IMM Quarterly Markets Performance Reports

Winter 2021 Report

December 2020 – February 2021 outcomes

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Outline

- Overview of Winter QMR 2021:
  - Winter QMR includes a review of the fifteenth Forward Capacity Auction.
  - No special analysis section in this report.
- Appendix contains Fall 2020 QMR slides.

Summary for Winter 2021

- **Wholesale market costs totaled $2.33bn**, a 31% increase (up $0.55bn) on Winter 2020 costs of $1.78bn.
  - Driven by higher energy costs.
- **Large increase in energy market costs**, up by 69% (totaled $1.7bn, up by $0.7bn) compared to prior winter, driven by an increase in natural gas prices.
  - Avg. day-ahead and real-time Hub LMPs were $51.30 and $51.66/MWh respectively, a 69-72% increase compared to Winter 2020 prices.
  - Winter 2021 temperatures averaged 31°F, a 2°F decrease compared to Winter 2020.
  - Avg. natural gas price was $5.83/MMBtu (or $45.47/MWh assuming a 7,800 Btu/kWh heat rate), up 71% on the Winter 2020 price of $2.42/MMBtu (or $18.88/MWh).
  - Avg. hourly load of 14,283 MW was up by 2%, driven by colder weather (31°F vs. 33°F) and less behind-the-meter solar generation.
- **Decrease in capacity market costs**, down by 19% (totaled $607m, down by $144m) on Winter 2020.
  - Winter 2020 was the third quarter of the FCA 11 commitment period, with clearing prices of $5.30/kW-month for rest-of-system, compared to an FCA 10 price of $7.03/kW-month.

Seasons: **Winter: Dec-Feb** Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

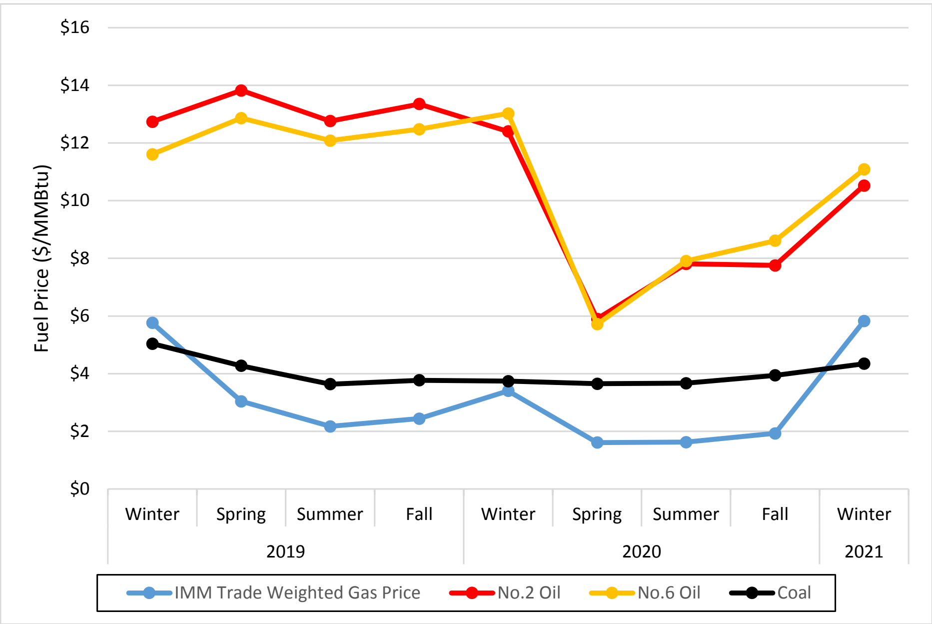
Summary for Winter 2021 (cont.)

- **Gross real-time reserve payments totaled $2.1m**, a 23% increase from $1.7m in Winter 2020.
  - All reserve payments were for spinning reserve (TMSR).
  - Frequency of non-zero ten-minute spinning reserve pricing in Winter 2021 was similar to that of Winter 2020.
  - The average non-zero hourly spinning reserve price increased relative to Winter 2020, from $7.56 to $9.75/MWh. The increase was due to higher LMPs, which increased re-dispatch costs to provide reserves rather than energy.
- **Total regulation payments were $6.0m**, up by $0.3m (5%) compared to Winter 2020.
  - The small increase in payments reflects a modest increase in regulation service prices and payments during the Winter 2021 period.
- **Net Commitment Period Compensation (NCPC) costs totaled $9.6m**, a $2.2 million increase compared to Winter 2020 payments.
  - NCPC costs represented less than 1% of the total energy costs in both Winter 2021 and Winter 2020.
  - Economic payments made up 63% ($6.1m) of the total, up by $1.8m on Winter 2020 costs. Most (62%) economic payments occurred in the real-time market.
  - Local Second-Contingency-Protection Resource (LSCPR) payments totaled $3.0 million, up by $0.3 million relative to Winter 2020. Most (54%) LSCPR payments occurred in December and were paid to generators that were committed in the day-ahead market to meet reliability needs in Maine due to a planned transmission outage.

Seasons: **Winter: Dec-Feb** Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

Higher gas prices and higher LNG injections than prior winter

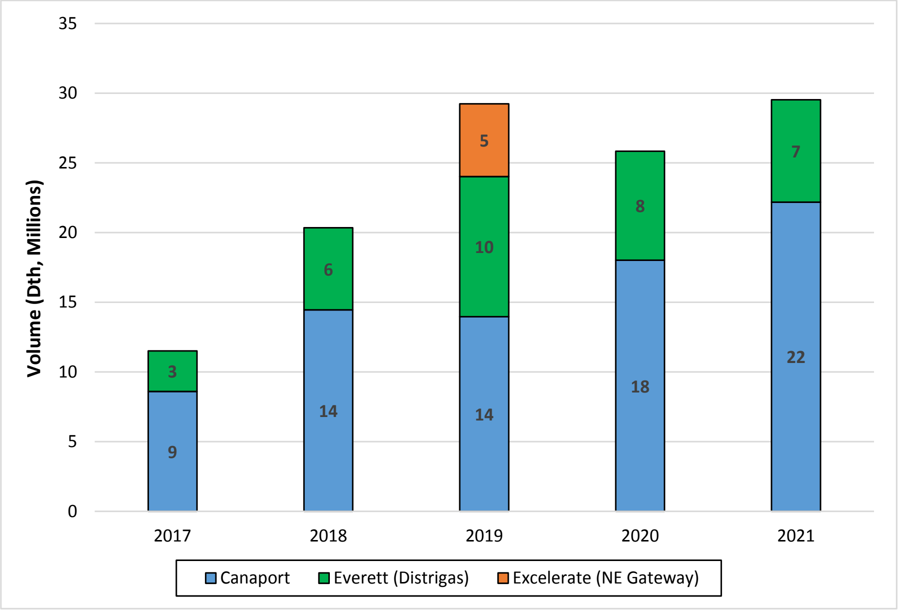
Fuel Prices



For context, the decatherm amounts are equiv. to operating the following gas-fired generation capacity all winter (assuming 7.8 heat rate, numbers round):

- 30m Dth = 1,800 MW
- 20m Dth = 1,200 MW
- 10m Dth = 600 MW

LNG Injections by Facility



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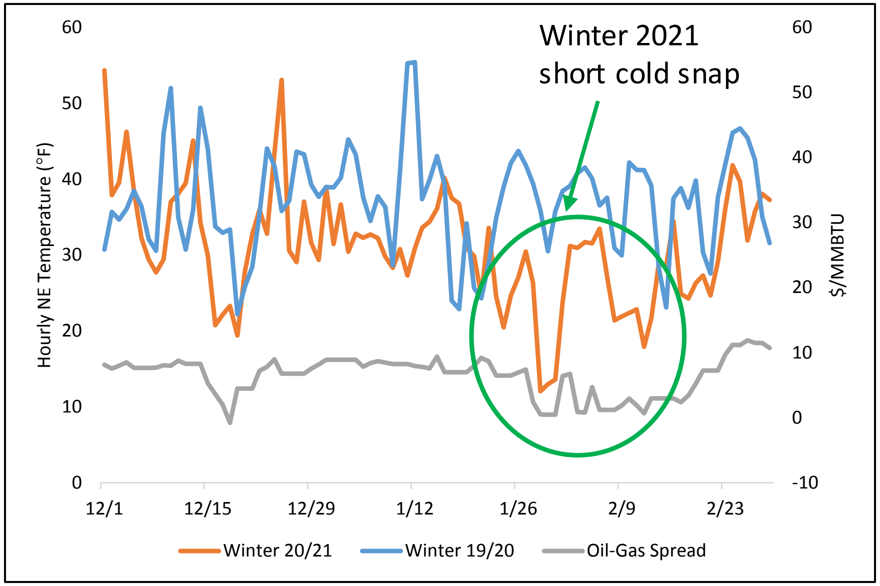
Energy Market Opportunity Costs (EMOC) were greater than zero for the first time this winter

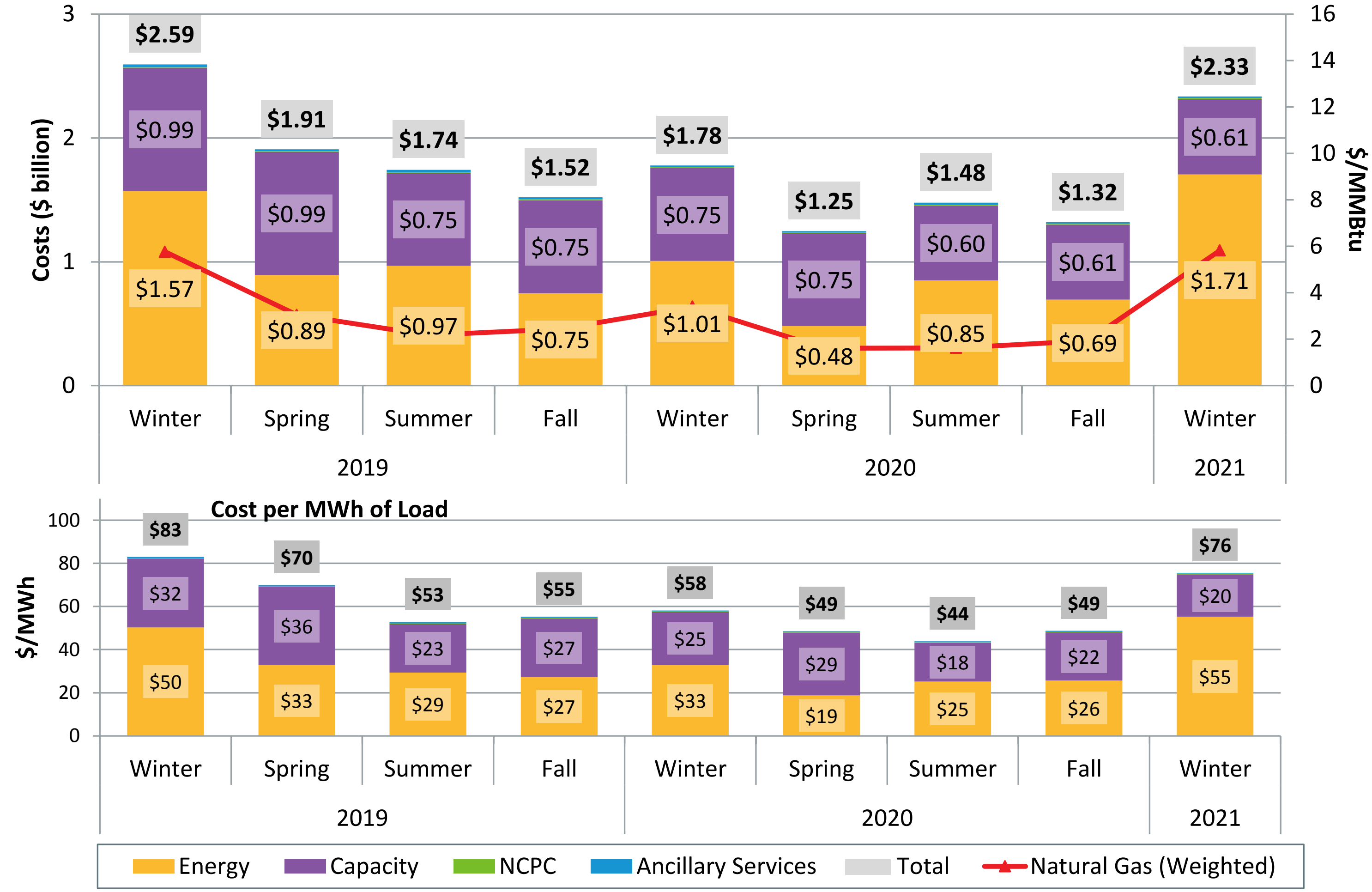
- In December 2018, EMOCs started to be included in reference levels; intended to let the market preserve limited oil inventories for times when gas supply is low during extreme cold weather.
- Winter 2021 had a sustained drop in average temperatures that was sufficient to produce non-zero EMOCs for two small generators.
- In early February, the average daily temperature was just below 24°F for seven days.
- The average EMOC was $7.54/MWh across these seven days.

Winter Temperatures



Seasons: **Winter: Dec-Feb** Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

Higher energy prices drove a 31% increase in Winter 2021 wholesale costs compared to Winter 2020



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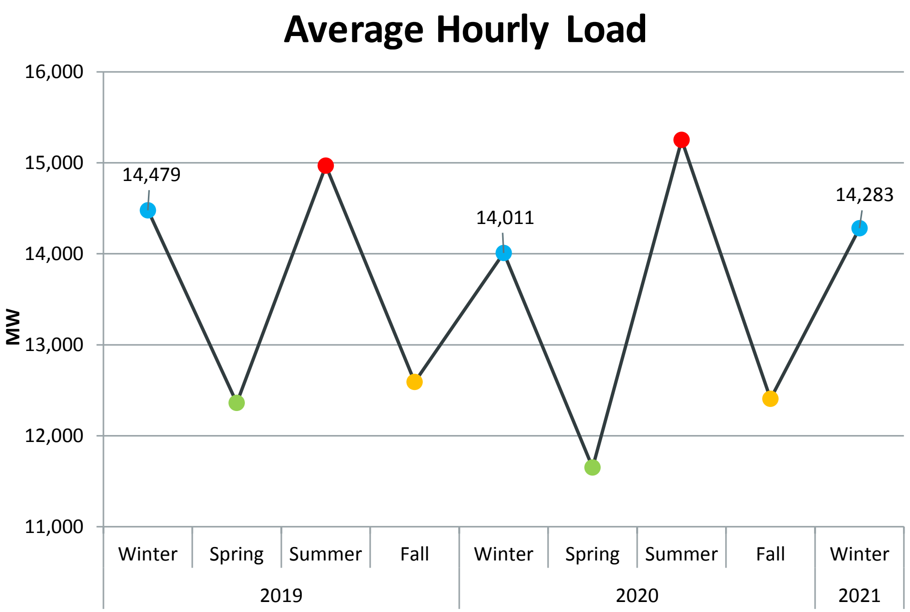
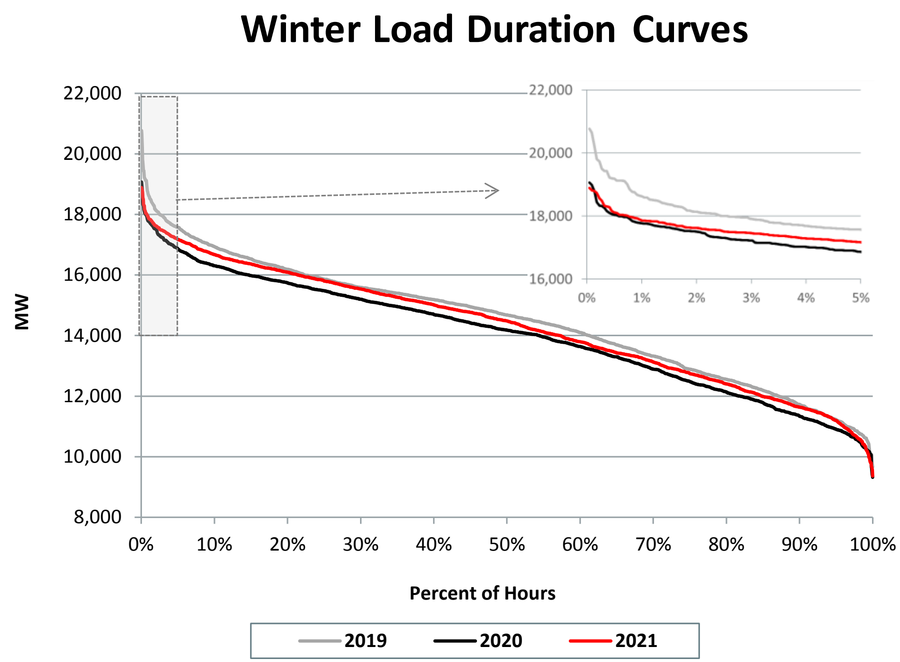
Higher average and peak loads; Colder average temperatures and less BTM solar than previous winter

- In Winter 2021, increased cloud cover led to an estimated 37% decrease in behind-the-meter solar generation compared to Winter 2020.





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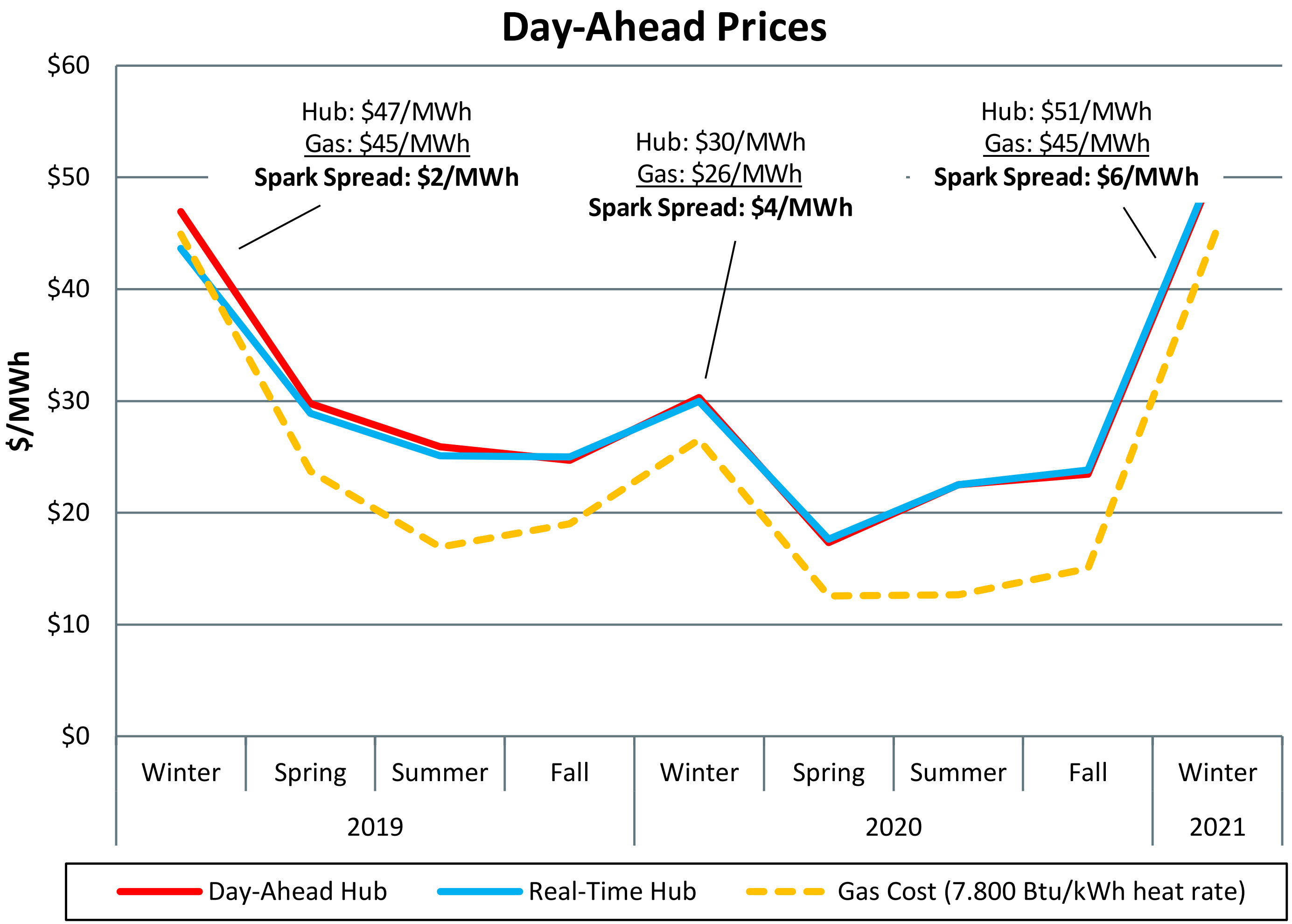
Gas spark spread increased from previous two winters



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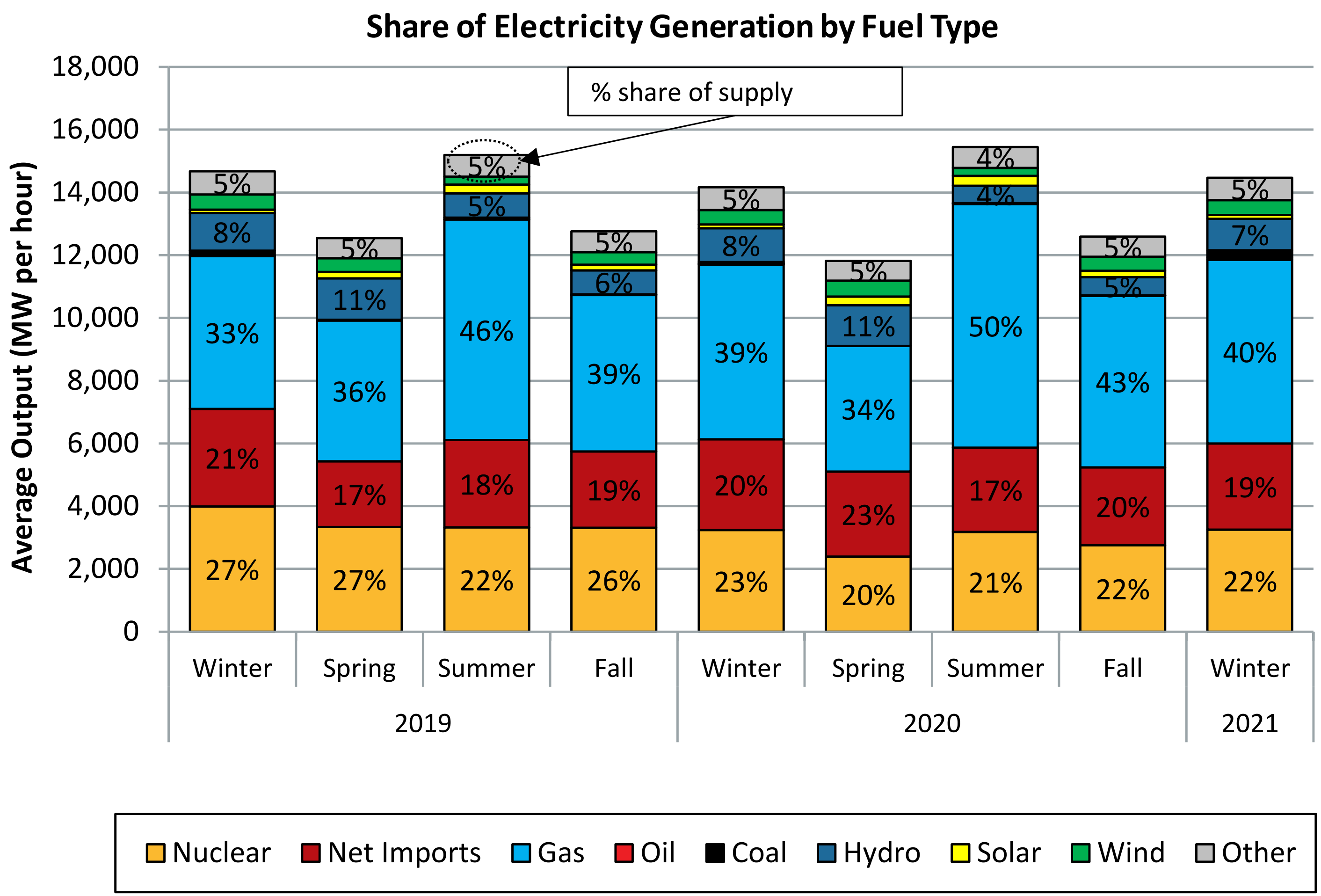
Gas generation share was similar to prior winter, coal generation increased



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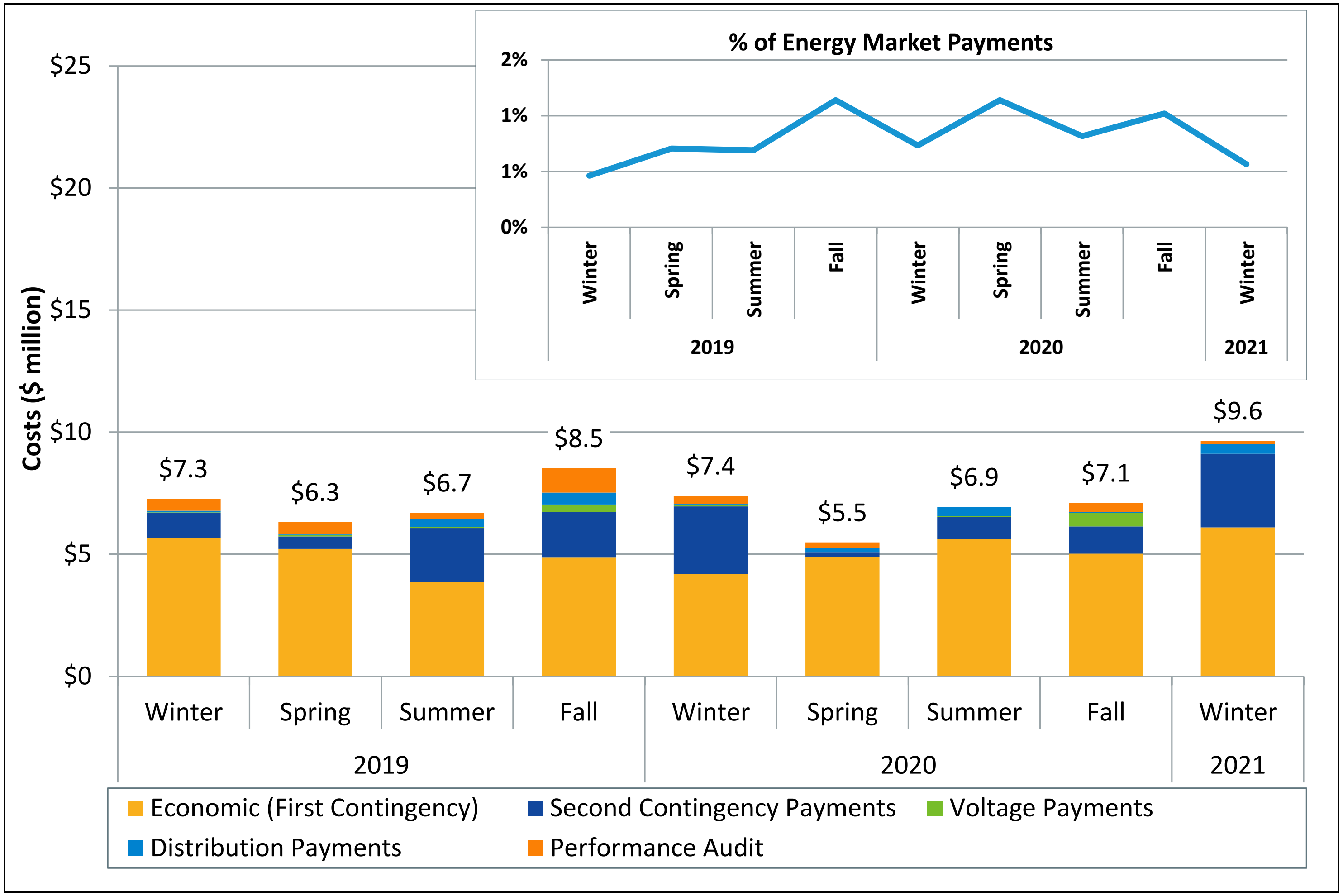
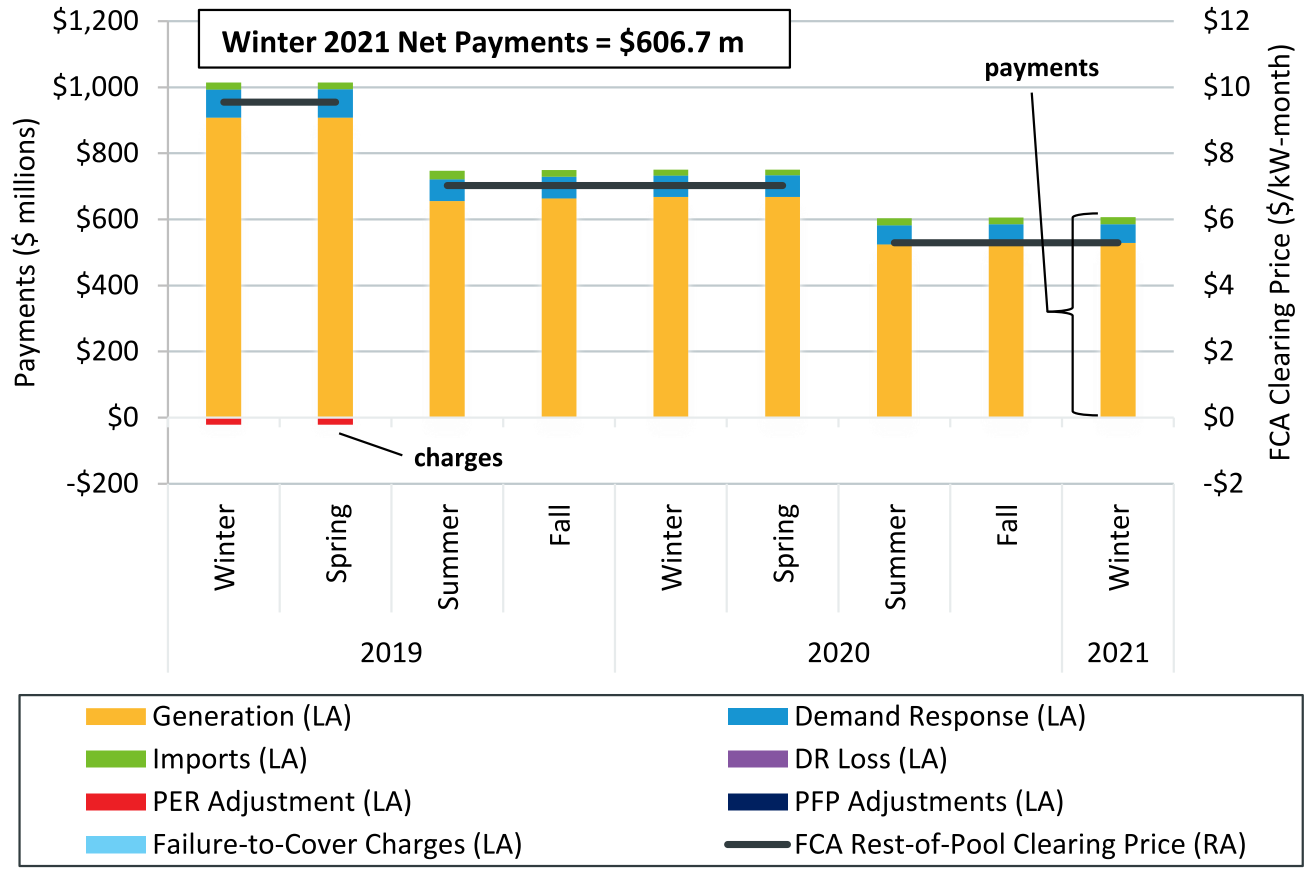
Higher NCPC payments - 63% was economic NCPC mostly paid in real-time market



Seasons: **Winter: Dec-Feb** Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

Third quarter of FCA 11; lower clearing prices

FCA 11 prices: $5.30/kW-month for all resources in New England and imports from Quebec and New York



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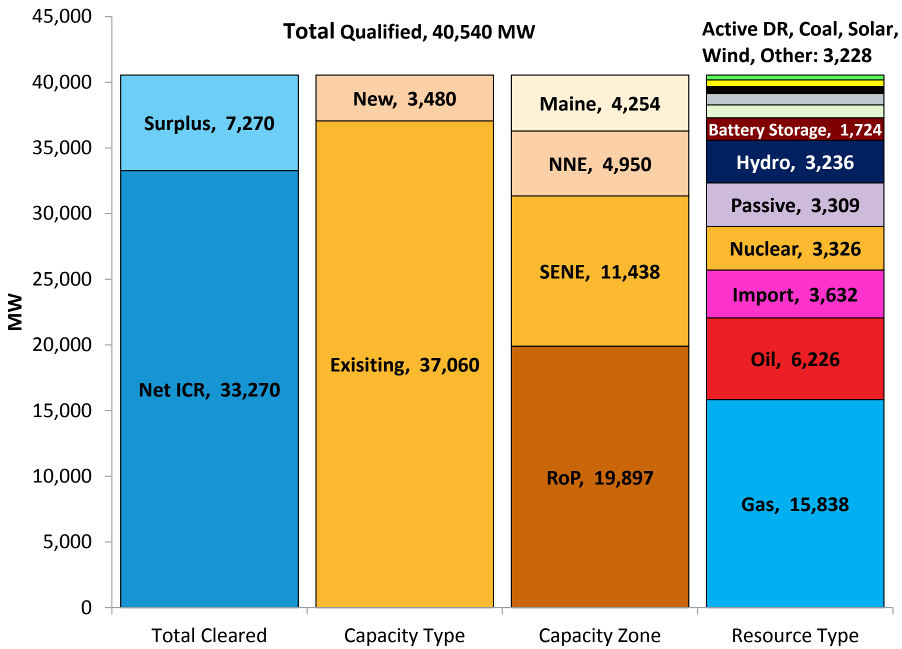
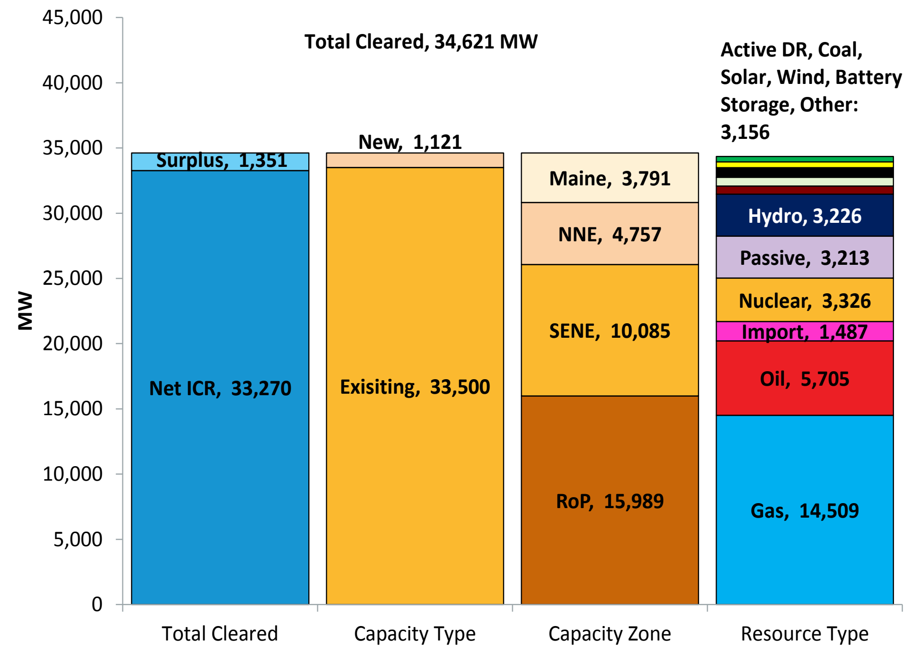
FCA 15 Highlights

Total qualified capacity was 40,540 MW, of which 34,621 MW (85%) cleared at a price of $2.61/kW-month for Rest-of-Pool, $3.98/kW-month for Southeastern New England, and $2.48/kW-month for Northern New England

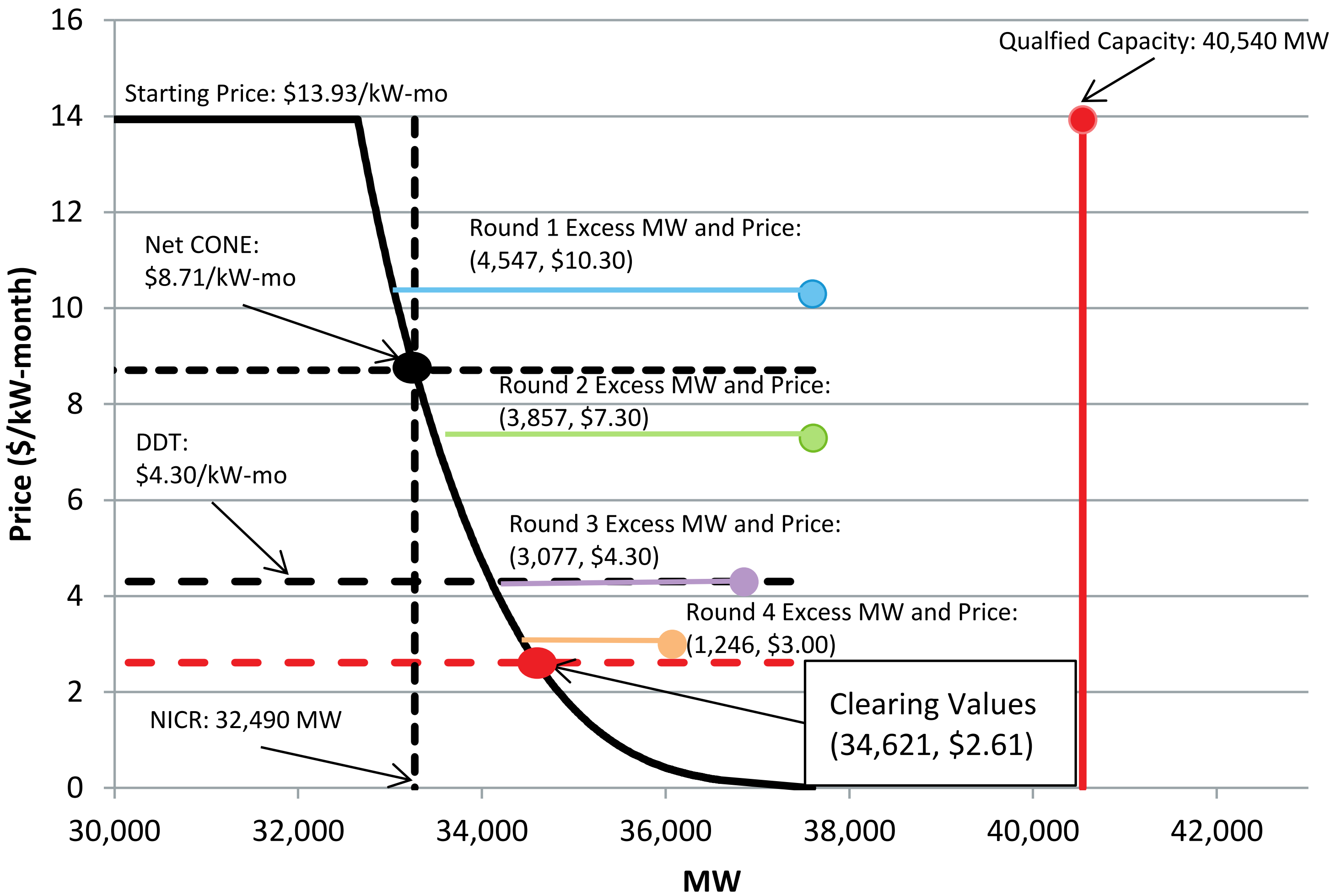
Qualified Capacity across Capacity Type, Zones, and Resource Type



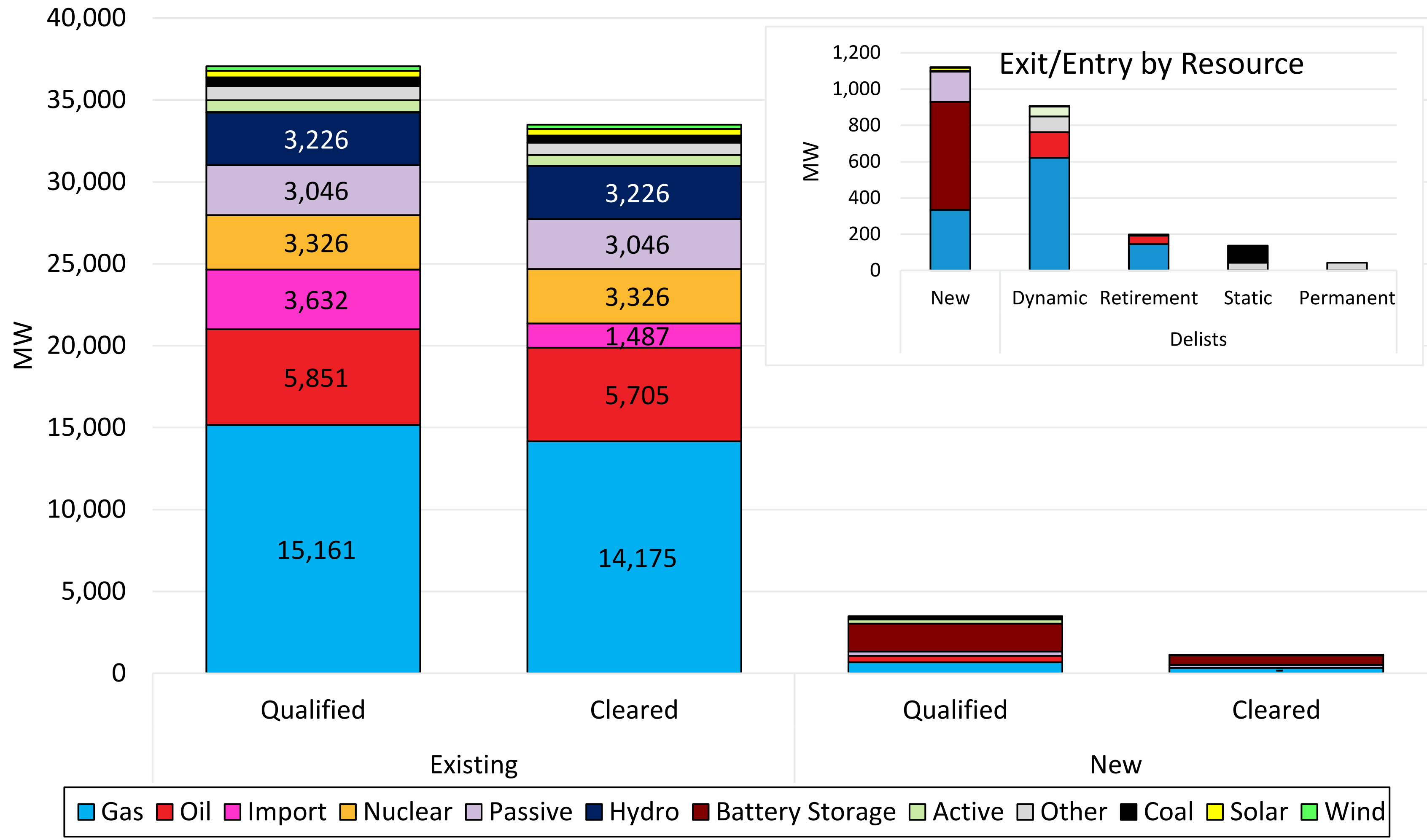
Cleared Capacity across Capacity Type, Zones, and Resource Type



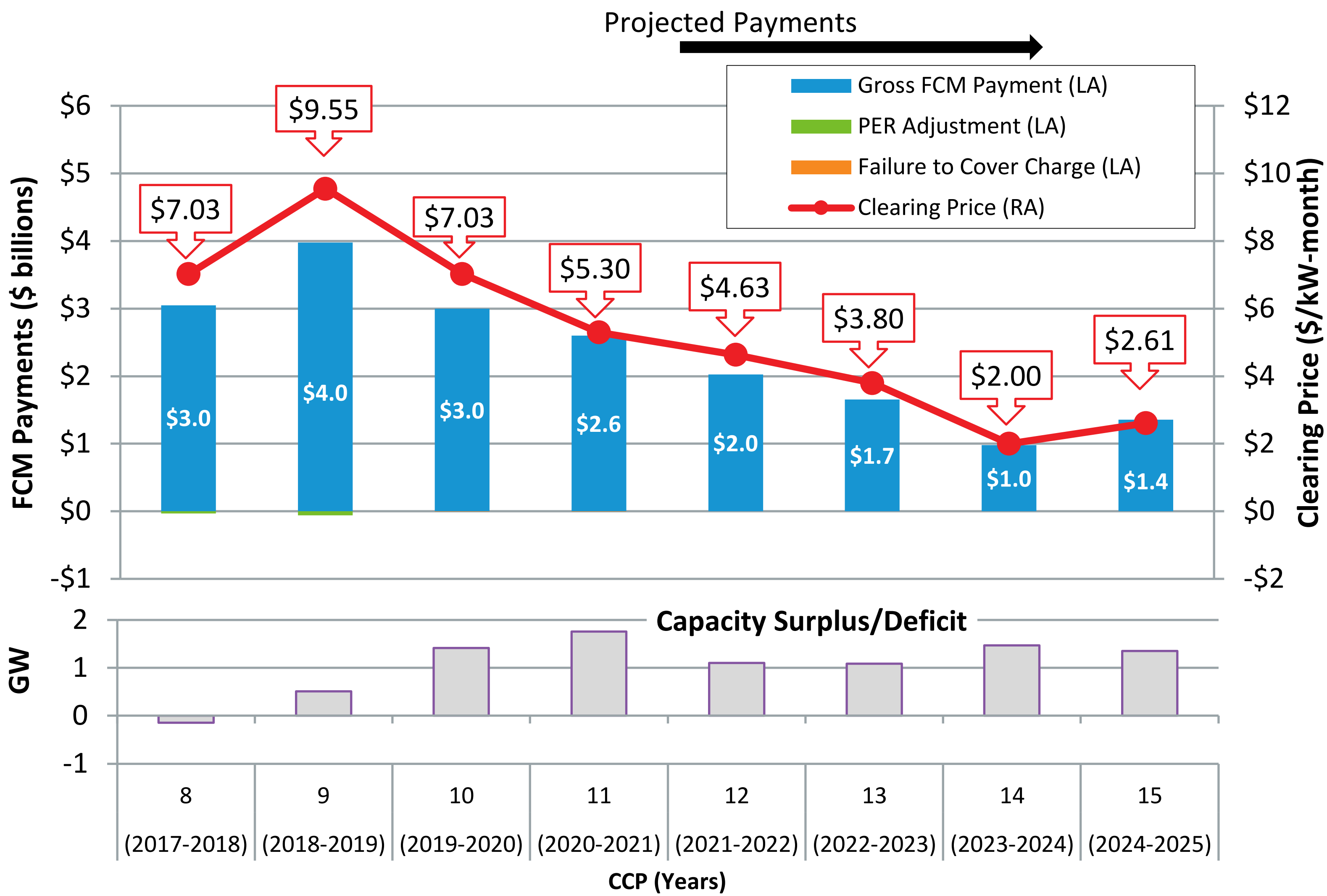
In FCA 15, prices cleared below the dynamic delist threshold as they did in the prior year's auction



Resource mix by cleared capacity and entry/exit



Payments, Prices and System Margin



Energy Market Competitiveness

This new section of the QMR examines the potential for market power and summarizes mitigation instances.

- There was at least one pivotal supplier present in the real-time market for 8% of 5-minute intervals in Winter 2021.
- The residual supply index for the real-time market in Winter 2021 was 107.9, indicating that on average, the ISO could meet load and the reserve requirement without energy and reserves from the largest supplier.

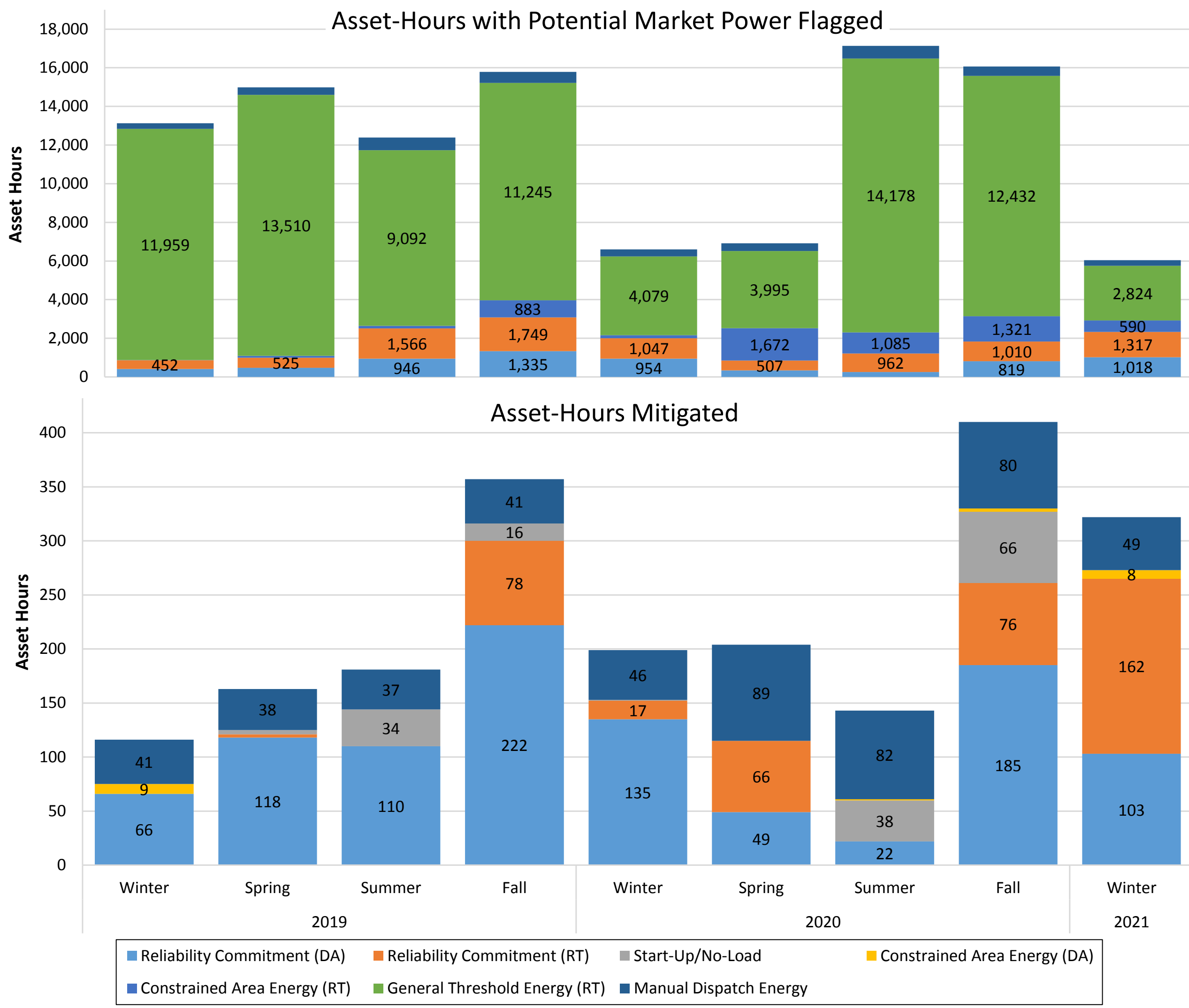
Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2019	106.3	11%
Spring 2019	107.5	8%
Summer 2019	106.7	18%
Fall 2019	104.8	21%
Winter 2020	108.6	8%
Spring 2020	109.2	8%
Summer 2020	104.8	27%
Fall 2020	105.1	24%
Winter 2021	107.9	8%

Seasons: **Winter: Dec-Feb** Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

Energy Market Competitiveness Mitigation

- In general, mitigation occurs very infrequently relative to the structural test failures.



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Questions

APPENDIX

Fall 2020 QMR

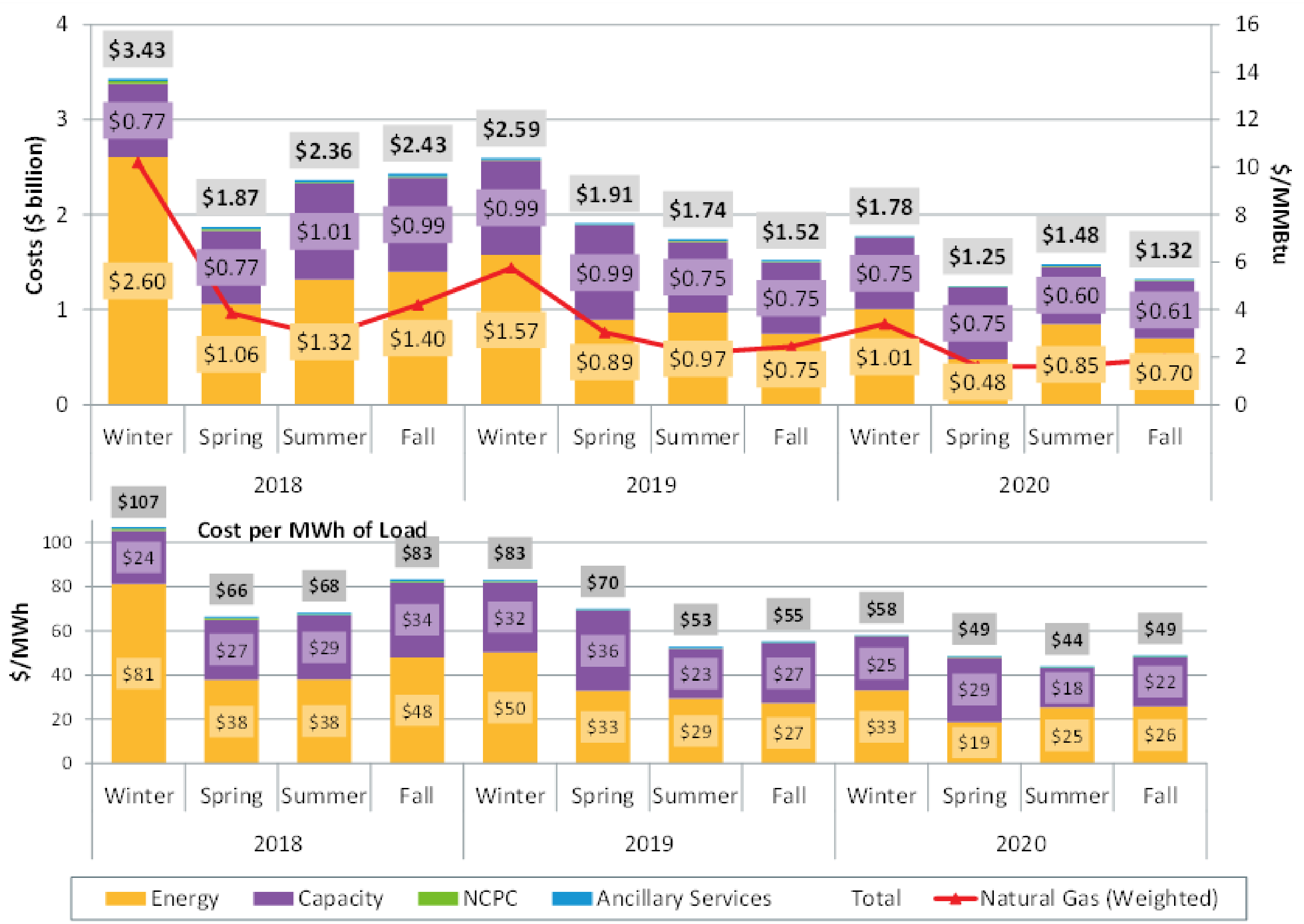
Summary for Fall 2020

- Wholesale market costs totaled \$1.32bn, a 13% decrease (down \$0.2bn) compared to \$1.52bn in Fall 2019.
  - Both energy and capacity market costs decreased as well as NCPC and ancillary services costs.
- Energy costs were down by 7% (totaled \$696m, down by \$51m), due to lower natural gas prices , but partially offset by greater baseload generation outages in Fall 2020.
  - Avg. day-ahead and real-time Hub LMPs were \$23.46/MWh and \$23.82/MWh; Both 5% lower than Fall 2019 prices.
  - Avg. natural gas price was \$1.93/MMBtu down 21% on the Fall 2019 avg. price of \$2.44/MMBtu.
  - Hourly load averaged 12,402 MW in Fall 2020. This was similar to average load in Fall 2019 (12,592 MW).
- Large decrease in capacity market costs, down by 19% (totaled \$605m, down by \$144m) on Fall 2019.
  - Fall 2020 was the second quarter of the FCA 11 commitment period, with clearing prices of \$5.30/kW-month for rest-of-system, compared to a higher Fall 2019 price (FCA 10) of \$7.03/kW-month.

Summary for Fall 2020 (cont.)

- Real-time reserve payments totaled $2.6m, up by $0.5m on Fall 2019.
  - Higher Fall 2020 prices and payments were driven by increases in non-spinning reserve payments, and an increase in the frequency of TMSR pricing.
  - Non-spinning reserve pricing occurred on September 8, 2020, when forecast error and higher real-time load obligations caused tight system conditions in the early evening. There were no payments for non-spinning reserves in Fall 2019.
- Total regulation payments were $5.4m, down by $0.8m (13%) compared to Fall 2019.
  - Decrease in payments reflects a reduction in regulation opportunity costs due to lower energy prices and no significant system events.
- Net Commitment Period Compensation (NCPC) costs totaled $7.1m, down by 17% (by $1.4m) on the prior fall.
  - NCPC costs represented about 1% of the total energy costs, consistent with the historical range.
  - Economic payments made up 71% ($5.0m) of the total, similar to Fall 2019 costs of $4.9m.
    - Most of these payments occurred in the real-time market.
  - Local reliability payments were comparable to the prior fall at $1.1m. Most of these payments went to generators to support planned transmission upgrades in northern New England.

Total costs less than Fall 2019; lower energy and capacity costs



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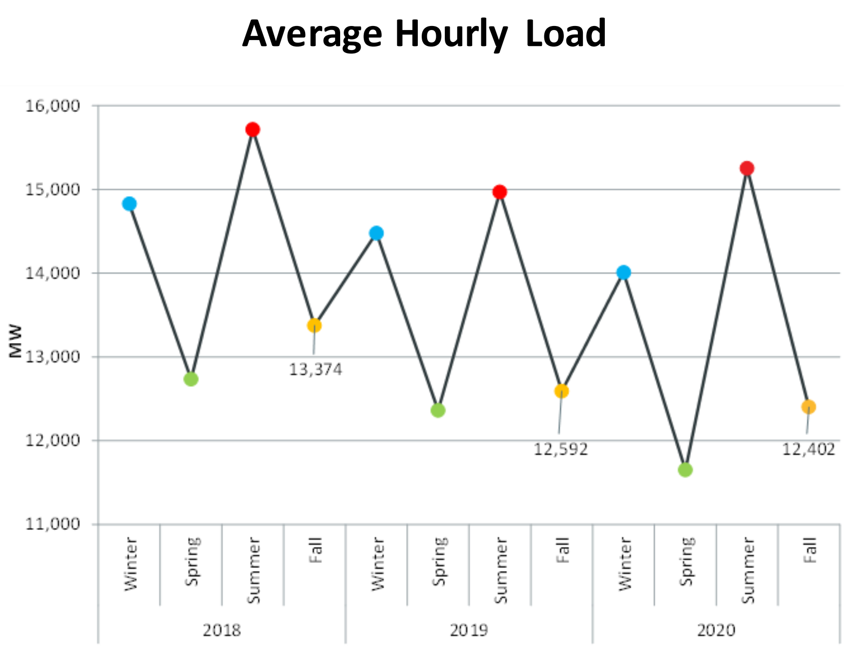
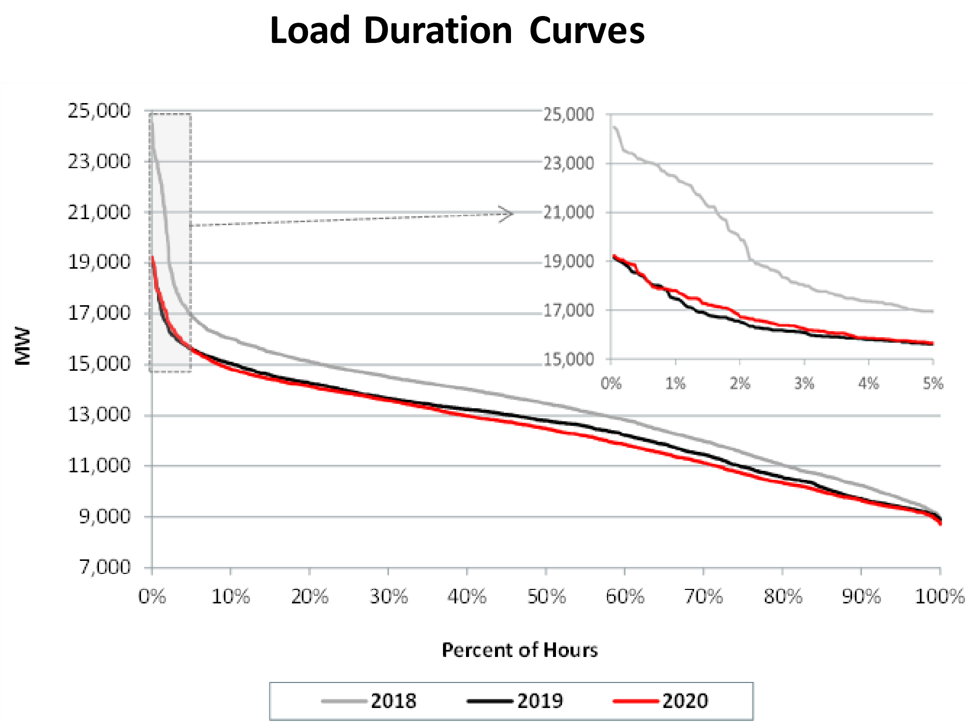
Average and peak loads very similar to last fall





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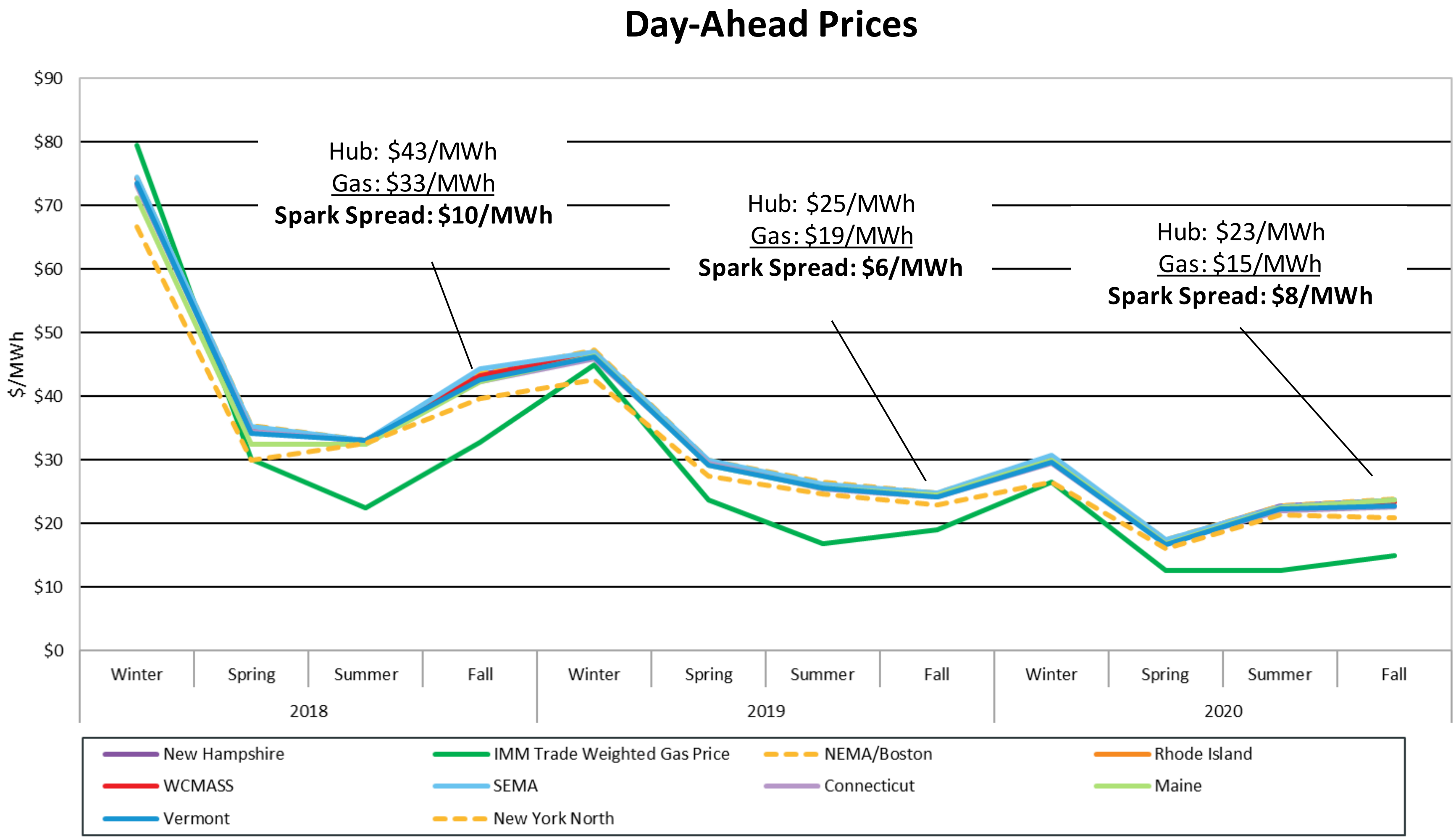
Lower gas prices offset by planned nuclear outages; higher margins for baseload gas generators



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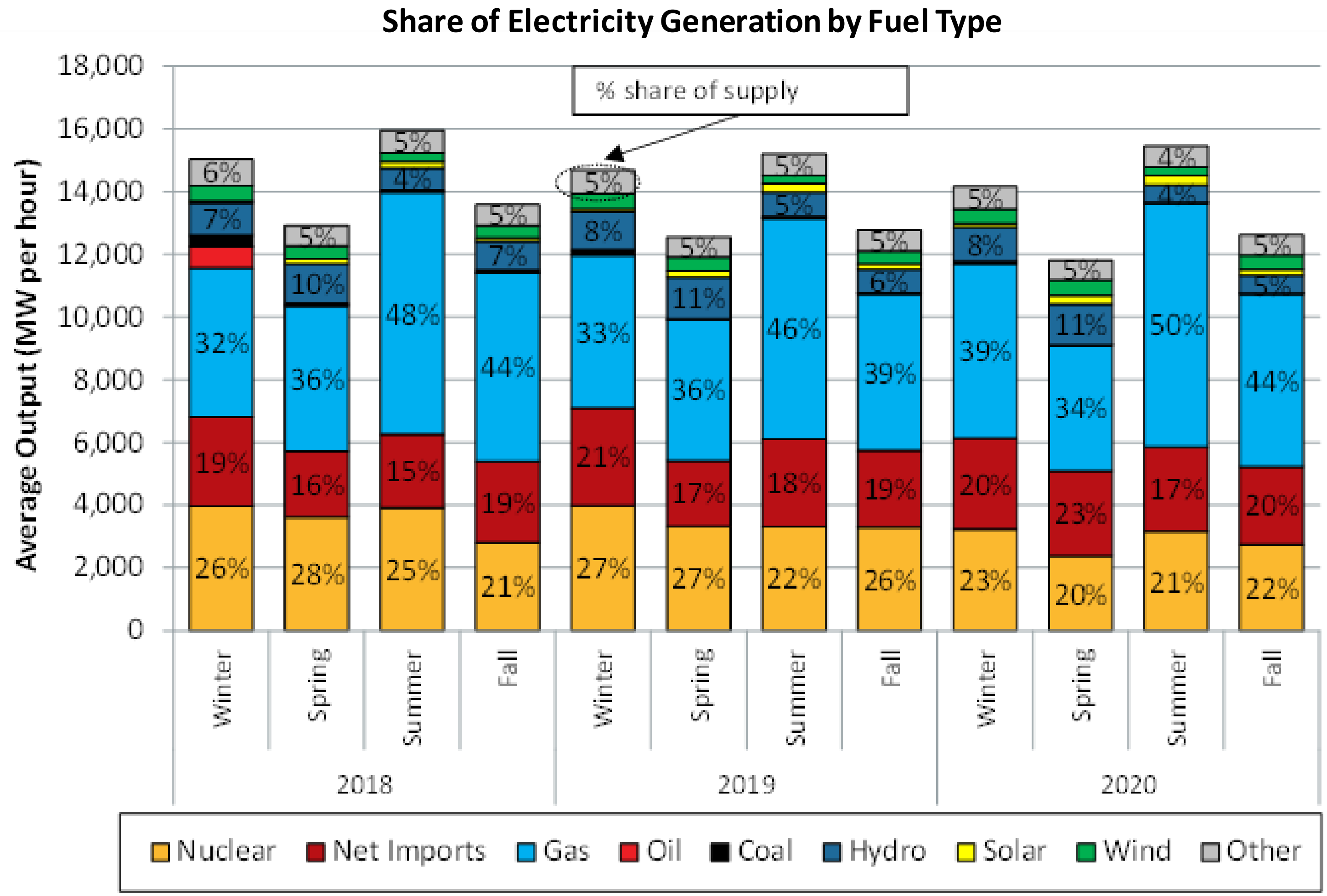
Reduced nuclear generation in Fall 2020 due to refueling; share of natural gas increases as a result



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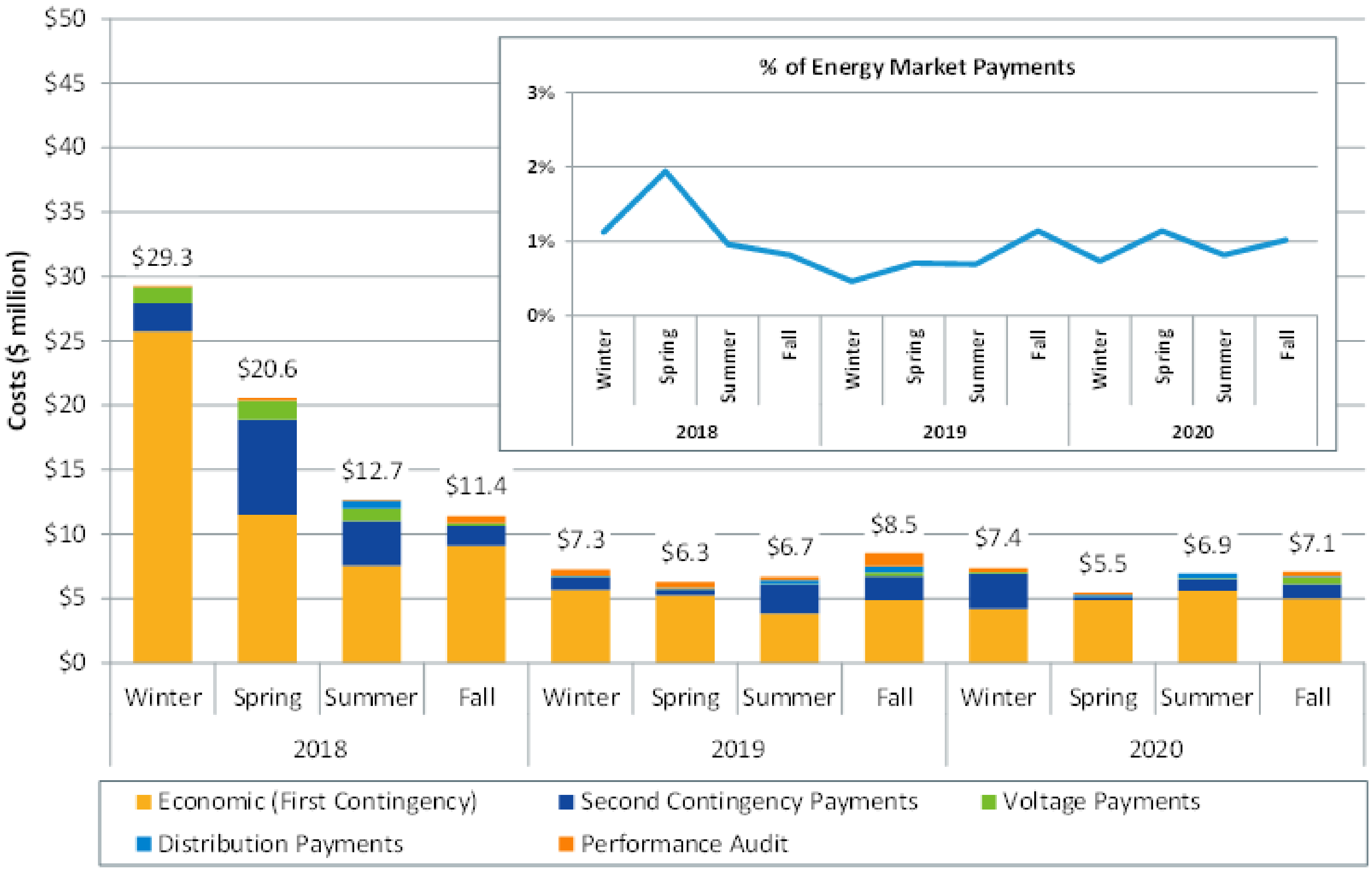
Lower NCPC costs driven by decreased economic payments; consistent with lower gas and energy prices



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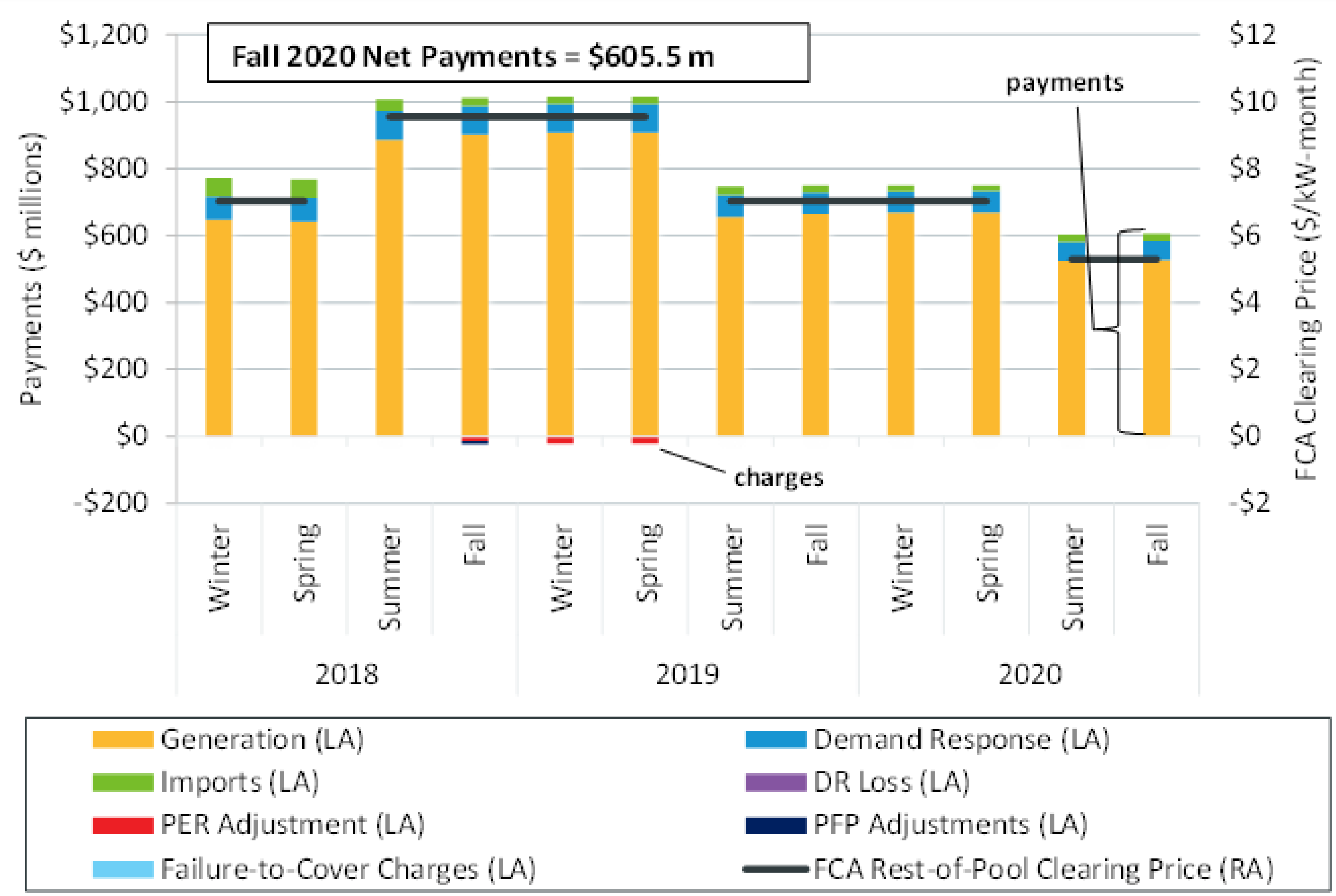
Second quarter of FCA11; lower clearing prices

FCA 11 prices: $5.30/kW-month for all New England resources, New York Imports and Quebec imports; $3.38/kW-month for New Brunswick imports



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- The residual supply index for the real-time market in Fall 2020 was 105, indicating that on average, the ISO could meet load and the reserve requirement without energy and reserves from the largest supplier.

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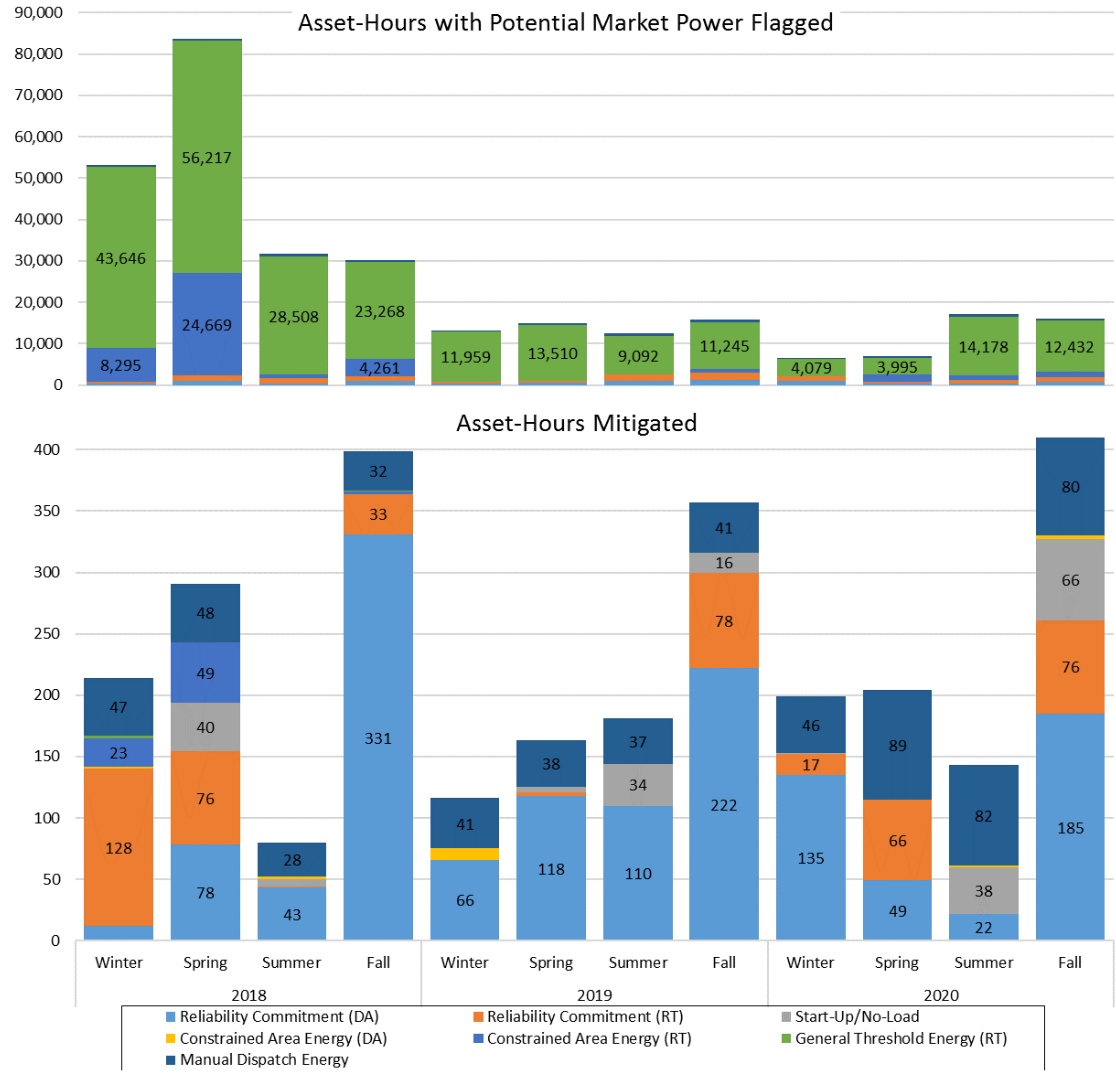

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