# 2023
# Common Metrics
## Performance Metrics for ISOs, RTOs, and Regions Outside ISOs and RTOs for the Reporting Period 2019 to 2022

Staff Report

January 31, 2024

FEDERAL ENERGY REGULATORY COMMISSION
**Office of Energy Policy and Innovation**

# ACKNOWLEDGEMENTS

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# PREFACE

This report continues Commission staff's initiative to examine the performance and benefits of Regional Transmission Organization (RTO) and Independent System Operator (ISO) (collectively, RTO/ISO) markets. The initiative arose in response to a 2008 Government Accountability Office (GAO) report recommending that the Commission do more to track the performance and benefits of RTO/ISO markets.[1] The previous report on this initiative, issued in July 2021 (2021 Report), established a set of common performance metrics for evaluating the performance of RTO/ISO markets and individual utilities in regions outside of RTOs/ISOs (referred to hereinafter as "non-RTO/ISO utilities") in areas where these entities perform identical functions.

The source of data for this report is primarily information collected from RTOs/ISOs under Information Collection FERC-922, "Performance Metrics for ISOs, RTOs and Regions Outside ISOs and RTOs" (Office of Management and Budget Control No. 1902-0262) (Information Collection FERC-922). Consistent with past practice in this initiative, respondents submitted information on a voluntary basis. Six RTOs/ISOs responded, and no non-RTO/ISO utilities responded. Commission staff greatly appreciates the efforts of those who contributed information to this initiative.

The report contains data and graphics that are based on the data provided by RTO/ISO respondents, unless noted otherwise, but do not necessarily reflect the positions or conclusions of the respondents themselves. The data submitted by RTOs/ISOs under Information Collection FERC-922 is publicly available on the Commission's eLibrary website (elibrary.ferc.gov) in Docket No. AD19-16-000. Furthermore, the opinions and views expressed in this report do not necessarily represent those of the Commission, its Chairman, or individual Commissioners, and are not binding on the Commission. Any errors are those of Commission staff.

The metrics included in this 2023 Report are identical to the metrics reported in the 2021 Report. However, reports issued before 2021 used different metrics than those used in the 2021 and 2023 Reports. The 2021 and 2023 Reports reflect changes implemented in the calculation or derivation of some of the metrics. These changes may make direct comparisons between the metrics in past reports and this 2023 Report difficult.

1 U.S. Gov't Accountability Off., GAO #08-987, Gov't Accountability Off. Report to the Committee on Homeland Security and Government Affairs, U.S. Senate; Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance (2008) (2008 GAO Report).

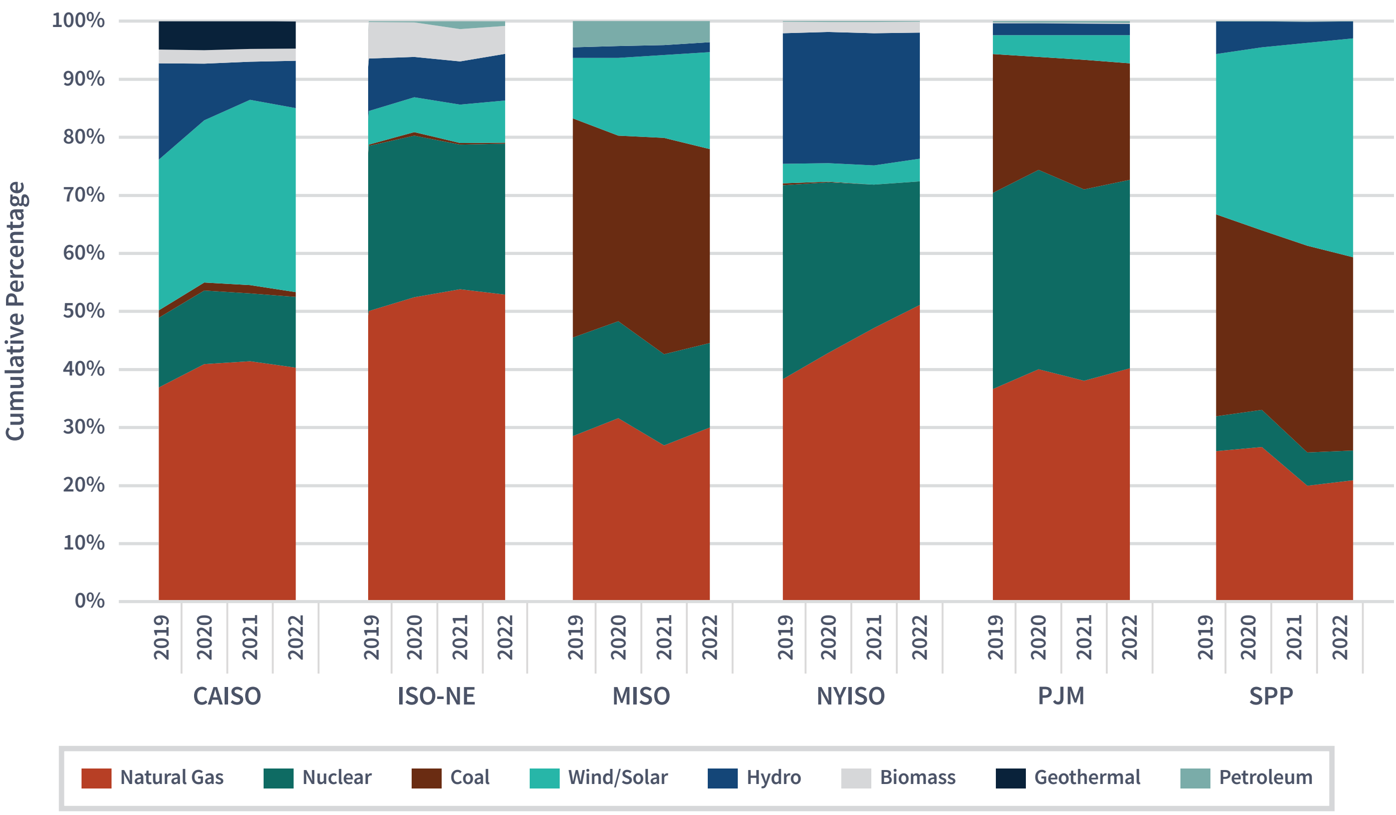
# EXECUTIVE SUMMARY

This report contains a review of performance metrics for RTOs/ISOs for the 2019 to 2022 reporting period.

**RTOs/ISOs managed the dispatch of energy from a diverse set of generating fuel types during 2019 to 2022.** RTOs/ISOs manage the scheduling and deployment of different resource types through day-ahead and real-time energy markets, which operate as market-clearing auctions that establish commitment and dispatch schedules subject to system constraints. RTOs/ISOs report managing the dispatch of energy from varying fuel sources during 2019 to 2022, as shown in Figure 1. Natural gas and nuclear, together, comprise over half of most regions' total generation during the 2019-2022 period. Most RTOs/ISOs report managing the dispatch of energy from an increasing share of renewable generation and varying shares of natural gas-fired generation and coal-fired generation.

**RTOs/ISOs regions experienced varying levels of demand response implementation during 2019 to 2022.** As shown in Figure 2, demand response as a percent of total installed capacity has remained the highest in CAISO at around 10%, approximately 3-6% in MISO, NYISO, and PJM, and below 2% in ISO-NE. SPP reports an increasing amount of the total MWh of demand response, increasing from 101 MWh in 2020 to 1,202 MWh, or slightly less than 2% of installed capacity, in 2022.

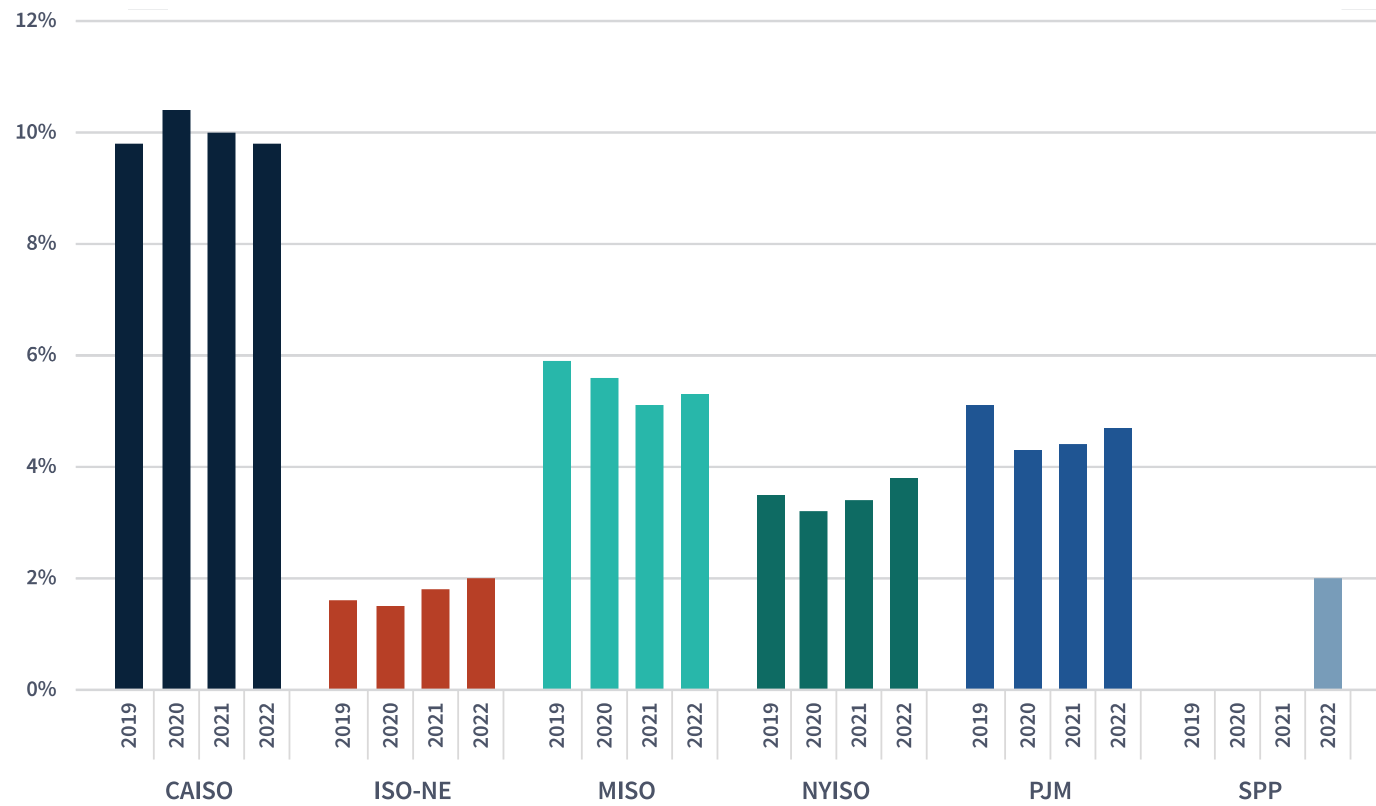
**Figure 1: Share of Total Energy Generation by Fuel Type**




**NOTES:** The natural gas-fired generation in NYISO includes all generation from dual-fuel (natural gas and oil) resources.

Source: Based on Information Collection FERC-922.

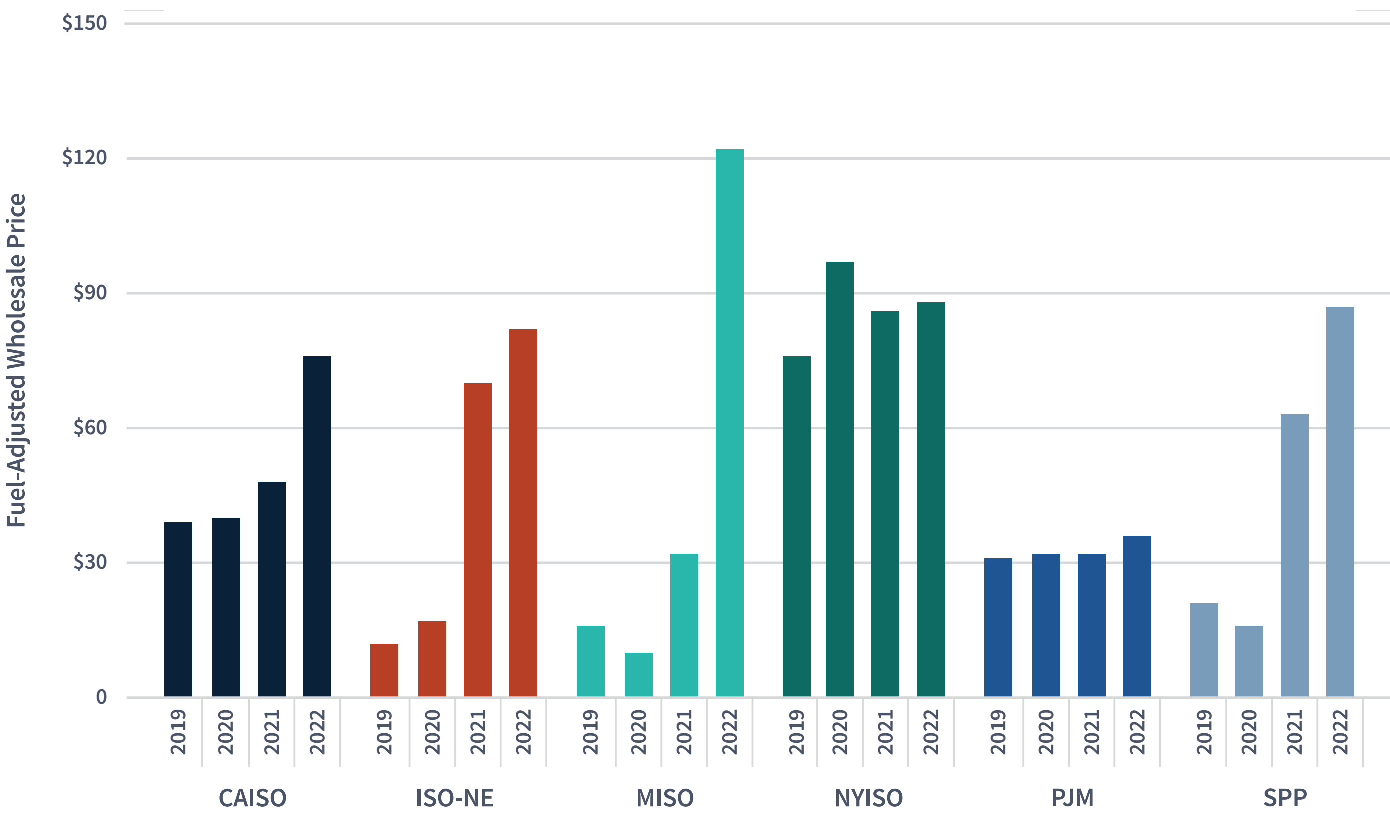
**Figure 2: Demand Response as a Percentage of Total Installed Capacity**




Source: Based on FERC-922 Information Collection.

**Load-weighted, fuel-adjusted locational marginal prices have varied across time and region.** As shown in Figure 3, ISO-NE and SPP experienced large increases in load-weighted, fuel-adjusted locational marginal prices in 2021, whereas CAISO and MISO report similar large increases in 2022. NYISO and PJM report relatively stable fuel-adjusted prices over the reporting period.

**Figure 3: Load-weighted, Fuel-adjusted Locational Marginal Prices, 2019 to 2022**



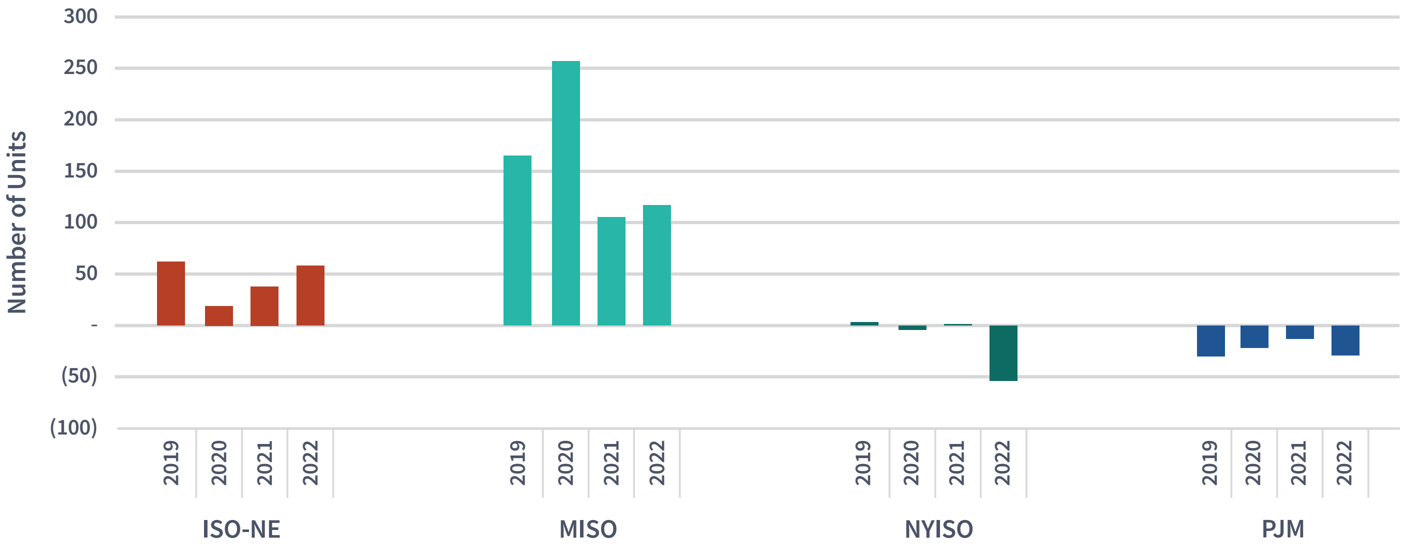

Source: FERC-922 information collection.

**Among the four RTOs/ISOs with capacity markets, the net number of generating capacity units added to service varies significantly.[2] The net number of additions within those RTOs/ISOs also changed over time.** The net number of generating capacity units accounts for additions as well as retirements, where negative values indicate retirements that exceeded additions. As shown in Figure 4, MISO reports that a relatively high number of net generating capacity units were added. NYISO reports little net change from 2019 to 2021, with retirements exceeding additions in 2022. PJM reports a net decrease in generating capacity units over the reporting period.

**The net increase in megawatt (MW) capacity supply obligations also varies significantly across the four RTOs/ISOs with capacity markets, as well as within those RTOs/ISOs over time.** Capacity with a capacity supply obligation is the amount of generating capacity that has cleared in an auction that has a resulting obligation to offer into the energy market during the reporting period. Negative values indicate that the amount of MW that exited the market due to retirement exceeded the MW added from new generation. As shown in Figure 5, MISO reports the largest and most consistent net increase in MW with capacity supply obligations. ISO-NE, NYISO, and PJM report increases and decreases in net generating capacity with capacity supply obligations over the reporting period.

2 ISO-NE, MISO, NYISO, and PJM are the RTOs/ISOs with capacity markets.

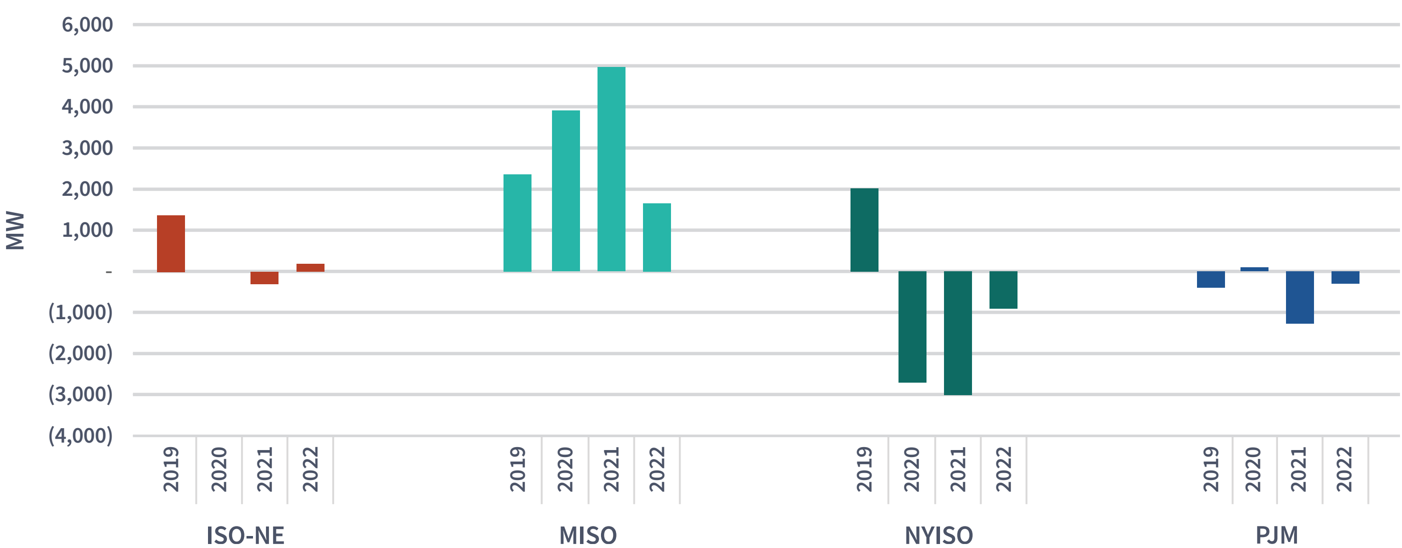
**Figure 4: Net Number of Generation Capacity Units Added**




**NOTES:** ISO-NE notes that its data does not include one-year exits or partial retirements.

Source: FERC-922 information collection.

**Figure 5: Net Change in Capacity Supply Obligations, MW**




**NOTES:** ISO-NE notes that its data does not include one-year exits or partial retirements.

Source: FERC-922 information collection.

# INTRODUCTION AND OVERVIEW

This report presents Commission staff's review of performance metrics data on RTOs/ISOs activities for the 2019 to 2022 reporting period. The report also presents Commission staff's review of data submitted by RTOs/ISOs specific to RTO/ISO administrative functions, energy markets, and capacity markets.

Commission staff collected the information on the 29 common metrics divided into three groups from six RTOs/ISOs under Information Collection FERC-922.[3] The three groups of metrics in Information Collection FERC-922 are:

- **Group 1: Administrative and Descriptive Metrics.** There are seven Group 1 metrics: Reserve Margins, Average Heat Rates, Fuel Diversity, Capacity Factor by Technology Type, Energy Emergency Alerts (EEA Level 1 or Higher), Performance by Technology Type during EEA Level 1 or Higher, and Resource Availability (Equivalent Forced Outage Rate Demand (EFORd)). Group 1 metrics were collected from all respondents (i.e., RTOs/ISOs and non-RTO/ISO utilities).

- **Group 2: Energy Market Metrics.** There are 12 Group 2 metrics: Number and Capacity of Reliability Must-Run Units, Reliability Must-Run Contract Usage, Demand Response Capability, Unit Hours Mitigated, Wholesale Power Costs by Charge Type, Price Cost Markup, Fuel Adjusted Wholesale Energy Price, Energy Market Price Convergence, Congestion Management, Administrative Costs, New Entrant Net Revenues, and Order No. 825[4] Shortage Intervals and Reserve Price Impacts. Group 2 metrics pertain to information collected from organized RTO/ISO energy markets.

- **Group 3: Capacity Market Metrics.** There are ten Group 3 metrics: Net Cost of New Entry (Net CONE) Value, Resource Deliverability, New Capacity (Entry), Capacity Retirement (Exit), Forecasted Demand, Capacity Market Procurement and Prices, Capacity Obligations and Performance Assessment Events, Capacity Over-Performance, Capacity Under-Performance, and Total Capacity Bonus Payments and Penalties. Group 3 metrics are new to this Information Collection. They were designed to be collected only from respondents with capacity markets (i.e., RTOs/ISOs with capacity markets – ISO-NE, MISO, NYISO, and PJM).

Table 1 lists the entities that submitted the metrics data reflected in this report and the acronyms used to refer to these entities in the remainder of this report.

3 Table 8 in Appendix A lists the 29 common metrics.
4 *Settlement Intervals and Shortage Pricing in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).

**Table 1: Respondents that Submitted Performance Metrics Reports in 2023**

| RTOs/ISOs | Non-RTOs/ISOs |
|---|---|
| California Independent System Operator Corporation (CAISO) | None |
| ISO New England Inc. (ISO-NE) | |
| Midcontinent Independent System Operator, Inc. (MISO) | |
| New York Independent System Operator, Inc. (NYISO) | |
| PJM Interconnection, L.L.C. (PJM) | |
| Southwest Power Pool, Inc. (SPP) | |

# BACKGROUND

In May 2007, Senators Joseph I. Lieberman and Susan M. Collins of the U.S. Senate Committee on Homeland Security and Governmental Affairs requested that the GAO investigate RTO/ISO costs, structure, processes, and operations.[5] In a September 2008 Report to the U.S. Senate Committee on Homeland Security and Governmental Affairs, the GAO recommended that FERC work with RTOs, ISOs, stakeholders, and other interested parties to develop standardized measures to track the performance of RTO/ISO operations and markets; report on those measures; and interpret how the measures communicate evidence of RTO/ISO benefits or performance concerns.[6]

Commission staff developed the Common Metrics initiative in response to the 2008 GAO Report. The evolution of the initiative included Commission staff taking steps to meet five objectives. These objectives, as described in FERC's Fiscal Year 2009-2014 Strategic Plan, include: (1) developing appropriate operational and financial metrics for RTOs/ISOs; (2) exploring and developing appropriate operational and financial metrics for non-RTO/ISO utilities; (3) establishing appropriate common metrics between RTOs/ISOs and non-RTO/ISO utilities; (4) monitoring implementation and performance; and (5) evaluating performance and seeking changes, as necessary.[7]

In April 2011, after establishing metrics for RTOs/ISOs under the first objective, the then-Chairman's Office submitted a Report to Congress summarizing RTO/ISO performance for the years 2005-2009.[8] To meet the second objective, Commission staff issued a report on performance in regions outside RTOs/ISOs in October 2012.[9] An August 2014 Commission Staff report[10] satisfied the third, fourth, and fifth objectives by establishing, implementing, and evaluating a set of common metrics.

5 The senators made this request in a May 21, 2007, letter to the GAO. The letter expressed the senators' concern that RTOs/ISOs may not be living up to their full potential with respect to improving efficiencies and reducing costs, and that RTOs/ISOs might not have adequate incentives to minimize costs.

6 *See* 2008 GAO Report at 56, 59-61.

7 FERC, *The Strategic Plan: FY 2009-2014 (Revised 2013)*, at 13, http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

8 FERC, *Performance Metrics For Independent System Operators and Regional Transmission Organizations*, Docket No. AD10-5-000, at 5 (2011); *see also* FERC, *2010 ISO/RTO Performance Metrics Commission Report*, Docket No. AD10-5-000 (2010).

9 FERC, *Performance Metrics In Regions Outside ISOs and RTOs Commission Staff Report*, Docket No. AD12-8-000 (2012).

10 FERC, *Common Metrics Commission Staff Report*, Docket No. AD14-15-000 (2014), http://www.ferc.gov/legal/staff-reports/2014/ad14-15-performance-metrics.pdf.

In December 2017, the GAO issued a report on the RTOs/ISOs with centralized capacity markets.[11] Among other recommendations, the GAO found the Commission should take steps to improve the quality of the data collected for the Common Metrics Reports, such as implementing improved data quality checks and, where feasible, ensuring that RTOs/ISOs report consistent metrics over time by standardizing definitions.

Furthermore, the GAO recommended the Commission develop and document an approach to regularly identify, assess, and respond to risks that capacity markets face.

In response to the 2017 GAO Report, Commission staff implemented changes to the 2021 Common Metrics Report. Commission staff improved the data collection process by creating a standardized information collection Input Spreadsheet. Commission staff also provided an updated, more detailed User Guide, which provides guidance on reporting data from the metrics being collected. This User Guide includes important definitions and a description of the types of metrics and their structure in the information collection, as well as how to properly use the reporting form. Commission staff also updated the list of Common Metrics to expand upon metrics related to capacity markets. After FERC staff implemented these recommendations, GAO "closed" them as "implemented" by FERC. However, the overall GAO request for FERC to track the performance and benefits of RTO/ISO markets remains in place. This 2023 Common Metrics Report contains metrics identical to those in the 2021 Report.

# DISCUSSION OF COMMON METRICS

## Overview of Group 1 Administrative and Descriptive Metrics

### RESERVE MARGINS

The anticipated reserve margin metric is designed to measure the amount of generation capacity available to meet expected demand.[12] Sufficient reserves help ensure there is a low probability of loss-of-load due to inadequate supply. Each region has a minimum reserve requirement that is established to provide sufficient capacity in the event of sudden generation loss. The actual reserve margins measure the realized amount of reserves within the reporting period based on actual generation availability and observed load. The comparison of the actual reserve margin to the anticipated reserve margin is one measure of the extent to which generation resource planning processes are ensuring long-term resource adequacy and reliability.[13] Actual reserve margins more than anticipated reserve margins represent a low risk of loss-of-load due to inadequate supply.

Most RTOs/ISOs had actual reserve margins lower than anticipated reserve margins, meaning these RTOs/ISOs had less capacity than expected. As shown in Figure 6, CAISO, ISO-NE, MISO, and NYISO report actual reserve margins significantly below anticipated reserve margins between 2019 and 2022. In contrast, PJM reports actual reserve margins

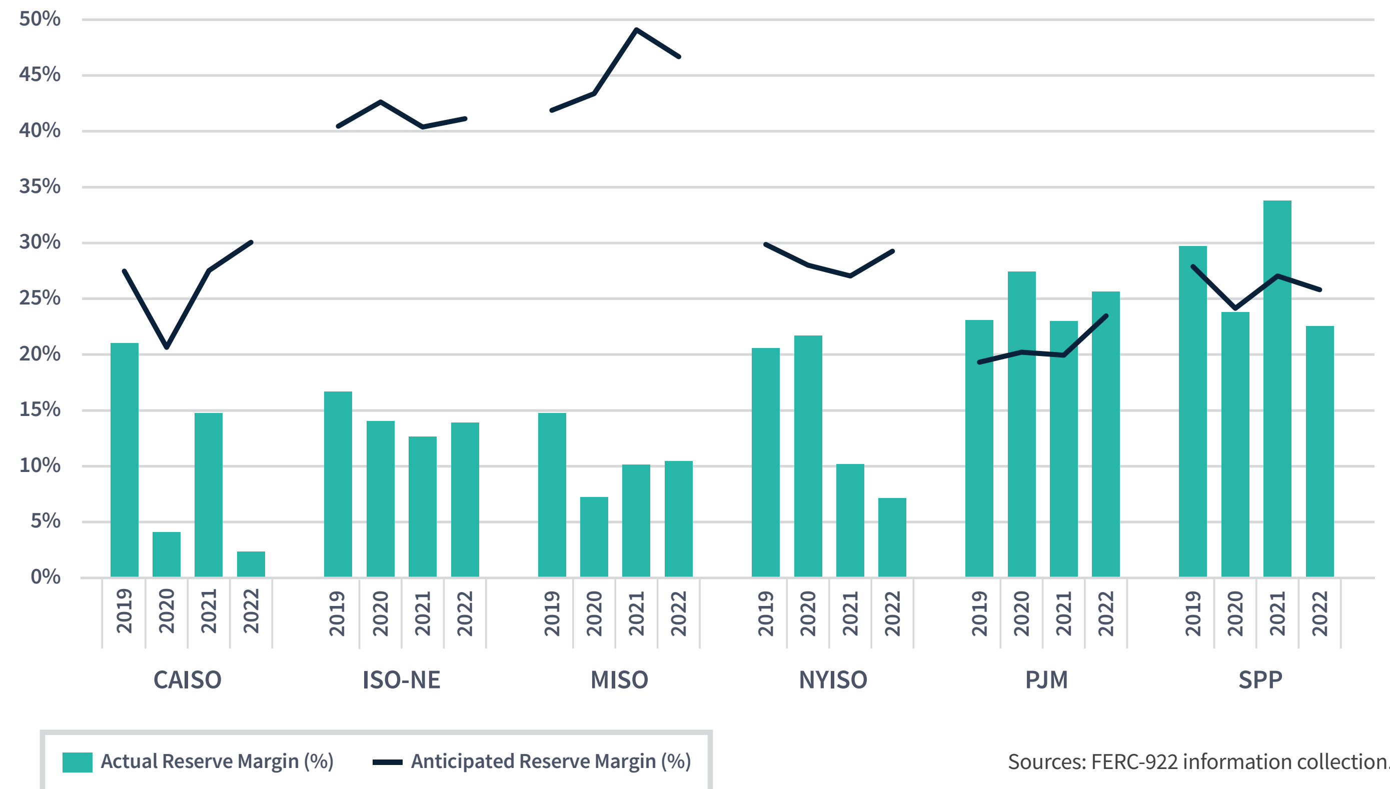
11 U.S. Gov't Accountability Office, GAO-18-131, *Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance* (2017), https://www.gao.gov/assets/690/689293.pdf (2017 GAO Report).

12 Anticipated reserve margin is generally determined at the beginning of the operating year using forecasted peak demand and expected generation availability. PJM is a notable exception in that it reports its forecasted peak demand three years prior to the current reporting year. *See generally*, N. Am. Electric Reliability Corp., *M-1 Reserve Margin (2017)*, https://www.nerc.com/pa/RAPA/ri/Pages/PlanningRes berveMargin.aspx.

13 This comparison is not the only measurement or standard by which resource adequacy and reliability can be measured to ensure sufficient reserves. Each region may have other confounding factors that make such a comparison less relevant.

above anticipated levels between 2019 and 2022. SPP reports actual reserve margins above anticipated reserve margins in 2019 and 2021, but not in 2020 and 2022. MISO reports the largest difference, with actual reserve margins, on average, 35% below anticipated reserve margins between 2019 and 2022. During that period, the average actual reserve margin in MISO was approximately 11% and the average anticipated reserve margin was approximately 45%.

**Figure 6: Anticipated and Actual Reserve Margins, 2019 to 2022**

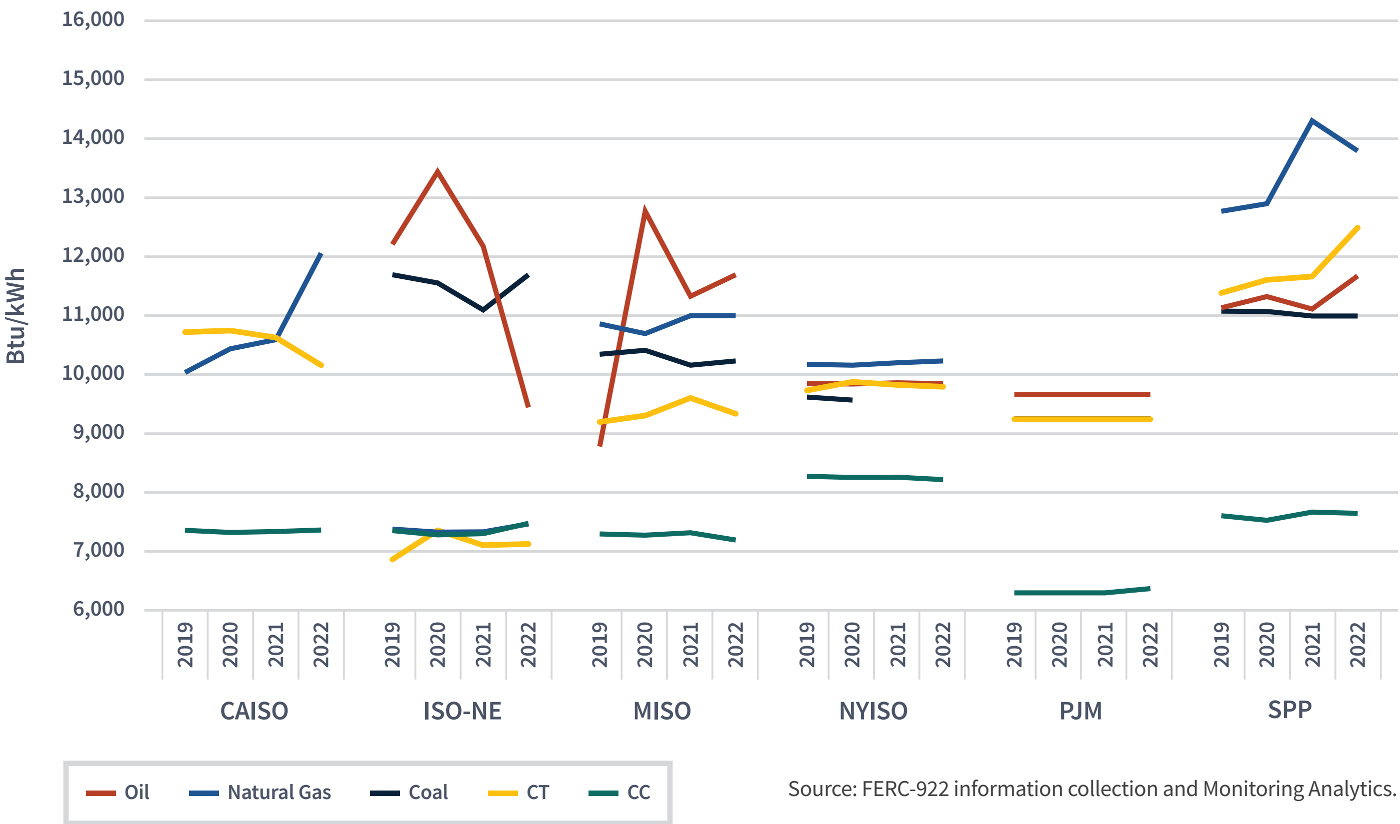



Sources: FERC-922 information collection.

## AVERAGE HEAT RATES

Average heat rates represent the efficiency of a resource to convert thermal power into electric power. A heat rate can be calculated as the quotient of the thermal power input divided by electric power produced. Therefore, low heat rate values are associated with greater efficiency than high heat rate values. Trends in aggregate heat rates across technologies may indicate changes in the efficiency of fuel consumption. Average heat rates for the same technology type may vary across different regions and markets based on model, vintage (age of generating unit), and utilization.

**Figure 7: Average Heat Rates, 2019 to 2022**




Source: FERC-922 information collection and Monitoring Analytics.

Many of the RTOs/ISOs indicate average heat rates that vary over time for the same technology type. Heat rates can change over time for a variety of reasons, such as emissions-control measures, changes in usage patterns, and installing more-efficient generating capacity while retiring relatively less efficient capacity.[14]

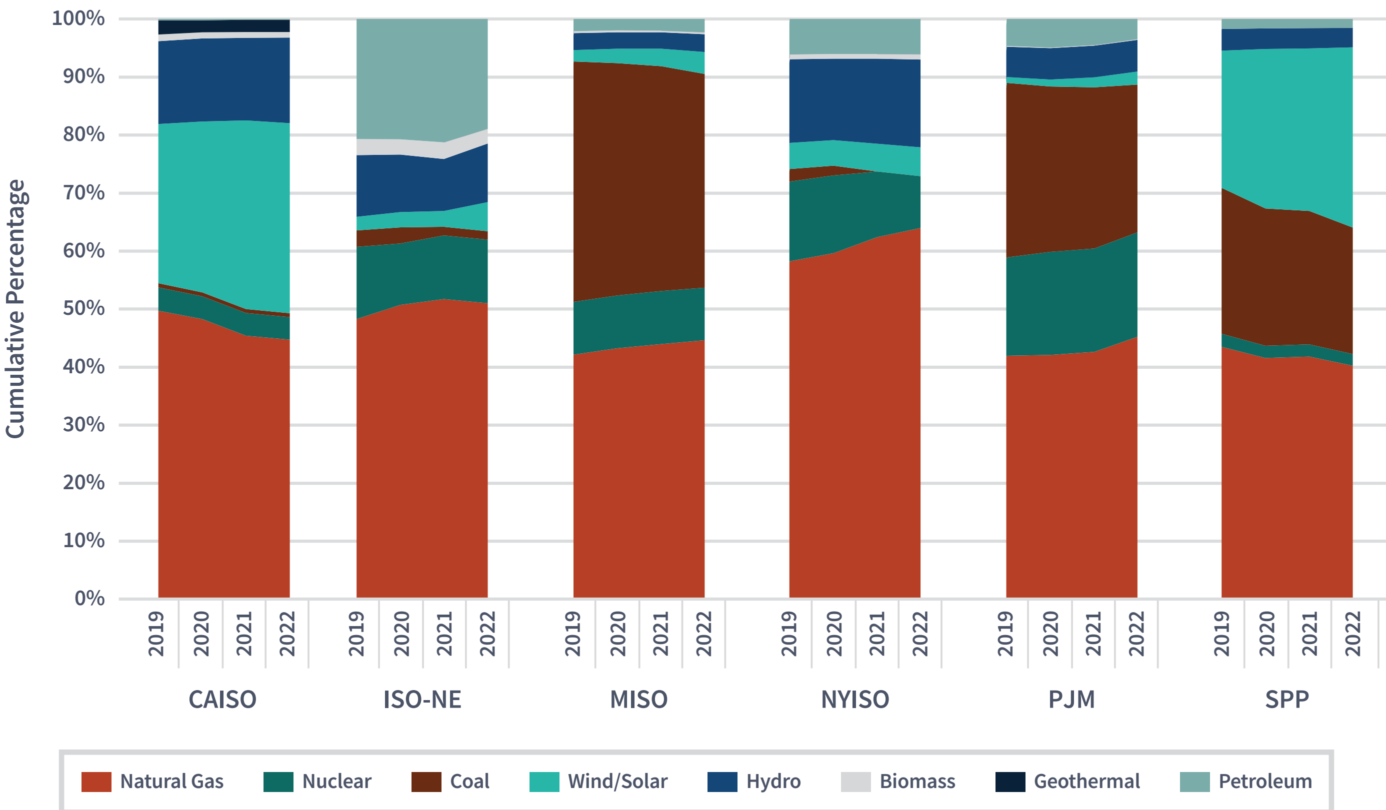
Figure 7 shows average heat rates across reporting entities by technology type from 2019 to 2022. Natural gas-fired steam generators generally had the highest average heat rate within CAISO, NYISO, and SPP over this time.[15] Combined cycle generation resources had the lowest average heat rate, except for ISO-NE in 2019, 2021, and 2022, where combustion turbines had the lowest average heat rate. However, NYISO and PJM report similar and relatively constant heat rates for oil, coal, and combustion turbine generating resources.[16] Combined cycle average heat rates appear to be the most stable over time across all reporting entities.

14 Energy Information Administration, "Natural gas-fired electricity conversion efficiency grows as coal remains stable." https://www.eia.gov/todayinenergy/detail.php?id=32572.

15 Natural gas resources did not have the highest average heat rate in CAISO between 2019 and 2021 or in MISO between 2020 and 2022. Oil units in ISO-NE had the highest average heat rate in 2019, 2020, and 2021.

16 PJM does not collect heat rate data. PJM's heat rate data came from Monitoring Analytics' annual *State of the Market Report for PJM* (State of the Market Report). The State of the Market Report reporting categories do not exactly match the data FERC requested.

**Figure 8: Generating Capacity Mix by Fuel Type, 2019 to 2022**




Source: Based on FERC-922 information collection

# FUEL DIVERSITY

## Generating Capacity by Fuel Type

The fuel diversity metric measures the fuel-type mix of installed generating capacity. Net summer capacity represents the maximum output that generating equipment can supply to meet system load at the time of summer peak demand (i.e., period of June 1 through September 30). This metric provides insight into the different types of generating capacity installed in different regions.

Generating capacity mix of certain regions reflects increasing percentages of renewable and natural gas-fired capacity and flat or declining percentages of coal-fired capacity. Figure 8 illustrates the generating capacity mix by fuel type in RTOs/ISOs and non-RTOs/ISOs utilities.

*Natural gas-fired generating capacity*

All RTOs/ISOs report natural gas-fired capacity as the largest single fuel type from 2019 to 2022. The largest increase in natural gas-fired generation capacity occurs in NYISO, increasing from 58% in 2019 to 64% in 2022. ISO-NE, MISO, and PJM report modest increases in natural gas-fired generation capacity over the four-year time period. In contrast, natural gas-fired capacity relative to total capacity decreased in CAISO and SPP, falling 8 percentage points in CAISO from 49% in 2019 to 41% in 2022, and from 43% in 2019 to 40% in 2022 in SPP. The decline in the share of natural gas-fired capacity in these regions is likely driven by the relatively large increases in wind and solar generating capacity, instead of natural gas retirements.

*Nuclear generating capacity*

Respondents report relatively constant shares of nuclear generating capacity. The shares of nuclear generating capacity by respondent for 2022 are, from greatest to least: PJM (18%); ISO-NE (11%); NYISO (9%); MISO (9%); CAISO (4%); and SPP (2%). NYISO experienced the largest change in nuclear generating capacity, declining from 14% in 2019 to 9% in 2022.

*Coal-fired generating capacity*

MISO, PJM, and SPP report the highest shares of coal-fired generating capacity among RTOs/ISOs in 2022. The share of MISO's installed coal-fired capacity declined from 41% in 2019 to 37% in 2022. PJM reports the largest change in coal-fired generation capacity as a share of total capacity, falling from 30% in 2019 to 25% in 2022. SPP also reports a decline in the share of coal-fired generation capacity, declining from 25% of installed capacity in 2019 to 22% in 2022. CAISO, ISO-NE, and NYISO report shares of coal-fired generating capacity under 3%. Unlike the situation with natural gas-fired capacity, the decline in share of coal-fired capacity is likely driven both by coal retirements and relatively large increases in wind and solar generating capacity.

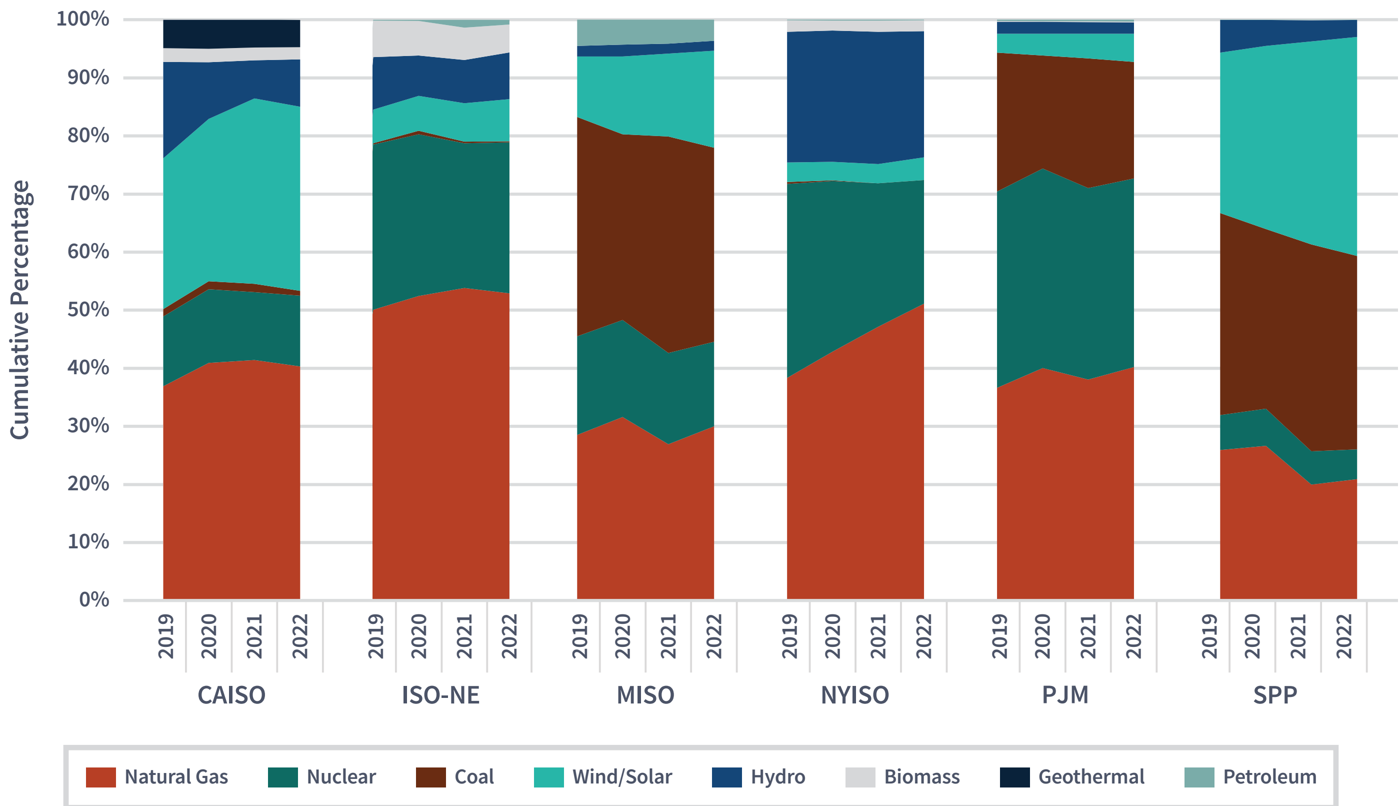
*Wind and solar generating capacity*

Among RTOs/ISOs, SPP and CAISO report the largest shares of installed wind and solar generating capacity. As of 2022, wind and solar generators represented 31% of installed capacity in SPP, and 30% of installed capacity in CAISO. The largest relative increase in generating capacity of these resource types occurred in SPP, where the share of wind and solar capacity increased from 24% in 2019 to 31% in 2022.

## Generation by Fuel Type

This metric measures the percentage mix of fuel types used to generate electricity (generation fuel diversity). The mix of fuels used to generate electricity in a given time period follows from, among other factors, the types of generating capacity in service and conditions in fuel markets. This metric reflects the fuel types used to generate electricity over the four-year period from 2019 to 2022, whereas generating capacity mix by fuel type, reflected in Figure 8, represents capacity in place at the time, whether or not it was generating power. Figure 9 shows the share of generation by fuel type from 2019 to 2022.

**Figure 9: Share of Total Generation by Fuel Type**




**NOTES:** The natural gas-fired generation in NYISO includes all generation from dual-fuel (natural gas and oil) resources.

Source: Based on FERC-922 information collection

*Natural gas and coal generation*

NYISO reported the largest increase in the share of generation from natural gas-fired resources, from 38% in 2019 to 51% in 2022. In SPP, the share of generation from natural gas-fired resources decreased from 26% in 2019 to 21% in 2022. The other RTO/ISOs reported modest increases in the share of generation from natural gas-fired resources from 2019 to 2022.

MISO, PJM, and SPP relied most heavily upon coal-fired generation to meet energy requirements from 2019 to 2022; however, the share of coal-fired generation declined in these regions over that period. PJM reports that generation produced from coal declined from 24% in 2019 to 20% in 2022. In MISO, the share of generation from coal-fired generators declined from 37% in 2019 to 33% in 2022. In SPP, the share of generation from coal-fired resources declined from 35% in 2019 to 33% in 2022.

*Nuclear generation*

Most of the respondents report minor changes in the share of total generation from nuclear plants. NYISO reports the largest change in the share of generation from nuclear plants, which decreased from 33% in 2019 to 21% in 2022, due to the retirement of the 3,216 MW Indian Point Nuclear Generating Unit 2 in April of 2020. The other RTO/ISOs report modest declines or no changes in the share of total generation from nuclear plants from 2019 to 2022.

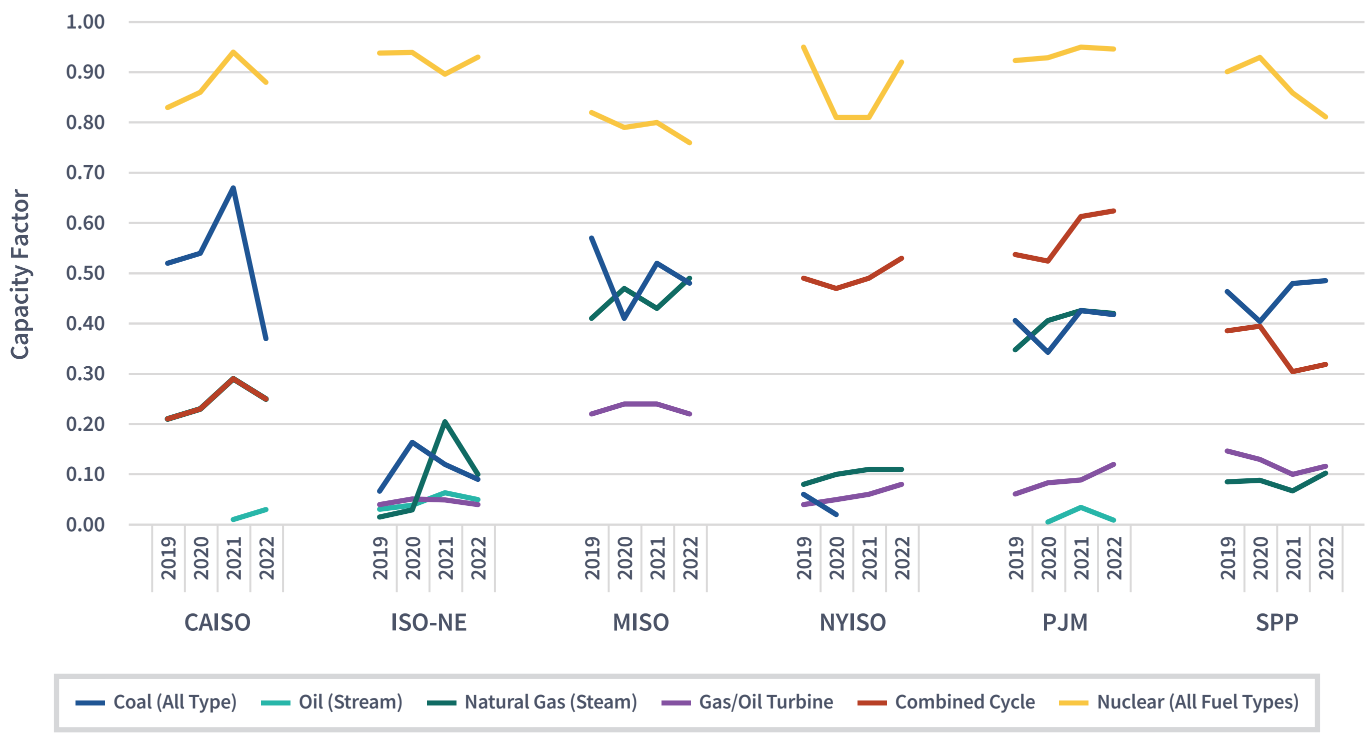
*Wind and solar generation*

All RTOs/ISOs report increases in the proportion of energy generated from wind and solar resources between 2019 and 2022. SPP, MISO, and CAISO report the largest gains in the share of wind and solar generation among RTOs/ISOs, with SPP increasing from 28% in 2019 to 38% in 2022, MISO increasing from 10% in 2019 to 17% in 2022, and CAISO increasing from 26% in 2019 to 32% in 2022. ISO-NE, NYISO, and PJM report increases of less than 2% in the proportion of energy generated from wind and solar resources from 2019 to 2022.

## CAPACITY FACTOR BY TECHNOLOGY TYPE

The capacity factor metric measures the actual energy produced at a generation station as a fraction of the maximum possible energy that could have been produced if the generator was operating at full capacity 24 hours a day, 365 days a year. The capacity factor metric aggregates generator output by generation technology types and provides insight into changes in the utilization rate of generation technology types. Figure 10 shows capacity factor by fuel type for non-renewable generation. Figure 11 shows capacity factor by fuel type for hydroelectric, wind, and solar generation.

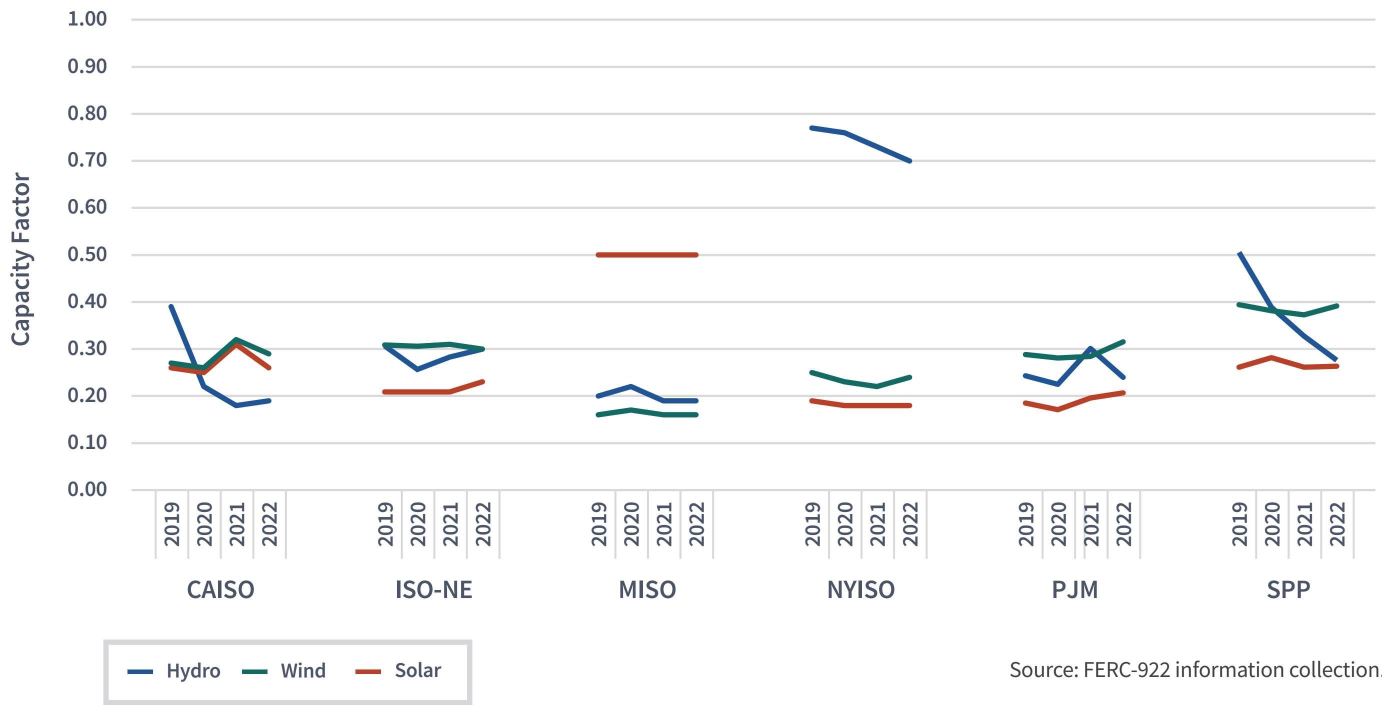
**Figure 10: Capacity Factor by Fuel Type, Fossil Fuels and Nuclear**




**NOTES:** De minimis capacity factors are not displayed. For CAISO, all natural gas resources are reported together under natural gas, gas/oil, and combined cycle.

Source: Based on FERC-922 information collection

**Figure 11: Capacity Factor by Renewable Fuel Type: Hydro, Wind, and Solar**




Source: FERC-922 information collection.

Across all respondents, nuclear generation had the highest capacity factors, with values ranging from 0.76 to 0.95 and an average of 0.88 over the reporting period. Combined cycle and coal generation had the second highest capacity factors after nuclear generation for most respondents. Combined cycle generation had an average capacity factor of 0.41 with values ranging from 0.21 to 0.62, while coal had an average capacity factor of 0.38 with values ranging from 0.02 to 0.67 over the reporting period. CAISO and SPP had coal generation with higher capacity factors than other fossil-fired generation, whereas ISO-NE, NYISO, and PJM had combined cycle generation with higher capacity factors than other fossil-fired generation.

Oil (steam), gas/oil turbine, and natural gas (steam) had the lowest capacity factors among respondents with values ranging from 0.001 to 0.06 for oil (steam), 0.04 to 0.29 for gas/oil turbine, and 0.02 to 0.49 for natural gas (steam).

With respect to renewable resources, hydroelectric, wind, and solar generation had average capacity factors of 0.35 for hydroelectric, 0.28 for wind, 0.27 for solar; with values ranging from 0.18 to 0.77 for hydroelectric, 0.16 to 0.39 for wind, and 0.17 to 0.50 for solar. CAISO, NYISO, and SPP report significant decreases in hydroelectric capacity factors over the reporting period.[17, 18, 19] However, NYISO had the highest capacity factor for hydroelectric generation with an average value of 0.74 over the reporting period. For most respondents, capacity factors for solar and wind resources remained steady over the reporting period. CAISO, ISO-NE, NYISO, PJM, and SPP report higher capacity factors for wind generation than solar generation.

## ENERGY EMERGENCY ALERTS (EEA LEVEL 1 OR HIGHER)

The energy emergency metric provides information on the frequency of energy emergencies. Respondents report the number of North America Electric Reliability Corporation (NERC) Energy Emergency Alerts (EEA) Level 1 or Higher in each reporting period.[20] An overview of the three levels of EEA is provided below.

1. EEA Level 1 — All available resources in use.
   During an EEA Level 1 event, the balancing authority is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required contingency reserves. Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. EEA Level 2 — Load management procedures in effect.
   During an EEA Level 2 event, the balancing authority is no longer able to provide its expected energy requirements and is an energy deficient balancing authority. An energy deficient balancing authority has implemented its operating plan(s) to mitigate emergencies and is still able to maintain minimum contingency reserve requirements.

3. EEA Level 3 — Firm load interruption is imminent or in progress.
   During an EEA Level 3 event, the energy deficient balancing authority is unable to meet minimum contingency reserve requirements.[21]

Table 2 shows the number of EEAs (Level 1 or Higher) and the number of EEA hours for each year the respondents report.

17 In CAISO, hydro capacity factors are consistent with the normal range depending on the snowpack conditions the CAISO area experiences each year. 2017 was one of the highest precipitation years in the recent record with a heavy snowpack, which allowed more hydro resources to operate deep into the summer and a greater amount of energy was produced relative to other years. CAISO assesses snowpack conditions each year in the summer assessment report.

18 In NYISO, the gradual decline in the capacity factor for New York hydroelectric resources over 2020-2022 is tied to the intermittent derating of the Niagara facility during the reconstruction of multiple 115 kV transmission facilities in western New York (necessitated by the retirement of coal units in the Buffalo area).

19 In SPP, the decline in reported hydroelectric power output over the specified window can be attributed to reduced total MW participation of hydro resources in the market. Hydro resources have reduced the amount of MW offered by submitting lower Economic Maximum parameters. The Economic Maximum dictates the maximum amount of MW the market can dispatch the resource to.

20 Information on EEAs is available at https://nercstg.nerc.com/pa/rrm/ea/Pages/Energy-Emergency-Alerts.aspx

21 See https://nerc.com/pa/stand/reliability%20standards/eop-011-2.pdf

**Table 2: Number of EEAs (Level 1 or Higher) and EEA Hours, by Year**

| Metric | Region | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Number of EEAs (Level 1 or Higher)** | CAISO | 2 | 6 | 2 | 6 |
| | ISO-NE | 0 | 0 | 0 | 1 |
| | MISO | 3 | 1 | 5 | 1 |
| | NYISO | 0 | 0 | 1 | 1 |
| | PJM | 1 | 0 | 0 | 5 |
| | SPP | 1 | 0 | 2 | 2 |
| **Number of EEA Hours (HH:MM)** | CAISO | 0:43 | 32:27 | 7:15 | 21:40 |
| | ISO-NE | 0:00 | 0:00 | 0:00 | 2:30 |
| | MISO | 12:15 | 11:20 | 29:20 | 3:35 |
| | NYISO | 0:00 | 0:00 | 6:24 | 0:06 |
| | PJM | 28:45 | 0:00 | 0:00 | 46:10 |
| | SPP | 4:15 | 0:00 | 91:25 | 3:33 |

Source: FERC-922 information collection.

Most respondents had few EEAs, if any, in any given year. However, there were some outliers. CAISO reports six EEAs in both 2020 and 2022, MISO reports three EEAs in 2019 and five in 2021, and PJM reports five EEAs in 2022. CAISO, MISO, and SPP report experiencing load shed during EEAs over the reporting period. CAISO reports 468 MW of load shed in 2020. MISO reports 6,494 MWh of load shed in 2020 and 1,633 MWh in 2021. SPP also reports 8,234 MWh of load shed in 2021. These load sheds are mostly attributable to winter storms (such as Uri and Elliott) and high heat events in these regions.

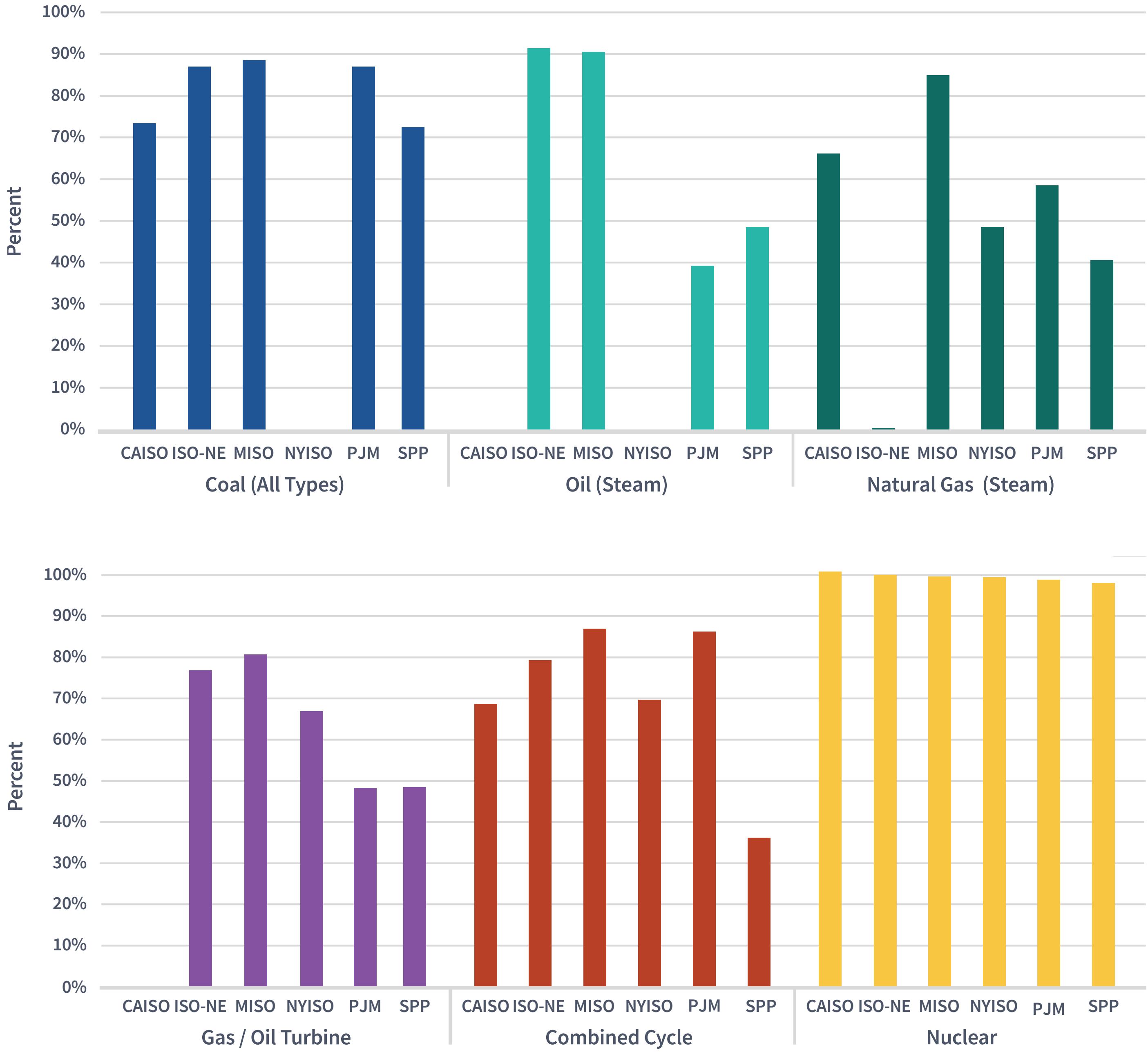
## PERFORMANCE BY TECHNOLOGY TYPE DURING EEA LEVEL 1 OR HIGHER

The performance by technology type during EEA Level 1 or higher metric provides information on aggregate performance of technologies by measuring the total five-minute intervals when an alert is present and how generators, by technology type, performed. The performance factor of a technology type measures the total MW generated from a technology type during an EEA Level 1 or higher as a percentage of the economic maximum of all MW for that technology type. Figure 12 displays the average performance factors for fuel types reported by the respondents for the reporting period.

Nuclear resources were the highest performing resources across the RTOs/ISOs during EEA events. Nuclear resource performance factors were at or near 100% on average over the period 2019 to 2022. Combined cycle resources generally exhibited strong performance during times of stress, with resource performance factors at near 70% or higher for four of the RTO/ISOs. All resources in MISO, regardless of fuel type, had relatively high performances during

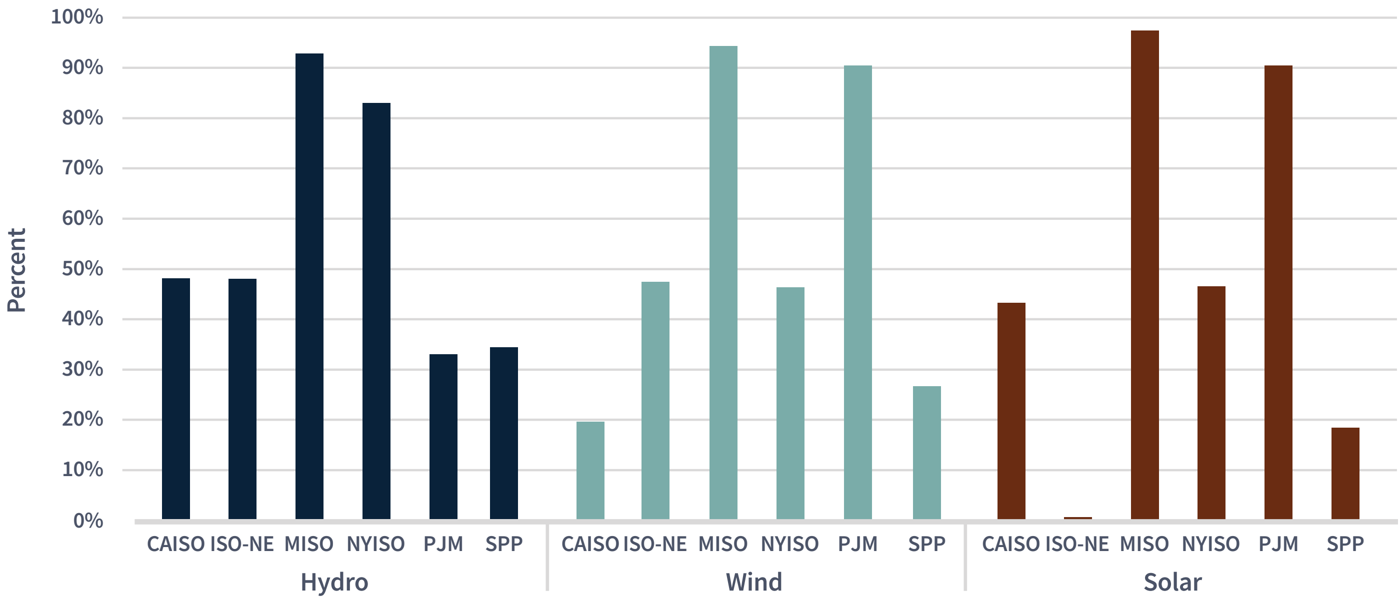
EEA events, relative to other regions. Performance factors for natural gas varied amongst the RTOs/ISOs. The lower performance factors for renewable resources during EEA events may be attributed to the fact that they are intermittent resources subject to weather conditions (wind, cloudy conditions, etc.) influencing wind and solar production.[22, 23]

**Figure 12: Average Performance by Technology Type for EEAs Level 1 or Higher**




22 In CAISO and NYISO, some of the EEA hours occurred during evening hours when solar resources were ramping down.

23 In SPP, the reported reduction was caused by different factors. In 2019, for example, the events giving rise to EEAs had an impact, but weather models had already caused SPP to forecast lower variable energy resource output. In 2021, poor performance by most wind farms resulted from Winter Storm Uri and related icing on turbines. In 2022, Winter Storm Elliot caused turbine icing and poor performance by most wind farms.




Source: FERC-922 information collection.

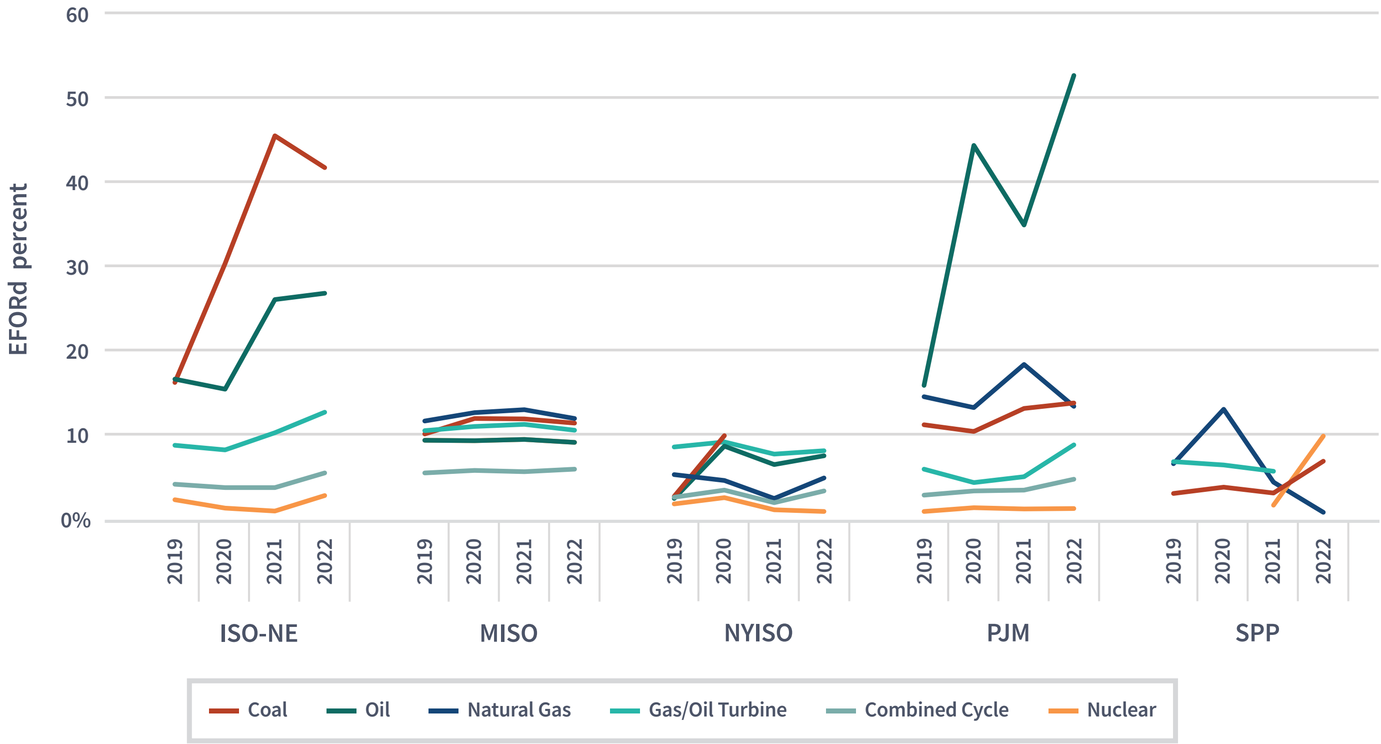
## RESOURCE AVAILABILITY - EQUIVALENT FORCED OUTAGE RATE DEMAND

The resource availability metric measures the forced outage rates across different technology types. A forced outage occurs when a generator is unavailable to provide energy from all or part of its capacity. Greater resource availability can result in the commitment of fewer higher-cost peak generators (or fewer high-cost imports), thereby resulting in reduced costs. This metric is based on effective forced outage rate demand (EFORd).[24] Lower EFORd values are preferred since this indicates greater resource availability and lower costs.

As shown in Figure 13, EFORd values for non-renewable resources varied between respondents and by technology type.[25] NYISO and SPP had the lowest overall EFORd values among respondents. Nuclear and combined cycle resources had the lowest incidences of forced outages. Nuclear resources had EFORd values ranging from 0.03% to 9.78% and combined cycle resources had EFORd values ranging from 0.15% to 5.85%. The non-renewable technology type with the highest EFORd values varied by region. Coal resources had the highest EFORd values in ISO-NE, ranging from 16.14% to 45.44%. Oil (steam) resources had the highest EFORd values in PJM ranging from 15.76% to 52.58%. Oil (steam) and gas/oil turbine resources had the highest EFORd values in NYISO, ranging from 4.57% to 11.33% for oil (steam) resources and 6.81% to 8.94% for gas/oil turbine resources. Natural gas (steam) resources had the highest EFORd values in MISO, ranging from 11.56% to 12.91%, and in SPP, ranging from 0.71% to 12.93%.

24 *See* Common Metrics Information Collection User Guide Version 1.0, Docket No. AD19-16-000, Appendix C.
25 While the information request specified EFORd, respondents' submissions reveal the use of other calculation methods, such as effective forced outage rate (EFOR). Due to concerns about the comparability of the responses received, Commission staff only includes a graphical comparison of EFORd values that were submitted for non-renewable resources.

**Figure 13: Resource Availability (EFORd) by Technology Type.**




**NOTES:** CAISO does not calculate EFORd for the reporting period. For NYISO, a simple average of the Winter Season (November to April) EFORds of each unit has been reported.

Source: FERC-922 information collection.

# Overview of Group 2 Energy Market Metrics

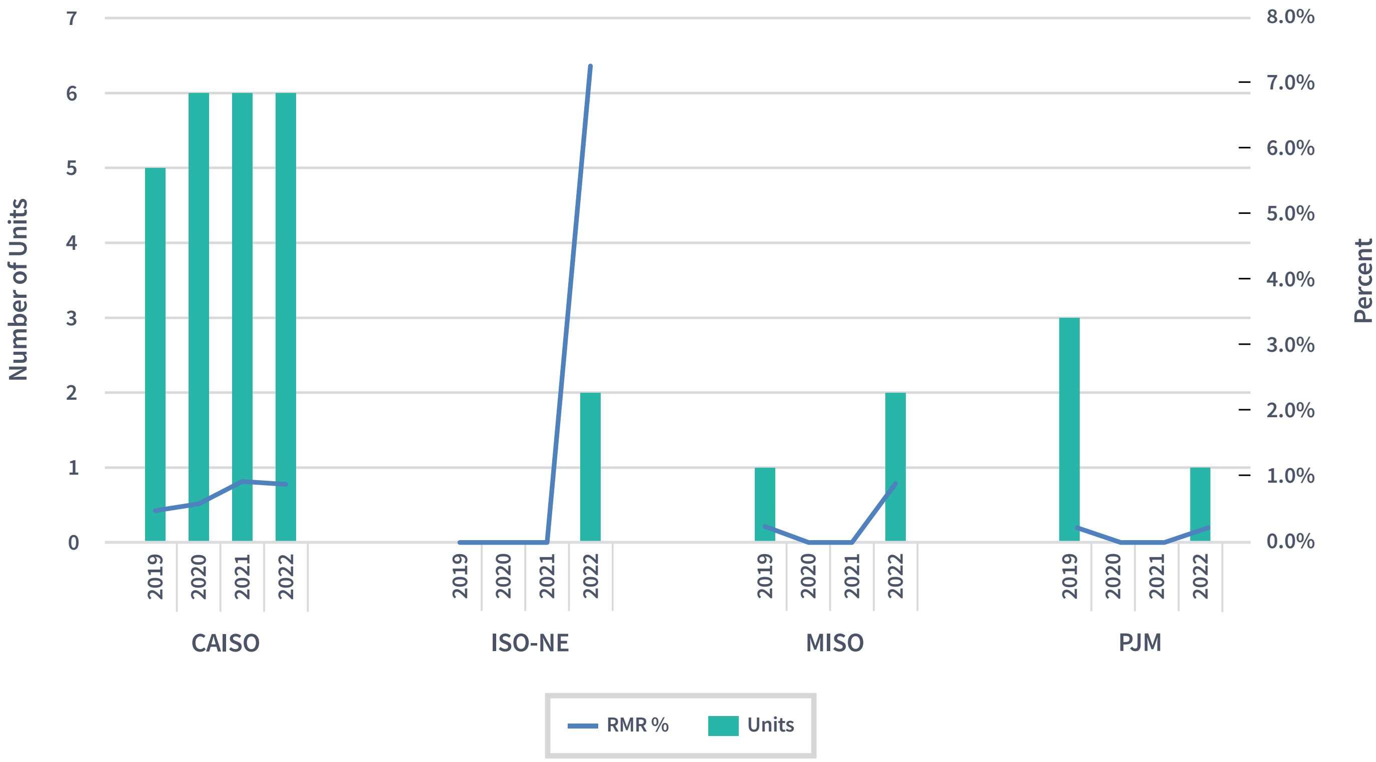
RTOs/ISOs report additional metrics that are part of Information Collection FERC-922 that measure the performance of RTO/ISO day-ahead and real-time markets. The following sections contain an overview of RTO/ISO energy market metrics.

## NUMBER AND CAPACITY OF RELIABILITY MUST-RUN RESOURCES

The reliability must-run (RMR) metric provides a measure of the degree to which an RTO/ISO must depend on specific, critical generation facilities to maintain reliability. An RMR unit is typically a unit that continues to operate under a temporary contract after a planned retirement decision to address a reliability need. RMR units' energy and/or ancillary services are typically procured through out-of-market actions. RMR contracts are defined differently by each RTO/ISO. Four of the RTO/ISOs rely on RMR units and the general naming conventions for each RTO/ISO respondent for this metric are provided below:

- ISO-NE: Reliability Must-Run
- CAISO: Reliability Must-Run Generation
- MISO: System Support Resources
- PJM: Must-Run for Reliability Generation

**Figure 14: Capacity Under RMR Contract, 2019 to 2022**




**NOTES:** MISO and PJM reported zero RMR units for 2020 and 2021.

Source: FERC-922 information collection.

Figure 14 illustrates the capacity under RMR contracts or similar arrangements in these four RTOs/ISOs from 2019 to 2022. ISO-NE reports the highest percent of capacity under such agreements, at approximately 7.5%. In CAISO, capacity under such agreements increased from 260 MW to 469 MW from 2019 to 2022, representing 0.89% of the total available installed capacity in 2022. Capacity under RMR contract or similar arrangements in MISO and PJM varied over the same period. For capacity under such agreements, MISO reports 335 MW in 2019 and 1,195 MW in 2022, and PJM reports 416 MW in 2019 and 410 MW in 2022. NYISO and SPP did not report any RMR contracts or similar arrangements during this period.

## RELIABILITY MUST-RUN CONTRACT USAGE

The RMR contract usage metric includes information from contracts in effect during any portion of the reporting period. If an RMR contract is in effect during part of the reporting period, respondents included information from the contract in that period. If the RMR contract is in effect for parts of two reporting periods, respondents included the appropriate information from that RMR contract in each reporting period. Table 3 reports the total MWh provided by RMR units and Table 4 reports the cost of RMR units during the reporting period.

### Table 3: Total MWh Provided by RMR Units

| RTO/ISO | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| CAISO | 95,119 | 62,729 | 22,955 | 20,957 |
| ISO-NE | | | 529,069 | 2,035,569 |
| MISO | 183,488 | - | - | 426,825 |
| PJM | - | - | - | 3,005 |

Source: FERC-922 information collection.

### Table 4: Total Cost of RMR Units

| RTO/ISO | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| CAISO | $3,046,968 | $11,164,994 | $32,885,296 | $33,542,095 |
| ISO-NE | | | $9,826,310 | $523,652,736 |
| MISO | $(5,214,409) | $ - | $ - | $11,657,407 |
| PJM | $14,238,736 | $ - | $ - | $53,871,424 |

**NOTES:** System Support Resource contract data for this metric is governed by section 38.2.7 of the MISO tariff. PJM reports that certain recoverable costs may extend beyond the deactivation date per the details of each RMR contract.

Source: FERC-922 information collection.

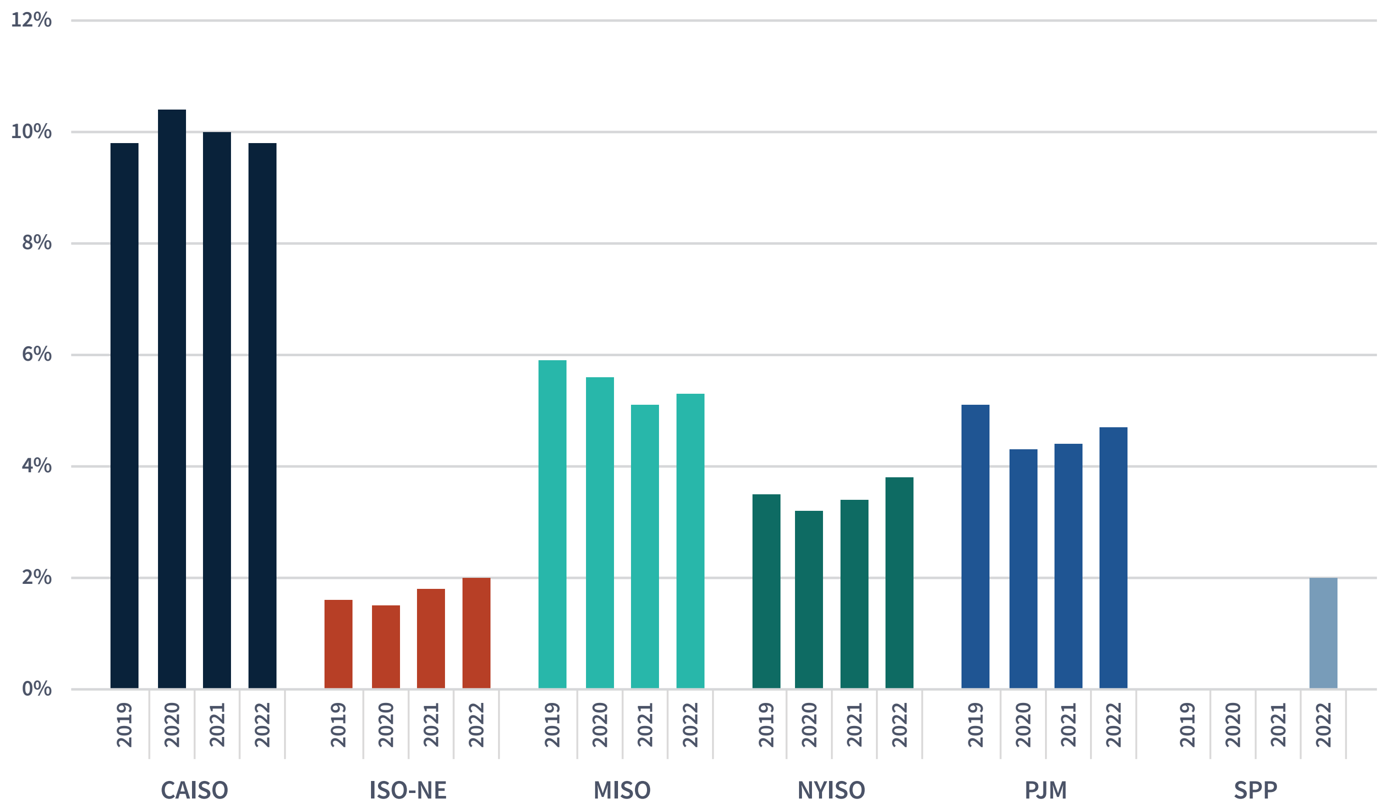
## DEMAND RESPONSE CAPABILITY

The demand response capability metric provides an indication of the role played by demand response resources in maintaining short-term and long-term reliability in RTOs/ISOs. Demand response can lead to deferred investment in generation capacity by reducing load during peak periods. In Order No. 745, the Commission established rules for compensating demand response resources in organized wholesale electricity markets.[26] Demand response resources participating in organized wholesale electricity markets may be compensated through energy and/or capacity payments in the various demand response programs specific to RTOs/ISOs. In addition, demand response resources may earn other revenues through bilateral arrangements and ancillary services.[27]

26 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187, *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), reh'g denied, Order No. 745-B, 138 FERC ¶ 61,148 (2012), vacated sub nom. *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760 (2016).

27 Order No. 745, 134 FERC ¶ 61,187 at P 59 n.126.

**Figure 15: Demand Response as a Percentage of Total Installed Capacity**




**NOTES:** These figures do not include any resources not registered and controlled by the RTO/ISO but may include behind-the-meter demand response programs. These figures do not include energy efficiency programs or resources.

Source: FERC-922 information collection.

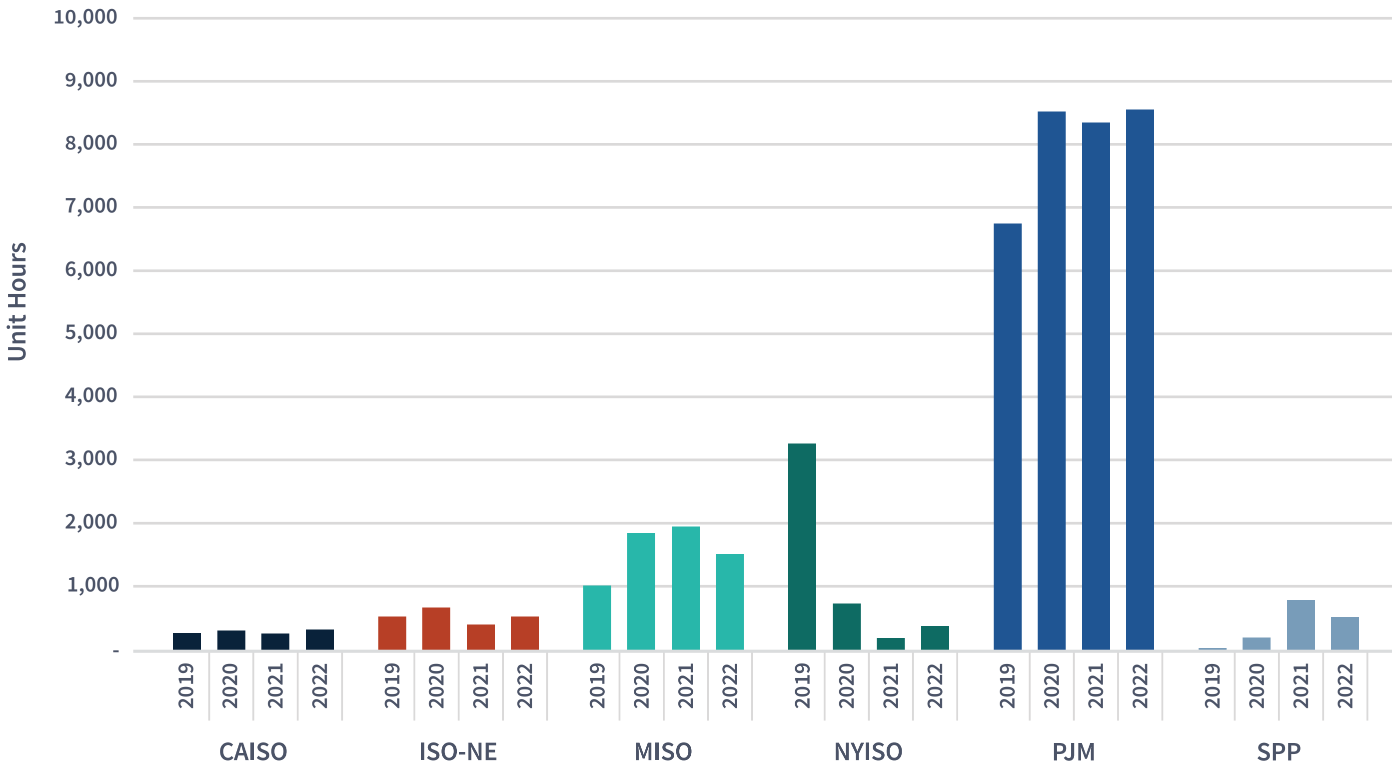
Figure 15 shows demand response as a percentage of total installed capacity in the RTOs/ISOs from 2019 to 2022. During this period, CAISO reports the largest percentage of demand response as a percentage of total installed capacity at approximately 10%. MISO, NYISO, and PJM all report demand response as a percentage of total installed capacity in a range from 3-6% during the reporting period. No region displayed a consistent upward or downward trend in demand response as a percentage of total installed capacity during the reporting period.

## UNIT HOURS MITIGATED

The unit hours mitigated metric provides an indication of the frequency that resources have been mitigated to protect against the exercise of market power. This metric shows the number of unit-hours when mitigation occurred, regardless of whether the mitigated unit set the clearing price. For example, if there is at least a single resource that is mitigated in every hour during the year, the related mitigation value would be 8,760 unit-hours.

As shown in Figure 16, RTOs/ISOs report varying ranges of the number of unit-hours with active mitigation in the day-ahead market. Across all the RTOs/ISOs, PJM reports the highest number of unit-hours mitigated from 2019 to 2022. CAISO, ISO-NE, and SPP report the lowest number of unit-hours mitigated in the day-ahead market among the RTOs/ISOs.

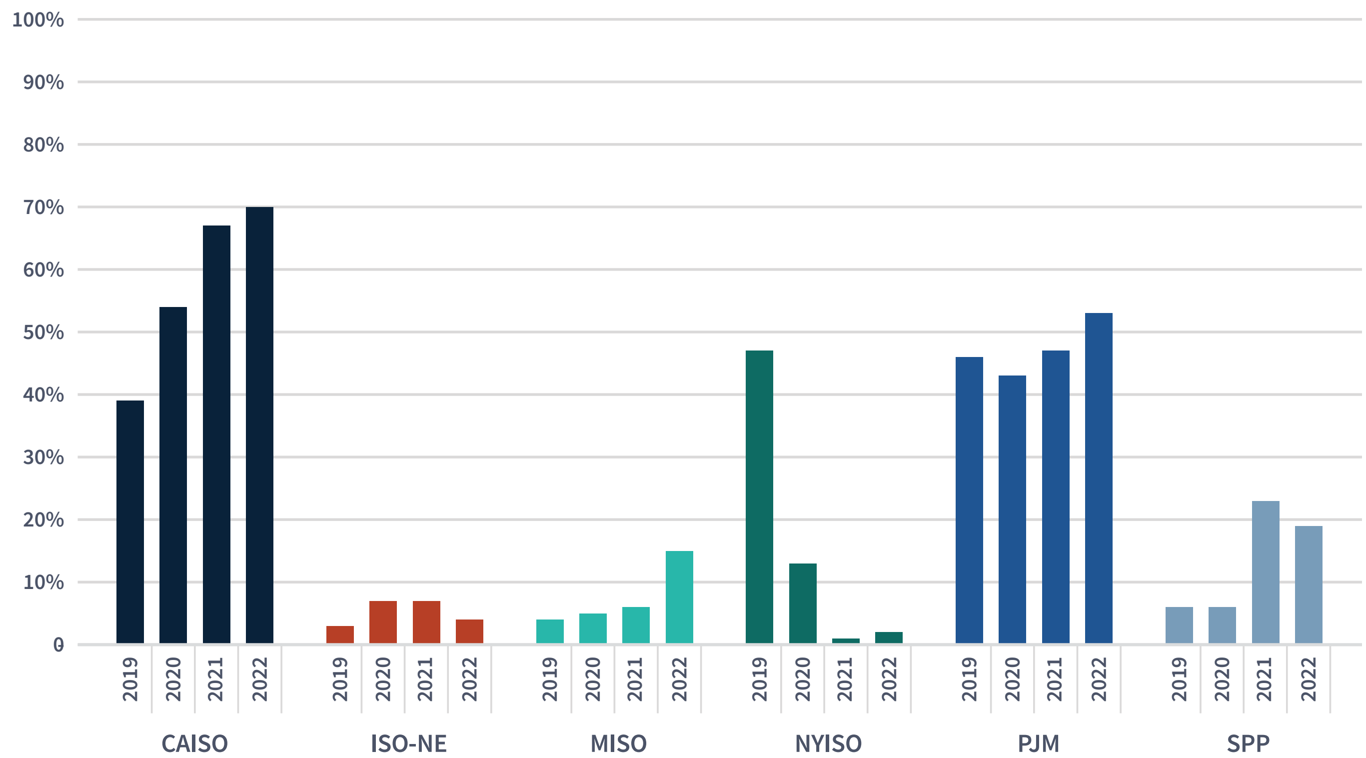
**Figure 16: Unit Hours with Active Day-ahead Mitigation**




Source: FERC-922 information collection.

As shown in Figure 17, RTOs/ISOs report varying percentages of hours with active mitigation in the real-time market as well. Across RTOs/ISOs, CAISO reports the highest percentage of hours mitigated from 2019 to 2022, with an upward trend over those years. ISO-NE reports the lowest percentage of hours mitigated in the real-time market among the RTOs/ISOs during the reporting period.

**Figure 17: Percent of Intervals with Real Time Active Mitigation**




**NOTE:** ISO-NE's original data submission was revised by Commission staff to be consistent with the guidance Commission staff provided in the User Guide for the FERC-922 information collection.

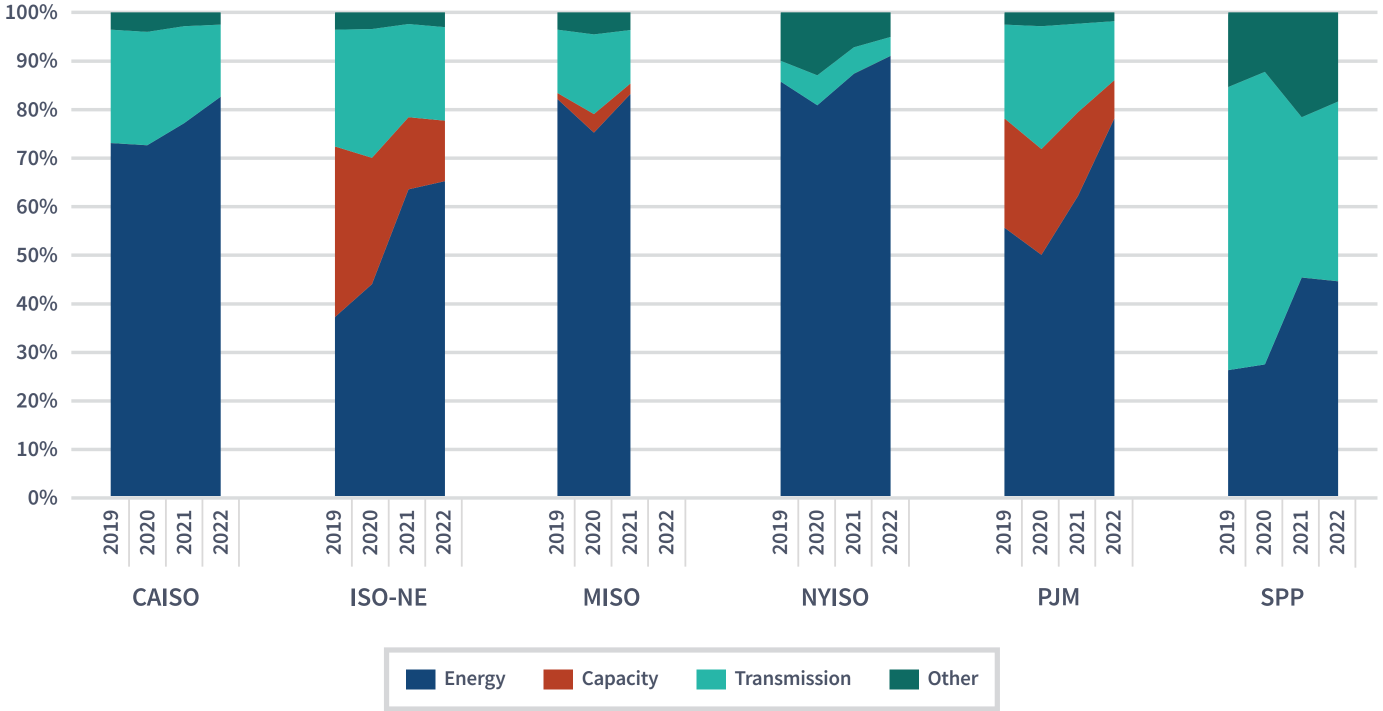
Source: FERC-922 information collection.

## WHOLESALE POWER COSTS BY CHARGE TYPE

The wholesale power costs by charge type metric disaggregates costs paid by load, thereby providing a comprehensive assessment of all RTO/ISO market costs, as shown in Figure 18. The cost breakdown includes the following cost categories: capacity costs, energy costs, operating reserve costs, ancillary services costs, transmission costs, and RTO/ISO costs and regulatory fees. This metric should be considered within the context of different fuel mixes and market designs in each RTO/ISO region.

As shown in Figure 19, ISO-NE reports the highest total wholesale power costs, with capacity costs representing a significant component. The three eastern RTOs/ISOs (ISO-NE, NYISO, and PJM) operate centralized capacity markets and report varying levels for the capacity-related component of wholesale power costs. MISO also operates a voluntary capacity market to help ensure resource adequacy in its region. MISO reports a relatively low capacity-related component of wholesale prices as of 2019. A complete dataset containing the wholesale power costs breakdown for each RTO/ISO is in Appendix B.

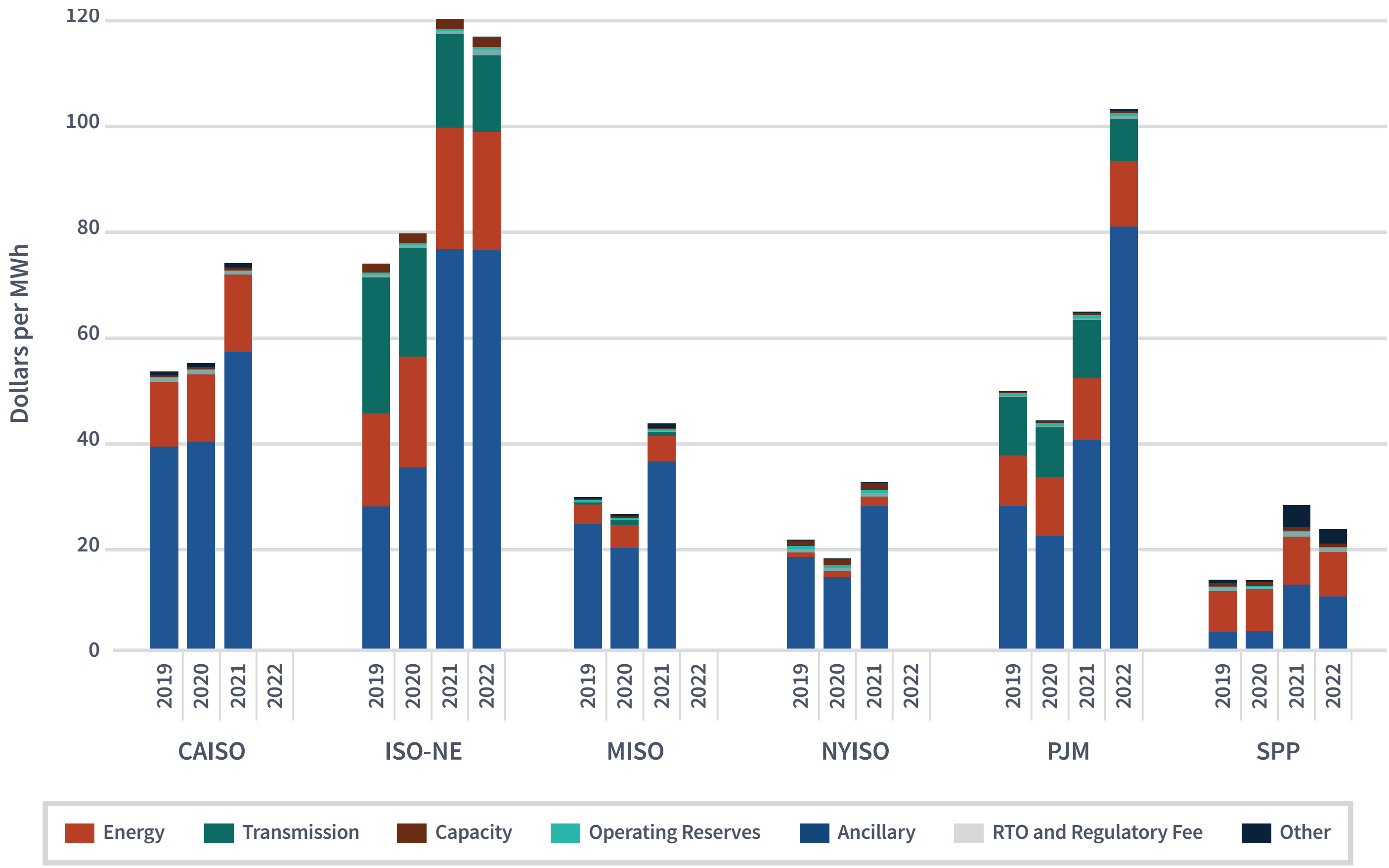
**Figure 18: Wholesale Power Costs by Charge Type**




**NOTE:** The values for capacity in NYISO are not available as the NYISO does not record the capacity components of total wholesale power. MISO did not have data available for 2022 at the time data submissions were due.

Source: FERC-922 information collection.

**Figure 19: Wholesale Power Cost Breakdown, Dollars per MWh**




**NOTE:** Table 10 in Appendix B contains the detailed data submitted for wholesale costs by RTO/ISO. The values for capacity in NYISO are not available as the NYISO does not record the capacity components of total wholesale power cost.

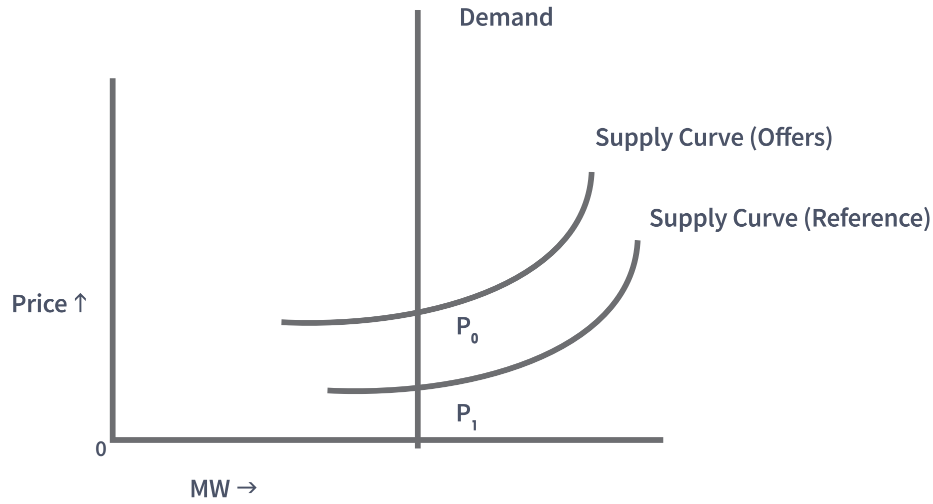
Source: FERC-922 information collection.

## PRICE COST MARKUP

The price cost markup metric measures the differences in system-wide price that would result from using cost-based offers/reference levels instead of as-submitted generation offers. That difference represents the price cost markup. This metric also examines average markups in the top and bottom ten percent of hours based on system-wide energy prices.

To calculate this figure, RTOs/ISOs construct two different supply curves for each five-minute interval in the reporting period. One supply curve is based on the generation offers and the second curve is based on the RTO/ISO reference cost for each unit. The intersection of each such supply curve with the demand curve provides a price for that five-minute interval.

The intersection of the demand curve and the offer-based supply curve provides the “price” for that interval. The intersection of the demand curve and the reference cost-based supply curve provides the “cost” for that interval. The difference between the calculated “price” and the “cost” provides the Price Cost Margin for that interval which is then averaged across the reporting period. The visual representation of the calculation is shown below.




As shown in Figure 20, price cost markups varied between respondents during the reporting period. Respondents report average price cost markups ranging from a low of negative $25.49/MWh (SPP in 2022)[28] to a high of $11.96/MWh (MISO in 2022). The average price cost markup across the RTO/ISOs during the reporting period is negative $0.44/MWh. This indicates that generation facilities in these RTO/ISOs, on average, bid into the market at or near their reference points which reflects a competitive market, setting a marginal cost of energy very close to that based on the RTO/ISOs reference points. Except for NYISO and SPP, respondents report positive price cost markup values during the reporting period from 2019 to 2022. A negative price cost markup indicates that, on average, generation facilities bid into the market below their reference levels.

28 For SPP, during the reporting period, there were significant drops in the price cost markups due to high levels of wind penetration on the SPP system. To construct the cost curves, SPP used the submitted day-ahead economic maximum values and the mitigated offers. To construct the offer curves, SPP used real-time economic maximum values and real-time offers. The day-ahead economic maximum of wind resources was significantly lower than the real-time economic maximum for wind resources during the reporting period, which resulted in significantly lower (negative) price cost markups.

**Figure 20: Price Cost Markup, 2019 to 2022**


**NOTE:** PJM reports that it sources the data for this metric from Monitoring Analytics' State of the Market Report, which defines this metric as the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price- or cost-based, and the system price based on the cost-based offers of those marginal units.

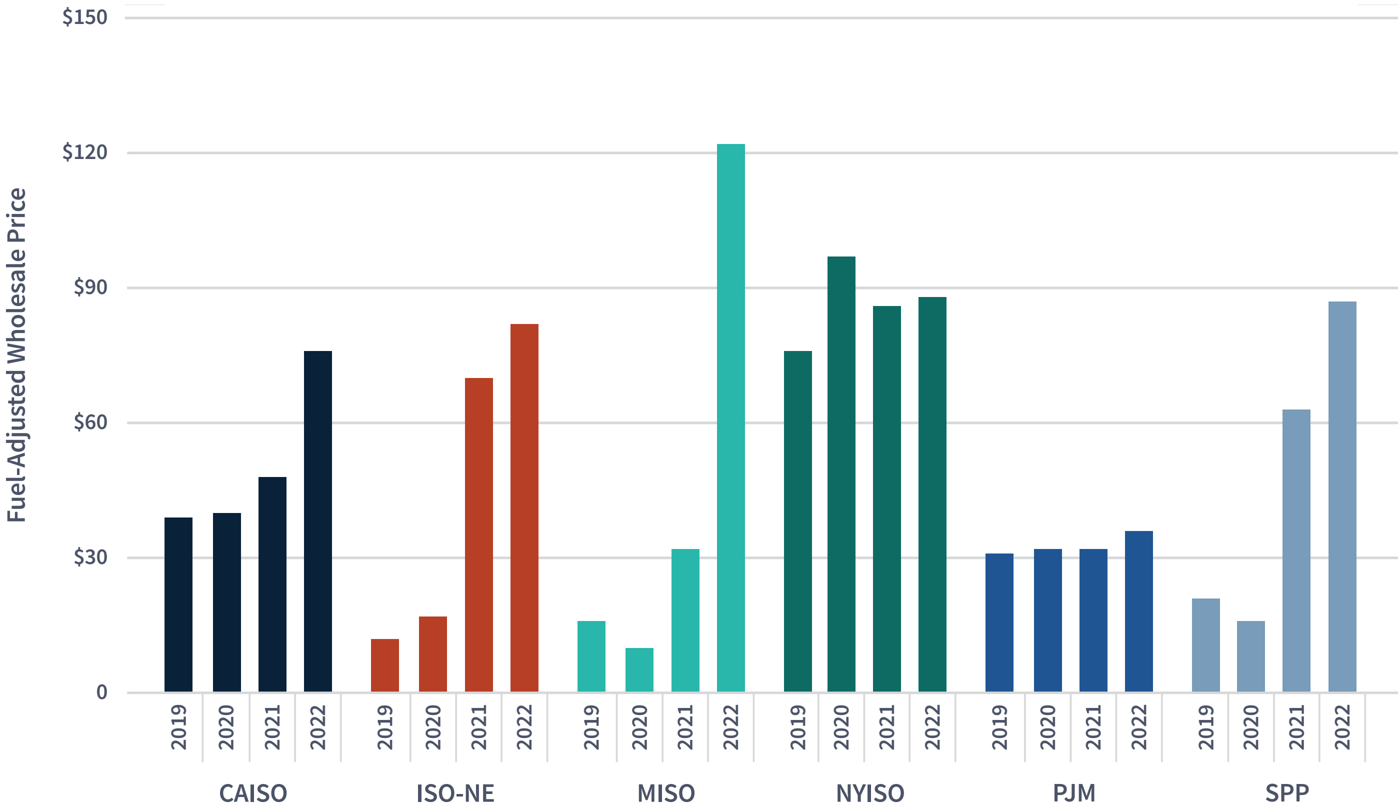
Source: FERC-922 information collection.

## FUEL-ADJUSTED WHOLESALE ENERGY PRICE

The fuel-adjusted wholesale energy price metric measures the load-weighted, fuel-adjusted locational marginal price across the RTOs/ISOs for a given reporting period and is derived by holding fuel costs constant over a defined time period. This metric allows for wholesale energy price comparisons while removing fuel price volatility.

As shown in Figure 21, MISO reports the highest and lowest fuel-adjusted price among RTOs/ISOs from 2019 to 2022. Respondents report fuel-adjusted wholesale energy prices averaging $51.24/MWh and ranging from $10.41/MWh to $121.80/MWh over the reporting period. Each RTO/ISO uses a different base year for its fuel adjustments. For instance, PJM uses a fuel cost reference year of 1999. CAISO and NYISO use a base fuel cost reference year of 2022. ISO-NE, MISO, and SPP use a base fuel cost reference year of 2021, 2014, and 2019, respectively.

**Figure 21: Load-weighted, Fuel-adjusted Locational Marginal Prices, 2019 to 2022**




Source: FERC-922 information collection.

## ENERGY MARKET PRICE CONVERGENCE

Convergence of day-ahead and real-time energy prices is an indication of the efficiency of RTO/ISO markets. Since most energy settlements and generator commitments occur in the day-ahead market, day-ahead price convergence with the real-time market ensures efficient day-ahead commitments that reflect real-time operating needs.

Figure 22 shows the trend in convergence of day-ahead and real-time energy prices during the 2019 to 2022 reporting period for each RTO/ISO. The blue lines show the load-weighted average price differences between the real-time and day-ahead market, while the red lines show the load-weighted average absolute value of the differences in the real-time and day-ahead market. The load-weighted price difference (green line) is the day-ahead price subtracted from the real-time price and indicates if prices, on average, are higher in the day-ahead or real-time market. Positive values indicate load-weighted real-time prices are, on average, higher than the load-weighted day-ahead prices. Negative values indicate load weighted day-ahead prices are, on average, higher than load-weighted real-time prices. The absolute price difference (red line) measures the magnitude of load-weighted price differences between the day-ahead and real-time price, regardless if the load-weighted day-ahead price is greater than the load-weighted real-time price or vice versa. In both cases, smaller differences in magnitude are an indicator of price convergence between the real-time and day-ahead market prices.

**Figure 22: Load-weighted Average of Day-Ahead & Real-Time Price Differentials**


Source: FERC-922 information collection.

Respondents report an upward trend in the load-weighted average of absolute value prices differences between the day-ahead and real-time markets over the reporting period. ISO-NE reports the lowest average of absolute value price differences, with an average difference of $9.89/MWh from 2019 to 2021. Conversely, SPP reports an average difference of $21.36/MWh, indicating a higher degree of price divergence from 2019 to 2022.

Figure 23 shows the difference in the day-ahead and real-time market prices over day-ahead market prices. The green line shows the quotient of the price difference and day-ahead prices, the purple line shows the absolute value of the quotient. Except for CAISO and SPP, the differences in prices relative to the day-ahead price are similar across the other respondents and are relatively stable over the reporting period.

**Figure 23: Load-weighted Average of Quotient and Absolute Value of Quotient of Price Difference and Day-Ahead Market Price**


Source: FERC-922 information collection.

## CONGESTION MANAGEMENT

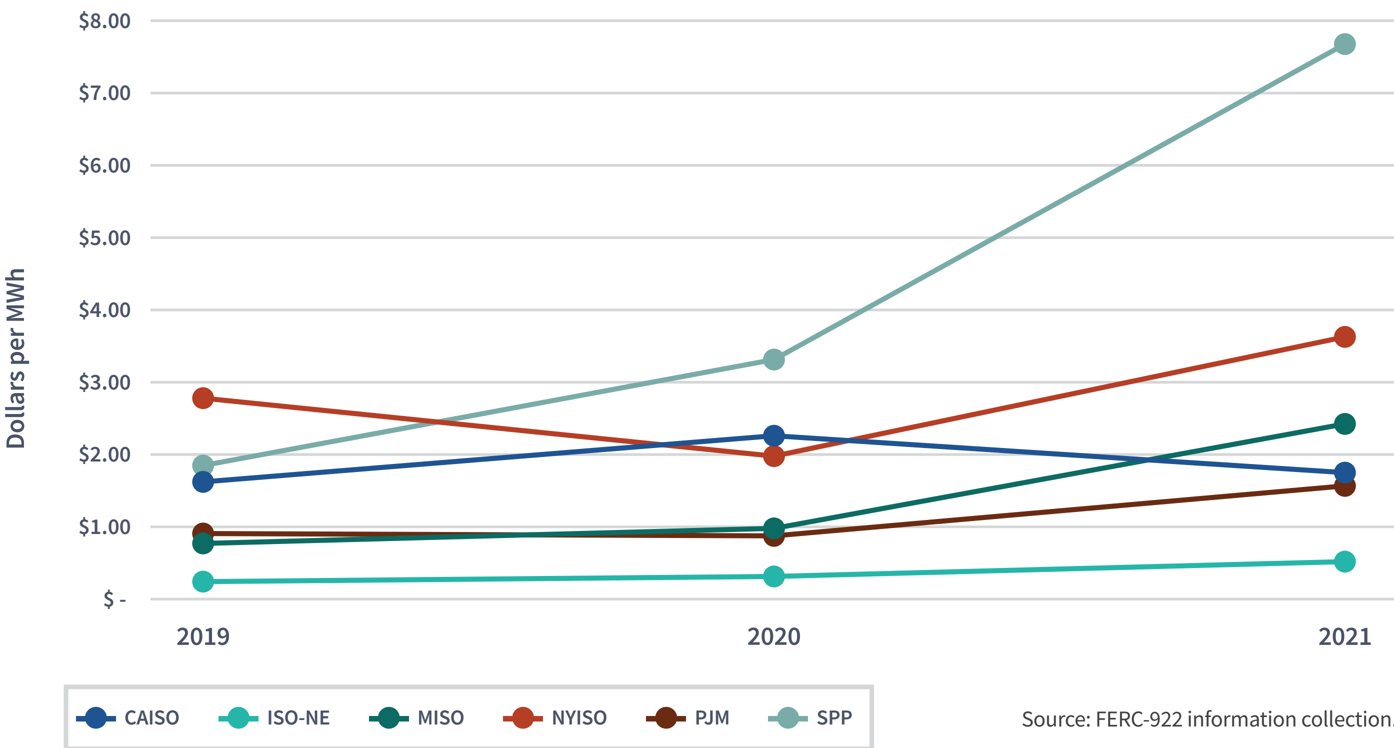
Congestion represents the cost to customers of paying for more expensive energy because physical transmission line limits do not allow full delivery of least-cost energy. This metric can be measured in two ways. First, annual congestion charges divided by the MWh of load served reflects congestion charges relative to load, indicating the effectiveness of RTO/ISO management of congestion charges. This measurement is not entirely within the control of the RTO/ISO because other factors, such as load trends, also influence this metric. Figure 24 reflects congestion charges measured in that way.

Second, congestion can be expressed in terms of net congestion payments as a percent of day-ahead congestion charges, as shown in Figure 25. RTOs/ISOs use day-ahead net congestion payments to fund the financial entitlements of congestion rights holders. The blue line represents whether net congestion payments were sufficient to compensate all Financial Transmission Rights (FTR) holders. The red line represents the percentage of congestion charges owed by Load Serving Entities (LSEs) that were recovered through all revenue streams including through both FTRs held and Auction Revenue Rights (ARR) auctions, unless specifically noted otherwise.

Figure 24 shows that all RTOs/ISOs experienced an increase in congestion charges per MWh of load served by the end of the reporting period.[29] SPP reported the largest increase of $5.83/MWh of load served, from 2019 to 2021. The majority of SPP's increase occurred in 2021. MISO reported the second-largest increase from 2019 to 2021 in the amount of $1.65/MWh of load served. The other RTO/ISOs reported modest increases below $1.00/MWh of load served.

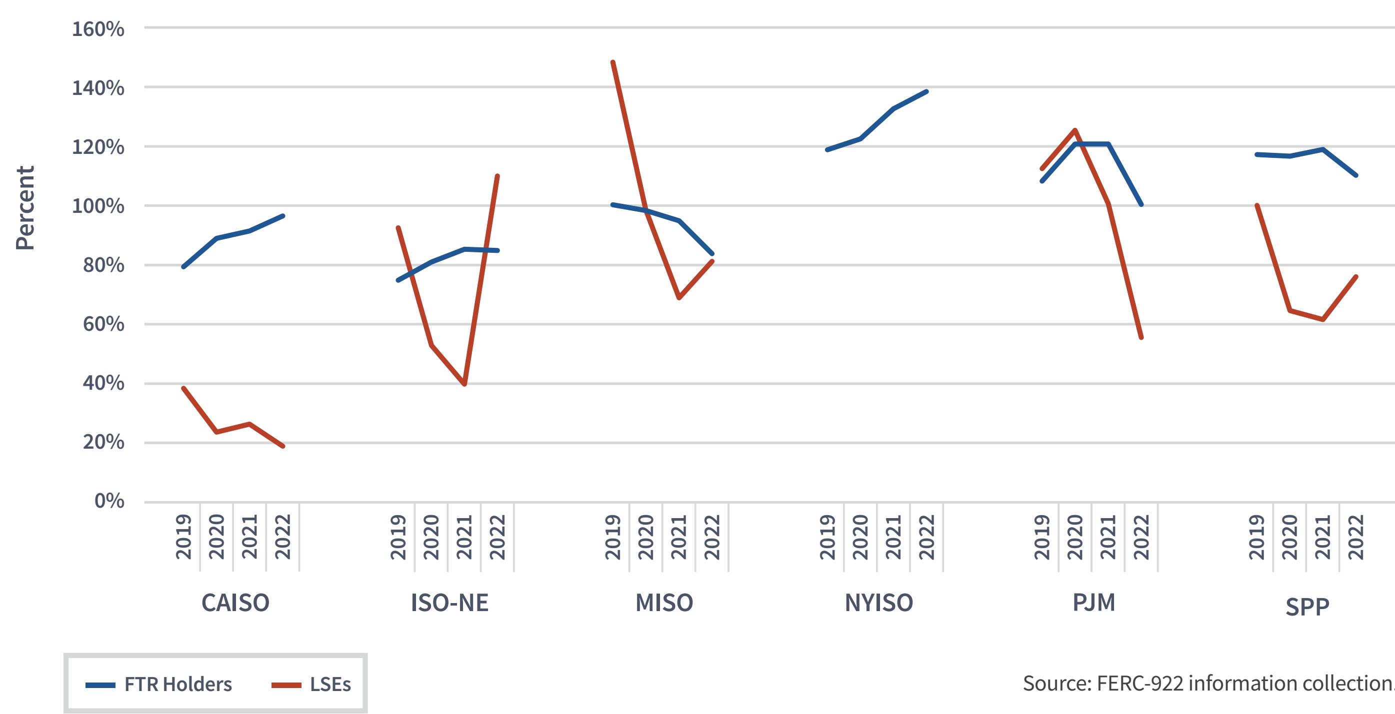
29 Only two RTO/ISOs had data available for 2022; therefore, this figure shows data for 2019-2021.

**Figure 24: Congestion Charges per MWh of Load Served**




Source: FERC-922 information collection.

**Figure 25: Net Congestion Payments as a Percentage of Day-ahead Congestion, by Participant Type**




Source: FERC-922 information collection.

Figure 25 reports varying levels of the net congestion payments as a percentage of day-ahead congestion by participant type for the RTO/ISOs. Generally, net payments to FTR holders exceed the congestion costs owed by LSE that were recovered through FTRs and ARRs. These differences in net payments are most notable in CAISO and SPP.

## ADMINISTRATIVE COSTS

The administrative costs metric examines the total financial cost of operating an RTO/ISO and measures the ability of RTOs/ISOs to manage the growth rate of administrative costs as the growth rate of system load changes.

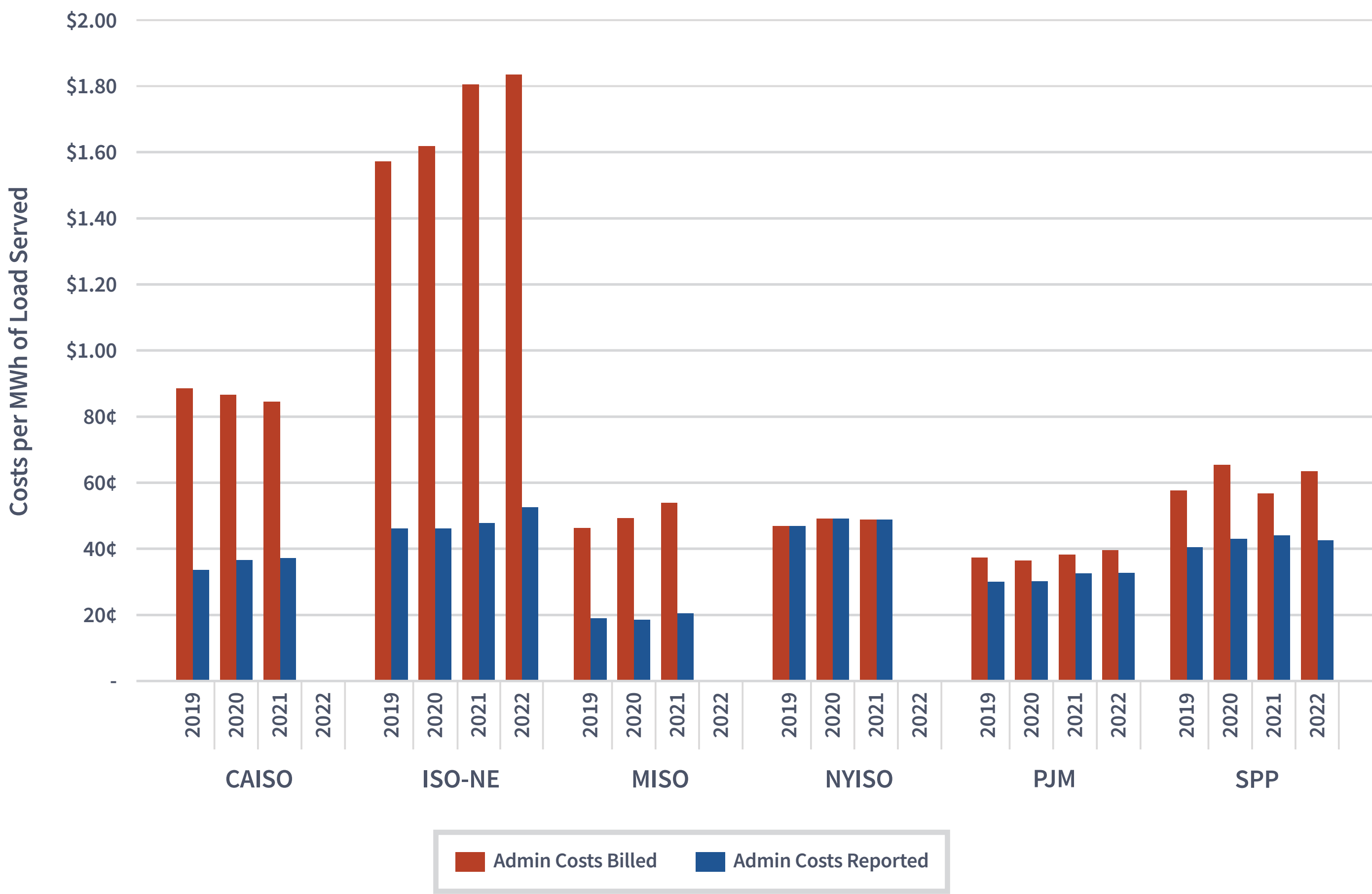
This metric reports two different values of administrative costs: (1) the sum of capital and non-capital administrative costs billed by the RTO/ISO (Admin Costs Billed) and (2) the administrative costs reported for the FERC Form No. 1 (Admin Costs Reported).[30]

Figure 26 shows the administrative costs per MWh of load served for both administration costs billed and administration costs reported. ISO-NE reports the highest average administration costs billed at $1.67/MWh of load served from 2019 to 2022. Administration costs billed and reported increased in all years for ISO-NE. For administration costs billed, ISO-NE reports a 4.1% increase in 2020 and a 12.9% increase in 2021 resulting from annual budget increases (1.6% for 2021) as well as collection true-ups, including variances in actual spending compared with planned spending, billing factors, or both. Moreover, changes in administration costs reported include a 7.1% increase in 2022 (over 2021). ISO-NE indicates that the increase in 2022 was due primarily to costs of employee benefits, employee training costs, information technology, and utility and facility maintenance.[31] MISO reports the lowest amount for administration costs reported, with an average of $0.19/MWh of load served during the reporting period.

30 This metric sources data from the TOTAL Administrative & General Expenses section of FERC Form No. 1, at row 197 located on page 323 from the last quarter of the filing for the reporting period, which is a calendar year.

31 The 2015 increase for employee benefits is related to ISO-NE’s Defined Benefit Pension Plan.

**Figure 26: Sum of Capital and Non-Capital Expenses Billed by RTO/ISO and FERC Form 1 Total Administrative and General Expenses per MWh of Load Served**




**NOTE:** CAISO, MISO, and NYISO did not report values for 2022 due to the unavailability of data.

Source: FERC-922 information collection.

## NEW ENTRANT NET REVENUES

The new entrant net revenues metric measures the total revenues from the energy and ancillary services markets that a new entrant could be expected to receive, based on proxy resources, for both a combustion turbine and a combined cycle resource. This metric can indicate whether generator net revenues are sufficient to ensure new investment and are consistent with competitive markets.[32]

In order to establish new entrant net revenues, each RTO/ISO utilizes assumptions about the combined cycle and combustion turbine units, including the size (MW). Table 5 shows the size of each proxy unit used in each RTO/ISO.

32 This metric reflects computations and analysis conducted by each RTO's/ISO's market monitor.

### Table 5: Proxy Unit by Size for Combined Cycle and Combustion Turbine

| Region | Combined Cycle Size | Combustion Turbine Size |
|---|---|---|
| CAISO | 720 MW | 49 MW |
| ISO-NE | 260 MW | 50 MW |
| MISO | 250 MW | 100 MW |
| NYISO | 525 MW | 342 MW |
| PJM | 656 MW | 390 MW |
| SPP | 429 MW (2019)<br>418 MW (2020-2022) | 237 MW |

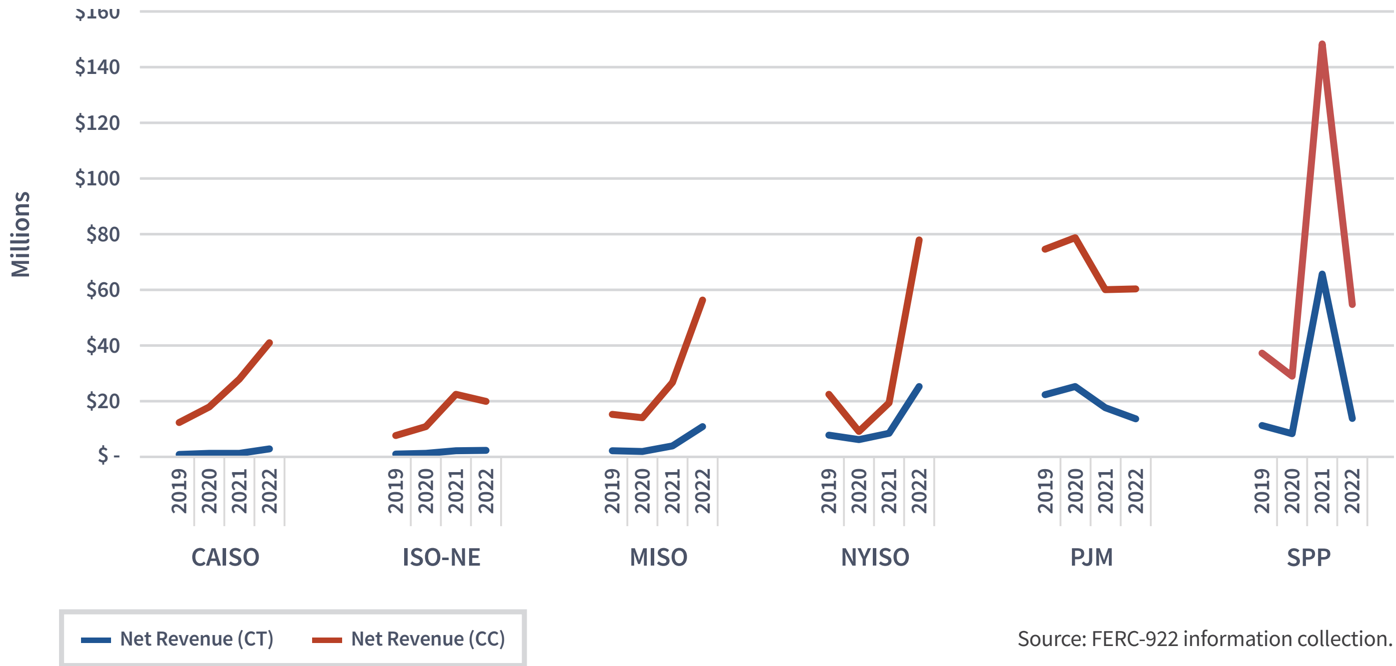
Source: FERC-922 information collection.

Figure 27 shows the annual new entrant net revenues for each RTO/ISO by generation type, while Figure 28 shows the percent difference in net revenues between 2019 and 2022 for each RTO/ISO by generation type.[33] CAISO, MISO, and NYISO report large increases in new entrant net revenue for combined cycle electric generation facilities during the reporting period.

Aside from NYISO and SPP, combustion turbine new entrant revenues remained relatively flat, when compared to combined cycle revenues. For SPP, price spikes resulting from Winter Storm Uri (for example, natural gas price fluctuations near $1,000/MMBtu and electricity prices approaching $4,000/MMBtu) led to anomalous figures for the 2021 timeframe.

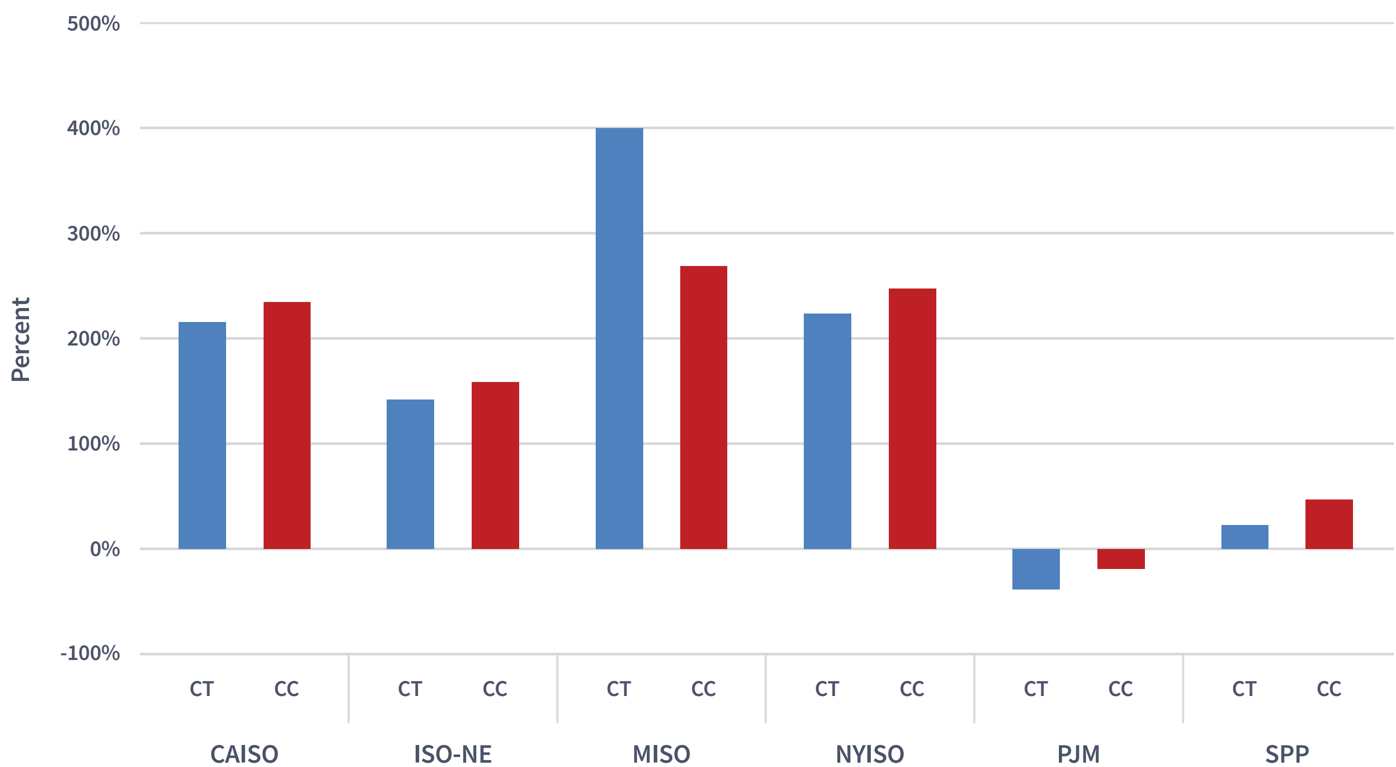
33 ISO-NE reports net revenues for proxy resources, while CAISO, ISO-NE, MISO, NYISO, PJM, and SPP specify that the net revenues are for new entrants.

**Figure 27: New Entrant Net Revenues, Combustion Turbine and Combined Cycle**




Source: FERC-922 information collection.

**Figure 28: Percent Change in New Entrant Net Revenues for Combustion Turbine and Combined Cycle, 2019 to 2022**




Source: FERC-922 information collection.

## ORDER NO. 825[34] SHORTAGE INTERVALS AND RESERVE PRICE IMPACTS

The Order No. 825 shortage intervals and reserve price impacts metric measures the size, duration, and impact that shortage events have on reserve market clearing prices. The Commission's regulations define an operating reserve shortage as "a period when the amount of available supply falls short of demand plus the operating reserve requirement."[35] The regulations require an RTO/ISO to "trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval."[36] Order No. 825 describes the requirement for triggering shortage pricing:

> Specifically, we require each RTO/ISO to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval. Under this requirement, whenever a shortage of energy or operating reserves is indicated in an RTO's/ISO's pricing run software for a particular pricing interval, shortage pricing should be invoked even if during that period resources are ramping up to a particular level they are likely to reach in a few minutes.[37]

For this metric, a shortage event is any event in which an RTO/ISO triggers shortage pricing. The criteria for this trigger may differ slightly in each RTO/ISO due to differences in software.

Figure 29 reports the average duration of shortage events. The average duration is the total number of minutes of shortage divided by the number of shortage events. CAISO and SPP report the longest average duration of shortage events among the RTO/ISOs during the 2019 through 2022 reporting period, with spikes in 2022. MISO and NYISO report average durations of shortage events under 10 minutes during the reporting period. PJM reports a minimal duration of shortage events for the reporting period.

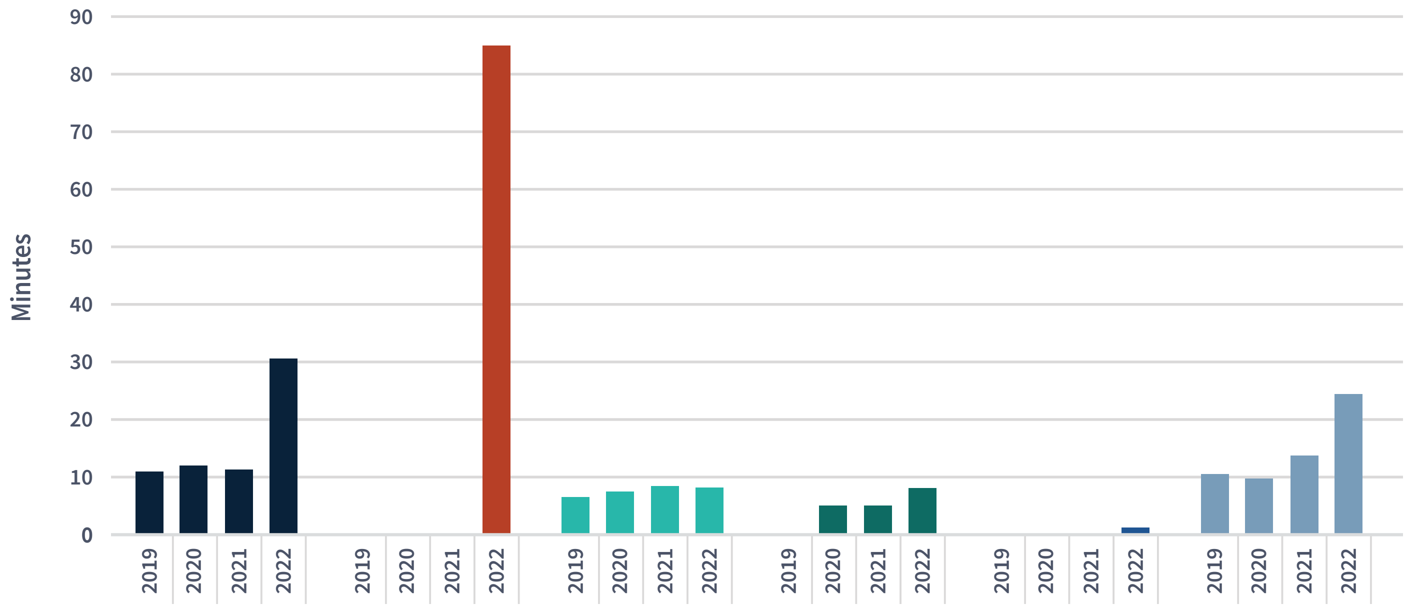
34 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).

35 18 C.F.R. § 35.28(b)(6) (2020).

36 18 C.F.R. § 35.28(g)(1)(iv)(A) (2020).

37 Order No. 825, 155 FERC ¶ 61,276 at P 162.

## Figure 29: Average Duration of Shortage Events in Minutes



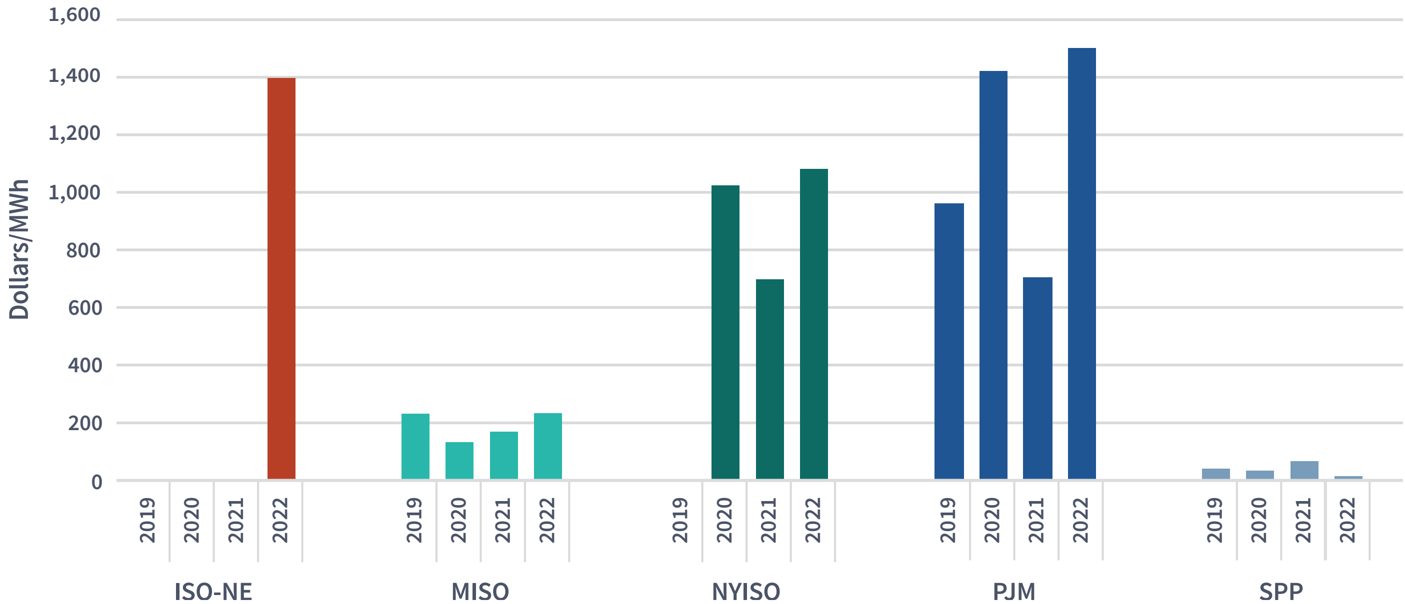

Source: FERC-922 information collection.

## Figure 30: Average Size of Shortage Events in MW


Source: FERC-922 information collection

Figure 30 reports the average size of shortage events. The average size is the total size of shortage events in MW divided by the total duration of shortage events. The average size of shortage events is below 225 MW. MISO's average size of a shortage event from 2019 to 2022 was 135 MW, the largest for any RTOs/ISOs. During the same time period, the averages for the other RTOs/ISOs were: 115 MW for NYISO, 74 MW for PJM, and 23 MW for SPP.

**Figure 31: Average Price Differential of Shortage Events in Dollars per MWh**




**NOTE:** CAISO did not report price differentials for shortage events. ISO-NE did not submit data for this metric. The original submission by the remaining four RTOs/ISOs calculated this metric as the average reserve price before the shortage minus the average reserve price after the shortage. The data presented in this figure are shown as the inverse of those values to provide a more intuitive interpretation for the reader.

Source: FERC-922 information collection.

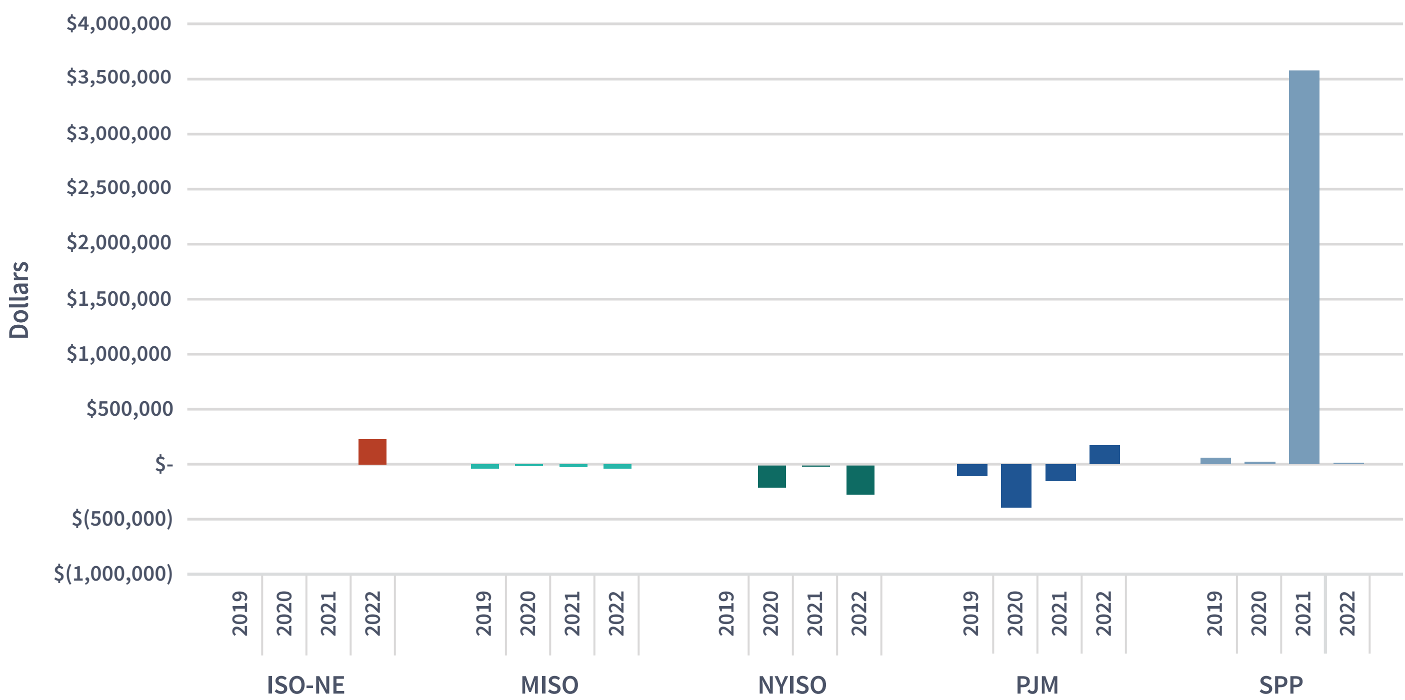
Figure 31 reports the average price differential of shortage events, which measures the increase in reserve prices after a shortage event relative to prices before the shortage event. The average price differential is the difference between the average reserve market clearing price (RMCP) of the highest quality reserve product (i.e., spinning reserve) during the shortage and the average RMCP of that product in the three intervals before the shortage began. Positive values indicate an increase in the RMCP after the shortage began, on average. Negative values indicate a decrease in the RMCP after the shortage began, on average.[38] The average price differentials during shortage events were: MISO ($133/MWh to $233/MWh), NYISO ($698/MWh to $1,082/MWh), PJM ($705/MWh to $1,502/MWh) and SPP ($14/MWh to $66/MWh) from 2019 to 2022.

Figure 32 shows that the average price impact of shortage events per year is typically small. For example, MISO and SPP report average price impacts in the tens of thousands of dollars whereas NYISO and PJM report average price

38 Based on how this metric is calculated, it is possible for figures to be negative due to product substitution for different reserve products and regulation service and the ability of the RTO/ISO to solve system requirements. The negative values may not capture the full price differential of the shortage events because other reserve products, regulation service, or energy prices may have increased during the specific shortage events.

impacts in the range of $100,000 to $400,000 per year. A notable exception is SPP in 2021, which reports an average price impact of $3,575,707 reflecting the increases in price impacts driven by Winter Storm Uri, which occurred from February 10-19, 2021.

**Figure 32: Average Price Impact of Shortage Events in Dollars**




**NOTE:** CAISO did not report price differentials for shortage events. The original submission by the remaining five RTOs/ISOs calculated this metric as the average reserve price before the shortage minus the average reserve price after the shortage. The data presented in this figure are shown as the inverse of those values to provide a more intuitive interpretation for the reader.

Source: FERC-922 information collection.

# Review of Group 3 Capacity Market Metrics

RTOs/ISOs with capacity markets report additional metrics that are part of Information Collection FERC-922. These additional metrics measure the performance of RTO/ISO capacity markets and apply only to ISO-NE, MISO, PJM, and SPP.

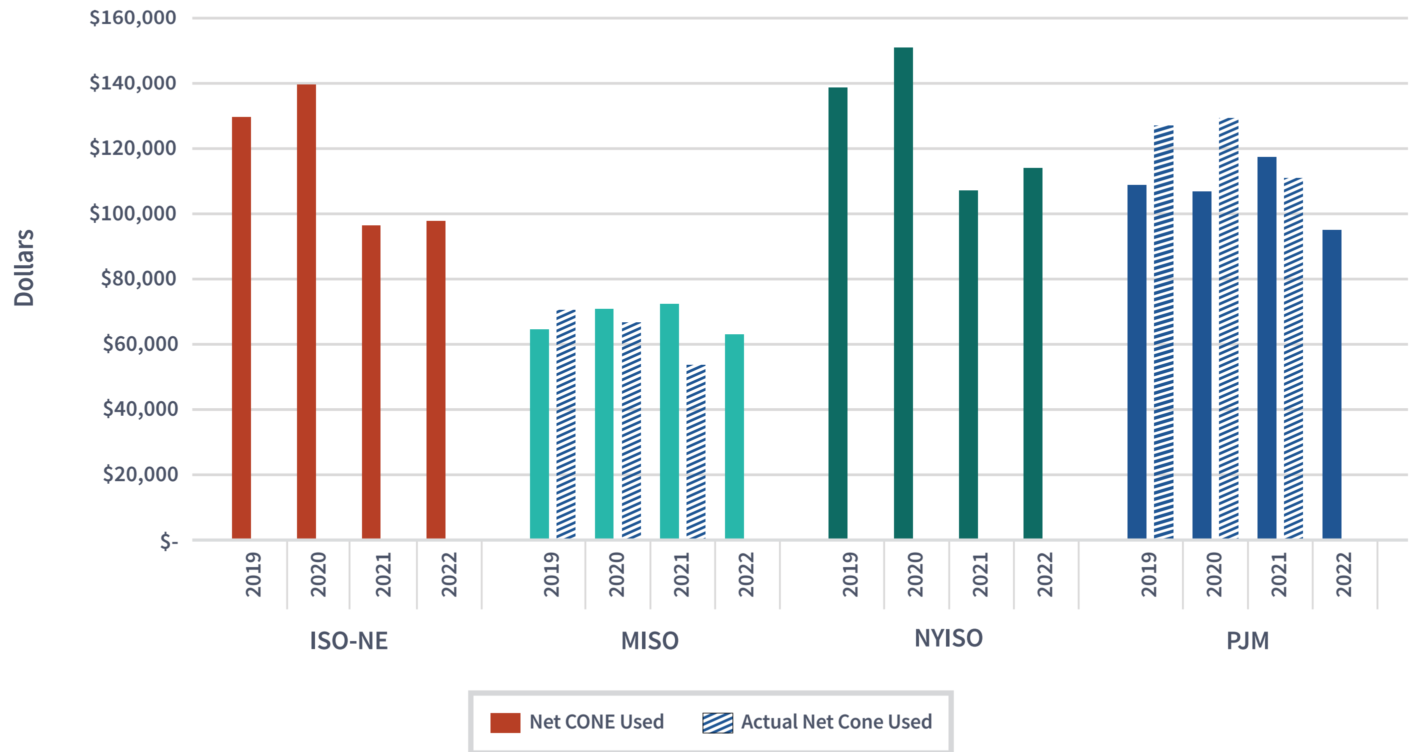
## NET COST OF NEW ENTRY (NET CONE) VALUE

The Net Cost of New Entry (Net CONE) Value metric is an estimate of the revenue a hypothetical resource needs to earn in the capacity market to break even on investment costs. The Net CONE metric is based on a proxy resource, such as a natural gas-fired combined cycle or combustion turbine, and represents annualized investment and fixed costs of the resource net of estimated net revenue from energy and ancillary services markets.

Net CONE is used as an input for constructing the capacity market demand curve in most RTOs/ISOs. If an RTO/ISO does not utilize a Net CONE value for the capacity market, an estimate based on the data in the metric for the New Entrant Net Revenues was requested. This metric compares the Net CONE value used by the RTO/ISO in the capacity market (or associated estimate for a planned delivery year) with the actual Net CONE value using the Locational Marginal Prices (LMPs) for that associated delivery year. Actual Net CONE is obtained by re-running the estimate for each historical reporting period using the actual value of LMPs realized in that reporting period. For example, if the estimate for 2019 was produced in 2016 for the initial auction, the actual Net Cone calculation would use the 2019 LMPs and re-run the Net CONE for 2019.

Figure 33 shows the Net CONE value used by each RTO/ISO for planning purposes. ISO-NE and NYISO both experienced large declines in the value of Net CONE used in the year 2021, declining by approximately $43,000 in ISO-NE and $44,000 in NYISO. MISO and PJM reported relatively steady levels of the value of Net Cone used.

**Figure 33: Net CONE Used at the Most Recent Update and Actual Net CONE Used**




**NOTE:** Average values across zones are displayed for MISO and NYISO. Data reported by zone can be found in Table 11 in Appendix B.

Source: FERC-922 information collection.

## RESOURCE DELIVERABILITY

The resource deliverability metric measures the import limitations into the RTO/ISO or sub-RTO/ISO capacity zone, considering any local generation requirements in the sub-RTO/ISO region. RTOs/ISOs that use capacity markets typically have a similar measurement that is analogous to a transfer capability and/or a local generation requirement. The following naming conventions refer to the RTO/ISO-specific terminology for such measurements:

- ISO-NE: Locational capacity requirement values are calculated for any specific capacity zone determined to be either import-constrained (Local Sourcing Requirement is calculated) or export-constrained (Maximum Capacity Limit is calculated).

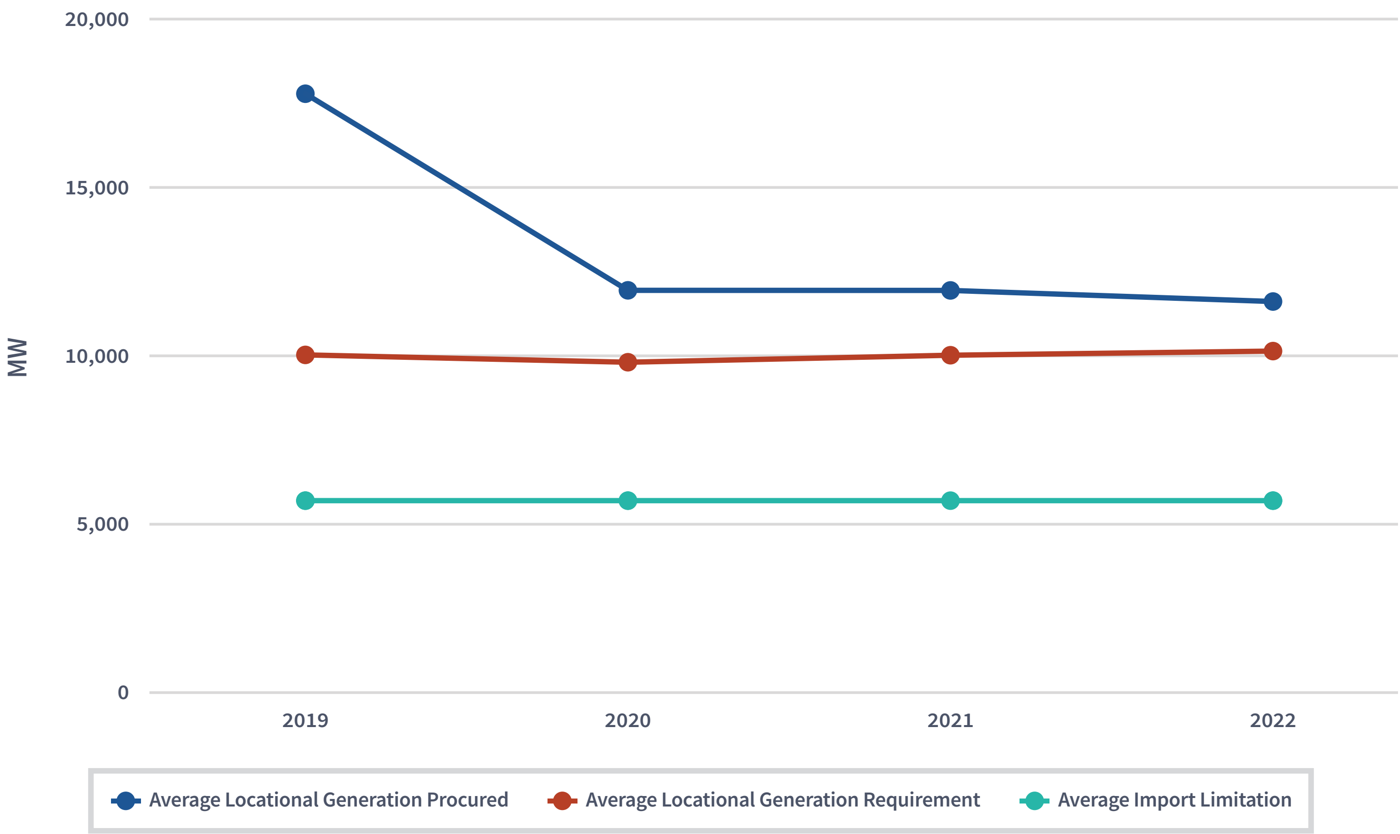
- MISO: Local Clearing Requirement (LCR): The minimum amount of Unforced Capacity that is physically located within a Local Reserve Zone (LRZ) that is required to meet the Loss of Load Expectation (LOLE) while fully using the Capacity Import Limit for such LRZ associated with the applicable Planning Resource Auction (PRA) or Forward Resource Auction (FRA).

- NYISO: Locational Minimum Installed Capacity Requirements

- PJM: Capacity Emergency Transfer Limit (CETL) and Capacity Emergency Transfer Objective (CETO).

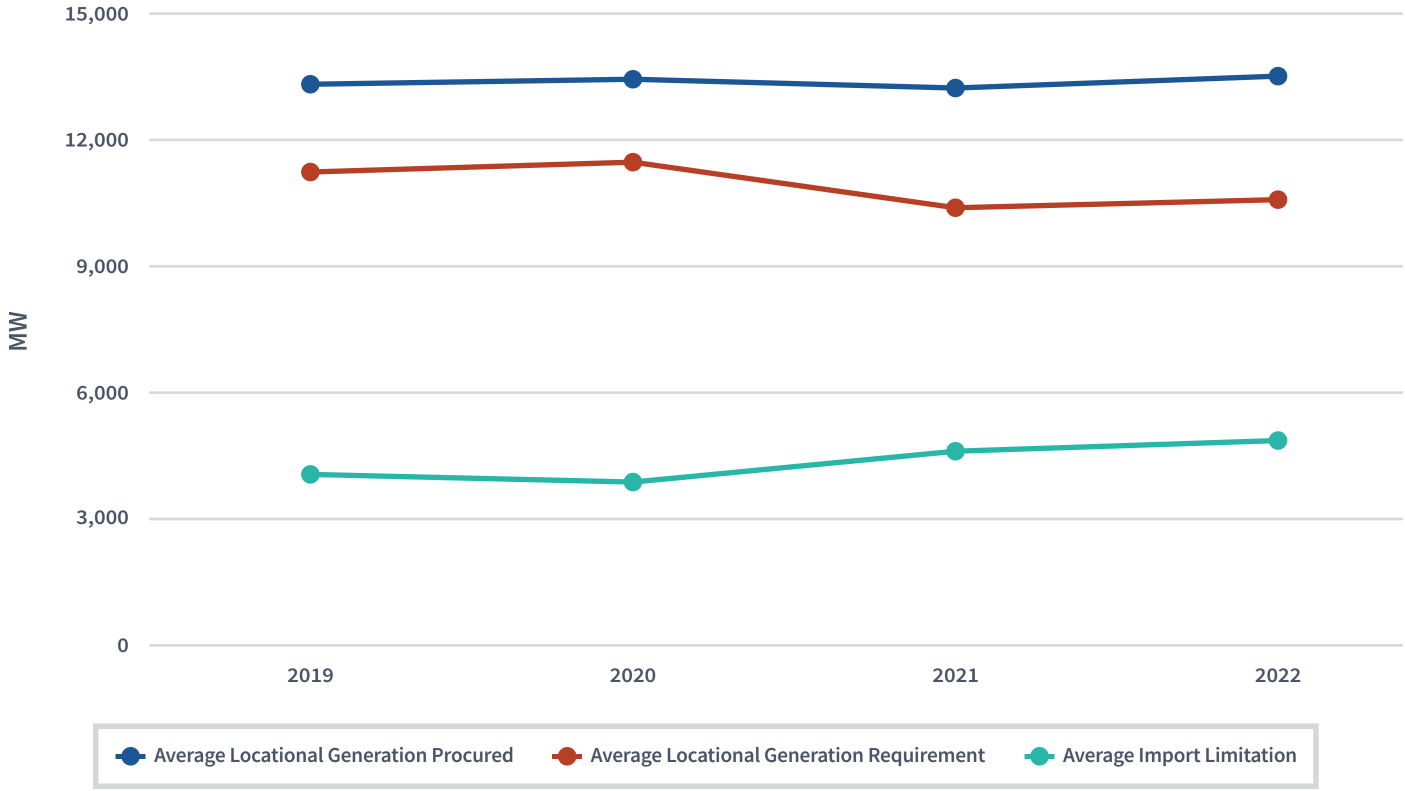
Figures 34-37 show that, for the time period 2019 to 2022, in ISO-NE, MISO, NYISO, and PJM, the locational generation procured was consistently greater than the amount required on average. Table 12 in the Appendix shows the detailed zonal data for these RTO/ISOs.

**Figure 34: ISO-NE's Average Locational Generation Procured, Locational Generation, and Import Limitation**



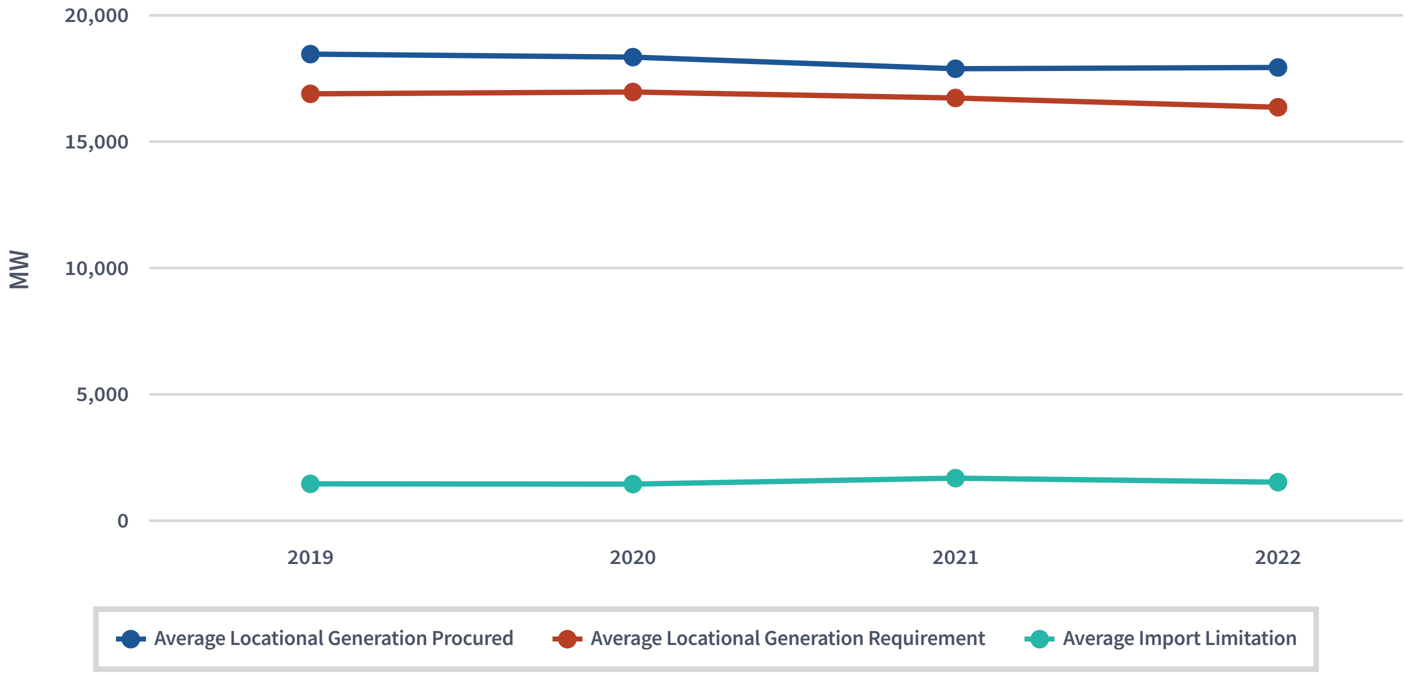

Source: FERC-922 information collection.

**Figure 35: MISO's Average Locational Generation Procured, Locational Generation Requirement, and Import Limitation**



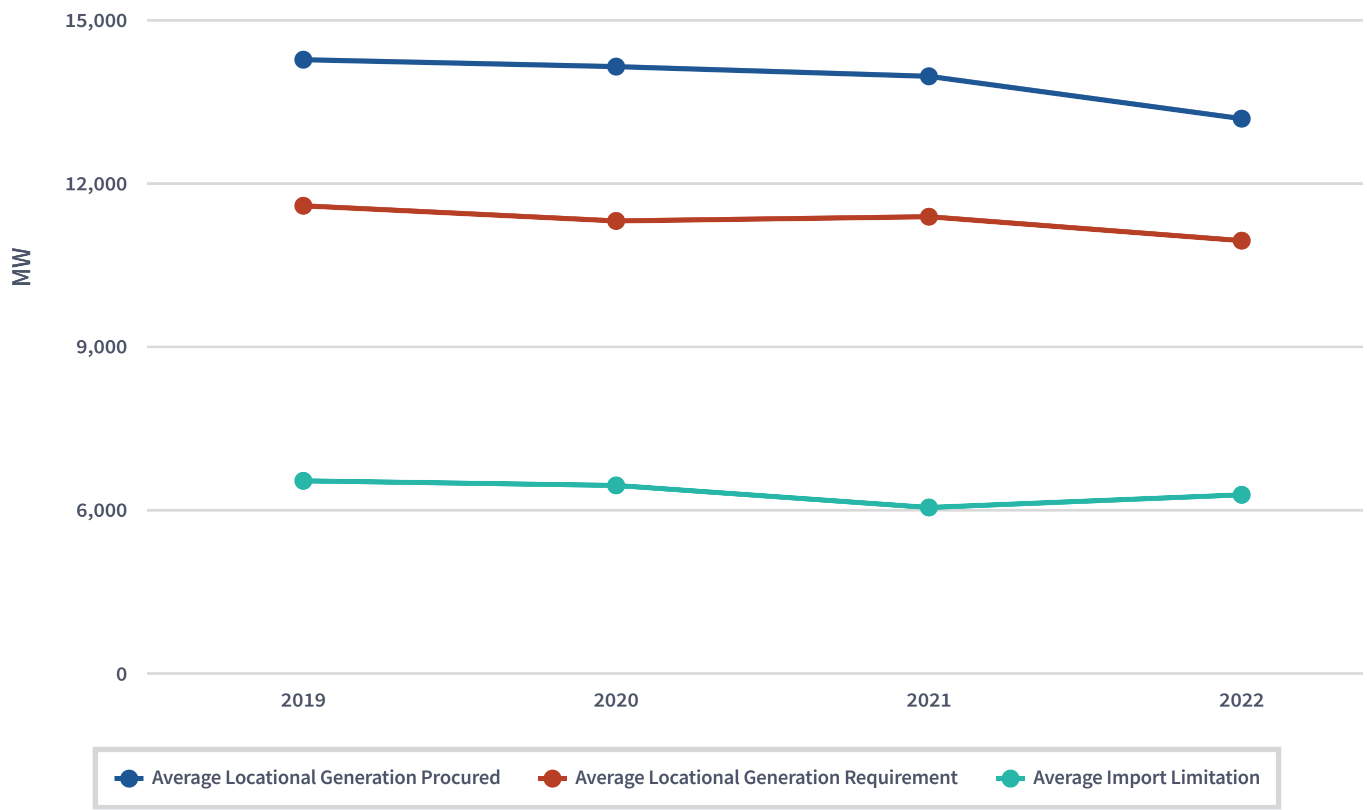

Source: FERC-922 information collection.

**Figure 36: NYISO's Average Locational Generation Procured, Locational Generation Requirement, and Import Limitation**




Source: FERC-922 information collection.

**Figure 37: PJM's Average Locational Generation Procured, Locational Generation Requirement, and Import Limitation**



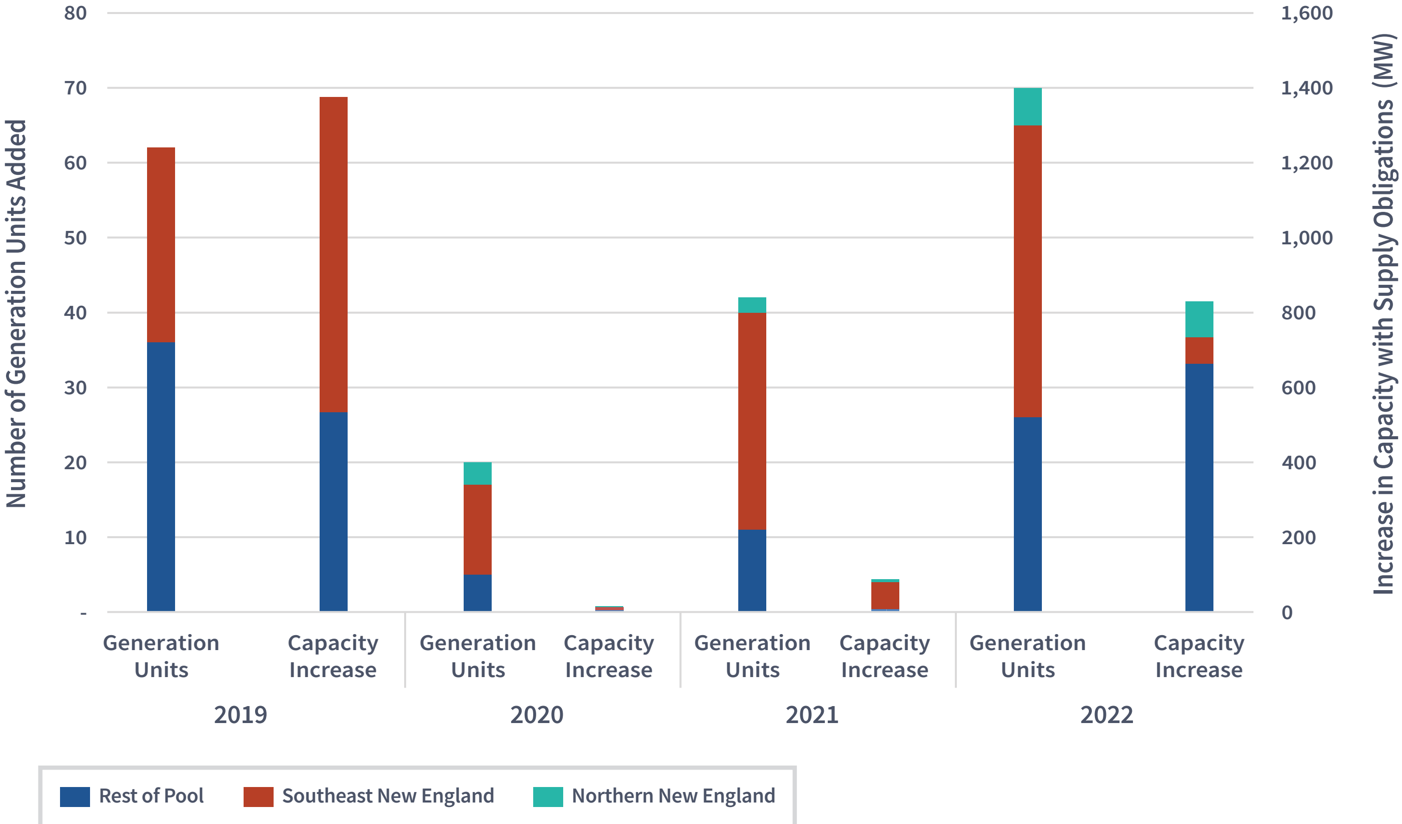

Source: FERC-922 information collection.

## NEW CAPACITY (ENTRY)

The New Capacity metric measures any new capacity that cleared a capacity auction in an RTO/ISO since the previous capacity auction, measured both RTO/ISO-wide and for specific sub-RTO/ISO regions that were modeled separately from the rest of the RTO/ISO.

As shown in Figure 38, the largest increase in the number of generation units added and capacity with capacity supply obligation (CSOs) in terms of MW in ISO-NE was during 2019 and 2022. In 2022, there were generation units added throughout the ISO-NE footprint, with the largest increase in capacity with supply obligations occurring in the Rest-of-Pool region.

**Figure 38: ISO-NE Number of Generation Units Added and MW Increase in Capacity with Supply Obligations, by Zone**

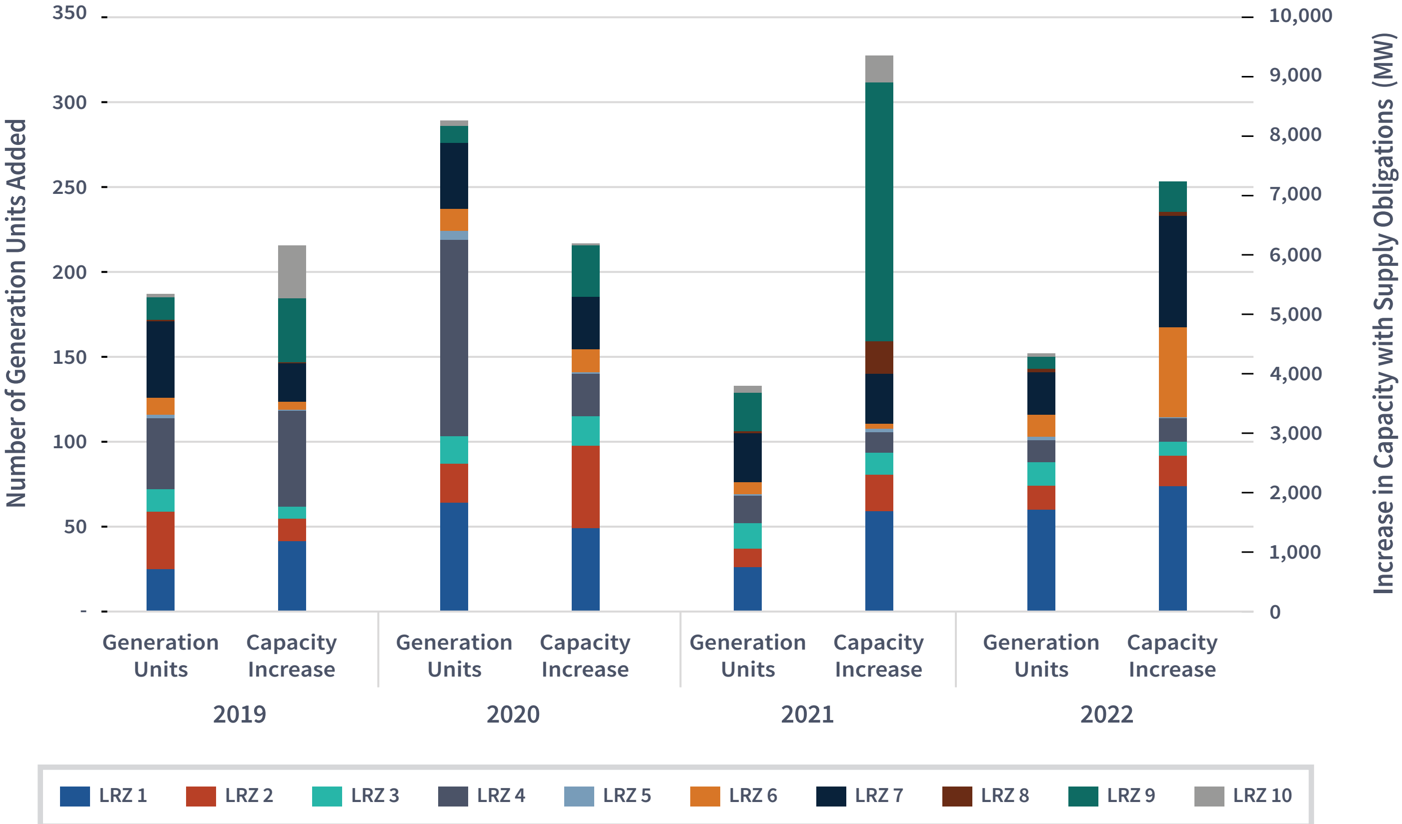



**NOTE:** ISO-NE states that data reported in Metric 22 include new generators and new imports backed by a new external generator that received a CSO either via the FCA, a reconfiguration auction, or CSO through a bilateral transaction. However, the data do not include subsequent transactions to shed or terminate a CSO.

Source: FERC-922 information collection.

As shown in Figure 39, MISO experienced increases in the number of generation units added and increases in capacity with CSOs throughout its footprint. The largest increase in capacity with supply obligations occurred in 2021 in LRZ 9 (4,348 MW). There was also a large increase of capacity with supply obligations in LRZs 1 and 7 in 2022 (2,108 MW and 1,878 MW respectively).

**Figure 39: MISO Number of Generation Units Added and MW Increase in Capacity with Supply Obligations, by LRZ**



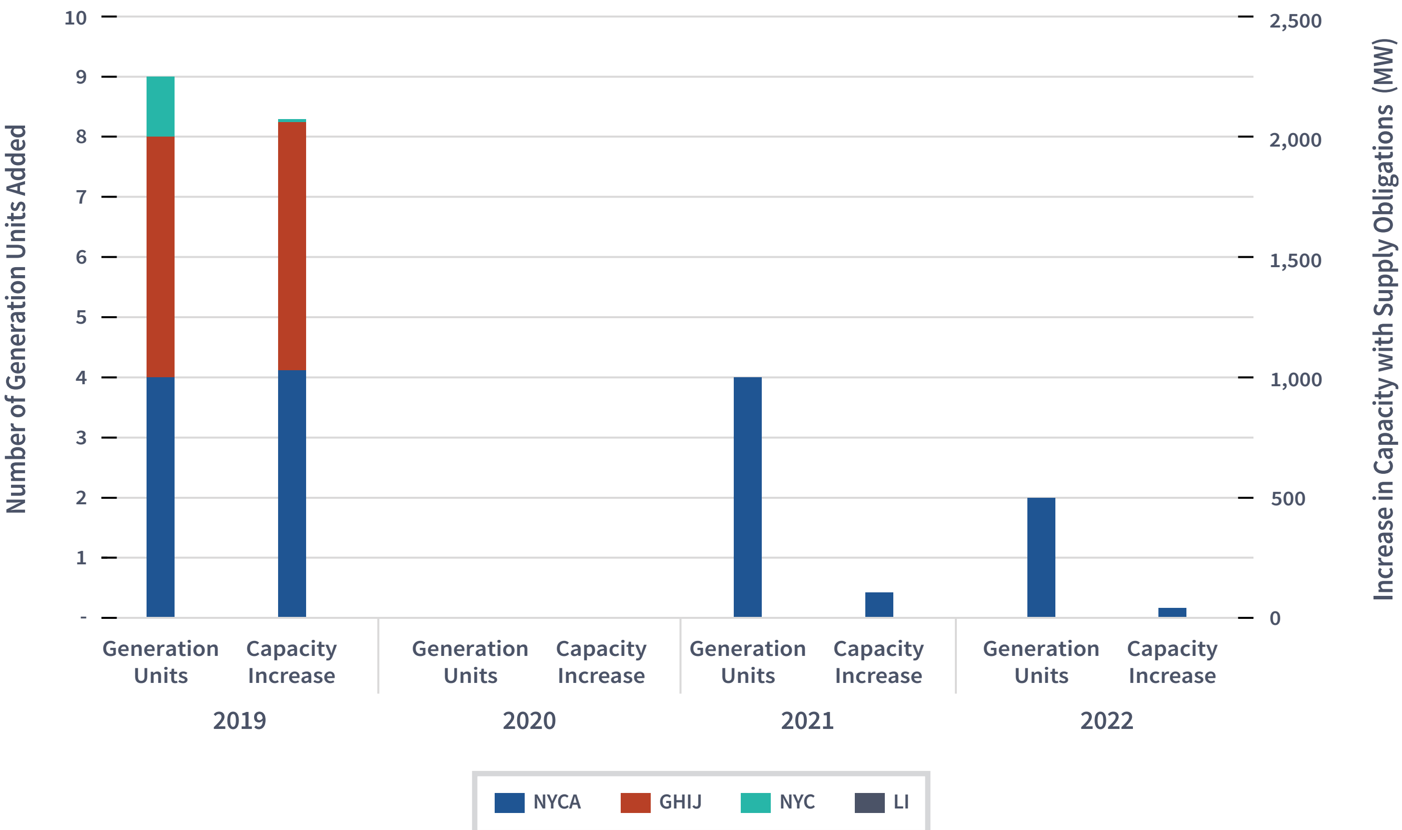

**NOTE:** MISO notes that not all capacity necessary cleared the MISO PRA. Number of units added and associated MW are taken from resources that did not participate in the MISO PRA in the prior year. As such, units may be new to MISO, but not newly constructed.

Source: FERC-922 information collection.

As shown in Figure 40, in NYISO most of the increases in the number of generation units added and increases in capacity with CSOs occurred in 2019 in the Lower Hudson Valley (GHIJ) region. NYISO reported relatively few units added and increases in capacity with CSOs for the years 2020, 2021, and 2022.

As shown in Figure 41, in PJM, there have been significant increases in the number of generation units added and increases in capacity with supply obligations except for 2021, which has a relatively low increase in capacity with supply obligations.

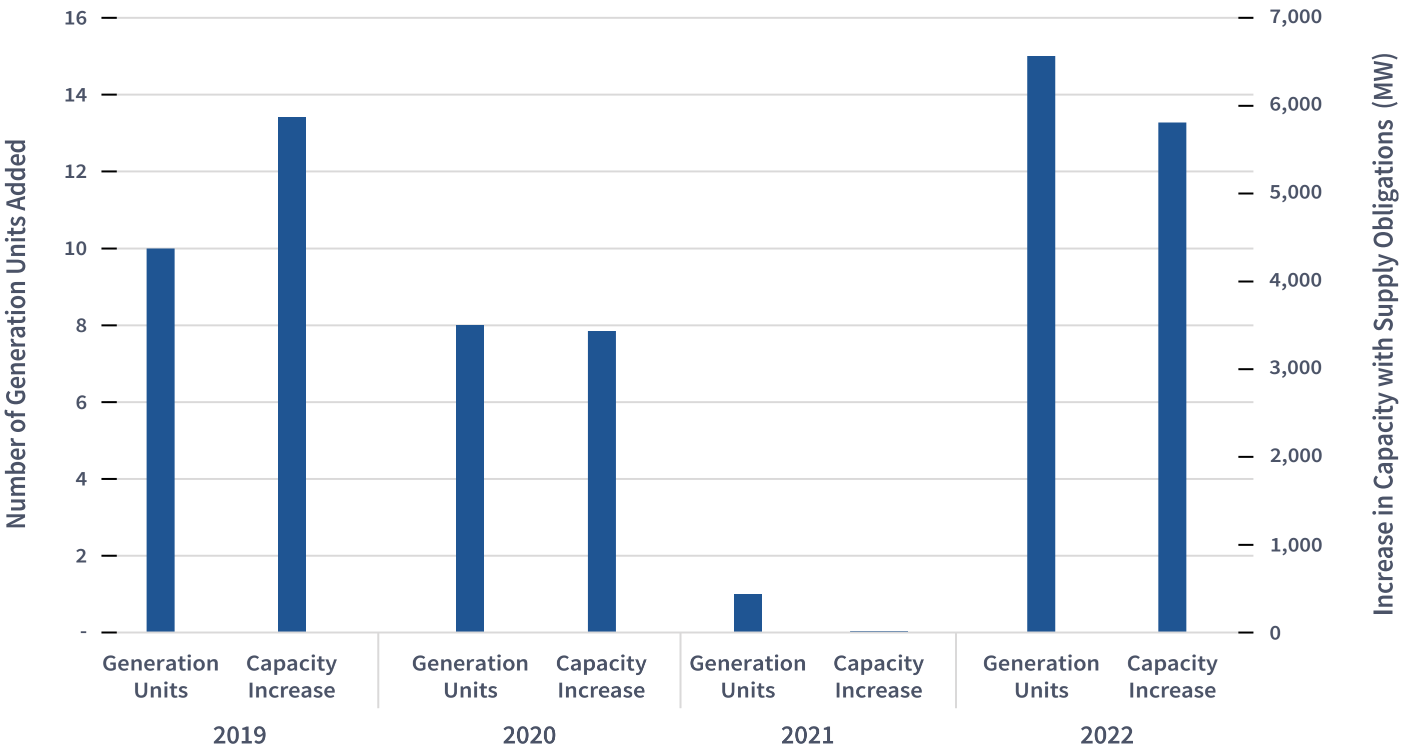
**Figure 40: NYISO Number of Generation Units Added and MW Increase in Capacity with Supply Obligations, by Zone**




**NOTE:** NYISO notes that summer MW were added to the data for each capacity zone per the Installed Capacity Market Operations Winter-Summer ratio process for adjustment of the demand curve.

Source: FERC-922 information collection.

**Figure 41: PJM Number of Generation Units Added and MW Increase in Capacity with Supply Obligations**




**NOTE:** PJM notes the data above reports the number and total MW quantity of generation capacity resources that cleared for the first time in the first auction conducted for the reporting period.

Source: FERC-922 information collection.

## CAPACITY RETIREMENT (EXIT)

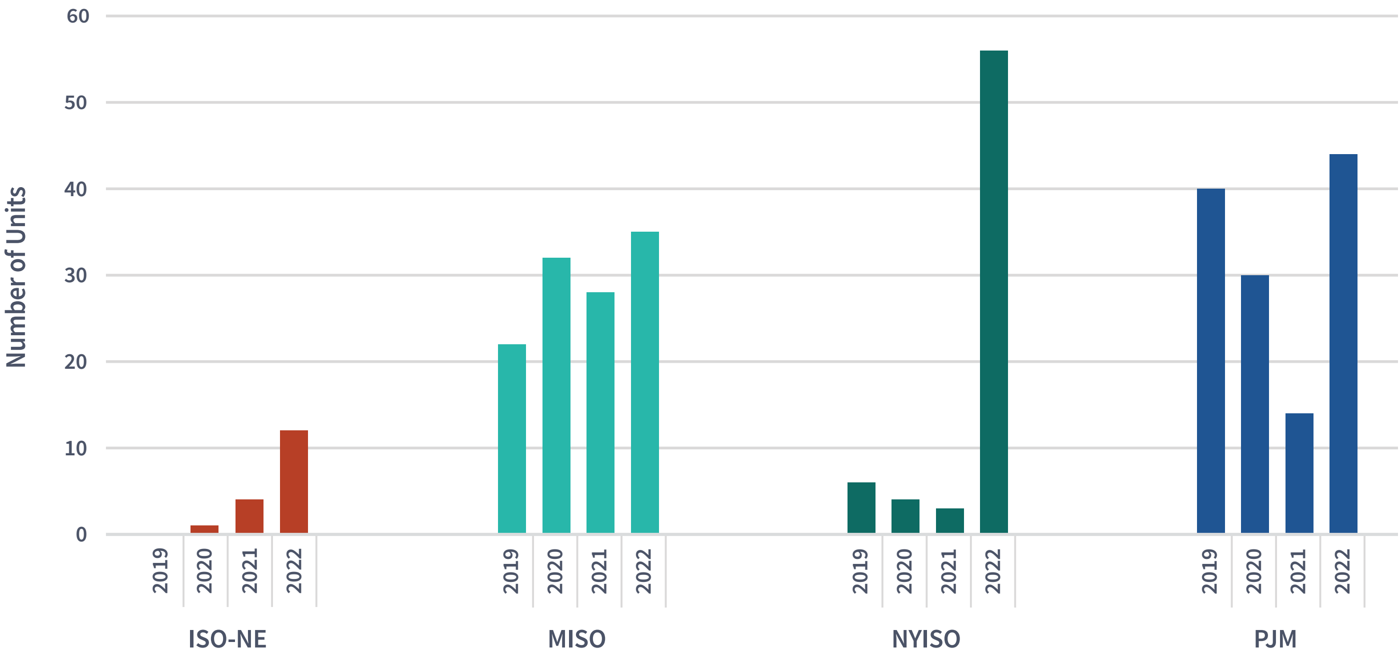
The capacity retirement metric measures capacity that has been taken out of service since the last capacity auction.[39]

RTOs/ISOs provided data on the total number of generation units taken out of service during the reporting period, as well as the MW decrease in capacity with CSOs, which reflects the amount of generating capacity that no longer has an obligation to offer into the capacity market during the reporting period (Figures 42 and 43 respectively). This decrease in CSOs does not include reporting of generation capacity that has been de-rated.

NYISO reports the largest number of units taken out of service during a single year with 56 units during 2022, although only a few units were taken out of service between 2019 and 2021. ISO-NE reports a steady increase in the number of units taken out of service from 2019 to 2022. MISO and PJM report various units being taken out of service from 2019 to 2022 without a clear trend but averaged approximately 30 units per year during the reporting period.

39 The definition of retirement is consistent with that used in the Energy Information Administration's Annual Electric Generator Report, specifically the categories of "standby" and "retired."

**Figure 42: Number of Generation Units Removed from Service**

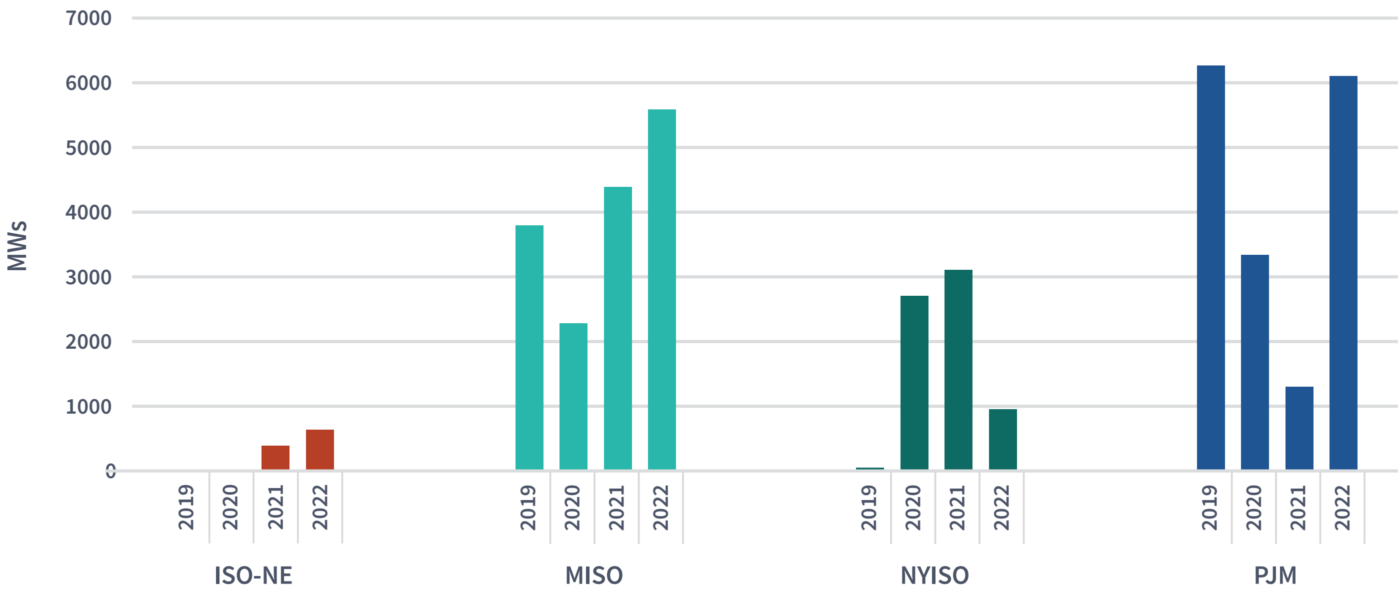



**NOTE:** ISO-NE notes that its data does not include one-year exits or partial retirements.

Source: FERC-922 information collection.

The trend in the decrease in capacity supply obligations in terms of MW (Figure 43) is similar to the trend in the number of generation units removed from service, with a notable of exception of NYISO. NYISO had relatively few units removed from service from 2019 to 2021 followed by a large increase in 2022, whereas Figure 43 shows NYISO's largest declines in capacity with CSOs occurred in 2020 and 2021.

**Figure 43: Decrease in Capacity Supply Obligations, MW**




**NOTE:** ISO-NE notes that its data does not include one-year exits or partial retirements.

Source: FERC-922 information collection.

## FORECASTED DEMAND

The forecasted demand metric measures the coincident peak demand in MW of a sub-RTO/ISO region or zone during a binding auction for capacity delivered during the reporting period[40] and compares it to the realized coincident peak[41] demand for that reporting period. The value of this metric is not weather-normalized. Forecasted demand above actual demand is generally acceptable because over-forecasting maintains a buffer if actual demand conditions exceed forecasts. Under-forecasting actual demand is generally a problem because sufficient generation resources may not be scheduled and committed to meet upcoming demand.

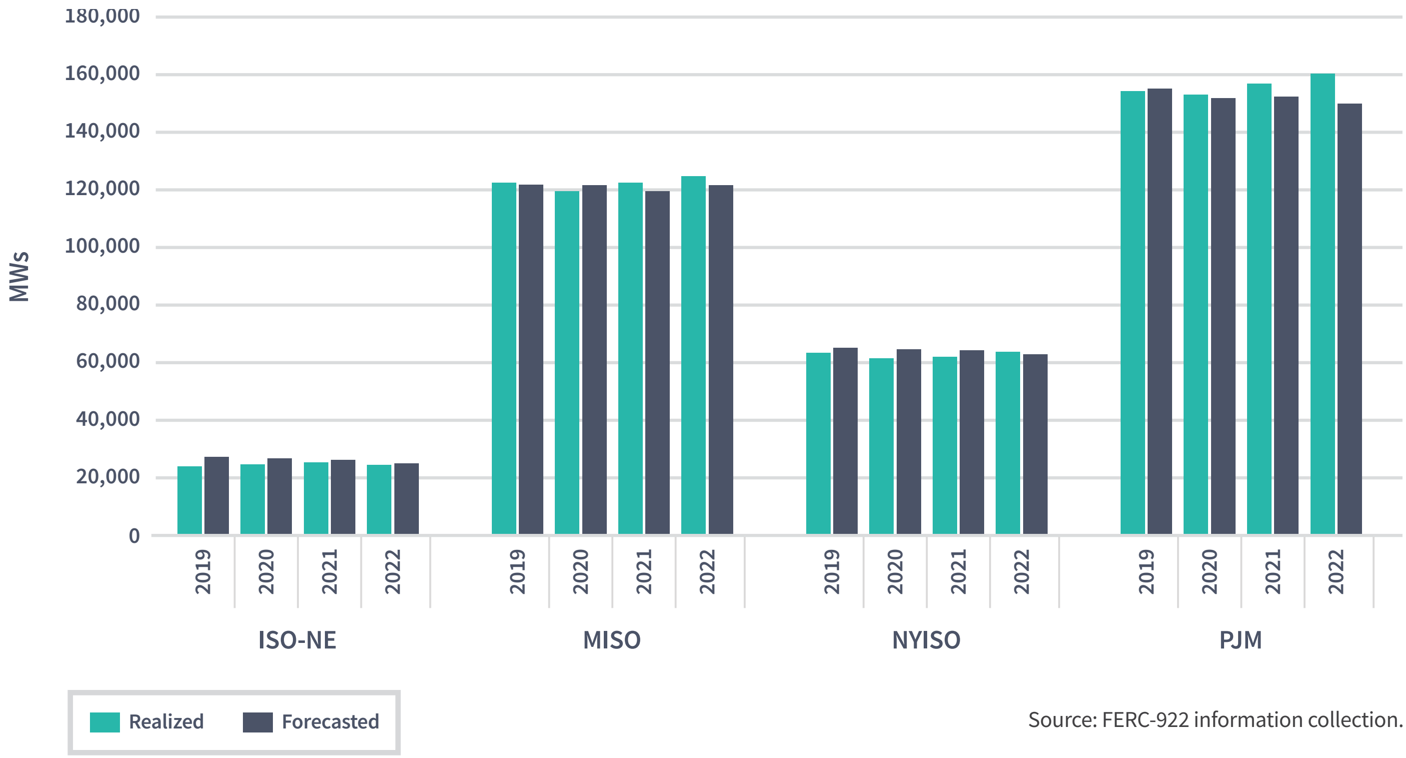
Figure 44 shows the Forecasted and Realized Demand in each of the RTOs/ISOs during the 2019 through 2022 reporting period. Across all RTOs/ISOs, the aggregate forecasted demand contained within this report is always higher than realized demand in the same reporting period. Total Forecasted and Realized Demand in each of the RTOs/ISOs remained relatively stable over the reporting period. Both PJM and MISO experienced the lowest Realized Demand in 2020 and the highest Realized Demand in 2022. Both PJM and MISO had the greatest difference in Forecasted versus Realized Demand in 2022, when total forecasted demand was 10,406 MW less than realized in PJM (6.5%) and 3,125 MW less than realized in MISO (2.5%).

In contrast, ISO-NE and NYISO experienced the lowest Realized Demand in 2019 and 2020, respectively. ISO-NE and NYISO experienced the highest Realized Demand in 2021 and 2022, respectively. Similar to PJM and MISO, ISO-NE and NYISO had the greatest difference in Forecasted versus Realized Demand in the years of lowest Realized Demand (i.e.,

40 Data for ISO-NE reflects values from the Forward Capacity Auctions. Data for PJM reflects values from the Base Residual Auctions. Data for MISO reflects values from the Planning Resource Auctions. Data for NYISO reflects auction values from July which is NYISO's summer peaking month.

41 Coincident peak refers to the total demand of the system at the moment of peak system load.

**Figure 44: Forecasted and Realized Demand**



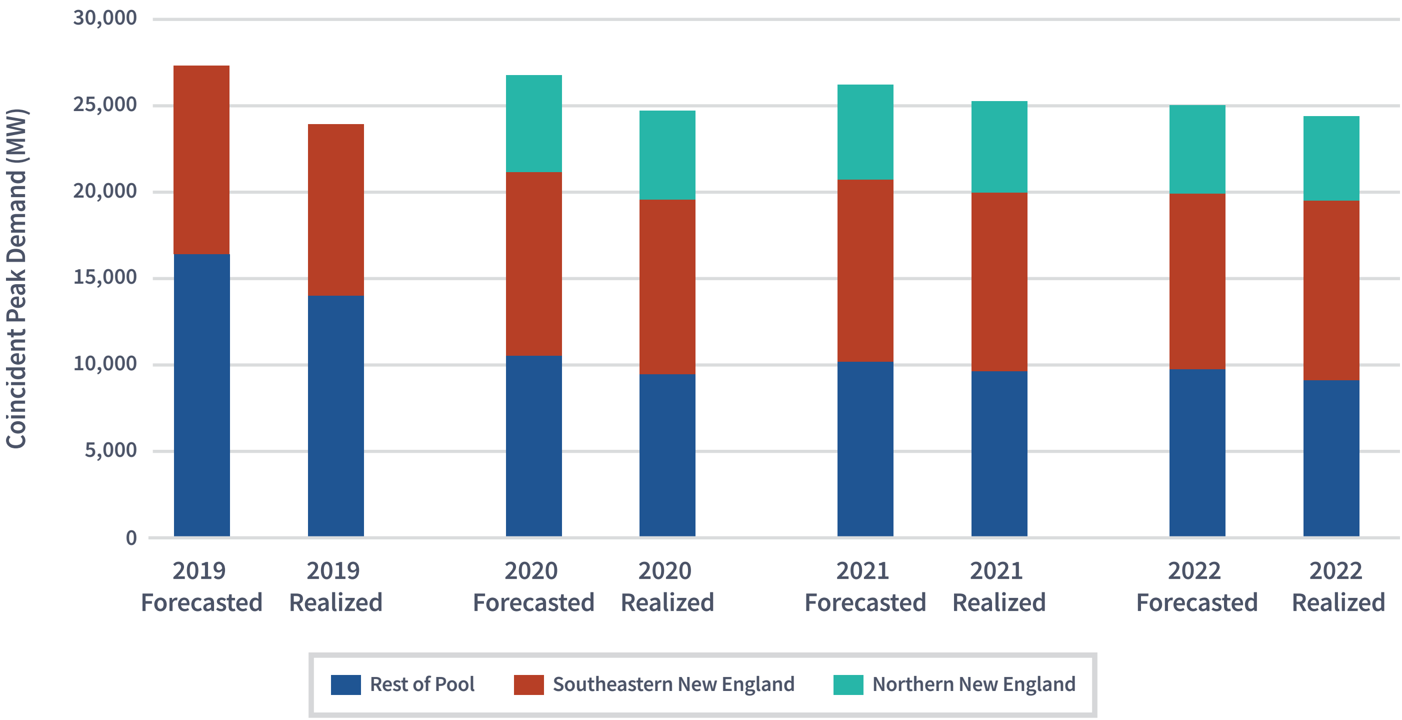

Source: FERC-922 information collection.

2019 and 2020, respectively). The difference in Forecasted versus Realized Demand was 3,381 MW (12%) for ISO-NE and 3,134 MW (5%) in NYISO.

Figures 45-48 show the Forecasted and Realized Coincident Peak Demand in each of the RTOs/ISOs separated out by sub-RTO/ISO region or zone. The trends in Forecasted and Realized Demand values observed in each sub-RTO region or zone are generally consistent with the RTO/ISO-wide trends described above.

In ISO-NE (Figure 45), the lowest Realized Demand for all zones occurred in 2020, just as it occurred ISO-wide. Rest-of-Pool had the lowest Realized Demand, at 9,120 MW, in 2022 (i.e., 965 MW less than the Realized Demand in that zone in 2021), while Northern New England had the lowest Realized Demand, at 4,896 MW, in 2022 (i.e., 427 MW less than the Realized Demand in that zone in 2021).

**Figure 45: ISO-NE Forecasted and Realized Coincident Peak Demand by Zone**

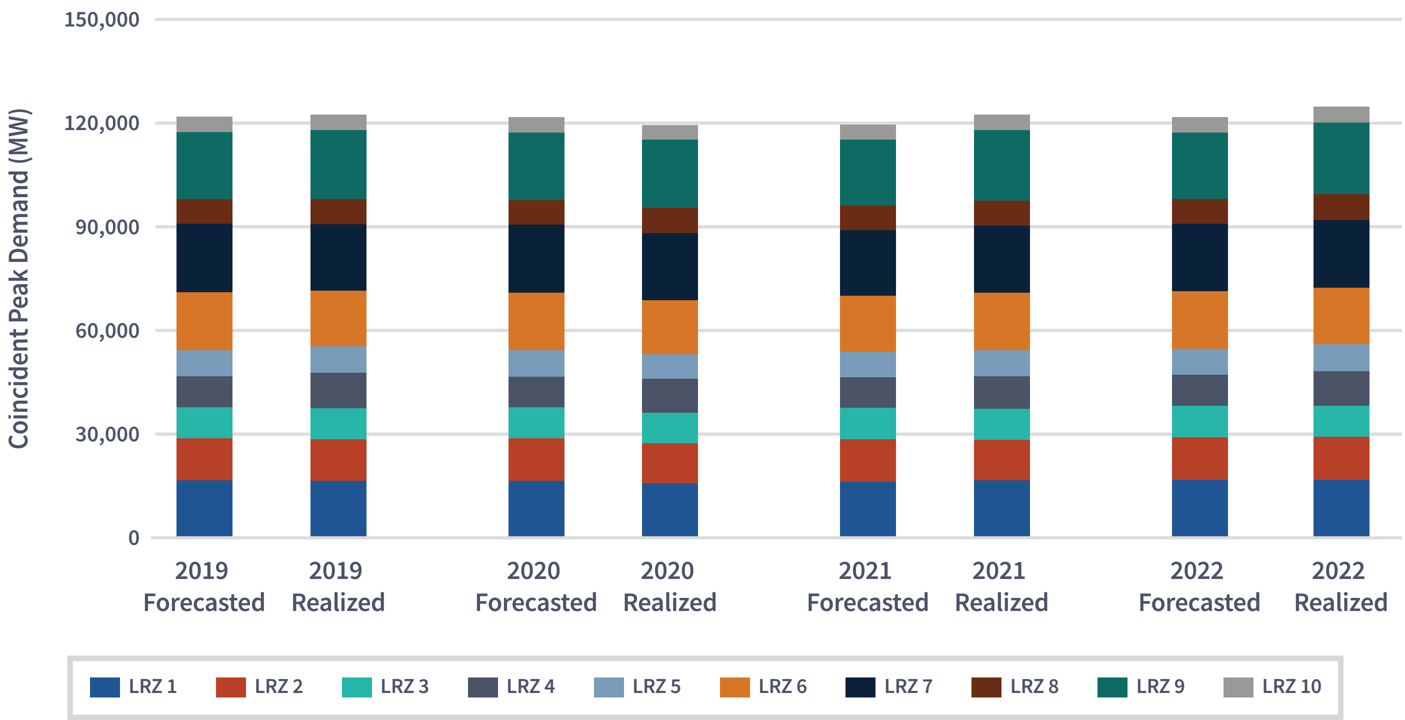



**NOTE:** ISO-NE notes that its data does not include one-year exits or partial retirements.

Source: FERC-922 information collection.

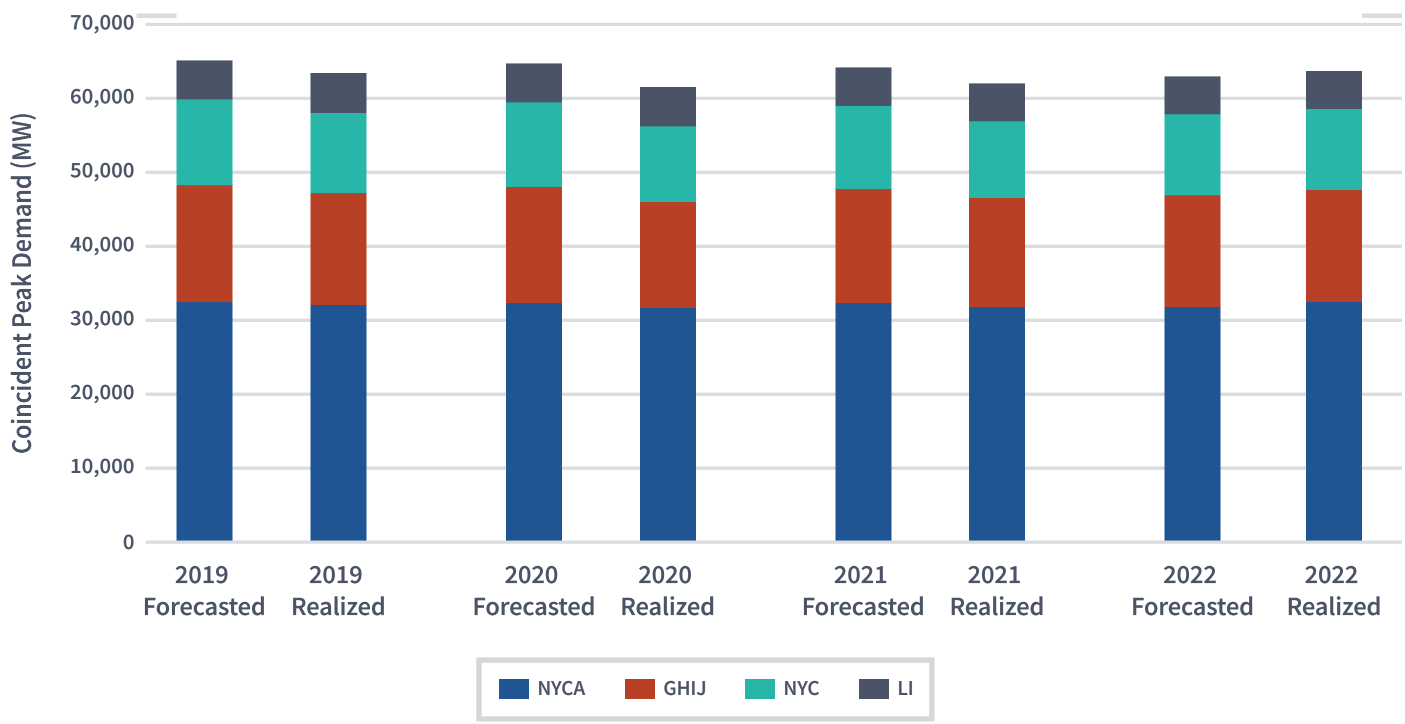
In MISO (Figure 46), zones LRZ 5 and LRZ 10 experienced the lowest Realized Demand in 2020, similar to the RTO-wide Realized Demand for the same time period. In NYISO (Figure 47), the lowest Realized Demand for all zones occurred in 2020, just as it occurred ISO-wide.

**Figure 46: MISO Forecasted and Realized Coincident Peak Demand by Zone**




Source: FERC-922 information collection.

**Figure 47: NYISO Forecasted and Realized Coincident Demand by Zone**




**NOTE:** IIn NYISO, forecasted demand values assume no demand response impacts, while realized demand values include the impacts of demand response programs.

Source: FERC-922 information collection.

**Figure 48: PJM Forecasted and Realized Coincident Peak Demand by Zone**


**NOTE:** In PJM, forecasted demand values for each zone represent the zone's forecasted load at the time of the PJM summer peak. Realized demand values are the zone's non-coincident peak drawn from the entire Delivery Year.

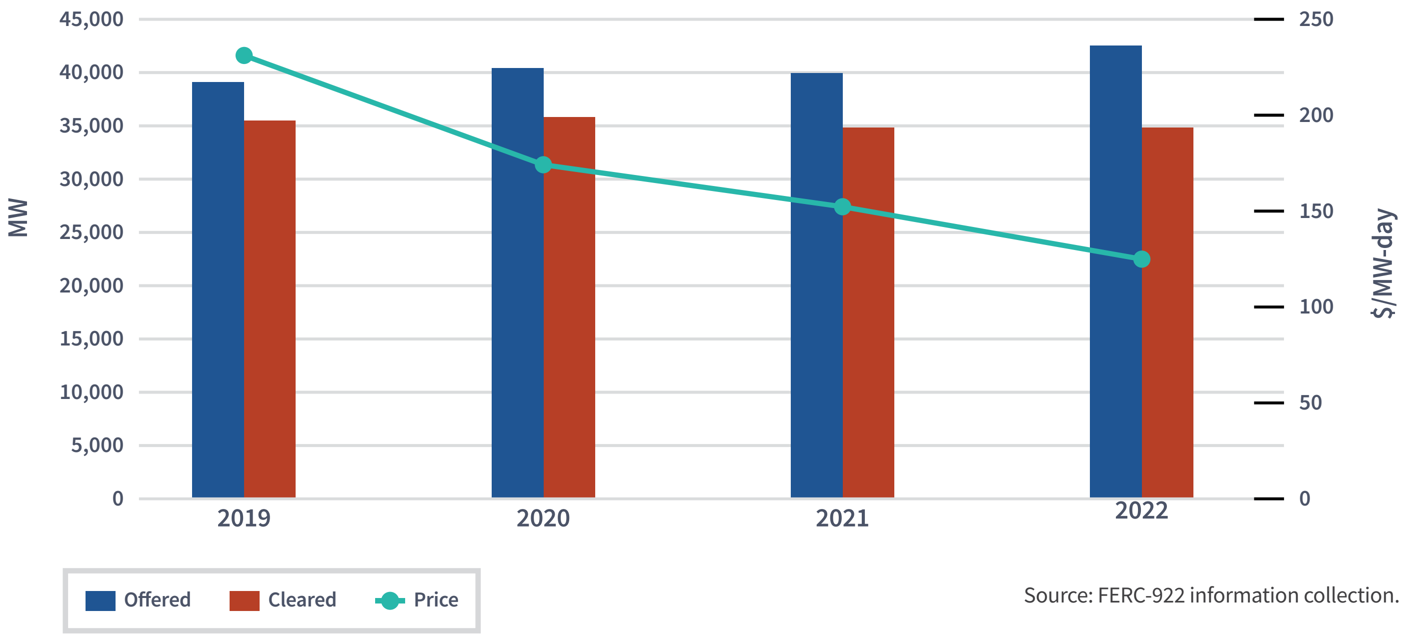
Source: FERC-922 information collection.

In PJM (Figure 48), zones American Electric Power Company (AEP), American Transmission Systems, Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), Metropolitan Edison Company (METED), Ohio Valley Electric Corporation (OVEC), PECO Energy Company (PECO), PPL Electric Utilities Corporation (PL), and Public Service Electric and Gas Company (PS) experienced lowest Realized Demand in 2020, the same trend as PJM experienced RTO-wide. Atlantic City Electric Company (AE) and Pennsylvania Electric Company (PENLC) experienced their lowest Realized Demand within the reporting period in 2022, the same year when PJM experienced its highest Realized Demand, RTO-wide. However, the Realized Demand in these zones in 2020 versus 2022 differed by less than 10%.

## CAPACITY MARKET PROCUREMENT AND PRICES

The capacity market procurement and prices metric measures the total capacity offered and procured through the central capacity market, as well as the associated capacity prices. Capacity procurement is done on a zonal level and may have price separation (i.e., zones or sub-RTO regions) where there is a different price from the remainder of the

Figure 49: ISO-NE Capacity Market Procurement and Prices




Source: FERC-922 information collection.

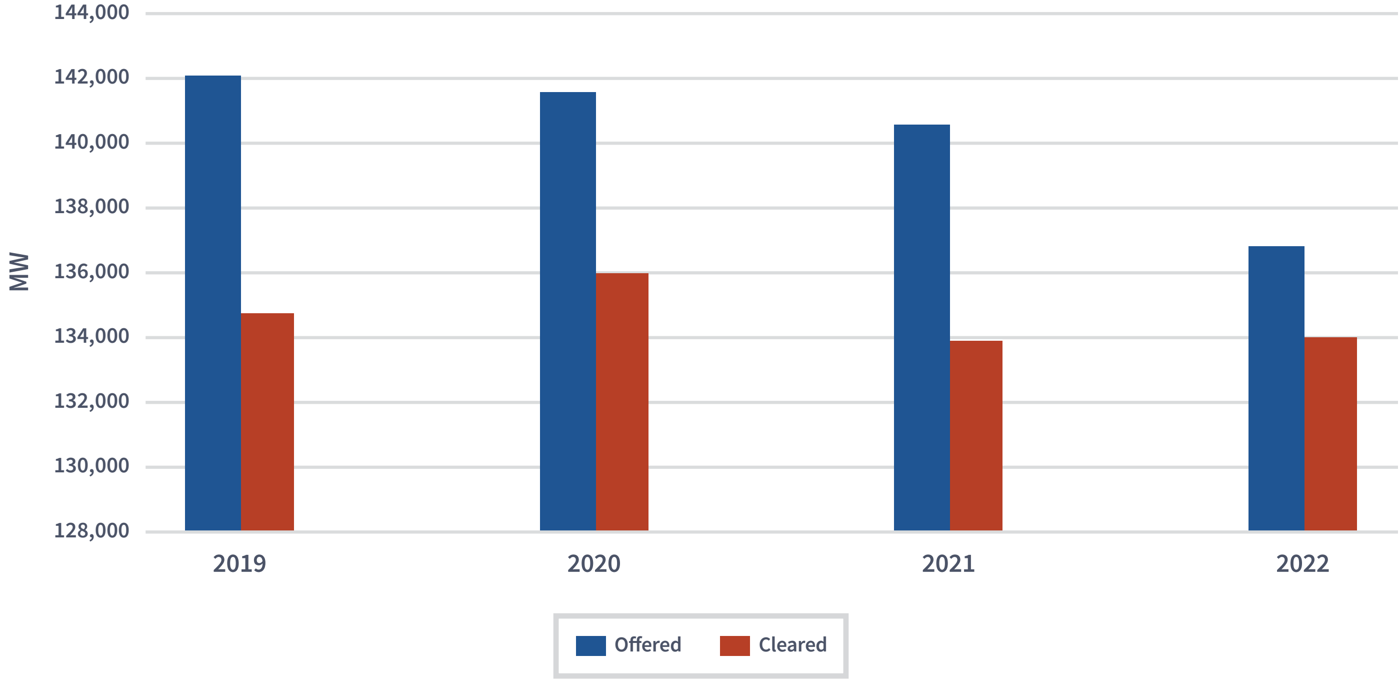
RTO (RTO/ISO-wide, which is commonly referred to as Rest-of-RTO or Rest-of-Pool prices). The aggregated capacity procurement values and RTO/ISO-wide prices are shown below.[42]

Figure 49 shows ISO-NE's total capacity market procurement and ISO-wide prices. Between 2019 and 2022, the amount of capacity offered into the market increased by 8.6% and the capacity cleared modestly declined by 2%, with a more noticeable decline from 2019 to 2020. During 2019, the ISO-wide capacity market clearing price was $231.12/MW-day, followed by a sharp decrease to $174.15/MW-day in 2020 and a lower price of $152.25/MW-day in 2021, with an overall decline of 45.9%.

Figure 50 shows MISO's total capacity market procurement. Between 2018 and 2022, the amount of capacity offered and cleared in the MISO capacity market declined by 3.9% and 0.5%, respectively.

42 Table 10 of Appendix B shows the zonal or sub-RTO region capacity values and prices for ISO-NE, MISO, NYISO, and PJM.

**Figure 50: MISO Capacity Market Procurement**

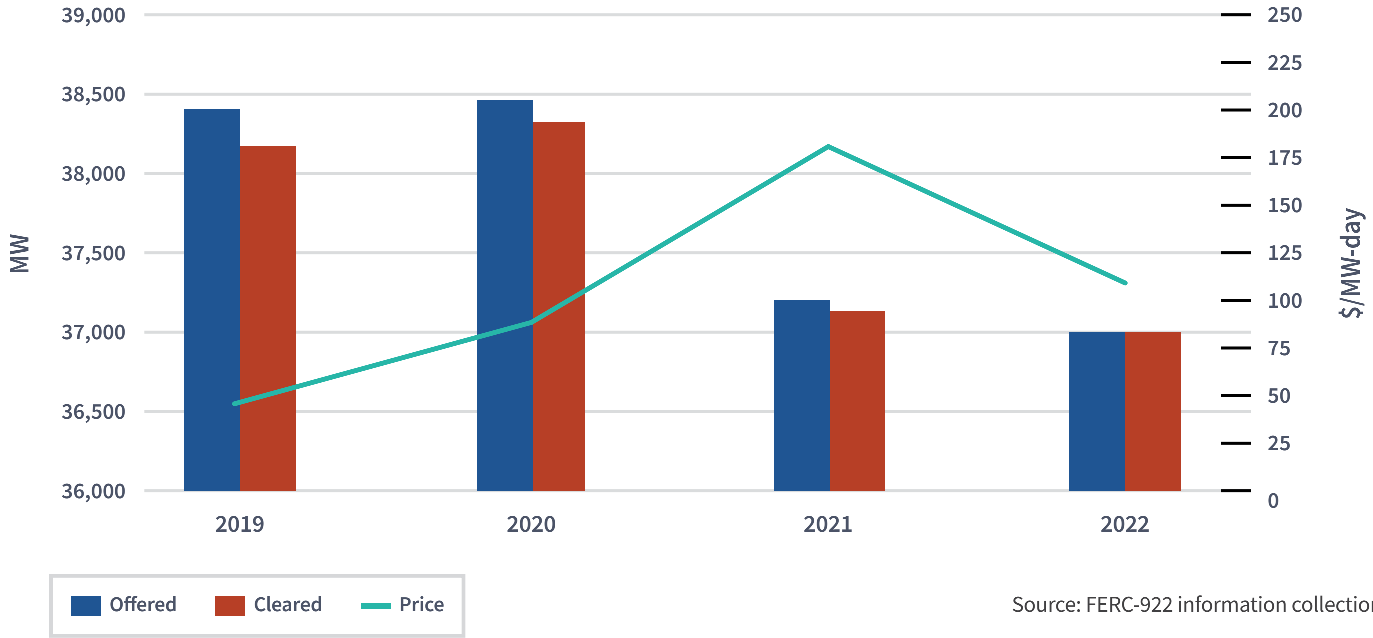



**NOTE:** MISO does not compute an RTO-wide Auction Clearing Price; therefore, that price is not included in this figure.

Source: FERC-922 information collection.

Figure 51 shows NYISO's total capacity market procurement and ISO-wide prices. Between 2019 and 2022, both the amount of capacity offered and cleared has decreased by 3.8% and 3.2% respectively. There were relatively large spikes in the amount of capacity offered and cleared in 2020 with a fall in the capacity offered and cleared in 2021. During the period 2019 to 2021, the ISO-wide capacity market clearing price increased from $45.69 to $180.80/MW-day (296%), and subsequently decreased to $109.14/MW-day (139%) in 2022.

## Figure 51: NYISO Capacity Market Procurement and Prices




Source: FERC-922 information collection.

Figure 52 shows PJM's total capacity market procurement and RTO-wide prices. Between 2019 and 2022, the amount of capacity offered and cleared decreased by 11.6% and 15.8%, respectively. Between 2019 and 2022, the RTO-wide capacity market clearing price decreased from $100 to $50/MW-day, with a noticeable increase to $140/MW-day in 2021 followed by a sharp decrease in 2022.

**Figure 52: PJM Capacity Market Procurement and Prices**


Source: FERC-922 information collection.

## CAPACITY OBLIGATIONS AND PERFORMANCE ASSESSMENT EVENTS

The CSOs and performance assessment events metric measures the total cleared capacity eligible for bonus payments for over-performance and subject to penalties for under-performance, where applicable, along with the number and duration of performance assessment events. This metric applies to RTOs/ISOs in which a resource with a CSO is expected to perform in a given delivery period. Similar to Metric 25, this metric also is reported both RTO/ISO-wide and by zone.

RTOs/ISOs that use Performance Assessment Events or Capacity Scarcity Conditions to determine performance used the time periods based on the 12 months comprising the delivery period that determine whether capacity resources are available at expected levels during performance intervals, as defined by each RTO/ISO. The following types of performance events are included in this metric:

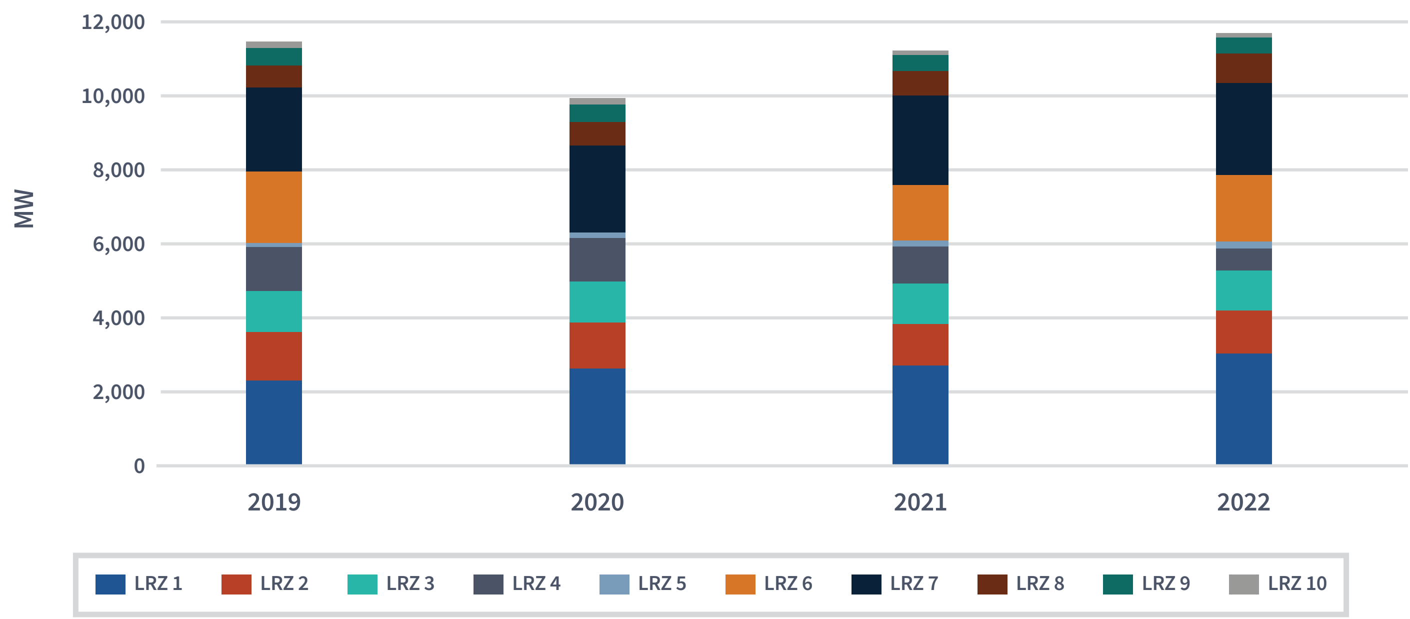
- ISO-NE: Capacity Scarcity Condition
- MISO: Events in which a Load Modifying Resource may be expected to perform
- NYISO: Requirements Applicable to Installed Capacity Suppliers: Sanctions for Failing to Comply with Scheduling, Bidding, and Notification Requirements
- PJM: Performance Assessment Interval (PAI)

Figures 53 and 54 show a relatively stable amount of CSOs in the ISO-NE and MISO regions. ISO-NE reports no performance assessment events during the reporting period. NYISO did not report data for this metric.

**Figure 53: ISO-NE Capacity Obligations by zone, 2019 to 2021**

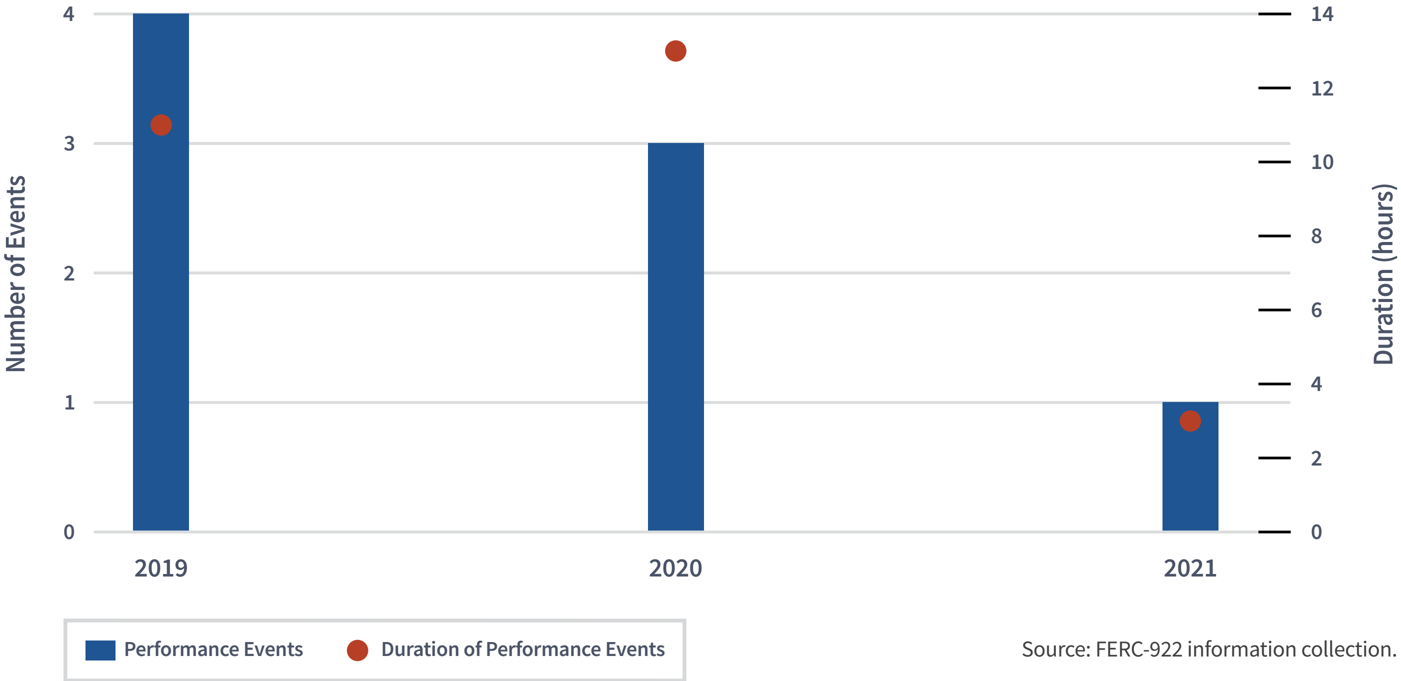

Source: FERC-922 information collection.

**Figure 54: MISO Capacity Obligations by zone, 2019 to 2022**




Source: Based on the FERC-922 information collection.

**Figure 55: MISO Performance Assessment Events and Duration, 2019 to 2021**




Source: FERC-922 information collection.

Figure 55 shows that MISO reported performance assessment events from 2019 to 2021. The largest number of performance events occurred in 2019 (four events) whereas the longest duration of performance events occurred in 2020 (13 hours). PJM reports one RTO-wide event during 2019 and four RTO-wide events in 2022, lasting a total of two hours and 44 hours, respectively.

## CAPACITY OVER-PERFORMANCE

The capacity over-performance metric measures the total number of units that over-performed relative to their CSO during a performance assessment period (as defined in metric 26).

ISO-NE reports 513 units in 2022 that over-performed during RTO-wide events, with a weighted average of capacity that overperformed of 15,957 MW. PJM reports 323 units in 2019 and 1,281 units in 2022 that over-performed during RTO-wide performance events. PJM reports that the weighted average of capacity that overperformed was 9,934 MW and 41,409 MW respectively. MISO and NYISO did not submit data for this metric.

## CAPACITY UNDER-PERFORMANCE

The capacity under-performance metric measures the total number of units that under-performed during a performance assessment period (as defined in metric 26).

ISO-NE reports 263 units in 2022 that under-performed during ISO-wide assessment events. ISO-NE reports that the weighted average of capacity that under-performed was 12,418 MW in 2022. MISO reports 191 units in 2019 and 74 units in 2021 that under-performed during ISO-wide assessment events. MISO reports that the weighted average of capacity that under-performed was 21 MW in 2019 and 10 MW in 2021.

PJM reports 58 units in 2019 and 856 units in 2022 that under-performed during ISO-wide assessment events.

NYISO did not submit data for this metric.

## TOTAL CAPACITY BONUS PAYMENTS AND PENALTIES

The total capacity bonus payments and penalties metric measures the total bonus payments and penalties charged to capacity resources with supply obligations that under-performed or over-performed during a performance assessment period (as defined in metric 26).

ISO-NE reports that in 2022 there were $27,967,047 in total bonus payments for over-performance and $35,853,045 in total penalties for under-performance. PJM reports that in 2019 and 2022, that there were $8,007,322 and $1,819,638,917, in total bonus payments for over-performance and $8,007,322 and $1,819,638,917 in total penalties for under-performance, respectively. MISO reports that from 2019 to 2021 there were $1,875,259.27, $59,671.42, and $604,965.87 total penalties for under-performance, respectively. For MISO, there was one under-performance event in December 2022; however, MISO's internal assessment is not final.

## CONCLUSION

FERC staff appreciates the voluntary submission of these metrics from the RTOs/ISOs that make this report possible. To view prior reports regarding these and similar metrics, please visit https://www.ferc.gov/industries-data/electric/electric-power-markets/rtoiso-performance-metrics.

# APPENDIX A: LIST OF COMMON METRICS

### Table 8: Common Metrics Included in Information Collection FERC-922

| Metric No. | Name | Description |
|---|---|---|
| *Administrative and Descriptive Metrics (Group 1: 1-7)* | | |
| 1 | Reserve Margins | The anticipated reserve margin metric is designed to measure the amount of generation capacity available to meet expected demand. |
| 2 | Average Heat Rates | A heat rate measures the efficiency of a resource to convert thermal power into electric power. |
| 3 | Fuel Diversity | The fuel diversity metric represents the different amounts of installed generating capacity and the different quantities of energy produced by various technology types. |
| 4 | Capacity Factor by Technology Type | The capacity factor metric measures the actual energy produced at a generation station as a fraction of the maximum possible energy that could have been produced if it were operating at full capacity 24 hours a day, 365 days a year. |
| 5 | Energy Emergency Alerts (EEA) | The energy emergency metric provides information on the frequency of energy emergencies (EEA level 1 or higher). |
| 6 | Performance by Technology Type during EEA Level 1 or Higher | The performance by technology type under the shortage metric provides information on aggregate performance of technologies during EEA Level 1 or higher alerts by measuring the total five-minute intervals when an alert is present and how the generators, by technology type, performed. |
| 7 | Resource Availability (EFORd) | The resource availability metric measures the forced outage rates across different technology types. A forced outage occurs when a generator is unavailable to provide energy its capacity. |
| *Energy Market Metrics (Group 2: 8-19)* | | |
| 8 | Number and Capacity of Reliability Must-Run Units | The reliability must-run (RMR) metric provides a measure of the number and capacity of units that an RTO/ISO must depend on to support critical facilities and to maintain reliability. |
| 9 | Reliability Must-Run Contract Usage | The RMR contract usage metric measures the usage of RMR contracts. This metric should include information from contracts that are in effect in any portion of the reporting period. |
| 10 | Demand Response Capability | The demand response capability metric measures the total amount of demand response available. |

| Metric No. | Name | Description |
|---|---|---|
| 11 | Unit Hours Mitigated | The number of unit hours mitigated metric provides an indication of the frequency and magnitude that resources have been mitigated to protect against the exercise of market power. |
| 12 | Wholesale Power Costs by Charge Type | The wholesale power cost metric disaggregates costs paid by load, thereby providing an assessment of RTO/ISO market costs. |
| 13 | Price Cost Markup | The price cost markup metric measures the difference in system-wide price that would result from using as-submitted offers and cost-based offers/reference levels. |
| 14 | Fuel Adjusted Wholesale Energy Price | The load-weighted, fuel-adjusted locational marginal price metric measures the wholesale price of energy across the RTO/ISO for a given reporting period and is derived by holding fuel costs constant over a defined time period. |
| 15 | Energy Market Price Convergence | The energy market price convergence metric measures how closely the day-ahead and real-time energy prices align. |
| 16 | Congestion Management | Congestion represents the cost to customers of paying for more expensive energy because physical transmission line limits do not allow full delivery of the least-cost energy resources. |
| 17 | Administrative Costs | The administrative costs metric examines the total financial cost of operating the RTO/ISO and measures the ability of RTOs/ISOs to manage the growth rate of administrative costs as the growth rate of system load changes. |
| 18 | New Entrant Net Revenues | The new entrant net revenues metric measures the total revenues from the energy and ancillary services (as defined in the RTO/ISO Tariff) markets that a new entrant could be expected to receive, based on proxy resources, for both a combustion turbine and a combined cycle. |
| 19 | Order No. 825 Shortage Intervals and Reserve Price Impacts | The shortage intervals and reserve price impact metric measures the size, duration, and impact that shortage events will have on reserve market clearing prices. |
| *Capacity Market Metrics (Group 3: 20-29)* | | |
| 20 | Net Cost of New Entry (Net CONE) | The Net CONE metric represents the revenues a resource could be expected to earn in the capacity market after netting out revenues from the energy and ancillary services market. The Net CONE metric is usually based on a proxy resource, such as a combined cycle or combustion turbine. |

| Metric No. | Name | Description |
|---|---|---|
| 21 | Resource Deliverability | The resource deliverability metric measures the import limitations into the RTO/ISO or sub-RTO/ISO zone, taking into account any local generation requirements in the sub-RTO/ISO. |
| 22 | New Capacity (Entry) | The new capacity metric measures whether there has been any new capacity added in the RTO/ISO since the previous capacity auction, measured by both RTO/ISO-wide and for specific sub-RTO/ISO regions that were modeled separately from the rest of the RTO/ISO. |
| 23 | Capacity Retirement (Exit) | The capacity retirement metric measures whether there has been any capacity that has been taken out of service since the last capacity auction. |
| 24 | Forecasted Demand | The forecasted demand metric measures the coincident peak demand of a sub-RTO/ISO region during a binding auction for capacity delivered during the reporting period and compares it to the realized coincident peak demand for that reporting period. |
| 25 | Capacity Market Procurement and Prices | The capacity market procurement metric measures the total capacity offered and procured through the central capacity market as well as the associated capacity price on an RTO/ISO-wide basis, as well as per individual zones that were modeled and/or cleared differently from the rest of the RTO/ISO |
| 26 | Capacity Obligations and Performance Assessment Events | The capacity obligations and performance metric measures the total cleared capacity eligible for bonus payments for over-performance and subject to penalties for under-performance, along with the number and duration of performance events. |
| 27 | Capacity Over-Performance | The capacity over-performance metric measures the total number of units that over-performed during a performance assessment period. |
| 28 | Capacity Under-Performance | The capacity under-performance metric measures the total number of units that under-performed during a performance assessment period. |
| 29 | Total Capacity Bonus Payments and Penalties | The total capacity bonus payments and penalties metric measures the total bonus payments and penalties charged to capacity resources with supply obligations that under-performed or over-performed during a performance period. |

Source: Commission staff based on Comment Request in Docket No. AD19-16-000.

## APPENDIX B: SUPPLEMENTAL DATA TABLES

### Table 9: Wholesale Power Costs by Charge Type

| RTO/ISO | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| *CAISO* | | | | |
| Energy | $38.52 | $39.47 | $56.47 | $- |
| Transmission | $12.31 | $12.70 | $14.58 | $- |
| Capacity | $- | $- | $- | $- |
| Operating Reserves | $0.73 | $1.00 | $0.82 | $- |
| Ancillary | $- | $- | $- | $- |
| RTO and Regulatory Fee | $0.46 | $0.47 | $0.49 | $- |
| Other | $0.67 | $0.69 | $0.78 | $- |
| *ISO-NE* | | | | |
| Energy | $27.26 | $34.68 | $75.91 | $75.69 |
| Transmission | $17.58 | $20.89 | $22.88 | $22.36 |
| Capacity | $25.66 | $20.50 | $17.70 | $14.48 |
| Operating Reserves | $0.53 | $0.46 | $0.55 | $1.09 |
| Ancillary | $0.40 | $0.44 | $0.45 | $0.47 |
| RTO and Regulatory Fee | $1.57 | $1.71 | $1.81 | $1.84 |
| Other | $0.08 | $0.06 | $0.04 | $0.08 |
| *MISO* | | | | |
| Energy | $23.83 | $19.43 | $35.75 | $- |
| Transmission | $3.77 | $4.23 | $4.69 | $- |
| Capacity | $0.37 | $1.00 | $0.91 | $- |
| Operating Reserves | $0.08 | $0.07 | $0.12 | $- |
| Ancillary | $0.38 | $0.35 | $0.40 | $- |
| RTO and Regulatory Fee | $0.29 | $0.32 | $0.30 | $- |
| Other | $0.28 | $0.43 | $0.75 | |
| *NYISO* | | | | |
| Energy | $17.68 | $13.92 | $27.38 | $- |
| Transmission | $0.88 | $1.07 | $1.70 | $- |
| Capacity | $- | $- | $- | $- |

| RTO/ISO | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| Operating Reserves | $0.68 | $0.59 | $0.69 | $- |
| Ancillary | $0.48 | $0.55 | $0.52 | $- |
| RTO and Regulatory Fee | $1.05 | $1.15 | $1.29 | $- |
| Other | $0.16 | $0.06 | $0.26 | $- |
| *PJM* | | | | |
| Energy | $27.32 | $21.77 | $39.78 | $80.14 |
| Transmission | $9.48 | $10.98 | $11.65 | $12.42 |
| Capacity | $11.06 | $9.46 | $11.04 | $8.00 |
| Operating Reserves | $0.20 | $0.16 | $0.29 | $0.49 |
| Ancillary | $0.59 | $0.63 | $0.64 | $0.64 |
| RTO and Regulatory Fee | $0.33 | $0.32 | $0.34 | $0.35 |
| Other | $0.11 | $0.12 | $0.23 | $0.36 |
| *SPP* | | | | |
| Energy | $3.52 | $3.65 | $12.47 | $10.22 |
| Transmission | $7.77 | $8.00 | $9.07 | $8.46 |
| Capacity | $- | $- | $- | $- |
| Operating Reserves | $0.61 | $0.32 | $0.89 | $0.66 |
| Ancillary | $0.18 | $0.20 | $0.20 | $0.18 |
| RTO and Regulatory Fee | $0.69 | $0.75 | $0.64 | $0.74 |
| Other | $0.56 | $0.35 | $4.18 | $2.61 |

**Table 10: Net Cone by RTO/ISO Zone**

| Capacity Zone | Metric | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | | *ISO-NE* | | | |
| **Rest-of-Pool** | Import Limitation | N/A | N/A | N/A | N/A |
| | Locational Generation Requirement | N/A | N/A | N/A | N/A |
| | Locational Generation Procured | 33,077 | 32,390 | 20,182 | 16,936 |
| **Maine** | Import Limitation | N/A | N/A | N/A | N/A |
| | Locational Generation Requirement | N/A | N/A | N/A | N/A |
| | Locational Generation Procured | 3,963 | 3,936 | 3,950 | 3,755 |
| **Connecticut** | Import Limitation | N/A | N/A | 2,600 | 2,800 |
| | Locational Generation Requirement | N/A | N/A | 7,603 | 7,319 |
| | Locational Generation Procured | N/A | N/A | 8,372 | 9,191 |
| **NEMA/Boston** | Import Limitation | N/A | N/A | 4,850 | 4,850 |
| | Locational Generation Requirement | N/A | N/A | 3,209 | 3,428 |
| | Locational Generation Procured | N/A | N/A | 3,716 | 3,821 |
| **SEMA/RI** | Import Limitation | N/A | N/A | N/A | N/A |
| | Locational Generation Requirement | N/A | N/A | N/A | N/A |
| | Locational Generation Procured | N/A | N/A | N/A | N/A |
| | | *MISO* | | | |
| **LRZ 1** | Import Limitation | 4,347 | 3,735 | 3,498 | 3,719 |
| | Locational Generation Requirement | 15,070 | 15,982 | 15,918 | 15,975 |
| | Locational Generation Procured | 18,522 | 18,495 | 18,775 | 18,929 |
| **LRZ 2** | Import Limitation | 3,083 | 2,903 | 1,760 | 2,227 |
| | Locational Generation Requirement | 11,739 | 12,332 | 12,986 | 11,980 |
| | Locational Generation Procured | 14,358 | 14,497 | 14,903 | 13,766 |
| **LRZ 3** | Import Limitation | 1,591 | 1,972 | 1,918 | 2,540 |
| | Locational Generation Requirement | 8,971 | 8,695 | 8,715 | 7,968 |
| | Locational Generation Procured | 9,787 | 9,813 | 10,138 | 10,285 |
| **LRZ 4** | Import Limitation | 3,025 | 3,130 | 6,468 | 5,911 |
| | Locational Generation Requirement | 8,879 | 8,852 | 5,476 | 5,839 |
| | Locational Generation Procured | 9,316 | 8,852 | 9,152 | 9,124 |
| **LRZ 5** | Import Limitation | 5,273 | 3,899 | 4,837 | 4,096 |

| Capacity Zone | Metric | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | Locational Generation Requirement | 5,002 | 6,527 | 5,026 | 5,885 |
| | Locational Generation Procured | 8,109 | 6,527 | 7,927 | 7,950 |
| **LRZ 6** | Import Limitation | 4,834 | 5,649 | 5,610 | 6,248 |
| | Locational Generation Requirement | 15,457 | 14,677 | 13,698 | 13,005 |
| | Locational Generation Procured | 19,551 | 19,015 | 18,398 | 18,665 |
| **LRZ 7** | Import Limitation | 3,884 | 3,813 | 3,521 | 3,320 |
| | Locational Generation Requirement | 21,293 | 21,442 | 20,851 | 21,109 |
| | Locational Generation Procured | 22,627 | 23,515 | 21,534 | 21,956 |
| **LRZ 8** | Import Limitation | 1,602 | 2,074 | 3,725 | 3,332 |
| | Locational Generation Requirement | 8,417 | 7,850 | 6,270 | 6,766 |
| | Locational Generation Procured | 8,582 | 8,526 | 9,995 | 10,139 |
| **LRZ 9** | Import Limitation | 3,585 | 3,320 | 5,417 | 5,482 |
| | Locational Generation Requirement | 24,080 | 18,406 | 17,477 | 17,295 |
| | Locational Generation Procured | 26,059 | 25,762 | 18,511 | 18,652 |
| **LRZ 10** | Import Limitation | N/A | N/A | 2,653 | 1,910 |
| | Locational Generation Requirement | N/A | N/A | 3,978 | 4,831 |
| | Locational Generation Procured | N/A | N/A | 6,151 | 5,287 |
| *NYISO* | | | | | |
| **Zone J** | Import Limitation | 1,767 | 1,968 | 2,299 | 2,159 |
| | Locational Generation Requirement | 10,016 | 9,961 | 9,494 | 9,511 |
| | Locational Generation Procured | 10,088 | 10,342 | 10,212 | 10,293 |
| **K** | Import Limitation | 385 | 194 | 137 | 190 |
| | Locational Generation Requirement | 5,881 | 5,733 | 5,616 | 5,617 |
| | Locational Generation Procured | 6,150 | 6,088 | 6,133 | 6,124 |
| **G-J** | Import Limitation | 1,955 | 1,552 | 1,631 | 1,365 |
| | Locational Generation Requirement | 14,336 | 14,788 | 14,678 | 14,696 |
| | Locational Generation Procured | 14,423 | 15,166 | 15,384 | 15,485 |
| **NYCA** | Import Limitation | 2,490 | 2,740 | 2,700 | 2,689 |
| | Locational Generation Requirement | 39,389 | 39,273 | 39,198 | 39,150 |
| | Locational Generation Procured | 40,869 | 42,044 | 41,473 | 43,040 |

| Capacity Zone | Metric | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| *PJM* | | | | | |
| **MAAC** | Import Limitation | 5,694 | 6,156 | 6,495 | 7,393 |
| | Locational Generation Requirement | 66,493 | 65,467 | 65,804 | 64,141 |
| | Locational Generation Procured | 67,289 | 65,790 | 66,546 | 68,429 |
| **EMAAC** | Import Limitation | 8,189 | 9,177 | 8,916 | 9,315 |
| | Locational Generation Requirement | 31,806 | 30,193 | 30,778 | 30,056 |
| | Locational Generation Procured | 32,667 | 33,048 | 31,522 | 32,211 |
| **SWMAAC** | Import Limitation | 7,719 | 8,373 | 8,786 | 8,053 |
| | Locational Generation Requirement | 9,640 | 8,865 | 8,530 | 8,882 |
| | Locational Generation Procured | 11,124 | 11,000 | 12,050 | 11,693 |
| **PSEG** | Import Limitation | 5,721 | 6,220 | 6,581 | 6,700 |
| | Locational Generation Requirement | 7,378 | 6,604 | 6,289 | 6,059 |
| | Locational Generation Procured | 7,583 | 6,730 | 6,299 | 6,111 |
| **PS-NORTH** | Import Limitation | 2,372 | 2,972 | 2,936 | 2,795 |
| | Locational Generation Requirement | 3,839 | 3,490 | 3,504 | 3,670 |
| | Locational Generation Procured | 3,818 | 3,641 | 3,702 | 3,893 |
| **DPL-SOUTH** | Import Limitation | 1,925 | 1,822 | 1,901 | 1,904 |
| | Locational Generation Requirement | 1,093 | 1,240 | 1,259 | 1,311 |
| | Locational Generation Procured | 1,552 | 1,722 | 1,746 | 1,682 |
| **PEPCO** | Import Limitation | 5,606 | 6,522 | 6,846 | 5,359 |
| | Locational Generation Requirement | 3,345 | 2,451 | 2,166 | 3,356 |
| | Locational Generation Procured | 5,615 | 6,136 | 6,094 | 5,938 |
| **ATSI** | Import Limitation | N/A | 5,418 | 7,881 | 8,470 |
| | Locational Generation Requirement | N/A | 10,783 | 8,374 | 7,539 |
| | Locational Generation Procured | N/A | 10,669 | 8,672 | 8,977 |
| **ATSI-CLEVELAND** | Import Limitation | N/A | N/A | 5,245 | 4,940 |
| | Locational Generation Requirement | N/A | N/A | 919 | 1,310 |
| | Locational Generation Procured | N/A | N/A | 2,850 | 2,549 |
| **COMED** | Import Limitation | N/A | N/A | N/A | 7,020 |
| | Locational Generation Requirement | N/A | N/A | N/A | 21,971 |
| | Locational Generation Procured | N/A | N/A | N/A | 22,551 |

| Capacity Zone | Metric | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **BGE** | Import Limitation | N/A | N/A | N/A | 6,217 |
| | Locational Generation Requirement | N/A | N/A | N/A | 2,484 |
| | Locational Generation Procured | N/A | N/A | N/A | 3,351 |
| **PPL** | Import Limitation | N/A | N/A | N/A | 4,336 |
| | Locational Generation Requirement | N/A | N/A | N/A | 6,477 |
| | Locational Generation Procured | N/A | N/A | N/A | 9,349 |

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