The Past as Prologue:
The Value Creation of Batteries on the U.S. Electric Grid as a Function of Time and Location

by

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Abstract

We simulate the revenue generated by transmission-connected, small scale energy storage in the energy and capacity markets using historic prices across 10,000 U.S. locations from 2014 to 2017. On average, including capacity market revenue doubles total revenue, such that five-times more systems breakeven. Furthermore, participating in the capacity market shifts the whereabouts of top-earning systems eastwards, and allows top-earning nodes to remain top-earning for longer. That being said, revenue generation still varies greatly across years for a given location. In order to reflect the contribution of storage to grid reliability during times of stress, we treat capacity market revenue as a function of output during given hours throughout the year; changing the identification of these hours - whether taken as some percent of top demand hours, or as determined by market regulators- can increase revenue up to ten-times that of energy market participation alone. Durations shorter than 8-hours are found to more significantly contribute to reliability than predicted via simplistic analysis of the durations of high risk hours. Considering that participation in the capacity market, as modeled, will always increase total revenue, and that storage units will change dispatch behavior even to earn comparatively small increases in total revenue, designing markets that appropriately incentivize system reliability is a critical task of regulators.

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1 Electricity Storage in the United States: Politics and Profitability

1.1 Introduction

There were 176,800 megawatts (MW) of energy storage worldwide in 2017. Storage accounted for less than 3% of global electricity generation capacity.[1] Of the 24,100 MW located in the United States (U.S.), almost all (94%) is pumped hydroelectric. Batteries account for only 3% of U.S. storage capacity.

That is changing. Although in 2019, storage accounted for less than 2% of new capacity added, there is increasing focus on the role of energy storage in the electric grid.[2] Annual storage installations in the U.S. are expected to double in 2018 to 600 MW, increasing to 1,000 MW in 2019 and to 2,500 MW in 2022.[3] The bulk of these new storage additions are predicted to be lithium-ion technologies. From 2013 to 2017, 94% of new storage installations were batteries, and of the batteries, 95% lithium-ion technologies (Figure 1).[4]

The deployment of grid-connected lithium-ion batteries is growing because of three factors: declining costs; increasing renewable penetration, and rising political interest. While the first two will have some impact on storage adoption in the short term, overwhelmingly current movement is driven by politics, in the form of temporary market incentives that will stimulate deployment for the next decade.

---

[1] "DOE Global Energy Storage Database," accessed January 2, 2018, http://www.energystorageexchange.org/projects/data_visualization; "The World Factbook — Central Intelligence Agency," accessed June 22, 2018, https://www.cia.gov/library/publications/the-world-factbook/geos/xx.html.

[2] "New Electric Generating Capacity in 2019 Will Come from Renewables and Natural Gas," U.S. Energy Information Administration, n.d., https://www.eia.gov/todayinenergy/detail.php?id=37952.

[3] Hering, "Power Surge Expected for U.S. Energy Storage Market in 2018 and Beyond."

[4] Todd Aquino et al., "Battery Energy Storage Technology Assessment" (Platte River Power Authority, November 29, 2017).

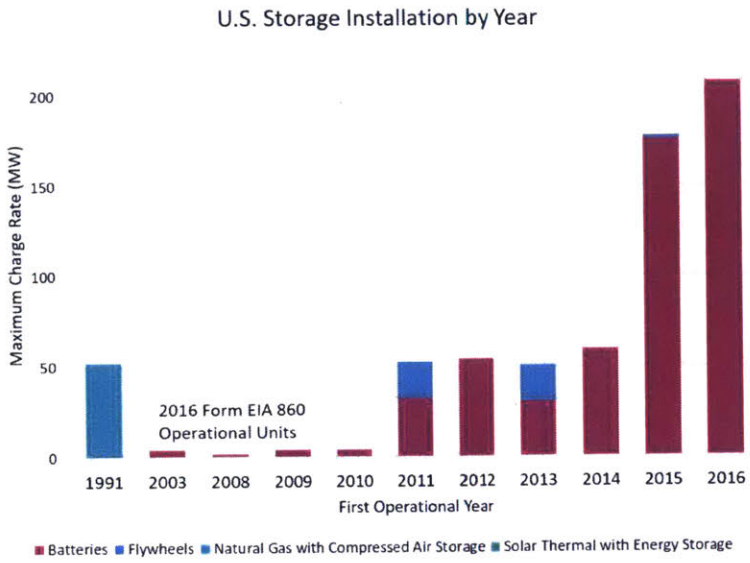

Figure 1: Operating Storage: Technology Type and Installation Year[5]

Lithium-ion battery cell costs have declined 65% from 2010 to 2015.[6] Taken as installed hardware system costs over the rated energy output, the price of lithium-ion batteries, around $275/kWh in 2016, is expected by some optimists to slip under $100/kWh by 2030.[7] The transfer of innovations in the electric car market helped kick-start battery development in the electric generation sector.

Despite rapidly declining costs, economics alone does not explain the increased penetration of lithium-ion batteries. Lithium-ion batteries still remain uncompetitive with other resources from a levelized cost of energy perspective (LCOE) (Figure 2).[8] Large scale lithium ion batteries are still five times the cost of natural gas. Small scale batteries are at least fifteen times costlier.

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[5] "Form EIA-860 Detailed Data," U.S. Energy Information Administration, n.d., 860, https://www.eia.gov/electricity/data/eia860/.

[6] Nicolas Zart, "Batteries Keep On Getting Cheaper," *CleanTechnica*, December 11, 2017, https://cleantechnica.com/2017/12/11/batteries-keep-getting-cheaper/.

[7] Curry, Claire, "Lithium-Ion Battery Costs and Market," accessed January 20, 2018, https://data.bloomberglp.com/bnef/sites/14/2017/07/BNEF-Lithium-ion-battery-costs-and-market.pdf.[at some

[8] The LCOE represents the breakeven price by spreading installation and operation costs over lifetime predicted energy output.

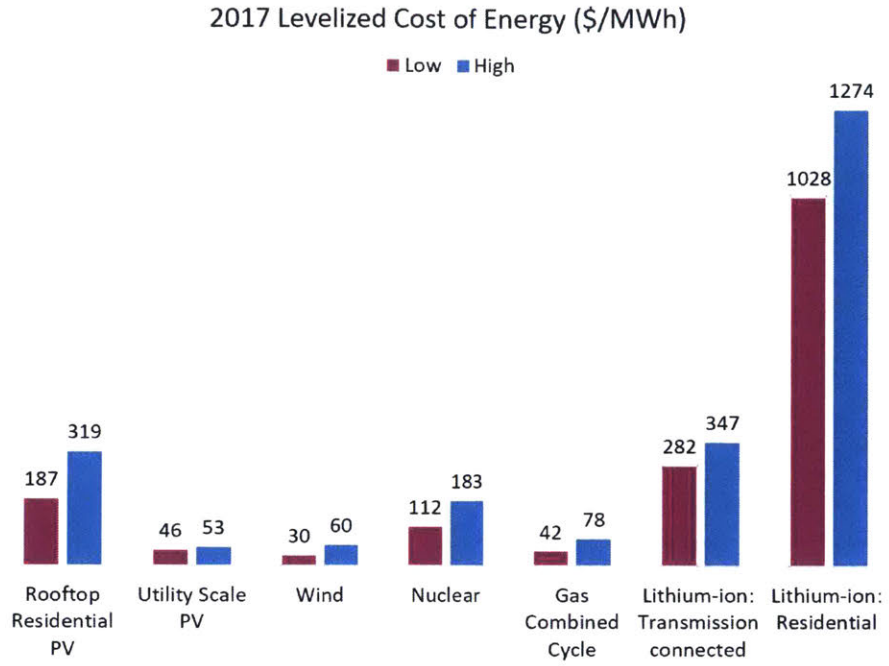

Figure 2: Unsubsidized LCOE[9]

Acknowledging that declining, but still prohibitively high costs, do not fully explain rapid storage deployment, storage's unique flexibility adds complexity to the picture. Batteries in particular can be customizable. Unlike other resources, storage can both inject and withdraw electricity. However, storage's ability to charge and discharge is similar to a large consumer varying usage or transmission importing power. Storage can be sized at various energy and power capabilities. A high energy device could help meet daily and annually high demand with stored renewable generation that may otherwise be wasted, and a high power storage unit could adjust to seconds-to-minutes variations to maintain instantaneous grid stability. But, resources like natural gas plants can also be interconnected at various locations and voltages. Storage, while a useful resource, is not inherently valuable.

Even if grids are powered by 100% renewable resources, the predicted need for storage capacity averages about 1.5% of total system capacity from various literature sources, with the need for storage ranging from 0% to 13.58% of peak, based on the underlying composition in resources.[10] While storage is perhaps valuable because its ability to both charge and discharge, be located at various voltage levels, and help integrate renewable energies, storage is not inherently irreplaceable. Many resources in the electric grid are interchangeable.

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[9] "Lazard's Levelized Cost of Energy Analysis: Version 11," November 2017, https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf; "Lazard's Levelized Cost of Storage Analysis 2.0 Key Findings," n.d., https://www.lazard.com/media/438041/lazard-lcos-20-executive-summary.pdf.

[10] Blanco and Faaij, "A Review at the Role of Storage in Energy Systems with a Focus on Power to Gas and Long-Term Storage."

Considering that costs of storage have declined, but economics remain uncompetitive, and that storage, while versatile, is not wholly irreplaceable, rapidly increasing deployment can help be explained by one other factor- political engagement.

Climate change explains the fascination with storage. Storage is a non-fossil resource. It is generally accepted that in order to remain under a 2°C temperature rise to prevent catastrophic environmental decay, carbon emissions must decline around 25% by 2030 and reach net zero around 2070.[11]

The problem, of course, with a fully renewable-powered grid (arguably necessary to help meet climate goals), is that the most common renewable resources - wind and solar- are also intermittent. Therefore, a powerful argument supporting storage deployment is its potential role in stabilizing a renewably powered grid. A politically smoother method of promoting decarbonization in the U.S. has been the financial support of specific technologies. Battery storage is one such technology.

Identified as a declining cost, flexible non-fossil resource that could help the transition to a carbon-free grid, state regulators are subsidizing and mandating storage deployments to accelerate investment. Five states (California, Oregon, Massachusetts, New York, and New Jersey) have adopted storage goals, with two more considering (Nevada and Arizona). State goals mandate contracts, which ensure that financing will be available to promote storage installation in the short term. The question is whether, in the longer term, the costs and the value of flexibility will support storage deployment. Storage may find its value on the distribution or transmission system, either directly attached or implicitly supporting renewable resources. Battery storage is relatively untested, so the role of energy storage over time, and its corresponding revenue potential, is unclear. This paper will provide input on the value of storage as a function of time and location.

1.2 Paper Structure

The objective of this thesis is to contribute to a body of literature on the potential revenue streams of storage in electricity markets. This thesis is structured as follows.

We begin with an analysis of the current political landscape (Section 1). Some state programs will incentivize storage deployment in the 2020s (Section 1.3.1). In particular, testing out new use cases, like storage substituting for wires, grabs attention (Section 1.3.2). Nonetheless, storage is not new. Most storage deployment, predominately pumped hydroelectric to date, has participated in large scale markets on the transmission grid (Section 1.3.3). Overwhelming, in these large markets storage has focused on stabilizing seconds-variations on the grid (Section 1.4). That aside, as storage looks to play a more significant role in providing longer duration production, of particular interest is participation in a specific large scale market, called the capacity market (Section 1.5). The objective of the capacity market is to support long-term reliability by compensating for the ability to meet peak annual demand. Literature to date is missing an exploration of revenue gathered by participating in both the

[11] "Special Report: Global Warming of 1.5 °C: Summary for Policymakers" (Intergovernmental Panel on Climate Change, IPCC), https://www.ipcc.ch/.

energy and capacity markets, as predicted by historic data, reliability parameters, and market rules.

After a description on methodology and a characterization of data (Section 2), the revenue generating capability in solely the energy market is calculated for over 10,000 individual locations in the U.S. from 2014 through 2017 to provide a baseline for comparison (Section 3.1). Then, we calculate revenue in both the energy and capacity market (Section 3.2). In order to evaluate the contribution of storage to reliability, with particular attention on the potential to support the integration of renewable resources, revenue in the capacity market is determined as a function of net output as as a fraction of total output over hours of top demand (3.2), hours of top demand net of renewable penetration (3.4), and hours of top demand net of increased renewable penetration (3.5). Breakeven costs are calculated in Section 3.6 to summarize the existing business proposition. However, the compensation of storage in capacity markets depends greatly on specific market rules (Section 3.7 and Section 3.8). Section 4 concludes.

Keeping this in mind, let's begin by examining the political trends that have helped stimulate recent interest in storage, in particular, in lithium-ion batteries.

1.3 Storage at Different Scales Across the Grid

One of the advantages of lithium-ion batteries is their ability to be sized and sited across the distribution and transmission system. Generally speaking, the distribution system is the low-voltage network that serves homes and businesses. The transmission system is the high-voltage system. Fossil-fuel power plants and intermittent resources like wind and solar typically feed into the high-voltage system.

To date, policies, not economics, have supported the installation of energy storage resources across the grid. Understanding these policies across the distribution and transmission networks are key, not only to identify the potential for profitability, as indicated by current market rules, but also to pinpoint areas of regulatory weakness that future rules may tackle.

1.3.1 Small Scale Storage

The U.S. electricity regulatory environment is complicated. Broadly speaking, states regulate intrastate electricity flow, and the federal government interstate flow. States, via regulatory bodies called some variation of the Public Utilities Commission or Public Service Commission, monitor utilities that control the electricity flow over low voltage (typically less than 69 kilovolts) system (called the distribution system). These utilities are granted a rate of return, determined by the Commission, on their investment in the infrastructure needed to provide electricity to customers. A federal body, the Federal Energy Regulatory Commission (FERC), monitors the behaviors of actors that work on the high voltage system (transmission system). Depending on the geographic area, these actors may not be guaranteed a profit, as they are competing in markets (more information in Section 1.3.3). The 50 U.S. states are 50 different electricity markets because of this interplay between state and federal jurisdiction.

1.3.1.1 Distributed Storage

Storage could be located on the smallest possible level, off the distribution network "behind the meter," or that is to say, on the utility customer's side of the property. Such storage is a distributed energy resource (DER). The U.S. has over 12 million DERs, representing about one-sixth of installed generation capacity.[12] Over 90% of DERs are combined heat and power (CHP), 86% of which is installed at industrial complexes.[13] Most DER to date is fossil-generated and located at industrial complexes, where synergies between processes using waste heat and steam allow for economies of scale and scope.

Furthermore, CHP has helped industrial consumers shave their peak and therefore minimize demand charges. In addition to a flat rate charged per unit of electricity consumers, industrial and commercial customers usually face a "demand charge" based on their peak consumption. Demand charges can be up to 30% of a commercial bill.[14] Consequently, it is unsurprising that DER installations have been mostly dispatchable (historically fossil-fueled) generation technologies used to reduce charges for larger users.

It is important to note that a 1987 regulation, the Public Utility Regulatory Policies Act (PURPA), incentivized quite a few of these smaller customer-sited fossil-plants. A legacy of the oil shock, PURPA encouraged cogeneration facilities, as well as small renewable plants.[15] PURPA, an embattled legislation today, does not incentivize cogeneration as much as renewable generation. Supporters argue PURPA is still crucial, and critics argue unnecessary.

Of the non-fossil technologies, DER is predominately distributed photovoltaics (PV). In 2016, the estimated distributed PV was about 1.2% of total U.S. generation and 3.0% of total U.S. capacity.[16] From 2010 through 2016, non-residential PV and residential PV was about 25% and 20% of total PV installed, respectively, although the residential percentage has steadily increased.[17]

PV has been incentivized via a rate structure called net energy metering (NEM). NEM is a single-metered program that "winds the meter back" when electricity is exported to the grid.[18] In 2017, 45 states and Washington DC reevaluated NEM policies. NEM is not considered sustainable: first, the cost of the commodity is only about 45% of the retail rate charged, so compensation of intermittent local injections at the full retail rate essentially pays double the injection's avoided cost value; and second, NEM indirectly subsidizes wealthier consumers

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[12] U.S. EPA, "Distributed Generation of Electricity and Its Environmental Impacts."

[13] US EPA; Lisa Swartz et al., "Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline" (Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Electricity%20End%20Uses%2C%20Energy%20Efficiency%2C%20and%20Distributed%20Energy%20Resources.pdf.

[14] Swartz et al., "Electricity End U.S.es, Energy Efficiency, and Distributed Energy Resources Baseline."

[15] "What Is a Qualifying Facility?," Federal Energy Regulatory Commission, n.d., https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp.

[16] Swartz et al., "Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline."

[17] Austin Perea et al., "U.S. Solar Market Insight Executive Summary: Q2 2018" (GTM Research, n.d.), accessed June 14, 2018.

[18] Lowder, Zhou, and Tian, "Evolving Distributed Generation Support Mechanisms: Case Studies from United States, Germany, United Kingdom, and Australia."

(those customers that install the solar generation) by socializing a greater portion of the costs that utilities must recover across fewer, non-generating consumers.[19]

States are looking to move away from NEM to retail rates that reflect time and locational constraints. California is one of the battlegrounds for rate reform. As of 2016, California had 7,000 MW of installed DER, equivalent to about 10% of California peak load.[20] Over 70% of this DER was distributed PV. Distributed PV injections without awareness of grid conditions stresses the distribution network.[21] California decided to transition to time of use rates beginning in 2019 to address the urgent need to balance distribution level grid conditions.[22] New York, which has only 58,000 residential PV systems, in contrast to California's 600,000 systems, has more time to create granular rates that respect both time and location through the Department of Public Service's Reforming the Energy Vision (REV) proceedings (2014).[23] However, as seen through some grandfathered subsidies in REV, new rate reform still remains embroiled in political considerations.

Transitions to time-and-location based rates with demand charges, necessary because increasing PV penetration is straining the distribution grid, may incentivize storage penetration. Distributed storage was 15% of storage capacity added in 2015, comprising about 7% of total storage capacity in the U.S.[24] However, current penetration is still negligible, about 364 MW, which is less than 0.1% of total U.S. generation capacity.[25] California hosts about 90% of distributed storage capacity.[26] In fact, one of the three California utilities hosts over two-thirds of total industrial distributed storage capacity, with the remaining two utilities hosting more than two-thirds of the commercial capacity.[27] Distributed storage installations are not only concentrated in California, but in certain sectors within particular utilities.

More than 60% of California's total battery capacity was installed in response to a gas leak found at the Aliso Canyon storage facility in 2015. Threatened by supply deficits, the California Public Utilities Commission mandated the affected utilities to accelerate procurement of over 100 MW of storage. In less than 6 months, 70 MW of battery storage were purchased and installed. That is one feature of modest scale distributed storage-they are pre-packaged containerized units that are quick and easy to deploy.

Rate design, as approved by state agencies, will significantly affect the profitability of distributed batteries. It is likely that in the long run, demand charges and time of use rates are

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[19] Scott P. Burger, "Electricity Tariffs: Design Principles," (April 10, 2018).

[20] "Distributed Energy Resources Technical Considerations for the Bulk Power System" (Federal Energy Regulatory Commission, February 2018), https://www.ferc.gov/CalendarFiles/20180215112833-der-report.pdf.

[21] "Distributed Energy Resources Technical Considerations for the Bulk Power System."

[22] Peter Maloney, "Residential Storage Faces Sunny Prospects This Year," Utility Dive, April 10, 2018, https://www.utilitydive.com/news/residential-storage-faces-sunny-prospects-this-year/520966/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202018-04-10%20Utility%20Dive%20Storage%20%5Bissue:14826%5D&utm_term=Utility%20Dive:%20Storage.

[23] "51st State Perspectives: Distributed Energy Resources Integration" (Scott Madden Management Consultants; Smart Electric Power Alliance, December 2016), http://www.scottmadden.com/wp-content/uploads/2016/12/SEPA-ScottMadden-51st-State-Report_DER-Integration-CA-NY.pdf.

[24] Swartz et al., "Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline."

[25] Swartz et al., "Electricity End U.S.es, Energy Efficiency, and Distributed Energy Resources Baseline."

[26] Manghani Ravi and McCarthy Rory, "Global Energy Storage: 2017 Year in Review and 2018-2022 Outlook" (GTM Research, April 2018); "U.S. Battery Storage Market Trends" (U.S. Energy Information Administration, May 2018).

[27] "U.S. Battery Storage Market Trends."

going to be particularly important. However, in the short term, political treatment is nudging growth. Aliso Canyon left a legacy: batteries are politically preferred resources that can be quickly deployed.

1.3.1.2 State Policies

In 2013, California became the first state to enact a storage mandate. Similar to a renewable portfolio standard (RPS), which requires that a certain percentage of electricity come from renewable energy by a given year, a storage mandate is a requirement that a certain amount of storage be procured by some year. When a mandate or RPS is declared, the state solicits for contracts or requires the distribution utilities to solicit proposals. These contracts are financed from surcharges on consumer energy bills. In theory, the projects that are awarded contracts will participate in the markets as they would otherwise. Of the 120,000 MW of renewable generation built since 2000, over 50% is attributed to RPSs.[28] As of this writing, twenty nine states plus the district of Columbia have RPSs.[29] State subsidization of preferred resources is not new.

California's storage mandate, along with California's Self Generation Incentive Program (SGIP), an over $375 million rebate program for customer-sited generation, are reasons why California dominates storage capacity. [30] In 2017, there were more SGIP applications than nationally installed storage projects.[31] State incentives and mandates are the key. As of March 2019, four other states joined California with energy storage goals, with New York's perhaps the most ambitious at 3,000 MW installed by 2030 (Table 1). The best business cases for storage are in states with storage mandates because of the essential guarantee of contracts; if contracts are being offered, financing is readily available. Some other states are trying to achieve the same end via tax breaks or strong supportive rate design instead of mandates (Table 2).

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[28] Herman K. Trabish, "Why Mandates Still Matter in the Age of Cheap Renewables," *Utility Dive*, January 3, 2018, https://www.utilitydive.com/news/why-mandates-still-matter-in-the-age-of-cheap-renewables/513797/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202018-01-03%20Utility%20Dive%20Newsletter%20%5Bissue:13443%5D&utm_term=Utility%20Dive.

[29] Jocelyn Durkay, "State Renewable Portfolio Standards and Goals," National Conference of State Legislatures, August 1, 2017, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

[30] "U.S. Battery Storage Market Trends"; "2017 Utility Energy Storage Market Snapshot," (September 2017), https://sepapower.org/resource/2017-utility-energy-storage-market-snapshot/.

[31] "2017 Utility Energy Storage Market Snapshot."

Table 1: Storage Mandates

State (RPS)	Mandate	Other Favorable Policies
California (50% by 2030)	The three utilities must purchase 1,325 MW by 2020 to be operational by 2024. Half may be utility owned. Various amounts are required at utility scale, on the distribution system, and sited with customers (2013, Senate Bill 2514). The amount of distributed storage under the mandate was increased to 500 MW (2016, AB 2868). Utilities may treat this as additional to the mandate. A proposed bill may increase the mandate to 2,000 MW (also by 2020) and apply obligations to other load serving entities (2018, Senate Bill 1347).[32]	In 2020, new residential buildings must have distributed PV.[33] Storage could help distributed PV systems respond to the planned time-of-use rates.
Massachusetts (100% by 2047)	200 MWh will be voluntarily procured by 2020 (2016, House Bill 4568). Senate passed a 2,000 MW by 2025 mandate with limited 20% utility ownership (2018, Senate Bill 2302).[34]	The Department of Public Service (Docket 17-146) set rules on who owns the capacity rights of distributed storage.[35] The Solar Massachusetts Renewable Target (SMART) has distributed storage incentives.[36]

[32] Peter Maloney, "California Looks to next Steps as Utilities near Energy Storage Targets," Utility Dive, June 12, 2018, https://www.utilitydive.com/news/california-looks-to-next-steps-as-utilities-near-energy-storage-targets/525441/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202018-06-13%20Utility%20Dive%20Newsletter%20%5Bissue:15739%5D&utm_term=Utility%20Dive.

[33] Perea et al., "U.S. Solar Market Insight Executive Summary: Q2 2018."

[34] "Bill S.2302," accessed June 19, 2018, https://malegislature.gov/Bills/190/S2302.

[35] Peter Maloney, "Massachusetts Starts Inquiry into Energy Storage Eligibility for Net Metering," *Utility Dive*, October 9, 2017, https://www.utilitydive.com/news/massachusetts-starts-inquiry-into-energy-storage-eligibility-for-net-meteri/506751/; Julian Spector, "Compromise Clears Path for Major Massachusetts Solar and Storage Incentive," July 30, 2018, https://www.greentechmedia.com/articles/read/compromise-clears-path-for-major-massachusetts-solar-storage-incentive.

[36] Wood, "Massachusetts Energy Storage Target Comes with Less Clout but More Money."

Oregon (50% by 2040)	10 MWh in total will be operational by 2020 (2015, House Bill 2193).	Portland General Electric plans to spend $50-$100 million for 39 MW of storage (maximum storage amount allowed).[37]
New Jersey (50% by 2030)	New Jersey is targeting 600 MW by 2021 and 2,000 MW by 2030 (2018, Assembly Bill 3723).[38]	New Jersey may restart its Renewable Electric Storage Incentive Program for non-residential storage paired with renewables for 2019-2022.[39] Of the 2016 program's original $3 million, all grant recipients planned to bid into the regulation market. At least nine projects refunded the grants.[40] No projects have been completed.[41]

[37] Frank Andorka, "Portland General Electric Plans to Invest in 39 MW of Energy Storage," *PV Magazine*, October 31, 2017, https://pv-magazine-usa.com/2017/10/31/portland-general-electric-plans-to-invest-in-39-mw-of-energy-storage/; Peter Maloney, "Portland General to Spend up to $100M for 39 MW of Energy Storage," *Utility Dive*, November 2, 2017, https://www.utilitydive.com/news/portland-general-to-spend-up-to-100m-for-39-mw-of-energy-storage/509845/.

[38] Johnson, "Energy Storage CEO Says Industry Is Finally Getting Noticed"; Maloney, "N.J. Sets 'aggressive' 2 GW Storage Target by 2030."

[39] "U.S. Energy Storage Monitor: Q2 2018 Executive Summary," (June 2018).

[40] Todd Olinsky-Paul, "New Jersey Takes Another Swing at Resilient Solar+Storage," *Renewable Energy World*, January 13, 2016, http://www.renewableenergyworld.com/ugc/articles/2016/01/new-jersey-takes-another-swing-at-resilient-solarstorage.html.

[41] "Renewable Electric Storage," New Jersey's Clean Energy Program, n.d., http://www.njcleanenergy.com/renewable-energy/programs/energy-storage.

New York (50% by 2030)	3,000 MW by 2030.	$60 million from New York State Energy Research and Development Authority (NYSERDA) and $200 million from New York Green Bank (NYGB) is available.[42] NYSERDA recommends reallocating $350 million total to storage.[43] Total storage funding will top $0.5 billion. NYGB is soliciting for comments on how it can best support storage development.[44] NYSERDA, in its 2018 Storage Roadmap, recommends an storage program within NY-Sun. NY-Sun is a 10-year, $960 million rebate program to incentivize 3,000 MW of distributed PV by 2023.[45] NY will purchase 800 MW offshore wind by 2020, for a 2030 goal of 2,400 MW. Storage may be part of the solicitation process.
Pending		

[42] Walton, "New York Clean Energy Proposal Seeks 1.5 GW of Storage, Coal Phase-out."
[43] "New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations (Roadmap)" (New York State Energy Research and Development Authority; Department of Public Service, June 21, 2018), https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage/Achieving-NY-Energy-Goals/The-New-York-State-Energy-Storage-Roadmap.
[44] "RFI 4: Financing Arrangements for Energy Storage Projects in New York State," 4, accessed June 27, 2018, https://portal.greenbank.ny.gov/CORE_Solicitation_Detail_Page?SolicitationId=a0rt000000FnuRZAAZ.
[45] "About NY-Sun," NY-Sun, accessed October 14, 2017, https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/About; "New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations (Roadmap)."

Nevada (25% by 2025)	The Public Utilities Commission has until October 1, 2018.[46]	Nevada wants to include storage incentives under its Solar Energy System Incentives Program. After NEM was eliminated in 2015, NEM was resurrected in 2017 at 95% of retail rate, declining 7% with every 80 MW of distributed PV installed, to floor at 75% (estimated to occur in 2021).[47] Storage is less attractive under NEM.
Arizona (15% by 2025)	A regulator proposed an "Energy Modernization Plan" (2018) that includes a 3,000 MW mandate by 2030.[48] The plan also supports a 80% RPS by 2050 and includes an increasing "Clean Peak Standard."[49]	In 2017, Arizona utilities released plans that included 600 MW of storage.[50]

[46] Spector, "Nevada JU.S.t Became the Most Exciting State for Energy Storage Policy."
[47] Julia Pyper, "Nevada's New Solar Law Is About Much More Than Net Metering," June 16, 2017, https://www.greentechmedia.com/articles/read/nevadas-new-solar-law-is-about-much-more-than-net-metering.
[48] Maloney, "N.J. Sets 'aggressive' 2 GW Storage Target by 2030."
[49] Andy Tobin, "Arizona's Energy Modernization Plan (ACC)," Arizona Corporate Commission, January 30, 2018, http://www.azcc.gov/commissioners/atobin/letters/energyplan.asp.
[50] Ravi and Rory, "Global Energy Storage: 2017 Year in Review and 2018-2022 Outlook."

Table 2: Storage Policies in States Without Mandates

State	Relevant storage Policies
Maryland	Maryland offers a 30% tax credit (capped at $750,000 total expenditures) for storage installed between 2018 and 2022.[51] Similar tax proposals have since failed in Florida, Hawaii, New Mexico and Virginia.[52] The four investor-owned utilities must have two operational storage pilots by 2022.[53]
Hawaii	Hawaii is the the largest residential storage market. The Smart Export tariff rewards storage consumers for exporting during non-sunlight hours.[54] This tariff addresses solar over-generation. Storage could help consumers leverage this tariff. Hawaii has a REV-like proceeding (Docket 2018-088) to reevaluate how to rethink utility compensation. [55]
North Carolina	The legislature commissioned a storage study for December 2018.[56] Prior to its mandate, Massachusetts commissioned a study.
Kentucky	Kentucky Utilities (largest state utility) has some of the highest demand charges in the nation. By 2021, the rate of return on storage investments with small/medium commercial customers could be 25%.[57]
Vermont	The Department of Public Service submitted a report (2017) to the legislature about storage .[58] Again, similar to Massachusetts. Utility Green Mountain Power's "Bring your own device program" credits storage that help system peaks.[59]

[51] Julian Spector, "Maryland Passes First-of-a-Kind Tax Credit for Residential and Commercial Storage," *Greentech Media*, April 12, 2017, https://www.greentechmedia.com/articles/read/maryland-passes-tax-credit-for-residential-and-commercial-energy-storage#gs.vKg_OVo.

[52] "U.S. Energy Storage Monitor: Q2 2018 Executive Summary."

[53] HJ Mai, "Maryland Passes Energy Storage Pilot Program to Determine Future Regulatory Framework," Utility Dive, April 2, 2019, https://www.utilitydive.com/news/maryland-passes-energy-storage-pilot-program-to-determine-future-regulatory/551769/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202019-04-02%20Utility%20Dive%20Newsletter%20%5Bissue:20190%5D&utm_term=Utility%20Dive.

[54] "Smart Export," Hawaiian Electric, Maui Electric, Hawai'i Electric Light, n.d., https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-renewable-programs/smart-export.

[55] "PUC Opens Proceeding to Investigate Performance-Based Regulation for the Hawaiian Electric Companies," April 18, 2018, http://puc.hawaii.gov/main/puc-opens-pbr-investigation.

[56] Brad Ives, "Energy Storage Study Update: Joint Legislative Commission on Energy Policy," (February 6, 2018), https://www.ncleg.net/documentsites/committees/BCCI-6576/2017-2018/Feb%206%202018/07%20-%20UNC%20Collaboratory%20-%20NCGA%20EPC%20Feb%202017.pdf.

[57] "7 U.S. States Where Energy Storage Works."

[58] "Act 53 Report: A Report to the Vermont General Assembly on the Issue of Deploying Storage on the Vermont Electric Transmission and Distribution System" (Vermont Department of Public Service, November 15, 2017), http://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/Energy_Storage_Report/Storage_Report_Final.pdf.

[59] "U.S. Energy Storage Monitor: Q2 2018 Executive Summary."

Texas	Under ERCOT's "Four Coincident Peak Pricing" (4CP), utilities bill commercial/ industrial consumers for their peak demand during the summer months' peak hours. [60] A 1 MW peak costs about $25,000 yearly.[61] Storage could help large customers manage their 4CP charges.

Given the intermittency of most renewable generation, the "value" of storage is very important. Given the relative newness of non-pumped storage technologies, the "value" of storage is also highly debated. There is no consensus as of yet as to the best place (whether on the distribution or transmission grid) or the best use of storage (whether helping industrial customers shave peak demand, stabilizing frequency on the transmission grid, etc.). Storage can offer a variety of services, given in Table 3. States are offering subsidies to get these resources deployed, on the theory that market participants can learn from experience while costs decline.

Table 3: Potential Storage Services

Service	**Description**
Energy	Buy and sell based of price differentials over time
Capacity	Prove long-term (months) assurance to meet yearly peak demand
Regulation	Output on a seconds-basis to maintain grid frequency around 60 Hertz
Reserves	Standby (<30 minutes) potential to balance grid in the case of emergency (generator, line outage, unexpected demand increases)
Voltage Support	Supply reactive power
Black Start	Restart network in event of system-wide blackout
Transmission Services	Act like a transmission line by increasing the ability of a corridor to hold energy
Renewable Firming	Avoid renewable shedding (not compensated by a market, but could result in resource operator receiving higher revenue)

[60] ERCOT Staff and stakeholders in the Demand-Side Working Group, "Load Participation in the ERCOT Nodal Market," n.d., http://www.ercot.com/content/services/programs/load/Load%20Participation%20in%20the%20ERCOT%20Nodal%20Market_3.02.doc.

[61] "ERCOT 4CP - June 2013 Review," Energy Tariff Experts, July 17, 2013, http://energytariffexperts.com/blog/2013/7/17/ercot-4cp-june-2013-review.

Distribution Deferral	Insulate a vulnerable substation
Distribution Replacement	Act as an alternative to distribution wires or substations
Bill Management	Help customer shift load in response to time-varying rates, or shave peak energy consumption to reduce peak demand
Back Up Power	Support uninterrupted service
Increased Self-Renewable Generation	Allow environmentally-conscious PV owners to increase their consumption of renewable power

This trend of short-term subsidies will likely continue. In 2016, about 25% of storage was located on the distribution system .[62] However, by 2021, some 50% of annual storage capacity may be, likely because of state emphasis on DER.[63] The Solar Energy Industries Association polled 115 utilities, and found that 81% of respondents were interested in offering a residential storage pilot and 89% in a commercial/industrial pilot. [64] Furthermore, 85% of polled utilities would like to use storage for ancillary series (electricity products that help reliability).

Opportunities for storage will be helped along in the near term via state subsidies so participants can test functionality across different services with the expectation that storage will be an important contributor to a low-carbon grid. In particular, states are curious about the use of storage as alternatives to traditional distribution infrastructure.

1.3.2 Storage as Wires

States are very interested in determining whether storage (distributed storage in particular) can cost-effectively substitute for investment in distribution infrastructure such as wires or substations.

1.3.2.1 Distribution

The substitution of storage for infrastructure like wires or substations is referred to as "Non-Wire Alternatives (NWAs)" or Non-Wire Solutions. This terminology was popularized by New York in its REV proceedings. As discussed briefly in Section 1.3.1, REV is a regulatory

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[62] "GTM: US Energy Storage Installations Grew 100% in 2016," Energy Storage News, accessed January 5, 2018, https://www.energy-storage.news/news/gtm-us-energy-storage-installations-grew-100-in-2016.

[63] Brett Simon, "The Behind-the-Meter Energy Storage Landscape 2016-2021: Market Trends, Frameworks and Evolution" (GTM Research, December 2016), https://www.greentechmedia.com/research/report/the-behind-the-meter-energy-storage-landscape-2016-2021#gs.0pUNjy8.

[64] "2017 Utility Energy Storage Market Snapshot."

proceeding that attempts to revamp distribution rates to more accurately reflect use at given locations and times.

The value of NWAs is discussed but unproven. The Massachusetts's *State of Charge* report, the precursor to Massachusetts's storage mandate, concluded that deferred investment in transmission or distribution infrastructure accounted of 13% of the $2.3 billion in system benefits from installing 1, 766 MW of storage. [65] Across six studies, the value of storage as NWAs ranged. The Rocky Mountain Institute estimated that in some circumstances, NWA value drastically surpasses all other value streams. [66] However, it is important to note that while storage and wires may have some similar traits, storage's abilities to provide ancillary services and transmission's abilities to relieve congestion are not inherently interchangeable. [67]

Storage on the distribution system is a relatively untested, location-dependent value stream. While market participants are brainstorming over value, sometimes the value assigned takes on the unmistakable appearance of a subsidy. For example, assigning a high value to the benefit of postponing (or eliminating) alternatives (such as transmission), the case for storage obviously improves. Great caution is required to differentiate value, preferably tested, from theoretical conjecture. [68]

Con Edison's Brooklyn Queens Demand Management Program (now called the Neighborhood Program) allegedly deferred a $1.2 billion substation for a $200 million investment (in 69 MW) that includes storage.[69] While some question the cost effectiveness, other New York utilities like Rochester Gas & Electric and New York State Electric & Gas are following suit.[70] They are doing so because they have to. As part of REV, utilities are required to have two distribution-connected storage pilots that offer two different services by year end 2018.[71]

Storage as wires may make more financial sense in heavily constrained areas, like New York City, or in sparsely inhabited or remote areas. In Arizona, a 2 MW/ 8 MWh facility was

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[65] "State of Charge: Massachusetts Energy Storage Initiative."

[66] Fitzgerald et al., "Executive Summary: The Economics of Battery Energy Storage: How Multi-Use, Customer-Sited Batteries Deliver the Most Services and Value to Customers and the Grid."

[67] Venkat Krishnan and Trishna Das, "Optimal Allocation of Energy Storage in a Co-Optimized Electricity Market: Benefits Assessment and Deriving Indicators for Economic Storage Ventures," *Energy* 81 (2015): 175–88.

[68] "State of Charge: Massachusetts Energy Storage Initiative."

[69] Robert Walton, "Straight Outta BQDM: Consolidated Edison Looks to Expand Its Non-Wires Approach," *Utility Dive*, accessed January 10, 2018, https://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/; Robert Walton, "The Non-Wire Alternative: ConEd's Brooklyn-Queens Pilot Rejects Traditional Grid Upgrades," *Utility Dive*, accessed January 10, 2018, https://www.utilitydive.com/news/the-non-wire-alternative-coneds-brooklyn-queens-pilot-rejects-traditional/423525/; Gregory Elcock, "Brooklyn Queens Demand Management Program, Implementation and Outreach Plan" (4 Irving Place New York, NY 10003: Consolidated Edison Company of New York, Inc., January 30, 2017), file:///Users/nettebrocks/Downloads/%7BEA551051-F5C8-4E51-9B83-F77017F0ED0D%7D.pdf.

[70] Ben Pickard, "Burning Questions for the Brooklyn-Queens Demand Management Program," April 27, 2017, https://www.greentechmedia.com/articles/read/burning-questions-for-the-brooklyn-queens-demand-management-program.

[71] Pickard; Walton, "The Non-Wire Alternative."

scheduled to come online in 2018 to replace 20 miles of transmission to a 600-person town.[72] The unit also helps stabilize seconds variations in electricity quality.[73] In Maine, Convergent Energy + Power installed a 0.5 MW/3 MWh system in less than six months (2015) for a fifth of the price of a power line.[74] National Grid will install a 6 MW/ 48 MWh Tesla System on Massachusetts' Nantucket Island to help defer a new undersea cable. [75]

Storage on the distribution system that wants to offer both NWA services and other services could open up new storage business models. For example, utilities could dispatch for distribution relief, but auction off the right to participate in other markets, with auction income refunded to ratepayers.[76] Or, utilities could contract with storage to provide distribution relief during a few select hours, with the remainder of the time open for the storage owner to operate as they wish. Utilities may or may not be allowed to own batteries, which will depend on state policies. The intricacies of utility battery ownership, and the legal hurdles that may stand in the way, are detailed in the following section.

1.3.2.2 Transmission

Storage as distribution reduces congestion on the low voltage network. As transmission, storage reduces congestion on the high voltage network. The former falls under state rules and regulation. The later may fall under regional rules and federal regulation.

The U.S. electricity industry began restructuring in the late 1990's and early 2000's, following the airline and telecommunication industries. In restructured states, which cover about two-thirds of U.S. territory, vertically-integrated utilities sold off generation assets. Scholars thought competition between privately-owned power plants would reduce electricity rates. Success is debated, there is no doubt that the efficiency of natural gas turbines has improved.[77] Regardless, these new market structures currently stand.

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[72] Peter Maloney, "Storage for T&D Deferral Works, Arizona Public Service Finds in Tonto National Forest," *Utility Dive*, November 21, 2017, https://www.utilitydive.com/news/storage-for-td-deferral-works-arizona-public-service-finds-in-tonto-natio/511485/.

[73] The unit supplies frequency regulation.

[74] "Convergent Energy + Power Commissions Innovative Energy Storage System in Maine – Convergent Energy + Power," accessed July 9, 2018, https://www.convergentep.com/52/; Walton, "Maine Turns to Battery Storage to Avoid Transmission Investment," *Utility Dive*, June 9, 2015, https://www.utilitydive.com/news/maine-turns-to-battery-storage-to-avoid-transmission-investment/400440/.

[75] Peter Maloney, "National Grid Plans to Install a 48 MWh Battery Storage System on Nantucket," *Utility Dive*, November 9, 2017, https://www.utilitydive.com/news/national-grid-plans-to-install-a-48-mwh-battery-storage-system-on-nantucket/510444/.

[76] Judy Chang et al., "The Value of Distributed Electricity Storage in Texas" (The Brattle Group, November 2014), http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf.

[77] Severin Borenstein and James Bushnell, "The US Electricity Industry after 20 Years of Restructuring," *Annu. Rev. Econ.* 7, no. 1 (2015): 437–63.

Independent system operators (ISOs) were created to support restructuring (also called, misleadingly, deregulation). ISOs control the high voltage transmission network and offer bulk electricity markets so generators can fairly interconnect and compete to provide power. Among other features, ISOs are nonprofits financial clearing houses that do not own physical assets. ISOs operate markets under security constrained, bid-based economic dispatch.[78] That is to say, resources bid in to sell and buy power, and the cheapest electricity is accepted, assuming safety and reliability.

Restructuring was paused after issues arose in California, so some states still function under the vertically-integrated utility model. The vertically integrated utility model can more conveniently plan integrated long term generation and transmission. Under an ISO model, market participants decide where it is profitable to develop.

Reliability itself is not always incentivized via competitive markets. Profit-motivated actors will stop building generation once revenues lower to breakeven with costs – there is no incentive in a market to build a little extra. Some components of reliability are therefore provided through contracts or other, extra market tools. These add-ons incentivize behavior that is optimal for the system, but not for individual actors. Three examples of contract based processes include reliability must run contracts (RMR), transmission, and capacity.

An RMR is a contract between the ISO and existing plant that allows the ISO to call upon the plant to generate energy. RMRs are negotiated to address short-term supply constraints. [79] Short-term supply constraints can happen when an existing plant wants to exit the market because it is unprofitable, but that plant exit would destabilize the grid. Alternatives to RMRs with existing non-profitable fossil plants include utilizing existing demand side management, or soliciting for contracts with quickly deployable new resources, as was done in 2016 when storage was deployed after the gas leak at California's Aliso Canyon.[80] Storage, because of its demonstrated ability to deploy quickly, could replace RMRs for existing plants should the installation and operation of the unit be cheaper than the cost of keeping the existing plant online. In the long run, ISOs look to transmission to replace RMRs, or another plant decides to enter through the market because it believes it can be profitable.[81]

Transmission is notoriously difficult to site and to price. Building transmission is also a fairly political process as it requires community buy-in. Transmission construction also goes

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[78] William W. Hogan, "Competitive Electricity Market Design: A Wholesale Primer," *December, John F. Kennedy School of Government, Harvard University*, 1998.

[79] "California Independent System Operator Corporation Fifth Replacement Electronic Tariff" (California Independent System Operator, July 1, 2013), https://www.caiso.com/Documents/Section41_ProcurementOfRMRGeneration_Jul1_2013.pdf.

[80] David Allen, "NYISO's Reliability Must Run Compliance Filing: NYISO Proposal" (June 24, 2015), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2015-06-24/RMR-ICAPWG%20ESPWG-v7%20June%2024_Final%206_18_15.pdf; Julia Pyper, "Tesla, Greensmith, AES Deploy Aliso Canyon Battery Storage in Record Time," *Greentech Media*, January 31, 2017, https://www.greentechmedia.com/articles/read/aliso-canyon-emergency-batteries-officially-up-and-running-from-tesla-green#gs.zc69N_s.

[81] "Reliability-Must-Run Procedures: Determining and Addressing the Need for Generation Units to Support Grid Reliability" (ERCOT, May 2016), http://www.ercot.com/content/wcm/lists/89476/OnePager_RMR_May2016_FINAL.pdf.

through ISO contract processes. The objective of transmission is to transport large amounts of cheaper power, likely generated at remote or low-demand areas, to high demand areas, where power is more expensive. Transmission is usually built in response to reliability or price concerns, or both. A transmission project could lower system prices and improve consumer surplus and total welfare. Because the market may not incentive investment that could help the system, ISOs are responsible for evaluating whether there is a need, selecting appropriate projects, and collecting payments to finance construction. Similar to transmission, bulk storage can transport enough power to eliminate profitable arbitrage opportunities. Storage's ability to store electricity to reduce congestion by waiting for a time of more open wire capacity is like wires' ability to reduce congestion.

Regulatory treatment of storage is uncertain.[82] This is because utilities, in deregulated states, are not allowed to own generation. A Texas utility looked to install a $0.9 million, 1 MW/2 MWh and a $0.7 million, 0.5 MW/1 MWh set of lithium-ion batteries at two rural communities instead of $11.3 million to $22.5 million in transmission upgrades. [83] The two batteries would have discharged less than a dozen times annually. The Texas Public Utilities Commission dismissed the request over concerns with utility generation ownership (not allowed in Texas under its restructuring) and over how the utility planned to charge the unit (would not pay for charging). The Commission opened a docket to explore how storage should operate and be compensated when providing transmission services (#48023, 2018). On the other hand, CAISO recently approved two projects as transmission assets that will be paid solely through a regulated rate, and is looking into how storage can receive both regulated (like transmission services) and market based payments. [84]

Generally speaking, in restructured markets distribution utilities are not allowed to own generation because of market power concerns. But, in the zeal to expedite storage, some jurisdictions are bending their rules against utility ownership. So while utility ownership of storage is not allowed in Europe, the U.S. is a more mixed picture. California utilities under the mandate can own half, and New York utilities can only own storage in the case where there is limited incentive for profit-oriented companies (like projects for low-income groups). Storage as transmission may be easier to develop within vertically-integrated utilities because vertically-integrated utilities do not have to skirt around ownership issues.

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[82] "Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery" (Federal Energy Regulatory Commission, January 19, 2017).

[83] Peter Maloney, "Proposed Texas Rule Highlights Storage's Challenges in Bridging Competitive, Regulated Energy Markets," *Utility Dive*, March 27, 2018, https://www.utilitydive.com/news/proposed-texas-rule-highlights-storage-challenges-in-bridging-competitive/520027/.

[84] "Storage as a Transmission Asset: Enabling Transmission Connected Storage Assets Providing Regulated Cost-of-Service-Based Transmission Service to Also Access Other Market Revenue Streams" (California Independent System Operator, March 30, 2018).

Large scale storage is more suitable to deployment on the bulk power transmission system. That moves the decision from the local distribution utilities to a broader based forum. For the deregulated states, this broader based forum is the ISOs.

1.3.3 Large Scale Storage

The U.S. has seven ISOs. The seven ISOs structure their markets differently, although there are some common denominators. Essentially, each ISO divides electricity into energy, capacity, and ancillary services (Table 4).

Table 4: ISO Services

Service	Timeline	Competitive or Regulated Rate	Description
Capacity	Months to years in advance	Competitive	Provide long-term assurance to meet yearly peak demand plus some cushion
Energy	Day Ahead and Real Time	Competitive	Produce power over time
Reserves	Day Ahead and Real Time	Competitive	Standby power in case of emergencies
Regulation	Day Ahead and Real Time	Competitive	Maintain grid frequency
Black start	Months to years in advance	Cost based regulated rate	Restart grid after blackout
Voltage Support	Months to years in advance	Cost based regulated rate	Maintain reactive power

Ancillary services are absolutely crucial to the electricity grid as a matter of physics, but their financial role is decidedly minor (Figure 3). Ancillary services such as black start, voltage support, and capacity are arranged months to years in in advance. The first two are compensated at a regulated cost based rate. For four of the ISOs, capacity is compensated based on a market-based rate. The other ISOs contract. Energy, reserves, and regulation are bid-based products typically traded on markets that occur both a day in advance and in real

time. It is important to note that buyers and sellers can contract with each other outside of these markets to hedge risk. Frankly, to leave a substantial component of unprotected would be unwise.

1.3.3.1 Longer Term Markets

Payments for capacity, the potential to produce energy (in MW), are made months to years in advance via bilateral contracts or through a competitive marketplace. Capacity is required, and paid a modified market based rate, to meet peak demand, plus some cushion. Four of the Eastern ISOs – ISO-NE, NYISO, PJM, and MISO- host centralized, bid-based capacity markets. Capacity markets are detailed in Section 1.5.1.

Black start, the ability to restart the grid after a system-wide outage, and voltage support, the ability to produce reactive power, are typically contracted over longer time intervals (months) at some ISO-determined cost based regulated rate.

1.3.3.2 Day Ahead and Real Time Markets

The Day Ahead Market (DAM) is an optional financial market (unless a resource has a capacity obligation, in which case, participation is mandatory) hosted the day prior to the operating day. The DAM allows market participants to hedge real time volatility. The Real Time Market (RTM) pays for excess services and penalizes for missed obligations. Different ISOs trade different services in the DAM versus the RTM (Table 5).

Table 5: Services and Timeline by ISO

ISO	Regulation	Reserves	Capacity	Other
Independent System Operator New England (ISO-NE)	Three, 4-second regulation signals available for a RTM product that merges capacity and service bids into single clearing price.	Winter/summer forward market for 30 minute and 10-minute nonspinning reserves. RTM market for 10-minute spinning.	Auctions conducted three years prior to delivery, with monthly reconfiguration markets. Penalties assessed for noncompliance during shortage events.	
New York Independent System Operator (NYISO)	Single, 6-second regulation signal for DAM and RTM product that merges capacity and movement bids into a single clearing price.	DAM product for 10-minute spinning, 10 minute nonspinning, and 30 minute (spinning or nonspinning).	Winter/summer "capability" periods, plus strip auctions for rest of months within a capability period. Spot auction for next month. Nonperformance results in de-rating in future auctions.	
Pennsylvania-Jersey-Maryland Interconnection (PJM)	Two, 2-second regulation signals (4 second reply) in RTM that merges capability and performance bids into single clearing price.	30-minute product in DAM, and 10-minute primary reserves (both synchronous, which are bid based, and nonsynchronous, which are cost based) in RTM.	Auction three years in advance with reconfigurations at 20 months, 10 months, and 3 months ahead. Penalties assessed for unavailability.	

Midcontinent Independent System Operator (MISO)	Single, 4-second signal in DAM and RTM that merges capability and mileage bids into separate clearing prices for up and down.	10-minute spinning and nonspinning (called supplemental) in DAM and RTM.	Optional year-of auction. Utilities can bilaterally contract.	Flexible ramping product for up and down in 5-minute RTM with compensation based on opportunity costs. If utilities own generation, utilities turn dispatch over to MISO.
Electric Reliability Council of Texas (ERCOT)	Single, 4-second regulation signal for DAM product with separate clearing prices for up and down.	DAM product for 10-minute spinning (responsive) and non-spinning.	Does not have. This is the only ISO in the U.S. without an explicit supply requirement.	Only ISO without regulation capacity and movement bids because it is the only ISO not under FERC jurisdiction. Only ISO with physically binding ancillary service awards penalized for noncompliance.
California Independent System Operator (CAISO)	Single, 4-second signal for DAM and RTM that merges regulation and mileage bids into separate clearing prices for up and down.	10 minute spinning and non-spinning DAM and RTM product in 8 zones	Utilities bilaterally contract.	Has a financially binding 15-minute RTM. Flexible ramping product for up and down in 5-minute and 15-minute RTM with compensation based on opportunity cost. If utilities own generation, dispatch is turned over to the ISO.

Energy, regulation, and reserves are "bid based" or "competitive" markets: generators offer into the ISO their marginal cost of providing the service (along with some technical constraints). When pricing energy, regulation, and reserves, ISOs include opportunity costs so that generators are indifferent to the service they provide. This process is referred to as co-optimization, and prevents resources from arbitraging different markets.

Energy (designated as MWh) trades in the DAM and RTM. In 2016, the percentage of energy procured in the DAM ranged from 95% (NYISO) to 53% (ERCOT).[85] In ERCOT, the only U.S. market without a mandated supply requirement, resources may rely more heavily on RTM price spikes. The energy price, commonly referred to as the locational marginal price, generally has three components:

1. Energy: the system wide cost of meeting the next unit of demand, defined at a reference bus.
2. Congestion: the difference between the reference bus and the more expensive local resource required because of overloaded wires.
3. Losses: the amount of extra energy needed because of thermal inefficiencies.[86]

Ancillary services refer to services other than energy and capacity: black start, voltage support, regulation, and reserves. Only the latter two are bid-based markets. When providing regulation service, resources ramp up or down on a seconds-basis to help stabilize grid frequency around 60 Hertz. In all ISOs except ERCOT, resources are compensated for both regulation capacity and regulation movement. FERC Order 755 (2011) required ISOs to compensate for both the ability to provide regulation, as well as the energy exerted to provide regulation.[87] Regulation capacity (also called capability) is the potential to provide regulation. Regulation movement (also called mileage) rewards for regulation output.

Another product, reserves, are capacity available to respond to a resource or wire tripping in real time. Generally, there are three categories, and portions of which might be required in vulnerable locations:

1. Online (synchronized or spinning) or offline (nonsynchronous or non-spinning) resources that can output in 30 minutes or less.
2. Offline reserves that can output in 10 minutes or less.

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[85] David Patton, Pallas LeeVanSchaick, and Chen, "2016 State of the Market Report for the New York ISO Markets," May 2017, http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2017_Load_and_Capacity_Data_Report.pdf; "2016 State of the Market Report for the ERCOT Electricity Markets," May 2017, https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf.

[86] ERCOT does not include losses as part of the energy price.

[87] Order 755: Frequency Regulation Compensation in the Organized Wholesale Power Markets, No. RM11-7- 000/ AD10-11–000 (Federal Energy Regulatory Commission October 20, 2011).

3. Online reserves that can output in 10 minutes or less.

Energy, far and away, is the largest market, in both amounts procured and revenue (Figure 3). Ancillary service markets are small in comparison to energy and capacity. Regulation is the smallest but most expensively priced ancillary service market. To date, storage has predominately functioned in the regulation market. In particular, one regulation market – PJM- as discussed in the following section.

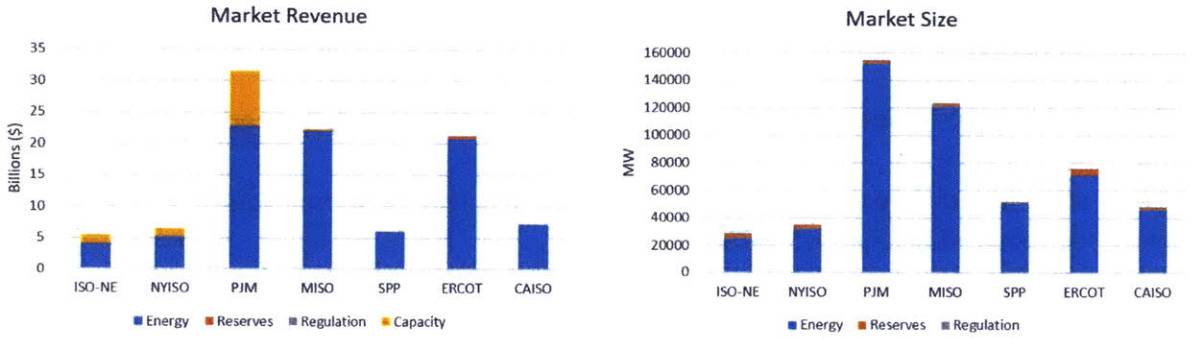

Figure 3: ISO Service by Revenue and Size[88]

1.3.3.3 Frequency Regulation in PJM

In 2012, PJM created a new regulation signal, called RegD, for fast-responding resources like batteries. PJM created this signal in response to new federal rules (the aforementioned FERC Order 755) that mandated that regulation resources get paid for both regulation capacity and movement.[89] As of 2017, nearly 40% of 1 MW or larger battery capacity operated in PJM's regulation market. [90]

Resources following PJM's RegD signal were made "energy neutral" over 15 minutes by evening out injections and withdrawals.[91] Slower-responding resources without duration constraints continued to follow the old RegA signal. PJM converted RegD bids and quantities to produce a single regulation clearing price and quantity. Battery project developers flocked to take advantage of the new signal. By 2016, regulation offered was two-to-three times regulation needed.[92]

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[88] Estimated from various "State of the Market" reports.
[89] Order 755: Frequency Regulation Compensation in the Organized Wholesale Power Markets.
[90] "U.S. Battery Storage Market Trends."
[91] Peter Maloney, "Is the Bloom off the RegD Rose for Battery Storage in PJM?," Utility Dive, September 5, 2017, https://www.utilitydive.com/news/is-the-bloom-off-the-regd-rose-for-battery-storage-in-pjm/503793/.
[92] "2016 State of the Market Report for PJM: Volume 1 Introduction," n.d., http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume1.pdf.

Two problems emerged with RegD. Resources returning to midpoint state of charge sometimes worked against the required system direction and difficulties with the conversion factor meant that RegD resources were underpaid or overpaid.[93] In 2015, the amount of RegD resources was capped at 26.2% of regulation procurement to handle operational concerns.[94] In 2017, the cap was removed, but the conversion factor was changed. Additionally, RegD resources were made neutral over 30 minutes, if excess RegA were available. The rule changes have drastically reduced profitability. Batteries in the PJM regulation market offer a cautionary tale: unsustainable market design will be corrected, and small-sized regulation markets can quickly saturate.

One reason batteries in ISO markets targeted a single service, like regulation in PJM, is because batteries were unable to bid for other services. With historically expensive battery prices, there was not a strong market-based demand for ISOs to address modeling complexities associated with time-constrained charging and discharging. This is changing.

1.3.3.4 Landmark Federal Regulation

In 2015, FERC began to investigate how storage participates in the wholesale markets. FERC's attention to storage came because of cost declines and political interest in storage as alternatives to fossil fuels. Historically storage (with the exception of pumped storage) was not in the markets because the technology wasn't advanced enough to economically compete. So, there was no push for ISOs to develop market structures for storage, in particular medium duration batteries, to engage in the markets. FERC's final decision (FERC Order 841, 2018) informs ISOs that they must allow transmission-connected storage resources as small as 0.1 MW to bid for all services by December 2019.[95]

Each ISO has its own method of modeling storage (Table 6). This adds yet another level of complexity to already complex markets. Since pumped storage resources were operational before ISOs were created, all ISOs created some pumped storage representation at inception (with the exception of ERCOT, which does not have pumped storage). ISOs, again with the exception of ERCOT, have some newer (late 2000's) frequency regulation only storage model that ensures storage energy constraints are not violated. ISOs usually have two demand response programs that distributed storage could use: an energy only price-taker called during peak times and a price-maker eligible to offer daily energy, ancillary services, and capacity.

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[93] "2016 State of the Market Report for PJM: Volume 1 Introduction."

[94] "2017 Utility Energy Storage Market Snapshot." Order 755: Frequency Regulation Compensation in the Organized Wholesale Power Markets.

[95] Order 841: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, No. RM16-23-000/AD16-20-000 (Federal Energy Regulatory Commission February 15, 2018).

Table 6: Storage Business Models

ISO	Description
ISO-NE	When supplying electricity, storage is modeled as settlement only generators (RTM, non-dispatchable, energy price-takers less than 5 MW) or as generators (1 MW or larger price makers eligible to provide energy, reserves, and regulation). To provide energy, storage is modeled as dispatchable asset related demand, a price maker model eligible for regulation and reserves. In order to become regulation only price makers, storage can add on the Alternative Technology Regulatory Resource setting. Storage can participate in the capacity market, but there are penalties for underperformance during constrained times.
NYISO	Storage can participate as limited energy storage resources, which are regulation only providers with less than an hour of maximum output. Storage can also participate as energy limited resources. In addition to energy and ancillary services, energy limited resources are eligible for capacity payments because they can withstand maximum output for minimum 4 consecutive hours. NYISO's energy storage resource model allows storage to bid for all available services.
PJM	Electric storage devices can follow the RegD signal to supply regulation. Storage can offer as capacity storage resources, either alone or paired with other storage/ energy efficiency resources. With a minimum duration of 10 hours for capacity payments, penalties are also imposed for unavailability during emergency conditions.[96]
MISO	Stored energy resources are regulation only providers whose state of charge is managed on a 5-minute basis. Stored energy resources- Type II- can provide energy, capacity, reserves, and regulation.[97]
CAISO	Non-generator resources can provide energy, regulation, spinning reserves, and nonspinning reserves. Non-generator Resources-Regulation Energy Management is a regulation only provider that resets state of charge every 15 minutes. If storage have 4-hours of duration, storage may bilaterally contract for capacity with a utility.
ERCOT	Wholesale Storage Load can provide energy and ancillary services.

Order 841 is predicted to incentivize 7,000 MW of storage – a ten-fold increase on what is installed on the grid now.[98] However, when paired with state incentives, total deployment could reach 50,000 MW. Order 841 is important because it sets a standard for ISO engagement,

[96] Todd Olinsky-Paul et al., "Energy Storage Market Updates," (September 30, 2015), http://www.cesa.org/assets/Uploads/Webinar-Slides-9.30.15.pdf.
[97] *Indianapolis Power & Light Company vs. Midcontinent Independent System Operator, Inc.*, 162 F.E.R.C. ¶ 61,266 (2018).
[98] Roger Lueken et al., "Getting to 50 GW? The Role of FERC Order 841, RTOs, States, and Utilities in Unlocking Storage's Potential" (The Brattle Group, February 22, 2018).

but a substantial fraction of storage revenue may come from state markets, as previously discussed in Section 1.3.1. In fact, FERC originally included DER in the draft version of Order 841, likely because some storage will be distributed, and because distributed storage and DER may be coded similarly into ISO software (planned in CAISO and NYISO). In the final order, FERC moved DER to a new docket (RM18-9-000). Treatment of DER in ISO markets must decide how different market participants (owners, operators, financers, aggregators, utilities, etc.) will interface at various time intervals with the ISO. DER poses tricky questions about ownership and authority. Who should be allowed to own DER? What DER services can be offered into what markets, and how can compensation be fair? Who has legal authority to regulate DER? MISO (the ISO with the greatest number of states), for example, is arguing that states instead of FERC should decide if DER can participate in ISO markets. DER treatment in ISO markets will be an extended legal and political debate.

1.4 Potential Profitability

To date, storage value has been heavily dependent on the specific rules of each ISO. High power batteries with small durations dominate the PJM frequency market because of the RegD signal. However, low power batteries with longer durations are mostly installed in CAISO because of preferred deployment of energy storage since the 2016 Aliso Canyon gas leak. [99]

1.4.1 Frequency Regulation

A 2010 National Renewable Energy Laboratory literature review found that storage revenue from energy, regulation, and reserves range from $37/kW (1997 through 2001 in California) to $429/kW, with regulation the most profitable (derived from 2003 through 2006 price analysis across PJM, NYISO, ERCOT, and ISO-NE).[100] A simulation of a storage price taker over one day in the NYISO DAM and RTM energy and regulation markets found that 97% of revenue was in regulation.[101] Accordingly, the Energy Information Administration reports that it follows that 88% of U.S. batteries supplied regulation as of 2016.[102]

Over 12,000 MW of storage are waiting in ISO interconnection queues.[103]Most ISOs have enough storage in the queue to fully meet regulation requirements. Prices are depressed in

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[99] "U.S. Battery Storage Market Trends."

[100] James M. Eyer, Garth P. Corey, and Joseph J. Iannucci Jr, "Energy Storage Benefits and Market Analysis Handbook: A Study for the DOE Energy Storage Systems Program." (Sandia National Laboratories, 2004); Paul Denholm and S. Letendre, "Grid Services from Plug-in Hybrid Electric Vehicles: A Key to Economic Viability," in *EEAST (Electrical Energy Storage—Applications and Technology) Conference, San Francisco, CA, USA*, 2007, 1–6; Paul Denholm et al., "The Role of Energy Storage with Renewable Electricity Generation," 2010.

[101] Asmae Berrada, Khalid Loudiyi, and Izeddine Zorkani, "Valuation of Energy Storage in Energy and Regulation Markets," *Energy* 115 (2016): 1109–18.

[102] "U.S. Battery Storage Market Trends."

[103] Data downloaded June 20, 2018.

oversupplied markets, as demonstrated in PJM's regulation market. Storage will not be able to depend on revenue from regulation service alone. The service is too small and too competitive.

1.4.2 Energy

Energy arbitrage refers to when energy is sold for a higher price than when it was purchased. Energy arbitrage is generally regarded in the literature as a less profitable use of storage compared to frequency regulation, and at current costs, rarely a justifiable investment.[104] For example, a previous analysis calculated that of all nodes across PJM in 2014, assuming operation of a 1 MW, perfect foresight price taker battery, less than 1% of nodes would have been profitable. [105] 2014 was a dramatic year, as prices spiked when temperatures plunged due to the "Polar Vortex." [106]

Energy arbitrage revenue is not only unprofitable at most locations, but also unpredictable. There are significant daily, weekly, and yearly variations in revenue. Connolly et al. found that from 2005 to 2009, energy arbitrage profit varied 50% from year-to-year across thirteen global ISOs.[107] Currently, other studies show that energy arbitrage is rarely profitable and rarely consistent.[108]

While energy arbitrage is not particularly attractive now, it may be in the future. Within ten years, consultancy GTM Research predicts that 4-hour batteries will cost less than new natural gas peakers on a LCOE basis.[109] Peakers supply electricity during times of "peak" demand when prices spike because supply is constrained. About 10% of U.S. generation capacity is peakers, which are used less than 10% of the year to produce 1% of annual generation.[110] About 13,000 MW of gas peakers will retire in 20 years in California alone; this is more than double the entire U.S. regulation market (5,000 MW).[111]

In some states, the substitution of storage for natural gas peakers will be accelerated because certain states pose an inhospitable environment for natural gas. New York is rejecting pipeline expansions, which in turn constrains supply to New England. CAISO offered three

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[104] Denholm et al., "The Role of Energy Storage with Renewable Electricity Generation."
[105] M. B. C. Salles, Michael J. Aziz, and William W. Hogan, "Potential Arbitrage Revenue of Energy Storage Systems in PJM during 2014," in *Power and Energy Society General Meeting (PESGM), 2016* (IEEE, 2016), 1–5.
[106] Salles, Aziz, and Hogan.
[107] David Connolly et al., "Practical Operation Strategies for Pumped Hydroelectric Energy Storage (PHES) Utilising Electricity Price Arbitrage," *Energy Policy* 39, no. 7 (2011): 4189–96.
[108] Robert L. Fares and Michael E. Webber, "A Flexible Model for Economic Operational Management of Grid Battery Energy Storage," *Energy* 78 (December 15, 2014): 768–76, https://doi.org/10.1016/j.energy.2014.10.072; Easan Drury, Paul Denholm, and Ramteen Sioshansi, "The Value of Compressed Air Energy Storage in Energy and Reserve Markets," *PRES 2010* 36, no. 8 (August 1, 2011): 4959–73, https://doi.org/10.1016/j.energy.2011.05.041.
[109] Ravi Manghani, "Will Energy Storage Replace Peaker Plants? Energy Storage for Peaker Plant Replacement: Economics and Opportunity in the U.S." (GTM Research, March 2018).
[110] "State of Charge: Massachusetts Energy Storage Initiative."
[111] Paul Denholm and Robert Margolis, "The Potential for Energy Storage to Provide Peaking Capacity in California Under Increased Penetration of Solar Photovoltaics" (National Renewable Energy Lab.(NREL), Golden, CO (United States), 2018).

Calpine-owned natural gas plants RMRs to delay retirement because of reliability risks to the region, but the California Public Utilities Commission intervened and told the local utility to procure storage instead. Storage may be a viable altnerative for natural gas peakers witin the next decade because of declining costs, but this replacement point may come sooner in states more heavily opposed to fossil fuel use.

1.4.3 "Value Stacking"

Storage units are expected to be most profitable when allowed to offer many services. Depending on ISO and year, studies have found that adding on regulation in addition to energy arbitrage can result in profits two-to-four times greater than those from energy arbitrage alone.[112] Locatelli et al. modeled that supplying reserves as well as energy may add 10% to 50% more revenue than energy arbitrage alone.[113] Overall, Krishnan and Das reports that storage could earn ten times more revenue offering energy, co-reserves, and regulation compared to just energy.[114] However, even with multiple revenue streams, under current costs, most installations are not profitable.

The idea of storage offering multiple services is referred to as "value stacking." This terminology comes up fairly frequently in releases from political bodies and from news sources. However, other resources also offer multiple services into markets. Value stacking is what resources on the power sector do.

Where value stacking is slightly different is for distributed storage, because distributed storage is able to inject and withdraw electricity within both retail and wholesale markets. This is new, and how distributed storage fits into the larger picture is still in question.

Being sited on the distribution system, and participating in the transmission system markets, is tricky for two different reasons: rules and safety. Note this is only of issue within ISO markets, as vertically integrated utilities can leverage their knowledge of the entire operating system and financial balance sheet. Within de-regulated states, participating in both markets is sometimes referred to as "dual participation." With dual participation, there is concern that resources could get compensated for the same service by both the local distribution utilities, as well as within the ISO market. This creates opportunities for arbitrage and market manipulation. Constructing rules to avoid this, and deciding who pays for what, is legally quite complex. Furthermore, as of right now, resources located on the distribution system may not

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[112] Raymond H. Byrne and César A. Silva-Monroy, "Potential Revenue from Electrical Energy Storage in ERCOT: The Impact of Location and Recent Trends," in *Power & Energy Society General Meeting, 2015 IEEE* (IEEE, 2015), 1–5; Raymond H. Byrne and Cesar Augusto Silva-Monroy, "Estimating the Maximum Potential Revenue for Grid Connected Electricity Storage: Arbitrage and Regulation," *Sandia National Laboratories*, 2012.

[113] Giorgio Locatelli, Emanuele Palerma, and Mauro Mancini, "Assessing the Economics of Large Energy Storage Plants with an Optimisation Methodology," *Energy* 83 (April 1, 2015): 15–28, https://doi.org/10.1016/j.energy.2015.01.050.

[114] Krishnan and Das, "Optimal Allocation of Energy Storage in a Co-Optimized Electricity Market: Benefits Assessment and Deriving Indicators for Economic Storage Ventures."

have the metering that transmission-resources have. Awareness of real-time conditions is imperative for maintaining a safe and reliable electric grid. Even when visibility into real-time conditions, which will undoubtedly improve with technological advancements, becomes technically possible, there are legal concerns over who gets access to that data, and practical concerns over who manages the data and how much is necessary to share for reliable operation. Value stacking, in the context of dual participation, is not only a legal and technical constraint for storage, but also for other distributed resources.

Quantifying realistic revenue for energy storage on the distribution level that "value stacks" is nearly impossible. One reason that it is impossible (because these rules do not yet exist) is that utilities and ISOs are unsure as to how much these resources are worth to them. "Testing value stacking opportunities" often comes as a justification for state subsidies. This phrasing invokes a fairly positive public reception. Hopefully, the market will reach a fair outcome, but the intermediate stages of figuring out how to compensate storage, and how different markets "stack" without being inefficient (a learning processes perhaps muddied by state drive to incentivize local, carbon free resources) – will likely result in some inherent short-term inefficiencies.

To summarize, the revenue streams embedded in this idea of "value stacking" are currently quite flexible, and may not persist into the future. Some of these revenue streams may be equivalent, and not additive, so when working with documents employ value stacking metrics, it's important to note what is and is not currently monetized. Uncertainties in market rules – which are uncertainties because these questions have never been asked at scale- is debatably the single most significant contributor to uncertainty in revenue generation.

1.4.4 Storage and Renewables

Storage could help integrate renewables. In fact, this is currently the best argument for supporting storage development. Li et al. finds that centrally controlled storage integrated with wind could reduce system costs via reduced curtailment and fewer ancillary service violations.[115] However, justifying investment in storage may depend on increased renewable penetration; for example, Das et al . finds that the payback period of compressed air energy storage increases as wind penetration increases because the system needs more frequency regulation.[116]

Even if the primary purpose of storage is to stabilize the electric grid even with significant renewable penetration, storage does not necessarily have to be colocated with renewables.

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[115] Nan Li et al., "Flexible Operation of Batteries in Power System Scheduling with Renewable Energy," *IEEE Transactions on Sustainable Energy* 7, no. 2 (2016): 685–96.

[116] Trishna Das, Venkat Krishnan, and James D. McCalley, "Assessing the Benefits and Economics of Bulk Energy Storage Technologies in the Power Grid," *Applied Energy* 139 (2015): 104–18.

Siting storage and renewables together (colocating) may not be the most efficacious design.[117] Storage is often better located within demand centers.[118]

Storage sited at renewable plants can minimize penalties for missed commitments and target higher price hours for developers.[119] However, colocation can actually be a disadvantage under current ISO rules. For example, NYISO does not pay traditional generators for more than 3% in excess of what the NYISO tells them to produce in real-time. Solar generators and some wind and run-of-river hydroelectric are exempt. [120] Since NYISO will pay these intermittent resources for all output, these settlement rules are highly favorable for the intermittent resources. However, in NYISO, wind paired with storage is not eligible for these intermittent exceptions.[121] So, adding storage would remove this beneficial treatment for the wind resource.

Why then, site storage with renewables directly? Currently, storage is sometimes integrated with renewable resources to take advantage of tax credits. If a storage unit is charged more than 75% from renewable energy, then the storage unit can get the federal investment tax credit (ITC), multiplied by that fraction charged from renewable resources.[122] If constructed before 1/1/2020, the ITC is 30% , which ramps down afterwards to 10% for solar in 2022. The ITC value, taken in the year construction begins, allows for a percentage of upfront capital costs to be credited (a dollar spent on the project is some percentage of a dollar "paid" in taxes) in the year the project becomes operational.[123] The ITC has been used by solar resources. Large scale wind generation used the Production Tax Credit (PTC) a credit rate applied to yearly generation eligible for 10 years. The PTC terminates for wind constructed after 2019. The ITC and PTC have been and are critical to the financial success of U.S. renewable projects.

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[117] Ricardo Fernández-Blanco et al., "Optimal Energy Storage Siting and Sizing: A WECC Case Study," *IEEE Transactions on Sustainable Energy* 8, no. 2 (2017): 733–43; Mir-Akbar Hessami and David R. Bowly, "Economic Feasibility and Optimisation of an Energy Storage System for Portland Wind Farm (Victoria, Australia)," *Applied Energy* 88, no. 8 (August 1, 2011): 2755–63, https://doi.org/10.1016/j.apenergy.2010.12.013; Emily Fertig and Jay Apt, "Economics of Compressed Air Energy Storage to Integrate Wind Power: A Case Study in ERCOT," *Energy Policy* 39, no. 5 (2011): 2330–42.

[118] Pandžić et al., "Near-Optimal Method for Siting and Sizing of Distributed Storage in a Transmission Network"; Dvijotham, Backhaus., and Chertkov, "Operations-Based Planning for Placement and Sizing of Energy Storage in a Grid with a High Penetration of Renewables"; Wogrin and Gayme, "Optimizing Storage Siting, Sizing, and Technology Portfolios in Transmission-Constrained Networks"; Sullivan, Short, and Blair, "Modeling the Benefits of Storage Technologies to Wind Power."

[119] Li et al., "Flexible Operation of Batteries in Power System Scheduling with Renewable Energy"; Javier Garcia-Gonzalez et al., "Stochastic Joint Optimization of Wind Generation and Pumped-Storage Units in an Electricity Market," *IEEE Transactions on Power Systems* 23, no. 2 (2008): 460–68; Yuan Yuan, Qifeng Li, and W. Wang, "Optimal Operation Strategy of Energy Storage Unit in Wind Power Integration Based on Stochastic Programming," *IET Renewable Power Generation* 5, no. 2 (2011): 194–201.

[120] "Accounting and Billing Manual," Version 3.4 (New York Independent System Operator, December 2016), http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Administrative/acctbillmnl.pdf.

[121] "New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations (Roadmap)."

[122] "Federal Tax Incentives for Battery Storage Systems" (National Renewable Energy Laboratory, January 2017), https://www.nrel.gov/docs/fy17osti/67558.pdf; "Notice 2018-59," n.d.

[123] "Business Energy Investment Tax Credit (ITC)," DSIRE, March 1, 2018, http://programs.dsireusa.org/system/program/detail/658.

Some onshore wind is paired with storage. About 52 MW is collocated with wind farms in Texas.[124] A 2017 solicitation for projects by Xcel Energy in Colorado saw a median bid of $21/MWh for onshore wind and storage. [125] There is only one operational offshore wind farm in the United States: Rhode Island's 30 MW Block Island, although according to the Department of Energy, an offshore wind project pipeline of 25,000 MW awaits. [126] Massachusetts, looking to procure 1,600 MW of offshore wind by 2027, contracted with Avangrid Inc. and Copenhagen Infrastructure Partners' for their 800 MW Vineyard Wind project, expected online by 2021, for less than than $80/MWh. [127] The original proposal offered $1 million annually over 15 years into a Resiliency and Affordability Fund, part of which would demonstrate how PV paired with distributed solar would strengthen reliability. [128] Wind and storage is not as popular of a pairing as solar and storage.

Solar and storage projects are more common. A 100 MW PV plus 30 MW/120 MWh storage contract in Arizona (2017) contracted for $45/MWh, with the storage portion costing about $15/MWh.[129] This contract beat the previous best in Hawaii (2017) at $110/MWh for 28 MW of PV with 20 MW/100 MWh of energy storage. Prices halved in less than six months. Recent low contacts that offer both an energy and capacity value have been heralded in Nevada (2018) at under $30/MWh for energy and $7,775/MW-month for capacity. [130] New contract styles demonstrate how the market is experimenting with measuring and compensating the value of storage.

Without proper market incentives, storage may not purchase renewable energy to output when renewables are not available. Market design and ownership structures matter.[131] For

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[124] K. Kaufmann, "The Stories behind the Numbers: SEPA's Top 10 Lists Track Solar and Storage Growth in Unexpected Places," SEPA, April 26, 2018, https://sepapower.org/knowledge/the-stories-behind-the-numbers-sepas-top-10-lists-track-solar-and-storage-growth-in-unexpected-places/.

[125] "Colorado Senate Approves Second Storage Bill, Waits on House." Median wind+ battery combo revealed December 2017 for Xcel's resource solicitation.

[126] "2017 Offshore Wind Technologies Market Update," Energy.gov, accessed March 31, 2019, https://www.energy.gov/eere/wind/downloads/2017-offshore-wind-technologies-market-update.

[127] Vineyard Wind LLC and Lars Thaaning Pedersen, "Vineyard Wind's Appendix B Redacted 800 MW of Section 83C Request for Proposal Application Form," n.d.

[128] "The Distribution Companies and Department of Energy Resources Have Completed the Evaluation of 83C Bids Received," May 23, 2018, https://macleanenergy.com/2018/05/23/the-distribution-companies-and-department-of-energy-resources-have-completed-the-evaluation-of-83c-bids-received/.

[129] Peter Maloney, "How Can Tucson Electric Get Solar + Storage for 4.5¢/KWh?," *Utility Dive*, May 30, 2017, https://www.utilitydive.com/news/how-can-tucson-electric-get-solar-storage-for-45kwh/443715/.

[130] Julian Spector, "Nevada's 2.3-Cent Bid Beats Arizona's Record-Low Solar PPA Price," June 12, 2018, https://www.greentechmedia.com/articles/read/nevada-beat-arizona-record-low-solar-ppa-price; "NV Energy 2.3-Cent Solar Contract Could Set New Price Record," Utility Dive, accessed June 20, 2018, https://www.utilitydive.com/news/nv-energy-23-cent-solar-contract-could-set-new-price-record/525610/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202018-06-13%20Utility%20Dive%20Newsletter%20%5Bissue:15739%5D&utm_term=Utility%20Dive.

[131] Ramteen Sioshansi, "When Energy Storage Reduces Social Welfare," *Energy Economics* 41 (2014): 106–16; Ramteen Sioshansi, "Welfare Impacts of Electricity Storage and the Implications of Ownership Structure," *The Energy Journal*, 2010, 173–98.

example, a price maker storage unit may integrate less wind that a price taker storage unit.[132] With abundant, low priced storage, firms that own hydroelectric and fossil plants may allocate more hydro generation to off-peak periods than they would otherwise in order to raise on-peak prices.[133] Some resources may be preferred for their environmental value, but care in their treatment cannot stop at installation. How these resources participate in the markets is equally as important.

1.5 Storage: Undervalued?

Right now, little storage is economic, no matter how many services it provides. Some ratepayers may view this as costly; others may view this storage as a weapon against climate change. With an eye towards market design, resources should be paid in accordance to which they are valued by the consumer. The more consistent the design, the better.

For storage in particular, there is a concern that current market revenues will be insufficient. The revenue received by transmission-connected storage operators may be less than the benefit felt by the grid, because storage can reduce fuel use and start-up costs (charges that consumers would otherwise incur).[134] Around half of the consumer benefits felt from storage come from storage's ability to displace peaker plants (this means that consumers pay less in the energy and capacity markets).[135] Some estimate that 30% to 40% of the grid benefits received from storage deployment are services like wire deferral that are not currently monetized in ISO markets.[136] Because of a failure in market design, reduced system costs do not equate to profitability for the storage unit. Since these traits of storage are connected to grid reliability, some look to the capacity market to complete the financial picture for storage.

The objective of competitive markets is to lower costs for consumers, not to ensure a certain amount of revenue for participants. The purpose of the capacity markets is to effectively compensate for fixed costs and reliability preferences- not to serve as a subsidy for expensive technologies. However, because capacity markets can represent upwards of a third of market revenue for some technologies, capacity market rules are sometimes structured to target revenue requirements, not reliability requirements. Poor market design, influenced by political motivations, may cause cascading reliability and cost concerns.

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[132] Jorge A.M. Sousa, Fábio Teixeira, and Sérgio Faias, "Impact of a Price-Maker Pumped Storage Hydro Unit on the Integration of Wind Energy in Power Systems," *Energy* 69 (May 1, 2014): 3–11, https://doi.org/10.1016/j.energy.2014.03.039.

[133] James Bushnell, "A Mixed Complementarity Model of Hydrothermal Electricity Competition in the Western United States," *Operations Research* 51, no. 1 (2003): 80–93.

[134] Paul Denholm et al., "The Value of Energy Storage for Grid Applications" (National Renewable Energy Lab.(NREL), Golden, CO (United States), 2013).

[135] Chang et al., "The Value of Distributed Electricity Storage in Texas"; Roger Lueken and Jay Apt, "The Effects of Bulk Electricity Storage on the PJM Market," *Energy Systems* 5, no. 4 (2014): 677–704.

[136] Ryan Hledik et al., "Stacked Benefits: Comprehensively Valuing Battery Storage in California" (The Brattle Group, September 2017); Chang et al., "The Value of Distributed Electricity Storage in Texas."

1.5.1 The Role of Capacity Markets

Generators may encounter a "missing money" problem.[137] The "missing money problem" occurs when generators do not receive enough revenue in the energy and ancillary service markets to justify investment to the reliability levels that an electric system requires. Lack of adequate revenue may be because of reliability preferences for excess supply, price caps in the energy market, relative infrequency of high demand (high price) times, out of market actions taken by market operators that warp market signals, and lack of demand side price sensitivity to inform price.[138]

For example, take a generator that operates only on a select few hot days. As the most expensive unit on the system, during those days this generator sets the price. This "marginal price" is based on the operational cost to make energy. Overall, this generator, while it can cover its marginal costs, is unable to pay back its fixed costs.

Arrangements for resource adequacy to meet reliability preferences vary based on location.[139] Here in the U.S., only ERCOT lacks contracting for reliability purposes. ERCOT is called an energy only market; it doesn't have secondary mechanisms to ensure a certain level of supply. The argument in an energy only market is that customers don't want capacity - they want the energy that capacity produces. If energy is priced high enough to support capacity in those few peak hours, then the capacity will be built. In ERCOT, higher price caps, a 'demand' curve for reserves, and increased prevalence of end-use consumer involvement has allowed for excess supply, despite lacking an explicit mandate.

Energy only markets, as seen by ERCOT, employ scarcity pricing, or pricing that essentially steeply ramps to incentivize generation to meet increasing demand.[140] When there is enough supply, the energy market price is set by the unit on the margin (the next unit to meet demand). When supply is constrained, the price is set not only by the marginal unit, but includes some extra, where this extra both signals that supply is low and provides some revenue for the marginal plant to cover costs.

Resource adequacy structures are a function of regulator preference. [141] Reliability is an essential part of a functional electric gird. Four of the ISOs – ISO-NE, MISO, NYISO, and PJM- host competitive, bid based markets for capacity. In the four ISOs that offer capacity markets, all allow loads to enter into bilateral contracts with generators, if wanted. These ISOs aim for a reliability level that meets demand all by 0.1 days per year. It is important to note that being an

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[137] Paul L. Joskow, "Capacity Payments in Imperfect Electricity Markets: Need and Design," *Utilities Policy* 16, no. 3 (2008): 159–70.

[138] P. Joskow, "Symposium on 'Capacity Markets,'" *Economics of Energy and Environmental Policy* 2, no. 2 (2013): V–VI.

[139] Carlos Batlle and Pablo Rodilla, "A Critical Assessment of the Different Approaches Aimed to Secure Electricity Generation Supply," *Energy Policy* 38, no. 11 (2010): 7169–79.

[140] William W. Hogan, "On an 'Energy Only' Electricity Market Design for Resource Adequacy," *California ISO*, 2005.

[141] Batlle and Rodilla, "A Critical Assessment of the Different Approaches Aimed to Secure Electricity Generation Supply."

'energy-only market' like ERCOT's does not mean that the market is free from regulatory interference, as decisions to set these ramping price curves relies upon operator judgement.[142]

In capacity markets, the ISO procures, on behalf of loads, enough capacity to meet the anticipated peak demand, plus some cushion, keeping in mind constraints like limited transmission capacity. That's why some ISOs have different prices for different capacity. Those zones are areas of higher risk where local supply is worth more.

Generators offer their capacity (MW) into the market at prices of their choice. Generators cannot simply offer the amount of capacity that they like. There are rules that dictate eligibility. First, resources typically perform some sort of test to demonstrate their maximum output. This is because the technology's nameplate capacity is not always what that specific resource can actually output. Then, in most cases (a notable exception being ISO-NE, which can allow generators to offer this demonstrated output), this tested level is decreased in some manner. As a result, resources, if they clear in the market, will get paid some fraction of their demonstrated capacity. This fraction will be referred to as their capacity credit. In equation form, capacity credit is

$$\text{Capacity credit } = \frac{\sum_{hr=0}^{hrs} caparray_{hr}[sell_{hr} - buy_{hr}]}{\sum_{hr=0}^{hrs} caparray_{hr} P_{Max}}$$

Where *Caparray* is a year-long hourly array of binaries with a value of 1 in critical hours and 0 in non-critical hours. Critical hours are the hours that the ISO is concerned about reliability. The battery's net power in that hour is $sell_{hr} - buy_{hr}$. P_{Max} is the rated power output.

Demonstrated output during some predetermined test conditions is not necessarily equivalent to what the resource has delivered (and will deliver) during times of system stress. Efficient capacity markets want to pay resources for their contributions in stressed times. Hence, the capacity credit calculations.

The objective of the capacity credit is to take into account the historic availability of the resource during times of system stress. For conventional fossil fuel generators, the capacity credit decreases output based on on the amount of time spent in unplanned outages. For intermittent generators, the capacity credit is generally some function of average output during given hours across seasons. The later effectively represents how intermittent resources reduces the probability of outages during critical times. For energy storage resources, eligibility in the capacity markets is being worked on via ISO stakeholder proceedings in an effort to be compliant with FERC Order 841. ISOs are governed by member votes. The stakeholder proceedings for energy storage resources have been particularly dramatic, as capacity market revenue represents a significant value stream for individual resources – which some other ISO

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[142] Peter C. Cramton and Steven Stoft, "The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem," 2006.

party must pay for – but the ability of storage to perform during these times of need is practically unknown because of limited penetration.

It is necessary to mention that capacity markets require redesign. There is a comprehensive body of literature on the topic (Jenkin et al. is one such source).[143] In short, renewable resources, with higher fixed costs but minimal to no variable costs, suppress energy market prices because bids are based on marginal (variable) costs. As prices in the energy market lower, reliance on capacity markets increases. However, renewable resources may be suppressing prices in capacity markets as well because they are receiving state subsidies (as well as some federal tax credits).[144] ISO-NE was the first to take more comprehensive action to mitigate the impact of state sponsored resources in the capacity market.[145] PJM is in the midst of market reform.

Hugely important, these reforms are quickly detailed in 1.5.1.1 and 1.5.1.2. Reforms will change the business cases for storage in the capacity markets. Commentary on storage in the current frameworks continues with Section 1.5.1 and 1.5.2.

1.5.1.1 ISO-NE

Capacity markets were originally designed to cover the fixed capital costs of traditional resources. Since these dispatchable resources were generally assumed to be able to execute when needed, there were minimal penalties in place for not being available during times of emergency grid conditions.

However, in a market with increasing number of intermittent resources, deliverability during peak times becomes a concern. Furthermore, the performance of traditional fossil-generators has not been as flawless as previously assumed. In the 2014 Polar Vortex, on the peak demand hour on January 7, 2014, 22% of the generation fleet was offline.[146] Of this, over 85% was coal or natural gas.[147]

ISO-NE introduced what is known as a "pay for performance" (PFP). [148] Under PFP, resources are rewarded/penalized for over/under-achieving during times of grid stress. PJM has

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[143] Thomas Jenkin, Philipp Beiter, and Robert Margolis, "Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy" (National Renewable Energy Laboratory, February 2016).

[144] Iulia Gheorghiu, "Capacity Pricing Changes: How Each Power Market Plans to Account for Resource Adequacy," December 18, 2018, https://www.utilitydive.com/news/capacity-pricing-changes-how-each-power-market-plans-to-account-for-resour/542449/.

[145] "Competitive Auctions with Sponsored Policy Resources (CASPR) Project," ISO New England, n.d., https://www.iso-ne.com/participate/support/customer-readiness-outlook/caspr-project.

[146] "Strengthening Reliability: An Analysis of Capacity Performance" (PJM Interconnection, June 20, 2018).

[147] 28% of plants were offline because of natural gas supply shortages.

[148] Sabely Peralta, "FCM Pay for Performance Evaluations (Effective June 1, 2018)" (October 23, 2017), https://www.iso-ne.com/static-assets/documents/2017/11/20171023-14-fcm101-pfp.pdf.

since adopted PFP. Approved in May 2014 with resources receiving applicable contracts in the 2015 auction, PFP began on June 2018, and will be full strength in 2024.[149]

Under PFP, capacity payments are the sum of the auction results plus real time performance true-ups. Utilities pay for the auction component.[150] The "performance component" should be revenue neutral for the system; underperforming resources pay over-performing resources to assume their real-time responsibilities.[151] Performance is calculated for 5-minute intervals where there is a shortage.[152] Shortages occur when there is a local thirty-minute reserve shortage, a system-wide thirty-minute reserve shortage, or a system-wide ten-minute non-spinning reserve shortage. In other words, shortages occur when the price of thirty-minute reserves or ten minute non-spinning reserves reaches $1,000/MWh or $1,500/MWh, respectively.[153]

Performance is what the resources outputs, minus some fraction of what it should have outputted given its commitments in the capacity market. This fraction is called the Balancing Ratio. The Balancing Ratio is the capacity of the present resources, divided by the capacity of the resources that should be present. The Balancing Ratio effectively weights resources' obligations by how bad scarcity is on the grid. Shortfalls, or bonuses, are compensated at some given rate, which increases from $2,000/MWh to $5,455/MWh depending on the year. [154] ISO-NE decided to ease into PFP by increasing the performance payment/penalty over the course of a few years. Resources without a capacity payment may receive performance payments, but cannot be charged for shortfalls. Equations are given below. [155]

$$\text{Balancing Ratio} = \frac{Load + Reserves\ in\ Action}{\sum System\ Wide\ Contracted\ Capacity}$$

Performance Score= Actual (energy +reserves)– (capacity obligation*Balancing Ratio)

Performance Payment/Charge = Performance Score * Performance Payment Rate

There appears no explicit duration for storage resources to receive capacity payments in ISO-NE. However, resources are exposed to risk.

On September 3, 2018, ISO-NE issued its first PFP interval. It lasted for 2 hours and 35 minutes for the whole system.[156] As of April 2019, no other periods qualified.

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[149] Coutu, "Benefits/Risks of Having Capacity Supply Obligation (capacity obligation)."

[150] Andrew Gillespie, "Introduction to ISO-NE Forward Capacity Market (FCM) Pay-For-Performance (PFP): A Training Module From "Introduction to Wholesale Electricity Markets" (WEM 101)" (March 19, 2018), 101, https://www.iso-ne.com/static-assets/documents/2018/06/2018-06-14-egoc-a4.0-iso-ne-fcm-pay-for-performance.pdf.

[151] Resources that do not have capacity obligation are eligible for a capacity bonus payment for performing during hours.

[152] The shortages are referred to as capacity scarcity conditions.

[153] Andrew Gillespie, "Lesson 2A: Pay-for-Performance (PFP) Basics" (October 22, 2018).

[154] Coutu, "Benefits/Risks of Having Capacity Supply Obligation (CSO)."

[155] Peralta, "FCM Pay for Performance Evaluations (Effective June 1, 2018)."

[156] "Capacity Scarcity Condition Report," ISO New England, n.d., https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/capacity-scarcity-condition-report.

We look at the real time reserve prices for ISO-NE, and determine the number of performance hours by seeing when reserve pricing was set by the shortage prices. For 2011, 2012, 2013, there would have been no performance intervals. In 2014, 2015, 2016, and 2017, there were 2, 1.6, 3.25, and 0.58 hours, respectively. The number of hours that classify as performance to date are minimal, and those that exist, quite short. A duration of 4 hours could theoretically meet these mandatory peaks.

1.5.1.2 PJM

PJM adopted PFP mechanisms (similar to ISO-NE) in the 2016/2017 delivery year. Previously, PJM had some real time performance assessments through its Peak Hour Availability (PHPA) and Peak Season Maintenance (PSM) tests.[157] The PHPA analyzed output during non-holiday weekends June through August, hours beginning 14-18, and for January through February, hours beginning 7 - 8 and 19- 20. PJM charged shortages. The PSM, not applicable to hydro or intermittent resources, penalized for bad behavior during the weeks that contain the 24th -36th Wednesdays. PFP is generally regarded to provide stronger performance incentives.

In 2016, PJM issued a new one-time auction to replace some previously rewarded contracts with PFP contracts. Unlike ISO-NE, which decided to ease into PFP by using an increasing performance rate, PJM also decided to ease in by applying PFP to an increasing percentage of the system's resources. For the 2016/2017 capacity year, 56% of supply was under PFP. By June 2020, all resources will use PFP.

PJM announces emergency actions when PFP will apply, which include things like voltage and load loss warnings. As of April 2019, PJM only called one performance interval, which was on May 29, 2018 and lasted for 24 minutes in a small region.[158] Despite limited data, PJM's believes that PFP has increased reliability, even during time periods where the PFP interval was not triggered, because of its looming risk.

PJM released what would have been performance assessments hours for 2011 through 2014. For those years, there were 11, 9, 9, and 43 performance assessment hours across 17 days. On January 7, 2014, resources would need upwards of 11 hours. Otherwise, 14 of the 17 disclosed times could be met with a 4-hour duration unit, with the other two missing periods lasting no more than 6 hours.

For the 2016 and 2017 capacity year, the PJM-wide penalty rate was $1,896.30/MWh, and the cap on the amount lost during the year was $85,333.70/MW. This penalty factor was about half of what it would have been, as part of PJM's transition into PFP. This penalty rate is calculated assumed 30 hours a year, where 30 hours is based upon PJM's actions in 2013 and

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[157] "RPM 301 Performance in Reliability Pricing Model," (April 20, 2017), 301, https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-301-performance-in-reliability-pricing-model.ashx?la=en.

[158] "Strengthening Reliability: An Analysis of Capacity Performance"; "Capacity Market (RPM)," PJM, n.d., https://www.pjm.com/markets-and-operations/rpm.aspx.

2014.[159] With this 30 hour penalty rate, it is estimated that the resource will hit the stop loss after 45 hours of non-performance during the intervals. However, this penalty rate may change.

PJM's market will continue to evolve. PJM is concerned over how state subsidized resources are suppressing prices in the capacity market. In 2018, PJM posed two capacity market redesigns to FERC.[160] The first would apply a minimum offer price rule to all resources. Some renewable resource could enter the market as price takers. Prices would likely still be lower than otherwise, but the effect would be dampened. The second option offered a two stage market. The first stage would carry on as described, but the second stage would set the price of the auction by replacing the offering price of subsidized resources. FERC declared that the PJM's market, as it then functioned, was unduly discriminatory because state-sponsored resources could bid in at unnaturally low prices that warped results for other resources. FERC rejected both designs and opened a new docket to find a way forward.[161] FERC floated an alternative concept, which would allow utilities in PJM to bilaterally contract for some (but not all, as currently mandated) of their capacity. A significant conversion of capacity market activity into bilateral contracts may reduce the competitiveness of the capacity market.

Despite PJM delaying its 2022/2023 auction, FERC did not respond in time. So, PJM plans to run the auction in August 2019 under its old rules.[162] These results could be legally suspect because FERC has invalidated these old rules. Capacity markets are in serious jeopardy.

1.5.2 Storage in Capacity Markets

Market participants and regulators alike want to know how much money storage, in particular lithium-ion batteries, can make in different electricity markets. Because of a substantial missing money problem for batteries, developers are looking to capacity market revenue to be "made whole." The missing money problem for batteries is particularly problematic in that there is a political perspective that batteries should be making more money than they are. This lack of grounding in an actual quantification of how much batteries actually make, given the current market rules, and how much money batteries need to make, given the current costs, makes for dangerously poor public policy. Treating the capacity market, in particular, as simply an additional source of revenue without a solid foundation will distort the markets for all resources.

By determining actual profitability of batteries in existing capacity markets, as opposed to rough revenue assumptions, market participants can better predict profitability and better

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[159] Patrick Bruno, "Balancing Ratio Determination," (March 7, 2018), https://www.pjm.com/-/media/committees-groups/committees/mic/20180307/20180307-item-09a-market-seller-offer-cap-balancing-ratio-determination.ashx.
[160] "Capacity Market Repricing Proposal" (PJM Interconnection, June 29, 2017).
[161] EL18-178-000
[162] "PJM to Run Capacity Auction in August under Current Rules," April 10, 2019, https://insidelines.pjm.com/pjm-to-run-capacity-auction-in-august-under-current-rules/.

assess the policies needed for their desired outcomes. However, there exists a gap in research to inform as to the revenue of batteries in capacity markets. The existing literature body:

1. Either ballparks capacity market revenue, or
2. Focuses on reliability, not revenue generation ability.

The research in this paper aims to fill a gap by back-casting the implicit profitability of batteries, across all nodes and ISOs between 2014 and 2017, in both the energy and capacity markets, using historic prices. By additionally calculating the capacity credit during the top percent of load hours, we find storage's contribution to reliability, given market signals.

This paper provides a location-and-time-specific estimation of capacity market revenue using historic prices that also quantifies the capacity credit, or reliability benefit, that storage provides. It is hoped that this research will serve as a benchmark of revenue for industry partners and a benchmark of reliability benefits for regulatory bodies.

The dispatch to optimize revenue in the energy and capacity markets will address some unanswered questions:

1. How much money would batteries have made in the energy market, given a nodal knowledge of historic prices? How does this revenue change with the inclusion of capacity market participation?
2. How does energy and capacity revenue compare to participating in solely the energy market? Is there a tradeoff in the energy market when participating in the capacity market?
3. What is the capacity credit of batteries? How can different batteries contribute to reliability?

For clarification, capacity market revenue is the product of capacity price, capacity obligation, and capacity credit. The capacity price and capacity credit are both explored in the literature as described in the sections below. Again, by "capacity credit", we mean not the rated capacity of the unit, but the demonstrated or certified capacity that, under the rules, is available for sale in the market.

1.5.2.1 Storage: Capacity Revenue

Research is available on "value stacking" storage's different revenue streams, like the participation in the energy and regulation markets,[163] the energy and reserve markets,[164] and

[163] Berrada, Loudiyi, and Zorkani, "Valuation of Energy Storage in Energy and Regulation Markets."
[164] Josh Eichman et al., "Operational Benefits of Meeting California's Energy Storage Targets," *Technical Results, National Renewable Energy Laboratory (NREL)*, 2015; P. Kanakasabapathy and K. Shanti Swarup, "Bidding Strategy for Pumped-Storage Plant in Pool-Based Electricity Market," *Energy Conversion and Management* 51, no. 3 (2010): 572–79; Drury, Denholm, and

the energy, reserve, and regulation markets.[165] No work is found on maximizing the profitability of batteries combined in both the energy and capacity markets.

Rarely are actual historic capacity prices for storage used, although Mills et al. uses zonal capacity prices in the context of offshore wind valuation for 2007 through 2016, and finds that if storage is added, the unit's revenue can increase 3% to 8% (mostly energy revenue).[166] However storage contribution to capacity revenue is unclear. More often, average capacity prices are used instead of locational historic prices.

2017 Yu and Foggo estimate capacity prices based on recent bids and the cost of new entry, and still found that 79% of revenue came from regulation compared to energy and capacity, (4% and 15%, respectively).[167] 2011 Sioshansi et al. adds a range of $20/kW-year to $60/kW-year to energy arbitrage in PJM from 2002 to 2008.[168] 2007 Walawalker et al. optimized storage in the regulation or energy markets in NYISO from 2001 through 2005, and cited some capacity values to highlight how capacity markets may be a future revenue source.[169]

In short, using actual capacity price, as opposed to some blend, is rare. This is likely because working with capacity prices can be a pain. There are multiple markets for capacity (years, a year, months, and a month ahead, depending on ISO). Furthermore, from year to year, the zones, or geographic swath that the price applies to, may change, so mapping location to price is a time-sensitive affair.

1.5.2.2 Storage: Capacity Credit Calculations

Some methods of calculating the capacity credit of storage, like Effective Load Carrying Capability (ELCC), Equivalent Conventional Power (ECP), and Equivalent Firm Capacity (EFC), require a generation expansion and dispatch pricing model (Table 7). These models, which involve a greater degree of complexity, evaluate storage's contribution to meeting peak load by entirely re-dispatching a fake system and seeing how storage performs.

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[165] Guannan He et al., "Optimal Bidding Strategy of Battery Storage in Power Markets Considering Performance-Based Regulation and Battery Cycle Life," *IEEE Transactions on Smart Grid* 7, no. 5 (2016): 2359–67; Das, Krishnan, and McCalley, "Assessing the Benefits and Economics of Bulk Energy Storage Technologies in the Power Grid"; Das, Krishnan, and McCalley; Eric Cutter et al., "Utility Scale Energy Storage and the Need for Flexible Capacity Metrics," *Applied Energy* 124 (July 1, 2014): 274–82, https://doi.org/10.1016/j.apenergy.2014.03.011.

[166] Andrew D. Mills et al., "Estimating the Value of Offshore Wind Along the United States' Eastern Coast," 2018.

[167] Nanpeng Yu and Brandon Foggo, "Stochastic Valuation of Energy Storage in Wholesale Power Markets," *Energy Economics* 64 (2017): 177–85.

[168] Ramteen Sioshansi, Paul Denholm, and Thomas Jenkin, "A Comparative Analysis of the Value of Pure and Hybrid Electricity Storage," *Energy Economics* 33, no. 1 (2011): 56–66.

[169] Rahul Walawalkar, Jay Apt, and Rick Mancini, "Economics of Electric Energy Storage for Energy Arbitrage and Regulation in New York," *Energy Policy* 35 (September 14, 2007): 2558–2568.

Table 7: Capacity Credit: Calculation Types

Abbreviation	Stands For	Method
ELCC	Effective Load Carrying Capability	The amount of load that a system can increase when a new generator is added, while maintaining the same level of reliability. The capacity credit is this new added load divided by the capacity of the new generator.
ECP	Equivalent Conventional Power	The capacity of a conventional generator (with a capacity credit) that would replace the generator in question. The capacity credit is this conventional generator added, divided by the capacity of the new generator.
EFC	Equivalent Firm Capacity	The capacity of a perfect generator (100% capacity credit) that would replace the generator in question. The capacity credit is this flawless generator divided by the capacity of the new generator.
2018 Denholm et al.	"peak demand reduction credit"	The capacity credit of the unit needed to meet the entire duration of peak demand. For example, at what rate would a 1 MW battery need to discharge in order to output across the whole duration of the peak demand period?

2016 Johal dispatches a future production of ERCOT in 2018 and finds that the capacity credit for 4-hour storage is almost 100% of the nameplate capacity under ELCC methodology.[170] 2009 Tuohy and O'Malley evaluate the capacity of pumped storage and finds that currently the capacity credit of 10 hour storage is equivalent to a conventional generator (above 95%). [171] 2013 Sioshansi improves upon the Tuohy and O'Malley ELCC approach so that behavior in an hour takes into account the probability of an outage, and finds that 1 to 10 hours of duration correlates to capacity credits of 40% to 100%, respectively, averaging 70% for 4-hour duration.[172] Denholm et al. estimate the capacity credit of storage as a "peak demand reduction credit" by adding storage to the system until 1 MW of storage will not equal a 1 MW reduction

[170] Harjeet Johal, Douglas Tome, and Kenneth Collison, "Unlocking the Hidden (Capacity) Value in Energy Storage" (ICF, n.d.).
[171] Aidan Tuohy and Mark O'Malley, "Impact of Pumped Storage on Power Systems with Increasing Wind Penetration," in *Power & Energy Society General Meeting, 2009. PES'09. IEEE* (IEEE, 2009), 1–8.
[172] Ramteen Sioshansi, Seyed Hossein Madaeni, and Paul Denholm, "A Dynamic Programming Approach to Estimate the Capacity Value of Energy Storage," *IEEE Transactions on Power Systems* 29, no. 1 (2014): 395–403.

in peak load because of duration constraints.[173] Once PV penetration increases to more than 17% of load, the capacity credit of 4-hour duration storage start to decrease from 100% as longer duration becomes necessary to shift renewable energy. To summarize, the literature offers a capacity credit of storage, even shorter 4-hour duration storage, similar to that of the fossil fleet. For comparison, the North American average capacity credit of for natural gas of 90.95%.[174]

2018 Callaway et al. estimated the average capacity revenue for wind, solar, and lighting systems (not storage) across ISOs as the product of an estimated capacity price (the average or median of ISOs from 2011 through 2012) and estimated capacity credit, following the 1999 Milligan and Parsons methodology.[175] 1999 Milligan and Parsons finds that calculating the capacity credit of wind as net output fraction over the top 30% of load hours is a reasonable approximation of the value it brings to the system.[176] 2012 Madaeni applies this methodology to thermal solar energy (without storage) across both the top 100 and top 10 hours.[177] This simplified approximation over less than the top 1% of hours is found a suitable predictor. The benefit of these approaches are that they are less computationally complex than a dispatch model, but still effective at getting to underlying value.

MISO calculates the capacity credit of individual wind plants using ELCC applied to the highest coincident peak periods in June, July, and August. CAISO calculates wind and solar using the ELCC approach. [178] Other than that, ISOs do not seem to run dispatch models to determine capacity credit. This may be because of two factors: first, the computational burden; and second, that having a standard set of rules creates a more certain environment for investors.

As a result, understanding how storage contributes to reliability by re-dispatching a system is important because that understanding can inform a standard set of rules. But in the end, what these rules say- less so the underlying value that these rules were originally founded on – are what matters for revenue.

ISOs take the capacity credit of conventional resources as the Equivalent Forced Outage Rate Demand (EFORd) The EFORd represents the amount of time the generator was offline due to unexpected outages in the past. For unconventional resources like wind and solar, ISOs generally take the capacity credit as the fraction of total output generated over pre-defined

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[173] Denholm and Margolis, "The Potential for Energy Storage to Provide Peaking Capacity in California Under Increased Penetration of Solar Photovoltaics."

[174] Maria Scibelli, "Review of Peaking Resources' Availability: In Transmission Security Analyses (TSA)" (n.d.).

[175] Duncan S. Callaway, Meredith Fowlie, and Gavin McCormick, "Location, Location, Location: The Variable Value of Renewable Energy and Demand-Side Efficiency Resources," *Journal of the Association of Environmental and Resource Economists* 5, no. 1 (2018): 39–75.

[176] Michael Milligan and Brian Parsons, "A Comparison and Case Study of Capacity Credit Algorithms for Wind Power Plants," *Wind Engineering*, 1999, 159–66.

[177] Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, "Estimating the Capacity Value of Concentrating Solar Power Plants: A Case Study of the Southwestern United States," *IEEE Transactions on Power Systems* 27, no. 2 (2012): 1116–24.

[178] Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Furthering Refining the Resource Adequacy program, No. 14- 06–050 (Public Utilities Commission of the State of California June 26, 2014).

hours. On average across ISOs, the capacity credit of intermittent resources is taken across 7% of yearly hours. Average capacity credits are given in Table 8. The capacity credit of fossil-fuel resources and nuclear power is 93%, and of hydro-based resources, 89%.

Table 8: Capacity Credits of Conventional Resources

Resources reporting events (2013-2017 average) to the North American Electric Reliability Corporation (NERC).[179] *NERC maintains data for more than 5,000 operating units in North America.180 Units large than 20 MW must report their information.*

Resource	Capacity Credit
Coal (1- 99 MW)	90
Oil (1- 99 MW)	92
Combined Cycle (all sizes)	95
Nuclear (400- 799 MW)	97
Hydroelectric (1-29 MW)	85
Pumped Storage (all sizes)	92
Fossil and Nuclear Average	93
Hydroelectric and Pumped Average	89

The capacity credit of intermittent resources are listed in Table 9. ISOs publish averages of the capacity credits of their resources. The average capacity credit of wind and solar is 31%.

Table 9: Capacity Credits of Intermittent Resources
ISOs publish capacity credits of intermittent resources within their territory. For MISO, PJM, and

ISO	Resource	Capacity Credit
PJM[181](2017)	Wind: mountain terrain	15
	Wind: open terrain:	18
	Solar: Ground Mounted Fixed Panel	42

[179] "Generating Unit Statistical Brochures: 2017 Generating Unit Statistical Brochure -- Five Years, 2013 - 2017, Units Reporting Events," North American Electric Reliability Corporation, 2017, https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx.
[180] "Generating Availability Data System (GADS)," North American Electric Reliability Corporation, n.d., https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx.
[181] "PJM Manual 21: Rules and Procedures for Determination of Generating Capability" (PJM Interconnection, May 1, 2019), https://www.pjm.com/~/media/documents/manuals/m21.ashx; "Class Average Capacity Factors: Wind and Solar Resources" (PJM Interconnection LLC, June 1, 2017), https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en.

	Solar: Ground Mounted Tracking PV	60
	Solar: Other than ground mounted PV	38
MISO [182]	Energy Storage (proposed in 2018)	95
	Wind: 2018-2019	15
	Wind 2017-2018	16
	Solar: 2018-2019	50
ISO-NE[183]	Hydro, Solar, Wind	87
NYISO[184]	Solar (summer, different fixed tilt arrays)	26 to 43
	Solar (winter, different fixed tilt arrays)	0 to 1
	Solar (summer, tracking)	46
	Solar (winter, tracking)	2
	Wind (summer, onshore)	10
	Wind (winter, onshore)	30
	Wind (offshore)	38
Averages	Wind	31
	Solar	31

In summary, there appears a gap in the literature to adequately reflect capacity revenue, not just from a capacity price perspective, but also from a capacity credit component, that actually reflects locational and historic trends. Section 2 describes how we manage to address that gap.

1.6 **Research Objective**

Recent technological improvements in lithium-ion batteries, and increasing political awareness of climate change- has stimulated a reawakening of the potential integration of energy storage on the electric grid. The technological characteristics of energy storage- its

[182] "Capacity Determination for Electric Storage Resource under Order 841 Issue ID: RASC007," (August 8, 2018), https://cdn.misoenergy.org/20180808%20RASC%20Item%2003b%20Capacity%20Determination%20for%20ESR263475.pdf; "Book 2: Resource Adequacy (MTEP18)" (MISO, n.d.), 2, https://cdn.misoenergy.org/MTEP18%20Book%202%20Resource%20Adequacy264875.pdf.

[183] "NERC GADS EFORd Class Averages as Used by ISO New England" (ISO New England, n.d.).

[184] "Installed Capacity Manual Attachments" (New York Independent System Operator, November 1, 2012).

ability to charge and discharge at various scales – allows storage to be installed across the distribution and transmission system.

Regulation of energy storage in the U.S. electricity markets is a complex beast. Because of limited cohesive federal environmental policy regulating carbon emissions, states are the dominant actors. Each state is essentially a unique electricity market. States are looking to promote the use of energy storage because storage is a non-fossil alternative it can stabilize the grid. But, states are unsure how to value energy storage – whether for its contribution to reliability, its ability to integrate renewable resources, its lack of carbon emissions, etcetera. Limited deployment to date has left unanswered questions. There is fundamental uncertainty over how storage helps the operation of the electric grid. Furthermore, lithium-ion batteries are entering the grid at a time where states are beginning to reconsider what to value in the power sector – price responsiveness and renewable attributes, in particular. States are subsiding resources to provide feedback on rates. As experience comes in, the compensation of storage, especially in the distribution markets, will change. Of particular vulnerability are the rules governing energy storage that participates in both the distribution and transmission systems because there is a limited existing legal framework. Gaps are fraught with uncertainties of who has access to what, and who pays for what.

Storage, because of its potential to help the grid as a whole, may integrate more nicely within vertically integrated utilities, where legal structures are clearer. That being said, ISOs are adjusting their market rules. State incentives that will increase deployment forced regulatory overhaul. ISOs must allow these resources to participate in their markets. Of big concern has been storage's compensation in the capacity markets. A significant component of storage's value may be linked to reliability, or in other words, supporting the safe and consistent integration of intermittent resources. Reliability is inherently tricky to value. Capacity markets, the ISO markets that reward for reliability, are constantly evolving, and are by no means stable.

Research to date has either focused on how storage contributes to grid reliability, or ballparks capacity revenue as some add-on. This presents problems. First, ISOs rarely compensate exclusively on the reliability benefit felt by a single resource. ISOs use generalized market rules to provide clarity for investors. So while underlying contribution to reliability may inform the market rule, the market rule itself is more relevant from a resource perspective when quantifying potential profitability. Second, participating in the capacity market is a location and time sensitive affair. Third, participating in the capacity market may involve tradeoffs. No analysis to date has investigated what it takes from an operational perspective to bid in both the energy and capacity market, much less with location specific, historic prices.

This analysis fills a gap by providing a granular reflection of not only the revenue generation abilities of energy storage, and what concessions may occur, but also the contribution of storage to constrained times. This profit-oriented and reliability founded analysis should be of interest to regulators and developers alike.

2 Market Data Characterization

Costs for lithium-ion energy batteries are declining. At the same time, political interest is peaking because of storage's ability as a non-fossil resource to integrate increasing amounts of intermittent resources. Because of the limited deployment of lithium-ion batteries to date on the grid, the best installation location – whether installed at smaller scale on the distribution system or at larger scale on the transmission system- and the best services deployed – like energy versus regulation- is uncertain. Furthermore, old compensation structures, formed prior to large scale intermittent penetration, are beginning to breakdown. For example, injections of PV power into the distribution system without awareness are straining distribution feeders. Consistently low prices in ISO markets, stimulated by no-marginal cost renewable resources, may jeopardize needed investment. Energy storage is entering the markets at a time where market rules are shifting. As a result, it is important to understand how much revenue storage can make under the current market rules, as a foundation upon which to make decisions, as well how storage contributes to grid operation, to get a sense of how these rules may change.

How much storage is worth in these markets is in question. In particular, storage is eyed for its potential contribution to reliability. Reliability in meeting extreme peak days is the domain of capacity markets. Currently, capacity markets are particularly unstable. Of energy, ancillary service, and capacity markets, capacity markets can represent upwards of a third of revenue. Capacity markets may hold a not only a significant revenue for developers, but also a significant service for consumers in the form of a more variable-resource based grid.

Little information has been found to date as to how much money energy storage makes in the capacity markets. There is no evaluation of how time and location– which are the most important factors behind profitability- affects revenue. Furthermore, there is no sense of the tradeoffs that may be involved should storage chose to participate. Lastly, there is no sense of how storage responds to market signals to provide reliability. This analysis quantifies past revenue in the energy and capacity markets, analyzing the tradeoffs between the two markets, to not only see how energy storage responds to price signals to support reliability, but also to determine whether revenue justifies investment. This analysis should be of interest, not only to developers to identify locations and general trends, but also to market designers to highlight areas where market incentives may not align with envisioned results.

2.1 Modeling Overview

We quantify the revenue of a battery in the energy and capacity markets. We do this by dispatching imaginary batteries that maximize revenue across hourly prices within a given year. The battery is assumed to have perfect knowledge of the year's prices. Location-specific prices for 2014 through 2017 across six ISOs - CAISO, ERCOT, ISO-NE, MISO, NYISO, and PJM- are used.

As a brief summary, resources on the electric grid have power capability and energy capability. Power capability (MW) is an instantaneous rate, analogous to how quickly water can

leave a tank. Energy capability (MWh) is analogous to how much water is within the tank. This analysis assumes a 1 MW power capacity, and varies energy capability.

The revenue of the battery within the energy market is a function of energy prices and net output. However, revenue in the capacity market is less straightforward, as it is a reflection of market rules. The market rules generally evaluate the contribution of storage during times of grid concern. With this in mind, we look at the output of storage as a fraction of its potential output (capacity credit) during times of peak demand on the grid. Later sensitivity cases evaluate revenue under specific ISO rules.

Using historic prices, the battery is dispatched across several combinations of markets to evaluate tradeoffs:

1. Energy market. The hourly day-ahead energy market (DAM) is used for all analysis.
2. Energy and capacity markets, with revenue in the capacity market a function of capacity credit during peak demand hours. Peak demand hours are defined as some percentage, which varies, of hours with the highest electricity load. Load is taken as system-wide demand or system-wide demand minus renewables generation.
3. Capacity market only.
4. Energy and capacity market, with capacity credit as defined during some ISO-specific market rules.

The next section explains how the data was (and can be) acquired.

2.2 Energy Market Data

Complete hourly DAM nodal energy market prices ($/MWh) for CAISO, ERCOT, ISO-NE, MISO, NYISO, and PJM are paired with geographic data for over 10,000 U.S. locations by 2017 (Table 10). These locations have matching capacity market data.

Sources for energy market pricing and geographic information are as described in 2019 Brown and O'Sullivan (pending as of May 2019). To summarize from 2019 Brown and O'Sullivan, price information is gathered from respective ISOs.[185] Geographic information for

[185] "California ISO OASIS," n.d.; "Pricing Data," New York Independent System Operator, n.d., https://www.nyiso.com/energy-market-operational-data; "Market Prices," ERCOT, n.d., http://www.ercot.com/mktinfo/prices; "Day-Ahead Pricing (Xls)," MISO, n.d., https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ADay-Ahead%2FMarketReportName%3ADay-Ahead%20Pricing%20(xls)&t=10&p=0&s=MarketReportPublished&sd=desc; "Daily Day-Ahead LMP" (PJM Interconnection, n.d.), https://www.pjm.com/markets-and-operations/energy/day-ahead/lmpda.aspx; "ISO New England - Pricing Reports," accessed April 8, 2019, https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/historical-annual-five-minute-reserve-zone-prices-and-designations.

MISO and CAISO is publicly available on ISO websites.[186] Geographic information for ERCOT and ISO-NE was provided by the respective ISOs via private communication. For PJM, there are lists of closest zones to each zip code, so the location of the node is the centroid of all that contain that node.[187] In NYISO, node locations are given at city and county level, so if listed multiple times, location is again taken as the centroid. [188]

Table 10: Number of Complete Energy and Capacity Market Locations Per ISO Per Year

	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	*All*
2014	2,204	1,561	593	202	430	4,896	9,886
2015	2,234	1,563	612	370	434	48,56	10,069
2016	3,285	1,568	746	372	435	4,739	11,145
2017	4,008	1,563	821	379	436	4,679	11,886

2.3 Capacity Market Data

Capacity prices are provided on a zonal, not nodal, locational basis. The data collection and locational conversion from zone to node, for purpose of replication by others, is detailed below.

2.3.1 CAISO

California does not have a centralized capacity market. Utilities are required to sign contracts with suppliers to meet state requirements. Bilateral contract prices, in $/kW-month, are extracted from the California's Public Utilities Commission's "Resource Adequacy Reports."[189] This analysis uses the annual weighted average contract price, as given in the year's respective report.[190]

By using average prices, locational value is not part of CAISO's capacity market analysis. Furthermore, when negotiating bilateral contracts, parties have leeway. Considering that batteries to date possess comparatively higher capital costs, and that California utilities are

[186] "Market Price Maps," California ISO, n.d., http://www.caiso.com/PriceMap/Pages/default.aspx; "LMP Contour Map," MISO, n.d., https://api.misoenergy.org/MISORTWD/lmpcontourmap.html.
[187] 2019 Brown and O'Sullivan.
[188] 2019 Brown and O'Sullivan.
[189] "Resource Adequacy," California Public Utilities Commission, accessed January 15, 2018, http://www.cpuc.ca.gov/RA/. The values for each year are taken from the respective RA reports, with the exception of the 2013 and 2014 data, which came from a joint report.
[190] For 2010 and 2011, we used the median price. After 2011, the reporting standards change. Analysis prior to 2014 is detailed in some graphs in the Appendix.

legally mandated to procure battery power, the contracts that batteries receive may be higher than the mean. Therefore, these prices likely represent conservative estimates.

2.3.2 ISO-NE

ISO-NE's Forward Capacity Auction is run 3 years in advance of when the product must be delivered.[191] Additional reconfiguration auctions are offered annually, in addition to 2 months prior to each delivery month. [192] Most activity is in the Forward Capacity Auction, so these prices are utilized.[193]

One capacity area had separate prices from the rest of the ISO. Prices diverge for Northeast Massachusetts/Boston in the 2016/2017 and 2017/2018 delivery years.[194]

Dispatch zone was provided on request from ISO-NE. To match each individual node with its capacity price, dispatch zones are mapped to capacity zone, as shown in Figure 4.

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[191] Jeff Mislak, "Capacity Supply Obligation Bilaterals and Reconfiguration Auctions" (October 23, 2017).

[192] "Overview and Timeline of Reconfiguration Auctions and capacity obligation Bilateral Periods," accessed June 7, 2018, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/overview-and-timeline.

[193] New resources can elect to receive the Forward Capacity Auction clearing price (adjusted for inflation) for up to seven years.[193]

[194] "Key Grid and Market Stats: Markets," ISO New England, n.d., https://www.iso-ne.com/about/key-stats/markets#fcaresults.

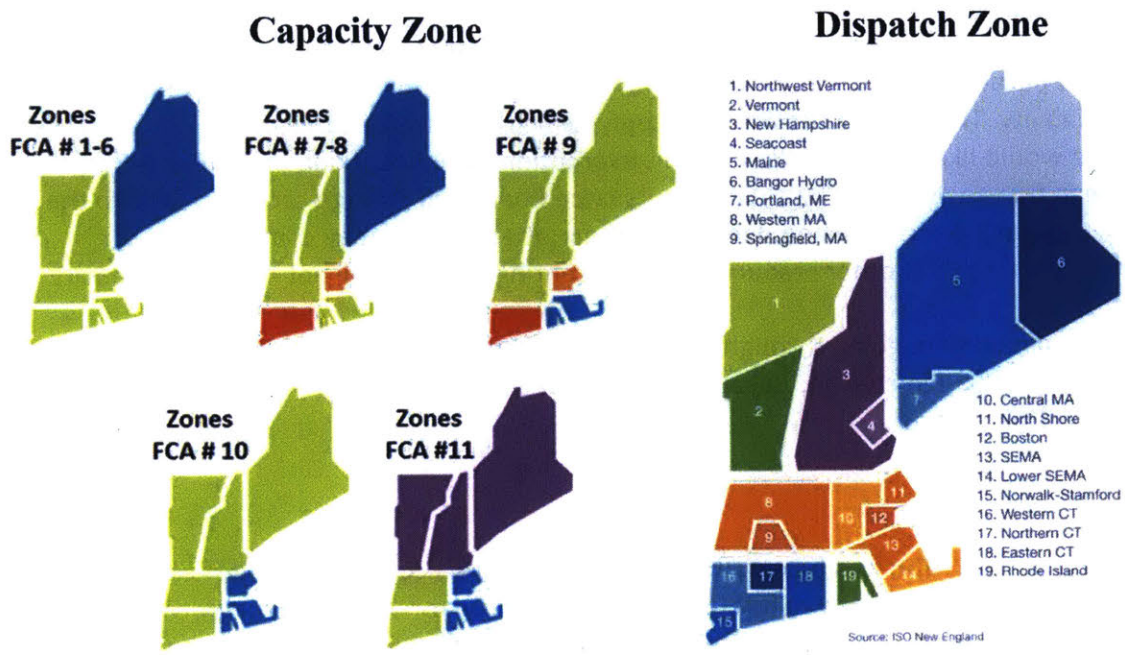

Figure 4: ISO-NE Capacity Zones and Dispatch Zones

ISO-NE transitioned to its "Competitive Auctions with Sponsored Policy Resources" (CASPR) for the 2022/2023 delivery year.[195] This is a two-stage capacity market. In the first stage, the Forward Capacity Auction functions about how it did before.[196] In the second phase (the "Substitution Auction"), retiring resources can exchange their capacity obligations with new state-subsidized entrants. The objective of CASPR is to preserve market signals in the presence of price suppression. Until 2024, there looks to be about 500 MW of state subsidized resources that can participate in the Forward Capacity Auction as price takers.[197] This is a nice exemption made for renewable resources that allows them to clear when they likely would not otherwise. This is because resources in the Forward Capacity Auction are subject to a price floor. The goal of price floors (called minimum offer price rules) is to prevent subsidies from warping market outcomes. For certain technologies, these price floors are quite high because of the resource's

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[195] Matt Brewster, "Competitive Auctions with Sponsored Policy Resources; Conforming Changes and Enhancements," (July 17, 2018).

[196] "ISO Newswire - Updates - ISO-NE Files Proposal to Harmonize Competitive Markets and State-Sponsored Resources," accessed January 12, 2018, http://isonewswire.com/updates/2018/1/8/iso-ne-files-proposal-to-harmonize-competitive-markets-and-s.html.

[197] "Qualification Process for New Generators," accessed April 6, 2019, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-new-generators.

underlying costs. Because of higher capital costs, these price floors can often prevent renewable resources from participating. But, the resources that cannot receive a capacity commitment because of price floors are still functioning in the market, and to some extent, provide reliability. This can lead to an oversupply, which is costly for consumers.

Storage would likely want to slip into this exemption category. If not, storage could still participate in first auction, but be subject to its price floor.[198] If storage cannot slide into the exception category, which is scheduled to disappear, then storage may compete in the substitution auction.[199] If other resources are not retiring, storage will not receive a capacity payment.

Capacity markets are going through, and will undoubtedly continue to go through, significant market design change. Because of continued market redesign, capacity markets carry some element of risk.

2.3.3 MISO

Unlike NYISO, PJM, and ISO-NE, MISO is predominately comprised of vertically integrated utilities. The capacity market serves as a backstop for vertically integrated utilities to meet state requirements. The last centralized capacity market to be developed, the annual Planning Resource Auction began in 2013/2014.

We map the latitude and longitude of each MISO node to the publicly available planning zones.[200] If the node's planning zone is missing, then the node is assigned to planning zone 5, which is chosen because of its lack of divergent price activity. In 2014, MISO added zone 8 for Arkansas and zone 9 for Louisiana, Texas, and Mississippi. In 2016, Mississippi was moved from zone 9 into a new zone 10 (Figure 5).[201] In short, a node's zone may change from one year to the next.

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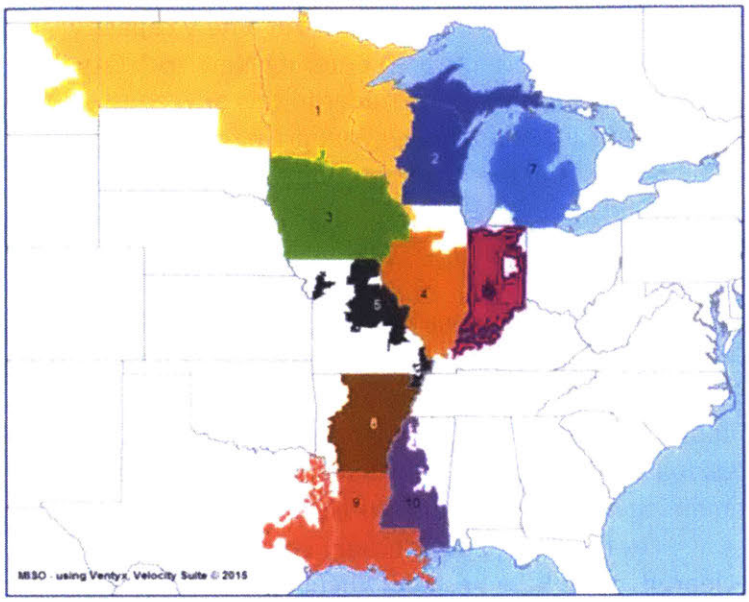
[198] Ryan Hoskin and Matthew Brewster, "Forward Capacity Market Substitution Auction for FCA #13," (October 11, 2018), https://www.iso-ne.com/static-assets/documents/2018/10/20181011-fcm-substitution-auction-fca13.pdf.
[199] "Competitive Auctions with Sponsored Policy Resources (CASPR) Project."
[200] "LMP Contour Map," MISO, n.d., https://api.misoenergy.org/MISORTWD/lmpcontourmap.html.
[201] "2016/2017 Planning Resource Auction Results" (MISO, April 15, 2016), https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf.



Source: MISO

Figure 5: MISO Planning Zones

It is worth noting that batteries may be more likely to receive their contracts from a rate-based utility than from the competitive marketplace. Utilities may be better positioned to adjust to state goals and leverage the benefits felt by consumers from storage usage.

2.3.4 NYISO

NYISO solves for a capability (otherwise known as strip) auction roughly 30 days prior to a six-month operating period. This operating period is May through October for the summer, and November through April for the winter. There is also a monthly auction roughly 15 days prior to the operating month, and a spot auction 2 to 4 days prior to the operating month.[202]

As determined from Winter 2015/2016 prices through Winter 2016/2017 prices, over 90% of trading occurs in the spot market. Monthly spot market prices in $/kW-month were thus used for this analysis. [203]

The NYISO-provided zone for each node was matched to its capacity market zone (Figure 6).[204] If a node's zone is missing, the node is deferred to the unconstrained New York territory.

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[202] Nicolé Grottoli, "Installed Capacity (ICAP) Market" (June 8, 2017).

[203] Unlike the pervious auctions, the spot auction uses an administratively set demand curve as opposed to load bids. "NYISO Installed Capacity: View Spot Auction Summary," New York Independent System Operator, n.d., http://icap.nyiso.com/ucap/public/auc_view_spot_detail.do. At https://www.nyiso.com/installed-capacity-market, click on the link for 'Spot Auction Summary.'

[204] Unlike the other ISOs, where capacity obligations are purchased within the respective zone that the utility functions, in New York the utility is allowed some capacity outside of its geographic scope. "Electric Power Markets: New York (NYISO)," Federal Energy Regulatory Commission, n.d., https://www.ferc.gov/market-oversight/mkt-electric/new-york.asp.

Figure 6: NYISO Capacity Zones

In May 2014, NYISO carved out a new capacity price to differentiate the area entering New York City. For the 2014 calendar year, the nodes in this new zone received the 2013 wider New York price for January through May, and the 2014 new zone price subsequently.

2.3.5 PJM

PJM's capacity market, called the Reliability Pricing Model, is run 3 years in advance of the delivery year (like ISO-NE), with reconfiguration auctions offered 20, 10, and 3 months ahead. [205] The first auction, called the Base Residual Auction, clears on a demand curve, and the remaining incremental auctions clear on bids.[206]

For the 2015/2016 delivery year auctions, 164,561.2 MW of total resources were cleared in the Base Residual Auction, while only 1,815.9 MW, 913.2 MW, and -2.0 MW (capacity sold) cleared in the 1st, 2nd, and 3rd incremental auctions, respectively.[207] Like ISO-NE, most activity occurs in the first auction. Participation is mandated for this first auction.

PJM may model up to 27 constrained zones within a given year.[208] These zones are effectively nested. The nodal price defaults to the zone "a level above" if unconstrained (Figure 7). [209]

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[205] *RPM 101: Part 5 - Auction Structure*, n.d., https://videos.pjm.com/media/0_7rn70j6x.
[206] "RPM 101 Overview of Reliability Pricing Model," (April 18, 2017), 101.
[207] "Capacity Market (RPM)." See the '2015 2016 BRA and other Results ' excel file.
[208] "RPM 101 Overview of Reliability Pricing Model," 101.
[209] "PJM Manual 18: PJM Capacity Market" (PJM Capacity Market Operations, July 27, 2017).

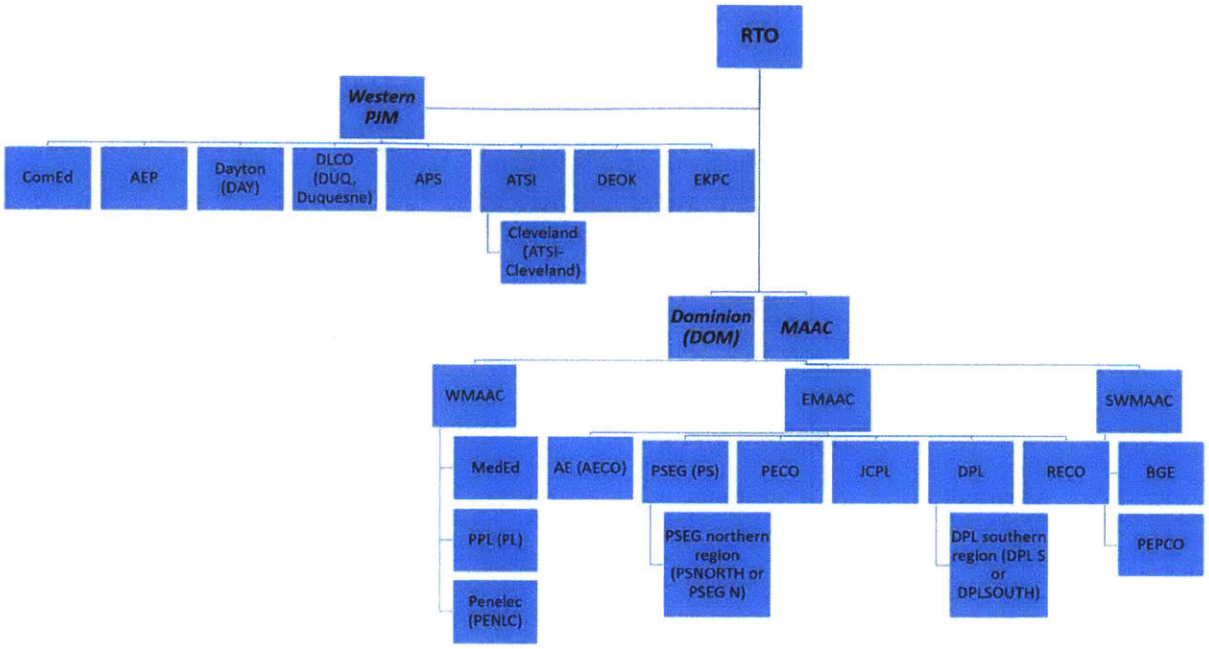

Figure 7: PJM Capacity Zones

The location zones that PJM provides for its nodes, and the price zones in the capacity market, are not the same. Translation between the two is given in Table 11. Considering storage will be a year round resource, the Base Residual Auction prices for the annual or capacity performance products, given in $/MW-day, are used. [210]

Table 11: PJM Capacity Price to Zone Conversion

Prices Available	Description	Zone Matches Available
RTO	System wide ISO price.	Default any missing entries. Dominion and AEP always default.
MAAC	WMAAC was assigned the same price as MAAC because WMAAC never binds.	Penelec and ME (MetEd) consistently default.

[210] Pikes are taken from 'https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-auctions-resource-clearing-price-summary.ashx?la=en' on https://www.pjm.com/markets-and-operations/rpm.aspx. Annual means the resource operates year round, and capacity performance means the resource functions under pay for performance treatment, described in 3.7.4. Annual product applies from 2014/2015- 2017/2018, and capacity performance afterwards.

MAAC + APS	This combination zone only has a price of $69,831.80/MW-year in 2009. To address this, APS is broken out as a separate zone that defaults to RTO when possible, and the MAAC is supplied with its 2009 price.	APS is a given zone. APS otherwise defaults to RTO (not MAAC).
EMAAC		RE is RECO, AEC is AECO. PECO and JCPL default to EMAAC.
SMAAC	BGE and PEPCO may default.	PS is PSEG. PS North could be mapped in the future.[211]
PS	PS North, embedded in PS, has a price of of $185/MW-day in 2012, where PS does not have a price. Aside from diverging prices in 2014, the zones are similar.	
PS North		
DPL South		Nodes are matched using zip code.
PEPCO		Given.
ATSI	The sole difference is that in 2015, ASTI has a price of $130,305 MW-year. Considering ATSI is above ATSI-Cleveland, ATSI and ATSI-Cleveland are equivalent.	There is no additional benefit in mapping zones to ATS Cleveland.
ATSI-Cleveland		
COMED, BGE, DAYTON, DEOK.		Given.
PL		Same as PPL.

[211] See "Subzonal Load Delivery Areas (LDA)" by Zip Code at https://www.pjm.com/markets-and-operations/rpm.aspx.

2.4 Price Analysis

Energy and capacity market prices are described below. Values are nominal.[212]

2.4.1 Energy Markets

Natural gas accounts for more than 30% of U.S. power generation.[213] Natural gas is frequently "on the margin," or in other words, sets the price. As a result, average electric market price is closely correlated to natural gas price (Figure 9). [214]

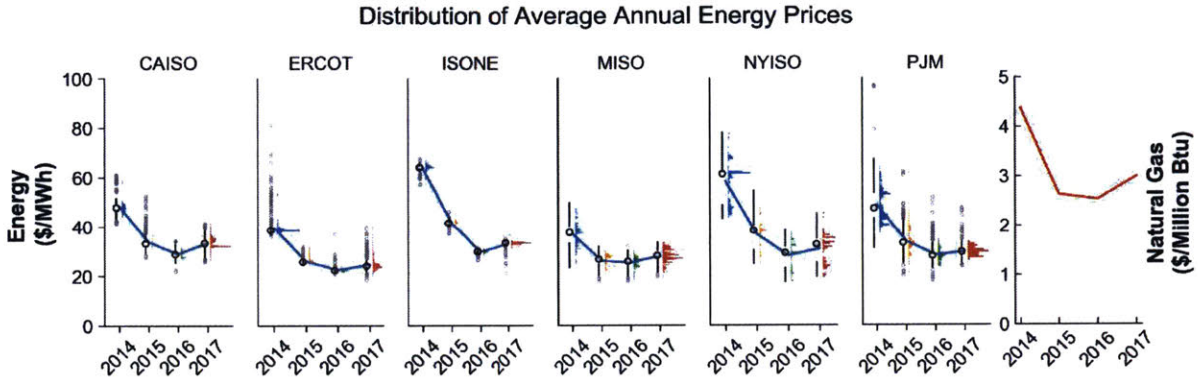

Figure 8: Distribution of Average Annual Energy Prices Across Nodes

The median is the empty black circle, the grey bar is the 5,000-sectioned bootstrapped 95% confidence interval, the black lines are the lesser of either 1.5 the interquartile range or the minimum/maximum value, the interquartile range is the white area in between the black lines, and the grey circles are outliers. The colored 101-bin histogram is the distribution of values across nodes per year (the exact number of nodes is given in Table 10). The solid colored blue lines trace the mean throughout the years.*

Prices are typically highest in ISO-NE. In ISO-NE, natural gas generates about 50% of electricity, and in the 2017 real time market, set the price for 64% of 5-minute pricing intervals.[215] A coastal territory with limited interconnections, natural gas supply to ISO-NE is further constrained because of New York's political unwillingness to construct pipelines. Across

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[212] As opposed to inflation adjusted.
[213] "What Is U.S. Electricity Generation by Energy Source?," U.S. Energy Information Administration, n.d., https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.
[214] Energy Only Dataset, 4-hour duration.
[215] "2017 Annual Markets Report" (ISO New England, Mag 2018), https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf.

all ISOs, 2014 was the highest hourly average priced year because a cold winter stretched gas supply. Natural gas politics and supply greatly influences electricity price.

Of particular interest for storage is the hourly price profile and – given that storage is being reviewed as a non-fossil alternative to support increased renewable deployment – the effect of increased renewable penetration on these hourly price profiles over time (Figure 9).

Annual wind generation in MISO, which has the largest wind generation of ISOs to date, grew almost 100% from 2011 to 2017, to meet about 8% of total MISO demand. Over the observed time period, the daily price profile in MISO demonstrates a single, wide peak period during the daytime, followed by lower evening prices.

Solar suppresses prices in the middle of a sunny day in regions with significant solar generation. The California Energy Commission estimates that from 2013 through 2018, utility-grade solar generation and behind-the-meter solar generation grew 490% and 310% , respectively, to meet 31% (30,262 thousand MWh) and 14% (13,618 thousand MWh), respectively, of California load in 2018.[216] The dip in the middle of the day, also called the "duck curve", is steepest in CAISO because California has the largest installation of solar within U.S. states. Solar appears to have a more significant influence on hourly price profiles than wind because of its consistent daily production curve.

[216] "California Energy Commission – Tracking Progress" (California Energy Commission, December 2018), https://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

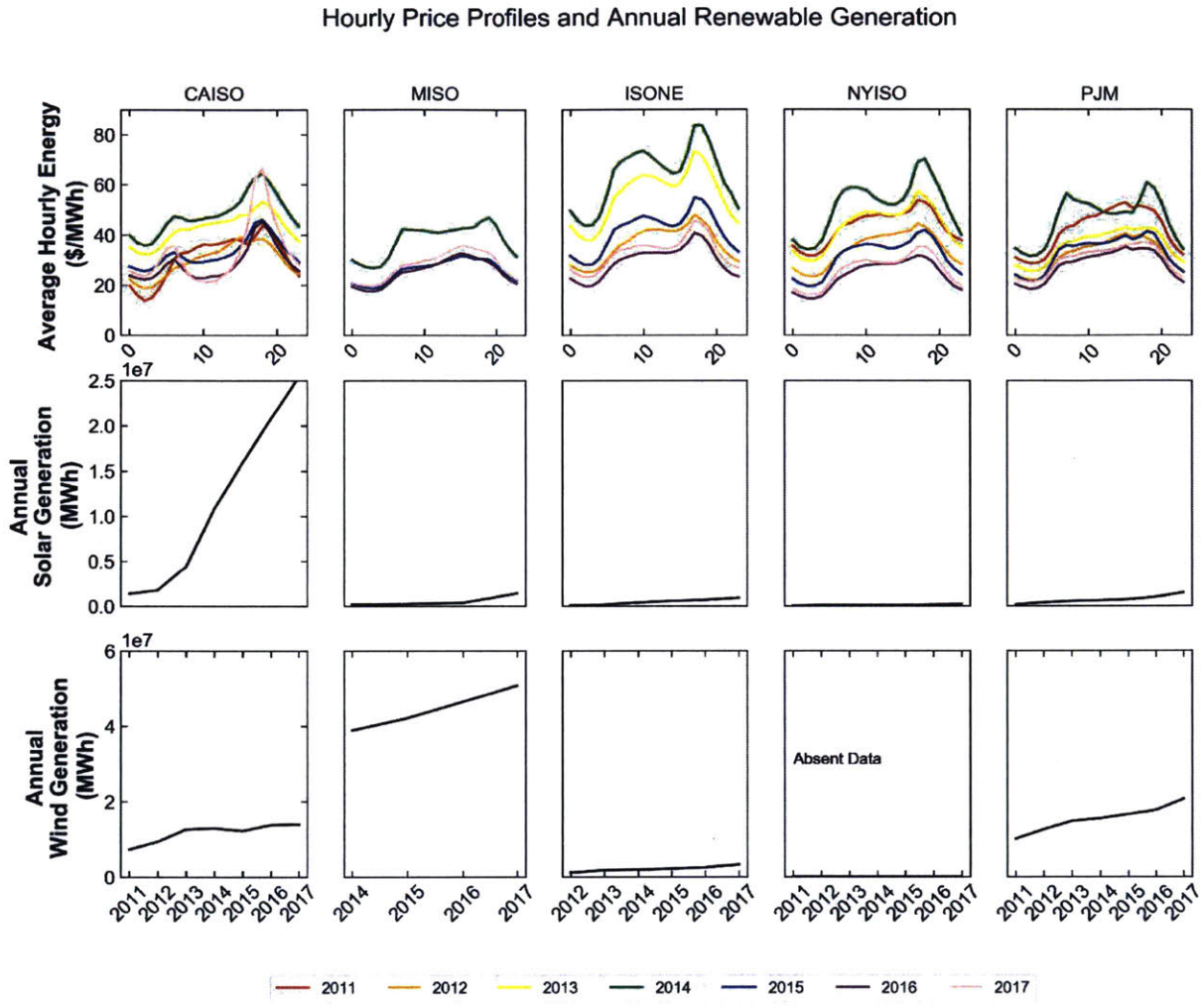

Figure 9: Hourly Price Profiles and Annual Renewable Generation by ISO[217]

2.4.2 Capacity Markets

Capacity prices averaged $3,300/MW-month across ISOs from 2014 to 2017, with a nodal minimum of $65/MW-month (2017, MISO) and an absolute maximum of $14,000/MW-month (2014, NYISO) (Figure 10).

[217] Data as described in Market Data Characterization. Hourly price profiles and wind generation (excluding NYISO) publicly available on ISO websites, and solar generation modeled by 2019 Brown and O'Sullivan.

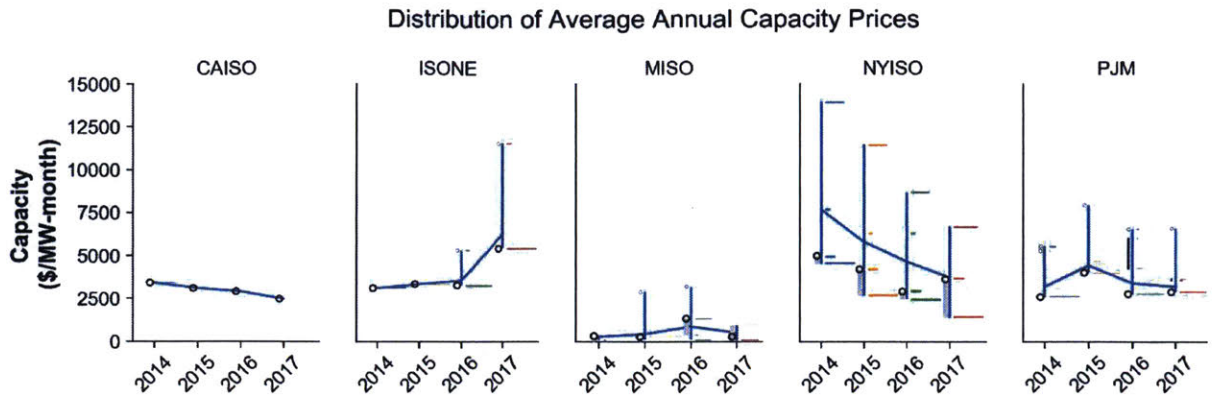

Figure 10: Distribution of Average Annual Capacity Prices Across Nodes

Since annual CAISO capacity prices are the mean bilateral contract price, capacity prices in CAISO are the same across all nodes. As previously discussed, batteries may receive higher than average capacity contracts because of the California state mandates that require utilities to contract with battery developers. Furthermore, as seen by the Aliso Canyon deployments, the fast installation into constrained areas may also precipitate a greater price MISO's capacity market serves as a backstop for vertically-integrated utilities to meet reliability requirements. MISO's capacity market consistently has the lowest prices of the four centralized markets. MISO's external market monitor outlines three major reasons. One reason is MISO's vertical demand curve. A vertical demand curve essentially means the first unit of capacity is valued at $0, and the last unit is valued at a much higher price. This "all or nothing" approach is not only highly volatile but has also leads to some low prices in a last resort market. Second, resources that submit for retirement are not allowed to participate in the capacity market; in other words, resources cannot see if capacity market revenue would change their decision of whether or not to retire. Lastly, MISO zones are based on state lines, not on transmission constraints, so may not accurately reflect locational value of resources.

In some ISOs and years, all zones clear at the same price, while in other ISOs and years, there is price divergence between zones resulting from transmission constraints. The appearance and disappearance of different price zones is shown on a more nodal scale in Figure 11.

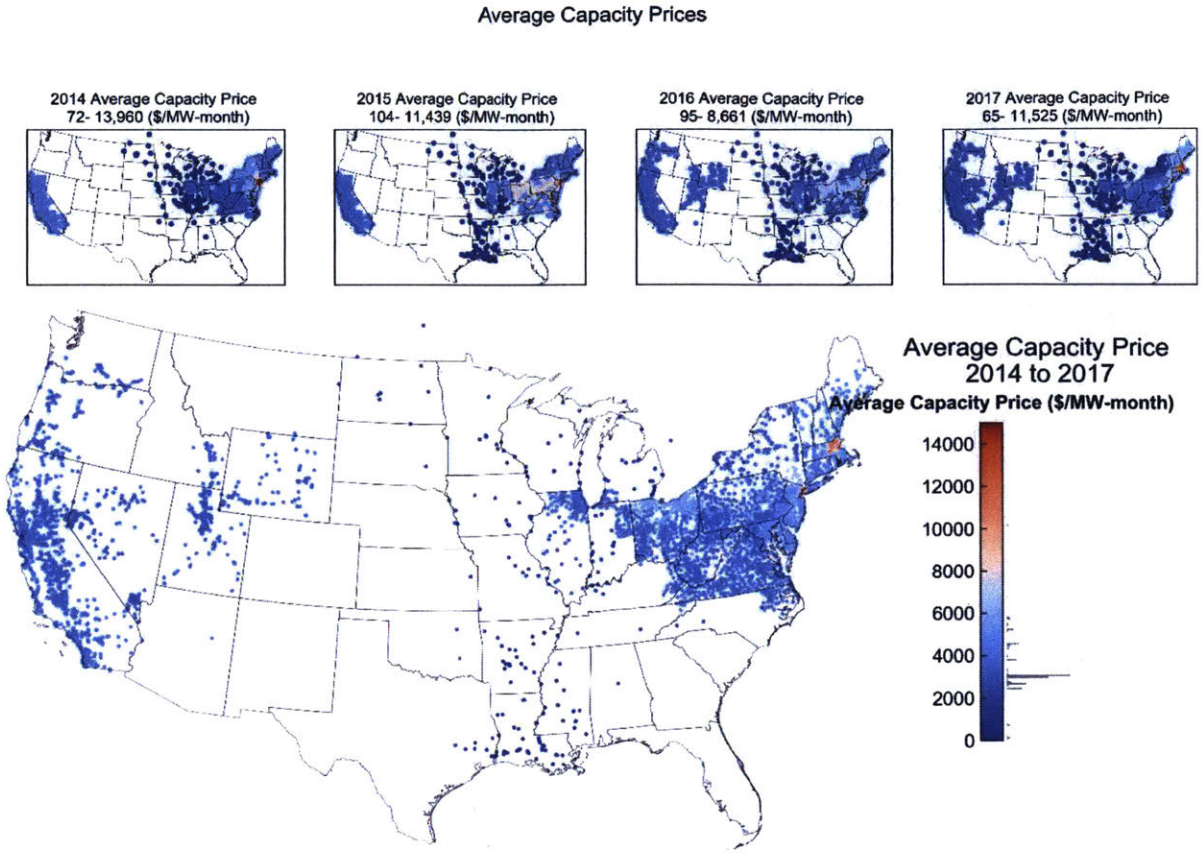

Figure 11: Geographic Maps of Average Capacity Prices

In this figure and similar figures hereafter, the color-bar scale applies to all graphs. The distribution next to the color-bar scale refers to the last graph, which in this case, is the 2014 through 2017 average capacity price. The values provided on top of the graphs refer to the minimum and maximum value for that year.

2.1 Definition of Peak Hours

Capacity revenue will be determined by the product of the capacity price, the rated power output of the battery (in this case, 1 MW), and the calculated capacity credit for the battery. The rated power output represents the amount of power that batteries bid into the capacity market. The capacity credit represents the derate factor, or fraction of rated capacity that the unit is allowed to bid into the market. The capacity credit methodology considers the

net output over a given period of hours. These given hours represent a risk for the system.[218] This method is a simplistic metric to evaluate contribution to reliability.

For the major component of this analysis, capacity credit is taken over the top 1%, 7%, and 12% of highest demand hours across the year. These percentages are chosen because they approximately frame the amount of hours that ISOs use to calculate the capacity credit of intermittent resources (discussed later in Table 12). Assuming that capacity markets are envisioned to ensure adequate supply for yearly peaks, looking at the capacity credit of storage during hours of peak demand provides an assessment of their reliability, as it relates to the underlying principles of capacity markets.

This approach values the contribution of storage to hours determined to be at risk, based on high demand. It is worth noting that high demand hours may not always be high risk hours. For example, equipment may go offline, which would not be reflected.

The classification of what is peak will affect the optimal duration of storage. Percent, year, and underlying load profile will affect what classifies as a peak hour. A lot of consecutive peaks may require a longer duration storage unit. For storage, it matters less when the peak hours are, compared to how long the consecutive peak hours persist. The effect of percent, year, and underlying load profile are described below.

2.1.1 Percent

First, the number of hours counted will affect the classification of a given hour. Increasing the percent of hours over which capacity credit is calculated widens the typical duration of peak hours (see Figure 12 for an example). In 2017 in CAISO, a duration of 4-hours would fully meet 47%, 15%, and 6% of peak hours under 1%, 7%, and 12% of top demand hours, respectively. In contrast, 8-hours of duration would fully cover 94%, 61%, and 33% of the top 1%, 7%, and 12% of top demand hours, respectively. Longer duration units may fully meet more peak hours than shorter duration units, in particular when capacity credit is taken across a greater number of hours, because peak hours may be consecutive.

[218] Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, "Comparison of Capacity Value Methods for Photovoltaics in the Western United States" (National Renewable Energy Lab.(NREL), Golden, CO (United States), 2012).

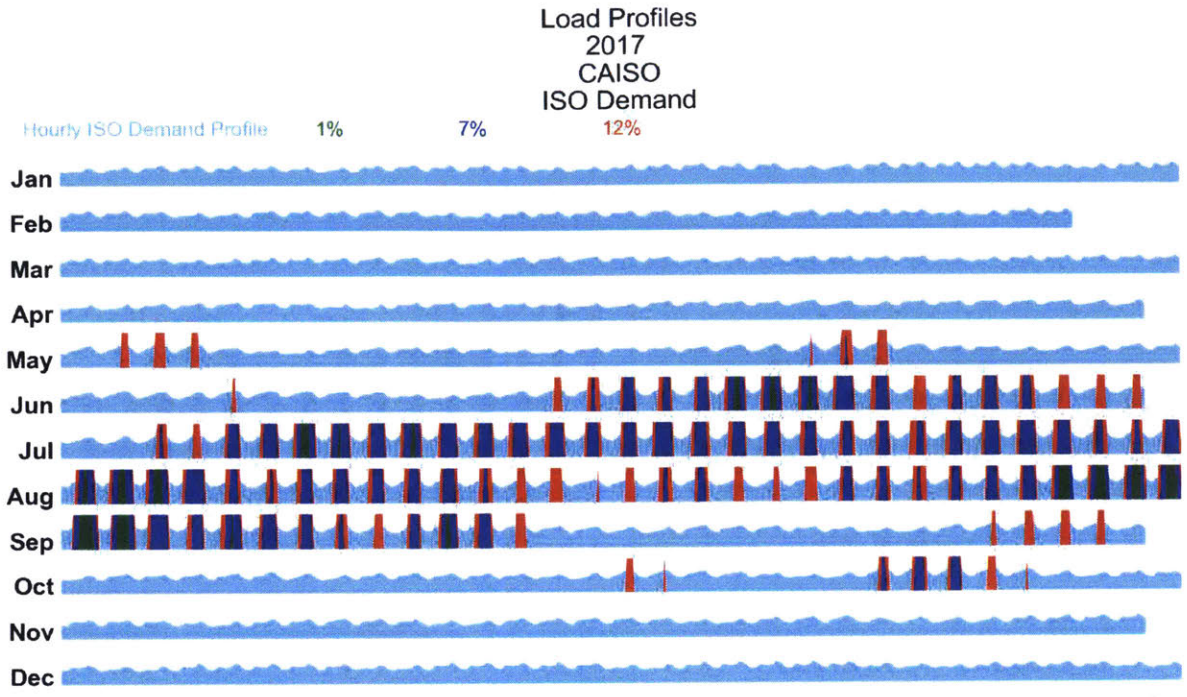

Figure 12: Peak Hour Classification: Percents

2.1.2 Year

Second, the timing of peak hours will depend on annual conditions. Peak hours may change from year to year. Between 2014 versus 2017 in CAISO under 7% of top load hours, only 51% of the timing of peak hours are the same (Figure 13). However, the longest duration peaks in 2014 and 2017, respectively, are 12 hours and 15 hours, and the mean peaks are 7 hours and 8 hours. While there is no guarantee that a tough winter or hot summer would not drastically skew values, for 2014 through 2017 it does not appear that from year to year, the durations of consecutive peak hours drastically change.

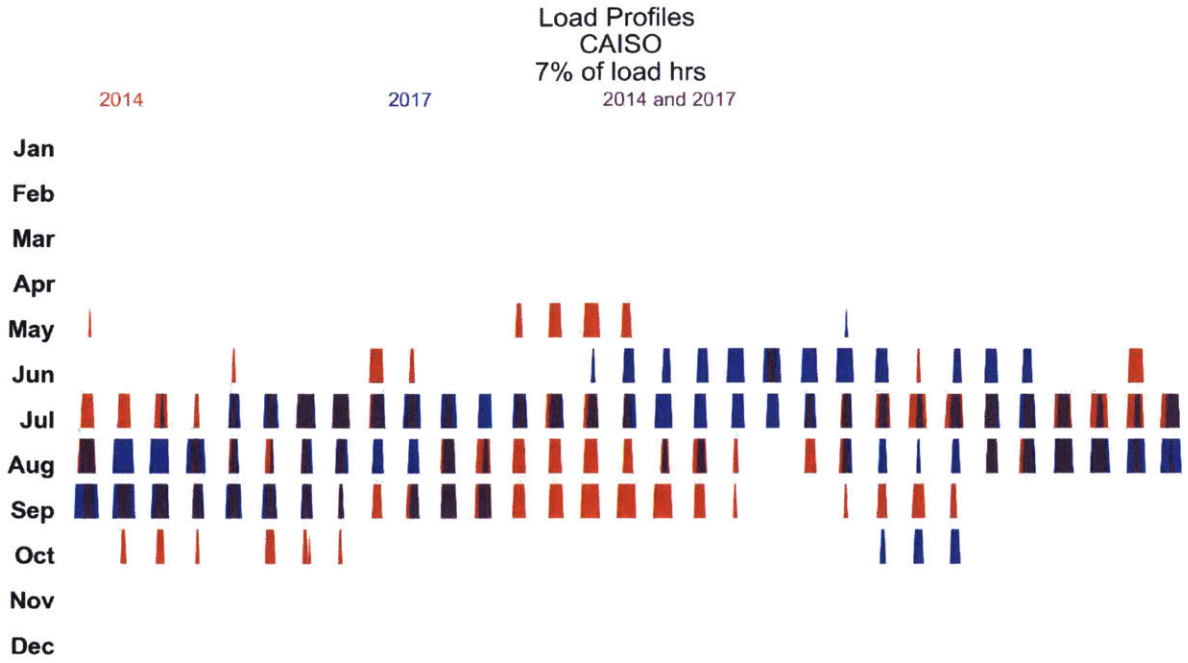

Figure 13: Peak Hour Classification: Year

2.1.3 Peak Hour Classification

To identify the hours of top demand, we must define demand. How demand is defined-whether

1. load as met by the ISO
2. load net of solar generation
3. load net of wind generation
4. load net of both solar and wind generation
5. as an ISO-determined set of hours

-may affect the classification of an hour as peak. Changing what classifies as peak may change the number of consecutive hours that count as peak. This may influence the optimal duration of storage. The effect of changing load profile on the number of hours of consecutive peaks, herby referred to as peak hours durations, is addressed in Section 2.1.4 .

We redefine load profiles because as discussed in Chapter 1, interest in energy storage currently centers around its potential, as a non-fossil resource, to support renewable integration into the electric grid. Redefining demand net of different renewables may be of

interest to regulators; storage may have a higher capacity credit under a net renewable load profile. This may imply that storage has a greater reliability contribution to the grid under larger penetrations of renewable resources, in comparison to the ISO demand profile. This is of predictive importance for developers, and of design interest for regulators, who may want to rethink how they value reliability.

Hourly load is taken from the FERC Form 714 database.[219] Solar generation is taken from 2019 Brown and O'Sullivan, who model utility-scale solar generation from Energy Information Administration Form 860 as well as distributed solar generation from the OpenPV project.[220] With the exception of NYISO, wind generation is provided by ISOs.[221]

Instead of tying capacity credit to peak demand, which is subject to some uncertainty, ISOs calculate the capacity credit of intermittent reosurces across certain hours that they identify as important to the system (Table 12).[222] Ideally, these hours should represent typical hours of jeaopardized system conditions.

Table 12: Summary of Capacity Credit Evaluation Methods Across ISOs

ISO Hour Beginning	**Summer Months**	**Summer Hours**	**Winter Months**	**Winter Hours**	**Percent of Year Hours**
ISO-NE[223] Intermittent	June-Sept	13, 14, 15, 16, 17	Oct-May	17, 18	12
NYISO Intermittent	June-August	14, 15, 16, 17	Dec-Feb	16, 17, 18, 19	8
PJM Intermittent[224]	June through August	14, 15, 16, 17, 18, 19	January through February	5, 6, 7, 8, 17, 18, 19, 20	10
MISO Non-wind[225]	June through and August	14,15,16	-	-	3

[219] "Form No. 714 - Annual Electric Balancing Authority Area and Planning Area Report," Federal Energy Regulatory Commission, n.d., 714, https://www.ferc.gov/docs-filing/forms/form-714/data.asp.
[220] "Form EIA-860 Detailed Data," 860; "The Open PV Project," n.d., https://openpv.nrel.gov/.
[221] "Generation," ERCOT, n.d., http://www.ercot.com/gridinfo/generation; "RT Data APIs," MISO, n.d., https://www.misoenergy.org/markets-and-operations/RTDataAPIs/; "Wind Generation," PJM Interconnection, n.d., https://dataminer2.pjm.com/feed/wind_gen/definition; "Daily Generation by Fuel Type," ISO New England, n.d.; "Renewables and Emissions Reports," California ISO, n.d., http://www.caiso.com/market/Pages/ReportsBulletins/RenewablesReporting.aspx.
[222] "Installed Capacity Manual Attachments"; "Manual No. 011 Business Practices Manual: Resource Adequacy" (MISO, January 22, 2018); "ISO New England Manual for the Forward Capacity Market (FCM) Manual M-20" (ISO New England Inc., February 3, 2017); "PJM Manual 18: PJM Capacity Market."
[223] Jacques Asselin and Jim Nichols, "Generation: Resource Registration and Performance Auditing" (October 23, 2017).
[224] Conleigh Byers, Todd Levin, and Audun Botterud, "Capacity Market Design and Renewable Energy: Performance Incentives, Qualifying Capacity, and Demand Curves," *The Electricity Journal* 31, no. 1 (2018): 65–74.
[225] Ronald Matlock, "Level 200: Resource Adequacy," (n.d.).

Furthermore, some ISOs model storage may look at the capacity credit of storage in alterantive ways. The specifics of these models are discussed in Section 3.7, which delves in to more ISO rules, but the hours are given here in Table 13.

Table 13: Alternative ISO-Specific Capacity Credit Modeling

ISO Hour Beginning	Summer Months	Summer Hours	Winter Months	Winter Hours	Percent of Year Hours
NYISO (starting 2021): Energy Storage Resources: Before 1,000 Incremental New Resources After January 1st 2019	May through October	13, 14, 15, 16, 17, 18	November through April	16,17,18,19,20,21	25
NYISO (starting 2021): Energy Storage Resources: After 1,000 Incremental New Resources After January 1st 2019	May through October	12, 13, 14, 15, 16, 17, 18, 19	November through April	12,13, 14, 15,16,17,18,19,20	33
MISO and NYISO: Energy Limited Resources	Number of daily hours required to bid is equal to storage's duration				4 hour durations; 16%; 8 hour durations, 33%
CAISO: Base Flexibility: 2019 & recommended 2020[226]	5 ,6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21				71
CAISO: Peak Flexibility: 2019 & recommended 2020	15, 16, 17, 18, 19				20

[226] Clyde Loutan, Hong Zhou, and Amber Motley, "Flexible Capacity Needs and Availability Assessment Hours Technical Study for 2020," (April 4, 2019), http://www.caiso.com/Documents/Presentation-PreliminaryFlexibleCapacityNeeds-AvailabilityAssessmentHourRequirements.pdf.

CAISO: Super Peak Flexibility: 2019 & recommended 2020	15, 16, 17, 18, 19 non-holiday weekends	14

2.1.4 Summary Statistics

We refer to the number of hours in a row that are peak hours as "peak hours durations." Peak hours durations, as categorized by the 25%, 50%, 75%, and 100% percentiles, can be interpreted as the duration needed to achieve a theoretical capacity credit equivalent to that percentile. In other words, if the 25% percentile of the peak hours durations from 2014 through 2017 across ISOs is 4 hours, then a 4-hour storage unit can receive a maximum theoretical capacity credit of 25%. We craft this simplistic metric to test as a predictor against our dispatch results. This simplistic metric may reflect how market regulators and developers think about the requirements of their system.

Across all ISOs under the demand profile, under 7% of load hours from 2014 through 2017, 8-hours of duration can achieve a theoretical 50% capacity credit (in other words, 8-hours of duration meets the 50% percentile of consecutive peak hours) and 11 hours can receive a theoretical 75% capacity credit (11-hours of duration meets the 75% percentile of consecutive peak hours).

At 12% of hours (the greatest number of hours used to calculate capacity credit for intermittent resources) across ISOs under the demand profile, 13-hours can achieve a 75% capacity credit across ISOs, but there is slightly more variation amongst ISOs in meeting the 25% or 50% percentile of peak hour lengths. The longer-duration extreme is in CAISO, where 8 and 10-hours can achieve a 25% and 50% capacity credit, and the shorter-duration extreme is in ISO-NE, where 3-hours and 5-hours can achieve the same 25% and 50% capacity credits. Regardless, even under a 12% simplified metric, storage durations of half days- not full days- can achieve a 75% capacity credit.

To summarize, across percentages, to receive a 50% capacity credit requires no more than 8-hours of duration. To contextualize, this capacity credit is greater than the approximately 30% ISO average of wind and solar capacity credits, but less than the approximately 90% average of hydroelectric resources.

To have a capacity credit of 100% requires meeting all peaks. Under 1% of load hours, to meet all peaks across ISOs requires at most 11-hours in duration. Under 7% of load hours, a duration of 17 hours will meet all peaks, with the exception of PJM in 2014, which needs 33 hours of duration. However, in 2015 through 2016 in PJM, a duration of 14 hours would meet all peaks; this 2014 peak hour duration is an outlier. Under the more extreme 12% of load hours, to meet all peaks requires at most 18 hours, with the exception of 2014 in MISO and PJM, which require 42 hours and 69 hours. But, MISO and PJM's next highest annual peak hours durations are 18 hours (MISO, 2015) and 20 hours (PJM, 2017), respectively. To fully meet all

peaks, with only a few annual exceptions in specific ISOs, requires less than a day of storage capacity.

In terms of redefining the load profile, which could change peak hours durations, since MISO has the greatest net wind penetration to date, we would expect that redefining the load profile from ISO demand to net wind would be the most significant in MISO. But for MISO in 2017, 89% of hours that classify as peak remain the same between the ISO demand and net wind profile. Wind production peaks tend not to align with demand peaks, so if wind production increases, the timing of peak hours may not be affected. In 2017 under 7% of hours, the 50% and 100% percentiles of ISO demand are 8 and 14 hours, respectively, but under net-wind, 9 and 15 hours (See Table 23 in Appendix). The capacity credit of shorter-duration storage may be lower under net-wind profiles. However, since the differences in peak hour classification (and as a result, in peak hours durations) between ISO demand and net-wind are an hour or less (in 2014 as well as 2017), we may not expect large differences in capacity credits between the two load profiles.

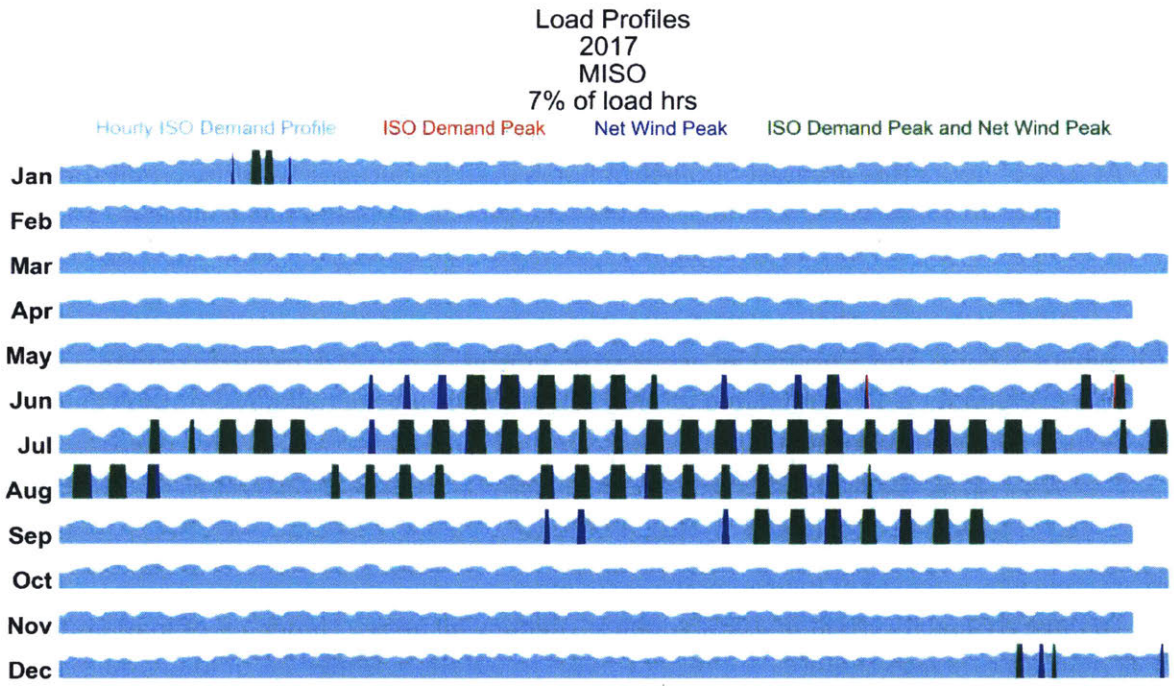

Figure 14: Peak Hour Classification: Net-wind

For CAISO in 2017, under 7% and 12% of top load hours, 70% of what classifies as a peak hours remains the same (Figure 15). In 2017, the median and maximum durations under ISO demand are 8 and 15 hours, and under net-solar, 6 and 13 hours. The capacity credit of storage

MISO				
Demand	8	4	10.25	17
Net of Wind and Solar	9	5	11	17
NYISO				
Demand	8	4	12	16
Net of Wind and Solar	8.5	4	12	16
PJM				
Demand	7	4	10	33
Net of Wind and Solar	7	4	10	32

To reiterate, this simplified metric suggests a duration of 8-hours should theoretically receive a capacity credit of at least 50% across ISOs, years, demands, and percents, and a duration of 12-hours is needed for a theoretical capacity of 75%.

However, a storage unit of 6-hours could theoretically achieve a 100% capacity credit if measured across the same hours used for intermittent resources (Table 15). This duration is less than half of what peak demand would otherwise indicate as necessary.

Table 15: Peak Hours Durations for Intermittent Resources' Capacity Credit Calculations

ISO	**Percentile**			
	25%	**50%**	**75%**	**100%**
ISO-NE	2	2	5	5
MISO	3	3	3	3
NYISO	4	4	4	4
PJM	4	4	6	6

Some ISOs use different peak windows for storage resources. In NYISO and MISO, at most 8-hours is needed, and in CAISO, 5-hours, to theoretically achieve a 100% capacity credit (Table 16).

Table 16: : Peak Hours Durations for ISO-Specific Capacity Credit Rules

Model	**ISO**	**Percentile**			
		25%	**50%**	**75%**	**10%**
Energy Storage Resources: 6 hour	NYISO	6	6	6	6
Energy Storage Resources: 8 hour	NYISO	8	8	8	8
Energy Limited Resources: 4 hour	MISO and NYISO	4	4	4	4
Energy Limited Resources: 8 hour	MISO and NYISO	8	8	8	8
Peak Flexibility	CAISO	5	5	5	5
Super Peak Flexibility	CAISO	5	5	5	5

may increase under net-solar profiles. Overall, shorter –duration storage may support solar more than wind.

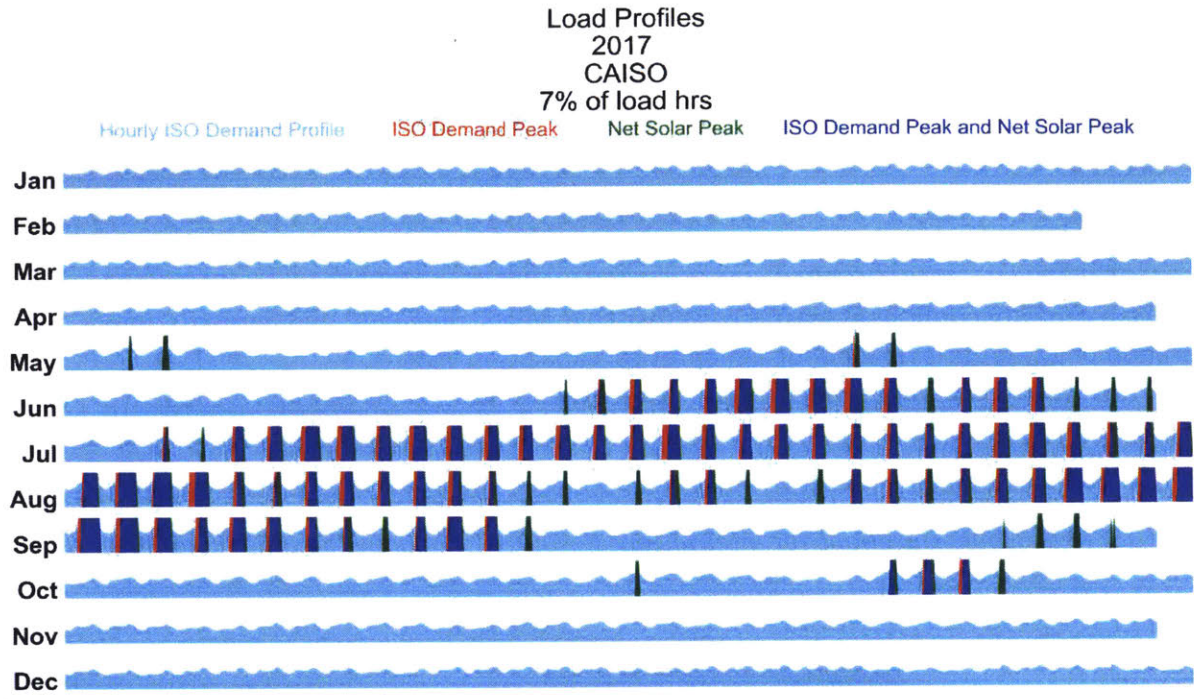

Figure 15: Peak Hour Classification: Net-solar

Across all profiles, percents, years, and ISOs, in general the most significant differences between alternative load profiles and ISO demand occurs in CAISO (Table 14 and Table 21 in Appendix). This is because of CAISO's aforementioned solar penetration (Table 22 in Appendix).

Table 14: Peak Hours Durations in 2014 through 2017 across 7% of Hours

Longest peak durations are colored in red, and shortest in green.

7% of load hours for 2014 through 2017	25% Percentile	50% Percentile	75% Percentile	100% Percentile
CAISO				
Demand	8	5	10	15
Net of Wind and Solar	6	4	8	14
ISO- NE				
Demand	6	3	11	16
Net of Wind and Solar	6	3	11	16

ISO determined hours, whether for intermittent resources or storage resources, halve the required duration to achieve a theoretical 100% capacity credit. With the exception of PJM, which requires 10-hours of duration to be eligible for capacity payments, most ISOs require 4-hours of duration at minimum. This appears shorter than durations empirically necessary to achieve a 50% capacity credit.

Keeping in mind the characterization of prices and the peak load hours which will be used for capacity credit calculations, we maximize the revenue of hypothetical 1 MW batteries in the energy and capacity markets, as determined in the next section.

2.2 Linear Optimization

Dispatch in the different energy/capacity markets is treated as a linear optimization that maximizes total revenue under perfect foresight of electricity prices, capacity prices, and critical capacity hours within a given calendar year. Objective functions are given in Section 2.2.1 and Section 2.2.2, with constraints given in Section 2.2.3.

2.2.1 Energy

Batteries of 1 MW (power capacity) were dispatched in the energy market alone to provide a baseline. Energy market revenue is a function of the hourly energy price and net output. Profit in the energy market is maximized according to equation 1:

$$1.)\ Total\ Revenue, energy\ only = Max \sum_{hr=0}^{hrs} (lmp_{hr} * [sell_{hr} - buy_{hr}] - OM_{cost*} sell_{hr})$$

Where *hr* (integer) annotates the hour in the year, *hrs* is the number of hours (integer) in a year, lmp_{hr} is the DAM energy price ($/MWh), $sell_{hr}$ is the battery's output power (MW) in the given hour, buy_{hr} is the battery's purchased power (MW) in that hour, and OM_{cost} is the variable operational cost.

Operational costs for batteries represent the costs of degradation. Wankmüller et al model degradation in MISO's RTM energy market in three different ways, and find that in comparison to models without degradation, models with degradation generate 12%-46% less revenue.[227] An operational cost is needed to prevent overestimation of revenue.

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[227] Florian Wankmüller et al., "Impact of Battery Degradation on Energy Arbitrage Revenue of Grid-Level Energy Storage," *Journal of Energy Storage* 10 (April 1, 2017): 56–66, https://doi.org/10.1016/j.est.2016.12.004.

Unlike the levelized cost of degradation, which simplifies degradation as some fraction of capital costs spread over usage, 2018 He et al. represents degradation in bids as the 'discounted marginal benefit of usage." [228] Independent of capital costs, this parameter spreads the lifecycle energy market revenue accrued over DAM, monthly/yearly, and lifetime actions, to reflect how degradation can be optimized over short-term use considering how actors schedule across different time horizons. For a 50 MW/200 MWh in CAISO 's energy markets in 2016, the loss of future benefits is $5/MWh. We assume $5/MWh.

The battery is assumed to have perfect foresight of prices. Back-casting, or looking at the past two weeks of prices to determine bids, captures about 90% of revenue.[229] So perfect foresight, although representing the upper bound on profitability, does not appear to dramatically overstate revenue.

2.2.2 Energy and Capacity

Revenue in the capacity market is determined by the product of capacity price, rated output, and capacity credit. To reiterate, capacity credit is

$$\text{Capacity credit } = \frac{\sum_{hr=0}^{hrs} caparray_{hr}[sell_{hr} - buy_{hr}]}{\sum_{hr=0}^{hrs} caparray_{hr} P_{Max}}$$

The battery's net power in an hour is $sell_{hr}$ - buy_{hr}. P_{Max} is the rated output, which in our analysis, is 1 MW. *Caparray* is a year-long hourly array of binaries with a value of 1 in critical hours and 0 in non-critical hours.

Initially, we identify critical hours as the hours of highest load, as determined by some percentage of annual hours. Percents of 1%, 7%, and 12% approximately frame the percent of load hours used to calculate the capacity credit of intermittent resources (detailed previously in Table 12). We define the load as the following:

1.) System-wide demand.

Load data comes from FERC.[230] This is our base case.

2.) The following are sensitivity cases.

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[228] Guannan He et al., "An Intertemporal Decision Framework for Electrochemical Energy Storage Management," *Nature Energy*, 2018, 1.

[229] Sioshansi, Denholm, and Jenkin, "A Comparative Analysis of the Value of Pure and Hybrid Electricity Storage."

[230] U.S. Federal Energy Regulatory Commission (2018). Form No. 714 - Annual Electric
856 Balancing Authority Area and Planning Area Report. https://www.ferc.gov/docs-filing/857 forms/form-714/data.asp.

3.) System-wide demand net of solar generation.

2019 Brown and O'Sullivan simulated PV production.[231] We subtract this PV generation from FERC load data.

4.) System-wide demand net of wind generation.

All ISOs (excluding NYISO) supply wind production data.

5.) System-wide demand net of wind and solar generation.
6.) System-wide demand net of five-times and ten-times solar generation in CAISO.
7.) We artificially increase hourly solar generation in CAISO by factors of five and ten.
8.) System-wide demand net of five-times and ten-times wind generation in MISO.
9.) The hours used to calculate capacity credits for intermittent resources in ISO-NE, MISO, NYISO, and PJM.
10.) The hours of performance expected from a particular type of capacity market product (flexible capacity) in CAISO.
11.) The hours flagged for specific representations of storage in NYISO and MISO.

Dispatch in the energy and capacity markets is optimized according to equation 2:

$$2.)\,Total\ revenue\ (energy + capacity) = Max \sum_{hr=0}^{hrs} (lmp_{hr} * [sell_{hr} - buy_{hr}]) - (OM_{cost} * sell_{hr}) + capval_m * 12 * \left(\frac{1}{\sum_{hr=0}^{hrs} caparray_{hr}}\right) * caparray_{hr} * [sell_{hr} - buy_{hr}]$$

Where $capval_m$ is the capacity price in $/MW-month. The factor of 12 in the equation converts the monthly price into a yearly price.

For PJM and MISO, capacity prices are given in $/MW-day. For CAISO, ISO-NE, and NYISO, capacity prices are given in $/kW-month. Prices are converted to $/MW-month. Strangely, in ISO-NE, MISO, NYISO, and PJM, the capacity market year is not equivalent to a calendar market year; capacity markets run from June 1st through May 31st. For ISO-NE, MISO, and PJM, since the optimization is run for a calendar year, so on June 1st, the capacity prices within the optimization change. NYISO has monthly prices.

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[231] "The Open PV Project"; "Form EIA-860 Detailed Data," 86.

2.2.3 Constraints for Both

Whether the resource is dispatched in the energy market or in the energy and capacity markets, the following constraints apply:

$$3.)\ 0 \leq sell_{hr} \leq 1$$
$$4.)\ 0 \leq buy_{hr} \leq 1$$
$$5.)\ 0 \leq SOC \leq \text{duration}$$
$$6.)\ SOC_{hr} = (SOC_{hr-1} - sell_{hr-1} * \left(\frac{1}{\eta_D}\right) + buy_{hr-1} * \eta_C * (1 - L)$$
$$7.)\ sell_{hr} + buy_{hr} \leq 1$$

Where SOC is the state of charge of the battery (MWh), L is the leakage rate (%), η_D is the discharge efficiency (%), duration is the hours available at maximum 1 MW output (equivalent here to MWh of energy capacity), and η_C is the charge efficiency (%).

Durations of 1-hour target regulation, durations of 4-hours meet MISO, NYISO, and CAISO requirements, and durations of 8-hours double the middle value. So, we model durations of 1, 4, and 8 hours.

Since average of the percent of load hours for intermittent resources across ISOs is about 7%, and 4-hour duration has been necessary to receive capacity payments in NYISO, MISO and CAISO, 7% of top load hours and 4-hour duration is treated the baseline case. Results are generally reported for these parameters for 2014 through 2017, inclusive, unless otherwise noted.

Hour 0 is the beginning of the year. SOC_{hr} is the energy level at the beginning of the hour. The state of charge at the beginning of the year is constrained to be equal to the state of charge at the end of the year. The leakage rate is 0.05% per hour. Charging and discharging efficiencies are set at 90%. [232]

To reduce computing load, the model did not contain a hard binary constraint to prevent instantaneous charging and discharging. Constraint 7 ensures that at most, the battery is operating at its peak capacity for that hour.

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[232] Dylan McConnell, Tim Forcey, and Mike Sandiford, "Estimating the Value of Electricity Storage in an Energy-Only Wholesale Market," *Applied Energy* 159 (2015): 422–32; Kyle Bradbury, Lincoln Pratson, and Dalia Patiño-Echeverri, "Economic Viability of Energy Storage Systems Based on Price Arbitrage Potential in Real-Time US Electricity Markets," *Applied Energy* 114 (2014): 512–19.

3 Revenue Generation

3.1 Energy Market

For 4-hour duration storage across 7% of top ISO demand load hours from 2014 through 2017, energy market revenue averages $24,000/MW-year. Individual nodes range from $3,100/MW-year (2015, MISO) to $256,900/MW-year (2014, ERCOT). ERCOT generally has the highest average revenue followed by NYISO (Figure 16 and Figure 73 in Appendix). ERCOT has the highest energy revenue in part because ERCOT lacks a capacity market; resource adequacy is incentivized via higher priced energy markets.

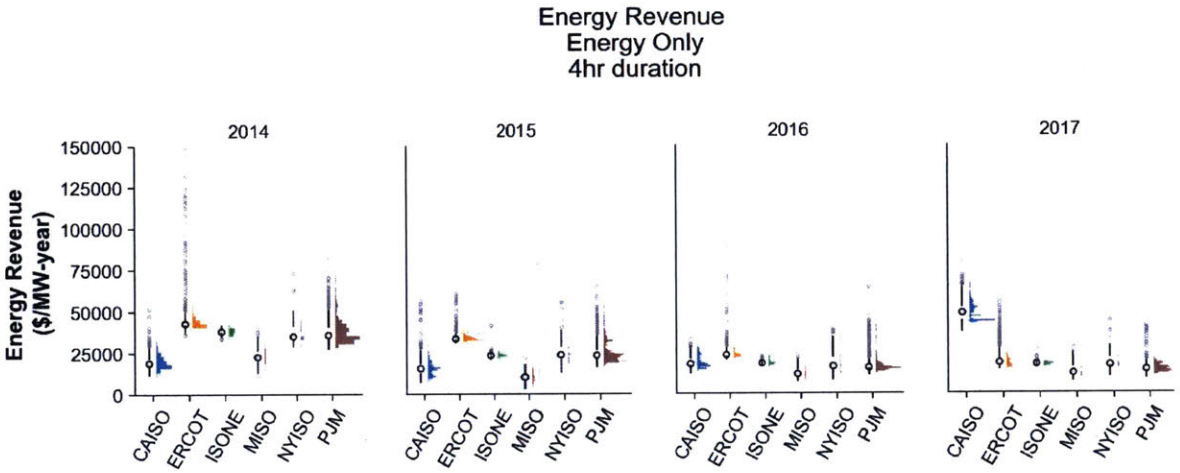

Figure 16: Distribution of Energy Revenue in Energy Only Dispatch

Some high earning nodes in ERCOT in 2014 are out of axis range.

However, as seen in Figure 16, even though ERCOT has the highest average revenue, individual nodes in ERCOT are not always the highest-revenue earning nodes . Each ISO has outlier nodes.

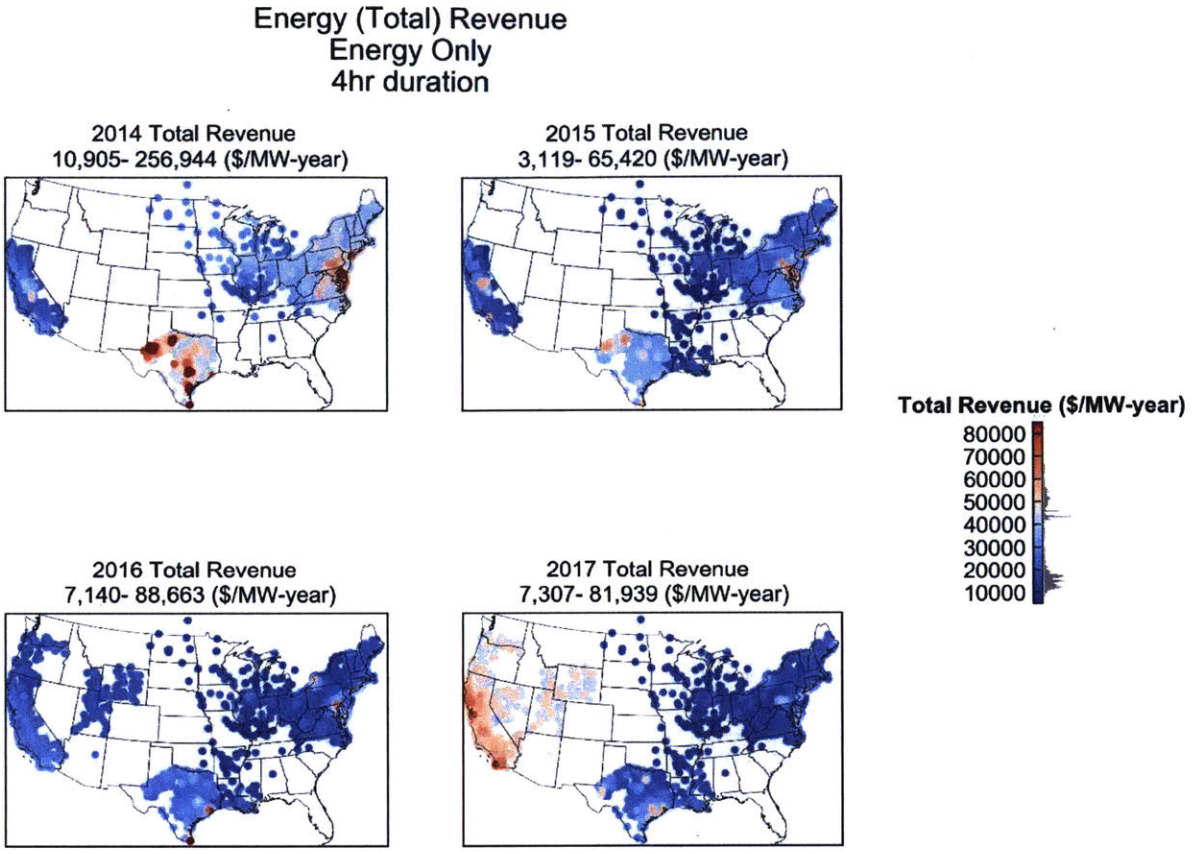

Figure 17: Geographic Maps of Energy Revenue for Energy Only Dispatch Only

If we arbitrarily select the top 1% (100) of revenue-generating nodes each year, ERCOT on average contains 30, but from year to year, this percentage varies. In 2014, ERCOT contained 66 of the top earners, but in 2016, PJM contained 61. CAISO held the top earning locations in 2017. Furthermore, from 2014 through 2017, of what would amount to 400 nodes studied, there are 346 unique nodes. Quite simply, the top revenue generating locations change from year to year. Figure 18 traces the revenue potential of top earning nodes from year to year.

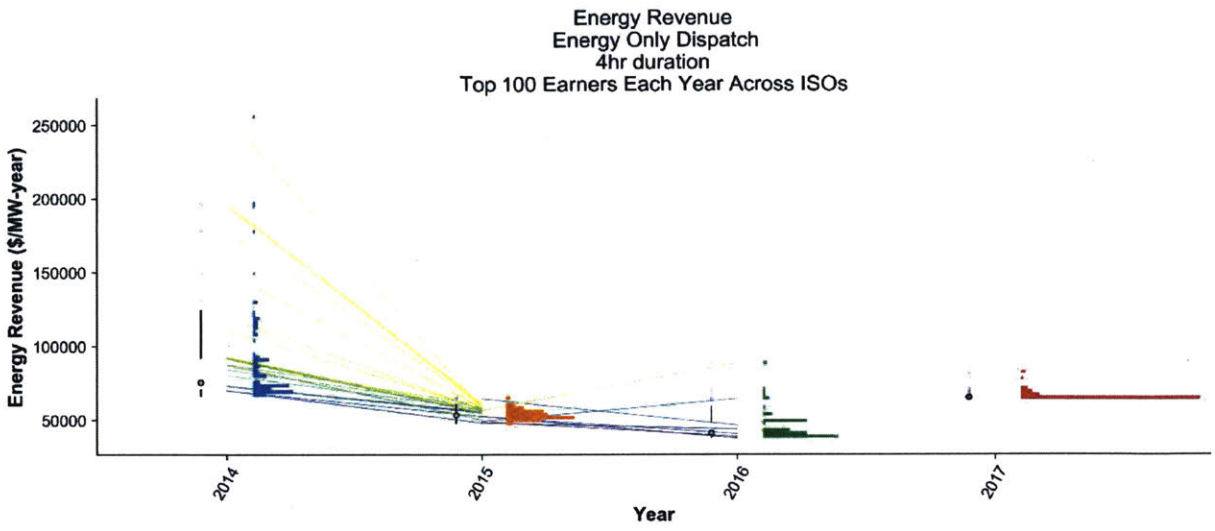

Figure 18: Persistence of Top 100 Earners for Energy Only Dispatch

Each colored line is an individual node. Lines are colored by average revenue from 2014 through 2017. Yellow represents high average earning nodes, and purple low average earning nodes. In 2017, all of the top 100 earning nodes are not previously within the top 100 of earners.

Furthermore, how much money these top 100 nodes make from year to year varies. Of the top 100 nodes, those in CAISO in 2017 made 32% less compared than those in ERCOT in 2014.

Previous analysis found that yearly revenue can range 50%. [233] We confirm that annual variation is significant. The difference between 2014 and 2014 average ISO revenue across all nodes (albeit a simplified metric) shows revenue variation larger than 50%: ERCOT (56% decrease); CAISO (144% increase); ISO-NE (55% decrease); MISO (43% decrease); NYISO (52% decrease); and PJM (63% decrease). From 2014 to 2017, the revenue of individual locations ranged from a 286% annual increase (2016 to 2017, CAISO) to a 71% annual decrease (varied nodes, Figure 19 and Figure 70 in Appendix).

[233] Connolly et al., "Practical Operation Strategies for Pumped Hydroelectric Energy Storage (PHES) Utilising Electricity Price Arbitrage."

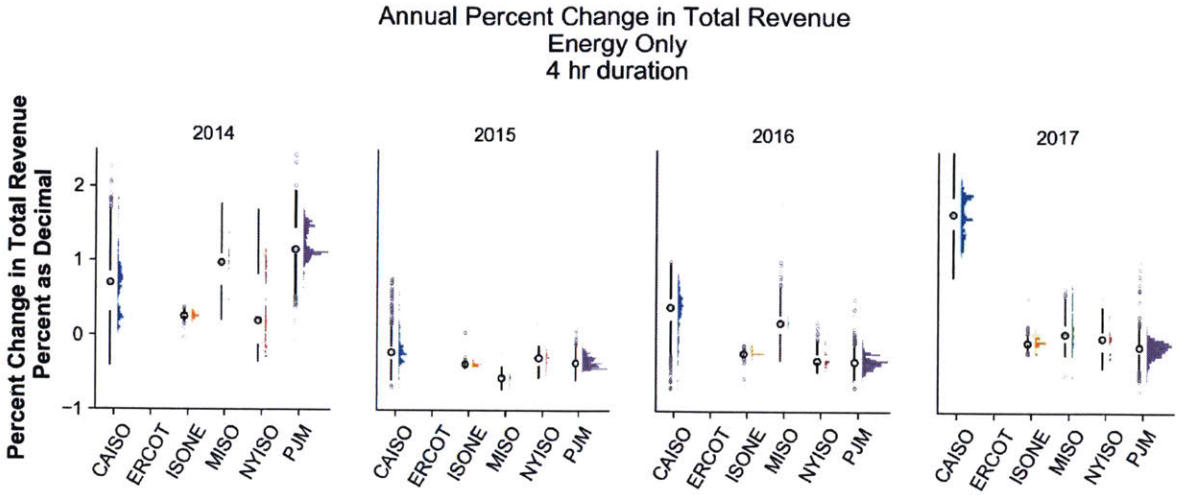

Figure 19: Annual Percent Change in Total Revenue in Energy Only Dispatch

For nodes with consecutive yearly dispatch.

In summary, the location of top revenue earning nodes, and the amount of revenue that these locations earn, is a function of year and ISO. Geographic and temporal variation in revenue contributes to uncertainty.

Storage units with longer durations generates higher revenues per unit of capacity (Figure 20). However, there is a decrease in marginal benefit (of revenue per unit of capacity when increasing energy capability. In 2017 across ISOs, moving from 1-hour to 4-hours of duration is associated with a $17,000/MW-year average increase, but moving from 4-hour to 8-hours of duration with a smaller $6,600/MW-year increase. In 2017 in CAISO, 4-hour storage generates 1.6-times the revenue of 1-hour storage, but 8-hour storage generates 0.2-times the revenue of 4-hours storage (Figure 20).

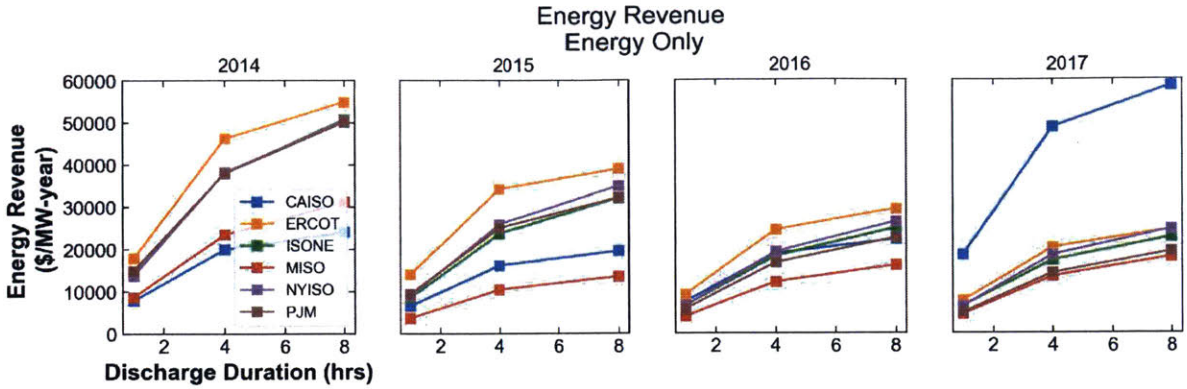

Figure 20: Average Energy Revenue as a Function of Duration in Energy Only Dispatch

On average, the capacity credit of 4-hour duration storage across ISOs from 2014 through 2017 is 56%, 40%, and 35% across 1%, 7%, and 12% of top load hours (Figure 21).

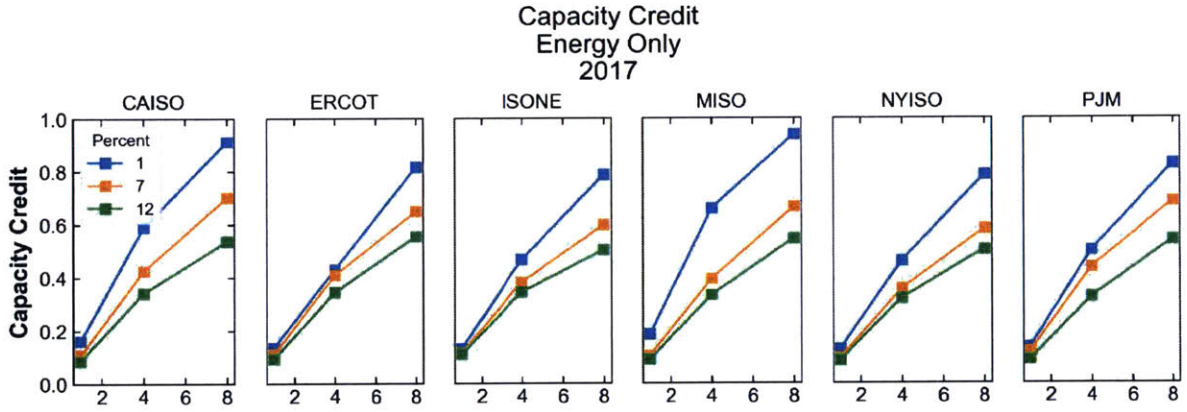

Figure 21: Average Capacity Credit as a Function of Duration in Energy Only Dispatch

3.2 Energy and Capacity Markets

Nodes were dispatched in the energy and capacity market (as described in the methodology in Section 2) with historic energy and capacity prices. Duration, operational cost, year, percent of top load hours, electricity and capacity prices, and the underlying load profiles (whether demand the ISO meets, demand net of solar generation, demand net of wind generation, or both) are independent variables.

The inclusion of capacity into the dispatch may affect the following: energy revenue; capacity credit; capacity revenue; and total revenue.

3.2.1 Energy Revenue

For 4-hour duration storage under 7% of load hours across ISOs from 2014 through 2017, the average loss in energy revenue is 0.5%. The addition of capacity value with minimal loss of energy revenue implies that capacity is a revenue stream that "value stacks." In other words, capacity revenue is an addition (Figure 22).

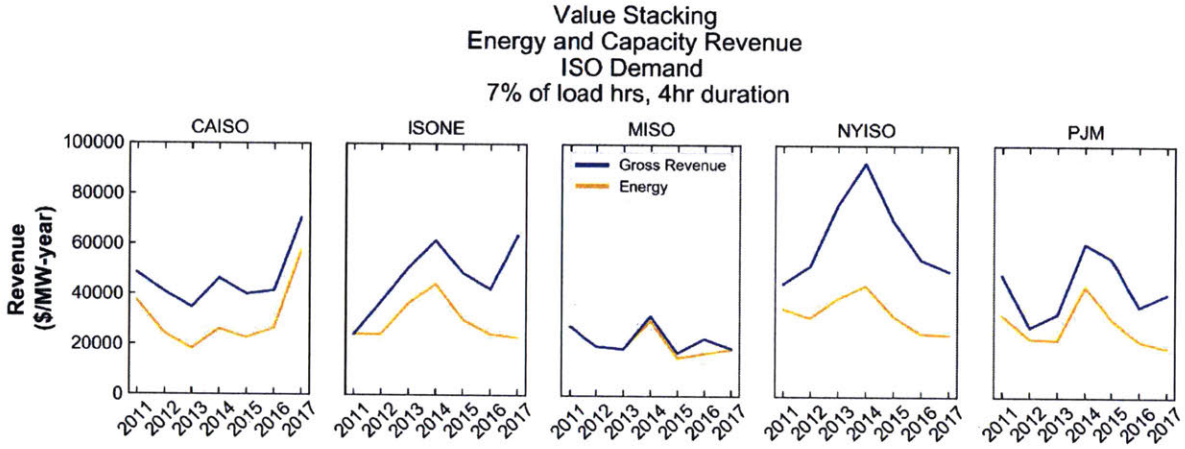

Figure 22: Value Stacking

For 2014 through 2017, the average percent of gross revenue that comes from energy is 64%, although individual nodes range from 23% (2017, ISO-NE and 2015, MISO) to above 98% (all years, MISO). These extremes are reflections of particular years (Figure 23 and Figure 24, and Figure 69 in Appendix).

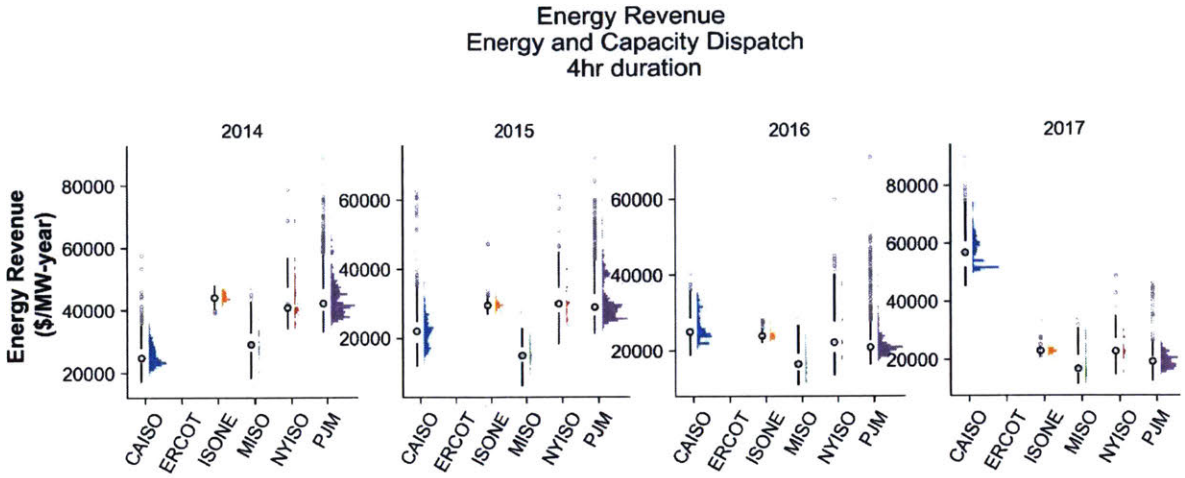

Figure 23: Distribution of Energy Revenue in Energy and Capacity Dispatch

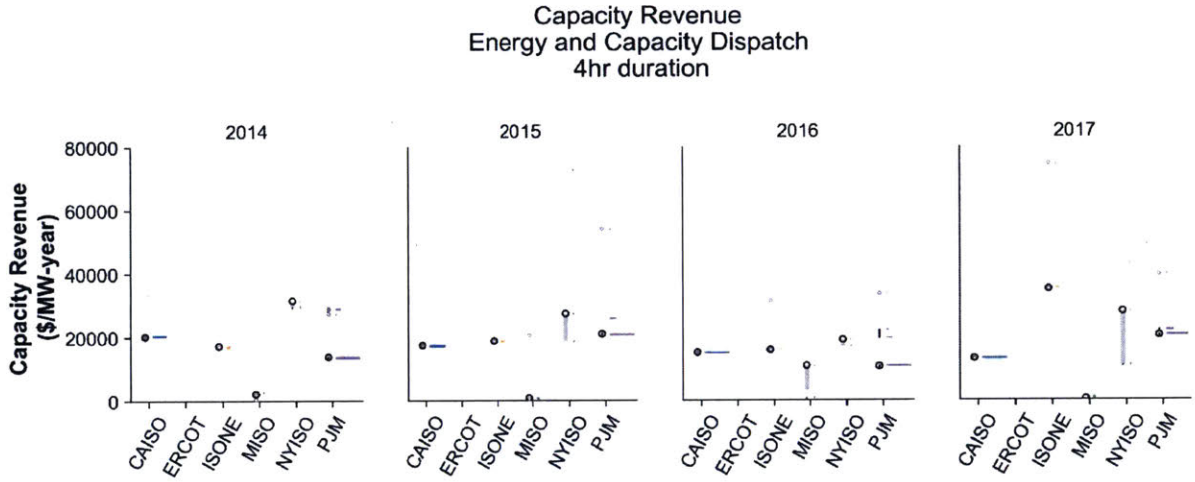

Figure 24: Distribution of Capacity Revenue in Energy and Capacity Dispatch

3.2.2 Capacity Revenue

Capacity revenue averages $19,400 /MW-year across ISOs and years, with an individual node minimum of $187/MW-year (2017, MISO) to an absolute max of $ 86,300/MW-year (2014, NYISO).

2011 Sioshansi et al. assumed that storage units generate $20,000/MW-year to $60,000/MW-year in capacity market revenue in PJM based on a range of 2002 through 2008

historic capacity market prices.[234] 2017 Yu and Foggo tacked on $26,890/MW-year based on 2009-2012 prices in CAISO.[235] These previous estimates are appropriate considering our average and range.

However, there is significant variation in capacity revenue based on location. In NYISO across all years, some locations within the state can make roughly $30,000/MW-year more in capacity revenue than others (Figure 25). As would be expected, capacity revenue streams in New York City are consistently higher than the rest of the state because of the high demand and limited transmission capacity into the city.

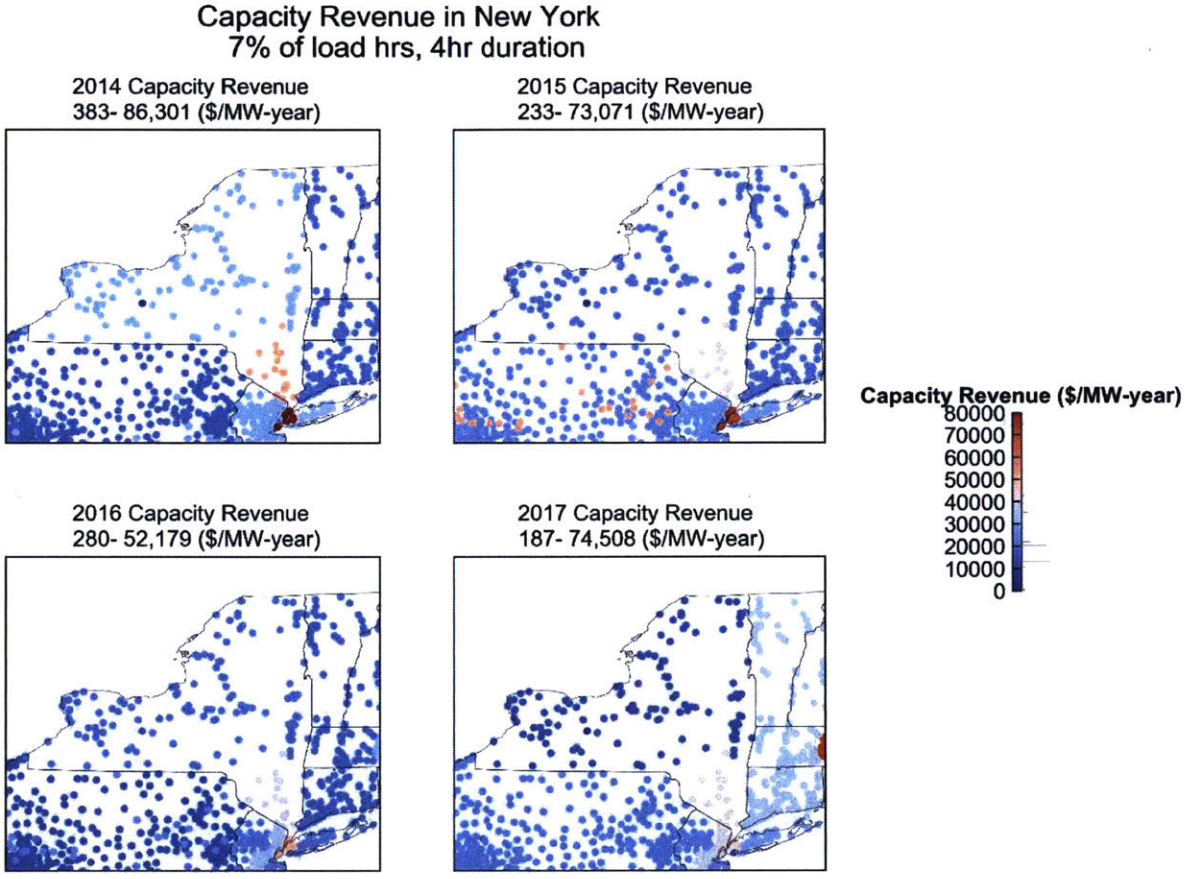

Figure 25: Geographic Maps of Capacity Revenue in New York

[234] Sioshansi, Denholm, and Jenkin, "A Comparative Analysis of the Value of Pure and Hybrid Electricity Storage."
[235] Yu and Foggo, "Stochastic Valuation of Energy Storage in Wholesale Power Markets."

3.2.3 Capacity Credit

For 4-hour duration storage under 7% of load hours, capacity credits average around 43% across ISOs (excluding ERCOT) from 2014 through 2017. Capacity credits are fairly tightly distributed around the mean (as can be inferred from capacity revenue in Figure 24).

Two major conclusions are drawn: firstly, the capacity credit of dispatched storage is higher than the simplistic statistical predictor. Based on peak hours durations analysis, 4-hour durations should receive a 25% capacity credit, and 7-hour storage should receive a 50% capacity credit. When dispatched, the average capacity credit of 8-hour storage is 74%. Capacity credits are higher than predicted.

Secondly, the capacity credit of storage averaged 40% when participating in energy only. Participating in the capacity market triggered a 10% increase in capacity credit (Figure 26 and Figure 27, and in Appendix, see for Figure 72 for the distribution of nodal differences, and Table 25 for capacity credit averages across ISOs and percents). Storage will change dispatch to support reliability should reliability be tied to capacity market revenue.

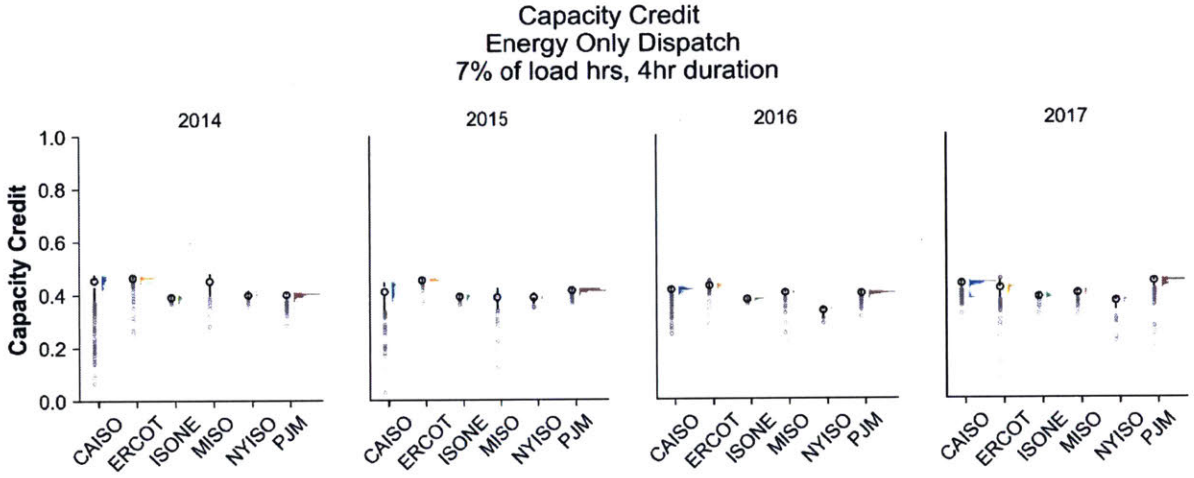

Figure 26: Capacity Credits in Energy Only Dispatch

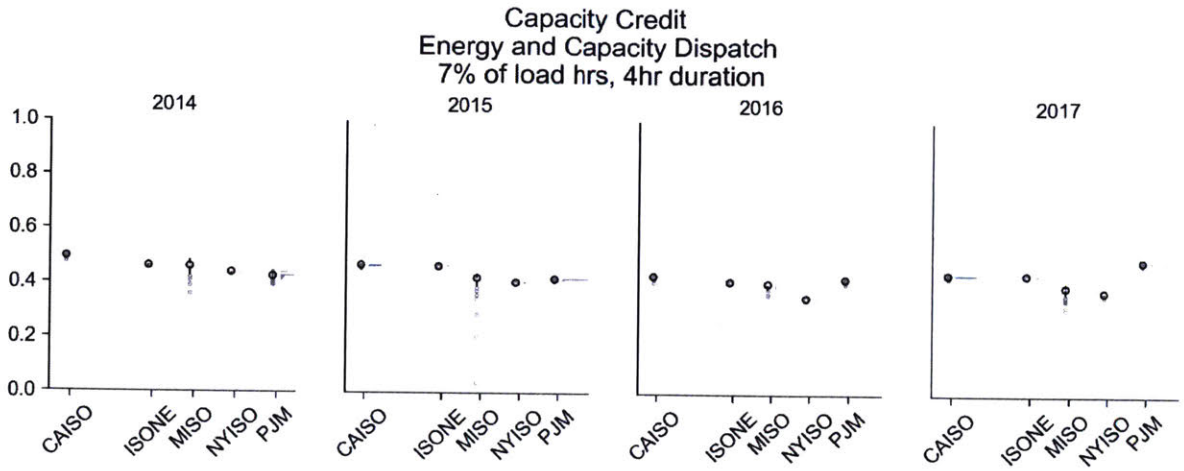

Figure 27: Capacity Credits in Energy and Capacity Dispatch

ERCOT excluded in capacity and energy dispatch.

The greater the duration, the greater the capacity credit, although there is a decreasing marginal rate of return (Figure 28). In 2017, in ISO-NE, a 1-hour unit has a 12% capacity credit, a 4-hour unit a 25% capacity credit, and an 8-hour a 75% capacity credit. Moving from 1 to 4-hour triggers a 250% increase in capacity credit, but moving from 4 to 8-hours a 67% increase. Average capacity credits are fairly consistent from year to year.

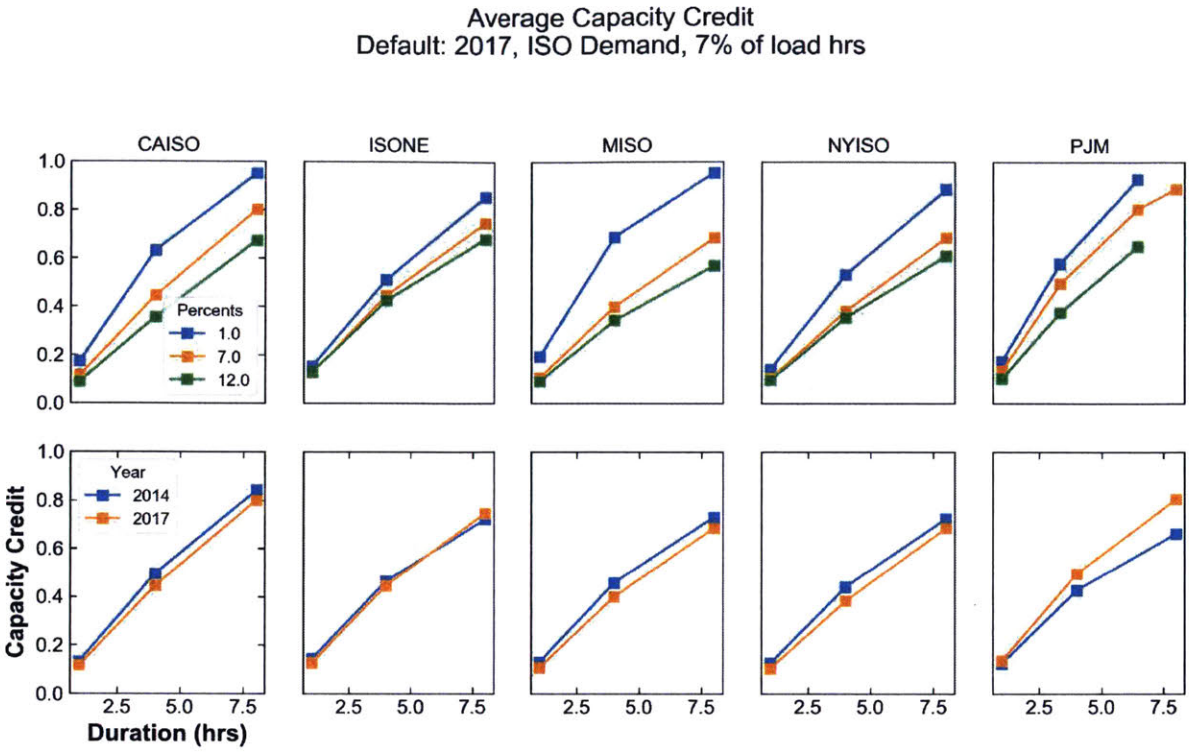

Figure 28: Average Capacity Credit as a Function of Duration, Percent, and Year in Energy and Capacity Dispatch

3.2.4 Total Revenue

Across 2014 through 2017, total revenue averages $ 42,000/MW-year, with individual nodes ranging from $ 5,000 /MW-year (2015, MISO) to $121,000 /MW-year (2014, NYISO).

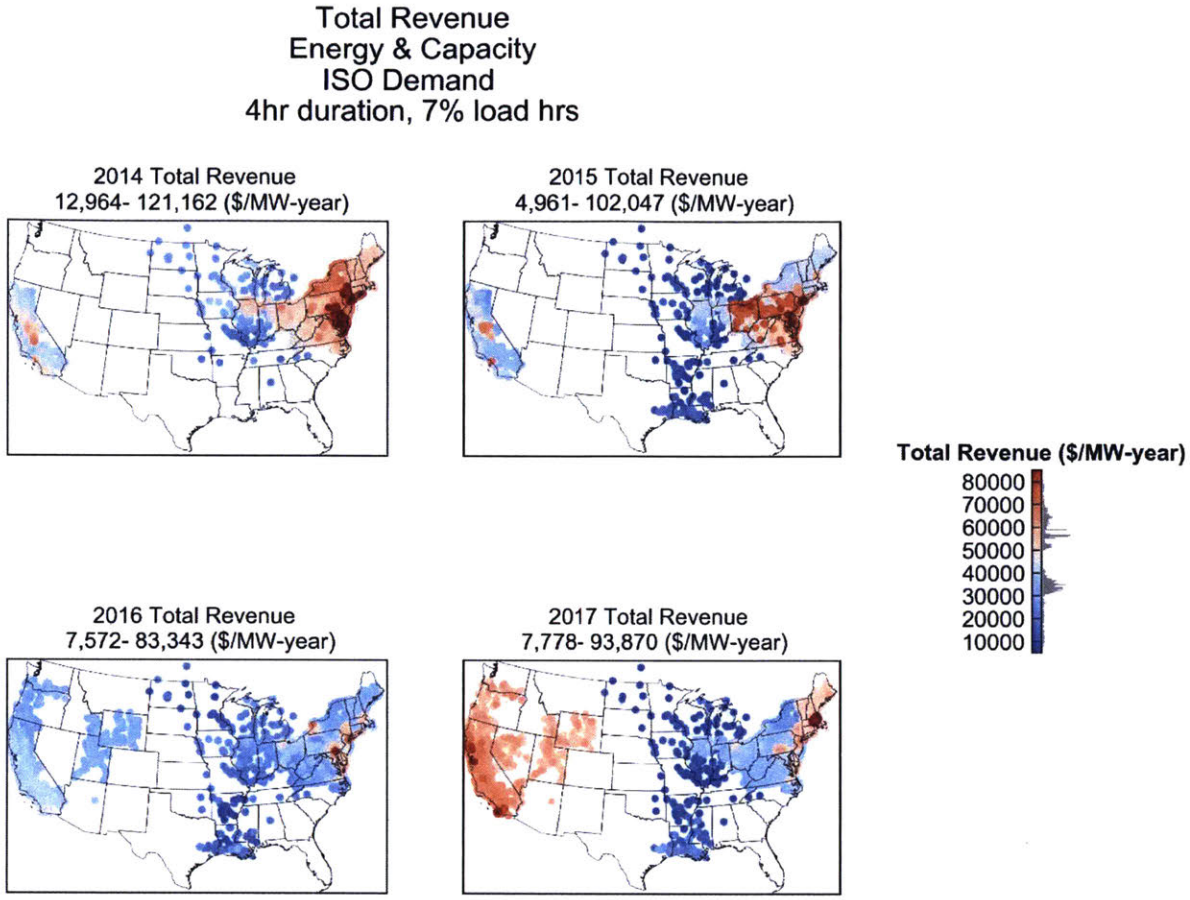

Figure 29: Geographic Maps of Total Revenue for Energy and Capacity Dispatch

On average across ISOs and years, participating in the capacity market alongside the energy market doubles total revenue – but the particular landscape is much more complicated, as contribution is dependent on location and year (Figure 30 and Figure 31). Individual storage units can experience extremes of a 1% increase to a 642% increase (both in 2015 in MISO). In terms of net dollar differences from energy only to energy and capacity revenue, differences in total revenue can range from a minimum of $84/MW-year (2015, MISO) to a maximum of $86,000/MW-year (2014, NYISO).

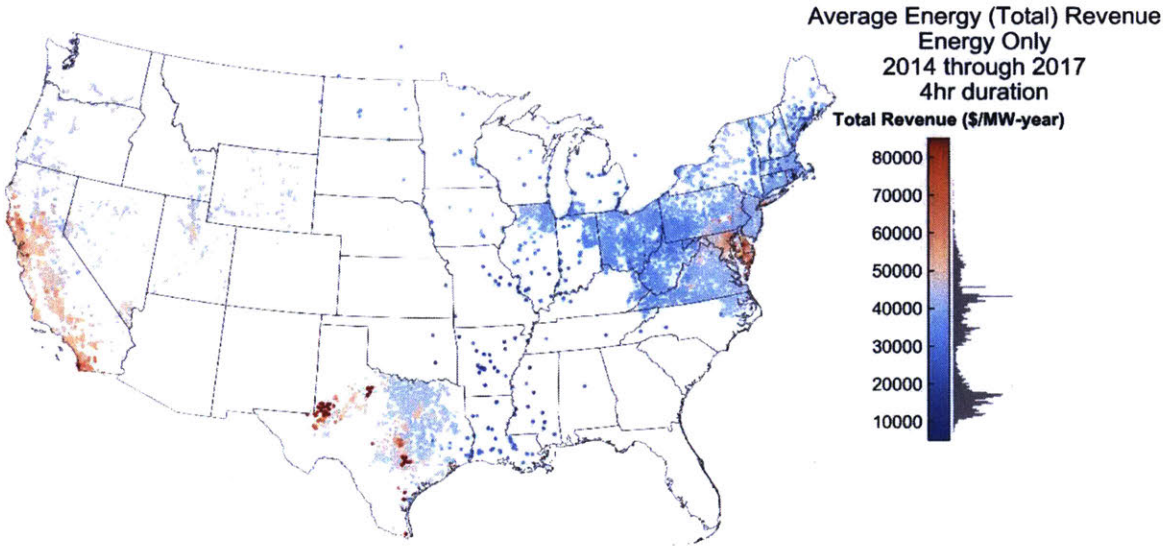

Figure 30: Geographic Map of Average Total Revenue for Energy Only

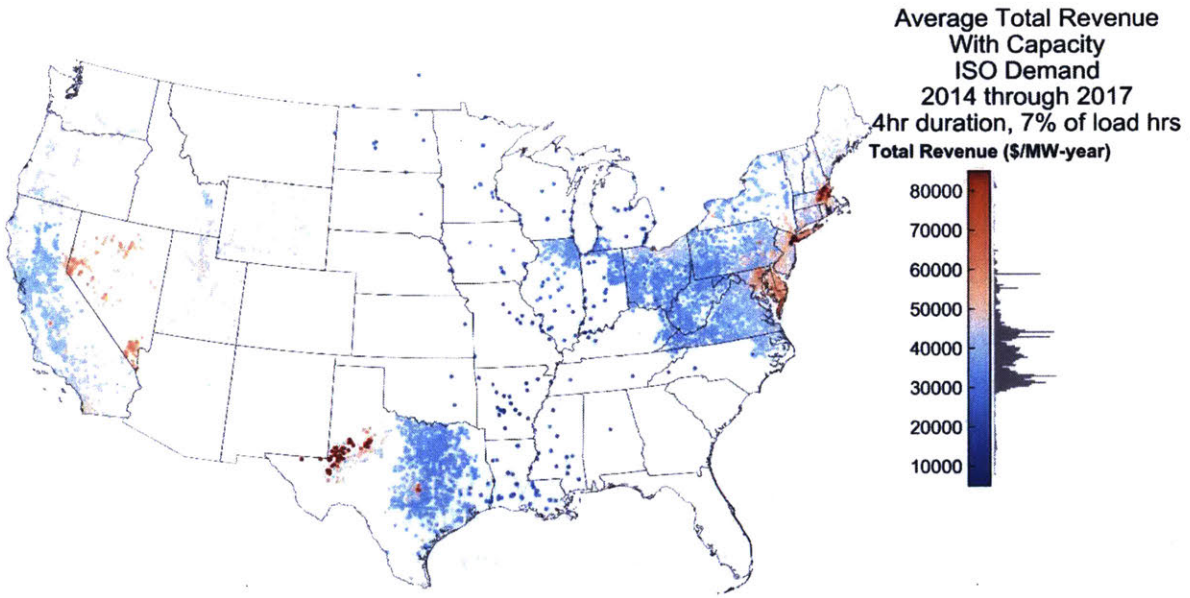

Figure 31: Geographic Map of Average Total Revenue for Energy and Capacity

Including capacity in the dispatch will always increase total revenue in comparison to energy only. Even for 1-hour duration storage across 12% of hours in 2014 and 2017 (end years only), differences in total revenue in moving from energy to both energy and capacity range from $46/MW-year (2017, MISO) to $19,800/MW-year (2015, NYISO). Even in this most extreme modeling case that would stretch duration requirements, participating in the capacity market does not decrease total revenue.

Including capacity revenue can change the location of top earning nodes (Figure 30). Prior to including capacity revenue, in 2014 ERCOT had 66 of the top 100 nodes, but in 2017, CAISO had all 100; the location of top earners in the energy market changed each year. When including capacity market revenue in addition to energy market revenue, from 2014 through 2016, NYISO had more than 97 of the top 100 top earners, but in 2017, ISO-NE had 98 of the top earners. In contrast to only energy market participation, where, 86% of top earners from 2014 through 2017 remained so for only one year, when adding capacity market revenue, 43% of the locations remain within the top 100 earners for three years (Figure 32).

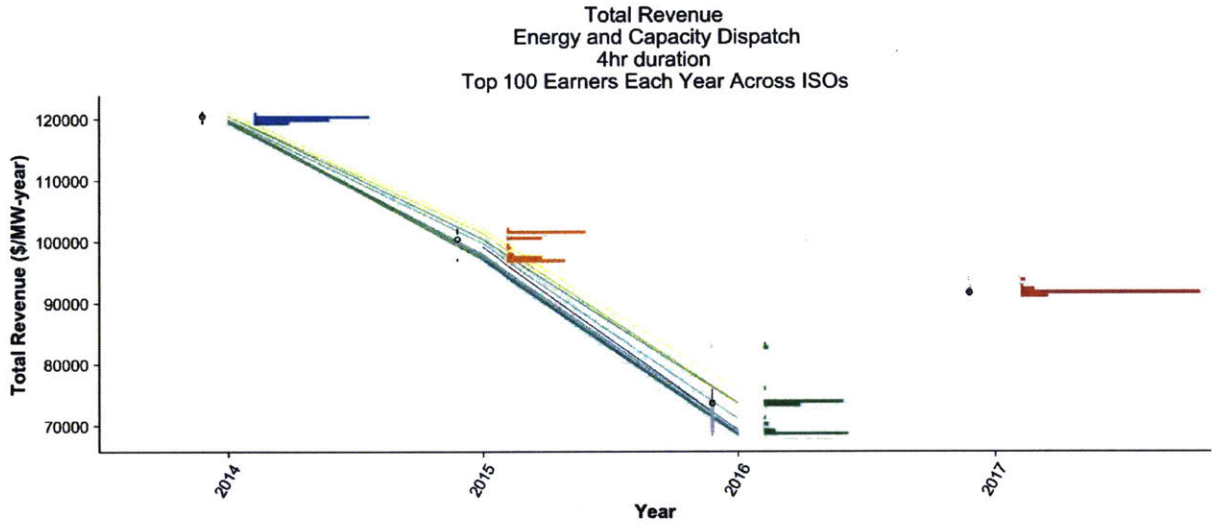

Figure 32: Persistence of Top 100 Earners for Energy and Capacity Dispatch

In summary, the inclusion of capacity revenue in addition to energy revenue swings the locations of top earners eastward. The inclusion of capacity revenue can make the location of top earners more consistent - but there is still huge annual variation in revenue (See Figure 74 and Figure 75 in Appendix). From 2014 to 2017, the percent change in revenue from year to year ranged from 69% decrease (MISO, 2014 to 2015) to a 272% increase (MISO, 2015 to 2016) (Figure 33 and Figure 72 in Appendix) . The top 100 earning nodes in 2014 earned 1.7-times the total revenue of the top 100 earners in 2016.

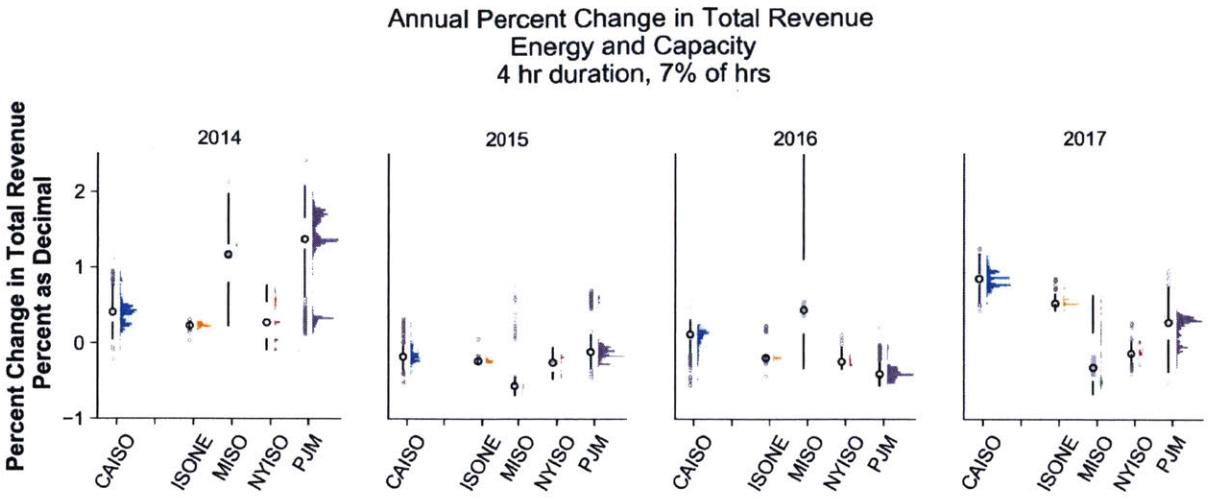

Figure 33: Annual Percent Change in Total Revenue in Energy and Capacity Dispatch

ERCOT excluded.

3.3 **Capacity Market**

We calculate the capacity revenue that storage units could have received as an afterthought, assuming they dispatch with only awareness of energy market prices. On average across ISOs from 2014 through 2017, there is a 0.12% increase in capacity market revenue when including knowledge of top demand hours, and a 0.45% decrease in energy revenue, for an overall average increase of 3.6% in total revenue. Overall, 75% of nodes earn less than 5% more (corresponding $1,800/MW-year) with awareness of capacity prices in comparison to without. However, for some individual nodes, differences in total revenue may not be trivial, as awareness of capacity market differences can earn some storage units up to $12,800/MW-year more (2014, CAISO) (Figure 30).

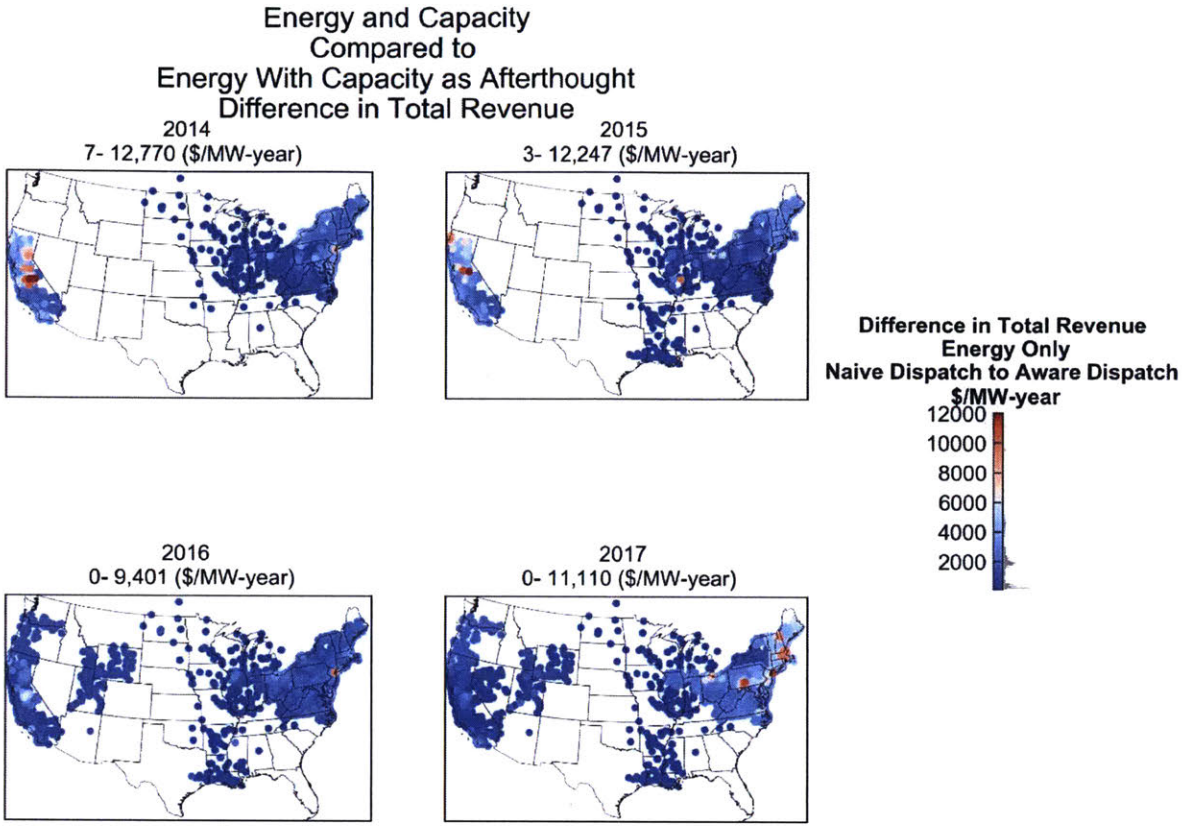

Figure 34: Geographic Maps of Difference in Total Revenue From Energy Only Dispatch (with capacity revenue calculated after dispatch) and Energy and Capacity Dispatch

Changes in revenue is tied to a changes in capacity credit (Figure 35). As explained previously, the transition from energy only dispatch to energy and capacity dispatch triggered a 10% average increase in capacity credit. Energy storage will change dispatch to capture what could be a small percent difference in total revenue.

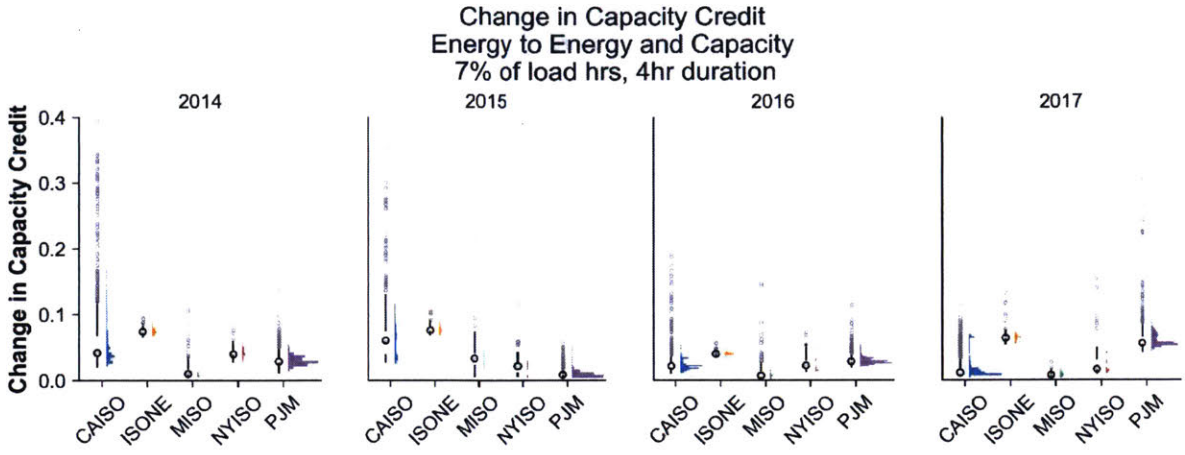

Figure 35: Change in Capacity Credit From Energy Only Dispatch to Energy and Capacity Dispatch

Next, we optimize for revenue in solely the capacity market. We do this to see how much capacity market revenue that storage loses by participating in the energy market. The equation is given below, and total revenue is given in Figure 36.

$$Total\ revenue\ (capacity) = Max \sum_{hr=0}^{hrs} capval_m * 12 * \left(\frac{1}{\sum_{hr=0}^{hrs} caparray_{hr}}\right) * caparray_{hr} * [sell_{hr} - buy_{hr}]$$

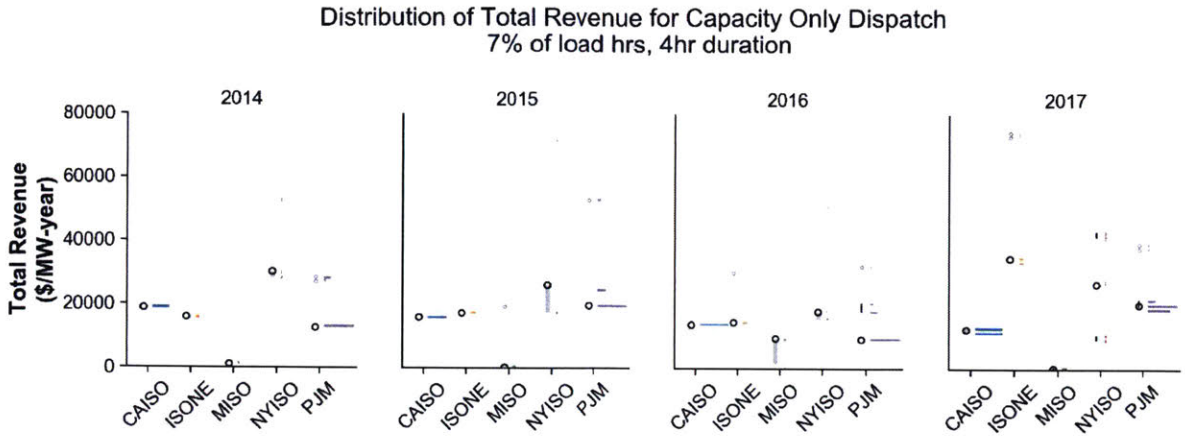

Figure 36: Capacity Revenue in Capacity Dispatch

It is possible to make more capacity market revenue when dispatching in the energy and capacity markets versus just the capacity market. This is because of operational cost; to participate in the capacity market exclusively may not be worth operational cost expended.

When eliminating operational cost, all nodes across ISOs make more in the capacity market under the capacity only dispatch, compared to also dispatching in the energy market, but only by $30/MW-year on average in 2017. In other words, at no operational cost, adding energy market revenue is associated with effectively zero (.008%) loss in capacity market revenue (See Figure 76 in Appendix for graphs of total revenue for dispatch with no operational costs).

Accounting for operational costs changes the dispatch profile, which increases the total revenue, compared to accounting for operational costs after-the-fact. Assuming a dispatch that does not take into considering operational costs, we calculate annual operational costs after-the-fact as $5/MWh multiplied by the amount of power sold (MWh). The resulting operational costs are 25% greater on average than what would have been expended.

Considering the objective of capacity markets is to compensate for fixed costs of plants needed for reliability, it is rather unsurprising that including capacity market revenue increases total revenue. But, what may be surprising is that even when capacity market profit is tied to output during peak load hours, units can essentially optimize solely in the energy market and perform decently. However, dispatch shows that units will change behavior (capacity credit), even slightly, to leverage comparatively small increases in total revenue (less than 5%). Later analysis of breakeven costs will determine whether increase in reliability factor affects the business case for storage, which will signal to market regulators the strength of this market signal.

3.4 Integration with Existing Renewables

The alternative load profiles are defined as the following:

1. ISO Demand: system wide demand.
2. Net-solar: demand net of utility scale solar generation as estimated by 2019 Brown and O'Sullivan.
3. Net-wind: demand net of utility scale wind generation as reported by ISOs. NYISO does not report wind data.
4. Net: system wide demand net of combined wind and solar generation.

As explained in Section 2.1, redefining the load profiles may change the classification of what is a peak hour. Reclassifying peak hours may change the durations of consecutive peaks hours. Responding to changes in peak hour classification is reflected in capacity credit (Figure 37, and Table 26 in Appendix). In 2017, the most noticeable difference in capacity credit is in CAISO under the net-solar profile.

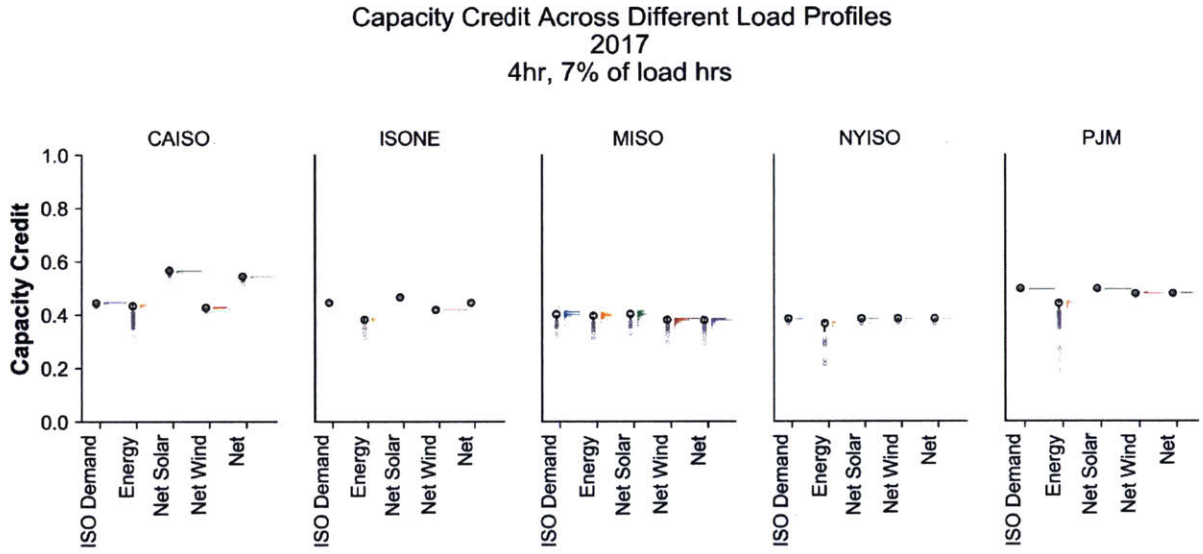

Figure 37: Capacity Credit Across Alternative Load Profiles

Looking at Table 17, in 2017 CAISO is the only ISO with a greater than 1-hour difference in percentiles of peak hours durations when transitioning from an ISO demand to a net-renewable profile, so it follows that capacity credit in CAISO will differ the most.

Table 17: 2017 Peak Hours Durations across ISOs for Demand, Net-solar, Net-wind, and Net-wind-and-solar

2017 7% of load hours	25% Percentile	50% Percentile	75% Percentiles	100% Percentile
CAISO	**5**	**7**	**9.25**	**14.25**
Demand	6	8	10	15
Net of Wind and Solar	4	6	8	14
Net Solar	4	6	8	13
Net Wind	6	8	11	15
ISO- NE	**3.25**	**7**	**10.5**	**15**
Demand	3	7	11	15
Net of Wind and Solar	3	7	10	15
Net Solar	3	6	10	15
Net Wind	4	8	11	15
MISO	**5.5**	**8.5**	**11.5**	**14.5**
Demand	5	8	11	14
Net of Wind and Solar	6	9	12	15
Net Solar	5	8	11	14
Net Wind	6	9	12	15
NYISO	**4.875**	**9**	**12**	**16**
Demand	5	9	12	16
Net of Wind and Solar	4.75	9	12	16
Net Solar	4.75	9	12	16
Net Wind	5	9	12	16
PJM	**3.9375**	**6**	**9**	**14**
Demand	4	6	9	14
Net of Wind and Solar	4	6	9	14
Net Solar	3.75	6	9	14
Net Wind	4	6	9	14

In 2017 under 7% of load hours for 4-hour duration, CAISO's average capacity credit under net solar load is 57%, which is higher than the 44% under the ISO demand profile. The average capacity credit under net wind is 43%. From a practical standpoint, wind power produces less predictable arbitrage opportunities in comparison to solar (Figure 38).

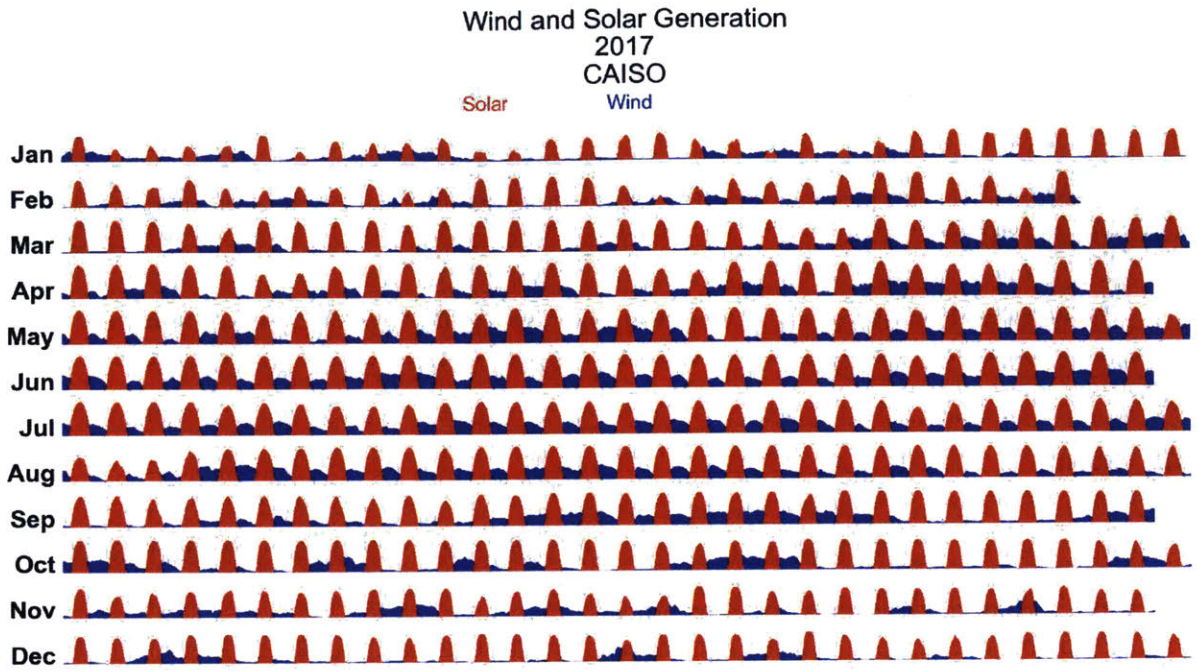

Figure 38: Wind and Solar Generation in CAISO in 2017

In CAISO in 2017 under 7% of load hours, the 50% percentile of peaks is 8-hours long for the ISO demand profile, and 6-hours long for the profile net of wind and solar. This simplistic analysis indicates that shorter durations are required to meet consecutive peaks under net renewables than ISO demand. Our results confirm. However, as proven by dispatch, an 8-hour unit has an 80% - not 50%- capacity credit under ISO demand. Under the net solar, a 4-hour unit achieves a 57% average capacity credit- 6-hours of duration is not needed for a 50% capacity credit. The simplistic metric appears to underestimate the capacity credit of storage durations 8-hours or less.

Replacing ISO demand with alternative profiles produces three major conclusions. Firstly, reclassifying to net of wind generation has minimal influence, likely because wind generation does not change peak hours durations. Secondly, the capacity credit of storage is higher under a profile net of solar because peak hours durations decrease. Thirdly, the capacity credit of storage is generally higher in dispatch than predicted for shorter-duration resources. In 2017 CAISO under the net profile, a duration of 4 would be predicted to have a 25% capacity credit, but in actuality it was over 50%.

3.5 Integration with Increased Renewables

We artificially increase existing wind generation in MISO and solar generation in CAISO to five and ten times annual generation in 2014 and 2017. We keep our price taking model with

historic prices, although with increased penetration of renewables, it is acknowledged that prices may (and likely will) change. We create new demand profiles that assume greater penetration of renewables to ask the following:

1. With greater renewable penetrations, how does the classification of peak hours change?
2. With new peak hour classifications, how does the capacity credit of energy storage resources change?

Answering these questions hints at the capacity credit of storage under increased renewable generation, which reflects on how storage may support reliability in a more intermittent-based grid.

3.5.1 Solar

Across 7% of load hours, 70% and 64% of peak periods remain the same as net-solar for five and ten times more solar, respectively (Figure 39). Of five and ten times more solar generation, 93% of peak periods are in common.

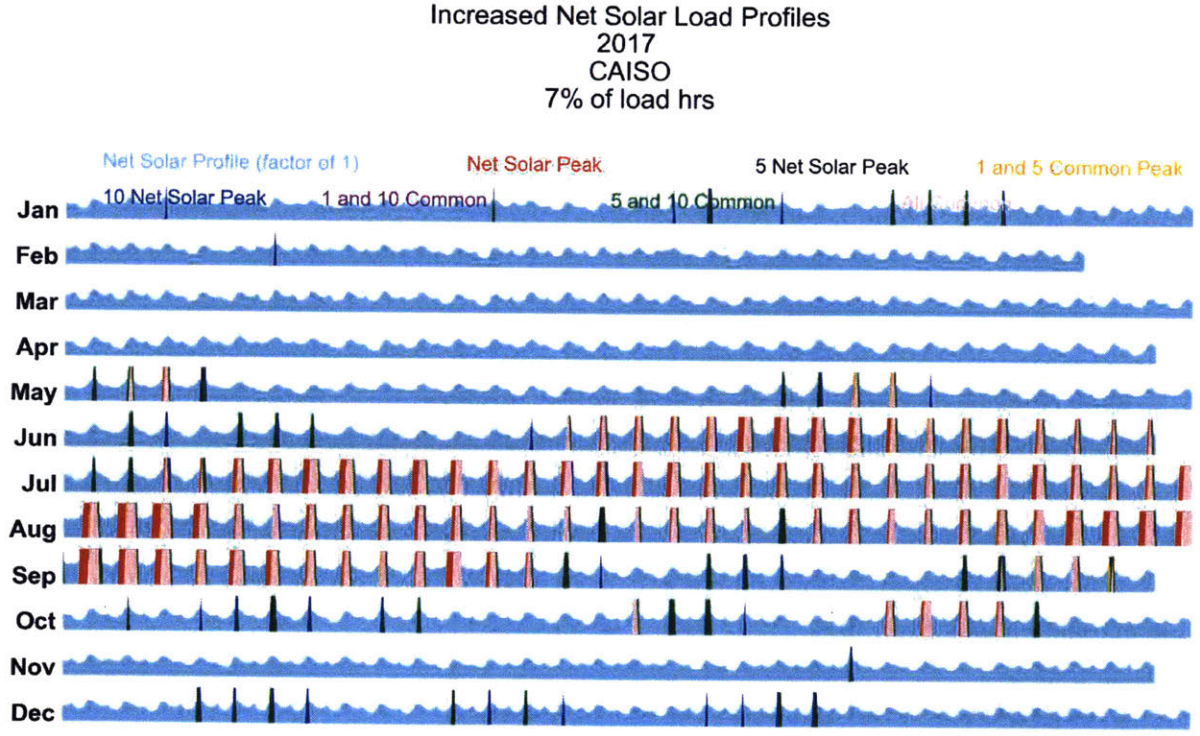

Figure 39: Increased Solar Generation in CAISO

The difference in peak hour classification for net-solar, in comparison to five and ten-times net solar, is reflected in changes in peak hours durations. Under 7% of load hours, the median duration of peak periods for net-solar, five-times-net-solar, and ten-times-net-solar is 6-hours, 5-hours, and 4-hours, respectively. The maximum duration of peak periods for net-solar, five-times-net-solar, and ten-times-net-solar is 13-hours, 9-hours, and 9-hours, respectively. For reference, the median and maximum ISO demand reference points for CAISO in 2017 is 8 hours and 15 hours, respectively. The greater the solar penetration, the smaller the average median and the smaller the maximum storage duration required (Figure 40 and Figure 41, and Table 22 in Appendix).

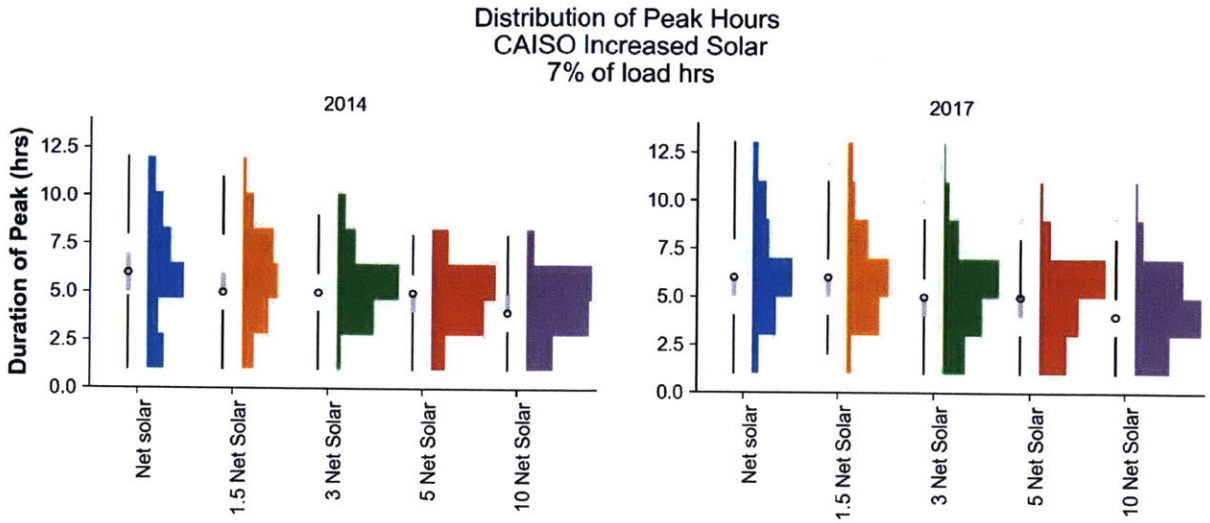

Figure 40: Effect of Increased Solar Generation in CAISO on Peak Hours Durations across Years

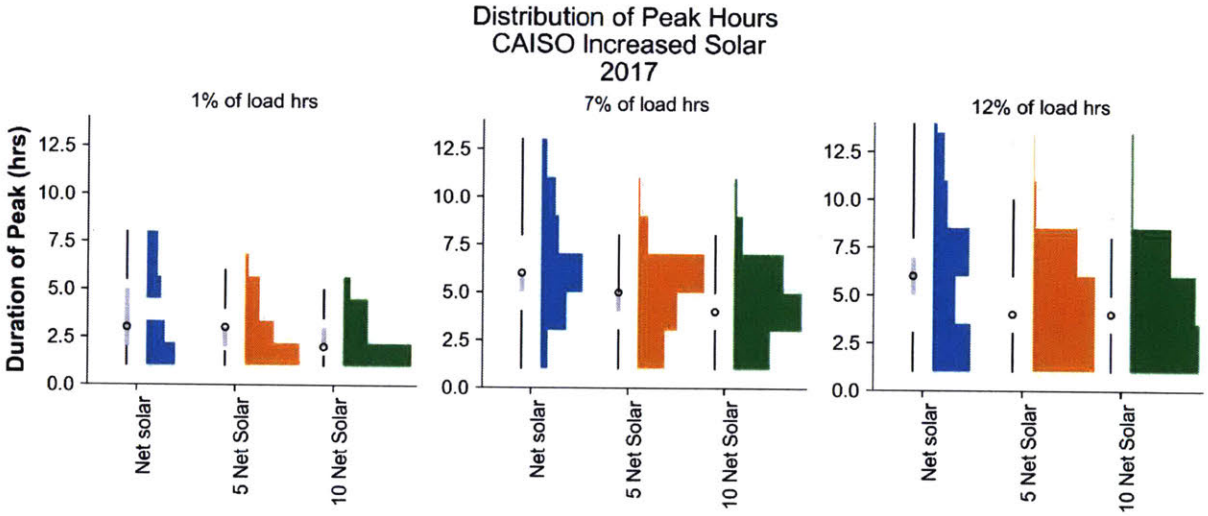

Figure 41: Distribution of Peak Hours for Increased Solar Generation in CAISO across Percents

Some data points outside graph range.

In 2017 in CAISO, for a 4-hour duration storage unit across 7% of load hours, moving to net-solar to five-times-net-solar to ten-times-net-solar is associated with average capacity credits of 57%, 70%, and 73%, respectively (Figure 42). For a 1-hour unit, the capacity credits are 15%, 21%, 23%, and for an 8-hour unit, around 94%, regardless. Increasing beyond five-times net solar does not result in a capacity credit increase as comparatively high as that

between net-solar and five-times-net-solar because the underlying peak hour durations are similar. For reference, in CAISO in 2017 under the ISO demand profile, the capacity credit of 1-hour, 4-hour and 8-hour storage in CAISO in 2017 averages 12%, 44%, and 80%

Three conclusions can be drawn from this work. First, storage has a higher capacity credit under net-solar profiles compared to ISO demand profiles. Solar may provide a greater reliability service in the context of solar. Second, increased solar penetration may shorten the duration of storage needed to achieve a high capacity credit. Third, the simplistic metric of looking at percentiles of peak hours durations is an estimation, and may not adequately summarize capacity credit. Assuming the percentile as capacity credit for that given peak hour duration may overestimate the duration needed for that capacity credit for the 75% percentile and under. In 2014 and 2017, peak hours durations indicate that durations under 6-hours could achieve a theoretical 75% capacity credit at five-and-ten-times solar generation, and overall, 9-hours of duration can fully meet all peaks under these increased scenarios. Our analysis hinted that shorter durations of 4-hours and 8-hours could achieve similar credits, within a 5% tolerance band.

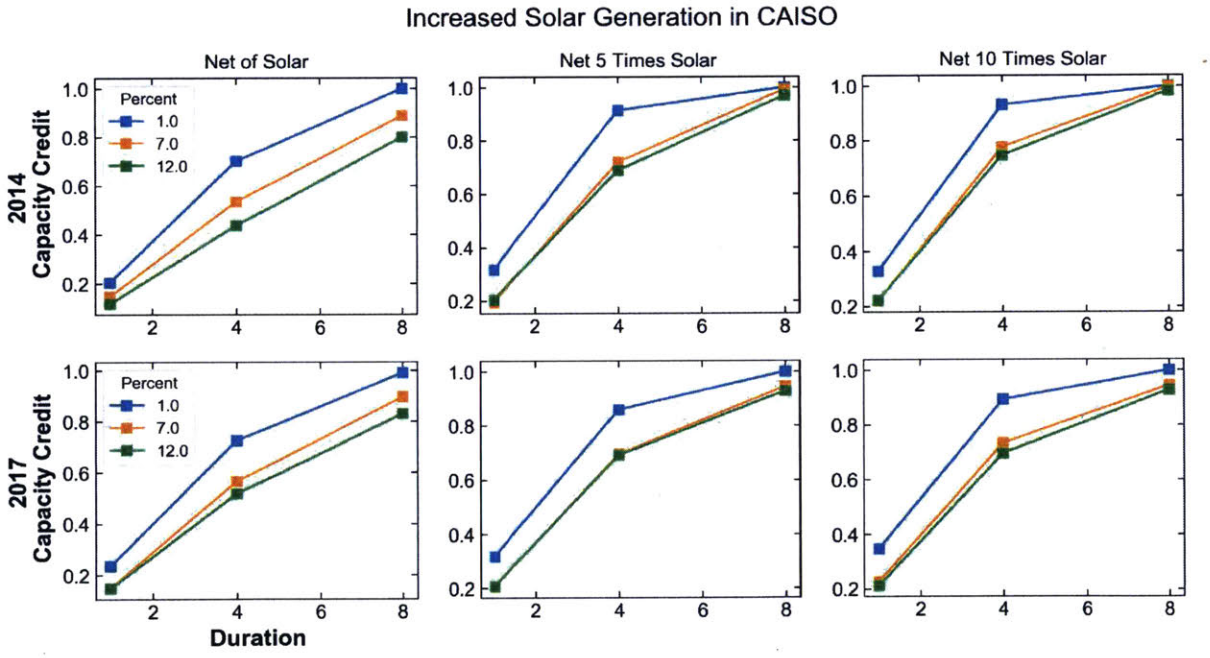

Figure 42: Average Capacity Credit Duration as a function of Duration, Percent, and Year for Increasing Solar in CAISO

3.5.2 Wind

Between the net-wind profile, five-times-net-wind, and ten-times net-wind 84% of the peaks identified as top load are the same (Figure 43).

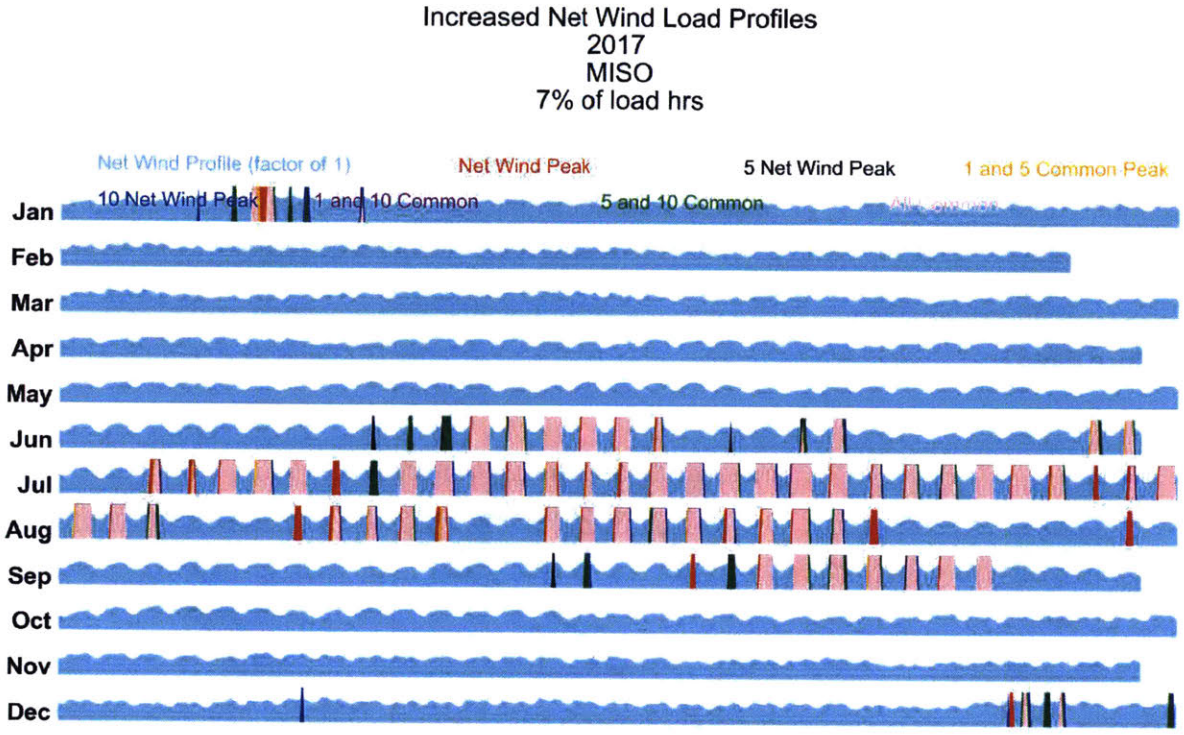

Figure 43: Increased Wind Generation in MISO

Assuming 7% of load hours in 2017, regardless of wind profile, the 50% percentile of peak hours durations is 9 hours, and the 100% percentile is at most 15 hours (14 hours for five-times-net-wind) (Figure 45 and Figure 46). Since there is minimal change in median and maximum, we would not expect the capacity credit of storage to significantly vary from different load profiles, and as seen in Figure 46, it does not.

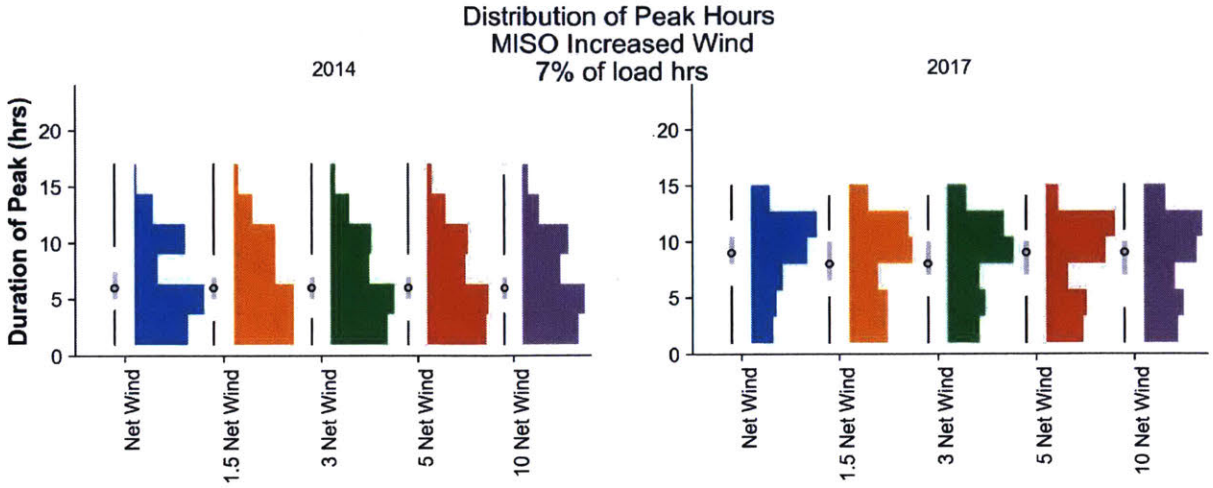

Figure 44: Effect of Increased Wind Generation in MISO on Peak Hours Durations across Years

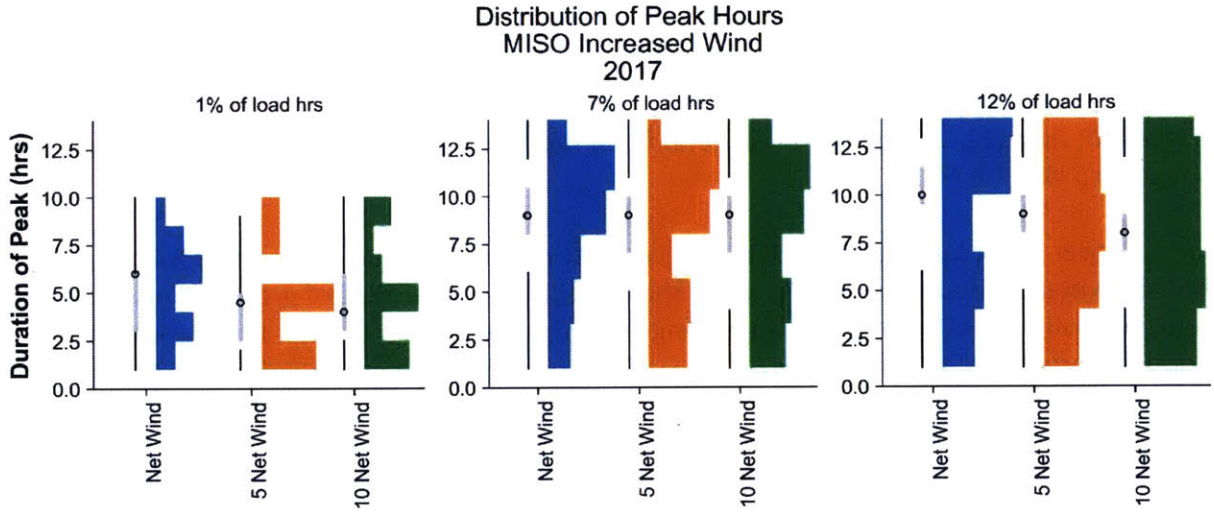

Figure 45: Distribution of Peak Hours for Increased Wind Generation in MISO across Percents

Some data points outside graph range.

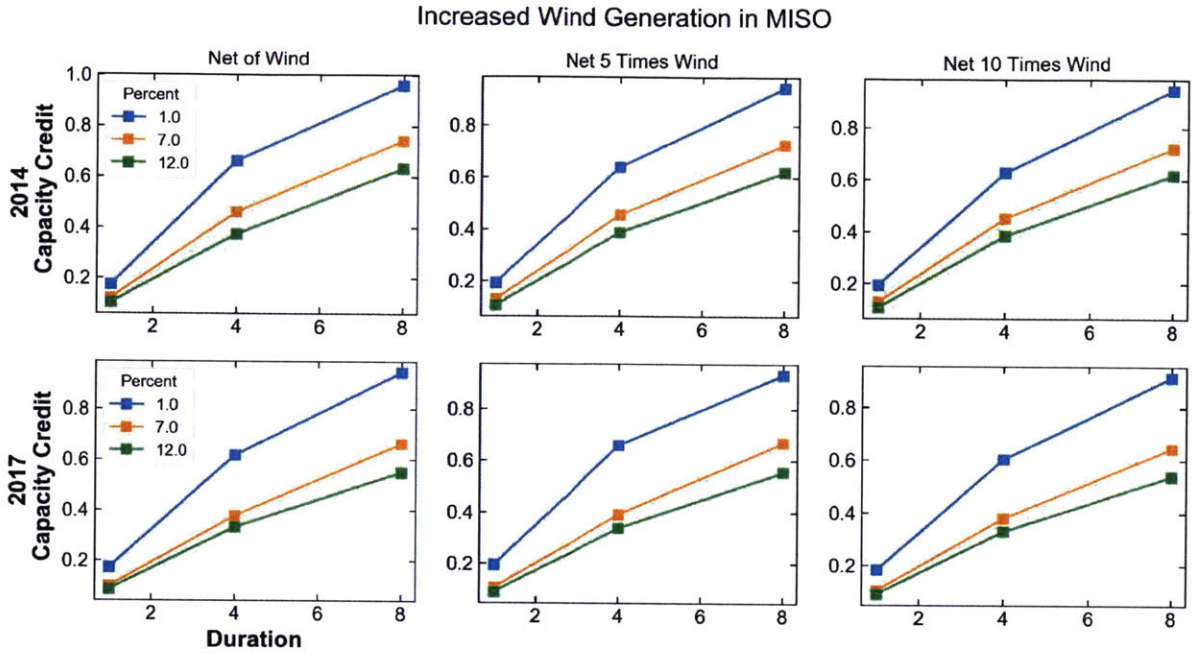

Figure 46: Average Capacity Credit Duration as a function of Duration, Percent, and Year for Increasing Wind in MISO

Under 7% of load hours in 2017, the capacity credit of 1-hour, 4-hour, and 8-hour storage averages around 13%, 45%, and 73%, respectively, regardless of profile. Under the ISO demand profile for MISO in 2017, the average capacity credits of 1-hour, 4-hour, and 8-hour storage averages 10%, 40%, and 68%.

Two conclusions are drawn: First, increased wind generation is not associated with significant changes in capacity credit because peak hour durations are about the same (Table 22 in the Appendix supplements Figure 45 and Figure 46 above). Second, the capacity credit of storage under wind profiles is better than estimated by the simplistic percentile measure; 6 hours of duration is needed to meet the 25% percentile of wind profiles, and 9 hours to meet the 50% percentile. However, the capacity credit of 8-hour storage, regardless of net wind or ISO profile, is more than 70%.

When investigating the effect of wind and solar, two trends are clear. First, as determined by an increase in capacity credit from ISO demand to respective renewable profile, shorter-duration storage (less than 8-hours) may better support solar than wind. Considering that in 2017, wind generation in MISO is about twice the solar generation in CAISO (or about 50 million MWh compared to 25 million MWh), the resulting change in capacity credit require comparatively less penetration. Second, predicting the capacity credit by taking the percentile of peak hours durations appears a low-estimate of capacity credits for peak hour durations, as indicated by the 75% percentile and under.

Overall, our metric is a guideline, not a reflection of behavior. This is because categorizing peak hour durations effectively assumes that a storage unit outputs at maximum. However, storage can dispatch at a slightly less than maximum to meet the durations- capturing this behavior is the objective of the capacity credit. So, the simplified metric is found to underestimate the capacity credit of shorter-durations (less than 12 hours here). While informational, we find a complete dispatch model is needed to reflect capacity credit.

3.6 Breakeven Costs

In the context of storage supporting reliability, it is important to step back and ask- at the given market prices, what does the cost of storage need to be to justify investment?

We solve for the breakeven point as done in 2019 Brown and O'Sullivan as the point at which the Net Present Value (NPV) is equal to zero, given that the yearly revenue stream for a given node applies over a lifetime:

$$NPV = \sum_{t=1}^{L} \frac{(Total\ Revenue^t - OM_{cost})(1-T) + \frac{D_t}{(1+i)^t}(C)(T)}{(1+WACC)^t} - C$$

L is the lifetime (20 years), OM_{cost} is the annual operations and maintenance cost ($20/kW-year), T is the combined federal and state tax rate (28%), D is the percentage of upfront cost using the 7-year Modified Accelerated Cost Recovery System, i is the inflation rate (2.5% per year), WACC is the weighted average cost of capital (7% per year), and C is the capital upfront cost ($/kW). We solve for C, the capital cost converted to $/kW, when NPV is zero. As represented in the equation, the breakeven cost represents how cheap the capital cost would have to be in order for the project to cover capital costs. For comparison, high and low estimates of current lifetime costs are $813/kW and $399/kW.[236]

On average from 2014 through 2017, with participation in the energy market, less than 1% of storage location breakeven at a lower-end capital cost of $399/kW. At a capital cost of $819/kW, only 21 nodes (out of a total of 9,886) breakeven in 2014 in ERCOT. For 50% of nodes to breakeven in the energy markets from 2014 through 2017, capital costs need to be $30.11/kW (Figure 47). As discussed, the location of top-earning nodes, and their respective breakeven points, varies from year to year (See Figure 77, Figure 80, and Figure 81 in the Appendix for more).

[236] "Lazard's Levelized Cost of Storage Analysis 2.0 Key Findings."

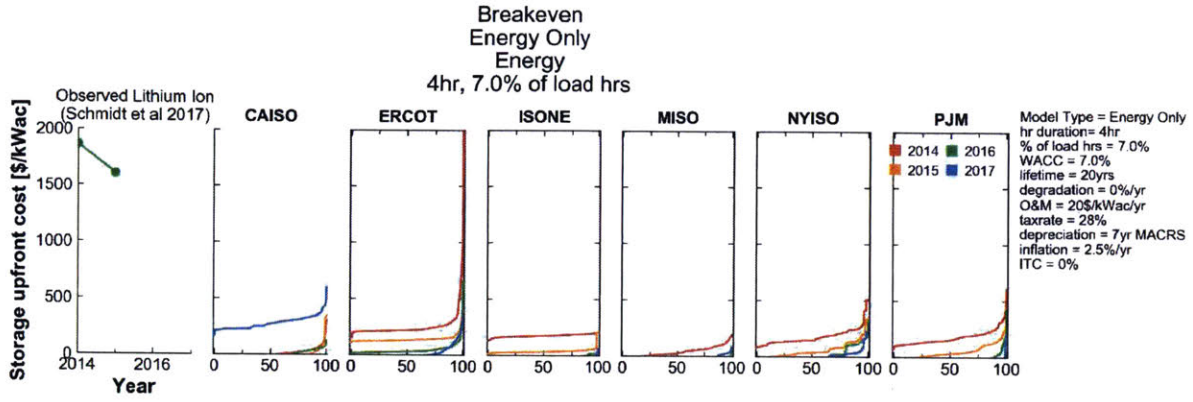

Figure 47: Breakeven Cost for Energy Only Dispatch

On average from 2014 through 2017, with participation in the capacity market as well as in the energy market, 11% of storage locations breakeven at a capital cost of $399/kW each year. At a higher capital cost of $819/kW, aside from the nodes that breakeven in ERCOT in 2014, 3 breakeven in PJM and 129 breakeven in NYISO. For 50% of nodes to breakeven, from 2014 through 2017 on average, capital costs can be $180.35/kW (Figure 48 and Figure 78 in Appendix). Capital costs can be six-times higher with the inclusion of capacity revenue compared to just energy revenue. But again, the breakeven costs vary from year to year (Figure 49 and Figure 79).

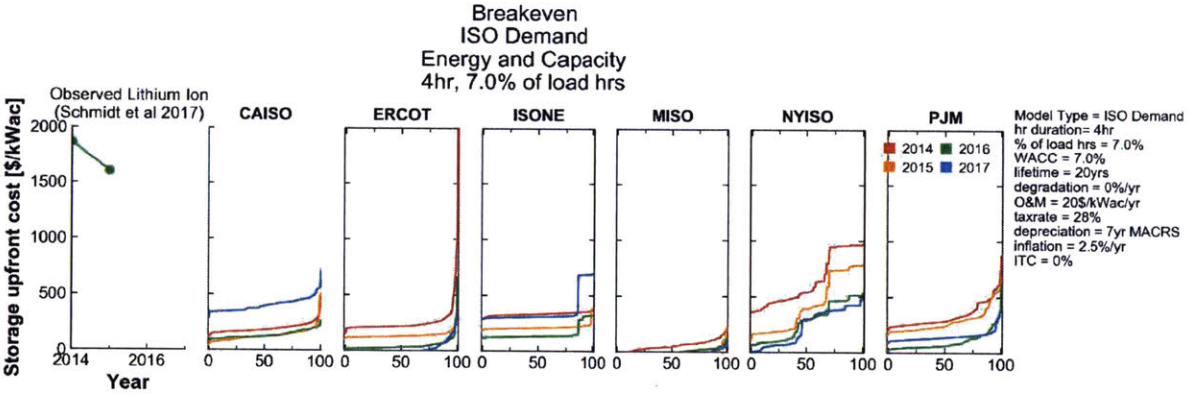

Figure 48: Breakeven Cost for Energy and Capacity Dispatch

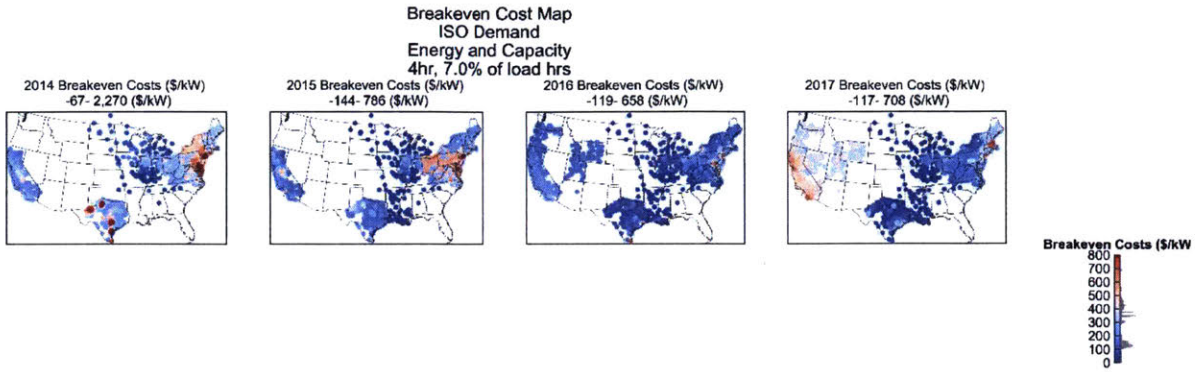

Figure 49: Geographic Maps of Breakeven Costs in Energy and Capacity Markets

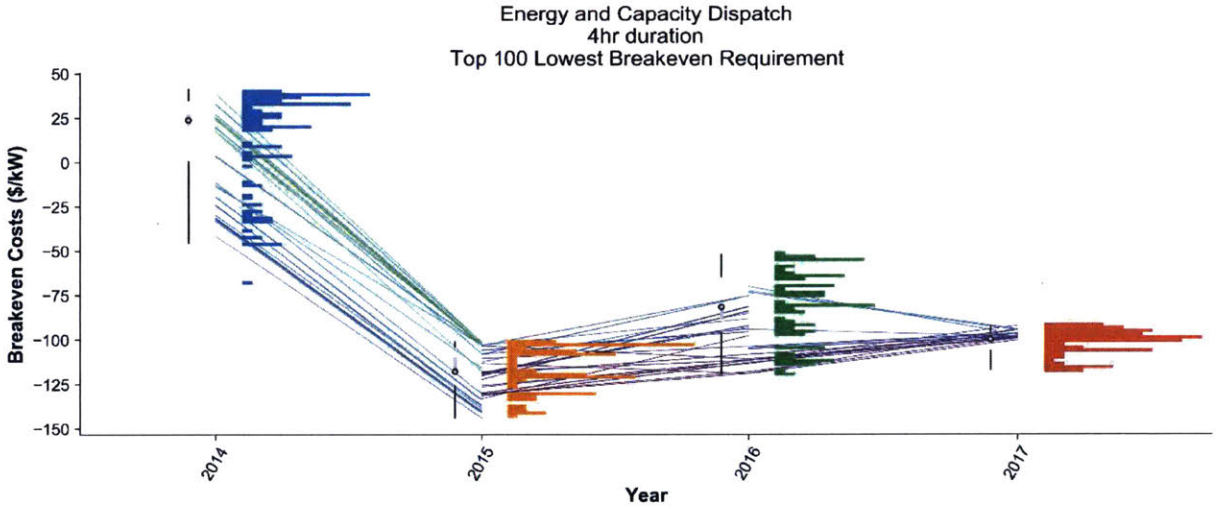

Figure 50: Persistence of Lowest 100 Breakeven Costs Earners for Energy and Capacity Dispatch

A negative breakeven cost implies that storage makes money at a capital cost of $399/kW.

In 2017 exclusively, across all ISOs and demand profiles, the percent of nodes that breakeven and the capital costs required for 50% of nodes to breakeven are given in Table 18 (See Table 24 for more comparisons). There is minimal difference between breakeven costs for the alternative load profiles. As previously discussed, this is likely because on a U.S.-wide scale, limited intermittent penetration has not changed peak hours durations.

Table 18: Breakeven Costs for Alternative Load Profiles in 2017

7% of load hours and 4-hour duration storage

Load Profile	Percent of Nodes that Breakeven	2017 Breakeven Costs ($/kW) for 50% of Nodes
Energy	1	-26.10
ISO Demand	18	162.90
Net-solar	24	162.28
Net-wind	16	157.81
Net	24	158.01

In conclusion, adding capacity market revenue can fifth capital costs required to breakeven, but whether or not compensation in the capacity market is tied to intermittent penetration has minimal effect.

3.7 Historic Market Rules

The revenue generating capabilities of energy storage resources in capacity markets will depend in part on the ISO-specific requirements. We model revenue in the capacity market as a function of ISO-specific rules. Each ISO is detailed in its own section. Section 3.8 summarizes results across ISOs.

3.7.1 NYISO

The only known storage units receiving capacity payments in New York are two pumped hydroelectric storage facilities. These facilities function as "energy limited resources." An energy limited resource is "an energy supplier that is unable to operate at a level that represents its [capacity] obligations for all hours of a day, but can operate at that level for at least four consecutive hours of each day."[237] Minimum of 1 MW, energy limited resources must bid into the DAM for their duration at their maximum output level.[238] Their capacity credit is based off its unplanned outages across the year.

Storage technologies will also be able to bid as energy storage resources. The capacity credit of 1 MW energy storage resources is determined via the equations below:

For a 1 MW battery:

$$\text{If SOC} \geq 1 \text{ MWh, capacity credit} = 1$$

[237] "Installed Capacity Manual Attachments."

[238] Other traditional generators must bid into the DAM for all hours of the market.

If SOC<1 MW, capacity credit = $[sell_{hr} - buy_{hr}]$

The NYISO is rating potential output, as constrained by energy. Until 2021, the capacity credit for energy storage resources is taken across the day. Beginning in 2021, two things may change. First, NYISO will determine capacity credit across given hours, not the day (Table 19). These hours will change based on how much new energy storage is added to the grid as of June 1st, 2019. Then, based on the duration of the resource, the resource is given a percentage of the capacity price.

Table 19: Proposed Storage Capacity Payments

	<1,000 MW storage added	**≥1000 MW storage added**
Duration (hours)	Percent (%) of Capacity Price Received	
2	45	36.5
4	90	75
6	100	90
8	100	100

There is an interesting policy option. The battery can operate as a self-managed resource, or an ISO managed resource. If the resource operates as an ISO managed resource, the ISO optimally schedules. The ISO will not penalize for the resulting loss in availability if it decides to dispatch the resource to provide energy. The only decreases in capacity credit that the resource could experience would be the result of unplanned outages - not of its selection to discharge during economically beneficial times. As a result, participating as an ISO managed resource is a smart bet, as it effectively guarantees an excellent capacity credit. If the resource decided to operate as self-managed (which the resource may consider for warrantee purposes), the resource will have to tradeoff energy prices for lower capacity credits in the capacity market.

For our purposes, the capacity credit for storage in NYISO is calculated under a few scenarios:

1.) Under the rules for intermittent resources.
2.) As average power output during the must bid hours for energy limited resources.

For 4-hour duration energy limited resources, each day, the must bid hours are considered to be the two hours prior to the top demand hour, the top demand hour, and one hour after, and for 8- hours, four hours before, the top demand hour, and three hours after.

3.) As average power output during the must bid hours for energy storage resources.
4.) The proposed methodology for calculation capacity credit of energy storage resources.

However, we take this over the top 7% of load hours. We do this so we can compare this methodology to our standard base case. This case is run from 2014 through 2017 across CAISO, ISO-NE, MISO, NYISO, and PJM.

3.7.1.1 Intermittent Resource

NYISO evaluates the capacity credit of intermittent resources across what is equivalent to 8% of hours of the year. Of the peak hours determined by the bid window used to calculate capacity credit, and of the top 8% of hours of peak demand, only 33% of peak hours are in common in 2017 (Figure 51). About 38% of peak hours were in common in 2014, which was a particularly cold year.

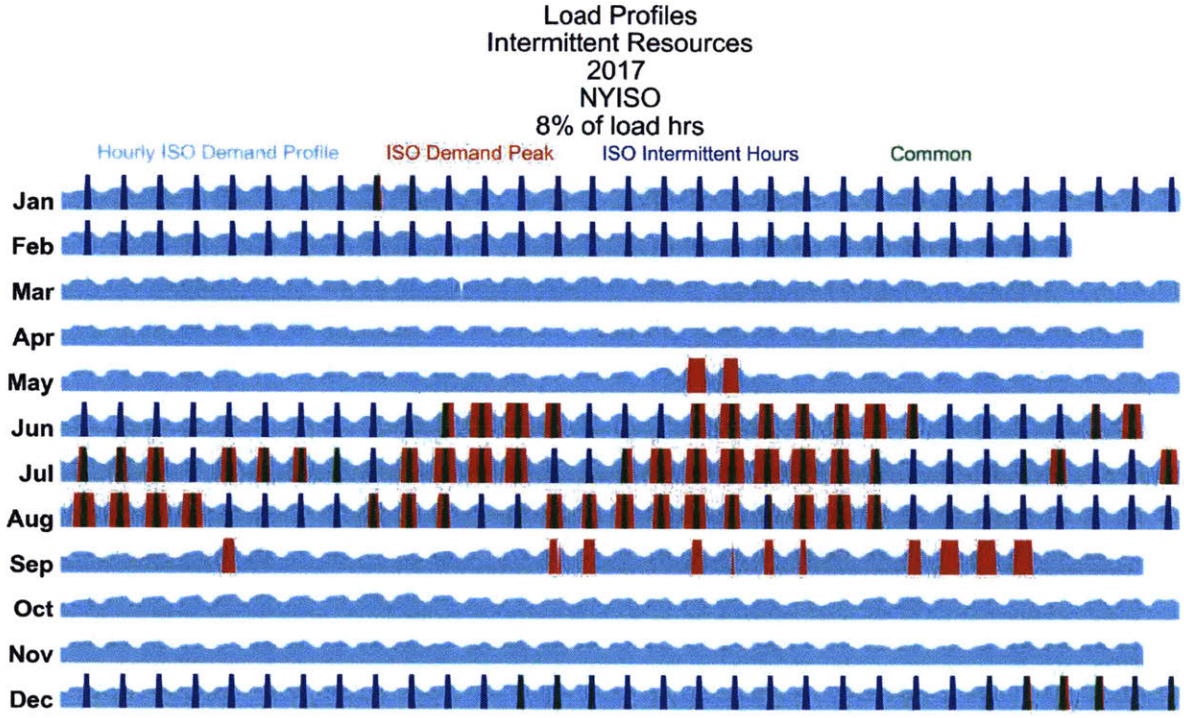

Figure 51: Peak Hour Classification: Intermittent Resources in NYISO

Few peak demand hours occur in the winter, and summer peak periods appear longer than the intermittent window. If the objective of the measuring capacity credit over a given peak window is to meet annual peak demand, the hours chosen do not seem a good approximation. However, using a given percent of top demand hours is a rough approximation of reliability. In the winter, fuel constraints, may stretch power supply more than high load.

In 2017, the capacity credit of 1-hour, 4-hour, and 8-hour resources across these given load hours for intermittent resources averaged 22%, 88%, and 98%. In comparison to 7% of load hours under ISO demand, the capacity credits were 10%, 38%, 69%. Capacity credits of storage are greater during the intermittent windows than across a similar amount of hours of peak demand.

The length of the intermittent window in NYISO is 4-hours. In 2017, the longest series of consecutive peaks under the top 7% of load hours lasted 16 hours. The consistent length of when the capacity credit is calculated under the intermittent approach lends certainty to dispatch, so capacity credit can be increased, in comparison to the top load hours methodology. Although, based on our simplified metric, a 4-hour duration could theoretically achieve a 100% capacity credit, but dispatch in response to price signals produces a lower capacity credit. Again, this simplified metric falls short.

By operating under a given window approach, both the ISO and the resource have consistent durations to target, which lends greater certainty of when to operate and generates greater capacity credits, or reliability benefits during those windows. However, while potentially advantageous for day-to-day operation, this window approach is not equivalent to targeting annual demand peaks.

Market design evaluating output during peak windows may support reliability, but not necessarily in the context of annual peak demand, which can be construed as a potential misalignment of market incentives.

3.7.1.2 Energy Limited Resource

Energy limited resources with 4-hours of duration have to bid for about 16% of hours within the year. Durations of 8-hours have to bid for about 33% of year hours. Of similar percentages of top demand hours in 2017, 37% of what 4-hour energy limited resources will bid, and 57% of what 8-hour energy limited resources will bid, correspond to top load hours (Figure 52 and Figure 53).

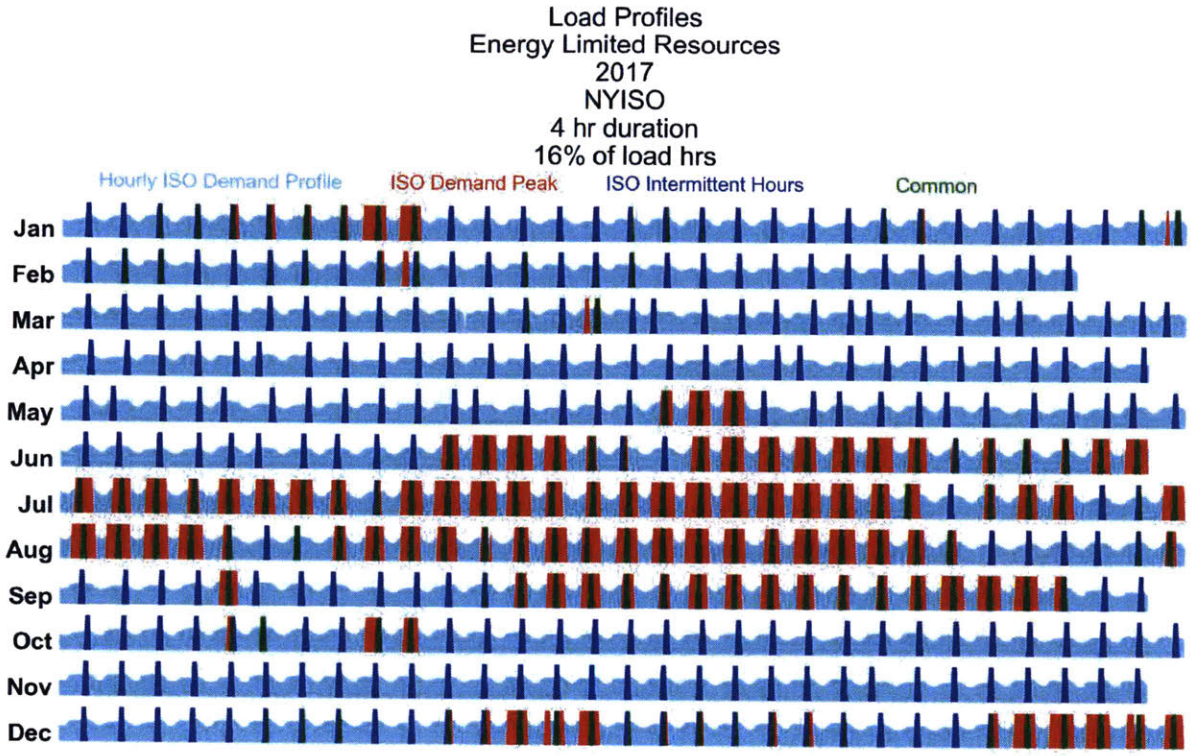

Figure 52: Peak Hour Classification: 4-hour Energy Limited Resources in NYISO

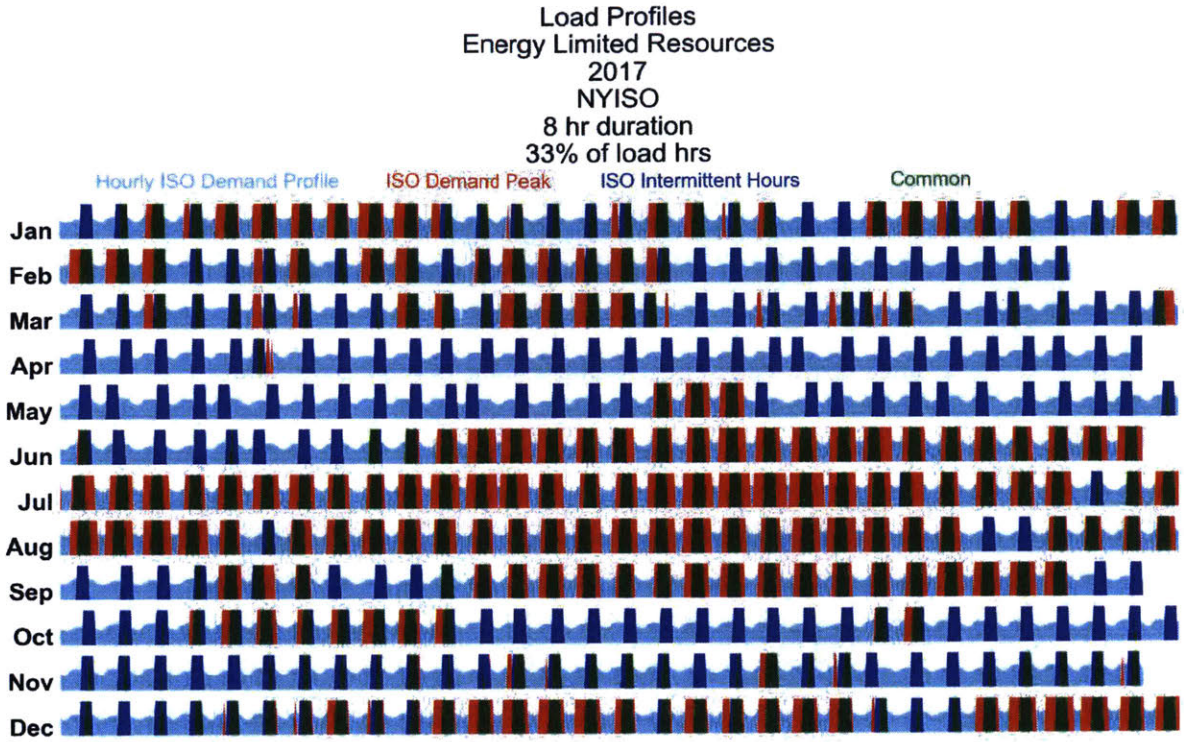

Figure 53: Peak Hour Classification: 8-hour Energy Limited Resources in NYISO

In 2017, the average capacity credits of 4-hour and 8-hour energy limited resources are 82% and 70%, in NYISO respectively. Measuring performance across the same interval as duration may remove the advantage of longer duration in the capacity market.

The capacity credit of pumped hydroelectric, an energy limited resource, is about 97%.[239] So, 4-hour energy limited resource receives a 15% greater capacity credit than historic output during its bid hours suggests. These comparisons are not necessarily equivalent; the 97% looks at unscheduled outages across the years, not at performance during the bid hours, as our analysis calculates. If the objective of the market is to meet the top 4-load hours each day, rewarding based on an annual metric overestimates value. However, if the objective is to meet top demand, looking at unscheduled outages across the year is likely a better metric. However,

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[239] "PJM 2013 - 2017 Average EFORd and Weighted Average EFORd and XEFORd by Fuel Type: Class Average Values Effective June 1, 2018" (PJM Interconnection, n.d.), https://www.pjm.com/-/media/planning/res-adeq/res-reports/2013-2017-pjm-generating-unit-class-average-values.ashx?la=en; Zachary Smith, "Expanding Capacity Eligibility: DER Market Design," (September 27, 2018).

considering that the number of hours of duration each day are not peak demand hours, this bid requirement is not necessary.

3.7.1.3 Energy Storage Resource

If there is less than 1,000 MW of storage installed, how many hours the capacity credit of energy storage resources is measured over is equivalent to 25% of hours within a year. About 48% of these hours are in common between the two profiles in 2017 (Figure 54).

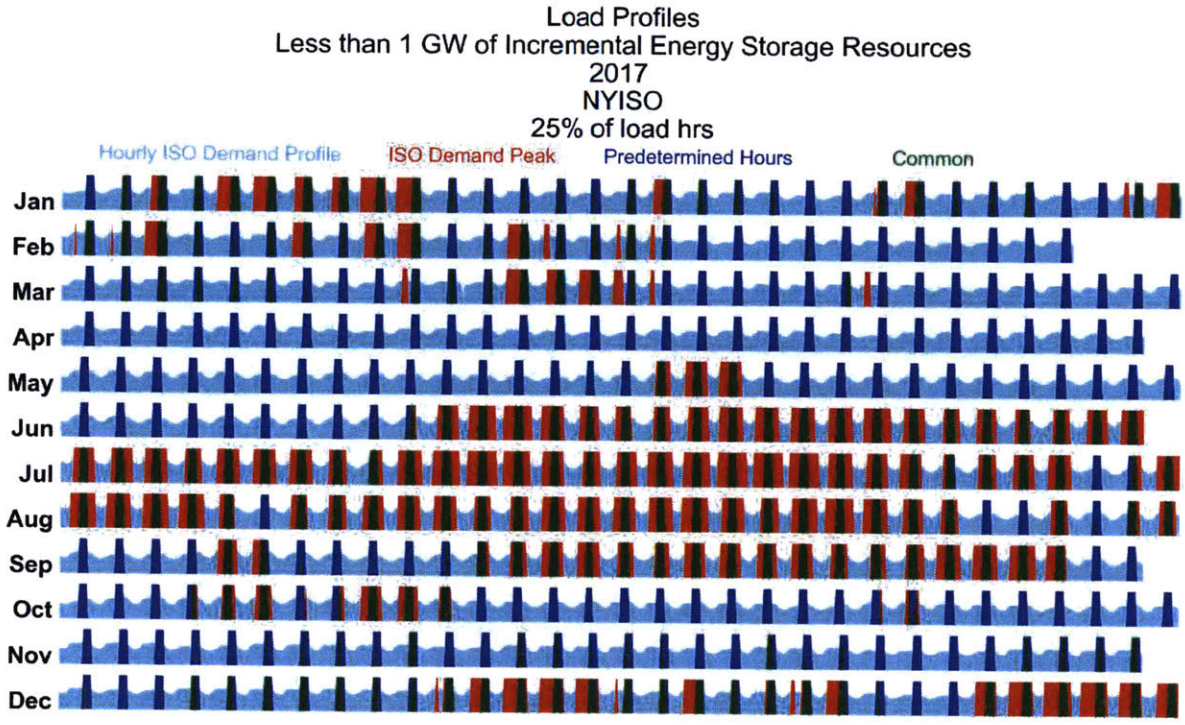

Figure 54: Peak Hour Classification: Less than 1,000 MW of Energy Storage Resources

With more than 1,000 MW installed, the amount of hours within the year that capacity credit is measured is 33% of yearly hours. About 56% in common with respective top demand (Figure 55).

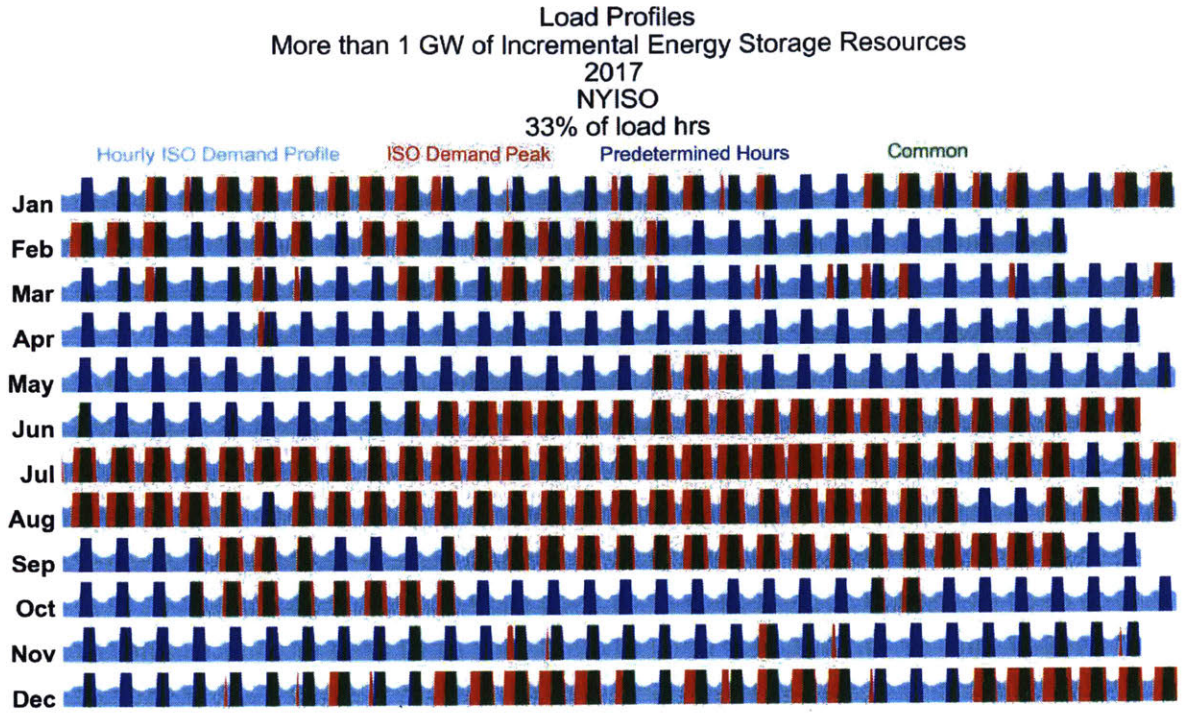

Figure 55: : Peak Hour Classification: More than 1,000 MW of Energy Storage Resources

The capacity credit for 4-hour and 8-hour energy storage resources, prior to 1,000 MW online, as determined by net output during those hours, is 56% and 87%. Theoretically, a duration of 6-hours could have received a capacity credit of 100% using our simplified metric. After 1,000 MW is added, the capacity credit, as determined by net output, decreases to 41% and 72%. Theoretically, a duration of 8-hours could have received a capacity credit of 100%. Actual performance is less than predicted by the simplified metric.

However, NYISO will use what we refer to as the "state of charge" methodology across those peak hours. The capacity credit for 4-hour and 8-hour energy storage resources, prior to 1,000 MW online, as determined during those hours is 73% and 89%, and after 1,000 MW is added, the capacity credits remain about the same. The capacity credits under this methodology is higher than actual output (Figure 56). The choice to value "what could be outputted" versus "what is outputted" represents a different market approach.

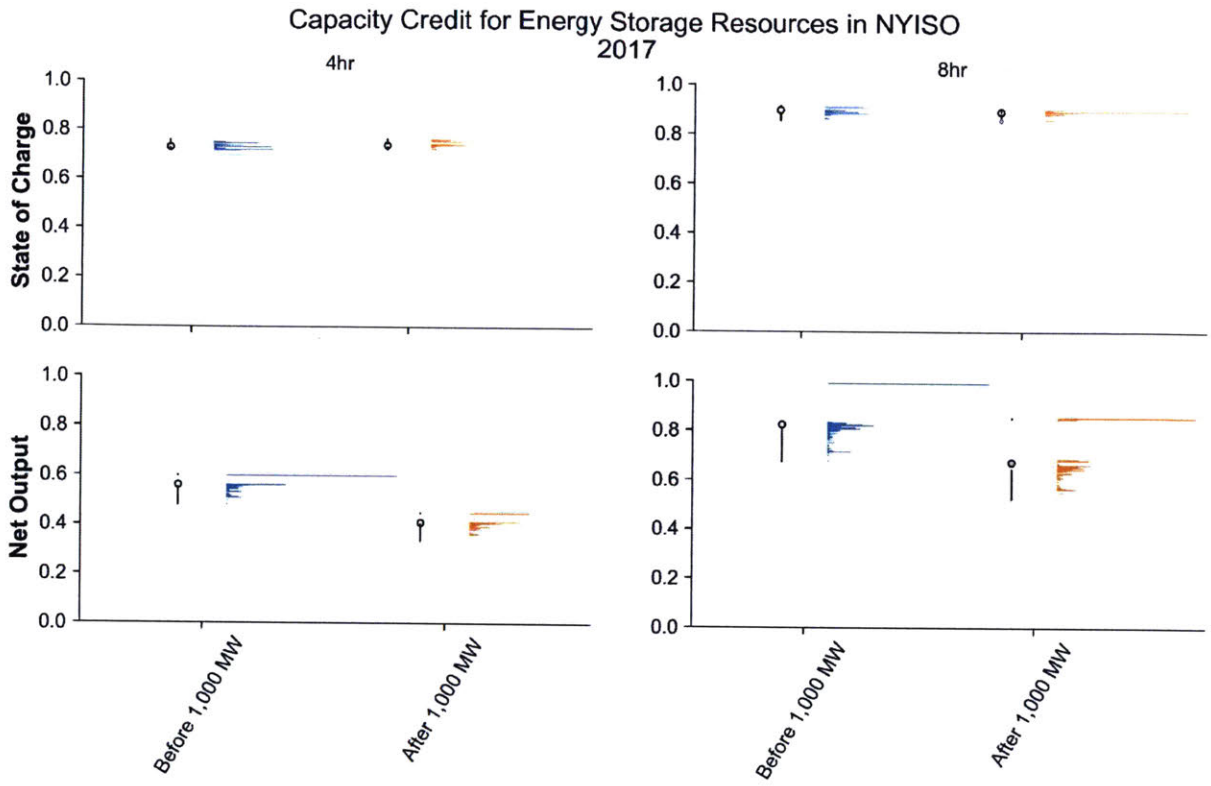

Figure 56: Capacity Credits for Energy Storage Resources

3.7.2 MISO

In MISO, storage is modeled like an intermittent resource. MISO also has energy limited resources like in NYISO.

3.7.2.1 Intermittent Resource

The capacity credit of intermittent resources is taken across 3% of hours within the year. In between the intermittent hours and the top 3% of annual demand in 2017, 33% of peak hour classifications remain the same (Figure 57).

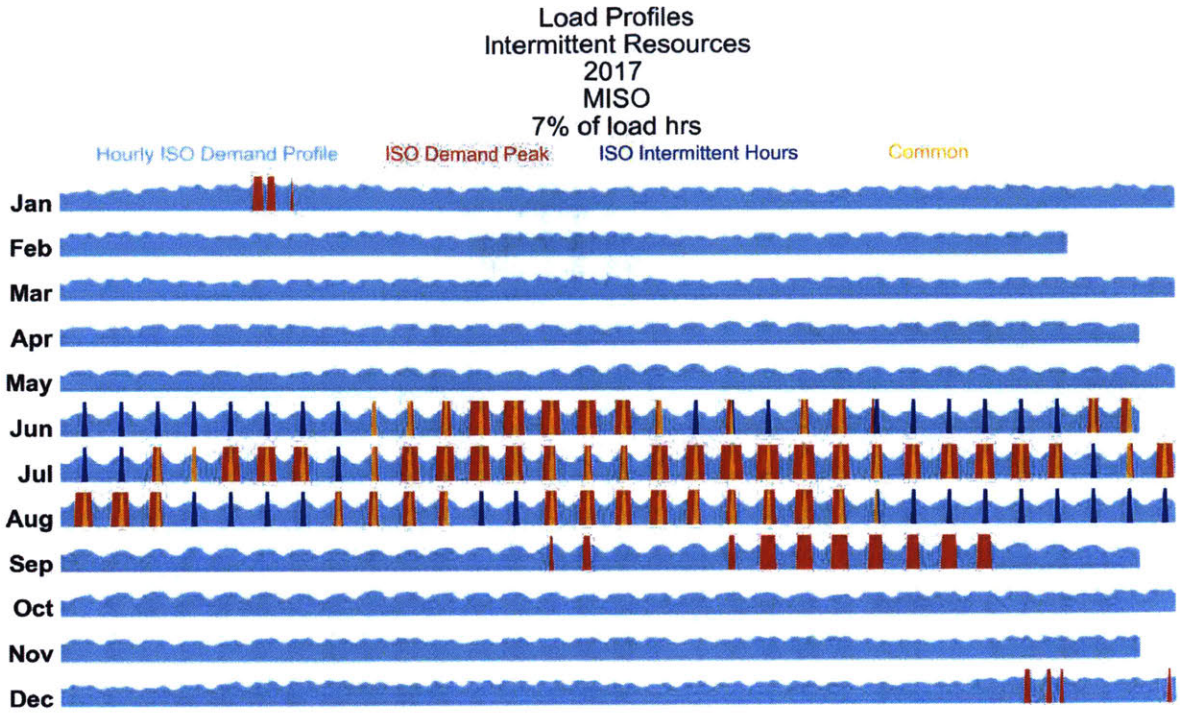

Figure 57: Peak Hour Classification: Intermittent Resources in MISO

In 2017, the capacity credit of 1- hour, 4-hour, and 8-hour units is 29%, 95%, and 96%, respectively. The length of the intermittent window is 3 hours. Storage does not achieve a perfect capacity credit in dispatch, but the minimal difference between 4-hour and 8-hour capacity credit is likely due to this smaller peak hour duration window.

3.7.2.2 Use Limited Resource

MISO's use limited resources are equivalent to NYISO's energy limited resources. Unlike NYISO, in MISO, the hours at which the resource bids are not up to the resource's discretion. The "must bid" hours are 2 hours prior to the anticipated daily peak, the daily peak, and 1-hour after peak.[240]

The capacity credit of 4-hour and 8- hour energy limited resources is 64% and 51%, respectively. Storage could theoretically achieve a 100% capacity credit if its bid window is equivalent to its duration. Again, our simplified metric of classifying peak hours durations does not hold true here. Furthermore, capacity credits for use limited resources (energy limited

[240] For convenience, this bid approach was mimicked for the dispatch of energy limited resources in NYISO.

resources) were higher in NYISO. Capacity prices are higher in NYISO. As previously discussed, nodes in MISO may be more sensitive to acting upon low capacity market prices in the presence of operational costs.

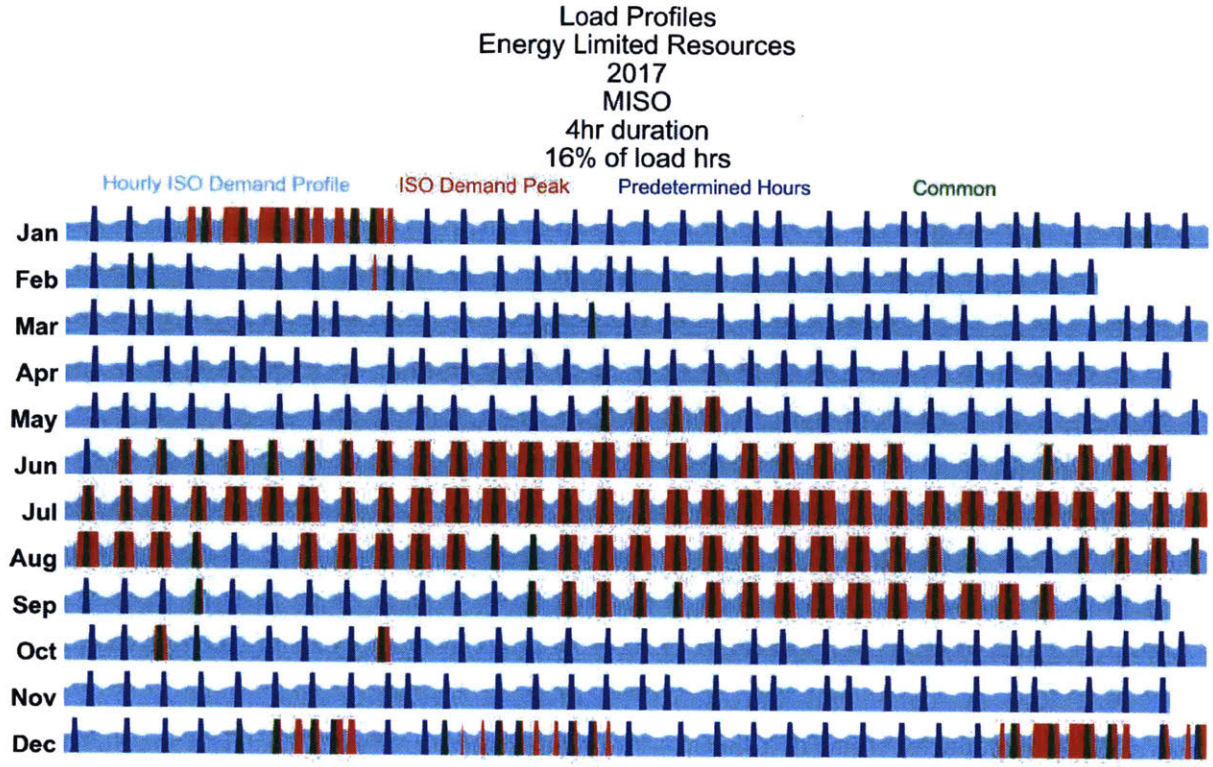

Figure 58: Peak Hour Classification: 4-hour Energy Limited Resources in MISO

3.7.3 ISO-NE

3.7.3.1 Intermittent Resource

Storage is modeled as an intermittent resource in ISO-NE. The number of hours that the capacity credit of intermittent resources is calculated over is 12%. Of the hours that ISO-NE uses to measure capacity credit, 39% coincides with a similar percentage of top load hours (Figure 59). Theoretically, 2-hours can achieve a capacity credit of 50%, and 5-hours a capacity credit of 100%, based upon a simple breakdown of standard peak hours durations as shown through the intermittent windows. In 2017, the average capacity credit of 1-hour, 4-hour, and 8-hour duration units is 30%, 84%, and 100%.

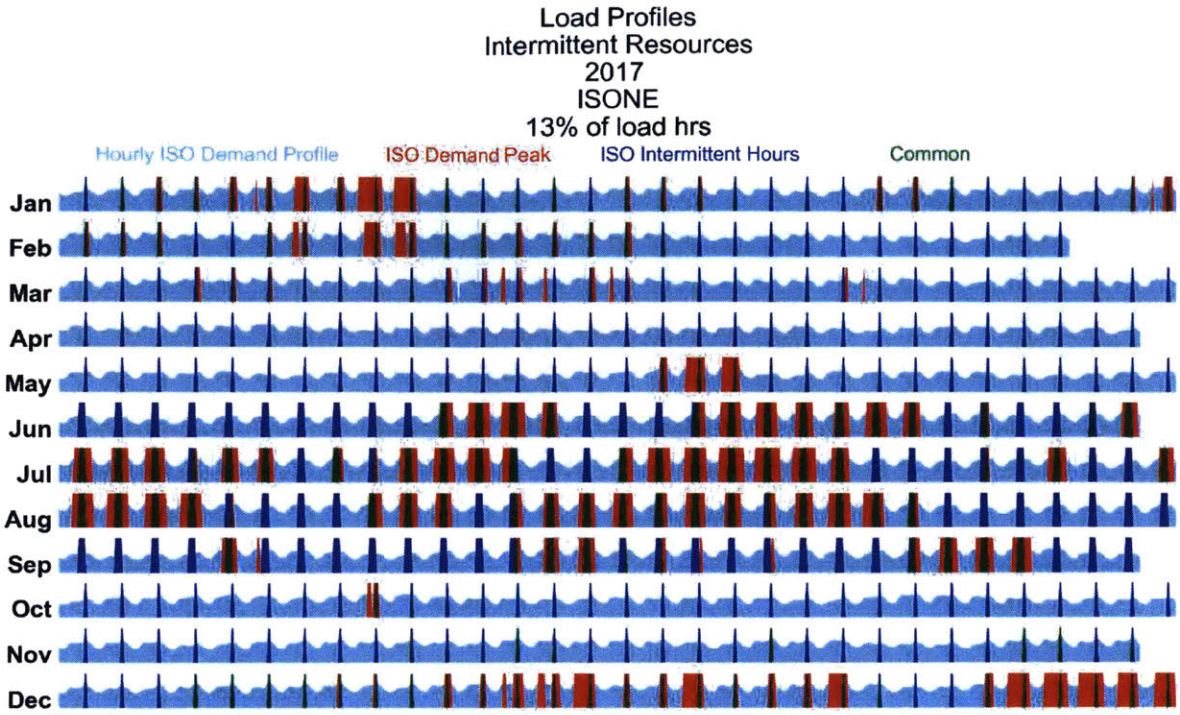

Figure 59: Peak Hour Classification: Intermittent Resources in ISO-NE

3.7.4 PJM

In order to participate in the capacity market in PJM, storage must have a 10 hour minimum duration.[241] In PJM from 2014 through 2017, under 12% of top load hours, to meet the 50% percentile of peak hours durations requires 9 hours on average, and to meet the 75% percentile of peaks, 12 hours (Table 20). Theoretically, for storage to contribute with a capacity credit above 50%, the 10-hour requirement initially seems appropriate. However, the capacity credit of wind in PJM is under 20%, and of solar, 60%, judging by the default values.[242] It may not be equivalent to force storage to possess a longer duration, for the purpose of a capacity

[241] "Q & A for Electric Storage Resource Participation Model: Electric Storage Resource Participation Model," June 8, 2018, http://www.pjm.com/-/media/committees-groups/committees/mic/20180627-special-energy/20180627-item-02-faq-for-order-841.ashx; "Current Rules Related Energy Storage in PJM Markets" (PJM, May 10, 2018), http://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special-electric/20180510-item-03b-all-manual-citing-of-esr-status-quo.ashx.

[242] "PJM Manual 21: Rules and Procedures for Determination of Generating Capability"; "Class Average Capacity Factors: Wind and Solar Resources."

credit greater than 50% as determined by this simplified metric, when not enforced for other resources.

Table 20: Peak Hour Durations for PJM from 2014 through 2017 for 12% of Hours

12% of Demand Hours in PJM	2014	2015	2016	2017
25% Percentile	4	7	4	5
50% Percentile	6	11	8	9
75% Percentile	10	13	12	12
100% Percentile	69	16	18	20

Assuming that capacity credit is taken across the top 7% of load hours in 2017 in PJM, the average capacity credit of 10-hour storage is 89%. Average total revenue is $59,000, with individual nodes ranging from $102,000/MW-year to $49,000/MW-year (Figure 60). Overall, about 66% of revenue for 10-hour duration storage units is derived from the capacity market, although individual percentages of capacity market revenue ranging from 37% to 83%.

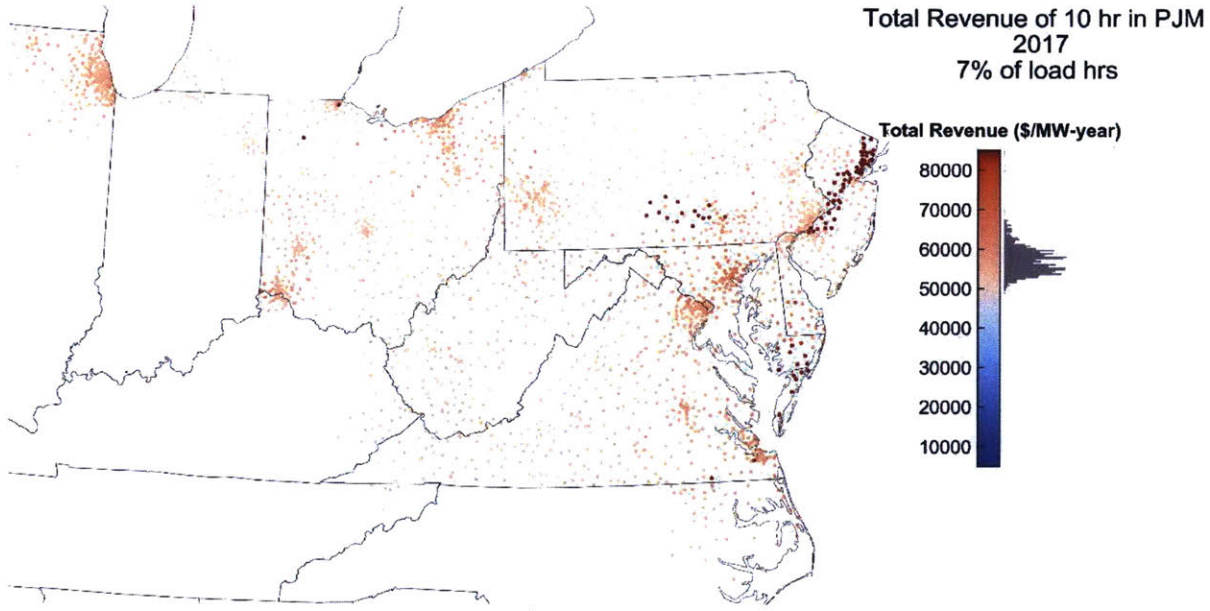

Figure 60: Geographic Map of Total Revenue for 10-hour storage in PJM in 2017

In 2017, 77 locations break even. In order for 50% of locations breakeven, costs need to be $68.16/kW (Figure 61). The cost of storage would have to be dramatically lower than it currently is to justify investment.

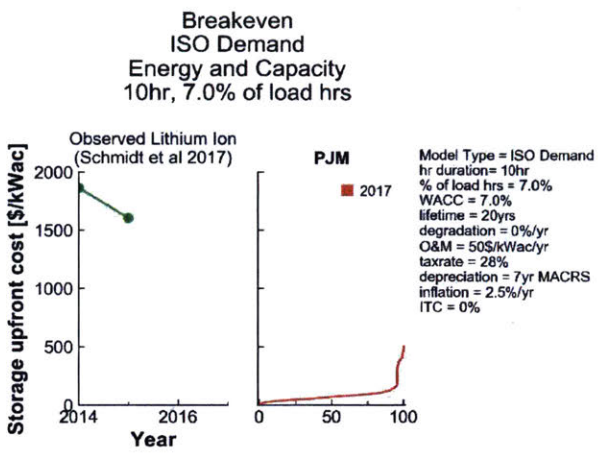

Figure 61: Breakeven of 10 hour storage in PJM

For comparison, the average capacity credits in 2017 of 1-hour, 4-hour, and 8-hour storage is 14%, 48%, and 80%. Even though the simplistic analysis indicates that an 8-hour duration is needed for a capacity credit of 50%, in actually, as shown via dispatch, 4-hours can essentially receive the same effect.

While a simplistic analysis shows the 10-hour requirement as necessary, shown via dispatch, durations shorter than 10-hours- like 4-hours and 8-hours- can achieve capacity credits theoretically assigned to longer duration resources.

3.7.4.1 Intermittent Resource

Intermittent hours in PJM cover around 10% of hours within a year. Of the intermittent hours and respective top 10% of demand hours, 41% of hours classified as peak are in common (Figure 62). The capacity credit of 1-hour, 4-hour, and 8-hour storage is 18%, 74%, and 100%, respectively. Considering the capacity credit of 8-hour duration, if the rationale behind the 10-hour duration is to ensure a certain capacity credit over the same amount of time across the year as other non-fossil resources, the requirement is unnecessary.

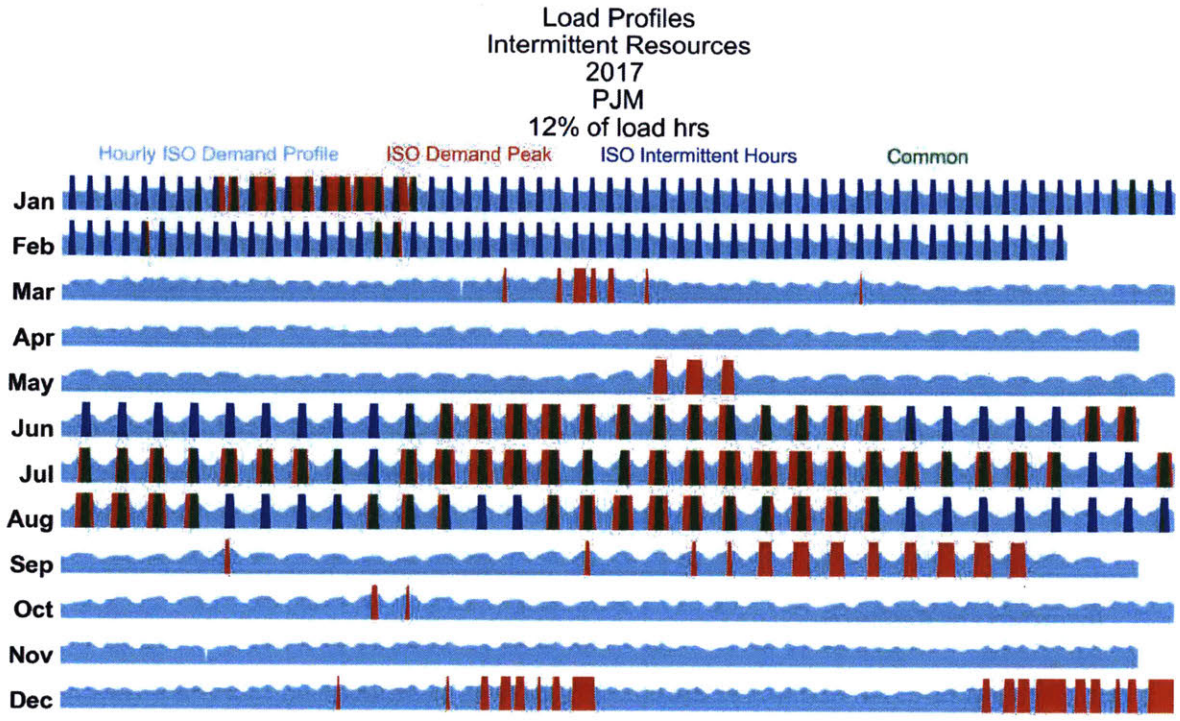

Figure 62: Peak Hour Classification: Intermittent Resources in PJM

3.7.5 CAISO

Unlike NYISO, ISO-NE, PJM, and MISO, CAISO does not host a centralized capacity auction. Instead, loads enter into bilateral contracts with generators to fulfill state mandated resource requirements.

Storage must have at least 4-hours of duration to be eligible to offer capacity. Loads must procure three different types of capacity: System, Local, and Flexible. Flexible Capacity is acquired to help meet ramp needs. [243] Requirements for Flexible Capacity is one way that California is addressing the daily load profiles caused by solar. Each type of Flexible Capacity product comes with different must offer DAM requirements.[244]

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[243] Lily Chow and Simone Brant, "The 2017 Resource Adequacy Report" (California Public Utilities Commission, August 2018).
[244] "Business Requirements Specification: Flexible Resource Adequacy Criteria and Must Offer Obligation" (California Independent System Operator, May 30, 2014), http://www.caiso.com/Documents/BusinessRequirementsSpecification-FlexibleResourceAdequacyCriteriaMustOfferObligation.pdf.

3.7.5.1 Flexible Resource

Base Flexibility requires storage to bid in for the equivalent of 71% of hours a year. Because of the sheer amount of hours, in 2017, 84% of the mandatory peak times correlate to the respective percent of top load hours. Base flexibility is an extreme and unlikely use of storage; as judging by our simplistic peak hours duration interpretation, a capacity credit of 100% would require 17 hours a day. Indeed, the average capacity credit of shorter-duration resources is quite low; as determined by net output during the mandatory bid hour windows, is 12% and 15% for 4-hours and 8-hours.

Peak Flexibility requires about bidding the equivalent of 20% of hours. In between the bid windows and the top 20% of hours in 2017, 45% of peak hours remain the same. If the capacity credit of storage is measured across the bid windows, then the capacity credit is 69% and 95% for 4-hour and 8-hour duration, respectively. Theoretically, as determined by the simplistic analysis, a 5-hour duration storage unit could achieve a 100% capacity credit. The theoretical capacity credit overestimates capacity credit in regards to actual dispatch behavior. Peak Flexibility is a more attractive use of storage than Base Flexibility.

Super Peak Flexibility covers the equivalent of 6% of the top load hours, about 14% of which are in common with the bid windows.[245] The capacity credit of 4-hour and 8-hour duration storage is on average 72% and 100%.

3.8 Comparative Analysis

The distribution of capacity credits for the alternative rules is given in Figure 63. Capacity credit is a function of ISO treatment. For example, if ISOs were to value the contribution of energy storage to reliability using intermittent rules, as judged by the range in capacity credits, ISOs have a different interpretation between each other of what the reliability value of 4-hour storage is. Furthermore, the simplified metric of predicting capacity credit by looking at peak hour durations would assume, across all ISOs, that 8-hours of duration (excluding Base Flexibility in CAISO, deemed an unrealistic use) could achieve a capacity credit of 100%, but as seen in Figure 63, this metric is too simplified.

[245]Because of the infrequency of holidays, the weekend constraint is not added into the code. Presumably with the exclusion of holidays, the capacity credit could be minimally higher.

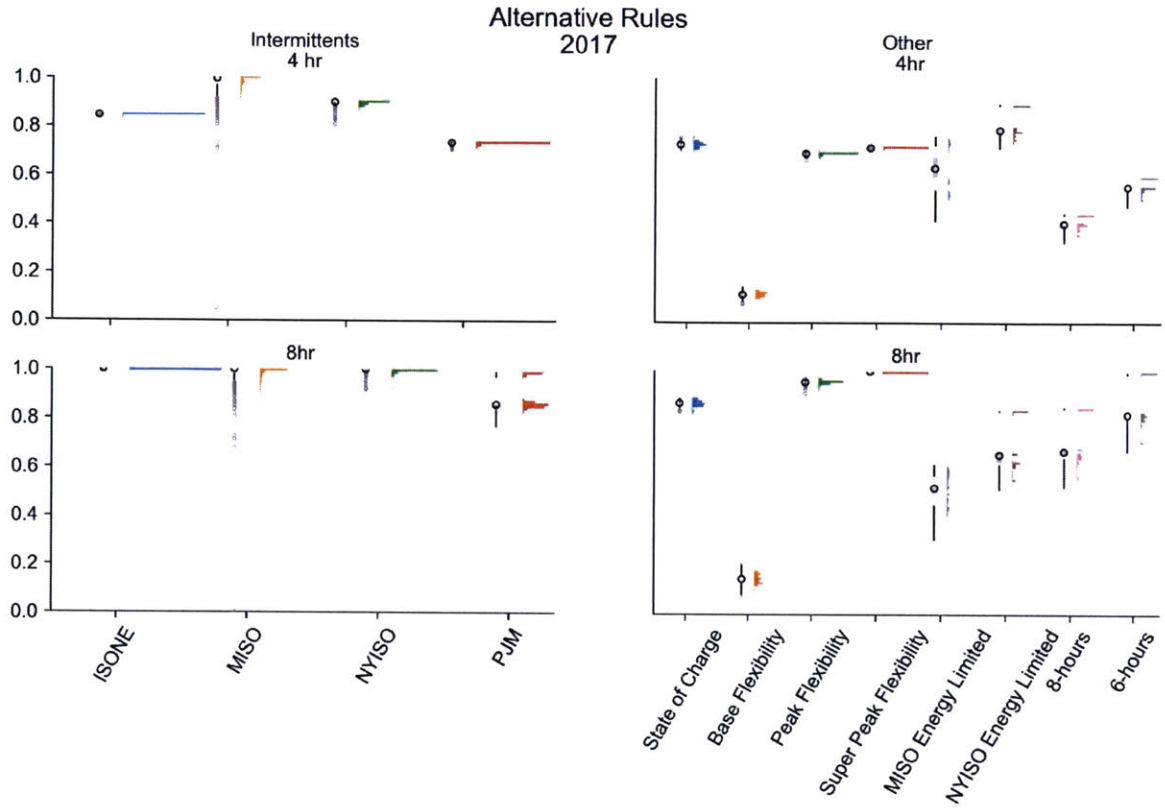

Figure 63: Capacity Credits across ISO Rules

Average capacity credits are higher under ISO rules than under the top demand schemes (Table 27 in Appendix). Across the ISOs using the intermittent rules from 2014 through 2017, average breakeven costs are $296.76/kW (Figure 64). Considering average breakeven costs from 2014 through 2017 are $180.35/kW under 7% of load hours, the business case for storage can significantly increase under this intermittent treatment; the capital costs for 50% of nodes to breakeven halves. In comparison to energy only revenue, participation in the capacity revenue as an intermittent resource has a capital cost requirement ten-times less for 50% of nodes to breakeven from 2014 through 2017. But, the extent of the benefit of intermittent treatment, in comparison to alternative capacity market modeling, depends on year. In 2017, the breakeven cost for intermittent resources was $157.00/kW, but for 7% under ISO demand, $162.90/kW. The benefit of intermittent treatment, in comparison to ISO demand, depends on year. From year to year, breakeven costs costs vary (Figure 65).

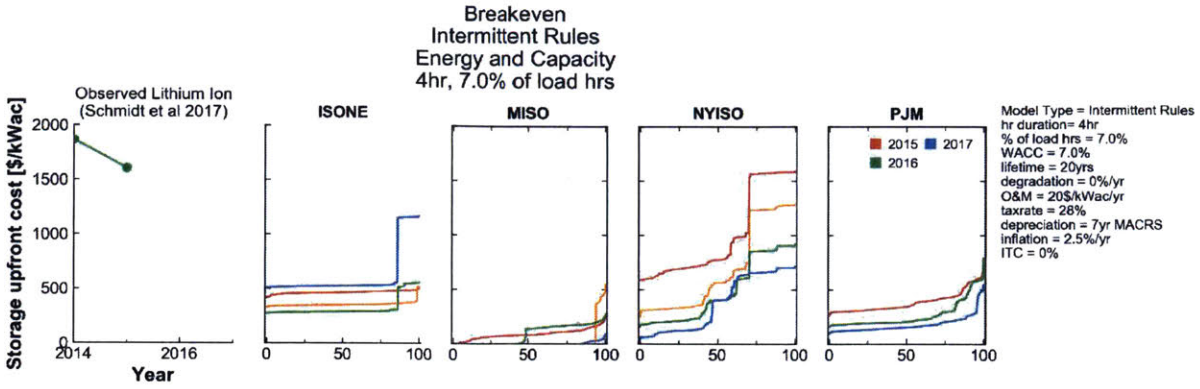

Figure 64: Breakeven Prices for Storage Assuming Intermittent Rules

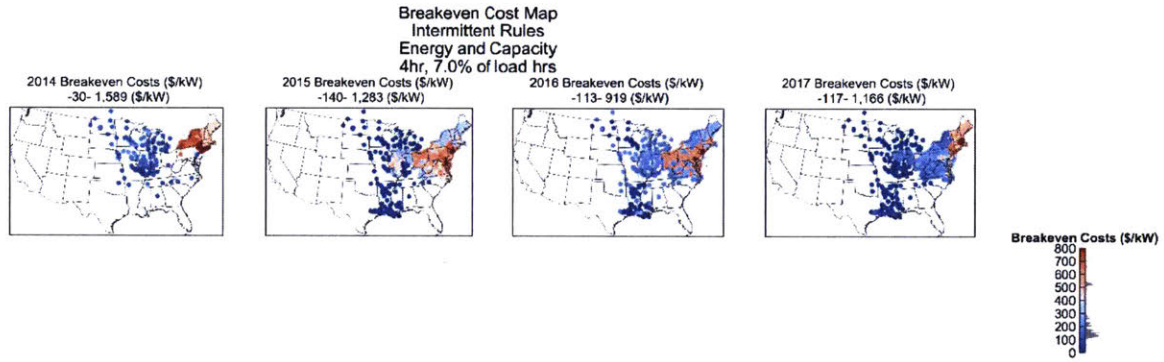

Figure 65: Breakeven Costs in Energy and Capacity Markets Across Locations Under Intermittent Rule Treatment

In 2017, of the 4-hour energy limited resources in MISO and NYISO, 23% breakeven at capital costs of $399/kW. But, breakeven costs for 50% of nodes is $42.86/kW (Figure 66). Of the 8-hour duration, 19% of locations breakeven at capital costs of $399/kW and for 50% of locations to breakeven, the breakeven cost is $-93.24/kW - nodes need to get paid (Figure 67). Treatment as energy limited resources does not present nearly as attractive of a business proposition as being modeled like an intermittent resource.

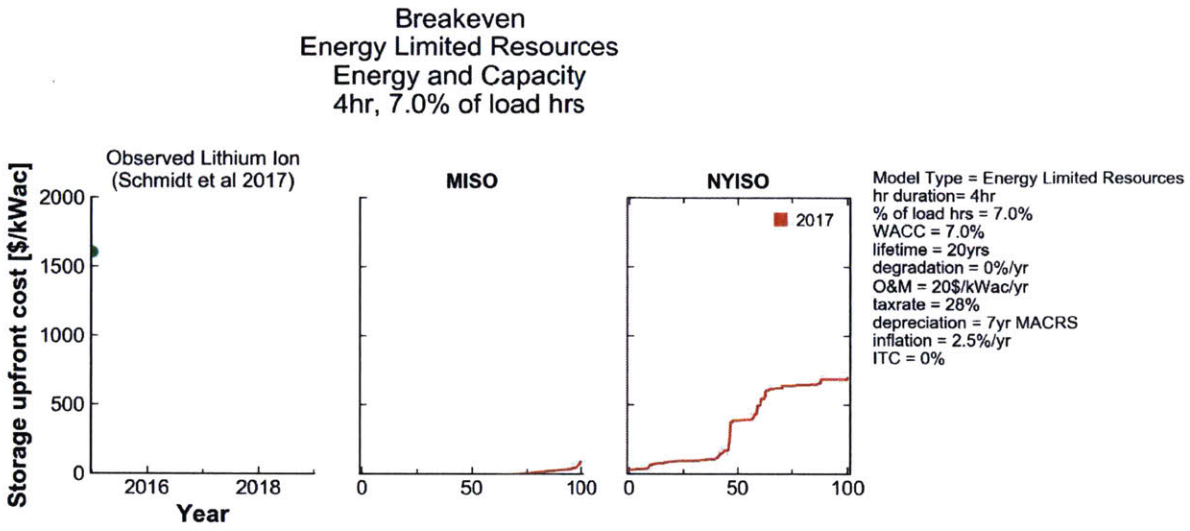

Figure 66: Breakeven Costs for 4-hour Energy Limited Resources

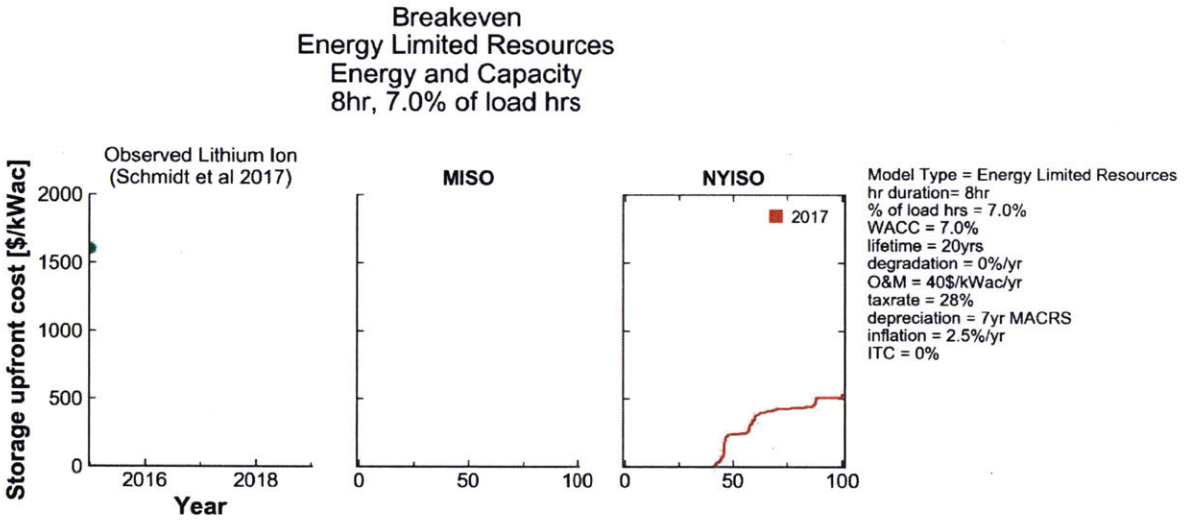

Figure 67: Breakeven Costs for 8-hour Energy Limited Resources

The "state of charge methodology" as proposed in NYISO represents another way to calculate capacity credit. We here compare this capacity credit, across ISOs and years, to our methodology (Figure 68, and Figure 82 and Table 28 in Appendix).

The capacity credit of storage is higher under this "state of charge" metric (Figure 68).

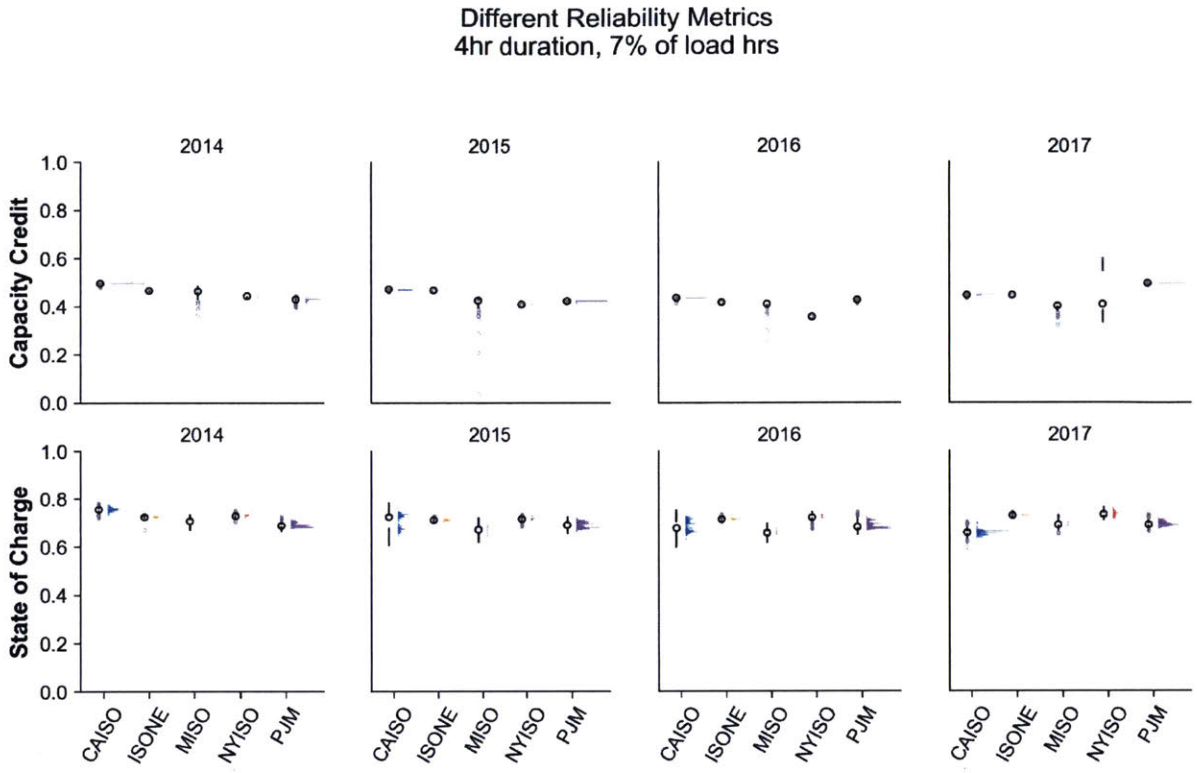

Figure 68: State of Charge Methodology: Reliability Comparison

State of Charge refers to the capacity credit as calculated via the State of Charge methodology.

In summary, how ISOs decide to calculate capacity credit could significantly affect revenue. The hours over which ISOs take capacity credit generally do not have a majority of hours in common with times of peak demand. Furthermore, even if we assume that the intermittent hours are of the hours of concern, there are alternative ways of compensating for availability within those hours, like the state of charge methodology.

Compensating for output during certain hours is an approximation of reliability benefit. This approximation became necessary when intermittent resources began to enter the market, because unlike fossil-resources that can be systemically studied for unplanned outages, intermittent resource value was less clear. For intermittent resources that cannot control output, stakeholders might agree, that if these hours are the concern, that this is a decent simplistic evaluation of capacity credit. However, energy storage resources, within the context

of limited durations, can plan output. Identifying value, and incentivizing it, is still very much in debate. We show that different metrics of compensating produce different dispatch results.

4 Conclusion

Increasing motivation to stem greenhouse gas emissions has naturally turned a critical eye on the generation sources within the U.S. power sector. Responsible for roughly a third of U.S. emissions, decarbonizing the power sector is a common-sense solution, as alternative technologies like wind and solar are currently active and available. However, shifting the generation mix towards renewables resources will require an entirely new operation method of the century-old grid. Variations in wind, solar, other generation, and demand must be balanced to provide safe, reliable, and affordable service.

As a non-fossil resource with costs that have declined some 65% in the past five years, lithium-ion batteries are being touted as a solution. But, batteries are a relatively new technology on the grid. There is a lack of consensus on where the value of energy storage rests.

This discussion is clouded by the complexity of the U.S. regulatory environment. In about a third of U.S. geographic territory, where electric utilities centrally plan the entire system, investments in storage can be rationalized based on storage's holistic contribution to the grid. But in other states, there are essentially two disparate electricity markets: the retail market, where local monopolies that own low-voltage equipment sell power at a state-regulated rate, and the wholesale market, where independent generators compete to offer the lowest-cost power in a technically-constrained clearing house, subject to federal oversight. In the absence of strong federal environmental goals, states are starting to subsidize energy storage resources, to meet immediate environmental goals, as well as to gain experience on how to best take advantage of these newer shorter-duration, energy limited resources. In response to lowering costs and increased penetration, competitive markets, under which a vast majority of storage has participated to date, must adjust.

Because of the novelty, there are some unanswered questions. First and foremost, what is the existing business case for lithium-ion batteries? Second, how do batteries respond to the existing rules to supply reliability, and what does this response say about how market incentives align with the idealized outcome? This thesis aims to answer these questions. A comprehensive analysis that employs historic prices, and reflects location and time sensitive trends, is a necessary foundation for regulators, who must decide how to incentivize, and developers, who prove whether incentives work.

We simulate battery dispatch at over 10,000 locations in the U.S. from 2014 through 2017 in two distinct markets, the energy market, which compensates for "the now," and the capacity market, which aims to make sure peak yearly demand is met ("the dangerous maybe") to understand, at a granular level, how batteries will make decisions, and whether the objective of existing market rules aligns with these decisions.

We represent behavior in the capacity market as a function of capacity credit, or net output as a fraction of rated output across certain hours. This methodology of calculating capacity credit mirrors how ISOs compensate intermittent resources in the capacity market. We identify these hours used for calculating capacity credit as the top 1%, 7%, and 12% of top load

hours across the year. The percentages frame the equivalent amount of hours that ISOs use for intermittent resources.

Adding capacity market revenue always results in an increase in total revenue. There are no worrisome tradeoffs between the energy and capacity market. Adding one revenue stream results in less than a 1% average decrease in the other. In short, energy and capacity market participation complement each other.

From 2014 through 2017 on average, adding capacity revenue doubles revenue- but the business case still depends on location and year. The percent increase in total revenue from adding capacity market revenue can range from 1% to 650%, based on year and location.

Of the top 100 earning nodes each year from 2014 through 2017 in the energy market only, 86% remain so classified for only one year. When adding capacity market participation, 44% remain within the top 100 earners for three years. Including capacity market revenue has the additional benefit of stabilizing the location of top revenue generating systems. The location of top earning nodes shifts eastward to the ISOs with capacity markets.

From 2014 through 2017 on average, if energy storage participates in the energy markets, less than 1% of 4-hour systems breakeven, assuming a low capital cost estimate of $399/kW. However, with the inclusion of capacity market revenue, then 11% of batteries breakeven.

From a reliability standpoint, participating in the capacity market increases the average capacity credit by 10%. Furthermore, there is less than a 4% average increase in total revenue when batteries optimize for capacity market revenue, versus when capacity market revenue is added as an afterthought to energy market participation. Batteries will respond to price signals sent in the capacity market, even for a comparatively small percent increase in revenue. Consequently, from a regulatory perspective, it is important to hone these market signals because of the sensitivity of response.

How to calculate capacity credit is up for debate. A simplistic approach of estimating capacity credit by looking at the durations of consecutive hours of top demand periods is not found to accurately predict the capacity credit of energy storage, in particular for resources with less than 8-hours of duration. It follows that ISO rules that set duration requirements based on heuristics may not be equitable.

Reevaluating capacity credit metrics can fundamentally change the business case of energy storage resources. For example, from 2014 to 2017, valuing energy storage resources like intermittent resources for capacity payment purposes lowers average breakeven costs to a tenth of those required by energy-only participation. As currently proposed in New York, calculating capacity credit as *potential* output- or the ability to discharge at rated output given energy constraints- can increase capacity credit up four-and-a-half times in comparison to the standard capacity credit treatment. The business case of storage is not only a reflection of prices, but also of market-specific treatment.

Energy storage resources will adjust operational strategies, in the presence of financial incentives, to support reliability. However, revenue is very much a function of time, location,

and market design. It is within the domain of regulators to decide how much they value the contribution of storage.

Appendix

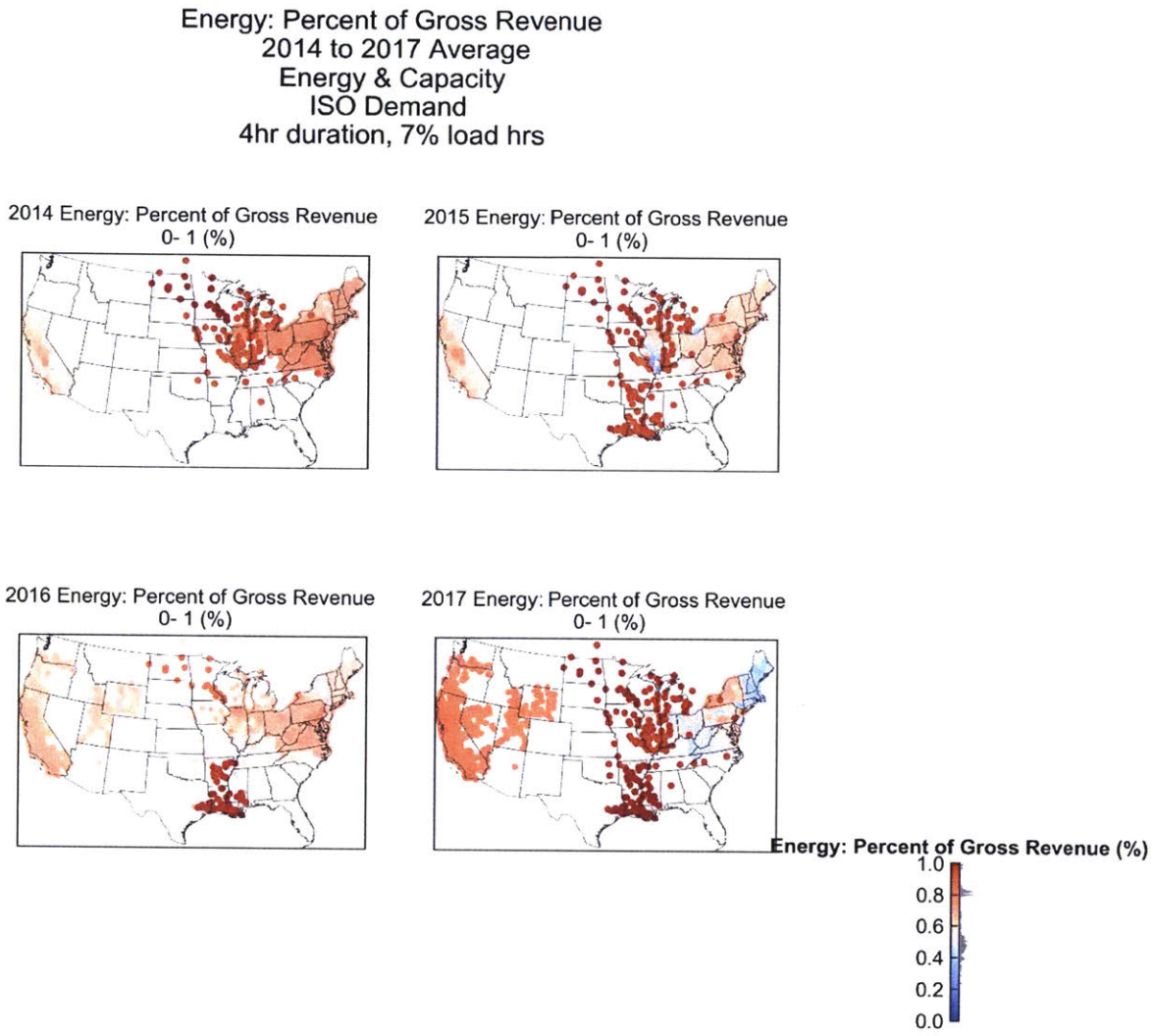

Figure 69: Geographic Maps of Energy Revenue as a Percent of Gross Revenue for Energy and Capacity Dispatch

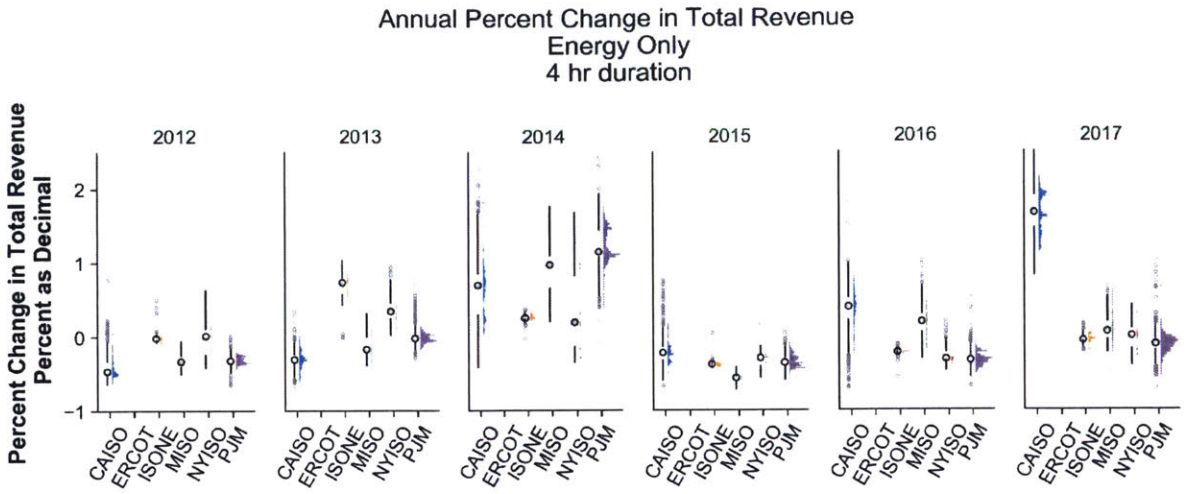

Figure 70: Annual Percent Change in Total Revenue in Energy Only Dispatch: 2011 onward

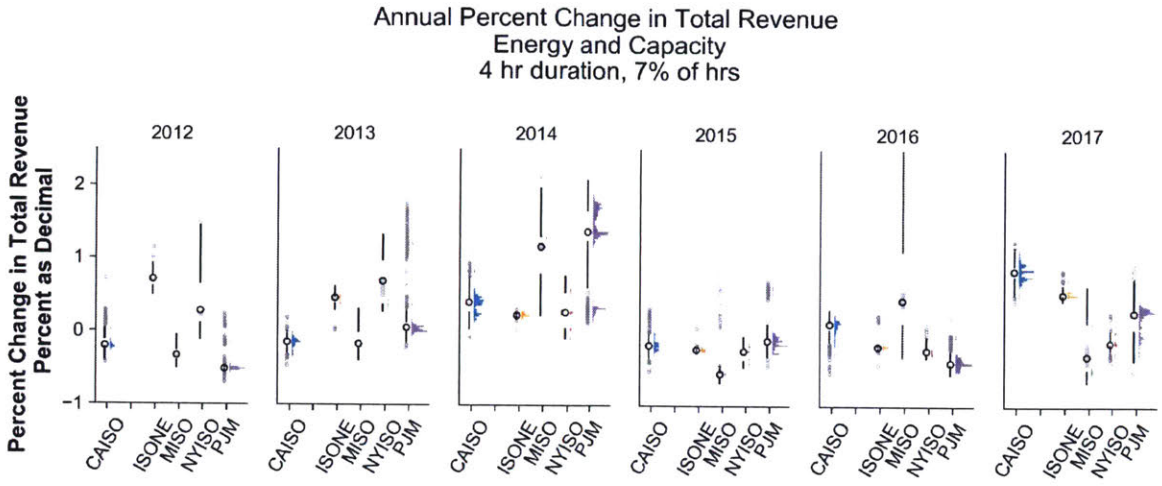

Figure 71: Annual Percent Change in Total Revenue in Energy and Capacity Dispatch: 2011 onward

The 2012 column represents the percent change from 2011 to 2012. Results are presented as decimals.
ERCOT excluded.
From 2011 to 2017, the annual percent change in revenue ranges from -70% (2011 to 2012, PJM) to 271% (2016, MISO).

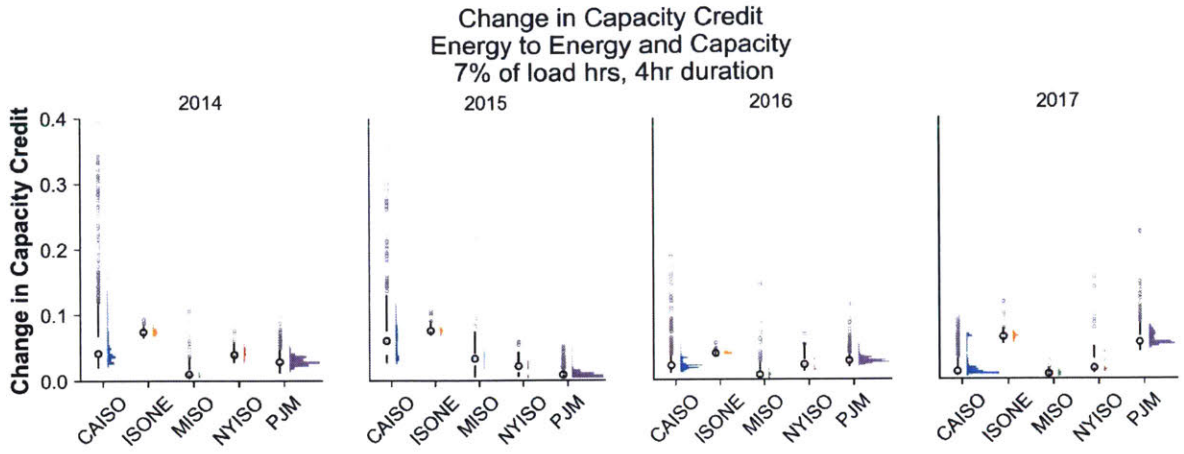

Figure 72: Change in Capacity Credit Upon Adding Capacity Revenue

Table 21: Detailed Analysis of Peak Hours Durations

Load	Percent	Year	ISO	Percentiles *Value of Percentile is hours of Peak Hours Durations*			
			ISO	25%	50%	75%	100%
		2014		3	4	6.5	9
		2015		2	4.5	7.75	9
		2016		3.25	5	6.75	8
		2017	CAISO	3	5	7	10
		2014		4	5	7.5	10
		2015		3	7	9	9
		2016		5	6	7	10
		2017	ISO-NE	2.5	7	9	10
		2014		2.5	5	6	9
		2015		3.25	5	6	10
		2016		3	5	7	9
		2017	MISO	3	5	5.5	9
		2014		2.75	5.5	8	11
		2015		3.75	5.5	8	10
		2016		3.25	4	6.5	10
		2017	NYISO	3.5	6.5	8.75	10
		2014		3	4	5	7
		2015		2	4.5	6	8
		2016		3	5	5.5	10
	1	2017	PJM	2	6	7	10
		2014		5	6.5	9	12
		2015		4	7	9	14
		2016		6.25	8	10	13
		2017	CAISO	6	8	10	15
		2014		2	5	11	15
		2015		3	5	11	15
		2016		3.25	8	12	16
		2017	ISO-NE	3	7	11	15
		2014		3	6	9	17
		2015		4	8	11	16
Demand	7	2016	MISO	6	9	11	14

Net of Wind and Solar							
		2017		5	8	11	14
		2014		3	6	12	15
		2015		4	7	13	16
		2016		7	10	13.5	16
		2017	NYISO	5	9	12	16
		2014		3	6	9	33
		2015		5	8	11	14
		2016		5	9	11	14
		2017	PJM	4	6	9	14
		2014		7.5	9	11	14
		2015		8	10	12	16
		2016		8	10	12.25	16
		2017	CAISO	7	10	12	17
		2014		3	5	12	16
		2015		3.75	6	12	16
		2016		3	8	12	17
		2017	ISO-NE	2	5	11	17
		2014		4	6	10.5	42
		2015		4	8	12	18
		2016		5	10	13	16
		2017	MISO	6	10	12.25	17
		2014		3	7	13	17
		2015		3	7.5	12	17
		2016		6	11	14	18
		2017	NYISO	4	10	13	18
		2014		4	6	10	69
		2015		7	11	13	16
		2016		4	8	12	18
	12	2017	PJM	5	9	12	20
		2014		2	4.5	6	8
		2015		2	3	6	10
		2016		1	3	5	7
		2017	CAISO	2	4	6	9
		2014		4	5	8	10
		2015		4	7	9	10
		2016		5	6	7	11
		2017	ISO-NE	5	7	9	11
		2014		4	5	6	9
		2015		3	5	6	9
	1	2016		4	6	6	9

	2017		3	6	6	10
	2014		2.75	5.5	8	11
	2015		3.75	5.5	8	10
	2016		3.25	4	6.5	10
	2017	NYISO	3.5	6.5	8.75	11
	2014		3	3.5	5	7
	2015		2	5	6.5	9
	2016		2.5	4	6	10
	2017	PJM	3	4	7	11
	2014		4	6	9	13
	2015		4	6	9	14
	2016		3	6	8	13
	2017	CAISO	4	6	8	14
	2014		3	5	10	15
	2015		3	5	11	15
	2016		4	8	12	16
	2017	ISO-NE	3	7	10	15
	2014		4	6	9.75	17
	2015		6	9	11	14
	2016		6	9	11	14
	2017	MISO	6	9	12	15
	2014		3	6	12	15
	2015		4	7	13	16
	2016		7	10	13.5	16
	2017	NYISO	4.75	9	12	16
	2014		4	7	9	32
	2015		5	8	11.5	14
	2016		4.75	9	11	14
7	2017	PJM	4	6	9	14
	2014		4	8	10	15
	2015		3	6	9	17
	2016		3	5	8	14
	2017	CAISO	3	5	8	17
	2014		3	5	12	16
	2015		3.25	5	12	16
	2016		3	7.5	12	17
	2017	ISO-NE	3	5	11	17
	2014		4	8	11	42
	2015		4	9	12	15
12	2016	MISO	6	10	13	16

2017		6	10	13	19
2014		3	7	13	17
2015		3	7	12	17
2016		6	11	14.25	18
2017	NYISO	4	10	13	18
2014		3	6	11	58
2015		7	11	13	16
2016		5	8	12	18
2017	PJM	5	9	12	21

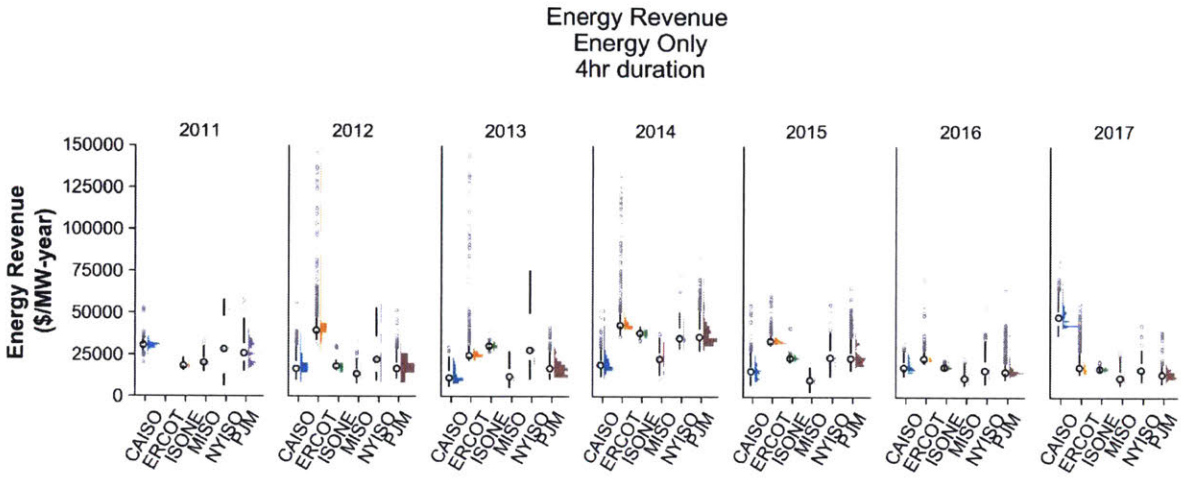

Figure 73: Energy Revenue for Energy Only Dispatch: 2011 through 2017

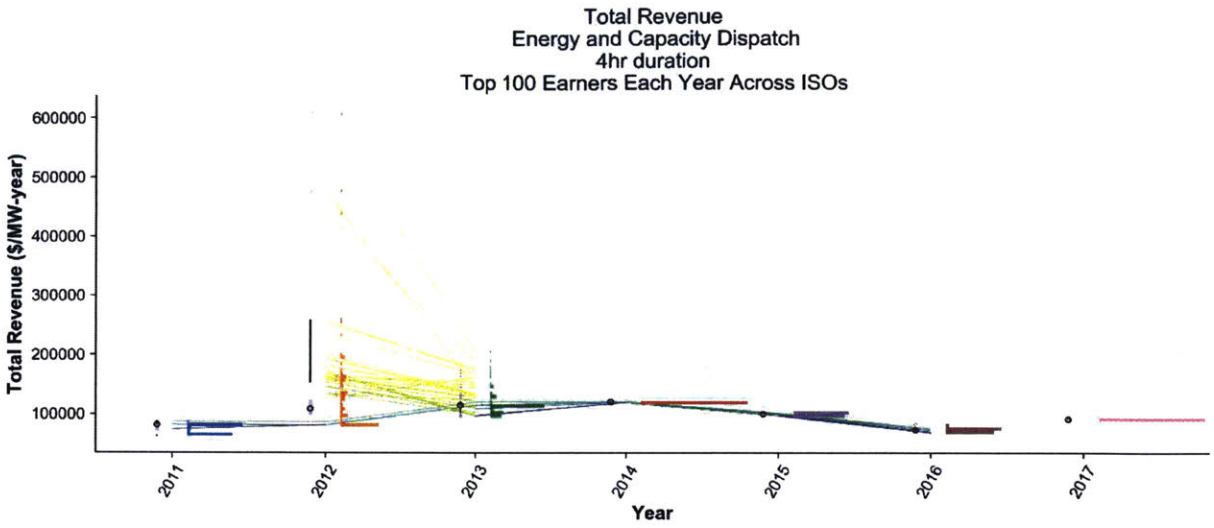

Figure 74: Persistence of Top 100 Earners in Energy and Capacity Markets: 2011 through 2017

For 2011, capacity prices are available for NYISO, PJM, and CAISO. In 2012, we have ISO-NE capacity prices, and in 2014, MISO prices. Missing prices are assumed to be zero.

Of the 309 unique nodal locations that classify within the top 100 nodes for 2011 through 2017 in the energy and capacity markets, 57% remain profitable for 1 year, 12% for two years, but 9% and 10% remain so classified for 5 and 6 years, respectively.

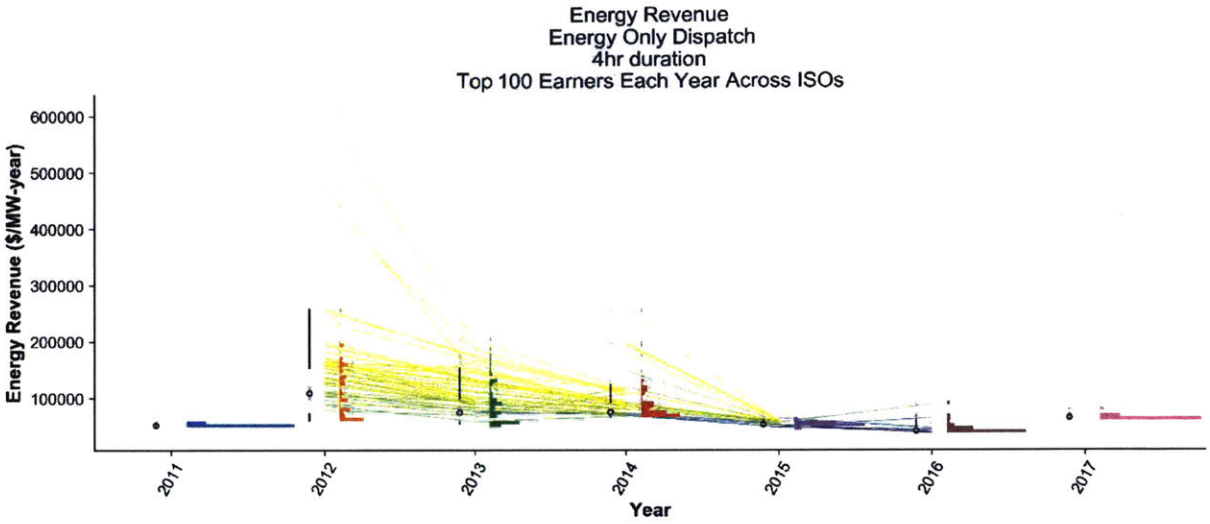

Figure 75: Persistence of Top 100 Earners in Energy Only Market: 2011 to 2017

In contrast to the energy market, of the top 496 unique nodes that fit within the top 100 node classification, 77% are profitable for 1 year. No nodes remain within the top 100 classification for 5 or 6 years.

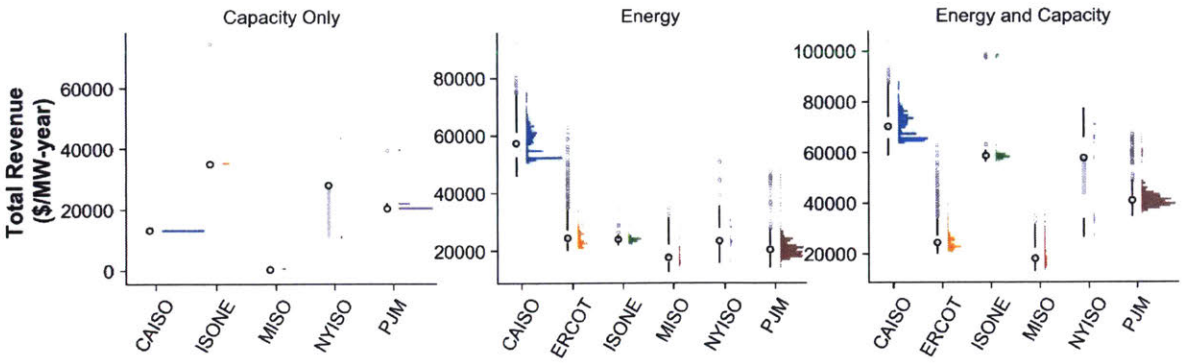

Figure 76: Total Revenue from Dispatch without Operational Cost

Table 22: Peak Hours Durations in CAISO Under Net-solar Load Profiles

7% of hours in CAISO	25% Percentile	50% Percentile	75% Percentile	100% Percentile
2014				
Ten-times-net-solar	3	4	5	8
Five-times-net-solar	4	5	6	8
Net-solar	4.75	6	8	12
Demand	5	6.5	9	12
2017				
Ten-times-net-solar	3	4	5	9
Five-times-net-solar	3	5	5	9
Net-solar	4	6	8	13
Demand	6	8	10	15

Table 23: Peak Hours Durations in MISO under Net-wind Profiles

7% of hours in MISO	25% Percentile	50% Percentile	75% Percentile	100% Percentile
2014				
Ten-times-net-wind	3.75	6	9	17
Five-times-net-wind	3	6	9	17
Net-wind	4	6	9.75	17
Demand	3	6	9	17
2017				
Ten-times-net-wind	4	9	11	15
Five-times-net-wind	5	9	11	14
Net-wind	6	9	12	15
Demand	5	8	11	14

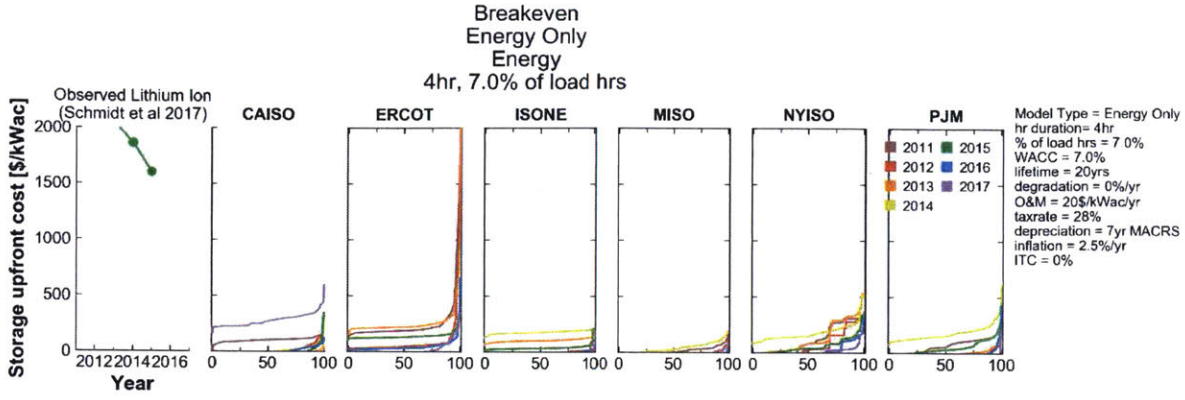

Figure 77: Breakeven Costs in Energy Only Dispatch: 2011-2017

No nodes break even in 2011, From 2012 through 2017 at a capital cost of $388/KW, 1% of nodes break even. For 50% of storage units to breakeven at a capital cost of $399/KW, prices must be $24.48/kW.

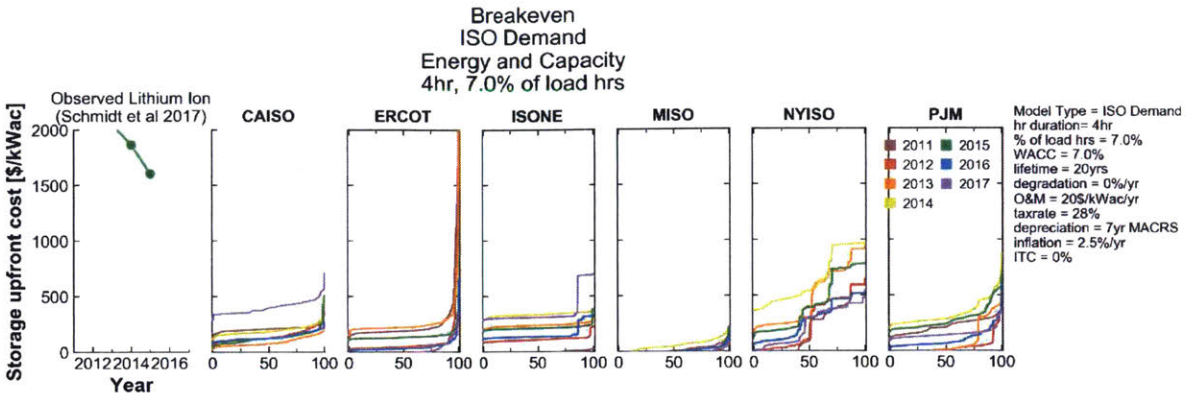

Figure 78: Breakeven Costs in Energy and Capacity Dispatch: 2011-2017

On average from 2011 through 2017, at a capital cost of $399/kW, 8% of nodes breakeven each year. For 50% of nodes to breakeven, average costs should be $154.38/kW.

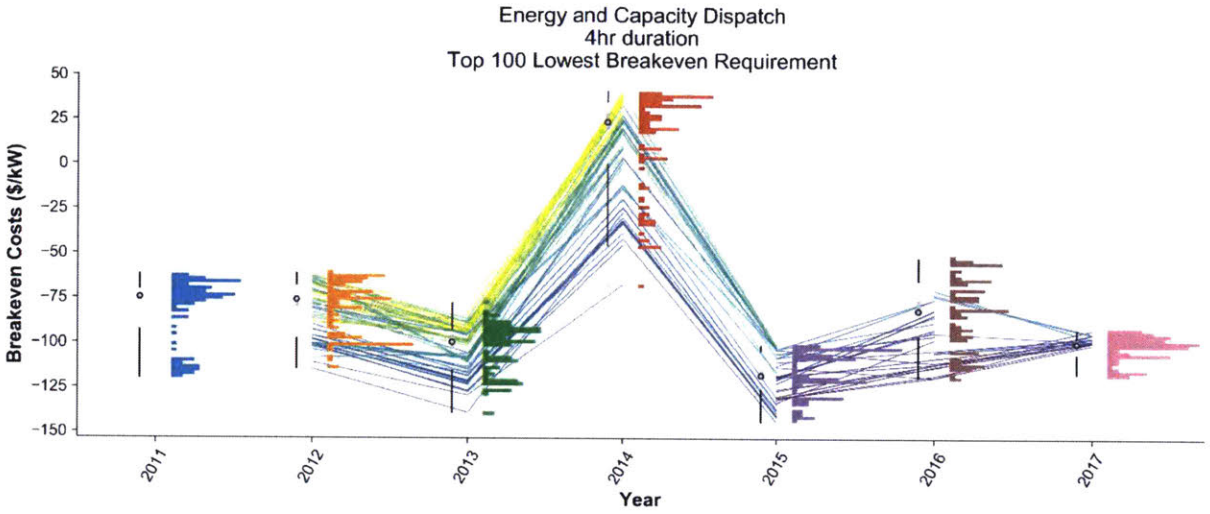

Figure 79: Persistence of Top 100 Earners in Energy and Capacity Dispatch: 2011 onwards

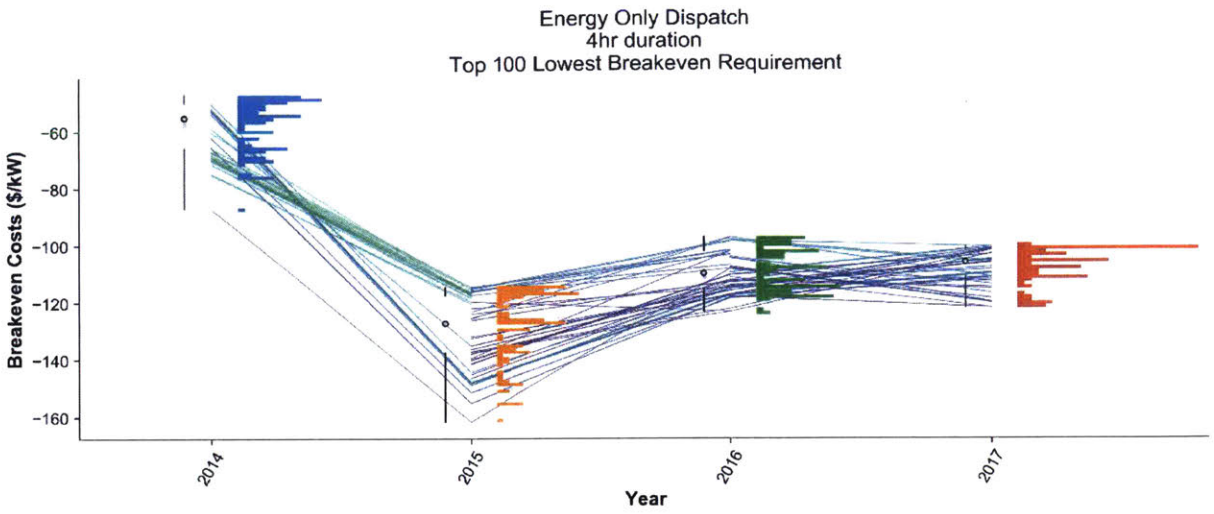

Figure 80: Persistence of Top 100 Earners in Energy Only Dispatch: 2014 onwards

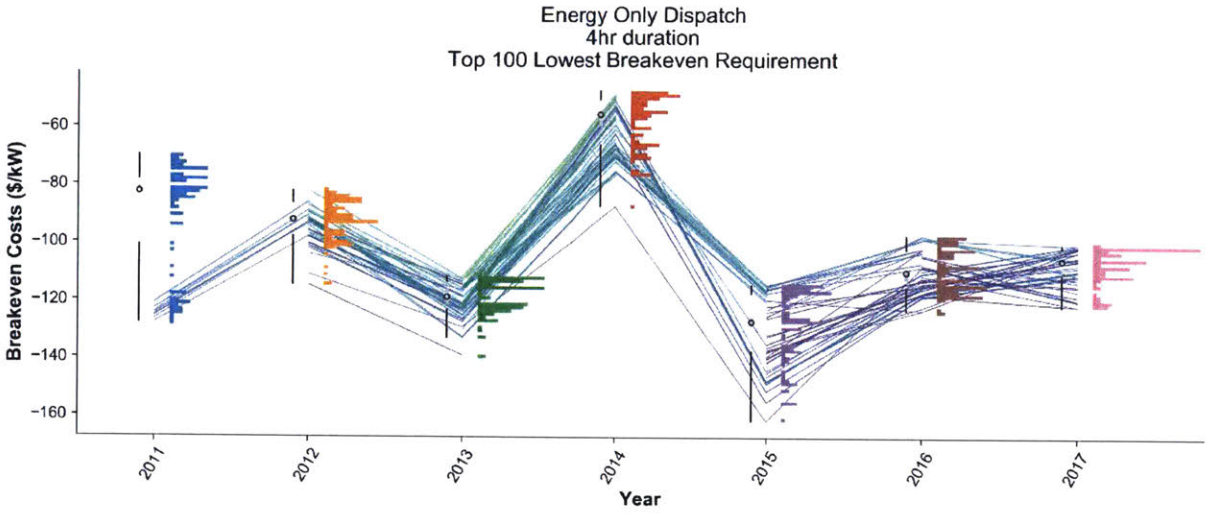

Figure 81: Persistence of Top 100 Earners in Energy Only Dispatch: 2011 onwards

Table 24: Breakeven Capital Costs: Averages

Model	Duration	Year	ISOs	Breakeven Cost for 50% of Nodes ($/kW)
Energy Only	4	2014-2017	CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM	30.11
Energy Only	8			-94.04
Energy and Capacity	4	2014-2017		
Energy and Capacity: Net of Renewables	4	2017	CAISO, ISO-NE, MISO, NYISO, PJM	293.49
Net of Solar	4	2017		302.91
Net of Wind	4	2017		278.17
Intermittent Resources	4	2014-2017	ISO-NE, MISO, NYISO, PJM	296.76
Intermittent Resources	8		ISO-NE, MISO, NYISO, PJM	232.43
Energy limited resources	4	2017	MISO, NYISO	42.86
Energy limited resources	8		MISO, NYISO	-93.24

Table 25: Average Capacity Credits For Energy and Capacity Markets under 1%, 7%, and 12% of Hours

	Year	2014					2017				
	ISO	CAISO	ISO-NE	MISO	NYISO	PJM	CAISO	ISO-NE	MISO	NYISO	PJM
Percent	Duration										
1	1	0.19	0.15	0.19	0.16	0.23	0.17	0.15	0.19	0.14	0.17
	4	0.67	0.58	0.65	0.56	0.77	0.63	0.51	0.69	0.53	0.58
	8	0.96	0.91	0.96	0.89	0.98	0.95	0.85	0.95	0.89	0.93
7	1	0.13	0.14	0.13	0.13	0.12	0.12	0.13	0.11	0.10	0.13
	4	0.49	0.46	0.46	0.44	0.43	0.44	0.45	0.40	0.38	0.50
	8	0.84	0.72	0.73	0.72	0.66	0.80	0.75	0.69	0.69	0.80
12	1	0.10	0.13	0.11	0.11	0.11	0.09	0.13	0.09	0.10	0.10
	4	0.39	0.44	0.39	0.40	0.38	0.36	0.42	0.34	0.36	0.38
	8	0.74	0.66	0.62	0.66	0.59	0.67	0.68	0.57	0.61	0.65

Table 26: Average Capacity Credits for Alternative Load Profiles

2017 under 7% of load hours for 4-hour duration storage

Load	CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM
Ten-times-net-solar	0.77					
Ten-times -net-wind				0.44		
Five-times -net-solar	0.74					
Five-times-net-wind				0.46		
demand	0.46	0.45	0.44	0.43	0.39	0.44
net	0.54		0.44	0.38	0.38	0.48
Net-solar	0.60		0.47	0.40	0.38	0.50
Net-wind	0.43		0.42	0.44	0.38	0.48

Table 27: Capacity Credit: ISO Rules compared to ISO Demand Methodology

2017	ISO	CAISO	ISO- NE	MISO	NYISO	PJM
Percent	**Duration**					
1	4	0.63	0.51	0.69	0.53	0.58
	8	0.95	0.85	0.95	0.89	0.93
7	4	0.44	0.45	0.4	0.38	0.5
	8	0.8	0.75	0.69	0.69	0.8
	10	-	-	-	-	0.89
12	4	0.36	0.42	0.34	0.36	0.38
	8	0.67	0.68	0.57	0.61	0.65
Intermittent						
	4		0.84	0.97	0.89	0.74
	8		1	0.98	0.99	0.97
Energy Limited Resources						
	4			0.64	0.82	
	8			0.51	0.7	

Table 28: Capacity Credit versus State of Charge Methodology

Capacity Credit

State of Charge Methodology

	ISO	CAISO	ISO-NE	MISO	NYISO	PJM		ISO-NE	MISO	NYISO	PJM	
Year	Duration											
2014	1	0.13	0.14	0.13	0.13	0.12		0.56	0.51	0.5	0.54	0.49
	4	0.49	0.46	0.46	0.44	0.43		0.75	0.72	0.7	0.73	0.69
	8	0.84	0.72	0.73	0.72	0.66		0.88	0.86	0.85	0.87	0.83
	10	0.94	0.81	0.8	0.81	0.73		0.9	0.88	0.87	0.89	0.86
	12	0.98	0.85	0.84	0.85	0.76		0.91	0.9	0.89	0.9	0.88
2015	1	0.13	0.13	0.11	0.11	0.11		0.49	0.51	0.48	0.54	0.49
	4	0.47	0.47	0.42	0.41	0.42		0.71	0.71	0.67	0.71	0.69
	8	0.81	0.74	0.68	0.68	0.75		0.85	0.85	0.8	0.86	0.83
	10	0.92	0.83	0.71	0.76	0.86		0.88	0.88	0.83	0.89	0.87
	12	0.96	0.87	0.73	0.8	0.91		0.89	0.9	0.84	0.9	0.89
2016	1	0.11	0.11	0.1	0.09	0.12		0.46	0.52	0.48	0.54	0.49
	4	0.43	0.42	0.4	0.36	0.43		0.68	0.71	0.66	0.72	0.69
	8	0.79	0.7	0.72	0.65	0.75		0.85	0.84	0.79	0.85	0.82
	10	0.91	0.8	0.81	0.74	0.88		0.88	0.87	0.83	0.88	0.86
	12	0.95	0.83	0.84	0.78	0.93		0.89	0.89	0.85	0.89	0.88

2017	**1**	0.12	0.13	0.11	0.1	0.13		0.45	0.53	0.51	0.55	0.51
	4	0.44	0.45	0.4	0.45	0.5		0.66	0.73	0.69	0.73	0.69
	8	0.8	0.75	0.69	0.76	0.8		0.87	0.85	0.83	0.88	0.83
	10	0.9	0.84	0.73	0.78	0.89		0.9	0.88	0.86	0.89	0.87
	12	0.94	0.88	0.75	0.82	0.93		0.91	0.9	0.88	0.91	0.89

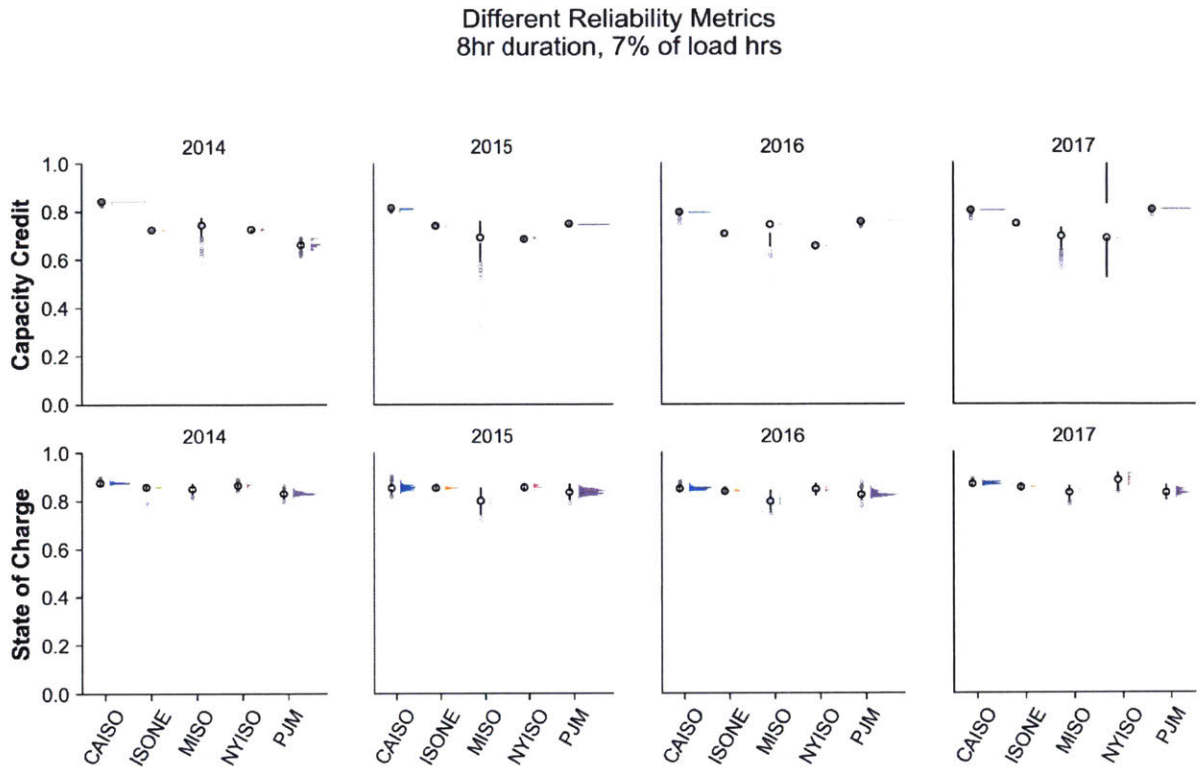

Figure 82: State of Charge Methodology: Reliability Comparison

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Acronyms

4CP	Four Coincident Peak Pricing
CAISO	California Independent System Operator
CASPR	Competitive Auctions with Sponsored Policy Resources
DAM	Day Ahead Market
DER	Distributed Energy Resource(s)
ECP	Equivalent Conventional Power
EFORd	Equivalent Forced Outage Rate Demand
EIA	(U.S.) Energy Information Administration
ELCC	Effective Load Carrying Capability
EFC	Equivalent Firm Capacity
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
kW	Kilowatt (1 MW= 1,000 kW)
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-hour
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NWA	Non-Wire Alternatives
NYGB	New York Green Bank
NYISO	New York Independent System Operator
NYSERDA	New York State Research and Development Authority
PFP	Pay For Performance (ISO-NE, PJM)
PJM	Pennsylvania Jersey Maryland Interconnection
PPA	Power Purchase Agreement
PTC	Production Tax Credit
PV	Photovoltaics
REC	Renewable Energy Credits
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
RTM	Real Time Market
SGIP	Self Generation Incentive Program (California)
U.S.	United States