# Capacity Market and its Evolution

## SUMMARY OF DISCUSSIONS WITH OCCTO STAFF FOR DEVELOPING THE CAPACITY MARKET IN JAPAN

**PUBLIC REPORT**

**PREPARED FOR**

Organization of Cross-regional Coordination of Transmission Operators (OCCTO)

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THE Brattle GROUP

# Notice

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Table of Contents


I. Capacity Market Goals and Organization ....3
A. Local Areas within a Capacity Market ....6
Price Variation across Sub-regions....7
B. Cost of New Entry Variation across Areas ....10
II. Evolution of Capacity Markets ....11
A. Market Rules by Resource Type ....16
Qualification Process – Thermal Resources ....16
Qualification Process – Intermittent Renewable Resources ....17
Qualification Process – Demand Side Resources ....20
Qualification Process – Storage Resources ....25
Operating and Performance Standards ....27
B. Other Changes Associated with the Evolving Market - Ancillary Services ....32
C. Market Rules for Capacity Imports ....33
D. Market Monitoring ....40
Supply-Side Mitigation - PJM ....40
Supply-Side Mitigation - NYISO ....42
Supply-Side Mitigation - MISO ....43
Buyer-Side Mitigation - PJM....44
Buyer-Side Mitigation - NYISO ....45
III. Capacity Market Delays ....47
A. Delays in New Markets....48
United Kingdom: Compliance with State-Aid Rules....48
Ireland: Delays in Integration of Wholesale Electricity Market ....49
Italy: Last Minute Market Rule Amendments....50
Singapore: Deadline for Capacity Market Implementation Extended....51
B. Delays in Existing Markets....52
ISO-NE: Offshore Wind Qualification Issues ....52
IESO: Challenges over Effects of Capacity Auction on Demand Response ....54
C. PJM Capacity Market Disputes....55
A Brief History of the Minimum Offer Price Rule....56
FERC Directed PJM to Expand MOPR to Cover State-Subsidized Resources....57

Capacity Auction Delays and MOPR's Impacts on Renewable Energy Resources ..............58
PJM's Capacity Market Future is Uncertain as States Explore Alternatives ........................59

IV. Impacts of COVID-19 on Capacity Markets ..........................................61

A. Economic and Capital Market Impacts ..........................................61
B. Electricity Demand Market Impacts ..........................................63
C. Fuel Market Impacts ..........................................70
Fuel Oil70
D. Natural Gas and Liquefied Natural Gas (LNG) ..........................................74
E. Energy Industry Impacts ..........................................78
Electricity Pricing ..........................................78
Summary of Actions Taken by Market to Date ..........................................80
Potential Delay in Market Activities ..........................................81
F. Potential Adjustment and Revision of Market Fundamentals ..........................................83

List of Acronyms ..........................................85

The Organization of Cross-regional Coordination of Transmission Operators (OCCTO) has been leading the development of a nation-wide capacity market for Japan, with its first capacity auction scheduled for the summer of 2020.[1] As part of this effort, OCCTO has retained The Brattle Group (Brattle) in an advisory role. This report summarizes the discussions held between OCCTO and Brattle between the summer of 2019 and 2020.[2] The report begins with an overview of capacity markets, including their goals and the evolution of different rules in light of changing resource mixes (largely in Section I - Capacity Market Goals and Organization and in Section II - Evolution of Capacity Markets), then transitions to a discussion on delays associated with implementing or operating capacity markets (largely in Section III - Capacity Market Delays), and finally on the potential impact of the global COVID-19 pandemic (largely in Section IV - Impacts of COVID-19 on Capacity Markets). The report focuses primarily on the U.S. capacity markets because they have the longest history, some with more than a decade of continuous delivery experience[3], and OCCTO is looking at the PJM market as its model. When appropriate, we expand the discussion to include the relevant trends and developments in non-U.S. markets as well.

# I. Capacity Market Goals and Organization

Capacity markets were born out of concerns that market incentives, particularly those designed around short-term marginal costs, could be insufficient to attract and sustain enough resources over the long-term to meet target resource adequacy requirements.[4] For example, wholesale energy prices may be

1 The 2020 auction is a forward-looking auction to secure capacity for 2024.

2 Key Brattle contributors to these discussions and this report include T. Bruce Tsuchida, Shaun Ledgerwood, Kathleen Spees, Johannes Pfeifenberger, Long Lam, Joshua Figueroa, Walter Graf, Tess Counts, Connor Haley, Daniel Jang, and Matthew Witkin.

3 For example, the New York ISO (NYISO) created its initial capacity market in 1999, which is over 20 years ago.

4 For in-depth discussion, please refer to the Brattle reports Estimating the Economically Optimal Reserve Margin in ERCOT, January 2014, prepared for ERCOT, available at: https://brattlefiles.blob.core.windows.net/files/6098_estimating_the_economically_optimal_reserve_margin_in_ercot_revised.pdf and Resource Adequacy Requirements: Reliability and Economic Implications, September 2013, prepared for the Federal Energy Regulatory Commission, available at: https://brattlefiles.blob.core.windows.net/files/6092_resource_adequacy_requirements_pfeifenberger_spees_ferc_sept_2013.pdf.

too low either to support investment or to sustain existing resources. An additional payment is needed to resolve the "missing money" issue to meet the reserve margin target.[5]

While no two capacity markets are identical, all capacity markets share a common objective: meeting resource adequacy requirements in a cost-effective manner. A capacity market establishes the quantity of capacity needed, and procures that capacity through a competitive auction that is, generally, open to all types of resources. Auction revenue to capacity resource owners should help ensure that customers' electricity needs will be met during the delivery period, while also enabling market participants to plan for the future. While different capacity markets have faced different challenges over time, the auction-based format has proven effective at leveraging competitive forces to attract the lowest-cost combination of available resources. When properly designed, a capacity market can create a level playing field that enables competition among new and existing generators, incumbents and new market participants, internal supply and imports, traditional and new types of technology, generation and demand-side resources, and centralized and distributed resources.

Following the deregulation of wholesale electricity markets in the late 1990s, PJM, ISO New England (ISO-NE), and the New York ISO (NYISO) established capacity markets as a competitive way to meet the target resource adequacy requirements. The Midcontinent ISO (MISO) also has a capacity market, but most investment in this jurisdiction is cost-of-service regulated.[6] Outside of the U.S., at least 11 jurisdictions, including the Ontario Independent System Operator (IESO), have added (or are in the process of implementing) capacity markets. [7] [8] Figure I-1 below shows the North American Regional Transmission Organizations (RTOs), including the aforementioned PJM, ISO-NE, NYISO, MISO, and IESO.[9] One of the driving forces, which Japan also faces, is the concern that large amounts of intermittent renewable energy resources are replacing older non-intermittent (i.e., dispatchable) resources.

5 Wholesale energy markets are designed to recover short-run marginal costs rather than long-run marginal costs, which includes annual fixed costs. Furthermore, offer rules and price caps in organized wholesale electricity markets may fail to express fully the value of energy in scarcity conditions, leading to artificially low energy prices. Inadequate revenue can threaten system reliability in many ways. For example, some generation companies may forgo maintenance, while others may be forced to retire prematurely.

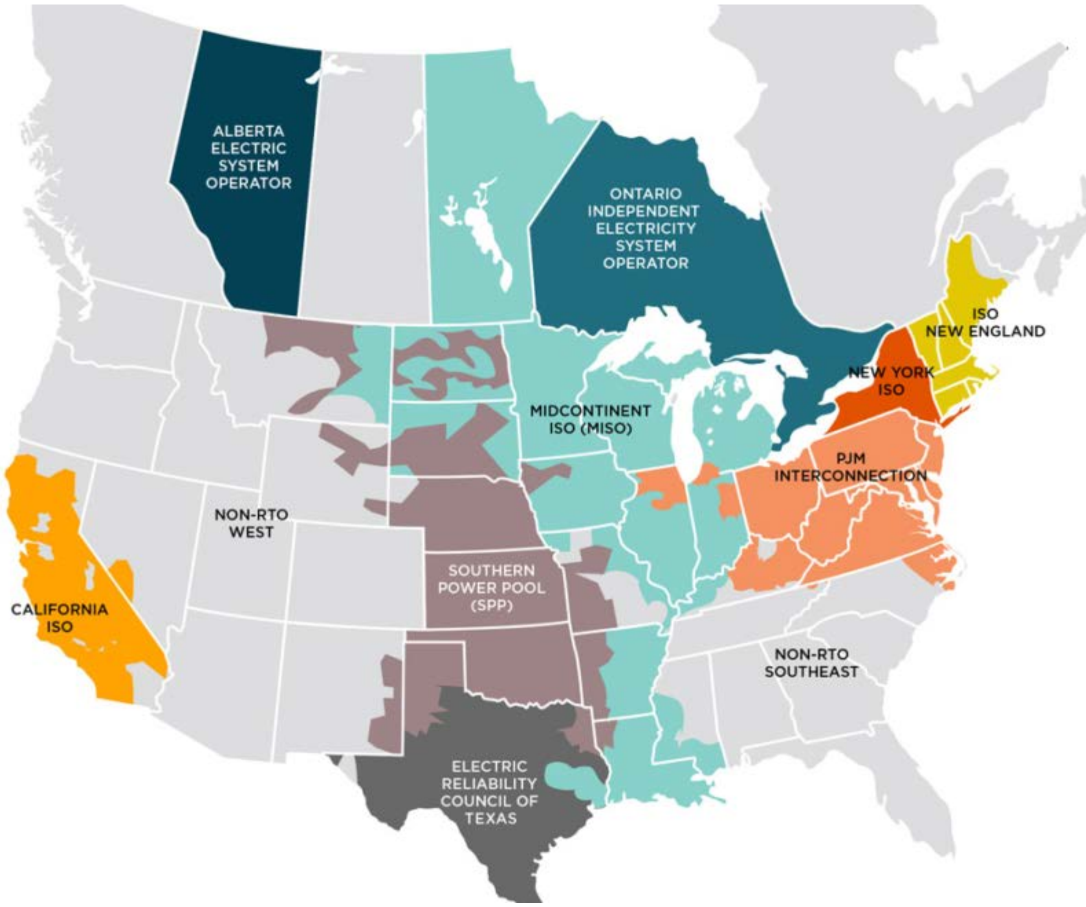
6 In jurisdictions like the California ISO (CAISO) and Southwest Power Pool (SPP), load-serving entities are expected to self-supply or to rely on bilateral contracts to meet resource adequacy requirements established by the RTOs. Others provide market-based incentives to ensure resource adequacy. For example, in the ERCOT market, market participants have opportunities to earn extra revenue in times of scarcity because of the high energy price cap.

7 European jurisdictions include Belgium, France, Germany, Great Britain, Ireland, Italy, Lithuania, and Poland. Other jurisdictions include Singapore, Ontario Canada, and Western Australia. Alberta (Canada) did consider and design capacity market, however, in July 2019, the Government of Alberta decided not to pursue its implementation.

8 The European Commission website lists "state aid" cases for a list of places that have capacity markets and capacity mechanisms (which may not necessarily be appropriate to refer to as markets). See https://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html

9 This report will not distinguish between Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) and refer them as RTOs, or system operators.

**FIGURE I-I-1: MAP OF REGIONAL TRANSMISSION ORGANIZATIONS (RTO) IN NORTH AMERICA[10]**




Source: PowerGrid

10 https://www.power-grid.com/2018/03/09/iso-ne-resiliency-report-to-ferc-warns-that-fuel-security-at-risk

# A. Local Areas within a Capacity Market

Some markets are divided into sub-regions. For example, the sub-regions in PJM's capacity market are known as locational deliverability areas (LDAs), and differ from the transmission zones that comprise PJM's energy market. PJM's transmission planning process has identified 27 sub-regions as potential LDAs, but only 12 were modeled as actual LDAs in the most recent auction.[11]

Whether a sub-region is modeled as an LDA is determined by comparing the import limit of an LDA (also known as Capacity Emergency Transfer Limit, or CETL) to the amount of capacity that needs to be imported into the LDA to meet the reliability criterion (known as Capacity Emergency Transfer Objective, or CETO). More specifically, a sub-region is modeled as an LDA if the LDA has CETL < 1.15 CETO, or had a locational price adder in any of three immediately preceding Base Residual Auctions (BRA).[12]

ISO-NE has sub-regions (referred to as zones) and its Forward Capacity Auction (FCA) process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.[13] Maine has generally been designated as an export-constrained zone in most FCAs, whereas Connecticut, Northeast Massachusetts/Boston, and Southeast Massachusetts and Rhode Island have been designated as import-restricted zones in several FCAs.

NYISO has four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. These zones also reflect transmission constraints; however, unlike PJM and ISO-NE, the zones are fixed and do not change over time.

[11] https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx?la=en

[12] In PJM's capacity market, the clearing price in a given LDA consists of two main components: the marginal value of system capacity (which is the same for all LDAs) and the locational price adder (which is specific to each LDA). A non-zero locational price adder arises in an LDA when existing transmission capacity is not sufficient, and limits the amount of capacity that can be imported into that LDA from the rest of the system. When such transmission limits bind consistently across a three-year period for a sub-region, it is formally modeled as an LDA by PJM with a price adder to encourage appropriate generation investment in that part of PJM.

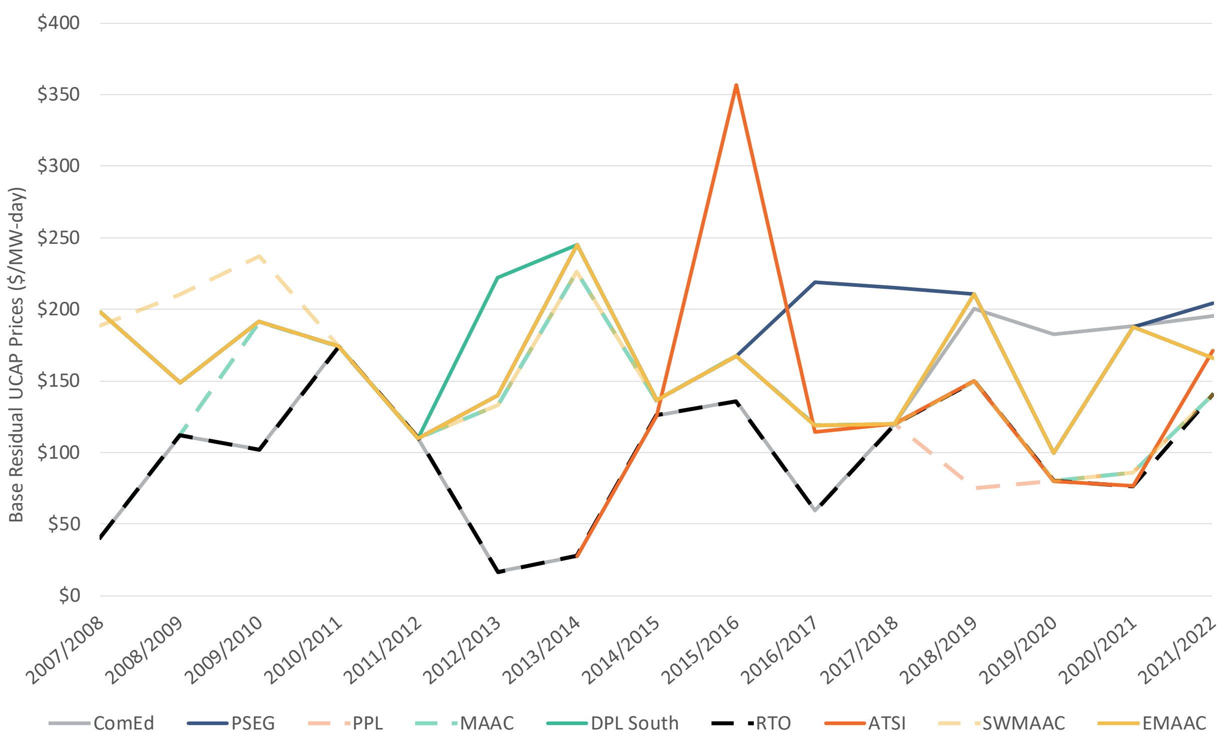
[13] From FCA #11 (held in 2017 for the 2019/2020 capacity commitment period) the region was split into three zones: the export-constrained Northern New England, including Vermont, New Hampshire, and Maine; the import-constrained Southeast New England, including Southeastern Massachusetts, Rhode Island, Northeastern Massachusetts, and Greater Boston; and the rest, including Connecticut and West Central Massachusetts. In the latest FCA #14 (held in 2020 for the 2022/2023 capacity commitment period), the region was divided into four zones: the export-constrained Northern New England, including Vermont, and New Hampshire; export-constrained Maine, the import-constrained Southeast New England, including Southeastern Massachusetts, Rhode Island, Northeastern Massachusetts, and Greater Boston; Maine; and the rest, including Connecticut and West Central Massachusetts.

## Price Variation across Sub-regions

Allowing prices to vary among the different sub-regions in a given market is the primary means by which the system operator can incentivize new builds in specific areas that would benefit most from additional capacity. Accordingly, none of the U.S. system operators imposes explicit limits on intra-market price differentials.

PJM's BRA yields separate clearing prices for the various LDAs that comprise the RTO. The most recent BRA modeled 12 LDAs; the system clearing price was $140/MW-day, but clearing prices for individual LDAs ranged from $140/MW-day to $204/MW-day.[14] Figure I-2 below shows the historical clearing price by LDAs.

**FIGURE I-2: HISTORICAL CAPACITY MARKET CLEARING PRICE FOR PJM[15]**



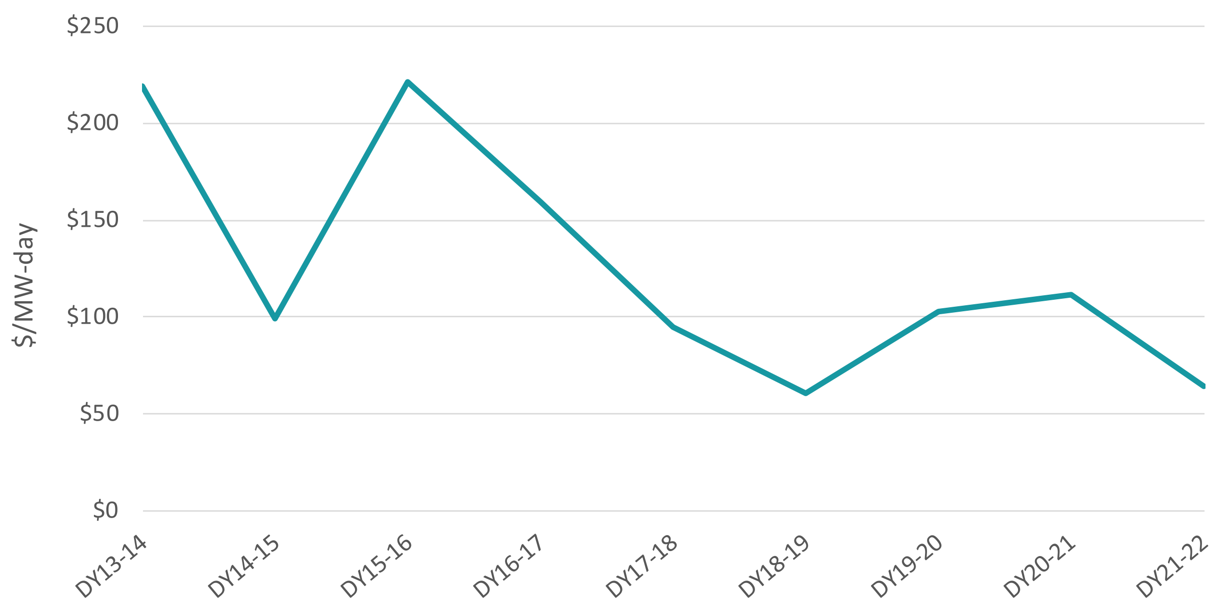

Note: MAAC: Mid-Atlantic Area Council; EMAAC: Eastern Mid-Atlantic Area Council; SWMAAC: Southwestern Mid-Atlantic Area Council; PSEG: Public Service Enterprise Group (in New Jersey); ATSI: American Transmission Systems, Incorporated (Ohio and Pennsylvania); COMED: Commonwealth Edison (Illinois); PPL: Pennsylvania Power and Light; DPL South: Southern Dayton Power & Light Company

14 2021-2022 Deliverability Year.

15 RPM Base Residual Auction Results.

As Figure I-2 above shows, the market clearing price can vary significantly by location. Figure I-3 below shows the highest price differential between the rest of the RTO and any given LDA. The highest price difference recorded to date in PJM was observed in the American Transmission System, Inc. (ATSI) LDA for the 2015-16 Delivery Year, when the ATSI LDA's clearing price was $221/MW-day higher than the clearing price for the rest of the RTO. This difference amounted to more than 60% of the ATSI LDA's Cost of New Entry (CONE) ($/MW-day) in that year. Such a large deviation from the system price shows the extent to which prices can vary within a capacity market.

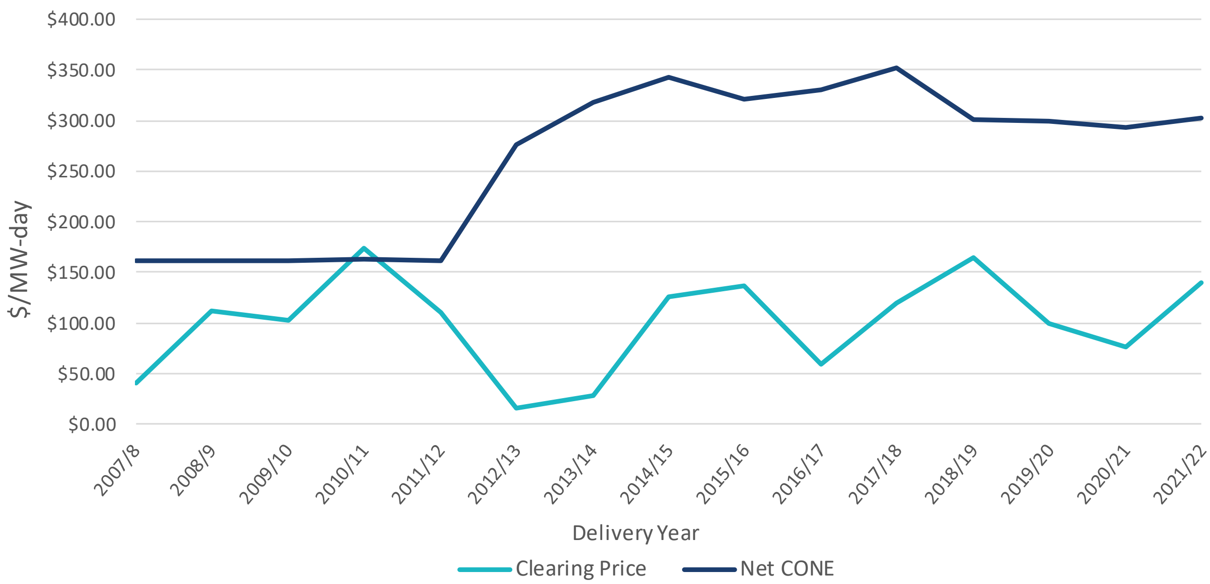
**FIGURE I-3: CAPACITY PRICE DIFFERENCES BETWEEN PJM LDAS AND REST OF RTO**




Note: The highest price differences were observed in the following LDAs and Deliverability Years: PEPCO (DY13-14), PSNORTH (DY14-15), ATSI (DY15-16), PS/PSNORTH (DY16-17), PS/PSNORTH (DY17-18), EMAAC/PS/PSNORTH/DPLSOUTH (DY18-19), COMED (DY19-20), COMED (DY20-21), PS/PSNORTH (DY21-22). Multiple LDAs for a given deliverability year means that multiple LDAs had the same capacity clearing price.

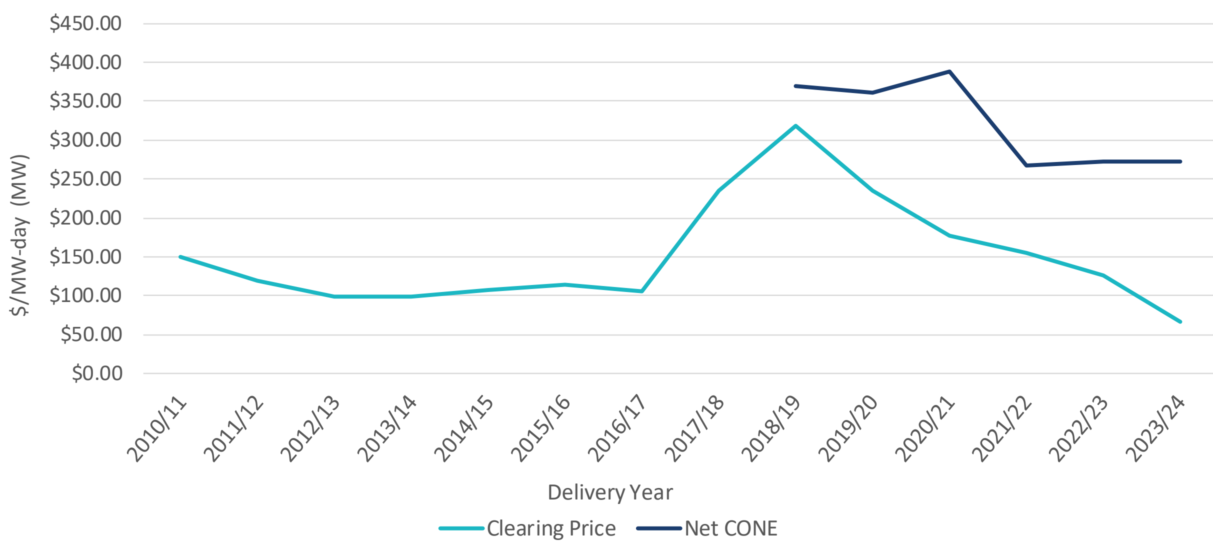
Nonetheless, there is a *theoretical* limit to how much prices can vary across any two LDAs in PJM. The lowest possible price could approach $0/MW-day, which can occur when an LDA has a very high reserve margin with no need for additional capacity, while existing resources have enough revenue to cover their fixed costs. The highest possible price corresponds to the price cap built into the capacity market's demand curve. For PJM, the price cap is defined as 1.5 x CONE. As such, the theoretical limit on price differences ($/MW-day) between any two LDAs in PJM would be 1.5 x CONE. Such an implicit limit on price differences within sub-regions can also be found in ISO-NE's Forward Capacity Market. Figure I-4 and Figure I-5 below compare the historical market clearing price and Net CONE values for PJM and ISO-NE.

**FIGURE I-4: PJM MARKET OUTCOMES**[16]




Source and note: PJM Clearing Price is RTO-wide.

**FIGURE I-5: ISO-NE MARKET OUTCOMES**




Source and note: ISO-NE, [Key Grid and Market Stats: Market](), accessed on July 2, 2020. For clearing prices, figure depicts floor prices for Delivery Years 2010-2011 to 2016-2017; prices for existing resource for Delivery Years 2017/2018; and RTO-wide prices for the remaining Delivery Years. ISO-NE used a vertical demand curve before Delivery Year 2018-19 and therefore did not have Net CONE data.

16 2021/2022 RPM Base Residual Auction Results; PJM, May 23, 2018.

## B. Cost of New Entry Variation across Areas

There are no explicit limits on the extent to which CONE values can vary across the different sub-regions in a capacity market. In fact, in 2014, Federal Energy Regulatory Commission (FERC) rejected PJM's proposal to impose a minimum on an LDA's Net CONE at the parent level.[17] The proposal sought to mitigate the risk of underestimating locational Net CONE and reducing reliability, but FERC stated, "this [Net CONE floor at parent level] proposal could operate to disconnect costs and/or revenues from the areas to which they can be attributed, particularly given that generators in a congested area may receive higher energy market revenues than in uncongested areas, thereby warranting a larger Energy and Ancillary Service offset in the congested area."

Even without a floor, however, the *long-run average* LDA Net CONE cannot remain lower than the parent Net CONE. If an LDA's Net CONE is temporarily lower than the parent Net CONE, the LDA would attract new supply; a lower Net CONE paired with equal or higher capacity prices would yield attractive margins. The additional supply would tend to reduce local energy prices and, in turn, increase the LDA Net CONE.

Cases in which the LDA Net CONE is higher than the parent Net CONE may not lead to optimal market outcomes. If the true Net CONE is higher in a given LDA, then the demand curve needs to reflect that reality and have price and quantity points appropriately adjusted. Without such adjustments, the market outcome may not reach the reliability target. Directly applying the system curve to each LDA may not provide the appropriate price signals, unless the curve is more carefully looked at. Brattle, in its 2018 review of PJM's variable resource requirement curve, found that if Net CONE were to become 5% higher in each LDA compared to its parent LDA, five of the fourteen LDAs studied at the time would fall short of the 1-in-25 (or 0.04) Loss of Load Expectation (LOLE) standard. Market design enhancements were recommended to mitigate potential reliability concerns, but these did not include any upper bounds on LDA CONE values (in fact, reducing the price premium in high cost regions may have the unintended effect of exacerbating the lack of investment in the locations where capacity is most needed).[18]

17 https://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180420-pjm-2018-variable-resource-requirement-curve-study.ashx?la=en

18 Id.

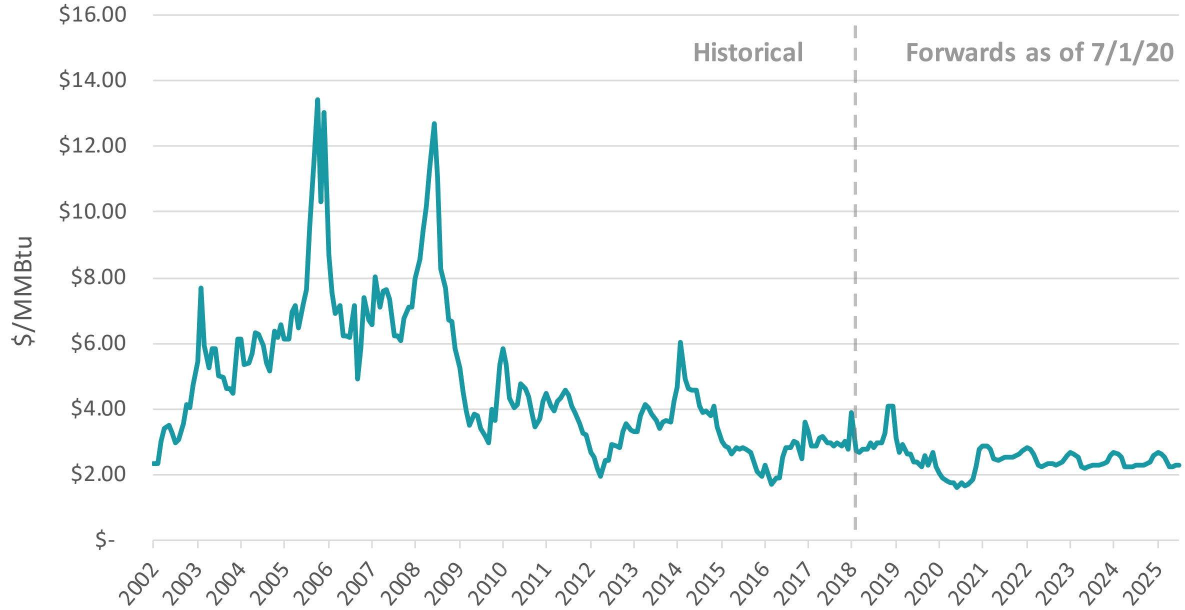
# II. Evolution of Capacity Markets

The introduction of capacity markets have facilitated an efficient transition of the generation fleet. In parallel to securing enough resources, these markets—through quantifying the amount of capacity needs and associated price signals—have played a role in enabling the retirement of older, less economic resources in an orderly fashion. On the other hand, the combination of deregulated wholesale energy markets (and comparative market conditions of the underlying fuel types) and capacity markets have led to a concentration of resource types as these markets reward resources that are most economically efficient. In the U.S., most of the thermal generation resources developed in the past two decades have been concentrated to those fueled by natural gas, largely using gas turbine technologies (either as a Combined-Cycle or Simple-Cycle application).

Over the past decade, natural gas rapidly supplanted coal as the primary fuel of choice for power generation in the U.S.[19] One of the foremost driver of the coal-to-gas transition has been the development of horizontal drilling (or "fracking") technology. Its widespread adoption across states including Pennsylvania, Texas, New Mexico, and North Dakota, has enabled the extraction of cheap natural gas from previously inaccessible shale reserves. Natural gas forward curves, which reflect the contract prices of future gas delivery, show that market participants continue to expect natural gas to retain significant cost advantages over coal. Figure II-1 below shows natural gas futures trading below $3/MMBtu for the next 10 years at Henry Hub. Another driver is the presence of stricter environmental regulations—in particular those aiming to curb carbon dioxide emissions (and other pollutants), which require large capital investments for coal generation.

[19] EIA, "More U.S. coal-fired power plants are decommissioning as retirements continue," July 26, 2019.

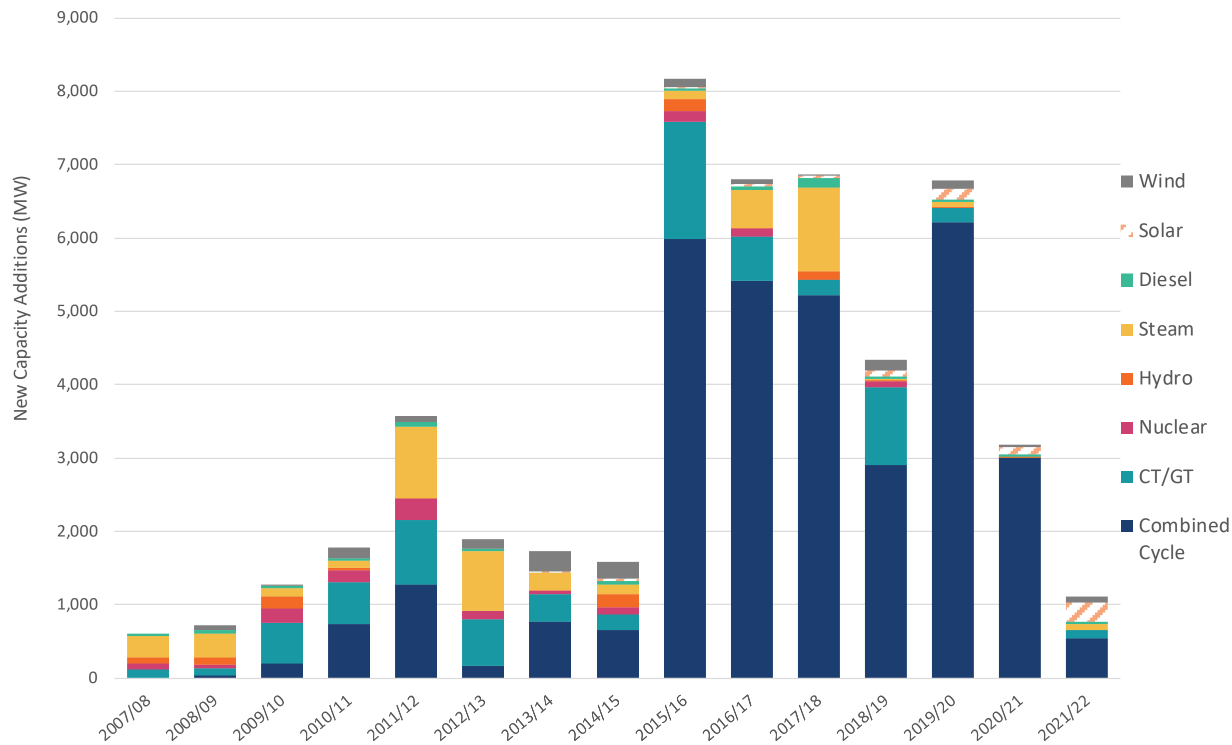
**FIGURE II-1: NATURAL GAS FUTURES – HENRY HUB ($/MMBTU)**




Source: SNL

The coal-to-gas shift is pronounced in wholesale power markets, which heavily incentivize least-cost generation. Compared to vertically integrated utilities—which might employ a "best fuel mix" strategy to achieve a diverse fuel portfolio—competitive markets, like those in PJM, will focus on the cheapest (in the short-term) option, which to date has been gas-fired power plants. As shown in Figure II-2, natural-gas-fired combined cycle (shown in navy color) and simple cycle gas turbine plants (shown in blue color) have dominated the new capacity additions since inception of PJM's Reliability Planning Model (RPM). Combined cycle and simple cycle gas turbine plants represent 80% of all new capacity additions since the 2007/2008 Delivery Year, and 88% of all new capacity additions since the 2015/2016 Delivery Year. In total, PJM has procured over 40 GW of natural-gas-fired capacity since the start of its capacity market.

**FIGURE II-2: PJM'S CUMULATIVE GENERATOR CAPACITY ADDITIONS (MW), DELIVERY YEAR 2021-2022**[20]



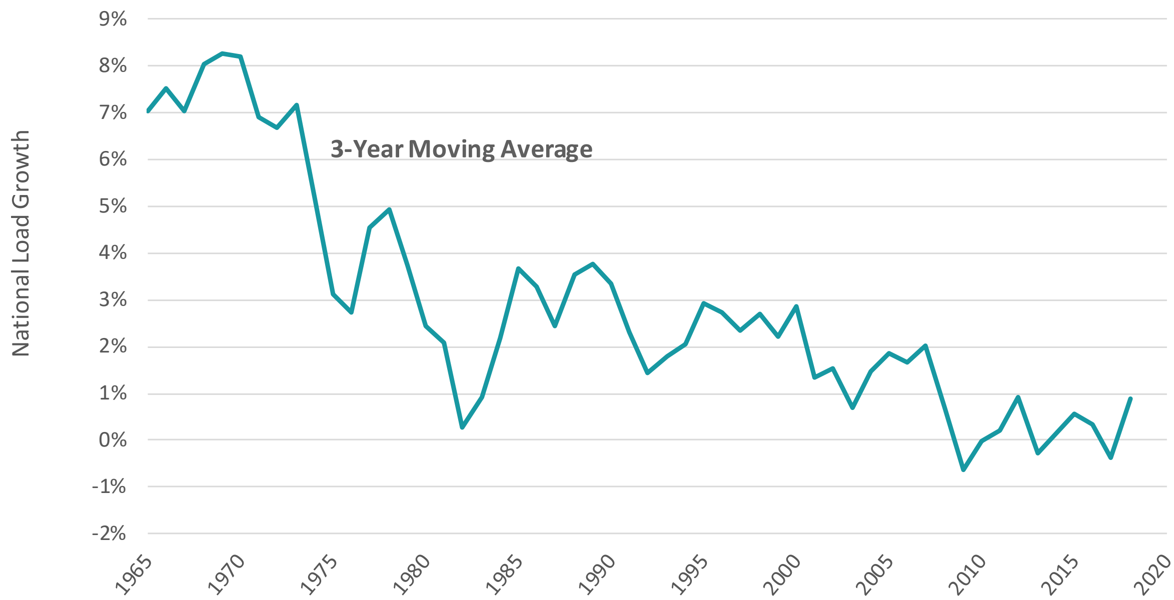

Source: PJM

Parallel to the increase in natural-gas-fired generation, more coal plants are retiring early. The accelerated retirements—some of which are decades ahead of schedule—are motivated in part by the high operations and maintenance expenses incurred by the aging assets, and by stringent environmental regulations that require capital-intensive pollution controls. Slow load growth (as shown in Figure II-3 below) and increase in renewable resources that contribute to lower wholesale power prices have also reduced profitability of the U.S. coal fleet. Figure II-4 below shows the change in generation by fuel type—that was largely driven by the urgent and sudden wave of coal retirements. It can also be seen as how the capacity market (and energy markets) responded and actually delivered the supply needed. The share of nuclear generation, on the other hand, has remained relatively steady throughout the coal-to-gas transition. While owners of the existing nuclear fleet are indeed contending with similar issues such as low demand and low wholesale power prices, they have enjoyed higher levels of support from state policymakers who recognize the zero-carbon attributes of nuclear generation.[21]

20 2021/2022 RPM Base Residual Auction Results.

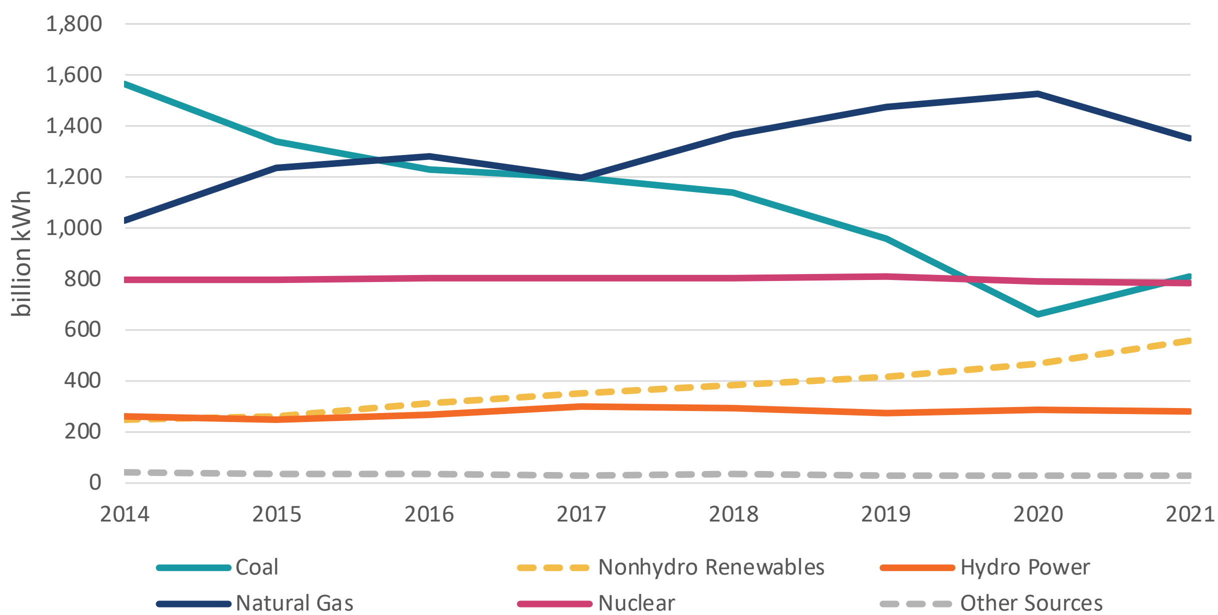
21 These support policies have caused significant tension among market participants. Issues surrounding the Minimum Offer Price Rule are the latest manifestation of such disputes. For more information, see Section III-C, PJM Capacity Market Disputes.

**FIGURE II-3: LOAD GROWTH[22]**




Source: EIA Electricity Data

**FIGURE II-4: ANNUAL U.S. ELECTRIC POWER SECTOR GENERATION BY ENERGY SOURCE (2014-2021) [23]**




Source: EIA

[22] EIA, Form EIA-861 annual survey data: By sector, by state, by provider (back to 1990), Release Date: October 1, 2019.

[23] https://www.eia.gov/todayinenergy/detail.php?id=42497

The new diverse resource technology types increase complexity for system operators. Wholesale markets were designed when most resources were expected to be dispatchable; these markets' rules initially reflected this expectation. System operators had to adapt market rules to accommodate new intermittent resource technologies, as well as storage, demand response, and energy efficiency resources. In the wholesale energy markets, rules must account for the variable availability of renewable resources and the distinct properties of storage and demand response resources. Capacity market rules now must reflect the actual ability of these new resources to contribute to system reliability.

# A. Market Rules by Resource Type

Initially designed with traditional dispatchable thermal resources in mind, capacity markets had to adapt to the changing market conditions, especially to accommodate new resource types. In the U.S. markets, a potential capacity resource first undergoes a rigorous qualification process in order to participate in the capacity auctions. Once qualified, the capacity resource is subject to strict operating and performance standards to fulfill its obligation. The qualification process and the operating and performance requirements vary across resource types, and every market has a unique approach. The capacity qualification process, also known as accreditation, typically reflects the system's specific needs, thereby ensuring the capacity resource's ability to handle the system's load variation and typical supply-shortage conditions. As many of today's electricity markets and operations were designed around a generation mix of non-intermittent, dispatchable resources (typically dominated by thermal resources), qualification processes and operating standards are similar across many jurisdictions.

## Qualification Process – Thermal Resources

For qualification of any resource, system operators first determine how to rate the capacity over the applicable period (for example, through a full year, or by season), based on ambient conditions and other considerations that could impact the resources' generation ability. System operators also establish methodologies for quantifying applicable outage rates. For example, the PJM capacity values for thermal resources are calculated as:

**UCAP=ICAP x (1-EFORd)**

where Unforced Capacity (UCAP) is calculated as the Installed Capacity (ICAP) modified for seasonal ambient limitations adjusted downward to account for forced outages. The effective forced outage rate (EFORd) is calculated using historical operating data for existing units, and often uses technology-specific reference rates for new units. [24]

New resources cannot rely on historical data, and also require a guarantee of availability during the delivery timeframe. Therefore, accreditation for new resources involves four broad steps:

- Secure necessary funding, permitting, and other requirements necessary to construct the project at its proposed location;
- Provide data for the execution of various interconnection studies by the system operator to identify any necessary upgrades to the transmission system and control equipment;

[24] For detailed EFORd equations, see PJM Manual 22, Section 3.

- Prior to the auction, submit data for the qualification process, which verifies that the planned resource will meet all operating requirements if it is to earn a capacity obligation; and
- After the auction and before the obligation period, demonstrate that each development milestone is achieved on schedule.

Taking PJM as an example, planned (new) generation resources are eligible for participation based on their progress in the qualification and construction process: [25]

- The planned online date of the unit must be on or before the start of the Delivery Year.
- Agreements and studies related to the generator interconnecting to the transmission system must be executed.[26]
- The market participant must establish an appropriate credit line prior to the auction.[27]

Other resource types typically involve additional considerations for accreditation, including hours of expected resource availability, penetration of the technology in the capacity mix, duration of availability, and how these characteristics need to match up with the reliability needs of the system. These additional accreditation steps require details and data not submitted for thermal resources.

## Qualification Process – Intermittent Renewable Resources

Many renewable resources, particularly wind and solar, have intermittent output. The variable nature of the output from these resources requires the system operator to accurately estimate the capacity value. The accuracy of this estimate becomes more important as the share of renewable generation increases. Underestimating the contribution of intermittent renewable resources to meet system peak loads can result in paying to procure more capacity from other resources and result in higher costs for customers. Overestimating the contribution of intermittent renewable resources can result in lower levels of system

25 PJM Manual 18, Section 4.

26 Three studies must be completed prior to the obligation period: the Feasibility Study, System Impact Study, and the Facilities Study. Both the Feasibility and System Impact studies must be completed prior to the capacity auction, and all three must be completed before construction begin. In addition, the project developer must sign several agreements, including the Interconnection Service Agreement and Wholesale Market Participation Agreement, which bind market participants to PJM's market-related requirements such as telemetry hardware requirements. See the PJM Connecting to the Grid FAQ webpage, PJM Wholesale Market Participation Agreement, and PJM Manual 14A and Manual 14G.

27 PJM Tariff Attachment Q details credit requirements for market participants. There are two types of market-based funding: power purchase agreements (PPAs) and private funds (private lenders and investors, or sourced internally). There are also non-market-based PPAs, and cost of service rates to regulate the revenue recovered by a resource. A Monitoring Analytics study indicates that, historically, the majority of funding (60%) has come from market-based sources.

reliability (resource adequacy) and increase the probability and risks associated with service interruptions (e.g., loss of load and potential widespread blackouts).

The qualification process for intermittent resources to enter the capacity market is generally similar to the process for thermal resources. Given the variable output, many jurisdictions require additional data submissions to verify the capacity value of the resource. For example, PJM requires intermittent resources to provide data on location conditions, such as solar irradiance, wind speed, or water conditions.[28]

To estimate the capacity value of renewables, a system operator generally takes either a deterministic or probabilistic approach. The deterministic approach is useful when the penetration level of renewables is lower, with higher shares of dispatchable generation. The concept of availability accounting based on capacity factors/outages has at least not caused significant reliability concerns (although it may have caused less economic outcomes and modest reliability impacts). Therefore, many jurisdictions start by using a deterministic approach. The most commonly used approach is the calculation of a simple average capacity factor (based on historical generation data or class-average values) weighted across peak hours or other high-risk periods. These approximations are simple to calculate and easy to explain for planning. In North America, the Electric Reliability Council of Texas (ERCOT),[29] PJM, NYISO,[30] ISO-NE,[31] Western Electricity Coordinating Council (WECC),[32] Southwest Power Pool (SPP), and IESO[33] all use similar deterministic approaches to calculate the capacity value of intermittent resources.

For example, PJM calculates the wind and solar capacity values based on the resource's average capacity factor during pre-defined peak hours in each season. PJM calculates the seasonal average over the past three years of operating data, and uses a class-average value for "immature" resources with insufficient available data.[34] Other jurisdictions, while using similar approaches, may look at slightly different hours, or use a different length of historical data. ERCOT uses 10 years of historical data to calculate the

[28] PJM Manual 18, Section 4.2.

[29] ERCOT does perform an ELCC calculation, and the industry widely recognizes that ELCC is a better metric.

[30] NYISO, Manual 4: Installed Capacity Manual.

[31] Ryan Hoskin, "FCM Existing Capacity Qualification Process," ISO-NE, January 14, 2020, p. 15.

[32] Michael Milligan and Eduardo Ibanez, "Capacity Value: Evaluation of WECC Rule of Thumb," NREL, WECC Data Working Group, June 9, 2015.

[33] IESO, "Methodology to Perform Long Term Assessments," September 2018.

[34] For step-by-step capacity factor calculations, see PJM Manual 21, Appendix B.

capacity value for wind resources.[35] In SPP, an intermittent resource's capacity factor is equal to its capacity factor during the top 3% of load hours in its balancing area, over the past three years of historical data.[36] Table II-1 below summarizes the various methodologies by different systems.

**TABLE II-1: SUMMARY OF DETERMINISTIC INTERMITTENT GENERATION QUALIFIED CAPACITY METHODOLOGIES**

| | Methodology | Wind (% of ICAP) | Solar (% of ICAP) |
|---|---|---|---|
| ERCOT[37] | Average of 10 years for wind and of 3 years for solar over the 20 peak load hours by season | 15% non-coastal / 58% coastal (Summer) to 20% non-coastal / 43% coastal (Winter) | 12% (Winter) to 74% (Summer) |
| PJM[38] | Average of prior 3 years, capacity factor during peak summer hours | 14.7% (Mountainous) to 17.6% (Flat) | 38% to 60% based on configuration |
| NYISO[39] | Average of prior year, capacity factor during peak summer and winter hours | 11% (Onshore) to 38% (Off-shore) for new resources | 26% to 43% for new resources based on configuration |
| IESO[40] | Median of prior 10 years, capacity factor during top 5 contiguous demand hours | 13.6% (Summer) to 37.8% (Winter) | 0.0% (Winter) to 10.1% (Summer) |
| SPP[41] | Average over 2014-2016 for wind during top 3% of load hours by balancing area in Winter/Summer | 27.5% (Summer) to 38.8% (Winter) | N/A (very low penetration) |

However, deterministic calculations risk ignoring unique characteristics of emerging technologies and changing patterns of renewable generation. For example, it may not account for the uncertainties around intermittent generation at times of high system load. Or it may not consider the combined effect of different resource types. To address this shortcoming, some system operators, including MISO and

35 ERCOT Nodal Protocols, Section 3.2.6.2.1.

36 SPP, "Wind and Solar Report," May 23, 2017.

37 ERCOT, "Section 3 Management Activities for the ERCOT System," ERCOT Nodal Protocols, November 1, 2018. See also ERCOT, "Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2019-2028," December 2018.

38 PJM, "Manual 21: Rules and Procedures for Determination of Generating Capability (Rev. 12)," January 2017. See also PJM, "Class Average Capacity Factors: Wind and Solar Resources," June 1, 2017.

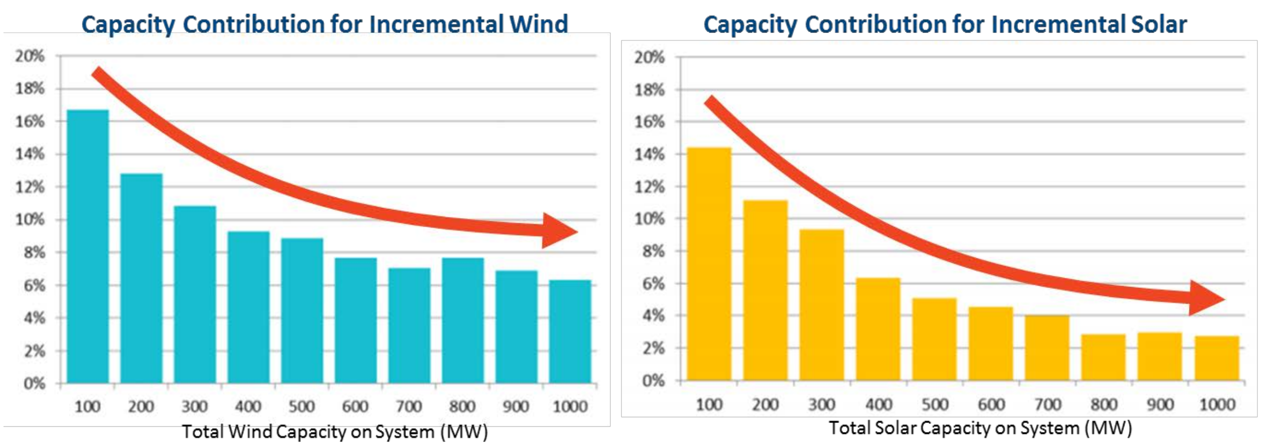
39 NYISO, "Manual 4: Installed Capacity Manual," December 2018.

40 IESO, "Methodology to Perform Long Term Assessments," September 20, 2018. See also IESO, "18-Month Outlook: An Assessment of the Reliability and Operability of the Ontario Electricity System," September 19, 2018.

41 SPP, "Wind and Solar Report," May 23, 2017.

the California ISO (CAISO), take probabilistic approaches to estimate the capacity contribution of renewables during system peak events. For example, CAISO calculates the LOLE in two cases: "with" and "without" the resource.[42] The case "with" the resource should inherently be more reliable and have fewer loss of load events for a given period (e.g., per year). However, as penetration of renewables increases, the marginal value to reliability of an additional renewable resource decreases due to the correlated output of nearby solar or wind units, as illustrated in Figure II-5 below.[43,44] CAISO utilizes this process for all resources, new and existing, before each obligation period, to determine the qualified capacity value of every resource.[45] In MISO, the probabilistic study is used only for estimating system reliability metrics; individual resources are qualified using a deterministic approach, similar to other jurisdictions.[46]

**FIGURE II-5: DIMINISHING CAPACITY CONTRIBUTION OF RENEWABLES AT HIGH PENETRATIONS[47]**




Source: PGE (2018)

## Qualification Process – Demand Side Resources

Demand side resources, represented by Demand Response (DR), also have unique qualification needs. In the U.S., system operators generally require DR aggregators to submit plans in advance of the capacity

42 California Public Utilities Commission, "Effective Load Carrying Capacity and Qualifying Capacity Calculation Methodology for Wind and Solar Resources," January 16, 2014.

43 MISO, "Planning Year 2019-2020: Wind & Solar Capacity Credit," Section 2, December 2018.

44 California Public Utilities Commission, Decision 17-06-027, June 2017.

45 CAISO, "Deliverability Assessment Methodology," Section 4, April 24, 2019.

46 MISO, "MISO Business Practices Manual 11" (MISO BPM 11), Section 4.2.3.

47 PGE, "Integrated Resource Plan," 2008, p. 105.

auction for any new resources that are not already in operation. These plans must specify target customers, customer acquisition plans, acquisition milestones, estimated success rates and load reductions, and resulting capacity. A system operator's demand response team then critically reviews each plan to assess its credibility, both individually (assessing the plan of each company) and in aggregate (identifying potential overlap in targeted end-use customers). After the auction, a cleared DR resource is required to meet development milestones and ensure its capacity will be ready for the delivery period. Failure to meet these milestones (as laid out in the pre-auction plan) is treated akin to missing a critical path schedule deadline for traditional generation resources. Consequences include increased scrutiny, and possible termination, of the capacity obligation. The prospect of measurement and verification before and during the delivery period, as well as performance penalties during the delivery period, help to solidify the promised resource.[48]

There are significant variations among system operators about the exact requirements for DR. Such differences include the number of allowed load interruptions per delivery period, the maximum notification time, hours of required availability, and the minimum and maximum duration of interruptions. Table II-2 below presents a summary of how several North American system operators qualify, activate, and measure the performance of DR resources. Note that Alberta Electric System Operator (AESO), after going through intense design and stakeholder process, has cancelled implementing its capacity market and is listed here for reference only.

[48] In addition, one must meet credit requirements to make a capacity offer (the concept being to make sure the RTO can collect on any penalties if you fail to deliver)—although in practice, the credit requirements and penalties may be too small to perform that intended function.

TABLE II-2: SUMMARY OF DR QUALIFICATION APPROACHES

| | PJM[49] | ISO-NE[50] | AESO[51] | ERCOT ERS[52] |
|---|---|---|---|---|
| **Qualifying Market** | Capacity | Capacity | Capacity<br>(now cancelled) | Energy-only but ERS is a DR-only capacity product |
| **Qualification Criteria** | • Unlimited interruptions<br>• 30-min lead time (can apply for 60- and 120-min if necessary)<br>• Qualified based off of customer acquisition plan | • Unlimited interruptions<br>• 10- and 30-min lead time<br>• Qualified based off of customer acquisition plan | • Based on customer acquisition plan<br>• If DR is not able to produce >75% of its stated UCAP by second rebalancing auction, it must buy out of the difference between tested production and UCAP | • 10- and 30-min lead time<br>• Can qualify as weather sensitive or non-weather sensitive<br>• Qualify for 3-4 hour time blocks across three seasons |
| **Measurement Approach** | Both Firm Service Level and Guaranteed Load Drop | Only Firm Service Level | Both Firm Service Level and Guaranteed Load Drop | Both Firm Service Level and Guaranteed Load Drop |
| **DR Operational Process** | Called when all non-emergency resources are exhausted. Longer lead-time DR called first. Dispatched according to energy offer or strike price (a higher price than the market-wide offer cap, for emergency use only). Can set prices in RT, at offer price or strike price | Called during shortage conditions. Dispatched according to energy offer. Can set prices in real time, at offer price | Eligible to bid into the day-ahead energy market, dispatched economically | Called in emergency conditions. 30-min reserves can be called if reserves are under 2,300 MW; 10-min reserves can be called if under 1,750 MW. Special provisions to avoid RT price reversal |

Specific rules around DR have varied since the introduction of capacity markets, often leading to significant changes to the level of DR participation within a market. For example, PJM began its capacity

49 PJM Manual 18, Section 8.7.

50 See the ISO-NE Demand Response webpage for links to DR M&V procedures and qualification procedures.

51 Toby Brown, Samuel A. Newell, David Luke Oates and Kathleen Spees, "International Review of Demand Response Mechanisms," Section III.B, Prepared for the Australian Energy Market Commission, The Brattle Group, October 2015.

52 Ibid., Section III.C.

market auction in 2007, and although DR was immediately able to receive capacity payments, most DR registered for payments via out-of-market contracts without participating in the capacity auction.[53] It was not until the 2012/2013 auction when DR was fully integrated into the capacity auction. Since then, PJM has refined the capacity products available to DR resources, by creating categories for seasonal DR and DR with limited interruptions. Starting in the 2018/2019 auction, PJM introduced Capacity Performance, a "pay-for-performance" requirement that rewards reliable resources with additional capacity payments funded by penalties assessed to underperforming resources.[54] By the 2020/2021 auction, all DR participants in the capacity market were required to meet the more stringent requirements of Capacity Performance resources, such as annual performance capability. This led to an immediate and noticeable reduction in DR offered and cleared in the 2020/2021 auction as can be seen in Figure II-6 below. In the 2021/2022 auction, the quantities of DR offered and cleared rebounded back to 2018/2019 and 2019/2020 levels, but they are still below levels of 2014/2015 and 2015/2016 before the transition to Capacity Performance. Yet, DR resources continue to rely heavily on capacity payments in the PJM market. For instance, 98% of the total revenues earned by PJM DR participants in 2018 are estimated to be from the capacity market.[55] Similarly, ISO-NE has refined its capacity market rules as DR availability has evolved. ISO-NE has taken steps to ensure DR reliability through new measurement and verification methodologies, and stricter performance incentives and penalties.[56]

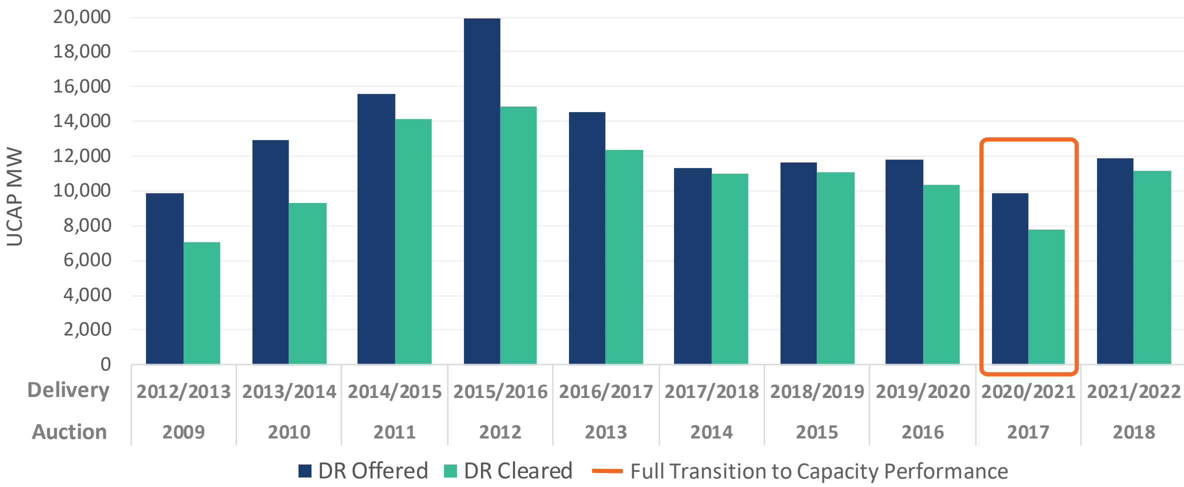
[53] Toby Brown, Samuel A. Newell, David Luke Oates and Kathleen Spees, "International Review of Demand Response Mechanisms," prepared for Australian Energy Market Commission, by The Brattle Group, October 2015.

[54] PJM, Capacity Performance at a Glance, 2015.

[55] Monitoring Analytics, LLC, "2018 State of the Market Report for PJM," Section 6 Demand Response, 2019.

[56] Id.

**FIGURE II-6: PJM DEMAND RESPONSE REDUCTIONS IN GWH (2009-2018)**[57]




Source: PJM

ERCOT's Emergency Response Service (ERS) procures load and generators to be available for deployment in the case of an emergency scenario, in order to avoid blackouts.[58] There are two different response times in the ERS: "ERS-30" and "ERS-10", thirty and ten minutes respectively. There is no minimum size requirement in order to participate. However, for ERS-30, only loads are able to participate. For ERS-10, generators are also eligible.[59] Currently, ERCOT has around 45 to 100 MW procured for ERS-10 and about 700 to 1,000 MW procured for the ERS-30.[60, 61] Despite the amount of load and generation ERCOT has procured, actual emergency situations are rare. In fact, between 2008 and 2016, only 3 ERS-10 events and 1 ERS-30 event occurred.[62]

[57] Id., also PJM, "2013 State of the Market Report for PJM," Section 6 Demand Response, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml;

[58] "Emergency Response Service", ERCOT, access July 20, 2020; http://www.ercot.com/services/programs/load/eils

[59] "Governing Document for 30-Minute Emergency Response Pilot Program", ERCOT, July 16, 2013, accessed July 20, 2020; http://www.ercot.com/mktrules/pilots/ers

[60] "Procurement results for Non-Weather-Sensitive ERS-10 for June 1, 2020 – September 30, 2020", ERCOT, accessed July 20, 2020; http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey

[61] Procurement results for Non-Weather-Sensitive ERS-30 for June 1, 2020 – September 30, 2020", ERCOT, accessed July 20, 2020; http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11465&reportTitle=ERS%20Procurement%20Results&showHTMLView=&mimicKey

[62] "ERCOT Emergency Response Service", CPower, accessed July 20, 2020; https://cpowerenergymanagement.com/wp-content/uploads/2017/03/ercot-overall-snapshot.pdf

## Qualification Process – Storage Resources

Storage capacity ratings have usually been based on maximum discharge (in MW) over a sustained duration (MWh). While the basic formula is widely used, the total required duration varies significantly across system operator. Further, the concept used to establish the minimum duration has differed substantially by region. One concept is that the discharge duration should reflect the average shortage duration estimated exclusively for each system; another concept is to probabilistically model the effective load carrying capability (ELCC) of storage resources at increasing penetration levels. For systems with relatively short-duration shortage events, the dispatch duration requirement could be as little as two hours, which is the test duration of energy storage tests in ISO-NE.[63] In NYISO, MISO, and SPP, a 4-hour rule is used.[64] PJM has a 10-hour requirement, which has received significant pushback from the FERC as being too restrictive and misaligned with the ELCC of storage resources.[65]

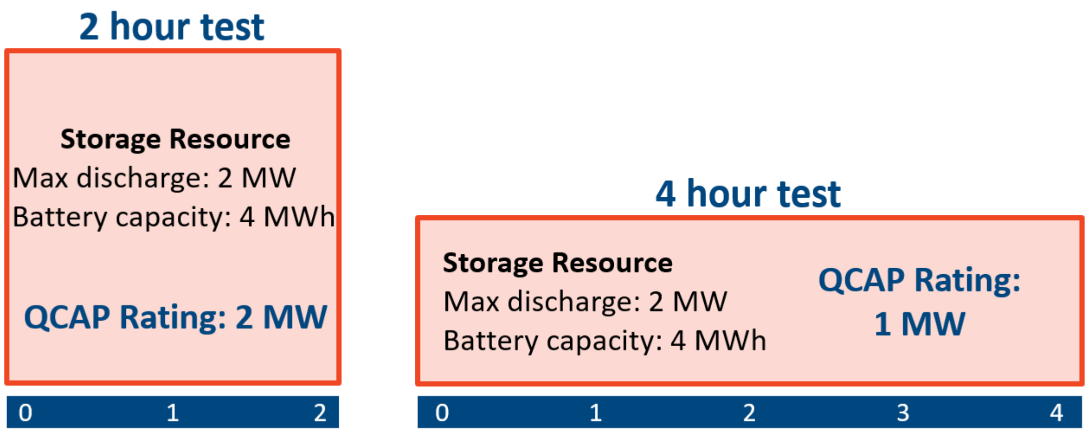
The discharge duration can have a significant impact on the capacity value of a storage resource, as shown in Figure II-7 below. In this example, a 4-MWh battery with a maximum output of 2 MW could receive a different capacity rating, depending on required output duration. In a two-hour test, it can output 2 MW for each of the two hours (for a total of 4 MWh), earning a capacity value of 2 MW. In a four-hour test, the same battery can output only 1 MW per hour for each of the four hours (for a total of 4 MWh), earning a capacity value of 1 MW. A longer discharge duration requirement means that the charge stored in the battery is spread out over a longer period, decreasing the qualified capacity of energy storage resources.

63 Andrew Levitt, "Capability of Energy Storage Resources in Other ISORTOs," ("PJM ESR"), January 30, 2020.

64 Id.

65 Jeff St. John, "Taking Aim at PJM's 10-Hour Duration Capacity Rule for Energy Storage," GreenTech Media, July 22, 2019.

FIGURE II-7: STORAGE QUALIFICATION BASED ON MAXIMUM OUTPUT OVER SPECIFIED DURATION




NYISO has proposed a tiered structure for qualifying capacity resources, as shown in Table II-3 below. The structure allows long-duration storage to be procured at its nameplate capacity, and shorter-duration storage resources to be qualified at a proportion to their nameplate capacity. NYISO undertook an ELCC analysis to arrive at de-rate rules based on the storage resource's duration, as well as the incremental penetration of storage in the system.[66]

TABLE II-3: NYISO DE-RATE METHODOLOGY FOR STORAGE RESOURCES[67]

| | Incremental Penetration of resources with duration limitations | |
|---|---|---|
| Durations (hours) | Less than 1000 MW | At and Above 1000 MW |
| 2 | 45% | 37.5% |
| 4 | 90% | 75% |
| 6 | 100% | 90% |
| 8 | 100% | 100% |

Source: NYISO

Similar to addressing the duration need on a system-by-system basis, the capacity value assessment for storage will vary by the resource mix. For example, a storage asset with 4-hour duration may not be seen to have much capacity value in a system that has an afternoon peak that lasts for 5 or 6 hours. However, if much solar were to be built on that system and reduces the net peak (i.e., peak load net of solar) duration to 2 or 3 hours, the same storage asset's capacity value goes up significantly. As the generation mix evolves, system operators may need to transition toward a more probabilistic approach rather than the simpler deterministic approach in estimating the capacity values for storage.

66 Zachary T. Smith, "Expanding Capacity Eligibility," NYISO, March 7, 2019.

67 Id.

Table II-4 below summarizes the additional considerations (i.e., details and data not submitted for thermal resources) required for the accreditation of these new resource types. They include hours of expected resource availability, penetration of the technology in the capacity mix, duration of availability, and how these characteristics need to match up with the reliability needs of the system.

**TABLE II-4: ACCREDITATION CONSIDERATIONS BY RESOURCE TYPE**

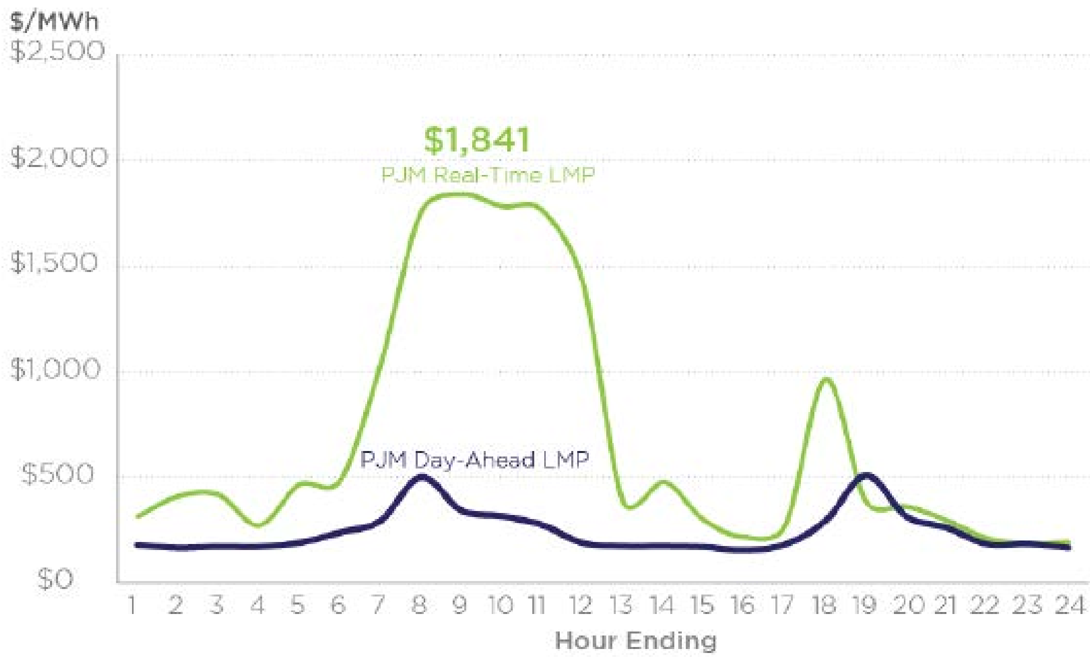
| Resource Type | Key Characteristics for Accreditation | Current Accreditation Approaches |
|---|---|---|
| **Dispatchable Generation** | • Dispatchable to max capacity during reliability events, except during forced outages and maintenance outages<br>• Fuel access can also limit availability during reliability events<br>• Rated capacity may vary by season | • Season-specific maximum output derated by EFORd (planned outages not part of derate in most, but not all, RTOs) |
| **Intermittent Renewable Generation** | • Availability dependent on wind resources and solar irradiation<br>• Increasing penetration tends to shift peak net load periods and decrease availability during those periods | • Deterministic approach: historical generation during peak periods<br>• Probabilistic approach: ELCC |
| **Energy Storage** | • Availability limited during longer reliability events<br>• Value dependent on resource mix | • Output over required duration (2–10 hours)<br>• ELCC |
| **Interruptible Load (Demand Response)** | • Availability specific to certain periods depending on load type (e.g., air-conditioning load in the summer, business hours)<br>• May have limited frequency and length of interruptions | • Planned capacity that can meet RTO-specific requirements, including interruption frequency and length, notification time, reliability periods (e.g., summer/winter), and M&V requirements |

## Operating and Performance Standards

Once a capacity resource earns and fulfills a capacity obligation through the qualification process, it is then subject to strict operating and performance standards. While these standards are generally similar, they do vary by system operator.

PJM has introduced and implemented Capacity Performance, a "pay-for-performance" requirement that rewards reliable resources with additional capacity payments funded by penalties assessed to underperforming resources.[68] The Capacity Performance was introduced following the extreme weather conditions in the winter of 2014 (known as the "Polar Vortex") that demonstrated a need for increased fuel security, especially as the capacity mix has transitioned significantly to a single fuel type (in this case, natural gas).[69] The extreme weather contributed to a forced outage rate of more than 22% of capacity, well above the 7% historical average in the winter, and caused a spike in the price of power, as shown in Figure II-8 below.[70]

**FIGURE II-8 SPIKE IN PJM REAL-TIME LMPS DURING THE POLAR VORTEX[71]**




Source: PJM.

Capacity Performance creates additional financial incentives for capacity resources to contribute to system reliability when needed. It provides payments based on performance during designated Performance Assessment Intervals (PAI) in which net load is expected to be at its highest. The PAI are

[68] PJM's penalty can go up to $3,000/MWh. Some market participants point that it may be more effective to put that money into the energy market rather than the capacity market.

[69] Natural gas pipelines in the Northeast US were initially developed for heating purposes, rather than for supplying power generation needs. The severe cold weather event that occurred in January 2014, known as the Polar Vortex, tested the reliability of grid operators as supplies of natural gas to power generators became constrained.

[70] PJM, "Operational Events and Market Impacts: January 2014 Cold Weather Events," May 9, 2014.

[71] Id.

spread throughout the year to reward all-season performance.[72] The stricter standards incentivize fuel security among other measures to increase reliability, while also increasing penalties for non-performance. Capacity Performance may limit available qualified capacity supply and result in higher capacity prices. Generators are expected to invest surplus capacity market revenues in modernizing equipment and increasing fuel security.

ISO-NE and NYISO have added similar requirements.[73] In ISO-NE, the system operator is working to establish a cost allocation approach to retain a fuel-secured power plant, to reduce dependence on natural gas-fired plants during peak winter demand. [74] In NYISO, generators have been given stronger incentives to secure fuel and enhance their preparation for peak winter demand, while also improving monitoring procedures for generator fuel inventories.[75] Natural gas makes up more than half of the New York's total generating capacity, and about 70% of this natural gas capacity can switch to oil.[76] Many generators in New York City that are connected to the local gas distribution network are required to maintain alternative fuel burning capabilities. In addition, the New York State Reliability Council (NYSRC) has a minimum oil-burn requirement rule that is intended to ensure the maintenance of electric system reliability in the event of gas supply interruptions. Similarly, about 20% of oil capacity can switch to natural gas.[77]

PJM's Capacity Performance rules require all non-intermittent generation resources that are cleared in the auction to offer into PJM's Day-Ahead Energy Market.[78] Other jurisdictions, including ISO-NE,[79] MISO,[80] and NYISO,[81] also have similar rules requiring offers into the day-ahead energy market. These must-offer requirements are implemented to ensure the availability of capacity resources whenever they are needed to meet system load. Resources must coordinate their planned outages (for

72 PJM, "Strengthening Reliability: An Analysis of Capacity Performance," June 20, 2018, pp. 3-5.

73 Paul J. Hibbard and Charles Wu, "Fuel and Energy Security in New York State, An Assessment of Winter Operational Risks for a Power System in Transition," NYISO, November 2019.

74 ISO-NE, "Forward Capacity Market: Retain Resources for Fuel Security Key Project."

75 NYISO Press Release, NYISO Forecasts Adequate Capacity for Upcoming Winter Season, November 21, 2019.

76 U.S. Department of Energy, "January's cold weather affects electricity generation mix in Northeast, Mid-Atlantic," January 23, 2018.

77 NYISO Power Trends 2020.

78 PJM Manual 18, Section 5.6. See PJM Manual 11 for details on Energy Market operations.

79 ISO-NE Market Rule 1, Section III.13.6.1.

80 MISO Business Practices Manual 11, Section 6.1.

81 NYISO ICAP Manual, Section 4.8.

maintenance, repairs, or upgrades) with the system operator, so the operator knows which resources can be counted on for capacity in each hour of the day.

Intermittent generation resources, unlike dispatchable resources (such as the traditional thermal generators), cannot guarantee level of output in any given hour. As a result, system operators rely on a different operational standard than traditional generation to evaluate their performance. For example, in PJM, intermittent resources are exempted from meeting the Capacity Performance must-offer requirement in the same way as non-intermittent generation.[82] Instead, intermittent resources usually meet the must-offer requirement by self-scheduling; otherwise, the resources can risk non-performance penalties if they offer into the Day-Ahead Market as dispatchable economic resources.[83] By offering at lower Capacity Performance quantities, intermittent resources can reduce risk of non-performance during PAIs, and increase the possibility for performance bonuses for actual energy delivered above the committed quantity.[84] Additionally, PJM encourages intermittent resources to aggregate their capabilities in order to meet Capacity Performance standards as an Aggregate Resource. ISO-NE requires intermittent resources to offer into the Day-Ahead Energy market at a level consistent with the market participant's expectation of output in real-time. Intermittent resources are subject to additional requirements in the energy market, including additional auditing and data reporting standards.[85] In MISO, intermittent resources are required to submit a day-ahead reliability forecast based on forecasted conditions for the next day, against which its real-time output is compared.[86] In NYISO, intermittent resources are not subject to the must-offer requirement. Instead, they are required to offer available capacity and notify the NYISO of all outages.[87]

Operational performances of DR are measured (and verified) in a quite different way. There are two main ways for this measurement:

- **Guaranteed Load Drop (GLD)** requires a resource to guarantee the amount of load it can shed from a running baseline. For example, a resource with a 6 MW GLD that is consuming 10 MW when called would be required to reduce to net load of 4 MW. This concept is especially easy to implement for end-use customers with DR based on a backup generator or interrupting a specific fixed load.

82 PJM, "Intermittent Resource Participation in RPM for 2020/21 and beyond" ("PJM Intermittent Resources"), March 5, 2018.

83 PJM Manual 11, Section 2.3.3.1.

84 PJM, "Intermittent Resource Participation in RPM for 2020/21 and beyond" ("PJM Intermittent Resources"), March 5, 2018.

85 ISO-NE, Market Rule 1, Section II.13.6.1.3.

86 MISO, "MISO Business Practices Manual 11" ("MISO BPM 11"), Section 4.2.3.6.

87 NYISO ICAP Manual 4, Section 4.8.6., June 20.

- **Firm Service Level (FSL)** requires a resource to reduce its consumption to FSL no matter how much it is consuming just before the event. The load "reduction" is counted as the customer's forecasted baselines minus the FSL. For example, a customer with a 10 MW forecast baseline and a 4 MW FSL would have to reduce to 4 MW when called, and it would be credited with providing 6 MW of capacity, even if it was consuming 9 MW or 11 MW just before being called.

In PJM, a single 1-hour test is required during designated peak hours in the summer season, which must be completed once per Delivery Year. If the resource is called on for a shortage event, its performance during the event is used instead of the test. PJM resources self-schedule their tests with the ISO, meaning they will know the test is coming in advance.[88] In ISO-NE, a similar testing procedure is required once per season, for a period of two hours per test.[89]

In actual operations, DR in PJM is only called when all non-emergency resources are exhausted. Longer lead-time DR will be called before fast-starting resources, then DR is dispatched according to offer price. DR resources can set prices in the real-time energy market at their offer price.[90] In ISO-NE, DR is required to offer into the Day-Ahead and Real-Time energy market at or above their capacity supply obligation, during their hours of physical availability which are specified in the resource's qualification package. DR resources are also subject to additional performance requirements, including seasonal auditing to ensure the end-use customer has curtailable load in all seasons.[91]

Finally, energy storage resources that typically have limited energy duration require its own unique operating standards. Many energy storage resources today are unable to operate continuously on a daily basis, rather, they are designed to operate for a minimum set of consecutive hours. In MISO, storage resources are required to submit a day-ahead energy offer of at least four continuous hours every day, across the MISO-forecasted daily peak.[92] In PJM, storage resources are treated like renewable resources, and are exempted from strict Capacity Performance availability requirements.[93] Instead, they are allowed to self-schedule to fulfill their must-offer requirement, or can bid into the day-ahead energy market. Storage resources participate in the wholesale energy market in a similar manner in ISO-NE.[94]

88 PJM Manual 18, Section 8.7.

89 ISO-NE, "Registration and Performance Auditing Manual M-RPA," Effective December 3, 2019, Section 1.6.

90 PJM Manual 18, Section 8.7.

91 ISO-NE, Market Rule 1, Section III.13.6.1.5

92 MISO Capacity and Resource Adequacy Administration, Physical Withholding and Must Offer, June 2, 2018.

93 PJM, Electric Storage Resource Participation Model, September 10, 2018.

94 ISO-NE, Energy Market Offer Requirements.

## B. Other Changes Associated with the Evolving Market - Ancillary Services

Despite the introduction of these new products in the capacity market that incentivize greater availability in times of need, some markets now recognize that pay-for-performance alone will not suffice to ensure performance. In the long term, as renewables become more prominent in the generation fleet, managing intermittency through the ancillary services market will become increasingly important. Grid operators like ISO-NE are already turning to ancillary services to help manage concerns that fuel security issues for thermal resources in particular may affect performance during peak demand.

Natural-gas fired generators in New England have grown increasingly reliant on just-in-time (i.e., non-firm) natural gas supplies as pipeline capacity becomes scarce. Given that the fuel is reserved first and foremost for residential heating in times of peak demand during the winter, concerns have grown over the past few years regarding whether the natural gas capacity in ISO-NE can actually supply the energy in the absence of adequate fuel supplies. In June 2020, ISO-NE received approval from FERC to implement a series of new ancillary services products to incentivize greater availability of generators in times of need—a goal that very much aligns with the purpose of the Capacity Performance product in the capacity market. The reform will be implemented across a short-term phase one (implemented for the 2023/2024 and 2024/2025 deliverability years) and a longer-term phase two (implemented for subsequent deliverability years).

With regards to a more short-term solution to New England's winter fuel security challenges, FERC recently approved ISO-NE's Inventoried Energy Program that would operate during the winters of 2023/2024 and 2024/2025. Under this program, the grid operator will pay resources for keeping enough fuel (i.e., "inventoried energy") on-site to last at least three days. Resources have the option to enter into forward contracts that require them to have a certain amount of inventoried energy ready for use whenever a cold-weather event is declared—the rate has been fixed at $82.49/MWh.

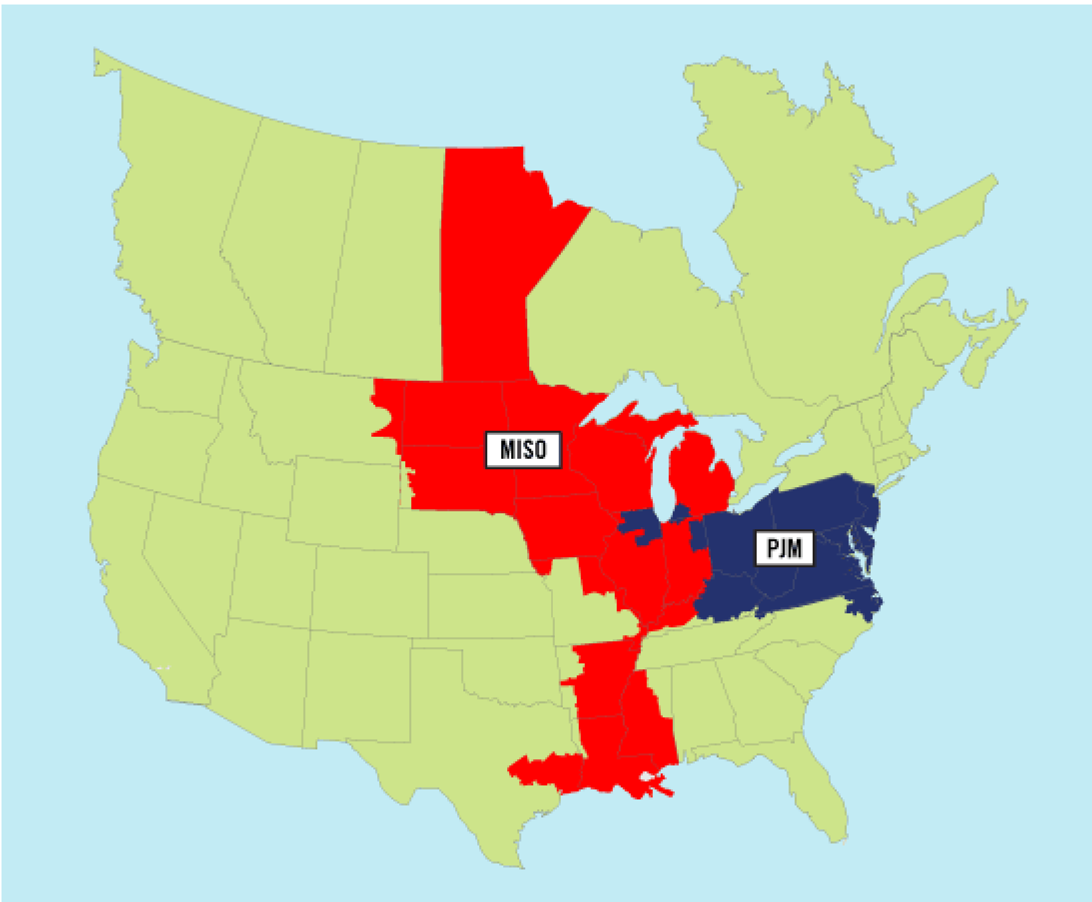
For a longer-term market-based solution, ISO-NE is introducing three new ancillary service products designed as energy options in the day-ahead market. First, the Energy Imbalance Reserve product will compensate resources that help meet the next-day forecasted load when that forecast exceeds total physical energy supply cleared in the day-ahead market. Second, the Generation Contingency Reserve product will parallel existing real-time operating reserves. Third, the Replacement Energy Reserve will help restore depleting operating reserves and address unexpected changes in supply or demand during the day.[95]

[95] Motion for Leave to Answer, Motion for Leave to Answer Out of Time, and Answer of ISO New England, Docket Nos. EL18-182-000 and ER20-1567-000, June 15, 2020.

## C. Market Rules for Capacity Imports

As the need for renewable generation grows, some system operators have found it challenging to find good renewable resources within its geographical footprint. One approach to solve such problem is to import the needed capacity from other jurisdictions.

**FIGURE II-9: MAP OF MISO AND PJM[96]**




Source: MISO-PJM

PJM and MISO provide a case study of the treatment of remote generation. As neighboring balancing areas (as shown in Figure II-9 above), the two system operators have a long history of coordinating

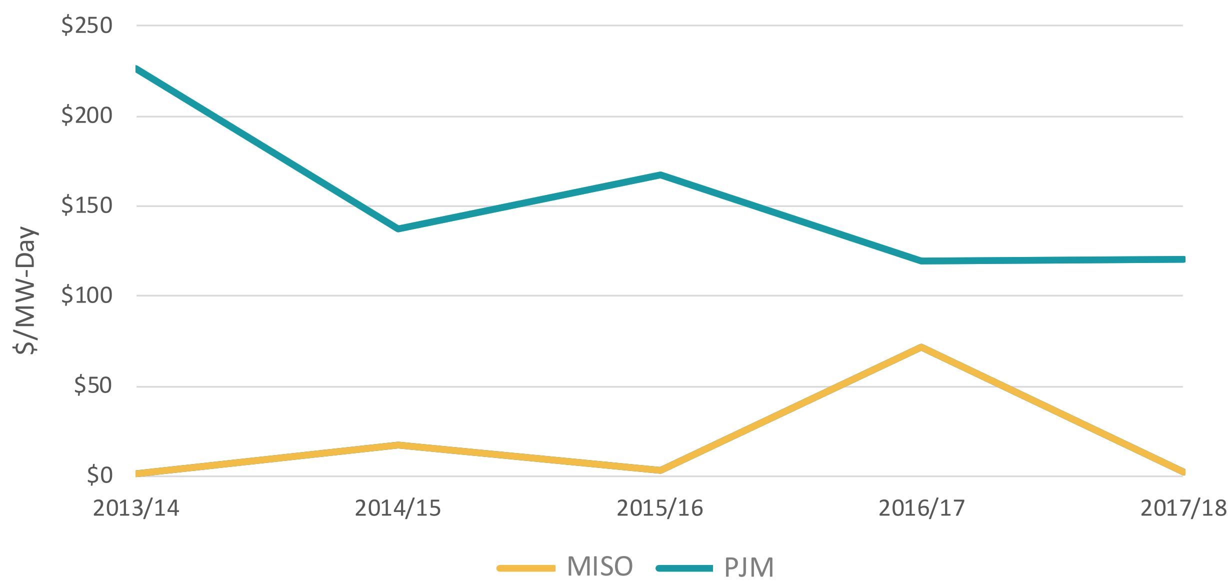
96 https://www.miso-pjm.com/

issues at their seam, with their joint operating agreement established in 2003. Nonetheless, the issue of *pseudo-ties* has generated significant controversy among PJM and MISO stakeholders in recent years.

A resource is said to be pseudo-tied into PJM if it is physically located outside PJM, but elects to serves load in PJM nevertheless.[97] Historically, pseudo-tying "was relatively rare and generally limited to the dispatch of jointly-owned units with owners in different control areas."[98]

Pseudo-tying became relatively more common during the last decade, with generators in MISO seeking to take advantage of high capacity prices in PJM. For the 2017/2018 Delivery Year, MISO's capacity auction (called Planning Resource Auction, or PRA) cleared at $1.50/MW-day while the BRA in RPM cleared at $120/MW-day.[99] Though price difference fluctuated from year to year, the general trend was clear as shown in Figure II-10 below.

**FIGURE II-10: PJM VS MISO PRICES[100]**




Source and notes: GAO. PJM prices are for the Southwestern Mid Atlantic Area Council. MISO prices are for Zone 6, which is immediately to the west of PJM.

97 https://www.pjm.com/about-pjm/member-services/dynamic-transfers.aspx

98 FERC Order on Complaint re Potomac Economics, Ltd. v. PJM Interconnection, L.L.C., Docket No. EL17-62-000 (Potomac Complaint), April 2017.

99 FERC Order on Complaint re Potomac Economics, Ltd. v. PJM Interconnection, L.L.C., Docket no EL17-62-000, (FERC Order Rejecting Potomac Complaint,) April 17, 2020.

100 https://www.gao.gov/assets/690/688811.pdf

Starting in 2015, pseudo-tying became mandatory for MISO generators bidding into PJM's RPM. PJM required external resources to be pseudo-tied in order to qualify as a Capacity Performance product. One key feature of pseudo-tying is the transfer of dispatch control of the pseudo-tied resource from MISO to PJM. In 2015 FERC accepted PJM's reasoning that dispatch control was necessary to ensure that external resources are just as deliverable to PJM as internal resources, even if the external resource is physically located outside PJM footprint.[101] For similar reasons, FERC also accepted as just and reasonable PJM's requirement that external resources procure long-term firm transmission rights (with rollover rights) to the PJM interface.[102, 103]

After the implementation of the pseudo-tie requirement, the amount of resources pseudo-tied from MISO into PJM increased from approximately 155 MW in June 2015 to 2,160 MW by June 2017.[104] RPM results for the 2021/2022 deliverability year indicate an amount exceeding 4,000 MW.[105] Potomac Economics, the independent market monitor for MISO, explained: "the negative effects of pseudo-ties on PJM's neighbors are much greater because the neighboring RTOs lose dispatch control of resources whose power flows primarily over their transmission systems. Based on our analyses of the numerous pseudo-ties that have been implemented in MISO to date, we have identified substantial dispatch inefficiencies and operational concerns."[106]

In April 2017, Potomac Economics filed a complaint before FERC, asserting that "PJM's requirement that external resources obtain a pseudo-tie to participate in PJM's capacity market is unjust and unreasonable."[107] In its filing, Potomac Economics argues that the pseudo-tie requirement causes market inefficiency and reduces grid reliability, among other things. It seeks to illustrate the effect of pseudo-ties on the proliferation of binding market constraints in MISO with the following series of diagrams.[108]

101 FERC Order Rejecting Potomac Complaint.

102 Id.

103 Rollover rights refer to the ability to renew the existing contract for transmission capacity.

104 Potomac Complaint.

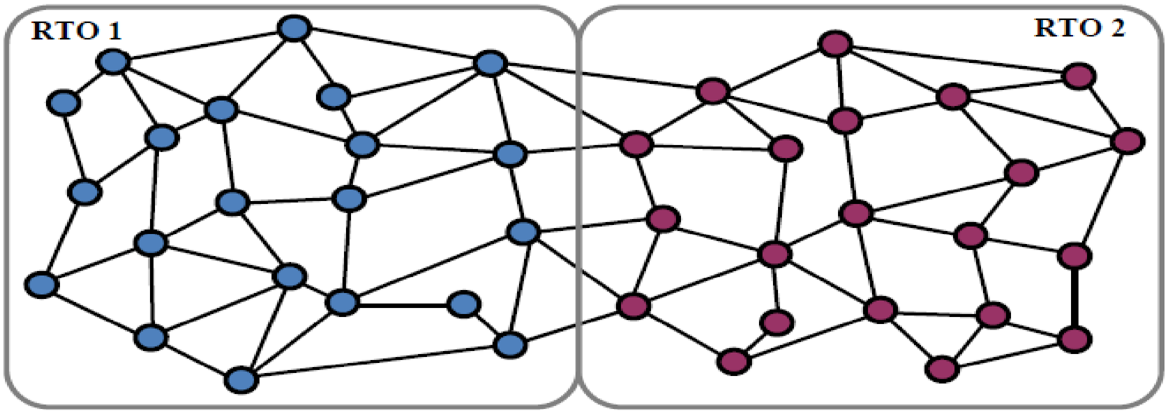
105 https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en

106 Potomac Complaint.

107 FERC Order Rejecting Potomac Complaint.

108 Potomac Complaint.

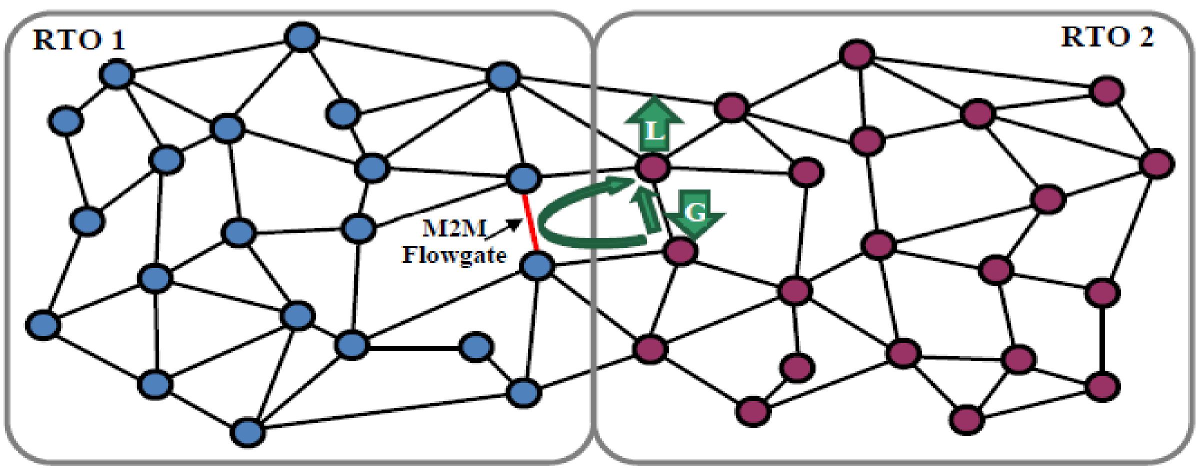
**FIGURE II-11: TYPICAL RTO CONFIGURATION WITHOUT PSEUDO-TIES**




Source: Potomac Economics

Potomac Economics explains that in order to "understand why pseudo-ties are so damaging economically and operationally, it is instructive to first describe the interaction between two RTOs without any pseudo-ties. Figure II-11 above shows two RTO systems with a well-defined seam" in which the blue generators are interconnected to RTO 1 (i.e., MISO) and the maroon generators are interconnected to RTO 2 (i.e., PJM).

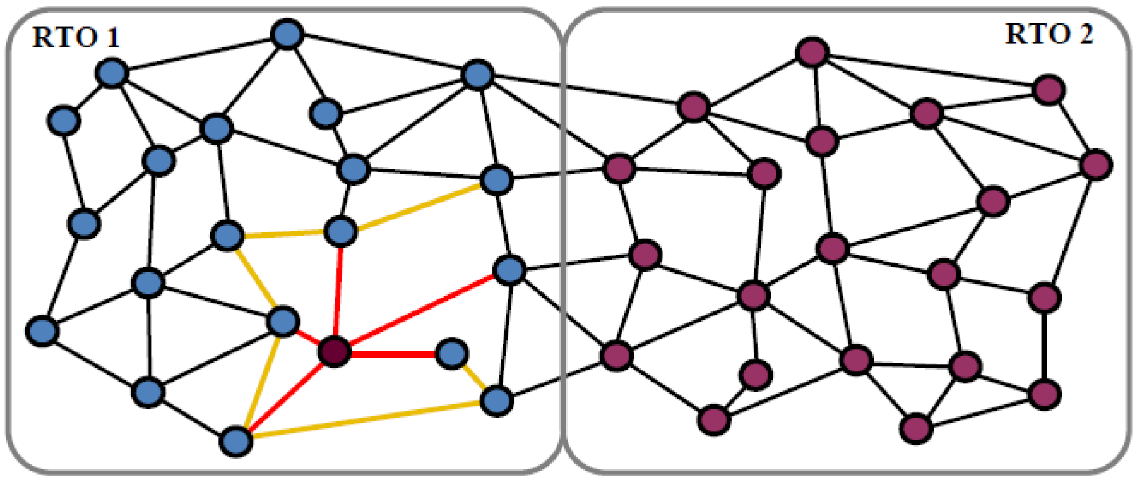
**FIGURE II-12: MARKET-TO-MARKET COORDINATION WITHOUT PSEUDO-TIES**




Source: Potomac Economics

Potomac Economics acknowledges that Figure II-11 above is an oversimplified and unrealistic portrayal of the two systems. Even in a world without pseudo-ties, dispatch by either RTO will still produce flows on the other's system. These "loop flows" are the reason for "market-to-market" (M2M) coordination processes, developed by PJM and MISO to manage unintended congestion on each other's systems.[109] Figure II-12 above "shows how the dispatch of generation by RTO 2 to serve its load can result in power flowing over a constraint on the RTO 1 system that causes the constraint to be coordinated as a market to market constraint… [RTO 2] will now recognize the effects of its dispatch on the market to market flowgate and these effects will… be included in RTO 2's LMPs."

**FIGURE II-13: MARKET-TO-MARKET COORDINATION WITH ONE PSEUDO-TIED UNIT**

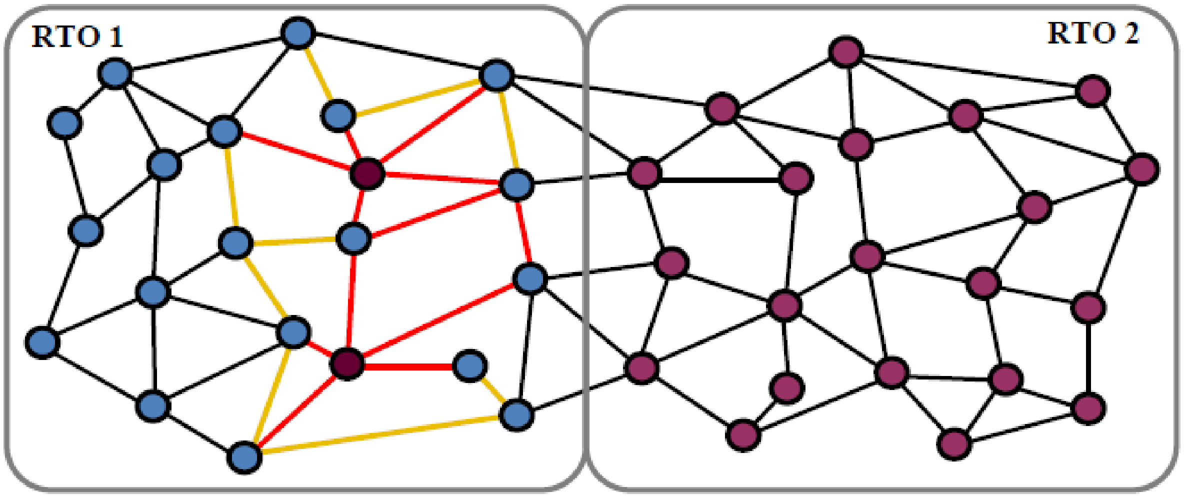



Note: Red line segments denote constraints that are explicitly coordinated by PJM and MISO due to pseudo-tied resources; yellow line segments denote constraints that also arise indirectly from pseudo-tied resources but are not coordinated by PJM and MISO

According to Potomac Economics, Figure II-13 above illustrates how just one unit pseudo-tied from RTO 1 to RTO 2 can create a host of new constraints (marked in red) that must now be coordinated between the RTOs as M2M constraints, requiring re-dispatch by both RTOs until the constraints are relieved. Coordination level becomes more complicated with multiple pseudo-tied units because it involves a larger network, as shown in Figure II-14 below.

[109] Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C., Section 6: Reciprocal Operations, December 11, 2008.

**FIGURE II-14: MARKET-TO-MARKET COORDINATION WITH MULTIPLE PSEUDO-TIED UNITS**




Note: Red line segments denote constraints that are explicitly coordinated by PJM and MISO due to pseudo-tied resources; yellow line segments denote constraints that also arise indirectly from pseudo-tied resources but are not coordinated by PJM and MISO

Potomac Economics also explains that the pseudo-tied units' effects on RTO 1 are not limited to the new M2M constraints. "It will also affect many other constraints that do not pass the tests to be coordinated under the market-to-market procedures," as indicated in yellow.[110]

In its response to Potomac Economics, PJM stresses that it is "actively coordinating with MISO to address implementation and management concerns… its ongoing communication and coordination with MISO specifically aimed at promoting visibility of PJM scheduling and dispatch directly addresses certain dispatch-inefficiency concerns raised by Potomac."[111]

In April 2020, FERC denied Potomac Economics' complaint, finding that "PJM's capacity market is not unjust and unreasonable because it requires external resources to be responsible for their own capacity obligations, just as internal resources are responsible for their capacity obligations." Furthermore, "Potomac's arguments here fail to recognize that, under PJM's approach, MISO must consent to a pseudo-tie so MISO could refuse to provide consent in circumstances where it believes the pseudo-tie would be too detrimental to the MISO system." By upholding the necessity of pseudo-ties, FERC has kept open a crucial mechanism for inter-regional coordination of remote generation that will likely play a key role in helping PJM manage capacity imports in the future.

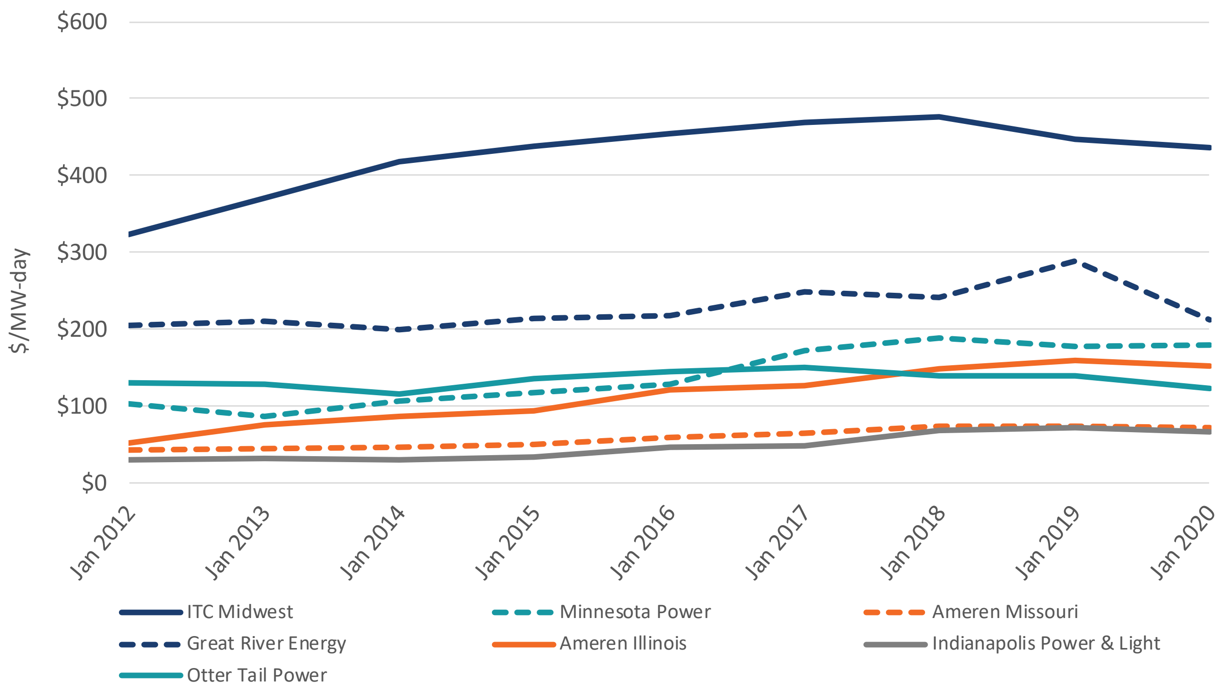
An associated concern for renewable resources may be the cost of transmission services of the pseudo-ties. Renewable resources often enter long-term power purchase agreements that last up to 20 years or longer. The price of energy is often fixed throughout the term of the contract, but transmission service

[110] Potomac Complaint.

[111] FERC Order Rejecting Potomac Complaint.

rates may change over time. Transmission rates, which are regulated by FERC, could rise substantially in the mid-term for a variety of reasons. A resource physically located in MISO pseudo-tying into PJM, for example, would be required to procure firm transmission to the PJM interface and could be exposed to rising MISO transmission rates that are not covered by the contractual price for energy to which it has agreed. Figure II-15 below shows historical point-to-point rates for a select group of entities in MISO. As the figure illustrates, it is not uncommon for transmission service rates to go up by 50% or more within several years.

**FIGURE II-15: ON-PEAK FIRM POINT-TO-POINT RATES ($/MW-DAY) FOR SELECTION OF MISO ENTITIES**




Source: MISO OATT Schedule 7

# D. Market Monitoring

As capacity markets evolve to accommodate newer resource types, the monitoring and mitigation rules governing the capacity markets—for both the supplier side and buyer side—have also evolved.

Supply-side monitoring and mitigation measures exist to prevent physical and economic withholding of capacity by suppliers that could lead to higher market clearing prices. Actual measures can include:

- Mandatory participation in capacity auctions for all existing generation resources;
- Screening for market concentration to determine whether certain additional mitigation measures including offer caps need be imposed; and
- Conducting an administrative review of high-priced capacity offers to ensure they are reflective of net going-forward costs.

Buyer-side mitigation measures are intended to prevent suppression of capacity market prices, which can be through subsidized entry of new resources. For example, large net buyers (or states) could benefit from suppressed capacity prices that would reduce total costs for their entire load, even if the individual subsidized resource were uneconomic. To guard against such buyer-side price suppression, minimum offer price rules (MOPR) have been implemented.

The design of both the supplier-side and buyer-side mitigation, while similar, varies by the system operator. The applicable rules also may vary by the resource type.

## Supply-Side Mitigation - PJM

PJM performs a Market Structure Test designed to identify if any capacity suppliers have the potential to exercise market power. This test is performed both on the individual capacity zones and PJM as a whole. An individual zone (or PJM as a whole) will be considered to be vulnerable to market power abuse if a three pivotal supplier (TPS) test determines the three largest generation suppliers in that zone are jointly pivotal.[112]

The Market Structure Test is conducted during the auction in two steps. First, it calculates the cost-based clearing price by assuming all suppliers were clearing at either: (a) their cost-based offer price that has been confirmed as reflective of net going forward costs by the market monitor, or (b) their price-based offer price. Then it assesses if there are three pivotal suppliers by checking against the incremental supply offered at less than or equal to 150% of the cost-based clearing price. If the test

[112] In general, most participants fail the test, indicating that this test may not be the best approach. The Alberta design that was based on a minimum supply share needed to have the ability/incentive to exercise market power may be worth looking into as an alternative.

indicates three pivotal suppliers, all pivotal suppliers will be subject to mitigation. Typically it takes only one or two suppliers to be jointly pivotal, and the third supplier would automatically also be deemed jointly pivotal no matter how small. This stringent test has resulted in every individual capacity zone in PJM to have always (or nearly always) fail—leading to every generation supplier in the market to be mitigated.

PJM then applies mitigation on a unit-specific basis after applying two additional tests—"conduct" and "impact" tests. The conduct test fails if the offer exceeds the no-look threshold, referred to as "the default offer cap." The no-look threshold is calculated as the product of the applicable Net CONE (by technology), and the average balancing ratios in the three consecutive calendar years that precede the respective auction.[113] It is released 150 days ahead of the auction date. In practice, the default offer cap is about 85% of Net CONE. By setting the default offer cap as a fraction of Net CONE, PJM intends to accommodate the costs of improving performance and the financial risk suppliers take by taking on a Capacity Performance supply obligation. The impact test fails if the offer would, absent mitigation, increase the market-clearing price in the relevant auction. Supplier offer caps do not apply to new generation, or demand-side resources, including DR and energy efficiency resources. DR resources are not subject to these mitigation measures because they are presumed to be submitted by competitive entrants that have substantial going-forward costs in all years. Similarly, all new generation is assumed to be competitive and is not subject to market power mitigation unless its supply is pivotal. If the offer of pivotal new generation is sufficiently above what would be expected for its particular asset class, the supplier will be notified that their bid has been rejected as excessive and invited to submit a new offer.

For capacity resources that are exempt from Capacity Performance (such as renewable resources), PJM assigns default offer caps that vary by resource technology type. The default offer caps are based on generic estimates of each resource type's net going-forward costs (i.e., the fixed costs of maintaining each plant less the net expected energy and ancillary services revenues). This net-going forward cost is also referred to as the default avoidable cost rate (ACR) minus projected revenues. There are two rates calculated for each type of technology—the costs that could be avoided if the unit were to mothball for one year, or the cost that could be avoided if the unit were to retire permanently.

[113] If a supplier's true net going forward costs are above those described by the default offer cap, the supplier can request a unit-specific cap in which they will provide documentation of net going-forward costs for a specific unit to the market monitor to justify a high offer price. The supplier needs to submit this 120 days ahead of the auction date. The market monitor will then notify participants of unit-specific offer caps 90 days ahead of the auction date. Suppliers then have ten days to agree or disagree and notify PJM. PJM will then notify both the suppliers and market monitor of their final determination of the unit offer caps 65 days ahead of the auction date.

Table II-5 below summarizes these costs by resource type. Suppliers are only allowed to submit offers at these high retirement-based cost levels under an officer's sworn affidavit that the plant will retire if it fails to clear in RPM.

TABLE II-5: PJM RPM DEFAULT AVOIDABLE COST RATES FOR 2019/20 DELIVERY YEAR[114]

| Technology Type | 2019/2020 Mothball ACR ($/MW-Day) | 2019/2020 Retirement ACR ($/MW-Day) |
|---|---|---|
| **Combustion Turbine** | $30.85 | $42.24 |
| **Coal Fired** | $175.04 | $201.79 |
| **Combined Cycle** | $37.82 | $52.02 |
| **Combustion Turbine – Aero Derivative** | $33.41 | $47.54 |
| **Diesel** | $32.55 | $41.34 |
| **Hydro** | $87.94 | $115.02 |
| **Oil and Gas Steam** | $80.75 | $98.32 |
| **Pumped Hydro** | $25.72 | $36.13 |

## Supply-Side Mitigation - NYISO

NYISO's capacity market includes a number of market monitoring and mitigation measures. There are several measures that are specifically applied only to market-internal import-constrained capacity zones with high concentration of both supply and demand. These factors tend to increase the risk and impact of market power exercise relative to the larger and more structurally competitive capacity zones. Both New York City and the Lower Hudson Valley zones are applicable to these mitigation measures.

NYISO uses a single-pivotal-supplier test. For example, for New York City, suppliers are tested against the City's Locational Minimum Installed Capacity Requirement (LCR). A supplier is considered pivotal if the

[114] PJM, "PJM RPM Default Avoidable Cost Rates for the 2019/2020 Delivery Year," available at: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-default-avoidable-cost-rates.ashx

supplier controls at least 500 MW of unforced capacity,[115] and also controls unforced capacity that is at least in part necessary to meet the New York City locality LCR in an ICAP spot market auction. The mitigation measures that are applied to pivotal suppliers also apply to resellers (and "affiliated entities") who have procured their supply from pivotal suppliers. That is, if a supplier assigns the right to bid a unit's capacity to another party, the supplier must inform the assignee that the unit is subject to mitigation measures.

For the Lower Hudson Zone, the NYISO determines that a supplier is pivotal if the supplier controls at least 650 MW of unforced capacity, and also controls unforced capacity that is at least in part necessary to meet the Lower Hudson Zone LCR in an ICAP spot market auction.

All NYISO pivotal suppliers are subject to a must-offer requirement to prevent physical withholding of capacity from the market. Generation capacity that is not already committed to a competitive retailer and not previously sold in the voluntary six-month or monthly capacity auctions must be offered in the capacity auction. If NYISO determines fraudulent physical withholding (e.g., falsely declaring a plant out of service, or adjusting a generator bid to reduce its capacity), the supplier will face financial penalties equal to the product of 1.5 times the difference in the local market clearing price caused by the supplier's withholding, and the supplier's entire UCAP portfolio.[116] Pivotal suppliers are also subject to an offer cap determined by the market monitor. This cap is set to the higher than the higher of the projected clearing price identified by the applicable ICAP demand curve and the supply of all unforced capacity in a capacity zone for the specified period ("UCAP offer reference level") or a market-clearing price that covers the going forward costs of the marginal unit. The going forward costs are compared to the alternative of mothballing the generation unit, retiring the unit, or selling into another market.[117]

## Supply-Side Mitigation - MISO

MISO's monitoring and mitigation measures are quite different from those in PJM and NYISO. This is partly because MISO maintains vertically-integrated utilities under cost-of-service regulation, with little incentive to manipulate capacity auction prices. MISO imposes mitigation measures only if it determines that exercise of market power could increase auction clearing prices by an impact threshold of at least 10% of CONE. In that case, must-offer or offer-cap mitigation measures may be applied.

[115] The market monitor developed this threshold by considering the demand curve from the Summer 2007 ICAP spot auction and determined that, if all competing supplies were sold, withholding could only be profitable for pivotal suppliers owning at least 590 MW of UCAP.

[116] For example, if a supplier with a 2,000 MW UCAP portfolio withheld some of its capacity that caused the zonal capacity price to increase by $10,000/MW-year relative to a situation where they had not withheld, the supplier could be charged 1.5 × $10,000/MW-year × 2,000 MW = $30 million.

[117] NYISO does have an exception consultation process that allows generators to present information to the market monitoring unit and the independent market monitor in support of a higher reference level price for particular units in their portfolio. To limit frivolous applications for higher bid levels, however, NYISO also expects permanent retirement of units that do not clear in the spot market after being granted a higher offer cap.

MISO also has a must-offer requirement that applies to a physical withholding threshold of 50 MW by a market participant, for each capacity zone. If a particular supplier offers capacity that is 50 MW or more below its known supply in a particular capacity zone or more than 200 MW or 5% of the supplier's total supply system-wide, it is subject to mitigation measures. Supply that is already committed to supplying capacity to meet the minimum procurement required for some load serving entity (whether within MISO or exported) is not considered physical withholding. However, if a supplier is exporting to an external capacity market with prices less than 50% of the MISO auction clearing price, it can be considered physical withholding.

## Buyer-Side Mitigation - PJM

PJM's minimum offer price rule imposes offer price floors on new entrants that are using gas-turbine based technologies. This offer floor is based on the estimated Net Asset Class CONE for new gas combined cycle, simple cycle combustion turbine, and integrated gasification combined cycle plants. Table II-6 summarizes those offer levels for the 2022/2023 Delivery Year.

**TABLE II-6: PJM MINIMUM OFFER PRICE LEVELS FOR 2022/2023 DELIVERY YEAR**[118]

| Resource Type | CONE Area 1 | CONE Area 2 | CONE Area 3 | CONE Area 4 |
|---|---|---|---|---|
| **Combustion Turbine** | $261.86 | $240.49 | $269.62 | $232.17 |
| **Combined Cycle** | $307.56 | $254.08 | $290.82 | $255.36 |
| **Other Resource Types** | $203.67 | $187.04 | $209.70 | $180.57 |

Notes:
Other Resource Types: Resource types other than Combustion Turbines and Combined Cycles are subject to MOPR. The MOPR is $0.00 for nuclear, coal, integrated gasification combined cycle, hydro, wind and solar facilities and is set to 70% of the CT Net CONE for all other resources.

- Cone Area 1 includes the following Transmission Zones: AE, DPL, JCPL, PECO, PSEG, RECO.
- Cone Area 2 includes the following Transmission Zones: BGE, PEPCO.
- Cone Area 3 includes the following Transmission Zones: AEP, APS, ATSI, COMED, DAYTON, DEOK, DOMINION, DUQUESNE, EKPC
- Cone Area 4 includes the following Transmission Zones: METED, PENELEC, PPL.

[118] PJM (2018), MOPR Floor Offer Prices for 2022/2023 BRA (ICAP Price $/MW-Day), available at: https://www.pjm.com/markets-and-operations/rpm.aspx.

To avoid unnecessary mitigation actions and over-mitigation that could increase capacity prices, PJM imposes these MOPR price floors only on a subset of new entrants.[119] Resources not subject to these rules include long-lead resources such as nuclear and coal, as well as all renewable resources, which are assumed to be built for other policy reasons. New suppliers can also request exemption from the application of MOPR if the resource is built as self-supply for a utility with a relatively balanced load and generation base (and so would not stand to benefit from suppressing prices), or the resource owner is a merchant supplier building with no long-term contract with a buyer (and so has no incentive to suppress prices). In the 2020/2021 auction, all suppliers' exemption requests were granted, resulting in 12,161 MW that were exempted as merchant entry.[120]

## Buyer-Side Mitigation - NYISO

NYISO applies buyer-side mitigations on a resource-by-resource basis by imposing a price floor on all new entry that is not exempted. Merchant generators can be exempted by applying for a Competitive Entry Exemption. Without an exemption, new suppliers will have an offer floor of no less than the lesser of: (1) 75% of the mitigation Net CONE translated into a seasonally adjusted monthly UCAP value for a generic new unit, and (2) its demonstrated first-year unit Net CONE translated into a seasonally adjusted monthly UCAP value.[121]

NYISO further limits the allowed market activity of uneconomic new entry to ensure this offer floor is binding. If capacity is determined to be uneconomic, it will not be allowed to participate in bilateral transactions or any of the voluntary (six-month or monthly) auctions that precede the final mandatory spot auction. The only option for selling this capacity will be through participation in the NYISO capacity market where it will be subject to the offer floor.

While the buyer-side mitigation market rules in NYISO are aimed at preventing uneconomic entry from artificially suppressing capacity prices, state regulators have recently been working to resolve emerging tensions between state policy and wholesale market design. In early 2020, FERC directed NYISO to significantly expand the scope of buyer-side mitigation and extend substantial floor prices to resources

[119] The original purpose of MOPR was to prevent intentional manipulative price suppression from large buyers. It was then later extended to apply to state-contracted resources, and more recently to all policy resources, such as renewables needed for satisfying state Renewable Portfolio Standard requirements.

[120] PJM, "MOPR Exemption Requests," March 27, 2017, accessed July 20, 2020, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-bra-mopr-exemption-request-quantities.ashx?la=en.

[121] Suppliers may be eligible for an exemption from the minimum offer price rule if: (1) the one-year ICAP spot market auction forecast price exceeds 75% of the mitigation Net CONE, or (2) the three-year average annual ICAP forecast exceeds its unit Net CONE.

that receive some form of state support (e.g., renewable energy certificates). These are disproportionately clean energy resources that are being developed in response to New York's codified goals of 70% renewable energy by 2030 and 100% GHG reductions (with up to 15% allowed through alternative mechanisms) by 2050. NYISO proposed buyer-side mitigation exemptions for 1,000 MW of renewable resources, but FERC rejected the proposal, and further clarified that demand response resources are also subject to buyer-side mitigation.[122]

[122] Brattle recently evaluated several alternative resource adequacy constructs in New York. Comparing a status quo in which new buyer-side mitigation rules remain in place versus a scenario without buyer-side mitigation applied to renewable resources, Brattle found that buyer-side mitigation rules could increase customer costs by $0.6-$2.0 billion/year. Drivers of increased costs include higher capacity market clearing prices—which result directly from the price floors—and also indirect contract cost increases for policy resources that would be defined capacity payments. For further details, please see Sam Newell, Kathleen Spees, John Imon Pedtke, and Mark Tracy, "Quantitative Analysis of Resource Adequacy Structures" prepared for NYSERDA and NYSDPS, May 29, 2020.

# III. Capacity Market Delays

Organized wholesale markets around the world have experienced various delays in their capacity auctions. Delays generally fall into two categories. In the first category, delays occur in already established auctions, and several examples caused by COVID-19 are discussed in Section IV - Impacts of COVID-19 on Capacity Markets. Other delays of this category stem from existing rules or proposed changes to existing rules. The second category relates to the establishment of new capacity markets owing to policy changes and unanticipated complications that arise during the design and implementation process. For example, countries within the European Union (EU) must obtain state-aid approval from the European Commission (EC) prior to setting up their capacity markets, a process that could pose substantial risks and uncertainty. In 2016, the EC published a report on its capacity mechanism sector inquiry, providing a framework on how member states can comply with state-aid rules when introducing capacity markets.[123] This report and subsequent regulation have helped to smooth the capacity market establishment process.[124]

A more recent and notable capacity auction delay is that of PJM. The issue centers on whether a MOPR applies to resources that either receive state subsidies or are subject to policy mandates (i.e., renewables and nuclear).[125] In its most recent order, FERC ruled that the MOPR indeed covers these resources. In response, states are considering exiting the PJM capacity market, and forming their own reliability plans. Such a development would greatly reduce the size and influence of the market.

This section will introduce several delay examples of each type.

123 https://ec.europa.eu/commission/presscorner/detail/en/IP_16_4021

124 The EU revised its Electricity Regulation to contain provisions on capacity market mechanism, including CO2 emissions limits for participating power plants. For more information, https://ec.europa.eu/energy/topics/markets-and-consumers/market-legislation/electricity-market-design_en

125 A MOPR establishes a price floor. Resources subject to this rule have to offer at or above this price floor, which is typically equal to the cost of new entry for the applicable asset class.

# A. Delays in New Markets

## United Kingdom: Compliance with State-Aid Rules

The UK capacity market, which was established in 2014, was suspended in 2018 after the General Court of the European Union ruled that the European Commission should have conducted an in-depth investigation into the market's design. The dispute over the UK's capacity market rules centered on the treatment of a particular resource. After the European Commission (EC) approved the UK's capacity market scheme to secure the country's electricity supply, the first auction took place in December 2014.[126] Tempus Energy, a demand-side response aggregator, complained that the market rules treated DR unfairly compared to other resources, such as thermal power resources. More specifically, multi-year contracts for supply capacity were available to other resources—for example, 15 years for new construction and 3 years for equipment renovation. However, only single year capacity contracts were available for DR and international interconnection; as a result, it did not ensure the most efficient and low-cost option for consumers.

On November 15, 2018, the General Court of the European Union issued a judgment that would halt the operations of the UK capacity market. The Court did not rule on issues related to state aid rule. Rather, it was of the opinion that the EC should have opened an in-depth investigation to gather more information on certain elements of the scheme (i.e., demand response). The Court found that the EC could not have adequately scrutinized the scheme as required, because of the short time period in which it approved the scheme.

The effects of the Court's ruling were immediate. The British Government discontinued the T *minus* 4 (i.e., the market looking four years ahead, supply year: 2022/2023) and T *minus* 1 (i.e., the market looking at the year ahead, supply year: 2019/2020) auctions scheduled for January-February 2019. The UK further halted payments for existing/ongoing capacity contracts. Afterwards, in the period of December 2018 through January 2019, the British government reviewed the definition of the one year-period suspension and clarified that only financial transactions with the contractor (such as payment of compensation and execution of penalties) would be subject to suspension.

In response to the ruling, the EC initiated a review in February 2019. Subsequently, the EC did not find that DR provider are at a disadvantage when it comes to participation in the capacity market, and allowed the UK capacity market to resume operation in October, 2019. At the same time, the UK committed to reviewing the neutrality of the system and improving its market rules, including:

- The lowering of the minimum capacity threshold for participating in the auctions;

[126] https://ec.europa.eu/competition/state_aid/cases1/201945/278880_2105752_352_2.pdf

- The direct participation of foreign capacity;
- The participation rules for new types of capacity;
- The access to long-term contracts;
- The volume in the year-ahead auction; and
- The compliance with the new Electricity Regulation.

The British government decided to hold the capacity auction during the suspension period, and promised to pay the market participants as soon as possible once EC approved the resumption. Regulators set the T *minus* 1 auction to be held in June 2019, and a T *minus* 3 auction between January to March 2020 in place of the T *minus* 4 auction. The T minus 1 auction was eventually held on February 7, 2020, with 1.02 GW capacity cleared (out of 3.03 GW entered) at £1.00/kW/year clearing price.[127] The T *minus* 3 auction for delivery in 2022/2023 concluded on January 31, 2020, with 45.1 GW cleared (59 GW entered; target capacity of 44.9 GW) at £6.44/kW/year clearing price.[128]

## Ireland: Delays in Integration of Wholesale Electricity Market

Ireland performed a major overhaul of the Single Electricity Market (SEM)—the wholesale electricity market for the entire island—to make it consistent and more integrated with the target European Union (EU) model for electricity markets. The project, known as Integrated SEM (I-SEM) was led by the energy regulators in Ireland (Commission for Energy Regulation) and Northern Ireland (Utility Regulator) with support from electricity system operators.

The anticipated completion date of this integration was October 2017. However, after a "stocktake exercise," the regulators delayed the start date to May 2018 due to delivery risks.[129] Specifically, there were concerns related to:

- Capacity auction timeline: at the time, Ireland was still waiting the EC to approve that the proposed market would not violate state aid rules.

[127] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Final%20Results%20T-1%20Auction%20DY20-21.pdf.

[128] NationalgridESO, "Final Auction Report, 2019 three year ahead Capacity Auction (T-3), Delivery year 2022/23," 7 February 2020.

[129] https://www.semcommittee.com/sites/semcommittee.com/files/media-files/SEM-16-078a%20SEMC%20Stocktake%20Summary.pdf

- Testing and trial of market systems: whether the overall test program is sufficient in time and in scope to establish the completeness and robustness of the delivered solution.
- Market coupling: whether the agreements between various stakeholders in Great Britain, Northern Ireland, and Ireland can be completed by the deadline.
- Participant readiness: whether the participants will have completed the full program of system delivery, commercial and operational readiness activities to allow their participation to the extent necessary in I-SEM.

The I-SEM eventually went live in October 2018.[130]

The new market has specific provisions on how disputes would be resolved.[131] The Capacity Market Dispute Resolution Board (CMDRB) handles disputes related to both the qualification process as well as general disputes. The system operator nominates the board members, who are in turn approved by the regulators.[132] In its decision, the CMDRB may recommend (but not decide) that regulators cancel, postpone, delay, suspend, re-run or annul a capacity auction. If the disputing party does not agree with a CMDRB decision, it must provide a notice of dissatisfaction before initiating any Court proceedings. The regulators may instruct the system operator to delay, postpone, or cancel the capacity auction no later than five working days prior to the capacity auction submission commencement date. Regardless of what the regulators ultimately decide, the system operator is not liable to other parties.

## Italy: Last Minute Market Rule Amendments

The EC approved Italy's capacity market proposal in 2018, finding that the country's design complied with EU competition rules, and the first capacity auction was planned for 2019.[133] However, in March 2019, Italy sought approval for market rule amendments, which would enable the country to meet its energy and climate goals. For instance, under its 2019 integrated national energy and climate plan, the country aims to phase out coal-fired generation by 2025 and increase the share of renewable energy resources as part of the country's resource mix.[134]

130 https://www.semcommittee.com/news-centre/new-all-island-wholesale-electricity-market-goes-live

131 Ireland Single Market Electricity Operator, Capacity Market Code, https://www.sem-o.com/rules-and-modifications/capacity-market-modifications/market-rules/

132 In general, the system operator carries out undertakings that are consistent with their rights, powers, functions, obligations, and liabilities as authorized by the regulators.

133 https://ec.europa.eu/competition/state_aid/cases1/201932/279418_2088284_196_2.pdf

134 https://ec.europa.eu/energy/sites/ener/files/documents/it_final_necp_main_en.pdf

The new amendments would apply $CO_2$ emission limits to generation capacity that participates in Italy's capacity market. In particular, all new, upgraded, and existing capacity resources would have an emission limit of 550g of $CO_2$ per kWh of electricity.[135] An existing resource with higher emissions rates can still participate in the auction if it commits to emitting less than 350kg of $CO_2$ per installed kW equivalent for any given delivery year. Under the new rules, coal-fired power plants would be unable to participate in the auction.

The proposed changes were approved by the EC in June 2019, and the first auctions were held later that year.[136]

## Singapore: Deadline for Capacity Market Implementation Extended

Singapore's Energy Market Authority (EMA) is planning to introduce a Forward Capacity Market (FCM) to enhance the country's wholesale electricity market. The FCM would help maintain Singapore's reliability and maximize economic efficiency by providing long term signals and incentives to existing and new resources. The EMA laid out its plans in a June 2019 consultation paper.[137] According to the plan, the design and implementation stage would conclude by 2021, and the transitional 'interim' auctions would begin in 2020, for delivery in 2021 till 2025, as shown in Figure III-1 below. These interim auctions would have simplified design parameters. The detailed design and rules would be ready for the first 'end-state' auction the following year (in 2022), for delivery in 2026.

Since then, the EMA has updated the timeline to allow for more time to develop market rules and IT systems.[138] The EMA has shifted the timeline by six months, with the first end-state auction to take place in the second half of 2022, as shown in Figure III-2 below. It is important to note that all timelines are indicative, i.e., they are not codified in any way.

135 Ibid., p. 133

136 https://www.ashurst.com/en/news-and-insights/legal-updates/capacity-market-in-italy/

137 See Energy Market Authority, "Developing a Forward Capacity Market to Enhance the Singapore Wholesale Electricity Market," Consultation Paper, July 8, 2019.

138 See Energy Market Authority, "Developing a Forward Capacity Market to Enhance the Singapore Wholesale Electricity Market," Third Consultation Paper, May 28, 2020.

FIGURE III-1: SINGAPORE'S CAPACITY MARKET AUCTION TIMELINE (JUNE 2019)

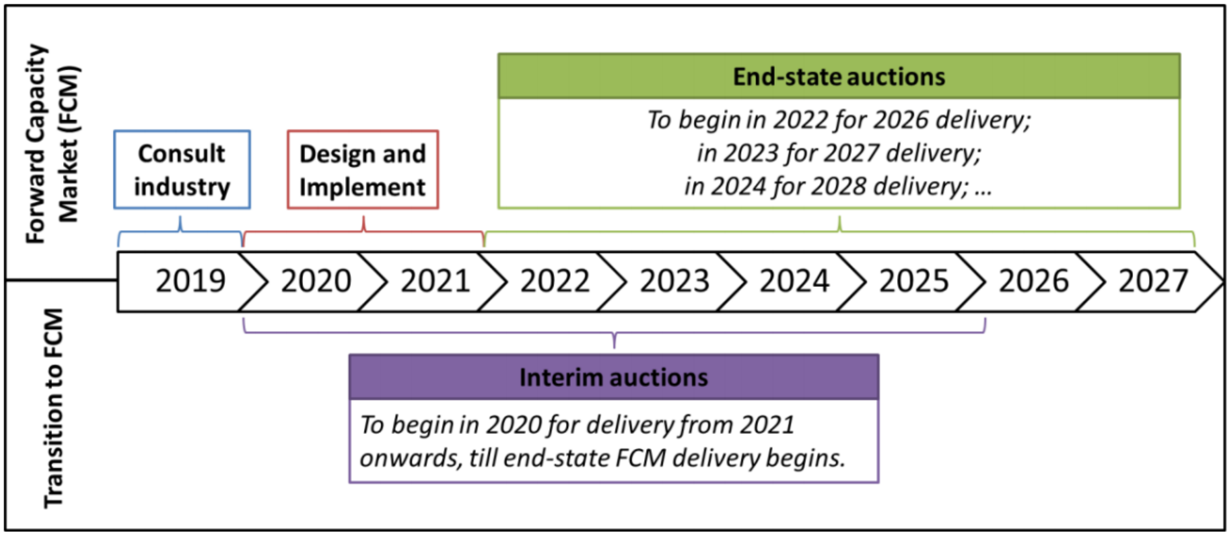
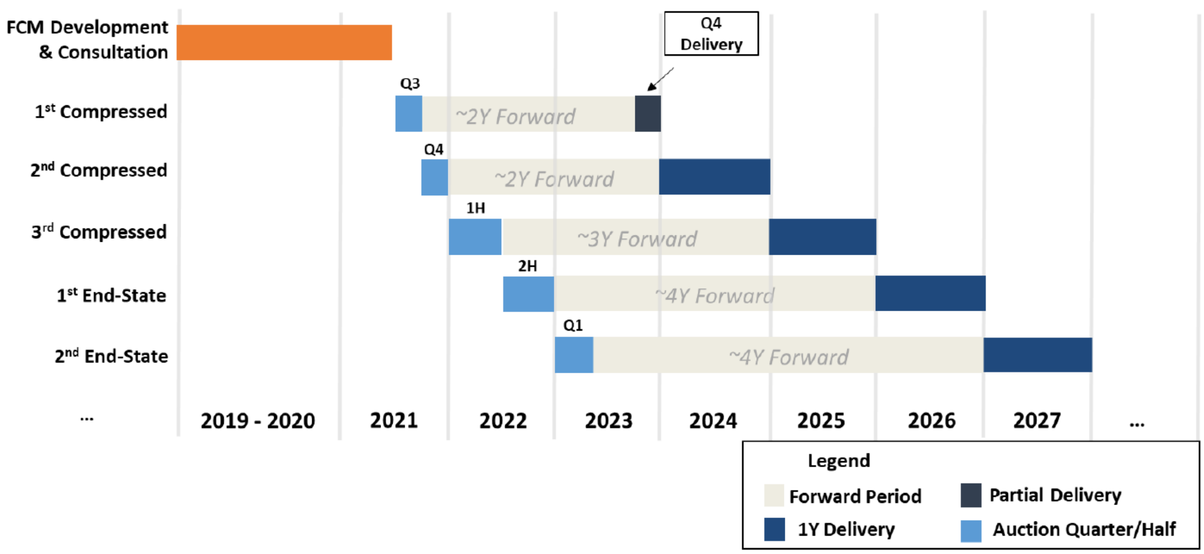



FIGURE III-2: UPDATED SINGAPORE'S CAPACITY MARKET AUCTION TIMELINE (JUNE 2020)




# B. Delays in Existing Markets

## ISO-NE: Offshore Wind Qualification Issues

Vineyard Wind, an offshore wind project in New England, has faced regulatory and permitting delays that affected its ability to participate in the ISO-NE's capacity auction. Under ISO-NE rules, the project did not qualify for the Renewable Technology Resource (RTR) status because it was located in federal waters. If qualified, the facility would be able to secure capacity obligations from power plants set to retire and bid into the auction at lower prices. Vineyard Wind petitioned FERC to waive the rule, and again to stay the ISO-NE's capacity auction. FERC did not address the request the first time, and declined the request the second time. Since then, ISO-NE has amended its rules to allow projects like Vineyard Wind to qualify for the RTR status.

To balance federal and state energy policies with competitive wholesale electricity market, ISO-NE coordinates the entry of new sponsored policy resources (SPRs) with the retirement of existing capacity resources (ECR) through the Competitive Auctions with Sponsored Policy Resources (CASPR). Approved by FERC in March 2018, CASPR was designed to limit the price-depressing effects that SPRs can have on the market.[139] Under the CASPR program, ISO-NE conducts the capacity auction into two stages. The first-stage auction is functionally similar to normal forward capacity market auction. A MOPR applies to participating resources, though certain renewable energy resources are qualified for exemption.[140]

Immediately after the primary auction, the system operator then conducts a second round of auction, also known as the substitution auction. Both ECRs that wish to retire and exit the markets permanently (such as a retiring coal plant) and SPRs participate in the substitution auction. ECRs enter the substitution auction on the demand side, and transfer their capacity supply obligations (CSO) acquired in the first auction to SPRs by paying them the (lower) clearing price.[141] In essence, the ECR receive the difference between the primary auction clearing price and the substitution clearing price. This design element provides ECR an incentive to retire and make room for policy resources to enter the market while limiting the effect of the latter on market prices.

In 2019 ISO-NE proposed amendments to its CASPR program to address a design issue. In the originally CASPR design, an ECR could intentionally suppress its bid price below its true break-even price in order to acquire a CSO in the primary auction. The ECR could then buy out of that obligation in the substitution auction at a lower price. In effect, the ECR could increase the likelihood that it would receive CSO payments to exit the market. To address this potential “bid shading” issue, ISO-NE proposed a new test price mechanism. First, the Internal Market Monitor would estimate the competitive price for each resource. If a resource is awarded a CSO in the primary auction, and the clearing price is less than

139 Accordingly to ISO-NE’s rules, Sponsored Policy Resources are resources that, among other things, “qualify to receive an out-of-market revenue source supported by a government cost-recovery mechanism; and conform to a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted either by statute or regulation in the New England state from which the resource receives the out-of-market revenue source; and elect to participate in the substitution auction during the show of interest submission window by the supply-election deadline. See https://www.iso-ne.com/participate/support/customer-readiness-outlook/caspr-project

140 Under the RTR exemption, up to 200 MW of renewable resources may enter the auction. Any unused portion of that 200 MW can carry forward for up to three years (two additional FCAs) for a possible maximum of 600 MW of exempt renewable resource capacity in any given FCA. The RTR exemption is being phased out in the next three years as the CASPR program is fully implemented.

141 The substitution auction clearing price cannot be higher than the primary auction clearing price.

ninety percent of the resource's test price, then the resource's demand bid will not be included in the substitution auction.[142] FERC approved the proposed changes in January 2019.

A major renewable energy project in New England was impacted by the market design improvement process. Vineyard Wind, an 800 MW offshore wind facility, has faced regulatory delays in qualifying for ISO-NE's capacity auction. Under established rules, the first major offshore wind project in the U.S. did not qualify for the RTR status because it is located in federal waters. ISO-NE limited RTR status to resources within the physical borders of a New England state. If qualified, Vineyard Wind would be able to secure capacity obligations from power plants set to retire, allowing the project to participate fully in the market and to bid into the auction at lower prices.[143]

Vineyard Wind asked FERC to waive the rule and allow the project to gain RTR status for the February 2019 auction. ISO-NE did not oppose the request. In January 2019, FERC issued an order approving many of the ISO-NE market changes, but did not address Vineyard Wind's request. In response to the order, Vineyard Wind filed an emergency request, asking the FERC to stay the grid operator's capacity auction. FERC ultimately declined the request.

Since then, ISO-NE has made changes to its tariff, allowing projects like Vineyard Wind to be eligible for the renewable technology exemption.

At the same time, Vineyard Wind faced some permitting delays. The U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM) published the initial draft of the environmental impact statement (EIS) in December 2018, and was expected to release the final EIS in August 2019. However, in the same month, BOEM decided withheld the final EIS in order to study the wider impacts of the offshore wind sector.[144] Recently, BOEM released a supplement to its initial EIS, stating that the scope for future offshore wind is greatly expanded from what was considered. A decision on the final permit for the project is expected by the end of the year.

## IESO: Challenges over Effects of Capacity Auction on Demand Response

Ontario's IESO planned to evolve its Demand Response Auction (DRA) to a Transition Capacity Auction (TCA) by amending its wholesale electricity market rules to generators that are not under contract or rate-regulated to participate. The first capacity auction was planned for December 2019 to secure resources for a delivery date three and a half years later.

142 https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf

143 https://www.utilitydive.com/news/ferc-passes-on-vineyard-wind-emergency-request-for-iso-ne-auction-delay/547712/

144 Without a favorable environmental assessment, the project would not be able to move forward.

The Association of Major Power Consumers of Ontario (AMPCO), representing large power consumers, filed an application to the Ontario Energy Board (OEB), arguing that the amendments would have an unjustly discriminatory effect to demand response providers. AMPCO asked the OEB to revoke the amendments.

In defending the proposed changes, the IESO argued that the amendments are not unjustly discriminatory because they treat DR and generation resources equally in the TCA—both types of resource receive the same availability payments. According to the IESO, there is no evidence that the current market design that treats generators and load participants differently in the energy market is defective or inequitable. Further, the IESO argued that DR had control to manage the probability or risk of activation by including economic activation costs in their energy market bids; and if they do this, the risk and associated cost of being activated is remote and immaterial.

In deliberating the case, the OEB stayed the TCA amendments for the December 2019 auction.[145] The regular DRA still occurred in that month.[146] The OEB issued its decision in January 2020, finding that the proposed changes did not unjustly discriminate against or in favor of a market participant or class of market participants. The OEB dismissed the demand response's complaint and lifted the stay of the amendments.[147]

In April 2020, the IESO announced that due to COVID-19 it would postpone the June 2020 capacity auction to the fourth quarter of 2020 (see Section IV - Impacts of COVID-19 on Capacity Markets).

## C. PJM Capacity Market Disputes

At the center of the ongoing disputes within PJM capacity market is the question of how to appropriately account for the market effects of state subsidies and mandates. On the one hand, incumbent fossil generators argue that PJM should establish a MOPR for resources (such as renewable and nuclear plants) that receive state contracts when bidding into the capacity market. Such a price floor would prevent these resources from offering at low prices and restore the capacity price to a higher level that would prevail in the absence of state clean energy policies.

145 OEB, "Decision and Order on Motion to Stay the Operations of the Amendments to the Market Rules," Issued November 25, 2019.

146 http://www.ieso.ca/en/Sector-Participants/IESO-News/2019/11/Changes-to-Capacity-Auction-Plans

147 The OEB's decision was largely based on a three-part test for what constitutes "unjust discrimination" as set out in the Electricity Act. The OEB found that "there is no question that different resources are treated differently, in the form of differences in eligibility for payments"; that "generation and DR Resources are functionally equivalent in balancing supply and demand in the energy market," so there are no relevant differences in their circumstances; and that there was no evidence on the costs incurred by DR resources that are activated, and "given the insufficiency of evidence, as described above, the OEB has no basis on which to make a positive finding of unjust discrimination and return the amendments to the IESO for reconsideration." See Ontario Energy Board, Decision and Order EB-2019-0242. January 23, 2020.

On the other hand, such a rule would increase the costs of achieving state policy objectives, increase total capacity market costs to customers (to the benefit of capacity sellers), and produce deadweight losses by increasing the total quantity of capacity to higher levels than what is needed to maintain resource adequacy. These disputes are being played out in both the regulatory and legal arenas, resulting in delays of the recent PJM capacity auctions. FERC recently ruled that the MOPR would encompass policy resources. In response, several states are exploring options to leave the PJM capacity market. As a result, there is significant uncertainty for the future of the PJM market.

## A Brief History of the Minimum Offer Price Rule

The MOPR, a product of a settlement between PJM and participants, aims to limit the market power of certain capacity sellers. Without a price floor, capacity sellers who are "net buyers" (such as load-serving entities), could offer capacity bids at prices below the competitive levels, suppressing the overall market prices and distorting the market signal to develop new generation. The MOPR establishes a price floor, requiring those resources to offer at or above the price floor, which is equal to the cost of new entry for the applicable asset class (by generator type and location).

Originally, the MOPR mostly focused on all new, non-exempted natural gas-fired resources.[148] The MOPR exempted nuclear, coal, integrated gasification combined cycle, and hydropower power plants, as well as planned resources that were being developed in response to a state regulatory or legislative mandate to resolve a project capacity shortfall. In subsequent reforms, the state mandate exemption was removed, and wind and solar generators were allowed to offer in the capacity market's BRA at a price of zero. Further, PJM and its independent market monitor were allowed to review and approve unit-specific cost justifications for sell offers below the established price floor.

Out of concerns that the unit-specific review process lacked sufficient transparency and efficacy in the face of ongoing state-supported development of new generation projects, PJM and a group of stakeholders proposed reforms to the MOPR. Specifically, PJM would shift from unit-specific review to a set of categorical exemptions for competitive, unsubsidized entrants, and for utilities seeking to supply their own capacity needs. In 2013, FERC accepted the categorical exemptions but kept the unit-specific review process in place. However, FERC rejected another request advocated by a group of generators to extend the period that the MOPR applies, or the mitigation period, from one year to three year. That group petitioned the D.C. Circuit Court to review FERC's order. The Court ultimately ruled against FERC, vacating the order, and the MOPR reverted to the earlier version.

[148] Sonal Patel, "The Significance of FERC's Recent PJM MOPR Order Explained," Power, December 26, 2019.

## FERC Directed PJM to Expand MOPR to Cover State-Subsidized Resources

Since 2013, thousands of megawatts of state-supported resources have entered PJM, alarming independent power producers (IPPs). Arguing that that the existing MOPR was unjust and unreasonable due to state policies attracting some electric resources (such as through Zero Emission Credits or Renewable Energy Credits), a group of incumbent fossil generators filed a complaint with FERC in March 2016.

Around the same time, PJM filed two alternate proposals to revise its tariff to address the price-suppressing effects of out-of-market state support for certain resources. The first proposal introduced a two-stage annual auction in which capacity commitments would be auctioned in the first round. PJM would then estimate a competitive price level by removing offers from policy resources in the second round. The second proposal, "MOPR Ex", would expand the existing MOPR to apply to any policy resource that receives state support while extending the geographic reach of the MOPR to apply to external capacity resources as well.[149]

In its June 2018 order, FERC sided with IPPs, finding PJM's existing tariff was not fair because state policies improperly distorted market prices.[150] FERC also rejected both of PJM's proposals, finding that the design was unjust and unreasonable.

In October 2018, PJM responded with two new approaches designed to recognize a state's authority to shape the makeup of its generation fleet. In both proposals, PJM would remove state policy resources from the capacity market and establish a strict price floor to resources that remain. PJM would then allow the blocked resources to enter the Resource Carve-Out (RCO) and obtain a capacity commitment without having to bid in the capacity auction. In the second option, known as the "extended RCO," PJM would take a step further and re-calculate capacity prices once subsidized resources are removed from the supply stack. This formulation would mitigate the price-suppressive effects of RCA resources that would be granted capacity commitments without a bid.

FERC again rejected PJM's proposals in its December 2019 order.[151] Instead, FERC required the MOPR to apply to nearly all new and existing state policy resources, inside and outside PJM's footprint regardless

[149] https://www.utilitydive.com/news/pjm-board-sends-competing-capacity-market-reforms-to-ferc/517318/

[150] https://www.utilitydive.com/news/pjm-recasts-capacity-repricing-in-market-reform-filing-at-ferc/538752/

[151] https://www.pjm.com/-/media/documents/ferc/orders/2019/20191219-el16-46-000-el18-178-000.ashx

of size (a construct that is essentially the same as the previously-rejected MOPR Ex). In addition, FERC widened the definition "state subsidy" to include:

"A direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge,[152] or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction." [153]

Exemptions to the rule essentially include all existing capacity resources receiving revenues from state-subsidies. Only nuclear power plants receiving ZECs or similar state-mandated revenues are subject to the MOPR. Additionally, FERC also requires PJM to retain the unit-specific exemption process.

In April 2020 FERC largely upheld its decision and offered some clarifications.[154] For instance, the MOPR will not apply to resources procured through voluntary Renewable Energy Credits supplied by private companies, or resources deployed as a result of the regional greenhouse gas cap-and-trade program. FERC also indicated that it will grant certain narrow requests for rehearing.

## Capacity Auction Delays and MOPR's Impacts on Renewable Energy Resources

Leading up to its December 2019 Order, FERC directed PJM to halt all BRA activities for the 2022/2023 and 2023/2024 Delivery Years. PJM complied and suspended all auction activities and deadlines for these Delivery Years while waiting for the capacity market order.[155] Significant uncertainty remains for the 2020 auction as states are contemplating to exit the PJM market (see sections following.)

If implemented as is, the December 2019 FERC order would have significant detrimental effect on new renewable energy resources that participate in state policy programs. These resources would have to

[152] A non-bypassable consumer charge refers to a component of the total electricity bill that customer cannot avoid. In the context of MOPR, the non-bypassable consumer charge may be levied to offset the maintenance costs of a nuclear plant.

[153] https://pjm.com/directory/etariff/FercDockets/4443/20200318-er18-1314-003.pdf

[154] https://www.utilitydive.com/news/just-plain-garbage-fercs-glick-says-as-commission-largely-upholds-its-p/576212/

[155] https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-pjm-message-regarding-suspension-of-rpm-base-residual-auction-activities-and-deadlines-until-further-notice.ashx?la=en

offer at a floor price equal to the Net CONE. In earlier filings, PJM estimated floors of $2,489/MW-day for onshore wind; $4,327/MW-day for offshore wind; and $387/MW-day for solar (which exceed the capacity auction price cap, thus making it impossible for the resources to clear).[156] For comparison, recent capacity market clearing prices range from $80/MW-day to $220/MW-day. While, existing renewable projects are exempted from the MOPR, the mandatory price floors mean that there is significant risk that new wind and solar capacity face. A renewable energy developer estimates that not clearing the capacity market translates to 10-20 percent price increase for wind power purchase agreement (PPA), and 15-25 percent for solar.[157]

## PJM's Capacity Market Future is Uncertain as States Explore Alternatives

FERC's MOPR decisions and ensuing events have created significant uncertainty in the PJM market. Immediately after FERC's April 2020 decision, New Jersey and Maryland launched a legal challenge against the Order and filed a petition for review with the D.C. Circuit Court of Appeals.[158] At the same time, states are exploring whether to opt out of PJM's capacity market through what would be a dramatic expansion of an existing mechanism called the Fixed Resource Requirement (FRR).

Through the FRR program, utilities would remain part of the larger energy market, but they could choose to supply their own capacity needs through bilateral contracts.[159] Utilities would plan to procure enough capacity to meet the current and forecasted peak demand for power for all customers within the designated zone, which is either as the utility's service territory or a certain geographic area in which the FRR entity has the obligation serve. The American Electric Power Company, a vertically integrated company, created the first FRR service area, receiving payment for generation capacity based on a cost of service model that Ohio regulators approve. In practice, utilities within PJM have seldom pursued this option because exiting PJM and creating an FRR program require complex legislation, administrative rulemaking, or both.

Illinois has indicated its interest in such an FRR solution, and the construct is under serious consideration in Maryland and New Jersey.[160] However, exiting the PJM capacity market and establishing an FRR

156 These are UCAP values.

157 https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/010820-pjm-capacity-market-auction-could-be-delayed-another-year-uncertainty-persists

158 https://www.nj.gov/oag/newsreleases20/Merged-MOPR-Petition-for-Review-4.27.2020.pdf

159 https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/frr-lse-capacity-rates.aspx

160 https://www.utilitydive.com/news/pjm-retail-suppliers-scrambling-to-appease-mopr-concerns-amid-state-threat/578251/

framework require substantial time and preparation. Illinois, for example, has been exploring this option for over a year, but recently legislative priority has shifted to COVID-19 activities.

At the same time, stakeholders are still assessing the costs and benefits of leaving the PJM capacity market. For example, Monitoring Analytics, PJM's independent market monitor, indicated in a series of reports that ratepayers would experience a significant increase in charges under an FRR framework. For example, Monitoring Analytics found that, relative to the 2021/2022 BRA, the FRR could result in $54-$207 million increase in costs for Maryland,[161] $414 million for Commonwealth Edison's northern Illinois territory,[162] and $32-$386 million for New Jersey.[163] Opponents of the MOPR argue that these analyses fail to include the cost of the MOPR itself, which could cost PJM customers $1-$2.6 billion annually.[164] More recently, Public Service Enterprise Group and Exelon Corporation urged New Jersey exit PJM and set up its own FRR program, asserting that the MOPR would actually cost New Jersey ratepayers up to $400 million annually by 2030.[165] Competitive power suppliers are advocating to create a competitive auction similar to New England ISO's Competitive Auctions with Sponsored Policy Resources, though such an option has its own limitations. Independent power producers competing in PJM are generally opposed to such a substantial shift away from market procurement of capacity.[166] Over-emphasis of the FRR in PJM's capacity market construct could potentially render it a "purely residual capacity market" like that found in MISO, where vertically integrated utilities still dominate ownership of generation.

161 http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf

162 https://pjm.com/-/media/committees-groups/committees/mic/2020/20200205/20200205-item-06b2-potential-impacts-of-comed-frr-imm-report.ashx

163 http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf

164 https://gridprogress.files.wordpress.com/2020/05/a-moving-target-paper.pdf

165 https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/pseg-exelon-say-pjm-capacity-market-exit-could-save-new-jersey-400m-annually-59184776

166 https://www.utilitydive.com/news/states-say-ferc-overstepped-its-bounds-in-pjm-capacity-market-order/528994/

# IV. Impacts of COVID-19 on Capacity Markets

In this last section, we discuss COVID-19's impact on the energy industry, and the implications for capacity markets. The most tangible impacts to date have been on energy markets and the day-to-day operations of the electric system. So far, the impacts to the capacity market are limited but to the extent that the pandemic or the economic impacts persist, it could have longer-term impacts on capacity markets.

## A. Economic and Capital Market Impacts

The U.S. economy has been hit particularly hard by the global COVID-19 pandemic. Much of the economy was shut down starting in mid-March, which resulted in a record rise in unemployment. According to Government statistics, over 40 million people have filed for initial unemployment as of the end of June.[167] The U.S. GDP decreased by an annualized rate of 5.0% in the first quarter,[168] which caused the economy to officially enter a recession on June 8, 2020.[169] As of July 2020, the U.S. Congressional Budget Office (CBO) estimates that 2020 real GDP is expected to decline by 5.8% with an average unemployment rate of approximately 10.6%.[170] CBO expects real GDP to recover by 4.0% in 2021, but unemployment is not expected to recover to pre-pandemic levels until at least 2030.[171]

[167] U.S. Department of Labor, "Unemployment Insurance Weekly Claims," June 25, 2020, accessed June 29, 2020, https://www.dol.gov/ui/data.pdf.

[168] U.S. Bureau of Economic Analysis, "Gross Domestic Product, 1st Quarter 2020 (Third Estimate); Corporate Profits, 1st Quarter 2020 (Revised Estimate)," June 25, 2020, accessed June 29, 2020, https://www.bea.gov/news/2020/gross-domestic-product-1st-quarter-2020-third-estimate-corporate-profits-1st-quarter-2020.

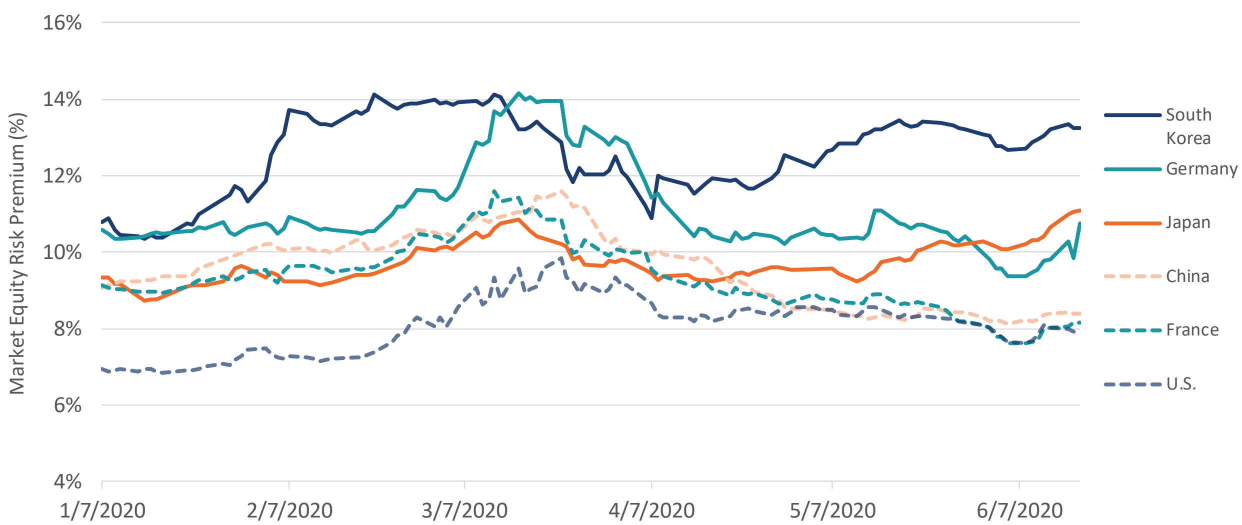
[169] Business Cycle Dating Committee of The National Bureau of Economic Research, "Determination of the February 2020 Peak in U.S. Economic Activity," The National Bureau of Economic Research, June 8, 2020, accessed June 29, 2020, https://www.nber.org/cycles/june2020.html.

[170] Congressional Budget Office, "An Update to the Economic Outlook: 2020-2030," July 2020, accessed July 5, 2020, https://www.cbo.gov/system/files/2020-07/56442-CBO-update-economic-outlook.pdf.

[171] Id.

At the same time, capital markets around the globe have experienced increased volatility and declining stock prices. Japan, and other Asian countries such as China and South Korea, have experienced moderate stock price decline (6.7% to 8.7%, respectively) from January 7 to June 15, 2020, whereas the stock markets of other hard-hit countries (e.g., France, Spain, and Italy) are down by 20%. The increased risk and uncertainty caused an increase in the premium required by investors to hold non-risk free assets in many countries. This premium is called the market equity risk premium (MRP), and the peaks in MRP generally coincided with the periods when these countries were hardest-hit by COVID-19, as shown in Figure IV-1 below. South Korea and Japan saw the largest MRP increase of 2.6% and 1.7% relative to pre-pandemic levels, respectively. China, France, and Germany saw MRP recent declines to, or slightly below, pre-pandemic levels after increasing by 1.4% to 2.3% during the height of the pandemic—most likely due to strict lockdown measures, government policy responses, and the composition of economic activity within each country. At the same time, 10-year government bond yields decreased by 0.1% to 0.6% in most countries. The U.S. and Canada saw the highest yield declines of 1.1% (from about 1.9% to 0.8%), likely due to flight to quality and quantitative easing measures. COVID-19's cumulative impacts on global capital markets suggest that the cost of equity for utilities could be elevated.[172] This effect is likely to persist if the economy recovery is slow and utilities continue to allow delayed customer payments. This will also likely impact financing for major capital expenditure programs.

**FIGURE IV-1: MARKET EQUITY RISK PREMIUM**




Source: Bloomberg as of June 15, 2020.

[172] Bente Villadsen, Robert Mudge, Frank Graves, et al., "Global Impacts and Implications of COVID-19 on Utility Finance," The Brattle Group, June 30, 2020, https://www.brattle.com/news-and-knowledge/news/brattle-economists-release-international-assessment-on-covid-19-impacts-on-utility-finance.

## B. Electricity Demand Market Impacts

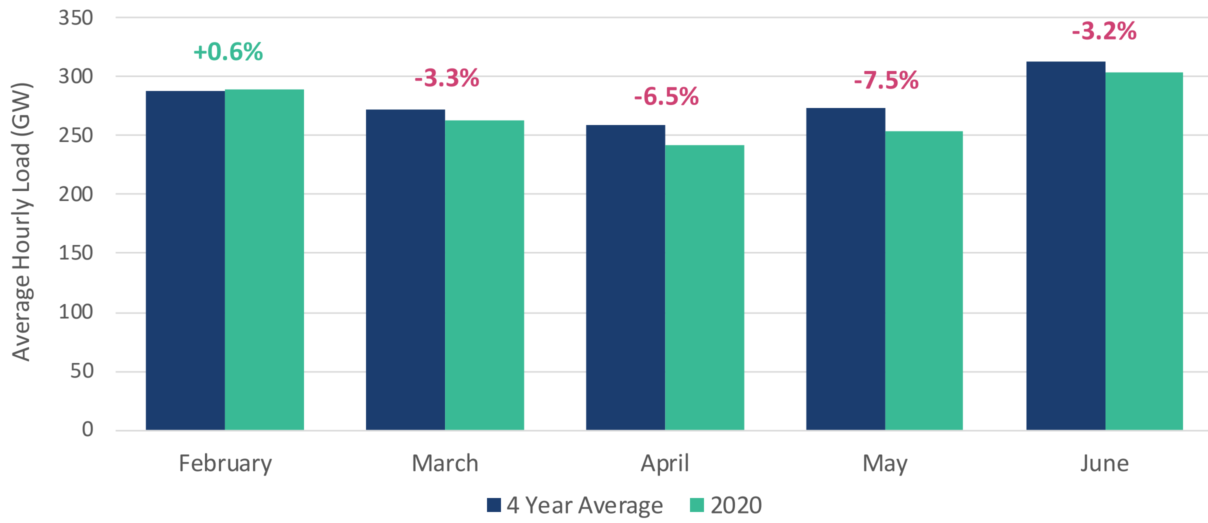
Since the start of the pandemic, there has been load reduction across major ISOs in the U.S., reaching as high as 7.5% in May; this is measured as the difference between the load weighted 2020 load average and the 2016-2019 average load, without incorporating weather normalization. Figure IV-2 below compares the reduction among system operators. As Figure IV-2 shows reduction varies across ISOs, with most ISOs experiencing a decline in load, while ERCOT has experienced an increase in load compared to historical averages in March through June.[173] In June, on average, there has been less load reduction compared to May, as social distancing protocols relax and cooling load picks up across the country. According to the World Economic Forum, energy usage hit a 16-year low during the week of April 4, 2020.[174] According to the U.S. Energy Information Administration (EIA), total U.S. electricity load declined by 4% in April 2020 compared to April 2019; residential load increased by 8% during April, while commercial load decreased by 11% and industrial load by 9% across the U.S.[175]

173 Note, ERCOT has reported load loss compared to previous forecasts. The measured increase in load, compared to the past 4 year averages, is likely due to a growth in service territory.

174 Scott Disavino, "COVID-19: America hasn't used this little energy in 16 years," World Economic Forum, April 14, 2020, Accessed April 28, 2020, https://www.weforum.org/agenda/2020/04/united-states-eneregy-electricity-power-coronavirus-covid19/.

175 "Stay-at-home orders led to less commercial and industrial electricity use in April," U.S. Energy Information Administration, June 30, 2020. Accessed July 1, 2020, https://www.eia.gov/todayinenergy/detail.php?id=44276&src=email.

**FIGURE IV-2: ISO-LEVEL LOAD REDUCTION**




Note: ISOs include NYISO, ISO-NE, PJM, SPP, ERCOT, MISO, CAISO.

Some of the largest and earliest COVID-19 outbreaks occurred in the Northeastern U.S.; consequently, in mid-March, major East Coast population centers issued stay-at-home orders. Unsurprisingly, ISO-NE, NYISO, and PJM experienced the largest load reduction impacts. In ISO-NE, weekly average hourly loads have decreased by as much as 11% compared to historical 4 year averages, as shown in Figure IV-3 below. However, in the last week of June, as warmer than normal temperatures hit the Northeast, both NYISO and ISO-NE saw average hourly loads rise above the historical average. In NYISO, state-wide weekly energy demand has been down ~8% since March 22 (weather normalized).[176] In March through May, NYISO saw an approximately 10% decline in weekly average hourly load compared to the 4 year historic average, as shown in Figure IV-4 below. Zone J (New York City) has seen the largest decrease with demand down ~14% since end of March. Load reduction during morning ramping period is most pronounced in Zones J and K (New York City and Long Island)—as high as 20% during the 7 to 9AM ramping period. NYISO reports overall energy use was 4-6% below expected demand in the second week of June.

[176] NYISO, "Estimated Impacts of COVID-19 on NYISO Load," June 23, 2020, accessed June 30, 2020.

**FIGURE IV-3: ISO-NE WEEKLY AVERAGE HOURLY LOAD: MARCH – JUNE**

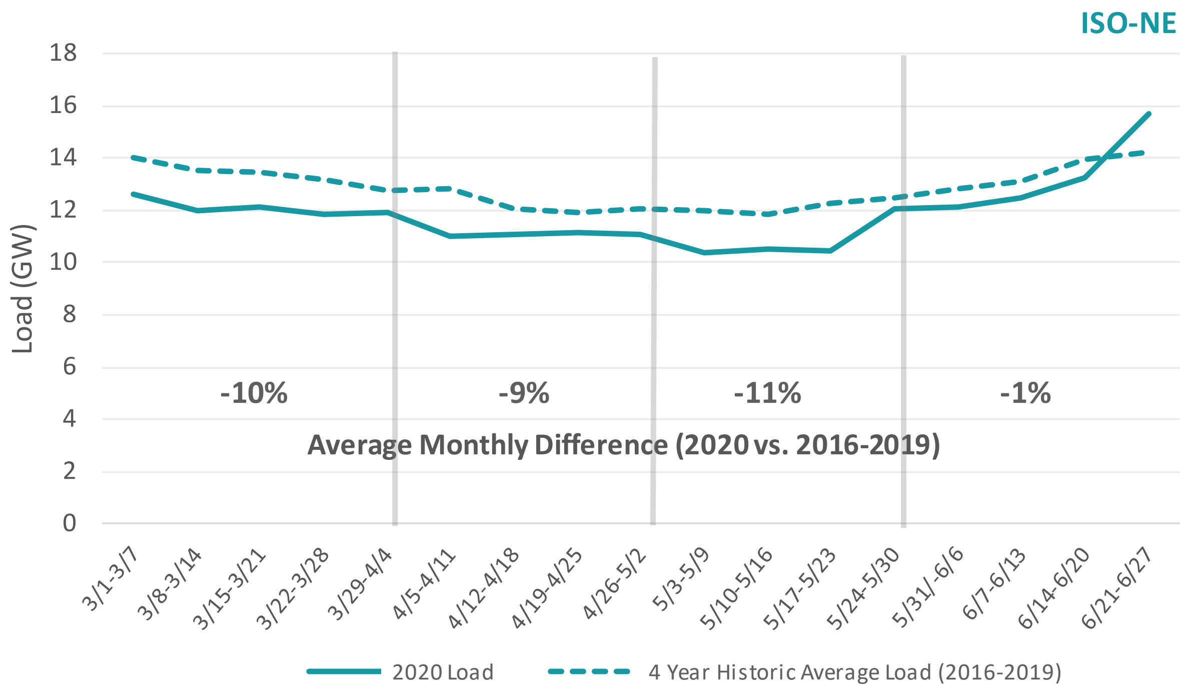
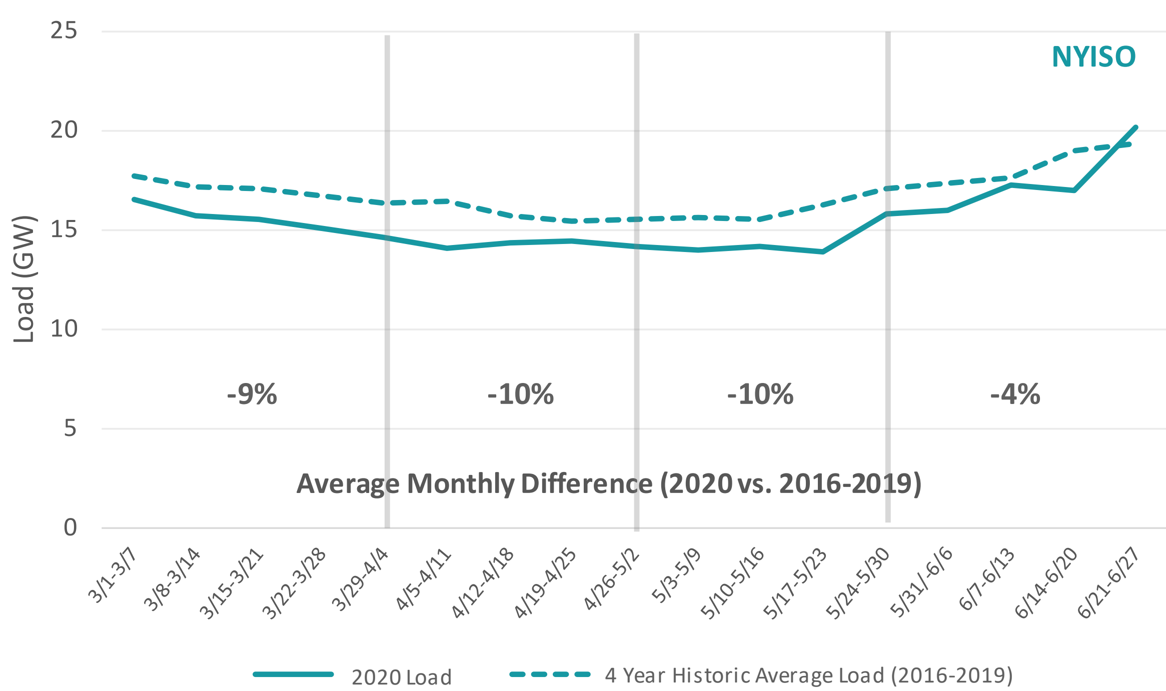
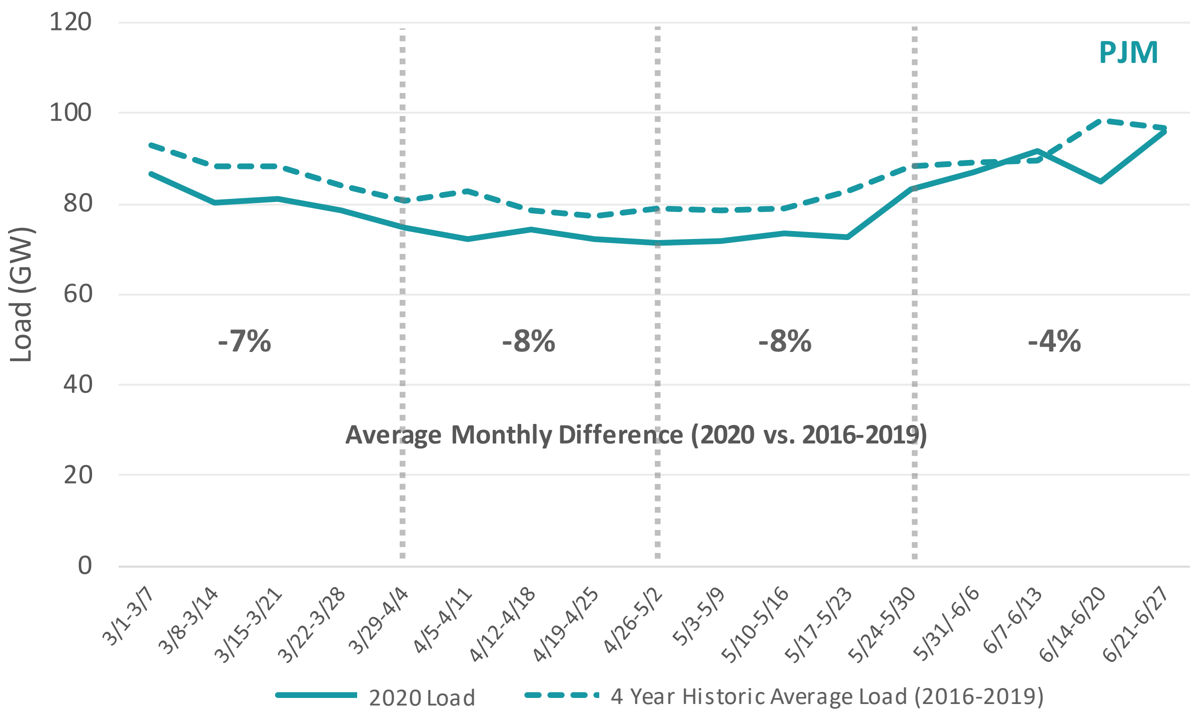



**FIGURE IV-4: NYISO WEEKLY AVERAGE HOURLY LOAD: MARCH–JUNE**




In PJM, weekly average load declined by 4-8% compared to the prior 4 year average, as shown in Figure IV-5 below. PJM estimates that, because of COVID-19, daily peaks were down by as much as 13%, and total energy use was down by as much as 16% (both occurring in early May).[177] PJM also reports that weekdays continue to be impacted more than weekends for both peaks and energy.

FIGURE IV-5: PJM WEEKLY AVERAGE HOURLY LOAD: MARCH - JUNE



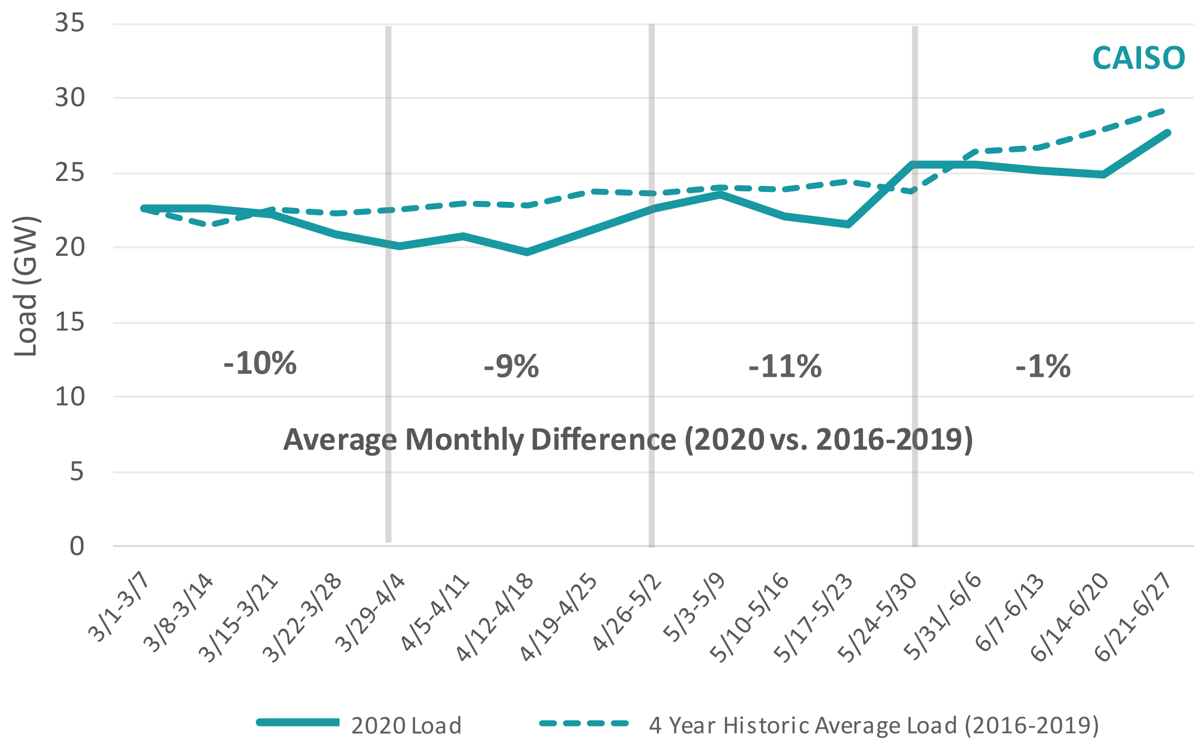

On the West Coast of the U.S., California was also hit particularly hard early in the pandemic, and issued a stay at home order on March 19, 2020.[178] CAISO saw 3 to 10% load declines, similar to those on the East Coast as shown in Figure IV-6 below. Loads were 8% higher than the historical average in the last week of May, but averaged a 3% load reduction over the full month. CAISO reports that weekday load reduced by 3.3% to 6.1%, weekend load reduction by 1.2% to 2.4%.[179] Energy prices lowered on average by about $10/MWh in the real-time and day-ahead markets.

[177] PJM, "Estimated Impact of COVID-19 on Daily Peak and Energy," June 21, 2020, accessed June 30, 2020, https://pjm.com/-/media/committees-groups/pandemic/postings/estimated-impact-covid-19-daily-peak-and-energy.ashx?la=en.

[178] Office of the Governor, "Executive Order N-33-20," State of California, March 19, 2020, accessed June 29, 2020, https://www.gov.ca.gov/wp-content/uploads/2020/03/3.19.20-attested-EO-N-33-20-COVID-19-HEALTH-ORDER.pdf.

[179] CAISO, "COVID-19 Impacts to California ISO Load & Markets: March 17-July 5, 2020," July 10, 2020, accessed July 14, 2020, http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf.

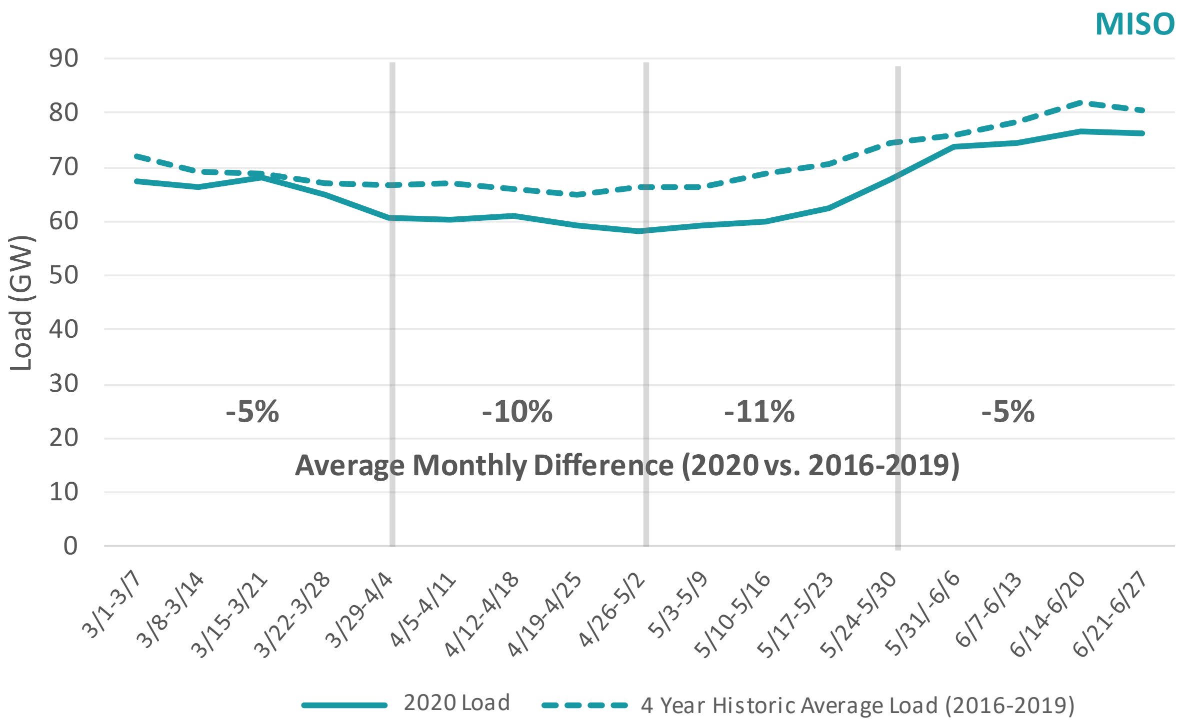
**FIGURE IV-6: CAISO WEEKLY AVERAGE HOURLY LOAD: MARCH–JUNE**




In MISO, weekly average hourly loads have decreased by up to 11% in May, as shown in Figure IV-7 below. However, energy and load have recovered in June, with MISO reporting a June average deviation from their load forecast of 5.1%, less than half of the deviation estimated in May.[180] MISO also reports that morning peaks shifted to later in the day, but afternoon energy use is in line with normal.

[180] MISO, "COVID-19 Impact to Load & Outage Coordination," June 22, 2020, accessed June 30, 2020, https://cdn.misoenergy.org/COVID%2019%20Impacts%20to%20MISO%20Load%20and%20Outage_as%20of%20June20454548.pdf.

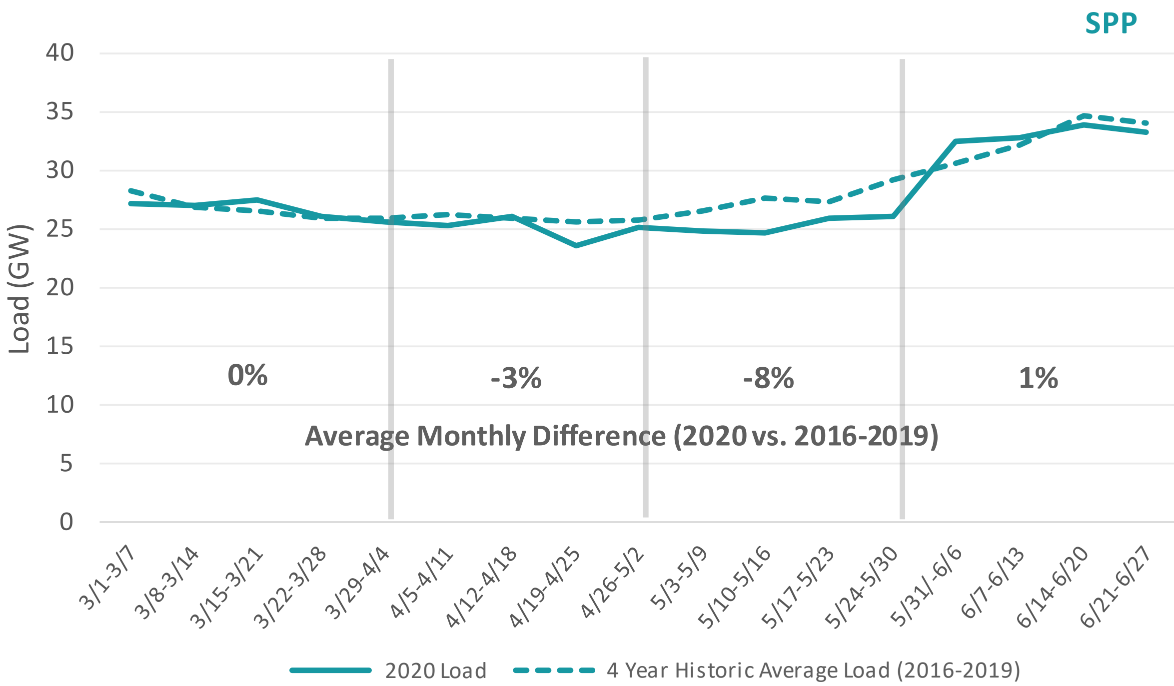
**FIGURE IV-7: MISO WEEKLY AVERAGE HOURLY LOAD: MARCH–JUNE**




The states in SPP were less impacted in the pandemic's early stages, relative to California and the Northeast. Several states in SPP did not issue stay-at-home orders, or only shut down for relatively short periods of time. It is not surprising that SPP saw some of the smallest impacts to weekly average hourly loads compared to other ISOs—an average deviation of 0% in March and reaching a high of 8% on average in May, as shown in Figure IV-8 below. SPP reports an increase in cancellation of planned generation and transmission outages.[181]

[181] SPP, "COVID-19," accessed June 30, 2020, https://spp.org/newsroom/covid-19/.

**FIGURE IV-8: SPP WEEKLY AVERAGE HOURLY LOAD: MARCH–JUNE**

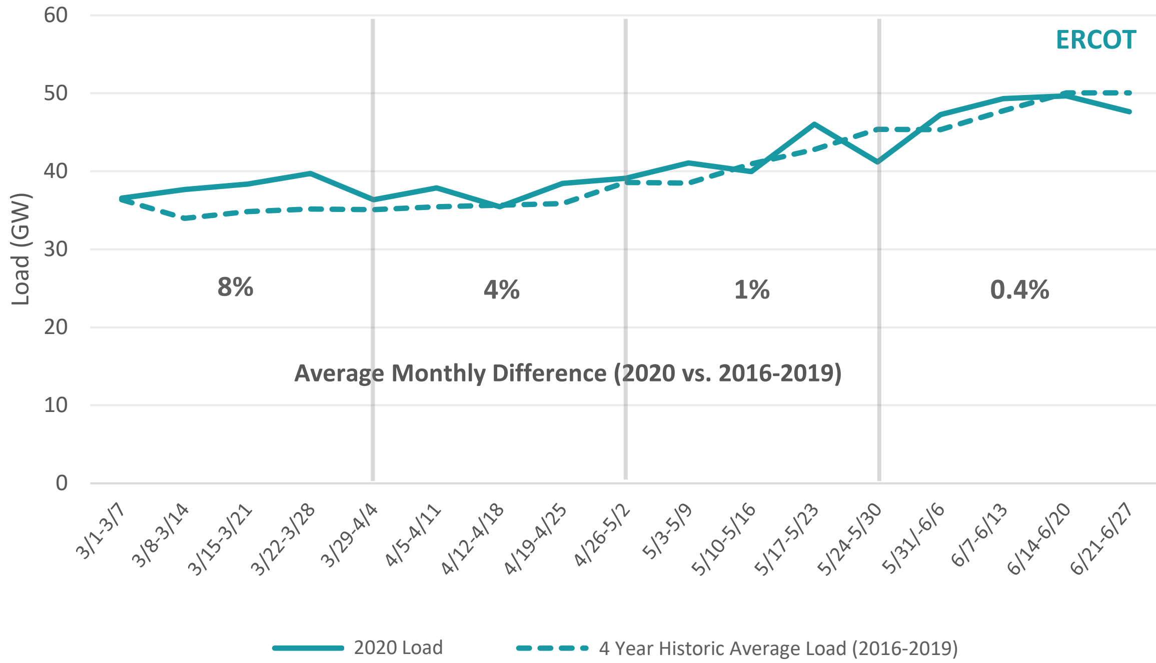



ERCOT is an outlier amongst the RTOs in that loads have been higher than historical averages due to demand growth, as shown in Figure IV-9 below. However, when accounting for COVID-19 impacts, ERCOT reports that weekly energy use and daily peaks were down 4-5% at the height of the pandemic impacts. However, with the rising summer temperature, ERCOT reports weekly energy use is 1% below normal at the end of June and there are now less COVID-19 impacts across all hours.[182] It is worth noting that Texas was slower to issue a statewide stay-at-home order (March 31) and the order was less restrictive than those in the Northeast.[183]

182 ERCOT, "COVID-19 Load Impact Analyses," June 23, 2020, accessed June 30, 2020, http://www.ercot.com/news/trendingtopics.

183 Office of the Texas Governor, "Governor Abbot Issues Executive Order Implementing Essential Services and Activities Protocols," The State of Texas, March 31, 2020, accessed June 29, 2020, https://gov.texas.gov/news/post/governor-abbott-issues-executive-order-implementing-essential-services-and-activities-protocols.

FIGURE IV-9: ERCOT WEEKLY AVERAGE HOURLY LOAD: MARCH–JUNE




# C. Fuel Market Impacts

Changes in the global economy and consumptions patterns have also substantially impacted commodity markets. Many countries have implemented various social distancing measures, including stay-at-home orders, and quarantining large portions of the population. This has led to unprecedented declines in demand for energy products within a relatively short period of time. With lingering uncertainty regarding the extent of the size and shape of the economic recovery, commodity prices remain under the pressure of this heightened risk. This subsection discusses COVID-19’s impacts on the oil, natural gas, and LNG commodity markets.

## Fuel Oil

Oil prices fell from around $66/barrel at the beginning of the year to as low as $20/barrel in late April: a 70% decline (see Figure IV-10 below). The most rapid declines started in early February as concerns about lower global demand, coupled with the failure of the Organization of the Petroleum Exporting Countries (OPEC) and associated oil producing nations (collectively called OPEC+) to reach an agreement on production cuts.[184] Concerns grew as oil storage levels across the globe began to increase and concerns were raised about running out of storage space. This led West Texas Intermediate (WTI) prices to drop to -$37/barrel on April 20, marking the first time WTI has ever settled at a negative price. WTI is an oil pricing point associated with Cushing, Oklahoma, where the largest U.S. non-governmental oil storage facility is located (approximately 13% of total U.S. oil storage capacity) and nearly two dozen oil pipelines converge.[185] Finally, OPEC+ agreed to a production cut of 9.7 million barrels per day (approximately 10% of global oil production), which began on May 1.[186] U.S. oil producers have also scaled back production, and several producers such as Whiting Petroleum and Chesapeake Energy have declared bankruptcy due to low oil prices and high debt levels.[187] Oil prices have risen moderately since the beginning of May and are currently around $40/barrel, but they remain approximately 40% below prices at the beginning of the year. Demand has increased as economies begin to reopen and OPEC+ agreed at the beginning of June to extend the 9.7 million barrels per day production cuts to July.[188]

[184] Current OPEC member countries are Algeria, Angola, Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, the Republic of Congo, Saudi Arabia, United Arab Emirates, and Venezuela. Associated oil producing nations include Russia, Azerbaijan, Bahrain, Brunei, Kazakhstan, Malaysia, Mexico, Oman, South Sudan, and Sudan. Collectively, the two groups together are referred to as OPEC+.

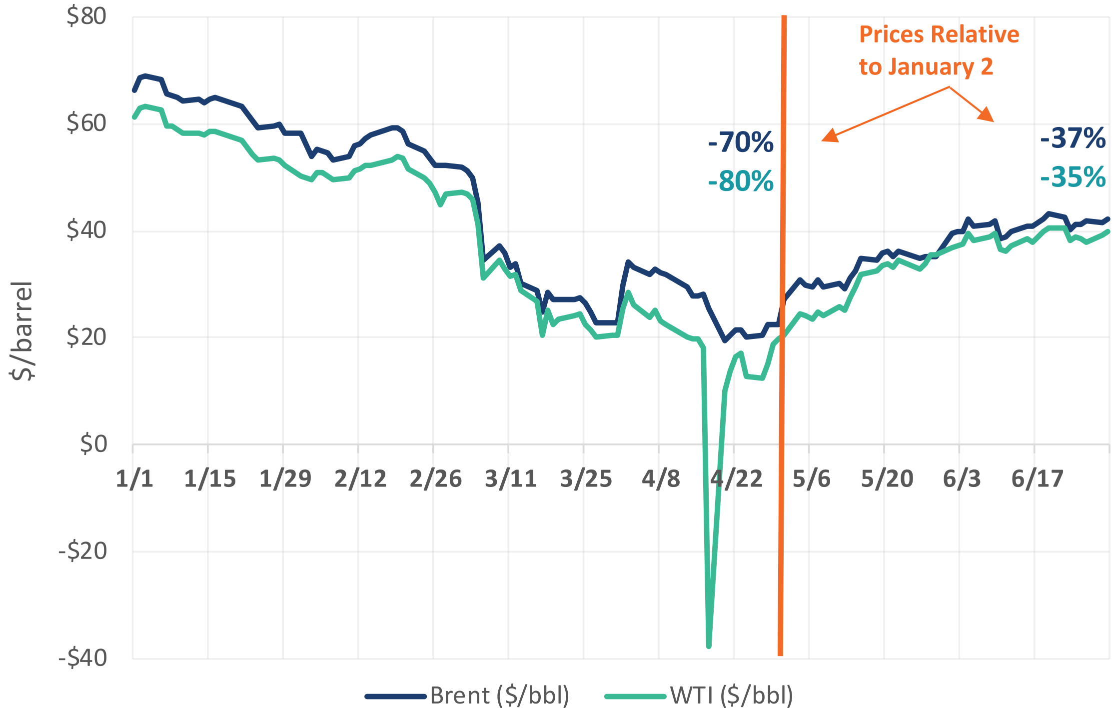
[185] CME Group, "The Importance of Cushing, Oklahoma," accessed July 10, 2020, https://www.cmegroup.com/education/lessons/the-importance-of-cushing-oklahoma.html.

[186] Alex Lawer, "OPEC April oil output surges to 13-month high before new cut deal," Reuters, April 30, 2020. Accessed May 1, 2020, https://www.reuters.com/article/oil-opec-survey/opec-april-oil-output-surges-to-13-month-high-before-new-cut-deal-idUSL8N2CI8JG?mod=article_inline.

[187] James Ludden, "Chesapeake Pushed Into Bankruptcy by Plunging Energy Prices," Bloomberg Law, June 29, 2020. Accessed June 29, 2020. https://news.bloomberglaw.com/bankruptcy-law/chesapeake-pushed-into-bankruptcy-by-plunging-energy-prices-1.

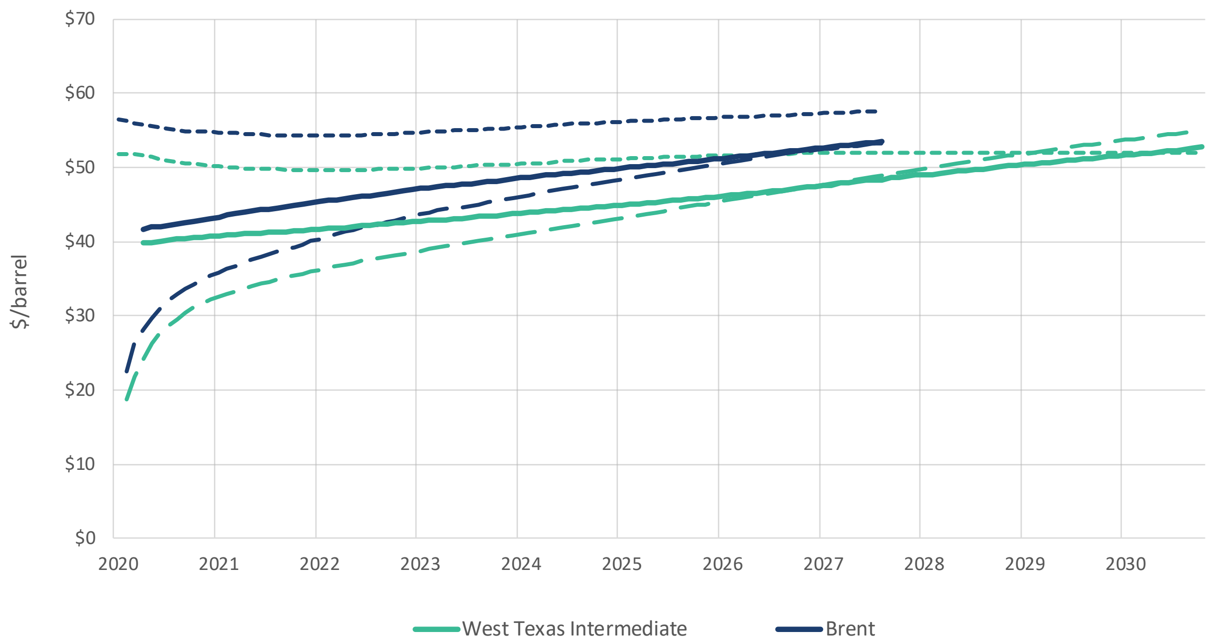
[188] Ahmad Ghaddar, Rania El Gamal, and Alex Lawler, "OPEC, Russia extend record oil cuts to end of July," Reuters, June 5, 2020. Accessed June 29, 2020. https://www.reuters.com/article/us-global-oil-russia-opec-graphics/opec-russia-extend-record-oil-cuts-to-end-of-july-idUSKBN23D007.

**FIGURE IV-10: OIL SPOT PRICES**




Oil futures were nearly flat across the curve on February 1, 2020 (~$55/barrel), but after COVID-19, the futures curve dropped about 20% on average by the end of April with near-term and medium-term contracts seeing the largest declines, as shown in Figure IV-11 below. At the time, futures did not show oil crossing $50/barrel until 2026 (Brent) and 2028 (WTI). As of the end of June, the futures curve for WTI and Brent has increased by 10% since the end of April, but still remains about 13% below the prices at the beginning of February. The current futures curve does not show futures crossing $50/barrel until 2025 (Brent) and 2028 (WTI). This indicates that the markets are still expecting a long-term economic impact, despite the beginnings of many countries' economic re-openings.

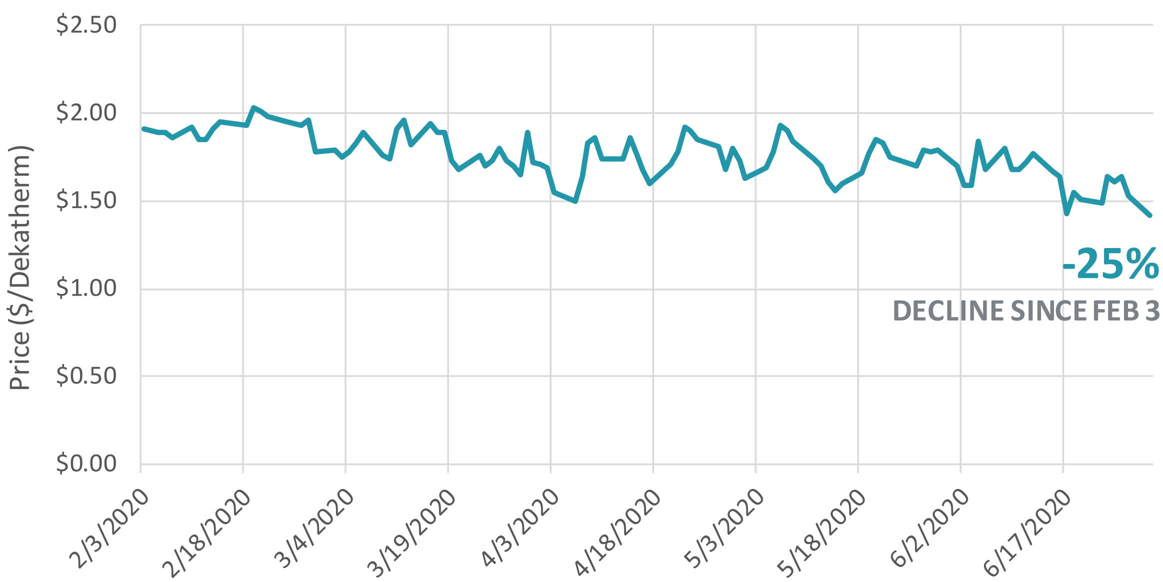
**FIGURE IV-11: OIL FUTURES**



# D. Natural Gas and Liquefied Natural Gas (LNG)

U.S. natural gas spot prices were not significantly impacted during COVID-19's March to May peak, because demand is low in these shoulder months for the natural gas markets regardless, as shown in Figure IV-12 below. Furthermore, COVID-19 coincided with the end of the winter heating season, when U.S. natural gas storage is at its lowest levels. This allowed U.S. natural gas storage facilities to keep supply and demand balanced by absorbing any excess supply in the market. As a result, most of the daily price movements appear to be more closely correlated with weather.

**FIGURE IV-12: HENRY HUB SPOT PRICES**

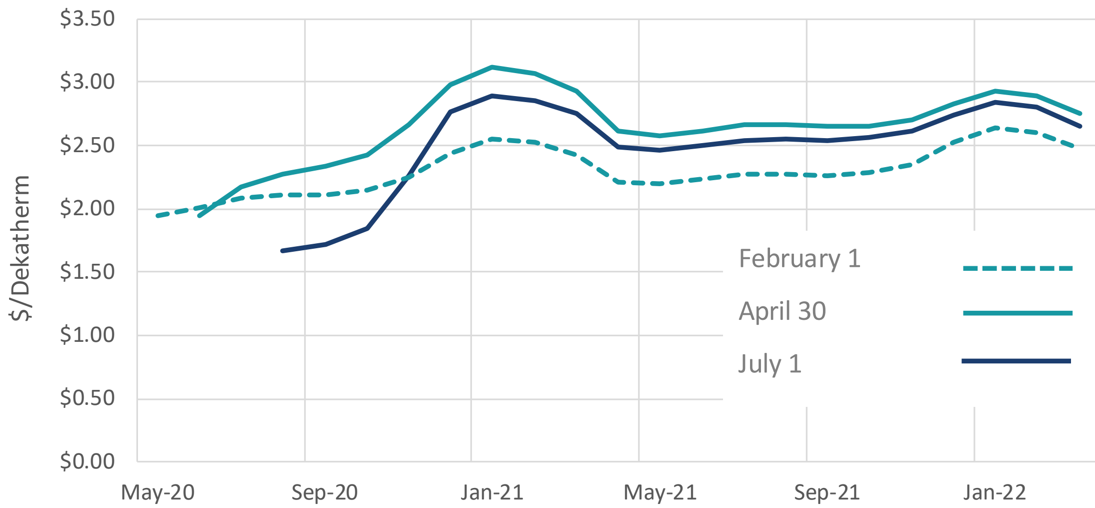



However, Henry Hub futures have generally increased since February due to impacts to the oil markets, as shown in Figure IV-13 below. As U.S. oil producers decreased production, associated natural gas production (a by-product of oil production) declined. This reduction in natural gas supply has led to higher Henry Hub futures starting in late 2020. As of the beginning of July, the futures has increased by approximately 6% on average since February 1 (from $2.34/dekatherm to $2.50/dekatherm)[189]. However, Summer 2020 prices have decreased by $0.44/dekatherm (21%) (from $2.12/dekatherm to $1.67/dekatherm) due to lower domestic and international demands for natural gas, including lower demand for power generation.

[189] 1 dekatherm (Dth) is 999,761 (or approximately one million) British Thermal Units (Btu).

Looking further out, starting in Winter 2020/2021, Henry Hub futures are approximately 10% higher than they were at the beginning of February. This is due to the markets expectation of a longer recovery for the oil markets (and associated gas production) and thus tighter natural gas supplies going forward. Associated gas production is not expected to return to 2019 volumes until 2023.[190]

**FIGURE IV-13: HENRY HUB FUTURES**




Near-term (August 2020 to October 2020), Henry Hub futures are on average 18% below February 1, 2020 levels (from $2.12/dekatherm to $1.74/dekatherm). This decrease is due to the lower U.S. LNG export volumes and high natural gas storage levels around the globe. EIA estimates a 25% utilization factor for U.S. LNG export facilities in July and August 2020.[191] Low natural gas demand in European has led natural gas storage facilities to be at 82% of total capacity currently (2,982 billion cubic feet [Bcf] vs. 3,682 Bcf), as shown in Figure IV-14 below.[192] Similarly, U.S. natural gas storage is currently 3 months ahead of the 5-year average and the EIA estimates an end-of-October storage level of 4,039 Bcf—the highest end of season storage level on record, as shown in Figure IV-15 below.[193] As a result, the combination of high storage levels and low demand is causing an over-supply situation in the U.S., which is putting downward pressure on near-term Henry Hub futures.

190 "Global Gas Production Set to Tumble in 2020," Yahoo! Finance, June 23, 2020, accessed June 29, 2020, https://finance.yahoo.com/news/global-gas-production-set-tumble-170000785.html.

191 U.S. Energy Information Administration, "Short-Term Energy Outlook," July 7, 2020. Accessed July 7, 2020, https://www.eia.gov/outlooks/steo/.

192 Gas Infrastructure Europe, "AGSI+ Aggregated Gas Storage Inventory," accessed July 7, 2020, https://agsi.gie.eu/#/.

193 U.S. Energy Information Administration, "Short-Term Energy Outlook," July 7, 2020. Accessed July 7, 2020, https://www.eia.gov/outlooks/steo/.

**FIGURE IV-14: EUROPEAN NATURAL GAS STORAGE LEVELS**

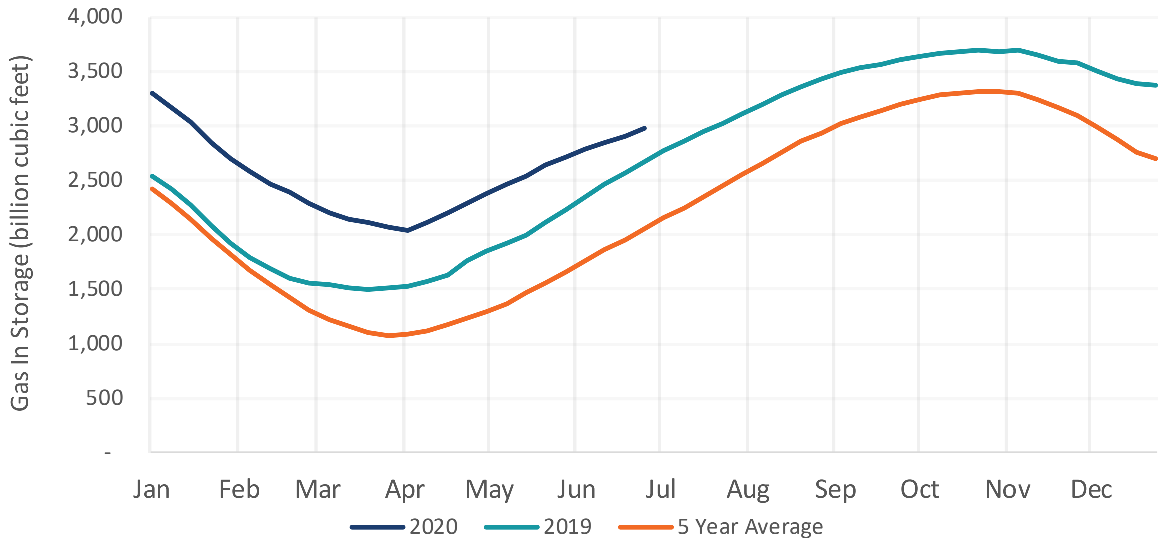
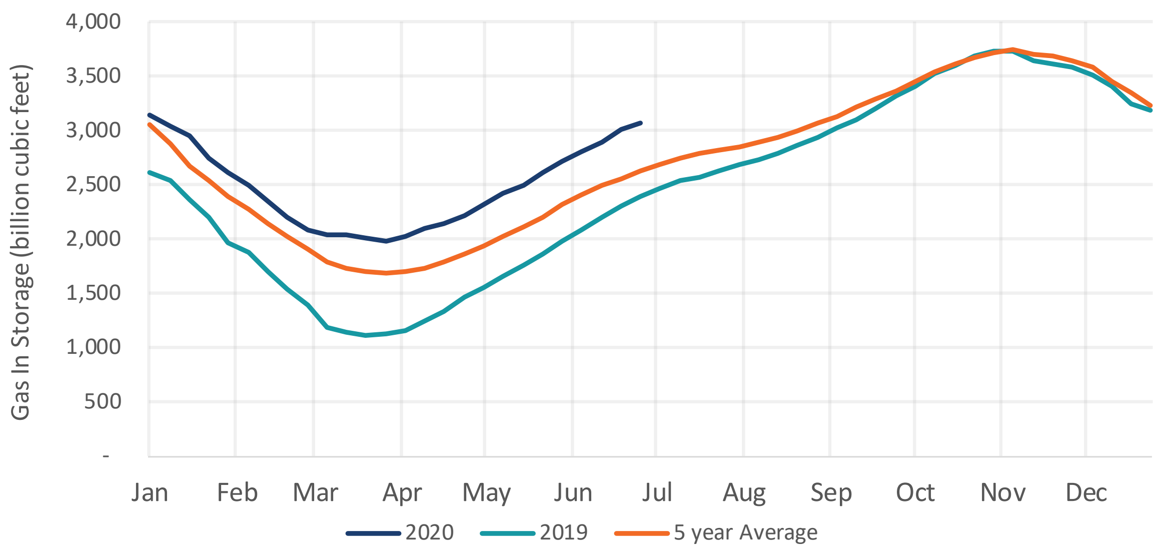


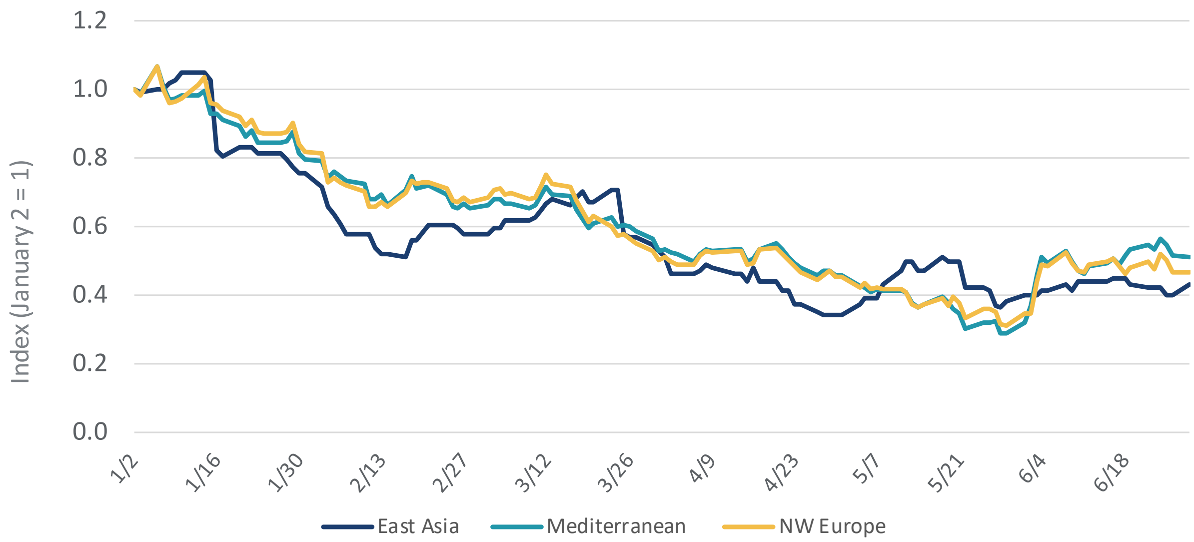

**FIGURE IV-15: U.S. NATURAL GAS STORAGE LEVELS**




With the drop in global demand for natural gas dropped, oversupply of natural gas has resulted in the fall of LNG prices in Asia (JKM, JCC), Mediterranean, and Northwest Europe (TTF) by approximately 50% since the beginning of the year, as shown in Figure IV-16 below.[194]

[194] Ekaterina Kravtsova, "Global LNG-Europe price slump drags down Asian LNG," Reuters, May 22, 2020, accessed June 26, 2020, https://www.reuters.com/article/global-lng/global-lng-european-price-slump-drags-down-asian-lng-idUSL8N2D44BP.

**FIGURE IV-16: LNG SPOT PRICES**[195]




Record low global gas prices created challenges for U.S. exporters as netbacks (e.g., gross profit per LNG cargo) to Asian and European became negative.[196] Utilization at Cheniere Energy's Sabine Pass—the largest US export terminal—reached a 16-month low.[197] It is estimated that U.S. LNG exporters saw 20 cargoes cancelled for June delivery, 45 cargoes for July, and 40 for August.[198] Several new U.S. LNG exporters have delayed either their final investment decisions or the start of new export terminal construction because of recent COVID-19 pricing pressures.[199]

195 ICIS Heren LNG Edge database. Accessed April 28, 2020.

196 Jamison Cocklin, "U.S. LNG Output Tested as Natural gas Prices Crater Worldwide," Natural Gas Intel, April 23, 2020. Accessed April 30, 2020, https://www.naturalgasintel.com/u-s-lng-output-tested-as-natural-gas-prices-crater-worldwide/.

197 Harry Weber, et. al., "US LNG feedgas drop may mean higher than reported June cargo cancellations," S&P Global Platts, June 15, 2020, accessed June 26, 2020, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/061520-us-lng-feedgas-drop-may-mean-higher-than-reported-june-cargo-cancellations.

198 Victoria Zaretskaya, "U.S. liquefied natural gas exports have declined by more than half so far in 2020," EIA, June 23, 2020, accessed June 26, 2020, https://www.eia.gov/todayinenergy/detail.php?id=44196.

199 Scott DiSavino and Arathy S. Nair, "Sempra delays big Texas LNG project as global energy demand slumps," Reuters, May 4, 2020. Accessed May 4, 2020, https://www.reuters.com/article/us-sempra-usa-results/sempra-delays-investment-decision-on-its-texas-lng-export-plant-to-2021-idUSKBN22G1IS.

In Asia, China has taken advantage of the low prices by increasing its LNG purchasing activity. Due to the resolution of recent trade disputes, China recently resumed the purchase of U.S. cargoes.[200] In May, Japan's LNG imports fell to an 11-year low of 4.5 million tons due to COVID-19's economic impacts. Japan's LNG import demand has also been declining due to the restart of nine of the country's nuclear reactors.[201,202] Japan has been the world's largest LNG importer for decades, but with China's growing demand, China is expected to overtake that distinction within the next 2-3 years.[203] In accordance with METI's 2030 vision, Japan will reduce LNG in its fuel mix from current levels of approximately 40% to 27% by 2030, while nuclear is expected to increase from 3% to 20-22% during the same period.[204]

# E. Energy Industry Impacts

Since the start of the pandemic, the global economy has faced substantial disruptions, with many countries choosing to shut down all non-essential activities during the pandemic's height. These disruptions also impacted the energy industry. For example, in the U.S. electric demand fell by up to 7.5% compared to normal across seven major RTOs. Certain fuel prices have fallen substantially (oil and LNG) due to oversupply and storage concerns. U.S. natural gas prices have increased slightly as a result of lower U.S. oil production. Lower demand has led U.S. electricity prices to fall by up to 30% compared to historical averages for this time of the year. If these trends persist, the capacity market will likely experience impacts (for example, energy ancillary services offsets applied to Net CONE could shrink, persistently lower demand could lower capacity market requirements, etc.).

## Electricity Pricing

Locational marginal prices have declined by 10-32% across the seven major RTOs in the U.S, compared to two-year historical pricing, as shown in Figure IV-17. Prices declined to as much as 55% in select ISOs during March and April, the peak months of COVID-19. Although we have seen increased load in June,

200 Jessica Jaganathan and Chen Aizhu, "U.S. LNG cargoes heading to China after Beijing awards tax waivers," Reuters, April 7, 2020, accessed June 26, 2020, https://www.reuters.com/article/us-usa-china-lng/us-lng-cargoes-heading-to-china-after-beijing-awards-tax-waivers-idUSKBN21P128.

201 Aaron Sheldrick, "China could top Japan's LNG imports in 2020 as coronavirus cuts demand," Reuters, June 18, 2020, accessed June 26, 2020, https://www.reuters.com/article/china-japan-lng/china-could-top-japans-lng-imports-in-2020-as-coronavirus-cuts-demand-idUSL4N2DT1I0.

202 Aaron Sheldrick, Yuka, Obayashi, "Japan clears restart at nuclear reactor closest to epicenter of 2011 quake," Reuters, November 27, 2019, accessed July 10, 2020, https://www.reuters.com/article/us-japan-nuclear-restarts/japan-approves-restart-for-nuclear-reactor-closest-to-epicenter-of-2011-quake-idUSKBN1Y10K7.

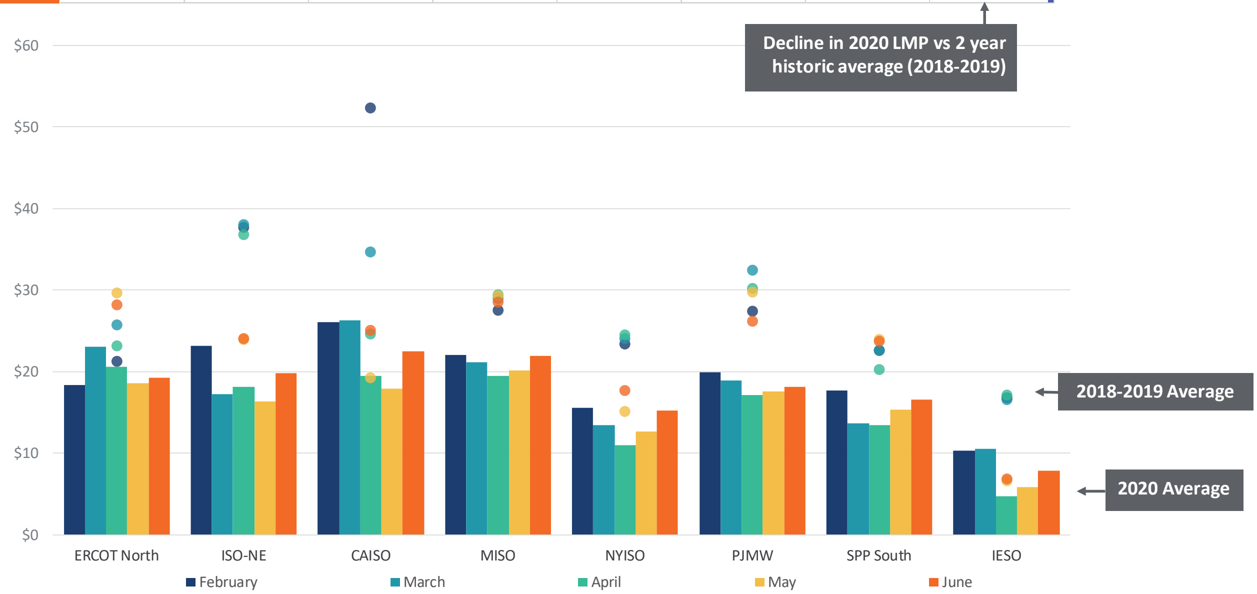
203 Id.

204 Ministry of Economy, Trade and Industry, Agency for Natural Resources and Energy, "Japan's Energy 2019," March 2020, accessed July 10, 2020, https://www.enecho.meti.go.jp/en/category/brochures/pdf/japan_energy_2019.pdf.

compared to May, this increase is not reflected in electric prices. There has been a steady decline is LMPs, compared to two-year averages, as shown in Figure IV-17 below. U.S. natural gas prices (Henry Hub) in February to June 2020 are, on average, 35% lower than the prior two-year average natural gas prices.

**FIGURE IV-17: DAY AHEAD AVERAGE LMPS**

| | ERCOT North | ISO-NE | CAISO | MISO | NYISO | PJMW | SPP South | IESO |
|---|---|---|---|---|---|---|---|---|
| FEB | -14% | -38% | -50% | -20% | -34% | -28% | -22% | -39% |
| MAR | -10% | -55% | -24% | -27% | -44% | -42% | -40% | -36% |
| APR | -11% | -51% | -21% | -34% | -55% | -43% | -34% | -72% |
| MAY | -37% | -32% | -7% | -31% | -16% | -41% | -36% | -12% |
| JUN | -32% | -18% | -10% | -23% | -14% | -31% | -30% | 14% |




Note: IESO data reflects HOEP data, without the global adjustment. Converted from Canadian dollars using a conversion rate of 0.75, the annual average as of July 3rd.[205] ERCOT North data reflects settlement point prices.

[205] "Currency Converter," Bank of Canada, data as of July 3, 2020, accessed July 3, 2020, https://www.bankofcanada.ca/rates/exchange/currency-converter/?lookupPage=lookup_currency_converter_2017.php&startRange=2010-07-05&rangeType=range&selectToFrom=to&convert=1.00&seriesFrom=Canadian+dollar&seriesTo%5B%5D=FXUSDCAD&rangeValue=1.y&dFrom=&dTo=&submit_button=Convert

## Summary of Actions Taken by Market to Date

During the height of the pandemic, energy system operators changed operational protocols to keep their employees safe while continuing to safely and reliably operate the system. A notable example of this is the NYISO, which sequestered its employees at the start of the outbreak.[206] NYISO split 37 employees—33 grid operators and four support staff—into two teams. One team lived at NYISO's Guilderland facility, and the other lived at NYISO's Rensselaer facility. The operators worked 12-hour shifts and were required to stay 6 feet apart and not share computer stations. After each shift, the control over the operation of the grid switch between one control center and the other. This reduced the risk of cross-contamination by not having the two groups of operators share the same control center.

PJM implemented similar measures by sequestering its control room operators at the PJM control room facility.[207] PJM also tested its employees, implemented two 12-hour shifts, and retained an epidemiologist to advise PJM on pandemic response measures and protocols for the control room and work place. PJM also released a document outlining best practices for control center operations during the COVID-19 outbreak.[208]

While CAISO, ISO-NE, MISO, SPP, and ERCOT have not sequestered employees, all have transitioned to virtual business environments. This includes transitioning stakeholder meetings to online formats.[209] RTOs have also been closely monitoring planned outages on their system. For example, the IESO has been working with its market participants to defer all non-critical generation and transmission outages, to ensure adequate redundancy in the system.[210]

206 Kelly Andrejasic, "Falling COVID-19 cases may signal beginning of the end of for NYISO sequestration," May 6, 2020, accessed June 29, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/falling-covid-19-cases-may-signal-beginning-of-the-end-for-nyiso-sequestration-58409473.

207 Jared Anderson, "PJM sequesters control room operators in response to pandemic," S&P Global, April 17, 2020, accessed June 29, 2020, https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/041720-pjm-sequesters-control-room-operators-in-response-to-pandemic

208 PJM, "Best Practices for Control Centers To Limit the Spread of the Coronavirus," April 22, 2020, accessed June 29, 2020, https://www.pjm.com/-/media/committees-groups/pandemic/postings/best-practices-for-control-centers-to-limit-the-spread-of-the-coronavirus.ashx?la=en.

209 Robert Walton, "Grid operators cancel travel, shift to remote meetings, as industry preps for broad coronavirus absenteeism," Utility Dive, March 12, 2020, accessed June 29, 2020, https://www.utilitydive.com/news/grid-operators-cancel-travel-shift-to-remote-meetings-as-industry-preps-f/573988/.

210 IESO, "IESO response to COVID-19," April 2, 2020, accessed June 29, 2020, http://www.ieso.ca/Sector-Participants/IESO-News/2020/04/IESO-response-to-COVID-19.

At the state regulatory level, twenty-two jurisdictions have approved deferral mechanisms for COVID-19 related costs and/or lost revenue.[211] Thirteen states have passed measures to allow customers to use payment plans to repay past-due balances from non-payments during the utility shut-off moratoriums.[212] Seventeen states have pending proceedings on COVID-19 related cost recovery provisions for utilities, including New York.[213] On June 11, the New York Commission started a generic proceeding to address the impact of COVID-19 on utilities and consumers.[214] The proceeding considered impacts to rate setting and design, low-income assistance programs, regulatory priorities, collections, service terminations.

## Potential Delay in Market Activities

In addition to operational impacts, some operators have delayed capacity auctions. For example, on April 3, 2020, IESO deferred the capacity auction that it had planned for June.[215] The IESO delayed the auction until fourth quarter 2020, attributing the delay to noticeable demand declines and their need to update planning forecasts to reflect the pandemic's impacts. IESO also suspended work on planned capacity auction enhancements and is reassessing the value of those enhancements. IESO expected to execute a second capacity auction in March 2021 for one-year commitments starting in May 2022.

In Europe, countries are largely moving ahead of renewable energy procurements despite the COVID-19 outbreak.[216] Germany has already procured approximately 1 GW of solar and wind capacity this year, and intends to procure an additional 4.3 GW. Germany intends to mitigate any impacts from

211 National Association of Regulatory Utility Commissioners, "COVID19 News & Resources – State Response Tracker," accessed June 29, 2020, https://www.naruc.org/compilation-of-covid-19-news-resources/state-response-tracker/ .

212 The thirteen states are Alabama, Colorado, Florida, Indiana, Montana, New Hampshire, New Jersey, North Carolina, Ohio, Rhode Island, South Carolina, South Dakota, and Washington. Source: W. Gerrit Jepsen, and Dimitri Henry, "Regulatory Responses to COVID-19 Are Key to Utilities' Credit Prospects," S&P Global, May 20, 2020, https://www.spglobal.com/ratings/en/research/articles/200520-regulatory-responses-to-covid-19-are-key-to-utilities-credit-prospects-11488785.

213 Arizona, Florida, Indiana, Kansas, Kentucky, Louisiana PSC, Louisiana NOCC, Maine, Massachusetts, Missouri, Montana, Nebraska, New Hampshire, New York, North Dakota, Oregon, South Dakota, Utah

National Association of Regulatory Utility Commissioners, "COVID19 News & Resources – State Response Tracker," accessed June 29, 2020, https://www.naruc.org/compilation-of-covid-19-news-resources/state-response-tracker/.

214 Tom DiChristopher and Kelly Andrejasich, "NY utility regulator takes comprehensive approach to coronavirus impacts," S&P Global, June 12, 2020, accessed June 29, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ny-utility-regulator-takes-comprehensive-approach-to-coronavirus-impacts-59032734 .

215 IESO, "Capacity Auction," April 3, 2020, accessed June 29, 2020, http://www.ieso.ca/Sector-Participants/IESO-News/2020/04/Capacity-Auction.

216 John Parnell, "European Countries Postpone Renewable Auction Project Deadlines for Coronavirus," GreenTech Media, April 1, 2020, accessed June 29, 2020, https://www.greentechmedia.com/articles/read/european-governments-cut-renewable-developers-coronavirus-slack.

construction delays and supply chain disruptions. Additionally, Germany will not publicly disclose the winning bids until the impacts of COVID-19 have “calmed down” (although the winners themselves will be notified). Germany is considering granting schedule extensions for projects on a case-by-case basis. Germany will suspended delay penalties for those projects granted an extension. Germany uses competition bonds whereby the builder has to pay a bond within 10 days of winning an auction. The bonds are worth $57/kW, or, if the building permit is in place, $28/kW.[217] If the project is not constructed within two years, the builder loses the right to remuneration for the electricity produced from the project.

Some countries have delayed their auctions due to COVID-19. In Ireland, the Renewable Electricity Support Scheme (RESS-1) auction for 1 GW of onshore wind and 300 MW of solar was postponed from April 2, 2020 to April 30. France delayed its solar auction by 2 months. Portugal postponed its second-ever solar energy auction, originally scheduled for January. Portugal started the 700 MW solar auction in early June, after delays due to the impacts of COVID-19. Entities have until July 31, 2020 to submit bids to the Portuguese Directorate-General for Energy and Geology.[218] Other countries such as the Netherlands and Spain have maintained their auction schedules.

In the U.S., renewable energy capacity is still growing at approximately 1,100 MW per month since January 2020, reaching almost 13% of total installed capacity as of June 2020. In comparison, the same period last year was approximately 700 MW per month.[219] However, New Jersey, New York, Pennsylvania, and Michigan suspended renewables construction as part of non-essential construction stoppage during the height of the pandemic. This stoppage could have effects on the future economic viability of renewable projects, as wind and solar projects were at risk for losing their tax incentives that require construction start by end of year 2020 ($15/MWh and 4% Investment Tax Credit, respectively). Additionally, wind projects that qualified for the Production Tax Credit in 2016—at $19/MWh—could lose the credit if in-service is delayed beyond year-end 2020. In March, the American Wind Energy Association estimated that 25 GW of wind projects were at risk, representing approximately $35 billion in investments.[220] On May 7, 2020, the U.S. Department of the Treasury announced a plan to extend the

217 Source states exchange rate of $1.13 USD/EUR as of end-2014, early 2015. International Renewable Energy Agency, “Renewable Energy Auctions, A Guide to Design,” 2015, PDF p. 182, accessed July 10, 2020, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/Jun/IRENA_Renewable_Energy_Auctions_A_Guide_to_Design_2015.pdf.

218 Emilliano Bellini, “Portugal kicks-off 700 MW solar auction,” PV Magazine, June 8, 2020, accessed July 21, 2020, https://www.pv-magazine.com/2020/06/08/portugal-kicks-off-700-mw-solar-auction/.

219 Velocity Suite, ABB Inc., data as of July 2, 2020. Accessed July 2, 2020.

220 American Wind Energy Association, “American Wind Energy Association Releases COVID-19 Outlook,” March 19, 2020, accessed June 30, 2020, https://www.awea.org/resources/news/2020/american-wind-energy-association-releases-covid-19.

ITC safe harbor deadline for energy projects that started construction in 2016 and 2017, in response to a letter from a group of U.S. Senators.[221]

# F. Potential Adjustment and Revision of Market Fundamentals

The long-term economic impacts of COVID-19 make it particularly challenging to accurately forecast electric loads relying on traditional tools. As a result, entities have turned to scenario planning in order to forecast loads utilizing a reasonable range of assumptions.

One such example is the Alberta Electric System Operator (AESO). In their May 2020 Long-Term Adequacy Metrics report, AESO performed stress tests on their 2019 long-term outlook (LTO) load forecast to study the impacts of COVID-19 and low oil prices.[222] Specifically, they studied the impact of lower demand and "potential temporary removal of generation resulting from the response to COVID-19 and oil price reductions." The 2019 LTO Load forecast was updated to reflect recent GDP and unemployment projections. The 2019 LTO uses a forecasted peak load of 9,752 MW and an average load of 7,752 MW. The updated load forecast resulted in a peak load of 8,944 MW and an average load of 7,039 MW—8.3% and 9.2% decreases, respectively, relative to the 2019 LTO forecast. AESO studied two scenarios of reductions in thermal generation capacity (coal, combined cycle or generation gas). One scenario removed 450 MW of thermal generation for 6 months and another scenario removed 900 MW of thermal generation for 6 months. The two scenarios showed no supply adequacy concerns. The supply cushion was better than 2019 LTO Base Case, primarily due to load declines.

PJM has been updating its load forecast to account for the impacts of COVID-19 since March 2020. The RTO relies on economic forecast by Moody's Analytics.[223] In its June Update PJM expects 2020 summer peak load will decrease by 1.7 percent relative to the previously published 2020 Forecast.[224] PJM

[221] Kelsey Misbrener, "Treasury agrees to modify safe harbor deadline for some renewable projects," Solar Power World, May 8, 2020, accessed June 30, 2020, https://www.solarpowerworldonline.com/2020/05/treasury-agrees-to-modify-safe-harbor-deadline-some-renewable-projects/.

[222] Alberta Electric System Operator, "Supplement to Long Term Adequacy Metrics – May 2020: Sensitivity Analysis for Long-Term Adequacy Metrics with effects to load and generation from COVID-19 and GDP shocks," April 24, 2020, accessed June 29, 2020, https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/.

[223] https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20200602/20200602-item-07-covid-19-impacts-and-load-forecast.ashx

[224] The underlying Moody's Analytics update forecasts that the third-quarter 2021 real GDP would be 7.1% lower than assumed in PJM's previous 2020 load forecast for the 2021 summer peak.

anticipates the reduction to persist in 2021, and recovery will begin in earnest in 2022. By 2025, the new summer peak load forecast will almost catch up with the previous 2020 Forecast. PJM has filed a waiver with FERC to use a new load forecast for the 2021/2022 Second Incremental Auction. FERC's decision is pending as of the time of this writing.

NYISO holds two ICAP market auctions each year. One is for the summer capability period (May through October) and one for the winter capability period (November through April). Typically, auctions are held 30 days prior to the capability period (late March). This year, the summer capability auction occurred at the height of the pandemic's impacts in the state of New York (New York City at the time had the highest case count in the U.S.). Despite uncertainties, NYISO did not lower its summer peak demand forecast, which was developed prior to COVID-19's major impacts in New York State.[225]

[225] NYISO, "ICAP/UCAP Translation of Demand Curve (Summer 2020)," March 18, 2020, accessed July 1, 2020, https://www.nyiso.com/documents/20142/11477343/ICAP-Translation-of-Demand-Curve-Summer-2020-FINAL.pdf/63166d63-50c4-e2fb-cfcc-38a17274997b.

# List of Acronyms

| | |
|---|---|
| **ACR** | **A**voidable **C**ost **R**ate |
| **AESO** | **A**lberta **E**lectric **S**ystem **O**perator |
| **AMPCO** | **A**ssociation of **M**ajor **P**ower **C**onsumers of **O**ntario |
| **ATSI** | **A**merican **T**ransmission **S**ystem, **I**nc. |
| **BcF** | **B**illion **C**ubic **F**eet (of natural gas) |
| **BGE** | **B**altimore **G**as and **E**lectric (Maryland) |
| **BOEM** | **B**ureau of **O**cean **E**nergy **M**anagement |
| **BRA** | **B**ase **R**esidual **A**uction (PJM) |
| **CAISO** | **C**alifornia **I**ndependent **S**ystem **O**perator |
| **CASPR** | **C**ompetitive **A**uctions with **S**ponsored **P**olicy **R**esources (ISO-NE) |
| **CBO** | **C**ongressional **B**udget **O**ffice |
| **CDR** | **C**apacity, **D**emand and **R**eserves (ERCOT) |
| **CETL** | **C**apacity **E**mergency **T**ransfer **L**imit (PJM) |
| **CETO** | **C**apacity **E**mergency **T**ransfer **O**bjective (PJM) |
| **CMDRB** | **C**apacity **M**arket **D**ispute **R**esolution **B**oard (Ireland) |
| **COMED** | **C**ommonwealth **Ed**ison (Illinois) |
| **CONE** | **C**ost **o**f **N**ew **E**ntry |
| **CSO** | **C**apacity **S**upply **O**bligations (ISO-NE) |
| **DPLSOUTH** | **D**elmarva **P**ower and **L**ight – **S**outhern portion (Delaware) |
| **DR** | **D**emand **R**esponse |
| **DRA** | **D**emand **R**esponse **A**uction (Ontario) |
| **EC** | **E**uropean **C**ommission |
| **ECR** | **E**xiting **C**apacity **R**esources (ISO-NE) |
| **EFORd** | **E**ffective **F**orced **O**utage **R**ate |
| **EIA** | **E**nergy **I**nformation **A**dministration |
| **EIS** | **E**nvironmental **I**mpact **S**tatement |
| **ELCC** | **E**ffective **L**oad **C**arrying **C**apability |
| **EMA** | **E**nergy **M**arket **A**uthority (Singapore) |

| | |
|---|---|
| **EMAAC** | **E**astern **M**id-**A**tlantic **A**rea **C**ouncil (PJM) |
| **ERCOT** | **E**lectric **R**eliability **C**ouncil of **T**exas |
| **ERS** | **E**mergency **R**esponse **S**ervice (ERCOT) |
| **EU** | **E**uropean **U**nion |
| **FCA** | **F**orward **C**apacity **A**uction (ISO-NE) |
| **FCM** | **F**orward **C**apacity **M**arket (Singapore and ISO-NE) |
| **FERC** | **F**ederal **E**nergy **R**egulatory **C**ommission |
| **FRR** | **F**ixed **R**esource **R**equirement (PJM) |
| **FSL** | **F**irm **S**ervice **L**evel |
| **GDP** | **G**ross **D**omestic **P**roduct |
| **GLD** | **G**uaranteed **L**oad **D**rop |
| **ICAP** | **I**nstalled **C**apacity |
| **IESO** | **I**ndependent **E**lectricity **S**ystem **O**perator (Ontario) |
| **IPP** | **I**ndependent **P**ower **P**roducers |
| **ISO-NE** | **I**ndependent **S**ystem **O**perator of **N**ew **E**ngland |
| **ISO** | **I**ndependent **S**ystem **O**perator |
| **LCR** | **L**ocational **M**inimum **I**nstalled **C**apacity **R**equirement (NYISO) |
| **LDA** | **L**ocational **D**eliverability **A**reas (PJM) |
| **LMP** | **L**ocational **M**arginal **P**ricing |
| **LNG** | **L**iquefied **N**atural **G**as |
| **LOLE** | **L**oss of **L**oad **E**xpectation |
| **LTO** | **L**ong-**T**erm **O**utlook (Alberta) |
| **M2M** | **M**arket-to-**M**arket |
| **MAAC** | **M**id-**A**tlantic **A**rea **C**ouncil (PJM) |
| **METI** | **M**inistry of **E**conomy, **T**rade and **I**ndustry (Japan) |
| **MISO** | **M**idcontinent **I**ndependent **S**ystem **O**perator |
| **MMBtu** | **O**ne **M**illion **B**ritish **T**hermal **U**nits |
| **MOPR** | **M**inimum **O**ffer **P**rice **R**ule |
| **MRP** | **M**arket **E**quity **R**isk **P**remium |
| **NYISO** | **N**ew **Y**ork **I**ndependent **S**ystem **O**perator |
| **NYSRC** | **N**ew **Y**ork **S**tate **R**eliability **C**ouncil |
| **OCCTO** | **O**rganization of **C**ross-regional **C**oordination of **T**ransmission **O**perators |

| | |
|---|---|
| **OEB** | **O**ntario **E**nergy **B**oard |
| **OPEC** | **O**rganization of the **P**etroleum **E**xporting **C**ountries |
| **PAI** | **P**erformance **A**ssessment **I**ntervals (PJM) |
| **PEPCO** | **P**otomac **E**lectric **P**ower **C**ompany (Washington, D.C. region) |
| **PJM** | **PJM** Interconnection |
| **PPL** | **P**ennsylvania **P**ower and **L**ight |
| **PPA** | **P**ower **P**urchase **A**greement |
| **PRA** | **P**lanning **R**esource **A**uction |
| **PSEG** | **P**ublic **S**ervice **E**nterprise **G**roup (New Jersey) |
| **RCO** | **R**esource **C**arve-**O**ut |
| **RESS-1** | **R**enewable **E**lectricity **S**upport **S**cheme (Ireland) |
| **RPM** | **R**eliability **P**lanning **M**odel (PJM) |
| **RTOs** | **R**egional **T**ransmission **O**rganizations |
| **RTR** | **R**enewable **T**echnology **R**esource (ISO-NE) |
| **SEM** | **S**ingle **E**lectricity **M**arket (Ireland) |
| **SPP** | **S**outhwest **P**ower **P**ool |
| **SPR** | **S**ponsored **P**olicy **R**esources (ISO-NE) |
| **SWMAAC** | **S**outhwestern **M**id-**A**tlantic **A**rea **C**ouncil (PJM) |
| **TCA** | **T**ransition **C**apacity **A**uction (Ontario) |
| **TPS** | **T**hree **P**ivotal **S**upplier (PJM) |
| **UCAP** | **U**nforced **C**apacity |
| **WECC** | **W**estern **E**lectricity **C**oordinating **C**ouncil |
| **WTI** | **W**est **T**exas **I**ntermediate |
| **ZEC** | **Z**ero **E**mission **C**redit |