy in the state.

Arizona's unorthodox approach is likely due to several distinguishing factors that simultaneously make the Grand Canyon State inherently unique and a benchmark for other states to be evaluated against. In other words, the factors that make Arizona unique also make it a testing ground for how to create an energy storage marketplace "from scratch." Consider the following dichotomies that exist within Arizona, which have caused the energy storage marketplace in the state to experience growth in a series of fits and starts.

- Arizona is one of the sunniest states in the country, with some areas having 300+ days of sunshine in an average year. Thus, Arizona's potential for solar power is enormous. And yet, Arizona still gets only about six percent of its energy from solar power. More than 50 percent of Arizona's power continues to come from fossil fuels and fracked gas, most of which ends up being transported to other states like California. The state's low levels of overall usage of solar power relative to other states, particularly in its own region, means that even with their aggressive approach toward renewables development Arizona's utilities are still behind the curve when it comes to moving toward a carbon-free marketplace.
- Despite being an exporter of power to neighboring states, Arizona does not participate in any RTO. The oversight to run a central energy market, provide reliability services and assure operating reserves to prevent power blackouts is arguably a level of oversight that is beyond the capability of Arizona's state regulators. And yet, although Arizona continues to operate in a rather isolated manner, its dependence on access to outside markets moves it increasingly closer to participation in an RTO, which due to geographical local would likely be the California ISO. If it were to participate in an RTO, Arizona's energy market would increasingly fall under federal jurisdiction, which would create its own layers of complexity. The decision of RTO participation is further complicated by concerns about the available transmission lines that connect Arizona to neighboring states. A lack of transmission capacity would limit Arizona's ability to export and import power from other states, thereby deepening its need for resource self-sufficiency through renewables and energy storage.

- Arizona was the first U.S. state, in 2006, to require utilities to get a certain percentage of their power from renewable resources, specifically 15 percent by 2025. And yet, Arizona presently falls last among its neighbors in terms of renewables mandate. By comparison, Nevada and New Mexico have adopted a 50percent requirement; Colorado has a 30percentby2020 requirement; and California's RPS is 60 percent by 2030. Efforts to increase the state's renewables requirement (including public ballot initiatives such as 2018's Proposition 127) have failed, mostly due to concerns about how an increased renewables target would result in increased costs for end-use customers.
- Arizona is in the midst of a contentious "turf war" between the state's executive and legislative branches regarding the policy oversight of its energy sector. Arizona's constitution uniquely establishes the Arizona Corporation Commission (ACC) as a separate entity outside of the legislative and executive branches. The governor believes that the ACC's role should be limited to setting rates and its recent move into setting new renewables targets represents an inappropriate and unwanted "mission creep." The ACC says its responsibilities are unambiguous and include the oversight of the state's investor-owned utilities, including their generation mixes. And yet, the conflict continues, which leaves Arizona in somewhat of a "policy paralysis" with regard to setting new renewables, energy storage, or clean energy policy. Having the state legislature — presumably with the governor in the driver's seat— setting energy policy for the state would potentially create a conflict with the specific powers given to the ACC under the Arizona Constitution. The ACC believes it has the power to enact and enforce rules over its sphere of influence just as if it were acting as the legislature. Whether or not a compromise can be reached remains unclear.
- Arizona continues to wrestle with the question of energy competition or "deregulation," which would open its generation market to independent providers. And yet, if deregulation were to include a separation between transmission & distribution responsibilities from generation, the question of potential utility ownership of storage assets would be further complicated.

Despite all these systemic challenges, the largest utilities in Arizona—Arizona Public Service (APS), Tucson Electric Power (TEP) and Salt River Project (SRP)—have all pursued renewables and energy storage on their own. Unlike APS and TEP, SRP is not under the jurisdiction of the ACC, but despite this difference all three utilities have been aggressively pursuing renewables and storage development [25].

Meanwhile, Arizona is also home to what have been two widely publicized fires and explosions at battery-powered plants, highlighting the challenges and risks that can arise as utilities rely more heavily on battery storage. APS had installed a 2 MW battery system at a substation in Surprise, AZ, just outside of Phoenix, and another near the Festival Ranch development in nearby Buckeye. But an April fire and explosion sent eight firefighters and a police officer to the hospital. An investigation into the causes of the event is ongoing [25].

In response to the fire and explosion, APS announced that would be temporarily delaying its investments in new battery storage, although it will still issue two requests for proposals to add up to 250 MW of wind generation to its portfolio no later than 2022 and 150 MW of solar power to its portfolio by 2021.

While Arizona continues to vet broader energy regulation issues (e.g., role of the ACC, increased renewables requirements, deregulation), the absence of energy storage policy in the Grand Canyon State persists. There are a number of issues pertaining to energy storage that the ACC (and potentially the Arizona Legislature) will need to consider as utilities in the state continue to pursue their own storage initiatives.

There are several opportunities for developing supportive state policies in Arizona:

1. Finalize interconnection policies to ensure that storage can connect to the grid
2. Consider whether an energy procurement mandate is appropriate for the state, similar to what has been enacted in neighboring states.
3. Introduce proceedings to evaluate the value of energy storage and consider MUAs for storage that would include varying value levels.
4. Determine whether Arizona's generation sector will be deregulated and, if so, how deregulation will impact storage deployments currently being initiated by utilities and opportunities for utility ownership of storage assets.
5. Consider whether the inclusion of energy storage alternatives should be mandated in regulated utilities' integrated resource plans.
6. Re-evaluate and extend financial incentives provided to energy storage initiatives.

Determine if Arizona will join the California ISO or another RTO and how that might provide opportunities for energy storage procured or developed by the state's utilities can be used in wholesale transactions at the RTO level.

5.2.2. California

With its innovative and ambitious policies, California is a global leader in the development and application of energy storage technologies. For the last decade, the state has been a frontrunner in both the development of storage technologies and the legislative and regulatory policies that are needed to enable the growth of an energy storage marketplace.

It is clear that California has set the course for developing a clean energy future, a course that other states continue to monitor and, in several cases, mirror in their own policies. The specifics of California's clean-energy infrastructure are impressive. As of 2018, California has generated about 29 percent of its power from renewables. Another nine percent came from nuclear and 15 percent from large hydropower (both of those count as carbon-free, but the last remaining nuclear plant in the state is slated to retire by 2025). Natural gas provided 34 percent of California's electricity. Further, since 2010, California has procured 1,514 MW of new energy storage capacity to support grid operations. Also in 2010, California became the first U.S. state to mandate energy storage procurement with targets imposed on the state's three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric), formalized by the California Public Utilities Commission (CPUC).

California recently upped the ante on its clean-energy goals, with its newly established goal to generate 60 percent of its generation from renewable resources. In addition, California has adopted a 100 percent carbon-free electricity by 2045.

Energy storage factors prominently into California's clean energy goals, and in fact some market observers have concluded that California's goals are not achievable without a significant amount of new storage capacity being developed over the next two decades. Policymakers in the state appear to agree on the critical role that storage will play going forward, and in 2013in through legislative and regulatory policy the state formally adopted a new energy storage target of 1,325 MW by 2020. This mandate is the outcome of California's conclusion that energy storage will continue to be a main ingredient in the mix of strategies the state is using to balance supply and demand; support the CA-ISO in maintaining grid stability; avoid voltage and frequency imbalances; and support the state's transition to a renewables-centric energy infrastructure [26].

With approximately 4.2 GW of energy storage capacity already in development, California has a large amount of installations that can be analyzed and used to inform related policy decisions. California also has been a pioneer in testing and utilizing large-scale lithium-ion battery deployments as a swift response to compromised grid conditions, and is the location for prominent demonstrations intended to evaluate storage technologies for various grid-scale applications, including PG&E's use of batteries to replace gas-powered plants that are shutting down. Moreover, due to the sheer volume of California's energy storage development and the fact that it has wrestled with what will ultimately be critical storage policy issues for other states, it is no surprise that California has become the benchmark against which policies and market development for storage across the U.S. are being evaluated [26].

California has used a mix of executive directives, legislation, and regulatory decisions to define energy storage policy, and has relied upon coordinated efforts among the Legislature, CA CPUC, California Energy Commission (CEC), and the CA-ISO. The policy initiatives related to storage that have been developed by California policymakers over the last decade have been focused in three key areas:

- Requiring utilities to procure significant amounts of new energy storage resources;
- Developing robust incentives through the Smart Grid Inventive Program) that provides consumer rebates to enable storage development (totaling about $450 million in 2019);
- Evaluating the value of energy storage through consideration of MUAs (i.e., storage's many contributions to grid stability and reliability).

Through these efforts, California has addressed a number of complex technology and policy factors including storage's role in a clean-energy environment, how a storage market should be designed, barriers that prevent storage's participation in both retail and wholesale markets, and the various ways in which storage can and should be used. Given that the state's legislators opted not to define specifics paths for storage development but rather deferred to regulators and market drivers, California has experienced somewhat of a "learning by doing" process as it pertains to developing its storage market. Accordingly, California's efforts provide many "lessons learned" for other states across the country, many of which have taken very few steps toward developing their own policies for storage. Key storage issues that California has addressed over the last decade include:

- Determining an appropriate amount to be included in a storage mandate
- Defining a realistic and achievable timetable for storage procurement
- Allowing flexibility in types of storage projects that will be considered
- Providing financial incentives that are offered appropriately and fairly
- Evaluating various ownership models for storage
- Determining the value for storage across a suite of MUAs

California has almost single-handedly jump-started the advanced storage industry by setting statewide mandates for renewables, storage and carbon-free electricity, but the state is still in the early stages of this rollout. That means utilities are still testing how storage works on the grid, and how it performs after several years of service, both of which are crucial to planning a grid that is all renewables

The challenges for the state to achieve its vision are significant. For example, according to a study prepared by the National Renewable Energy Laboratory (NREL), even with optimal grid improvements, California would still need an estimated 15 GW of additional storage just to reach 50 percent solar by 2030. That's more than 11 times the amount of storage mandated currently in California, and 66 times the total megawatts deployed in the U.S. last year [26]. For now, though, California has solidified its leadership role in building the future paradigm for clean energy and the grid. If it succeeds, others will learn from it. If it falls short, that expensive experiment will be instructive, too.

5.2.3. Hawaii

The state of Hawaii has many characteristics that make it an important and unique "test bed" for the development of energy storage solutions and the necessary policy structure to support those solutions. In fact, Hawaii is a prototype for a state—historically dependent on expensive, imported oil—moving to a 100-percent renewables market as a means to become self-sufficient regarding its energy supply. And it is doing so without the benefit of having an inter-island grid system to enable the transition, but rather through the development of stand-alone supply solutions independently placed across the state's eight separate islands and their isolated island grids. The result? Presently Hawaii is at the leading edge of incorporating renewable energy and energy storage, outpaced only by California, which tops the market for solar, storage and plug-in electric vehicles, the main technology manifestations of the clean-power revolution.

Hawaii's path toward its current market position has arguably been pursued out of economic necessity. Again, we must keep in mind Hawaii's unique geography. Separated by thousands of miles of ocean, for decades Hawaii has required the importing of petroleum fuel to support its energy needs, which has consistently resulted in electricity rates that are more than double (and sometimes triple) the national average. In fact, Hawaii has historically had the highest energy prices in the country, which due to historical fossil fuel prices have averaged about \$0.15/kWh but historically has run as high as \$0.30/kWh. The development of alternatives to the state's dependence on fossil fuel resources has largely been driven by policy directives. Only recently have we started to witness utility plans drive the market, with the economic impetus of lucrative power purchase agreements (PPAs) for solar + storage that are now beating petroleum-based power contracts.

The move toward a self-sufficient, clean energy infrastructure in Hawaii has been in place for well over a decade, with a mix of executive directives, legislation and regulatory mandates continuing to increase and accelerate the commitments placed on incumbent utilities. Perhaps more than any other state, Hawaii's transition to a carbon-free marketplace has been primarily driven by policy as opposed to utility-driven business initiatives. However, utility initiatives are expanding the use of renewables from what has been primarily a distributed solar market into one that is continuing to grow quickly through utility-scale initiatives. Within the last several years, new PPAs between Hawaiian Electric, Inc. (HEI) have included record-low prices for solar + storage contracts with unique capacity-promoting features, underscoring the competitiveness of renewables contracts when compared against fossil fuel contracts and validating the long-term clean energy goals of the state.

HEI provides most of the power consumed on the islands through its subsidiaries on Oahu, Maui and the Big Island. HEI issued a Power Supply Improvement Plan (PSIP) in December 2016 that put forth an ambitious five-year plan to double Hawaii's renewable energy penetration from 25 percent to 52 percent in 2021, and also nearly double the state's photovoltaic installations from 717 MW to 1,465 MW in the same time period. This PSIP is expected to put Hawaii on the road to get 100 percent of its electricity by 2040 from renewable sources, with no fossil fuels on the island by 2045.

Appendix A As the state of Hawaii continues to experience a rapid growth of renewables, DERS and energy storage deployments, it is anticipated that future regulatory proceedings will be focused on the intricacies of the performance-based regulation (PBR) implementation, integrated resource planning, and continued fine-tuning of the new tariffs designed for solar + storage customers.

Appendix B Although rather surprising, presently Hawaii does not offer any financial incentives for energy storage installations. Previous legislative measures that would have established a new tax credit for the addition of energy storage to existing solar PV systems have failed at the Hawaii Legislature. Given Hawaii's position as a "test bed" for developing innovative policy applications (e.g., revised NEM policies, use of PBR for solar + storage), it would be interesting to see how Hawaii could develop a financial mechanism to subsidize and encourage the development of storage solutions, particularly among businesses and commercial operations.

Appendix C The Hawaii PUC is also likely to address the potential unbundling of all technologies including demand response, energy storage, and customer-owned generation to compete in ancillary services to the distribution grids across the islands.

Appendix D Furthermore, the Hawaii PUC has not addressed the issue of how an increased use of aggregated DERS can be used to replicate or supplement conventional generation resources in the form of "virtual power plants" (VPPs). The question of how to integrate VPPs with the development of microgrids is also unclear and represents a policy gap. If Hawaii were to develop a policy regarding the use of virtual power plants, it would be the first state to do so.

Appendix E Finally, in comparison to California, Hawaii has not mandated that utilities development a comprehensive distributed energy resource plan to address issues such as location-specific valuation of storage solutions, use of advanced inverters on ESSs, how utilities will manage two-way communications with DERS customers attempting to interject resources onto the grid.

5.2.4. Illinois

Through a series of market-changing state legislation, Illinois and its executive leadership have for the last several years been moving steadily toward a clean energy environment that is enabled by a suite of emerging technologies (e.g., advanced smart meters, DERS, and energy storage). Moreover, stakeholder groups such as the Illinois Clean Jobs Coalition are well mobilized and aggressively advocating for Illinois to become the first state in the continental U.S. to be powered entirely by renewables. However, progress toward that renewables-based, clean energy future now appears to be stagnated by conflicts with federal policy and the state's participation in the PJM Energy Market. How the current policy disputes plays out will have a direct impact on the future for energy storage in Illinois.

The way that the deregulated market in Illinois has been structured is based on transactions in which individual customers and businesses purchase electricity from "wires only" utilities such as Commonwealth Edison (ComEd) and Ameren, which in turn purchase electricity through PJM and MISO, respectively. Illinois has also participated in PJM's capacity market, in which electric suppliers are required to have enough resources to meet customer demand plus a reserve amount.

The wrinkle in this existing set-up is that PJM has proposed two options that would impact the profit opportunities for specific resources bidding into its capacity market. The first option would set a minimum price for certain subsidized power generations (e.g., renewables and nuclear) that would require these resources to bid into the capacity market at prices they would have been bid at if they had not received any state subsidies. The second option is that PJM would allow states to take subsidized generation out of the capacity market altogether, eliminating capacity-guarantee payments that such generation is presently receiving.

Environmentalists have argued that any changes made to PJM's capacity market that negatively impact payments for renewable and nuclear energy from its capacity market would favor fossil fuels over non-carbon sources of energy. Further, any changes made to how PJM structures transaction fees for the wholesale market would have a direct impact on ComEd, which serves the northern part of Illinois that includes the Chicago metropolitan hub.

The basis of the opposition to such a change is that PJM's capacity market would become unquestionably biased toward larger power plants (i.e., fossil-fuel-based generation) and impede Illinois' ambitious renewable goals. In addition, the changes that PJM is proposing would also have a huge impact on Exelon Corp., the parent of ComEd, as the owner of the multiple nuclear plants in the state. Exelon has argued that any nuclear plant that would be decommissioned would likely be replaced by natural-gas fired plants, which would render the state's goal of a carbon-free power grid impossible to achieve.

For now, PJM's members are waiting for a final decision from FERC and have been in a "holding pattern" for a year or more. Therein lies the heart of the conundrum that is stalling clean-energy policy development in Illinois, and creating "collateral damage" (i.e., market stagnation) for energy storage in the state. What places Illinois in a state of limbo is that FERC has not issued a final ruling on PJM's proposed changes.

If FERC does not allow subsidized resources like wind, solar and nuclear to participate in capacity markets, it is likely that Illinois will re-evaluate its membership in PJM. There would likely be two potential outcomes for Illinois once FERC issues a final ruling on PJM's proposed changes: assume either full or partial responsibility for its own capacity market. If the first option becomes a reality, Illinois would likely exit from the PJM capacity market and create its own capacity market with oversight from the Illinois Power Agency. If the second option is elected, Illinois' ability to obtain capacity would be limited to specific resources. With the enormous operational changes that either move would create, it's no wonder that legislative policy on energy storage is (unfortunately) low on the totem pole for Illinois policymakers at this time.

The uncertainty of Illinois' path forward due to these issues taking place outside of the state's boarders has created a gap of state-based energy storage policy in Illinois. While there has been a lot of discussion among policymakers in the state, at present Illinois does not have any rules or regulations that explicitly pertain to energy-storage deployment. Unlike other states that have emerged as leaders in energy storage policy, Illinois has no procurement mandate, no financial incentives provided to ESS deployments, and utilities in the state are not required to include energy storage in their integrated resource plans.

An assessment by the Energy Storage Association characterized Illinois as having a "good opportunity for storage" even though the state has seen minimal policy action on storage to date. The ESA correlated Illinois' potential for energy storage development to its participation in regional transmission organizations like PJM and MISO.

At the present time, Illinois has very limited storage capacity. The most recent reports, compiling data from 2017, and published in a report from the Smart Electric Power Alliance in 2018, indicated that only 0.3 MW of storage has been deployed in the state (again, that is from 2017 data—more recent data has not been publicly available). The state has also struggled to meet its renewable requirements, which were codified in late 2016 through the Future Energy Jobs Act (FEJA), which confirmed the goal of 25-percent renewables by 2025. There is also an interim target of reaching 16-percent renewable energy by 2020. Based on 2017 data, Illinois produced about 7 percent of its electricity from renewable resources, falling far short of where it needs to be in only five years, or even next year.

State regulators at the Illinois Corporation Commission (ICC), the state regulatory commission, are considering proceedings that will investigate the value of storage and financial incentives for energy storage deployments. It has also been socialized that Illinois will need to update its interconnection rules and regulations to ensure fair, streamlined and cost-effective access to energy storage solutions. Given that Illinois has completed widescale deployment of AMI, the interconnection rules will need to be updated to address energy storage's impact on metering, telemetry, and accounting.

Moreover, Illinois can be characterized as a state that is slowly and deliberately defining the landscape for an expected proliferation of renewables and other distributed generation, including energy storage. It's clear that Illinois wants to lay a solid foundation for grid modernization and increased penetration of renewables and DERs. However, the "slow and steady" approach that Illinois is taking may be overshadowed by other states in the Midwest that are moving more aggressively toward defining storage and clean energy policies (e.g., Minnesota, which has taken substantive steps to create a cost-benefit analysis for storage while committing the state to generating 100 percent of its electricity from clean sources by 2050).

The ICC is presently holding investigations, inquiries and hearings to learn about the value of energy storage resources and the role they can play in the regional market. To move the market in Illinois forward, there are several areas for policy development that would seem to be necessary:

- Continue to set policy on energy storage through legislation, as the state has done so successfully for other technologies such as AMI.
- Develop a cost-benefit analysis for energy storage development that is specific to the state.

- Use the findings from the cost-benefit analysis to determine whether or not to set procurement targets for energy storage.
- Determine what financial incentives may be appropriate to attract investment in energy storage systems in the state.
- Consider what new rate designs might be necessary to stimulate the deployment of energy storage solutions.

Also, since Illinois is already one of the leaders in applying PBR principles to reliability and quality of service along with energy efficiency, it would be a natural extension to evaluate how these principles can be applied to DERs generally and/or energy storage specifically. PBR, which is not a new concept and has been applied in various regulatory jurisdictions, utilizes utility performance metrics and earnings adjustments to align financial incentives with state policy goals. The Energy Infrastructure Modernization Act of 2011 created new metrics and associated rewards for reliability and then the FEJA took this methodology a step further by applying PBR to energy efficiency. It is perfectly conceivable that the ICC could take additional steps to develop new metrics and earnings adjustments specific to renewables, DERS or energy storage to incentivize utility leadership in ESS development. Categories of utility performance could include peak demand reduction, system efficiency, customer engagement, and accelerated deployment of DERs or integration of renewables with DERS.

5.2.5. Maryland

Maryland represents “a small, slow and steady”—but nevertheless very important—market for energy storage development as it emphasizes its “learning by doing” approach toward developing the regulatory structure for energy storage and incentivizing market growth through state subsidies. Regulators in the state claim that ultimately Maryland will prove to be “one of the states in the union that is most advanced in its efforts to move utility treatment of solar energy, electric vehicles, and other DERs toward a customer-centric universe.”

Maryland began its grid modernization proceeding in October 2016. Early reports indicate that the Maryland Public Service Commission (Maryland PSC) appears focused on more specific technologies and issues rather than comprehensive reform of its market structure. The Maryland PSC regulates electric, gas, and combination utilities through the setting of rates, the promulgation of new rules and regulations, and the approval of applications to modify the type or scope of utility service. The primary investor-owned utilities in Maryland are subsidiaries of Exelon Corporation: Baltimore Gas & Electric, Delmarva Power, and Pepco. In addition, Maryland’s significant presence in the PJM Interconnection market provides unique challenges to the state’s reform process and will have many states watching closely as it charts its own path.

Unlike other states that have opted to mandate the procurement of energy storage, Maryland has a taken a different approach that is built around providing financial incentives to jumpstart storage development in the state, while simultaneously defining state policies to support the market in real time. With regard to energy storage specifically, Maryland is an important reference point due to the fact that it provides the best (and only) example at this time of a state that has developed a tax credit specifically designed for energy storage.

While other states (California, New Jersey, and Nevada for example) have incentive programs that are available for energy storage system, Maryland is the only state that has an actual tax credit that is provided for developers of energy storage. Thus far, the tax credit has enabled a number of demonstration projects involving storage paired with renewable energy systems.

However, Maryland also provides an example of how state subsidies (or a tax credit, in this case), while an important mechanism to stimulate the development of energy storage, may not be the only mechanism needed to elevate a state-level market to the upper regions of energy storage development. Despite its status of being the first state to offer an energy storage tax credit, Maryland is also finding that financial subsidies alone may not be enough to jumpstart and energy storage marketplace or achieve its full potential. In other words, the experience in Maryland suggests that state-level subsidies alone, or even state-level subsidies combined with the federal ITC, may not be enough to incentivize energy storage development. Specifically, Maryland does not yet have a revised ratemaking approach that is specific to storage, and it is unclear the extent to which energy storage can participate in the state's net metering, both of which would provide additional economic incentives for storage development.

Other inherent characteristics of Maryland's larger energy market also make the state's approach to storage unique. For instance, Maryland has not experienced constraints on other power sources or a rapid increase of resources stressing its transmission or distribution network. Much of the wind power that is used to meet the states' renewable portfolio requirements originates from other states, thus minimizing the need to pursue storage technologies as a means to build out new solar and wind generation within the state. In addition, unlike other states that have pursued energy storage due to a primary need for economic alternatives to traditional forms of generation (e.g., Hawaii), average electricity rates in Maryland have not been significantly higher than the national average.

Meanwhile, although solar has nearly tripled in Maryland since the mid-2010s and the state ranks in the top quartile for solar deployment, renewables development in the state currently comprises a very small portion of the total generation mix. The expansion of renewables in a given state can usually be correlated with an increase in storage. Maryland's storage market is unique in that it continues to take shape without having these conditions drive the market development.

Due to all of these factors, Maryland remains a comparatively small storage market. Until regulations and rate design are better defined in the state, which is a primary focus of the current regulatory proceedings, the growth of Maryland's energy storage market may remain on a slow track. However, that does not diminish the innovative policy work being presently conducted in the state that may end setting market precedents for energy storage in Northeastern U.S. states.

Accordingly, Maryland continues to take the slow and steady approach toward the development of energy storage technologies and the luxury of time to develop proactive (as opposed to reactive) policies for the growing storage market. Perhaps the best example of this approach is that the Maryland PSC is in the midst of an 18-month investigation (Public Conference 44) to consider five grid modernization topics: competitive markets and customer choice; rate design; electric vehicles; interconnection processes; and energy storage. It is one of the most unique aspects about the state in that Maryland is developing energy storage policies even in the absence of traditional market drivers such as resource adequacy concerns, high demand charges, or required planning and review of generation and transmission proposals. The Maryland PSC is also enacting a storage pilot program as part of the broader Public Conference 44 proceedings.

Presently the largest energy storage unit in Maryland is a 10-MW lithium ion battery, which is owned by Fluence Energy and provides ancillary services to the PJM Interconnection (PJM), which administers the region's wholesale bulk electricity system. There are approximately 12-15 other storage projects in the state, some subsidized by the state tax, which are being implemented to test the diversity of storage technologies and applications.

As noted, there are a few issues that appear to be stalling rapid growth of the energy storage market in Maryland. Perhaps the most critical issue that remains a market barrier is the question of utility ownership of storage assets. For example, the state prohibits third party ownership of energy storage assets and yet, due to the provisions of the state's energy competition/ deregulation policies, it is unclear whether utilities can own generation assets either if the assets include generation capabilities. Nothing in Maryland law explicitly prohibits utilities in the state from owning and operating storage assets. However, Maryland statute does prohibit "the generation, supply, and sale of electricity, including all related facilities and assets" from being regulated as an electric company service or function. The relevance is that, depending on how storage is classified, questions of cost recovery through rates and storage's eligibility to participate in broader wholesale markets remain unanswered.

Thus, it's an ambiguous grey area within the state's energy storage policy that will need to be resolved in order to provide market clarity that is essential for potential investors. With the regulatory mandate to develop energy storage pilot program at the utility level (with various ownership scenarios), Determining whether utilities may own storage, whether it's behind the meter or in front of the meter, would resolve a major source of uncertainty among utilities and third-party developers.

it is anticipated that the state of Maryland will resolve this ambiguity, but it may not be for a couple of years. If Maryland were to expand eligibility for the tax credit to allow for third-party ownership of energy storage systems, the market in the state would like to see significant gains. Whether or not state law is changed to allow third-party ownership of energy storage assets, or when, remains to be seen.

In addition, the other potential barrier to broader deployment of energy storage solutions across the state is the fact that, while innovative in its approach, the state tax credit for energy storage does not appear to be enough to address the array of financial considerations with the deployment of an energy storage system.

Policy questions relevant to energy in Maryland that still to need to be resolved include:

- *Rate design:* Maryland's basic retail electricity rates fold demand-related expenses into per-kWh charges and do not reflect the true cost of energy. The result is that customers have little incentive to minimize their energy usage at peak demand, thus diluting one of the primary reasons that end-use customers explore storage in the first place. Revised rate design will likely be necessary to Maryland to explore time of use rates, real-time pricing, or other innovative tariffs designed specifically to address the needs to storage customers.
- *Wholesale market participation:* It remains unclear in Maryland whether storage can provide capacity services or transmission deferral services to PJM based on market rules. In addition, there are limits on how BTM storage can participate in PJM, limiting it to a demand-response resource only. Definitions of how storage should be classified and thus its opportunities to provide other multiple use applications will need to be determined by the Maryland PSC in conjunction with PJM rules.

- *Interconnection rules:* Like many other states, Maryland is finding that its legacy interconnection rules will need to be revised to address the anticipated growth of storage. One question addresses whether an interconnection study of a specific project should be evaluated on the basis of gross or net capacity. Other questions will likely address the level of utility review that is required for interconnected projects and the cost and time needed to interconnect energy storage projects.
- *Market value of storage:* Regulatory proceedings in Maryland are also expected to address the universal issue of how to determine compensation levels for storage across multiple use applications. It is agreed that many of the uses of storage can result in system-wide benefits, but at the present time there is no established market value for these services, in Maryland or elsewhere. Moreover, due to the nascency of the storage market, there may be additional benefits (and costs) that result from energy storage projects. Maryland, along with other state regulatory jurisdictions, recognizes the need for a comprehensive valuation methodology for storage.

5.2.6. Massachusetts

Massachusetts is among a handful of U.S. states that is currently on the forefront of establishing energy storage policies through legislation and regulatory directives. Like California, Hawaii, and New York, Massachusetts has created policy on critical energy storage issues that now serve as reference points and/or precedents for developing storage policy in other states. In fact, Massachusetts has been a front-runner in developing energy storage policy since 2015 with the creation of an Energy Storage Initiative (ESI) for the Commonwealth, which included comprehensive studies about the capabilities of energy storage, funding for storage demonstration projects, and the Commonwealth's authorization to establish a statewide energy storage target.

Some of the unique decisions that have framed Massachusetts' precedent-setting energy storage policy include:

- Massachusetts is one of the first states to provide comprehensive guidance focused on pairing energy storage with solar panels
- Massachusetts became the first state to allow behind-the-meter (BTM) energy storage to qualify for energy efficiency incentives
- Massachusetts was one of the first states to adopt a target for storage and has ratcheted up the target to its current level of 1,000 MWh by 2025
- Massachusetts includes storage as an eligible resource for the state's solar incentive program, the Solar Massachusetts Renewable Target (SMART)
- Along with the SMART program, Massachusetts has several incentive funding mechanisms that are aimed at unlocking the full potential of energy storage, either as a stand-alone resource or as a hybrid resource with renewables (e.g., solar + storage).

Regarding incentive funding, Massachusetts has awarded approximately $20 million in grants to 26 energy storage projects, doubling the state's original $10 million commitment. The grants were awarded under the state's Advancing Commonwealth Energy Storage (ACES) program that is part of the ESI funded by the Massachusetts Department of Energy Resources (MA DOER).

Massachusetts is part of the ISO-NE which over the last several years has experienced a number of challenges including the retirement of traditional power plants, diminished capacity of available resource<s and restrictions against building new transmission lines that would enable the development of power-generating resources. Energy factor factors prominently into the region's efforts to address these challenges at the wholesale level. To date, energy storage in Massachusetts has been primarily limited to pumped hydro storage in Northwest Massachusetts that is provided as bulk energy to the ISO-NE. State-level incentive offerings are intended to spur storage deployment and enable broader opportunities for storage to participate in residential, commercial, and wholesale energy markets.

Massachusetts has made great strides in developing energy storage policy and other states continue to look at the state for insights as to how to approach complex policy issues in their own states. However, there are number of storage policy issues that remain "top of mind" for policymakers in Massachusetts and as of August 2019 remain unsettled. These issues include:

- Storage's eligibility to participate in the state's net metering program
- Which entity will have capacity value of storage that participates in ISO-NE's forward capacity market
- Restrictions against "gaming the system" at the distribution level should all forms of energy storage be allowed to participate in the state's net metering program
- Revision to existing tariffs and rate design in the state to further accommodate the participation of storage

5.2.7. Nevada

The energy sector in Nevada has experienced a rather tumultuous evolution over the last few years. While seeking to make systemic changes to its regulatory structure and its approach toward grid planning and operations, the state has experienced some very public setbacks with regard to its market and policy initiatives for clean energy. However, despite these setbacks, Nevada now appears to be back on track toward assuming a leading position in developing innovative energy storage policies while simultaneously supporting what is clearly a rapidly growing sector for clean energy development. Within these broader initiatives Nevada has also assumed its current position as a market leader for energy storage. What makes Nevada an important case study today is the extent to which voluntary, business-driven decisions to expand renewables and energy storage solutions has been spearheaded by the primary utilities in the state. This is in contrast to how the development of renewables and energy storage has evolved in other states, which has typically been driven through policy directives.

In addition, Nevada is also rather unique in the sense that it does not produce much of its own energy (the state ranks in the bottom ten in terms of states that produce their own energy). Compared to neighboring states, Nevada has very little generation capacity in-state, and reportedly nine-tenths of Nevada's power comes from outside of its borders. Moreover, Nevada has no significant fossil fuel reserves. Rather, natural gas is the primary fuel for power generation in the state, with the majority of the state's remaining power plants primarily relying on this fuel source. In 2017, about 72 percent of Nevada's generation mix came from natural gas; and only about 7 percent came from coal.

This fossil-fuel base still overshadows renewables, which in 2017 accounted for approximately 18 percent of the energy mix. In Nevada, renewables have mostly meant hydro, solar, and geothermal. Even though it is one of the driest states in the nation, historically most (over 80 percent) of Nevada's renewable resources have come from hydroelectric power plants, primarily the Hoover

Dam. This unique energy mix, particularly the need to import power, has made the state dependent on transmission capacity that can deliver power from other regions. Further, the lack of its own power resources or long-term commitments to traditional forms of generation arguably has positioned Nevada as state that can move to a completely clean energy mix more seamlessly than others.

The move toward a clean energy environment in Nevada has its roots in economic analysis, and thus even in the absence of stringent requirements the main utilities in the state have been moving away from carbon-intense energy sources for a number of years. Perhaps illustrating this point best is the recent announcement from NV Energy, the primarily utility in Nevada, which stated it will no longer own any coal generation plants moving forward.

The future of renewables in Nevada is now pointed toward the sun. Solar continues to develop rather rapidly in Nevada and is expected to supply an increasing share of Nevada's net generation. About one-fourth of Nevada's utility-scale electricity is now generated from renewable resources, and about half of those renewables are now coming from utility-scale solar resources. In fact, according to most rankings, Nevada leads other states in terms of solar power potential and has generally ranked within the top five states for installed solar capacity.

NV Energy (which operates through its two regulated utilities, NV Power and Sierra Pacific Power), provides about 81 percent of the state's electricity and is clearly the dominant utility operation in the state. NV Energy has publicized aggressive, voluntary plans for solar + storage development through its integrated resource plans, placing it in a lead position among utilities that are pursuing hybrid solutions. NV Energy is owned by Warren Buffett's Berkshire Hathaway Companies (which also owns PacifiCorp in the Northwest and MidAmerican Energy in Iowa). Berkshire Hathaway has established an over-arching strategy across its utility subsidiaries to strategically move away from coal-fired generation into a renewable-centric generation portfolio.

The new plan is part of the company's long-term goal, as outlined in its Integrated Resource Plan approved by the PUCN in December 2018, of serving its customers with 100-percent renewable energy. Again, in the absence of an enforced mandate via the legislature or the Public Utilities Commission of Nevada (PUCN), NV Energy is opting to pursue this increase of renewables and storage on its own accord. In April 2019, Senate Bill 358 was signed into law by Nevada Governor Steve Sisolak requiring Nevada energy providers to achieve a 50 percent renewable energy portfolio by 2030, which NV Energy publicly supported.

Public support for more renewables in Nevada was confirmed in November 2018 when a ballot initiative was approved that would require electric utilities to acquire at least 50 percent of their electricity from renewable sources by 2030. However, because it amends the Nevada Constitution, the ballot measure must be approved by voters twice in order for the requirement to go into effect. Nevada voters will vote on the measure again in 2020. Subsequent legislation (SB 358) enacted this increase into law.

A key part of Nevada's renewables law, which positions the state as an innovative leader in the energy storage realm, is that every kilowatt-hour of energy delivered by a qualified storage device will count double for the purpose of meeting the RPS requirement. This is a very innovative approach; Nevada may in fact be the only state to have enacted such a provision allowing energy storage to be eligible for a renewables requirement in such a significant way. There are two ways in which storage can meet the renewables requirement in Nevada: 1) if the energy storage system charges from renewable generation and discharges during a peak load period or 2) if the energy storage system performs ancillary grid services that enable the integration of renewable generation.

This policy alone positions Nevada among the ranks of other important storage markets (e.g., California, New York, Massachusetts) as in practice it will position storage devices as renewable energy assets that can delivery energy. It should be noted that the law caps the role of energy storage at 10 percent of the electricity eligible for RPS compliance, meaning that the majority of energy eligible for RPS compliance will still be generation.

Nevertheless, without a statewide storage mandate in place, this legislation in Nevada (SB 358) should be viewed as the leading policy measure that is now driving storage development in the state. In the absence of a statewide procurement mandate for energy storage (as of September 2019 the PUCN directed by state legislation under the enacted SB 205 in June 2017, is still evaluating the appropriateness of a mandate), this increased mandate for renewables is still viewed as a much-needed jolt for the solar + storage market in Nevada.

Nevada policymakers continue to vet the question of whether or not mandates for energy storage should be adopted statewide. It is expected that a decision along these lines should be make in early 2020. Meanwhile, behind the scenes, Nevada lawmakers, regulators, utilities and environmental and consumer stakeholders have also been putting together a plan to integrate DERS into the state's grid planning and operations. The PUCN has called NV Energy to evaluate hosting capacity, grid needs, and potential DER impact and values of each circuit and feeder line across its 1.3 million-customer territory. If approved, the distribution planning plan (DPP) requirements would put Nevada in a small club of states — California, New York and Hawaii — that are actively asking their investor-owned utilities to bring DERS into their grid plans on a number of levels.

Along with the current ongoing dockets to address energy storage targets, the PUCN is likely to consider the following issues related to energy storage policy through 2020:

- Revision of interconnection standards for distributed generation (e.g., adoption of IEEE 1547 standards)
- Along with including energy storage in utility integrated resource plans, the PUCN will also likely consider more stringent requirements to have utilities evaluate the cost effectiveness of storage along specific locations on the distribution grid where it would offer the greatest value
- Consideration of multiple use applications for storage and how those multiple uses should be valued differently
- Continue to develop financial incentives for energy storage
- Finalization of utility distribution resource plans (DRPs), including how utilities will gather data on how much DERS different circuits can support
- Continued consideration of opening retail competition in the state
- Continued coordination with regional wholesale markets to determine the role that energy storage can play in RTOs/ISOs

As of December 2019, the PUCN is considering adopting a 1,000 MW statewide energy storage target for utilities for the end of 2030, crafting a proposal more than two years after the legislature passed a bill directing the commission to look into storage goals. The PUCN's proposal would create biennial targets, beginning with 100 MW by the end of 2020 and then ramping to 400 MW and 800 MW by 2024 and 2028, respectively. The proposal was submitted to the state Legislative Counsel Bureau in November 2019 and is expected to be finalized in early or mid-2020.

5.2.8. New Mexico

New Mexico, for the most part, operates outside of a competitive, regional market (the eastern part of the state participates in the Southwest Power Pool, but the largest market in the state served by the Public Service Company of New Mexico (PNM) does not belong to an RTO). Therefore, policies that are specific to storage are being developed primarily through state legislative and regulatory directives. The primary focus of New Mexico's storage policy development has been placed on removing or reducing barriers for storage and including new opportunities for storage to participate on a more level playing field with other resource alternatives.

Put another way, to date, New Mexico has focused on policy revisions that are intended to broaden the competitive access for energy storage in the state. Broad policy initiatives that involve storage include the state's commitment to being "carbon free" by 2045. A primary example of New Mexico's efforts is the mandated inclusion of energy storage in utility integrated resource plans.

In 2019, the state of New Mexico began to officially define an energy transition plan that emphasizes renewables and storage objectives as a prerequisite for an envisioned carbon-free future in the state. Under the leadership of newly elected Governor Michelle Lujan Grisham, New Mexico has emerged among a handful of states that within the last year have publicly established a commitment to clean energy by directing power generators within its borders to produce more electricity from renewables, storage, and other non-polluting sources. In fact, New Mexico is among an elite group of states (California, Hawaii and, more recently, Washington and Nevada) that have publicly vowed to become carbon-free and receive most, if not all, of its power from renewable energy in the future. In New Mexico, the goal is to achieve zero-carbon electricity from public utilities by 2045 with 80-percent renewables by 2040.

It is an aggressive goal, given that presently New Mexico has achieved about 20 percent of its electric generation from renewables (in response to the previous renewable energy standard that was originally created in 2004). PNM is currently the only utility in the state with existing storage capability due to its Prosperity Energy Storage project that includes a 500 kV solar PV facility with a 250 kW, 1 MWh battery storage system.

As has been well documented, the state of New Mexico has tremendous wind and solar resources that for the most part have been untapped to date, with reportedly some of the highest rates of solar irradiance and best wind conditions in the United States. It is clearly anticipated by the state's policymakers that energy storage will play a vital role in renewables development and achieving the carbon-free mandate established by new legislation. Consequently, New Mexico has the opportunity to become a national leader in grid modernization and energy innovations specific to storage development due to the local presence and expertise of the Sandia National Laboratories and the number of storage pilot projects and storage experiments being conducted at the Labs.

Storage policy development that is currently taking place at the New Mexico Legislature and the state's Public Regulation Commission (PRC) is currently defining the specific role that energy storage will play. High-level and long-range objectives for storage have been outlined by new legislation, and the PRC should be watched closely for more granular-level regulations ***specific*** to storage interconnection standards, valuation initiatives, and potentially mandated storage targets that will be addressed in the near term.

While high-level policies in New Mexico are laying the foundation for energy storage to play a significant role in the carbon-free future envisioned by the state, there will likely be a number of initiatives before the New Mexico PRC that will address the more granular-level requirements and tactical considerations associated with an expanded role for storage. Two issues that have been identified but have yet to be introduced with a formal policy proceeding are the desire/need for mandates for storage procurement and a reliable approach for determining the value of energy storage across multiple use applications. Both of these issues are common considerations as energy policy is determined at the state level.

The ESA filed a position paper in response to the PRC's rule change regarding IRPs and storage and recommended that New Mexico should set targets for energy storage procurement by utilities, as has been seen in California (1.3 MW target) and to a lesser extent Massachusetts (200 MWh target) and some other states. However, at this point, the PRC has declined to set storage targets for New Mexico on the basis that there is presently only one utility-owned storage system in the entire state (PNM's Prosperity Energy Storage project) and there is no adequate framework for comparing storage targets for deployment. That could certainly change as more utility-driven storage projects are developed in New Mexico.

With executive directives setting baseline expectations for storage, the New Mexico Public Regulation Commission (NMPRC) now takes the lead position in developing state-level policies that are intended to lay the foundation for a robust market for energy storage going forward. It is anticipated that future regulatory proceedings in New Mexico that are relevant to energy storage will include considerations of:

- Revised interconnection standards
- Asset classification for storage technologies
- Potential revision of net metering policies to include energy storage
- Consideration of multiple use applications for storage
- Cost-benefit analysis / valuation proceedings for energy storage
- Potential increases to the state's existing Renewables Portfolio Standard

PRC staff also have mentioned the need for a cost/benefit analysis of energy storage. This is a similar need that other states (e.g., Minnesota) have expressed and is reminiscent of similar "value of solar" proceedings that have occurred in various states in recent years. An interesting aspect in New Mexico is that the PRC staff specifically referred to how energy storage options are considered and possibly rejected by regulated utilities and, in the absence of a reliable cost/benefit methodology, how those projects were evaluated.

5.2.9. New York

In 2018, Governor Andrew Cuomo called for an energy storage goal of 1.5 GW by 2025 and the state's regulatory commission subsequently established a deployment target of 3 GW by 2030, directing the New York State Energy Research and Development Authority (NYSERDA) and the Department of Public Service (NY-DPS) to recommend next steps [26].

Supported by a clear vision articulated by the state's governor, actions by the New York Legislature and New York Public Service Commission (NY PSC) have solidified the role of energy storage as an important foundation of the state's transition to a clean energy-powered future. In fact, New York has established one of the most aggressive procurement targets for energy storage in the country with its pledge to meet a target of 1,500 MW of storage deployed by 2025. By comparison, California has a 1,300 MW by 2020 target; Massachusetts is pursuing a target of 2,00 MW by 2025, and New Jersey recently adopted a 2,000 MW by 2030 target.

At this time, energy storage is still in the early stages of development in New York (as is the case with other states). Approximately 1,460 MW of storage have been deployed in New York, of which approximately 1,400 MW of pumped hydro at two New York Power Authority facilities. The largest non-hydro storage facility in the state is a 20-MW flywheel used for frequency regulation, operated by Beacon Power in Stephenstown, NY Beyond that, another 100 MW of storage is in various stages of development, mostly in constrained downstate regions, and about six other battery storage projects that in aggregate total 430 MW.

New York is defining energy storage policy within the broader efforts contained in the Reforming the Energy Vision (REV) initiative, which has been in place since 2015 and aims to make a number of systemic changes to the state's regulatory model and operational requirements. REV's clean energy goals for 2030 include:

- 40 percent reduction in greenhouse gas emissions from 1990 levels;
- 50 percent of New York's electricity must come from renewables; and
- 23 percent reduction in energy consumption from 2012 levels

Provisions of the REV proceedings include moving New York utilities from a cost-of-service business model to a market-based model. Specifically, utilities will maintain their former status as energy distributors, but will also assume the role of "market operators," facilitating transactions between those who provide energy and those who use it. Utilities will be incentivized to use DERs in their grid planning efforts. In this new role, utilities will own the distributed service platform that DERs sellers and retail customers use to buy and sell electricity. REV envisions that current utilities in New York state will become a sort of "mini-ISO" as it relates to DERs. Utilities will be incentivized to use DERs in their grid planning efforts.

The REV policy is being executed in two tracks. Both tracks seek to meet the same three goals: Track One described in an order released on February 26, 2015, focuses on shaping the new utility vision and DER ownership challenges. Track Two described in an order released on May 16, 2016, focuses on the necessary changes in the current regulatory, tariff, market, and incentive structures.

With regard to the development of energy storage specifically, New York is in the midst of developing an energy storage policy framework that can support what is anticipated to be a robust market in both the state's distribution system and wholesale market managed by the NYISO. To date, New York's energy storage policy framework has utilized procurement targets, financial incentives and demonstration projects to jumpstart the energy storage marketplace in the state. Two specific areas that have been the core tenets of New York's storage policy are: 1) financial incentives provided by the state that are geared toward enabling the unique system benefits storage can provide; and 2) changes in rate design that would enable a shift toward energy storage, which are being assessed as part of the broader REV initiative.

Recognizing that a sustainable business environment has yet to emerge under the current market rules and battery project pricing, the NYSERDA and the NY-DPS designed a Market Acceleration Bridge Program totaling $280 million to spur the first gigawatt of New York's 2030 energy storage deployment goal. The theory behind the funding is that it will monetize some of the value of energy storage that companies cannot get compensation for presently under the current rules. By supporting the early growth of the market, the program hopes to help the industry reach economic sustainability, phasing out incentives as deployments grow [26].

Even against the backdrop of the massive REV proceedings in New York, there are still a number of policy issues related to energy storage that are still being vetted by the state's stakeholders. Three significant policy issues that still require resolution in New York include:

- Utility ownership of storage assets
- Inconsistencies between New York's Energy Storage Roadmap and NYISO standards
- Siting challenges within New York City

With regard to utility ownership of energy storage assets, the New York PSC has made clear through various REV orders and proceedings that utility ownership of DERs would be prohibited, barring a few specific exceptions. DERs in this case is considered to be distributed generation, storage used for economic purposes, and customer-side demand management. However, the exceptions outlined by the New York PSC could prove to be favorable to utility-owned energy storage as a DERs.

Exceptions for utility ownership of energy storage assets currently include the following circumstances:

- Procurement of DERs has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative;
- A project consists of energy storage integrated into distribution system architecture;
- A project will enable low- or moderate-income residential customers to benefit from DERs where markets are not likely to satisfy the need; and
- A project is being sponsored for demonstration purposes

There are stakeholders in New York, including utilities, that continue to make the argument that storage deployment at a scale optimal to the power system, which could include utility ownership given that utilities historically have been most informed of grid needs and positioned to deploy resources throughout their territories. As energy storage technologies and opportunities continue to mature, it is likely that utilities will continue to challenge the prohibition against ownership.

With regard to potential inconsistencies between New York state law and NYISO policies, one of the key elements in New York's Energy Storage Roadmap is creating the potential for energy storage to draw revenues from both the retail market and wholesale markets. This is consistent with policy objectives established by FERC's Order 841 and was viewed positively by storage developers as it opens the possibility for storage technologies to pursue multiple revenue streams based on multiple-use applications. However, based on the New York ISO's filing response to FERC's Order 841, this is still likely unsettled policy and a potential conflict.

Here's how: Order 841 directs ISOs and RTOs to develop revisions to existing tariffs to open up their wholesale energy, capacity and ancillary services markets to energy storage resources on a nondiscriminatory basis. Grid operators had to submit their compliance filings by Dec. 3. However, in its filing NY ISO does not accommodate dual participation in both retail and wholesale markets. The NY ISO also requested an extension from FERC on the implementation of its new rules for energy storage in the wholesale market to May 2020.

This potential policy inconsistency may take some time to resolve, with strong arguments on both sides of the issue. Being able to participate in the ISO is going to be key to the full implementation of energy storage in New York. However, because the NY ISO is not under the jurisdiction of state agencies the goals outlined within New York’s Energy Storage Roadmap may be difficult to achieve unless participation in the wholesale markets is approved.

In addition, siting storage projects in highly congested areas, such as New York City, has remained a challenge as building and fire codes have not evolved sufficiently to address siting restrictions that impact storage development. One specific problem has been delays resulting from the Fire Department of New York’s permitting processes and concerns about safety and the risk of fire associated with battery storage. The lack of clarity around standards pertaining to the indoor siting of lithium-ion battery storage systems has limited energy storage projects in the city. This lack of clarity is impacting storage development and thus the potential to meet targets the state has established.

5.2.10. Oregon

Oregon deserves its place in the top tier of states that are defining new, precedent-setting energy storage policies that other states across the country are closely watching. Oregon’s steps toward defining energy storage policy have received much attention from the energy sector as the state continues to wrestle with a number of unique market challenges. While mass deployment of energy storage solutions may still be several years or more away, Oregon continues to make progress to “get its house in order” for the expected, significant acceleration of both renewable energy and storage technologies within the state.

For example, Oregon was one of the first states to follow in California’s footsteps to implement a statewide energy storage mandate. By setting a mandate through legislative and regulatory policy directives, Oregon now requires that utilities under the jurisdiction of the Oregon Public Utilities Commission (Oregon PUC) must have a minimum of 5 MWh of energy storage in service by January 1, 2020. It is true that this mandate is rather small compared to mandates adopted in the four other states that at this time also have storage procurement targets (California, 1,825 MW by 2020; Massachusetts, 200 MW by 2020; New Jersey, 2,000 MW by 2030; and New York, 3,000 MW by 2030). However, despite this comparatively low storage target, it is hard to envision scenarios that would not involve energy storage if Oregon is to meet its broader clean energy objectives.

The two utilities that are impacted by this mandate are Portland General Electric (PGE), which serves most of the customers in and around the Portland metropolitan area, and Pacific Power (a subsidiary of PacifiCorp, which is part of the larger Berkshire Hathaway company’s suite of utility assets), which serves the southern and eastern parts of Oregon. Both utilities are presently pursuing energy storage projects (details provided below). Together, Pacific Power and PGE provide 70 percent of Oregon’s electricity, and a large portion of that electricity originates from coal power from both in-state and out-of-state facilities. PGE’s Boardman facility is the only coal plant located in Oregon and it is scheduled to close by 2020. The utility, however, also imports coal power from Montana and Pacific Power imports 65 percent of its power from over 20 out-of-state coal plants located throughout the Western U.S.

Oregon has an aggressive renewables mandate, which requires the utilities to obtain 50 percent of the power sold to retail customers from renewable sources by 2040. This puts Oregon into an elite group of states that have set 50 percent or higher targets for renewable energy, which also include California and New York (both of which have set 50 percent targets by 2030; Vermont, which has set a 75percent target by 2032; and Hawaii, which has a 100percent target by 2045).

Oregon's RPS puts it on track to meet its aggressive greenhouse gas reduction goals, which call for reducing carbon emissions 75 percent below 1990 levels by 2050. The state also has a commitment to eliminate all coal-fired generation by 2035. This is a policy platform that has been embraced and advanced by Oregon's current governor Kate Brown (D), who has been in office since 2015. Gov. Brown campaigned on the issue of climate action, and along with approving several key pieces of legislation that support clean energy initiatives she has also released an Oregon Climate Agenda, which would create an Oregon Climate Authority to be charged with coordinating statewide clean energy programs and decarbonization efforts.

These policy objectives are being pursued against a backdrop of market challenges that are unique to Oregon, or at least the Pacific Northwest region in which it operates. The first challenge is the extent to which Oregon remains dependent on fossil fuels, despite its reputation in the marketplace as a renewables-based state. As of September 2019, nearly 40 percent of Oregon's electricity consumption originates from coal-fired power plants in Wyoming and Montana, and about 15 percent of the state's power comes from natural gas. Thus, well over half of Oregon's electricity continues to come from fossil fuels. The reason for this is largely due to the availability of existing transmission lines that transport power from other states into Oregon, and how those transmission lines are currently consumed by low-cost coal and natural gas. PGE and Pacific Power continue to fulfill their power supply commitments in Oregon from coal facilities they own in Utah, Wyoming and Montana, the regulation of which is outside the jurisdiction of the Oregon PUC.

With regard to renewables, a key factor that may be a challenge for the development of energy storage solutions is hydroelectric power, which dominates the power market in Oregon and the larger Northwest region. Recent data suggest that hydro provides nearly two-thirds of the electricity generated in Oregon. However, hydro accounts for less than half of the total electricity that is consumed in the state, due to Oregon's heavy reliance on power imported from other states, which largely still originates from coal.

There are several barriers for energy storage that result from this market dynamic. First, Oregon's heavy reliance on power purchase agreements that are largely tied up in coal-fired generation from other states may be difficult to eradicate. Secondly, the fact that hydro is so prevalent in the region may remain a barrier for in-state energy storage development, particularly battery storage, as hydroelectric power can also store energy in certain applications. Third, hydropower is a comparatively inexpensive resource, and as a result, it could be the case that storage remains uneconomic in this region when compared to other resource options.

In addition, while there is a lot of news about renewable energy projects in Oregon, the reality is that the state continues to export much of the renewable energy that it generates. To illustrate this point, consider wind energy as one example. Approximately 30 to 40 percent of the wind power that is generated in Oregon is exported to California to meet renewable mandates in that state. This includes power being sourced from one of the world's largest wind farms that is currently under construction in Oregon (Shepherds Flat Wind Far in Gilliam and Morrow Counties, with 845 MW of capacity), all of which will be exported to California.

Another market barrier is that the state does not participate in a regional wholesale market that would provide price signals for the variety of services that energy storage could provide. There is presently no RTO or ISO that serves the Pacific Northwest. In other regions (e.g., the Northeastern U.S.), wholesale markets have taken the lead in determining the multiple use applications for energy storage (e.g., energy arbitrage, resource adequacy, frequency regulation, voltage support, black starts, etc.). Without this market context that provides differential pricing based on locational and multiple use applications for storage, it may be difficult for the utilities in the Pacific Northwest to make long-term projections about the economic value of storage at the present time.

Without the reference point that participation in a wholesale market could provide for how to define storage, Oregon is taking matters into its own hands. In December 2016, the Oregon PUC provided guidance to the utilities under its jurisdiction that encourages them to propose multiple, differentiated projects that test varying storage technologies and applications. This is the first known example of a state specifically directing utilities to include multiple value streams for energy storage, touching upon various services such as:

- Energy shifting and arbitrage
- Ancillary services
- Renewable curtailment avoidance
- System peaking and capacity value
- Locational value

Attention has now turned to how the Oregon PUC will evaluate and rule on the required energy storage proposals submitted by Portland General Electric and Pacific Power. Through these proceedings, it is expected that Oregon will examine the following five “high interest” applications for storage:

- T&D upgrade deferral / management of peak demand
- Service reliability and resiliency
- Power quality / voltage support
- Grid regulation
- Renewable energy firming, ramp control and energy shifts

Accordingly, Oregon is an important state that will stay on the radar in terms of developing energy storage policy. Particularly on the topic of energy storage valuation, Oregon could set important precedents on modeling and policies specifics to multiple use applications, such as exploring:

- What value streams should be considered?
- Can the cost-benefit analysis for storage be based on market-price valuation?
- Are environmental costs and benefits included in the value of storage?
- Does the valuation include sub-hourly dispatches for storage?

5.2.11. Texas

It is rather difficult to make comparisons between Texas and other states when evaluating the development of energy storage policies because Texas is inherently unique regarding how its energy market is structured. In competitive areas of Texas, utilities have been unbundled into generation, transmission and distribution (T&D) utilities (i.e., “wires only” utilities”), and retail electric providers (REPs). There are also municipally owned, vertically integrated utilities throughout Texas, such as Austin and San Antonio, along with electric cooperatives. Utilities outside of the ERCOT region but still within Texas remain vertically integrated and may own generation and T&D assets. These utilities include El Paso Electric, Southwestern Public Service Company, Southwestern Electric Power Company, and Entergy Texas.

ERCOT, which serves over 75 percent of Texas and covers 90 percent of the electricity demand in the state, is intra-state and therefore is not under FERC jurisdiction. In addition, ERCOT is an "energy-only" market as opposed to a forward capacity market, and the Public Utility Commission of Texas (PUCT) Because it is an "energy-only" market, the PUCT has not established a mandatory reserve margin level, nor does Texas have any resource adequacy requirements.

Further, no state incentives exist to enable the development of energy storage in Texas. Indeed, the fact that energy storage is classified as a generation asset in Texas prohibits T&D utilities from owning energy storage or incorporating it into distribution operations. An exception to this rule was established through legislation that became effective in September 2019, allowing municipal utilities and electric cooperatives to own energy storage facilities that sell energy and/or ancillary services without being forced to register as a power generator.

As noted previously in this chapter, regardless of the wholesale market that is being discussed, there are generally three fundamental products that can be sold in wholesale power markets:

- Energy: Generators are paid for providing power on a day-to-day basis but are only compensated for power that has been produced
- Ancillary services
- Capacity: Generators are paid for commitments to provide generation for delivery years into the future and compensated for the mere readiness, or capacity, for power production.

As ERCOT does not have a capacity market, this restricts the opportunities for wholesale market participation in ERCOT to energy and ancillary services. The kinds of services that energy storage can provide in ERCOT are as follows:

- Fast-acting operating energy contributions that support regulation and help to balance generation and load (Electric supply capacity)
- Withdraw energy from the grid when prices are low and inject energy into the grid when prices are high (Arbitrage)
- Ancillary services

The ancillary services that are currently allowed in Texas are: 1) Regulation (both Regulation Up and Regulation Down); and 2) Spinning, Non-Spinning and Supplemental Reserves. Primary frequency response is not an ancillary service that is presently available in ERCOT.

Therefore, to survive in the ERCOT market, grid-scale energy storage system must rely on arbitrage (buying energy at low prices and selling it at high prices) OR provide ancillary services, which in ERCOT are essentially operating reserves that respond to variability in load or in generation output. However, to date, the use cases for energy arbitrage and ancillary services have not been attractive enough for energy storage to truly flourish in ERCOT. Successful arbitrage would require lucrative price spikes in Texas, which have not come regularly enough to support a business case for arbitrage based on energy storage. The only approach toward arbitrage in Texas that might be successful would be for a battery to store up on cheap or free wind power and wait for price spikes to sell the energy back at a higher price. However, energy storage would face competition from existing gas plants that are also eager to compete when price spikes occur.

Further, it is unlikely that a robust scale of storage deployment could be reached through merchant wholesale market participants alone, without capturing the array of T&D benefits that storage could provide through long-term utility contracts. The PUCT rule that prohibits T&D utility ownership of energy storage assets has been viewed as a barrier to storage deployment in ERCOT as it limits the amount of value that can be derived from storage to being either just a generation asset or a T&D asset, but not both.

The business case for arbitrage in Texas may improve as more wind and solar comes online, bringing more negative price events and transmission constraints. Nevertheless, the market reality in Texas at this time is that merchant investors nor regulated T&D companies can currently capture sufficient benefits to justify investing in storage to maximize ERCOT-wide benefits under the current policy framework in Texas. Without utility contracts to guarantee revenue, energy storage in Texas must compete with convention gas generators in the wholesale market, a challenge that has scared off even the most bullish storage developers.

It is useful to note that the challenge of earning revenue solely from arbitrage is not unique to Texas. Industry-wide data indicate that there are only a few places in the world that have the required price spreads that make arbitrage economical for an energy storage investment (e.g., some of the Hawaiian Islands). Add to this the lack of available financing for energy storage projects without long-term contracts, and it becomes quite clear why storage has not developed into a robust market in Texas of yet.

Presently, there are just 10 operational stand-alone energy storage projects operating in Texas, but only two are connected to the ERCOT transmission grid. According to ERCOT, these existing storage projects are primarily used for ancillary services.

To date, early projects have delivered some 89 MW of energy storage into ERCOT's grid. Another 1,800 MW have entered the interconnection queue with no guarantee that these projects will be build. Of the 89 MW that have been installed, support of ancillary services has been the primary revenue opportunity within the ERCOT region.

Although ERCOT is outside of FERC's jurisdiction, it has been reported that ERCOT is currently considering developing new market rules consistent with what FERC has directed under Order 841. Within the confines of the state borders, questions that remain before the PUCT include:

- The utility ownership issue: The issue is whether or not energy storage resources that are procured to support reliability constitute "generation" or "competitive energy services" such that they cannot be owned by T&D utilities
- Whether battery storage used to provide distribution-related services can be considered "distribution" and therefore be included in a T&D utility's rate-base for cost recovery
- How the energy consumed by battery storage facilities should be viewed under Texas law.
- Formal adoption of the Future Ancillary Service (FAS) process

6. Roadmap for Regulators

As illustrated throughout this chapter, there is not a single pathway for developing energy storage policy, either at the federal or individual state level. Even with the federal orders issued by FERC, implementation by independent ISOs/RTOs will undoubtedly be region-specific. At the state level, policies will need to be developed that take into consideration the unique market characteristics and existing regulatory framework within a particular state.

Fortunately, roles for policymakers are well defined. With its issuance of Order 841, FERC has clarified that sales of power into ESSs for the purpose of later resale to the grid, including in the form of ancillary services, should be considered wholesale transactions. As such FERC will continue to review the compliance plans submitted by ISOs/RTOs and seek clarifications on key implementation issues, which is likely to continue through 2020 until all of the compliance plans are formally adopted. In this critical position, FERC will continue to play a central role to ensure that energy storage is treated equitably when compared to other generation sources and has a level playing field when participating in wholesale transactions. In order to effectively implement this model, ISOs and RTOs must define and categorize the benefits energy storage systems can provide, and determine which benefit is going to be compensated at what level to ensure full, but not double compensation [19].

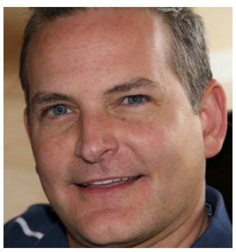
At the state level, sales of power into ESSs that is subsequently used by retail customers for their own power supply purposes constitute retail transactions and therefore fall under the regulation of state utility commissions. Accordingly, states will continue to take the lead role to enable energy storage at the retail/distribution level through new rate designs, cost recovery assurances, subsidies for storage development, and correlation with other renewables- and clean energy-focused initiatives being defined within a state. Policymakers at the state level should carefully consider the intended drivers and outcomes of greater storage deployment, to determine the most effective set of policies and ensure those policies are aligned with other incentives for clean energy in underserved communities [26].

According to the ESA, three fundamental policy considerations that should be vetted by state regulatory commissions, without regard to the current status of market development.

- Policy Consideration #1: Capture the full value of energy storage technologies
    - Ensure accurate market signals that monetize economic value, operational efficiency and social benefits
    - Policy initiatives: Incentives, procurement targets, cost/benefit analyses, and new rate design
- Policy Consideration #2: Enable competition in all grid planning and procurements
    - Storage can be a cost-saving and higher-performing resource at the meter, distribution and transmission levels.
    - Policy initiatives: Inclusion of storage in IRPs, RPS, resilience planning, resource adequacy and distribution planning
- Policy Consideration #3: Ensure fair and equal access for storage to the grid and markets
    - Reduce market and grid barriers that limit the ability for energy storage systems to interconnect
    - Policy initiatives: innovative ownership options, revised interconnection standards, multi-use applications

Other opportunities for energy storage policy development that state regulators may want to consider include the following:

- Revise rate structures to incentivize the deployment of ESSs at optimal locations across the distribution grid. Time-invariant rates do not reward customers for providing flexibility services, but opt-in rates aligned with modern, dynamic grid systems (like time-varying rates) empower energy-aware customers and third-party aggregators to maximize the value of storage, provide grid services, and stay connected.
- Require utility pilot programs that seek to assess the full range of energy storage technology options
- Encourage utilities to share aggregated data about distribution system locations where storage would be most valuable.
- Explore how performance-based regulation (PBR) methodologies can be incorporated into state regulatory proceedings as a means to incentivize energy storage development, removing disincentives that prevent utilities from investing in new storage technologies.



Will McNamara serves as Grid Energy Storage Policy Analyst for Sandia National Laboratories with a focus on energy storage policy development at the federal and state levels. Will has spent his entire 23-year career in the energy and utilities industry with a concentration on regulatory and legislative policy. He has served as a lobbyist in California and has represented major utilities across the U.S. in numerous jurisdictions in proceedings pertaining to integrated resource planning, procurement, cost recovery, rate design, and the development of policymaking best practices. Will's areas of subject matter expertise, in addition to energy storage policy, include distributed energy resources, AMI/smart grid, renewables, and competitive retail markets.

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