IMM Quarterly Markets Performance Reports

Summer 2019 Report Highlights

June 2019 – September 2019 outcomes

with Spring 2019 Report Highlights in the Appendix

March 2019 – May 2019 outcomes

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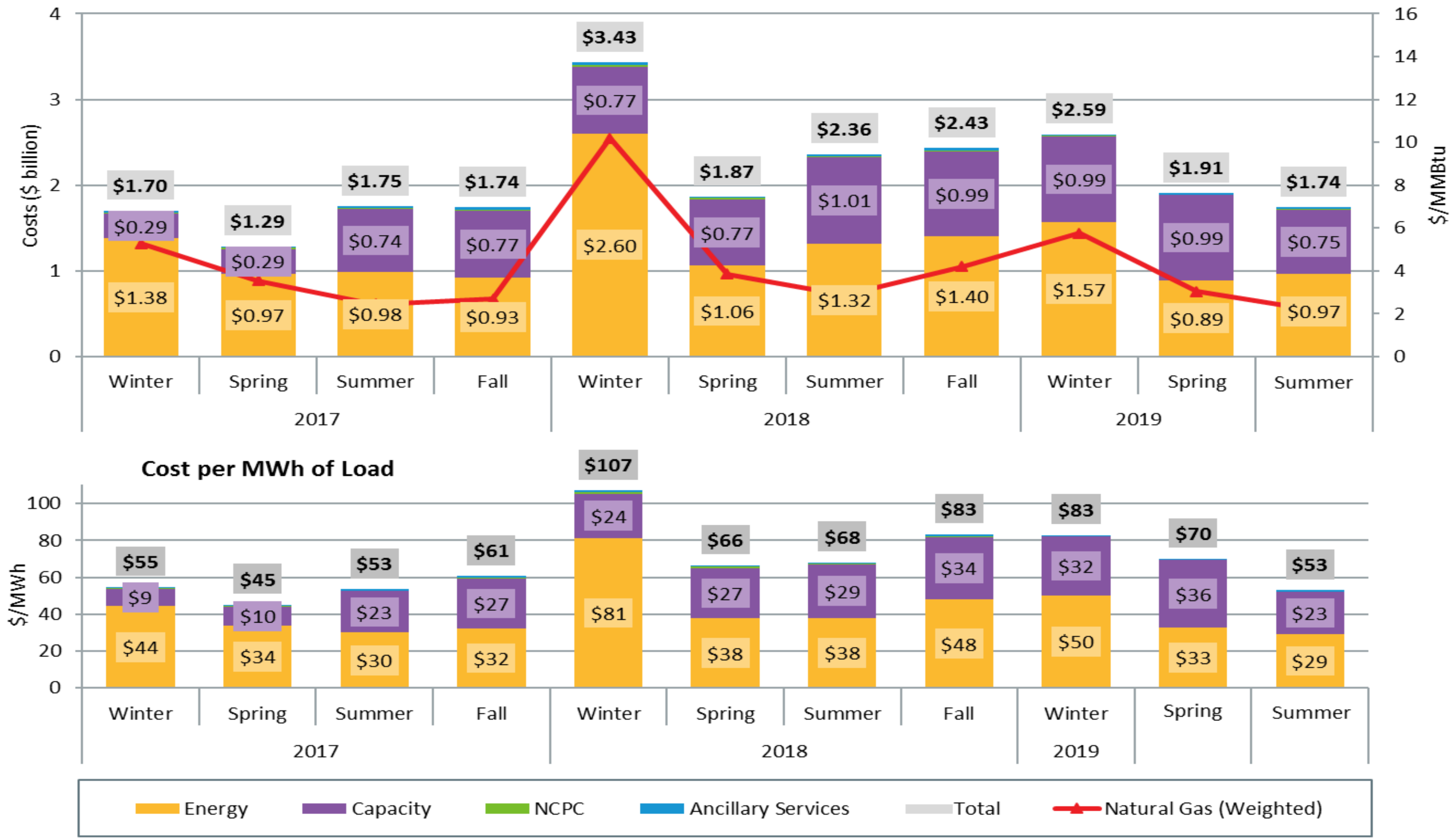
Summary for Summer 2019

- Wholesale market costs totaled $1.74bn, a 26% decrease (down $0.62bn) compared to $1.74bn in Summer 2018.
  - Both energy and capacity market costs decreased significantly.
- Large decrease in energy costs, down by 27% (totaled $967m, down by $353m), driven by a decrease in natural gas prices and lower loads.
  - Avg. day-ahead and real-time Hub LMPs were $25.89/MWh and $25.09/MWh; 21% and 24% lower, respectively.
  - Avg. natural gas price was $2.17/MMBtu (or $16.93/MWh assuming a 7,800 Btu/kWh heat rate), down 25% on the Summer 2018 price of $2.89/MMBtu (or $22.54/MWh).
  - Avg. hourly load of 14,904 MW was down by 5% (≈ 800 MW), driven by lower humidity and cooler weather.
- Large decrease in capacity market costs, down by 26% (totaled $746m, down by $260m) on Summer 2018.
  - Summer 2019 was the first quarter of the FCA 10 commitment period, with clearing prices of $7.03/kW-month for rest-of-system, compared to a higher FCA 9 price of $9.55/kW-month.

Summary for Summer 2019 (cont.)

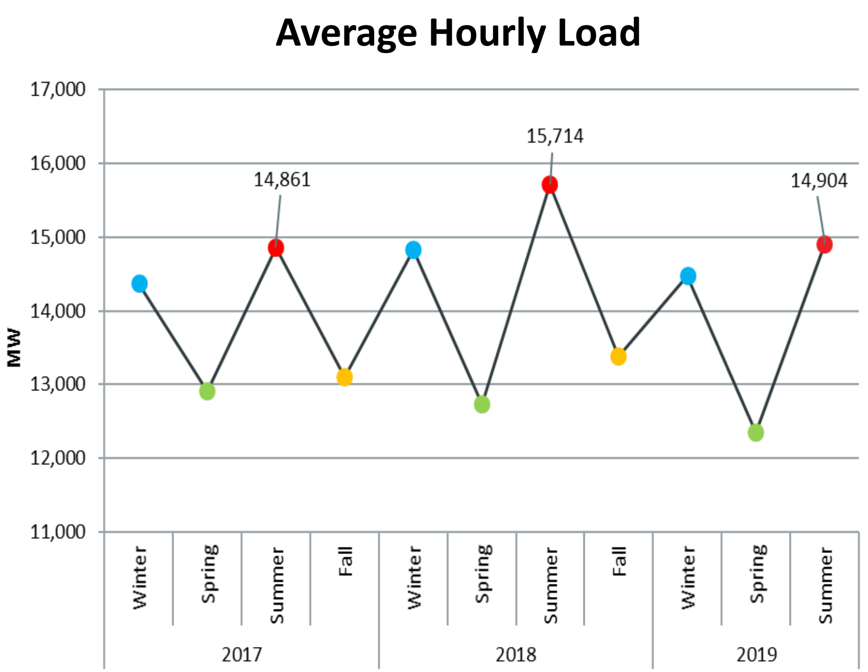
- Gross real-time reserve payments totaled \$2.6m, a 72% decrease from \$9.3m in Summer 2018.
  - Much lower peak load levels with higher reserve margins. Last summer, 50% of reserve payments occurred over two days in August.
  - Fewer hours of non-zero reserve pricing, and a lower average spinning reserve price, reflecting lower opportunity costs.
  - Most (96%) reserve payments were for spinning reserve (TMSR). Few instances of non-spinning reserve prices.
- Total regulation payments were \$5.8m, down by \$0.5m (9%) compared to Summer 2018.
  - Small decrease in payments reflects a reduction in regulation capacity supply offer costs that was partially offset by increased regulation service offer costs.
- Net Commitment Period Compensation (NCPC) costs totaled \$7.0m, down by 45% (by \$5.7m) on the prior summer.
  - NCPC costs represented less than 1% of the total energy costs, consistent with the historical range.
  - Economic payments made up 55% (\$3.8m) of the total, down by \$3.7m on Summer 2018 costs.
    - The decrease in economic payments was consistent with lower gas and energy prices.
  - Local reliability payments fell by 27% to \$2.5m. Most of these payments occurred in the day-ahead market and went to generators in SEMA, RI, or Maine, to support planned transmission outages.
- Two new rule changes went into effect on June 1; early observations consistent with anticipated market reaction. See later slides on: 1) delayed commercial operation rules, and 2) must-offer requirements for DNE dispatchable FCM resources (particularly wind).

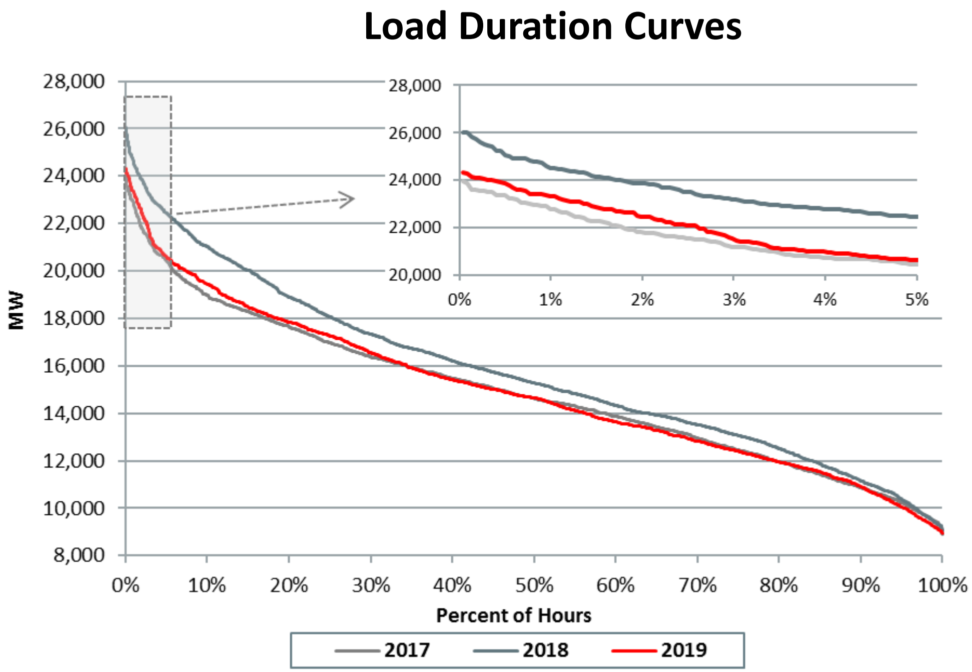
Total costs less than Summer 2018; lower energy and capacity costs



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

Average and peak loads down on last summer; less humid and cooler weather





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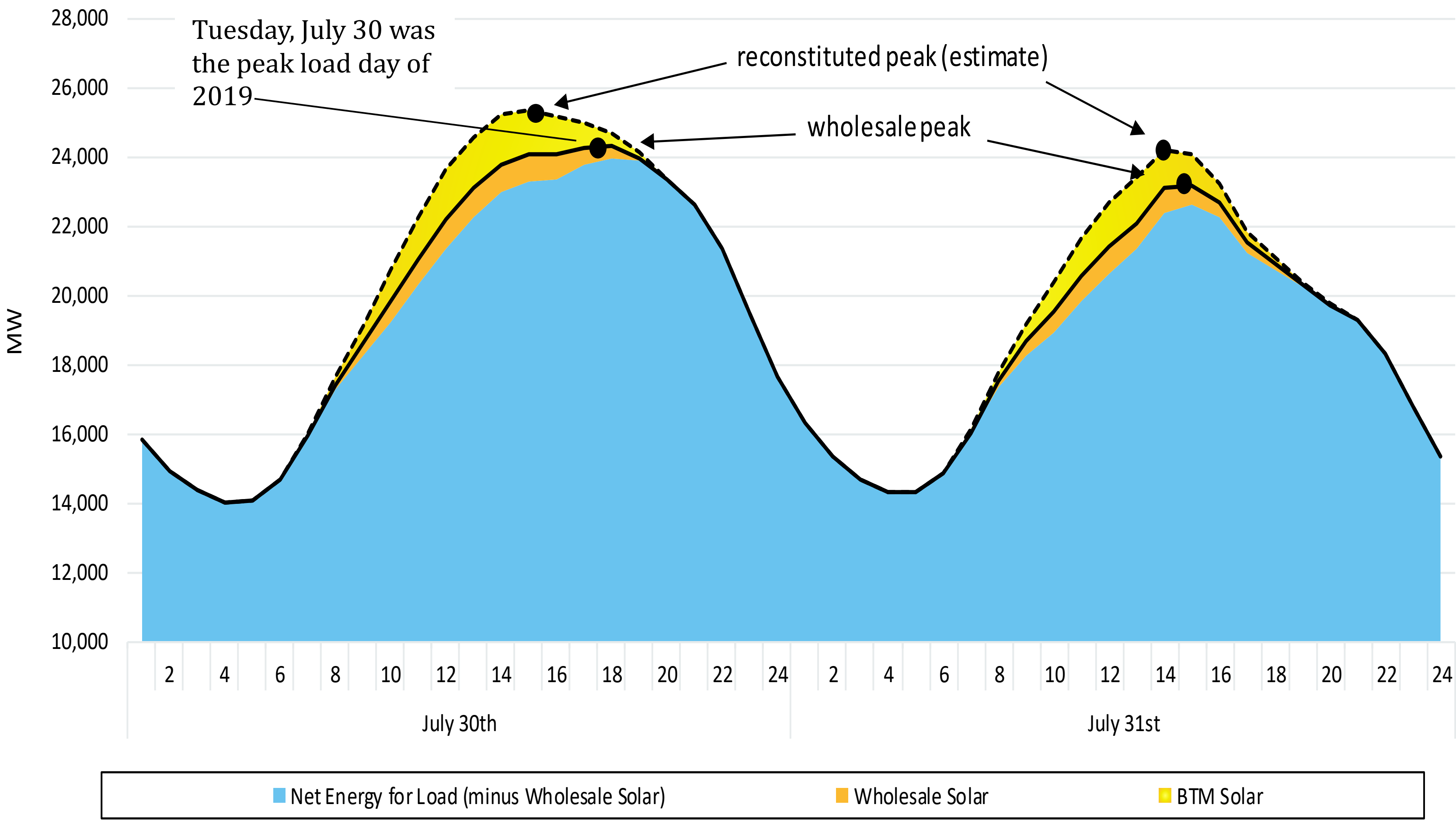
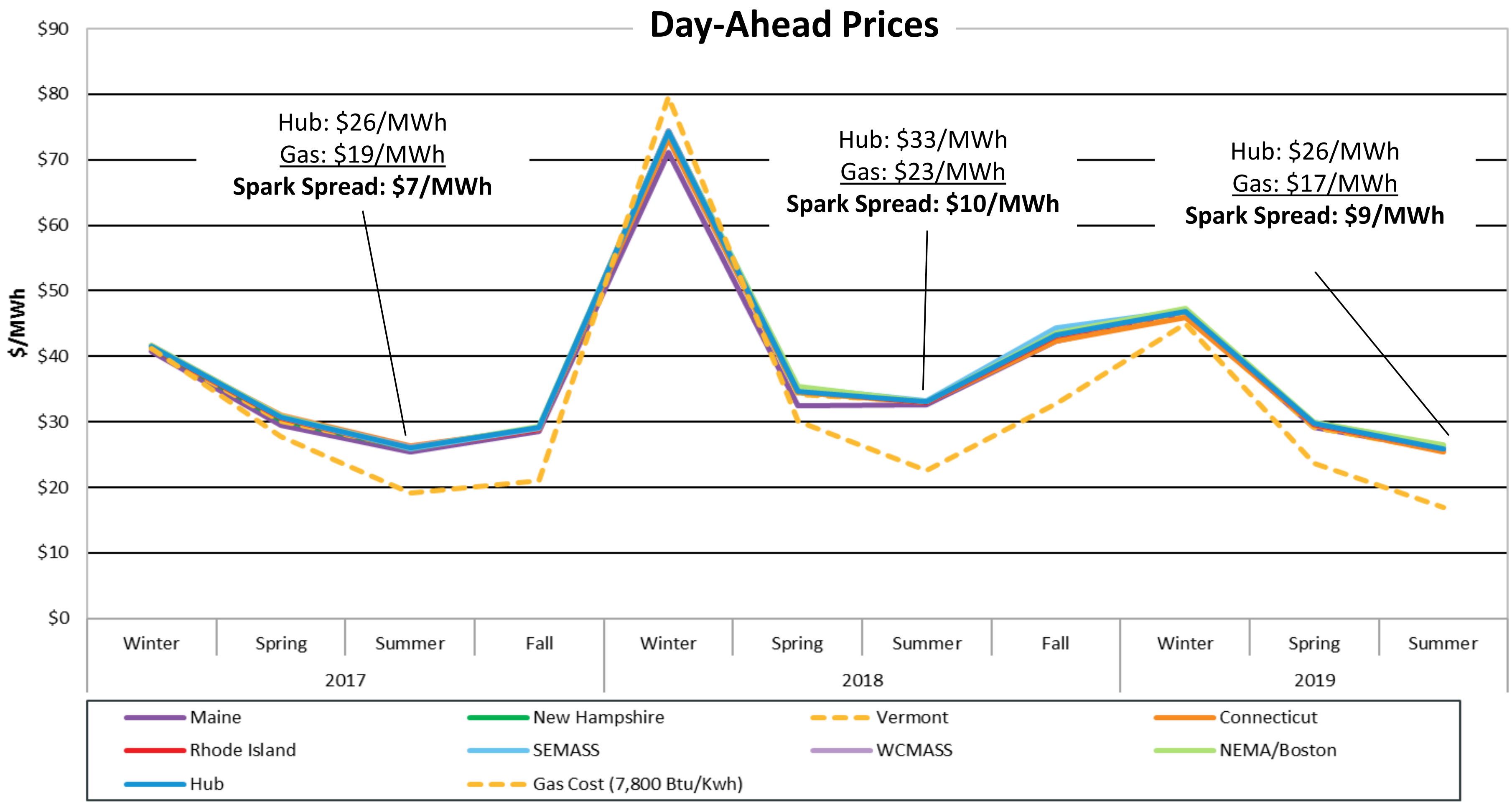
Behind-the-Meter Solar has a significant impact on summer load levels and load shape

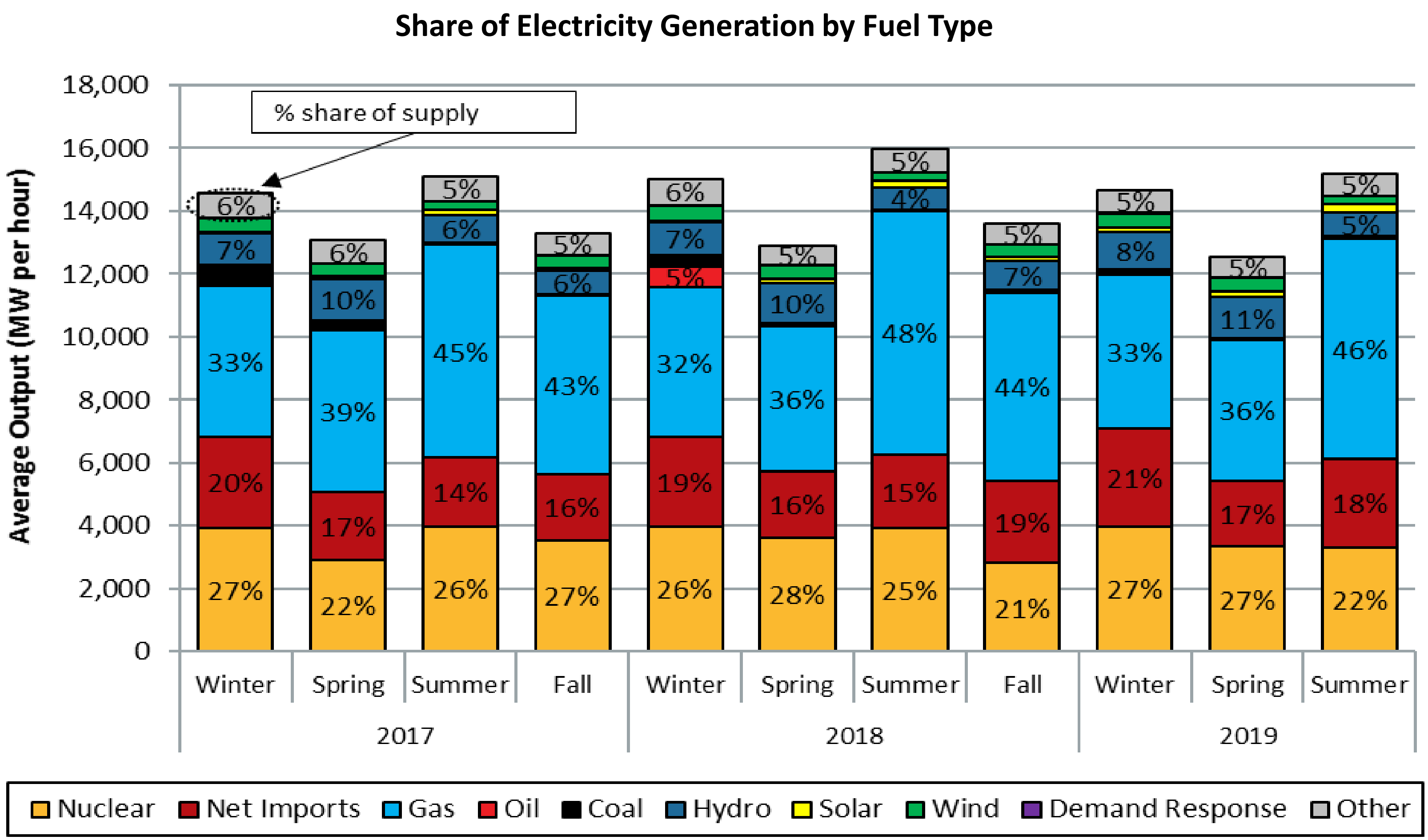


Lower gas prices and loads drove lower energy prices; similar margins for baseload gas generators



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

Less nuclear generation due to the retirement of Pilgrim; offset by increased imports from NY



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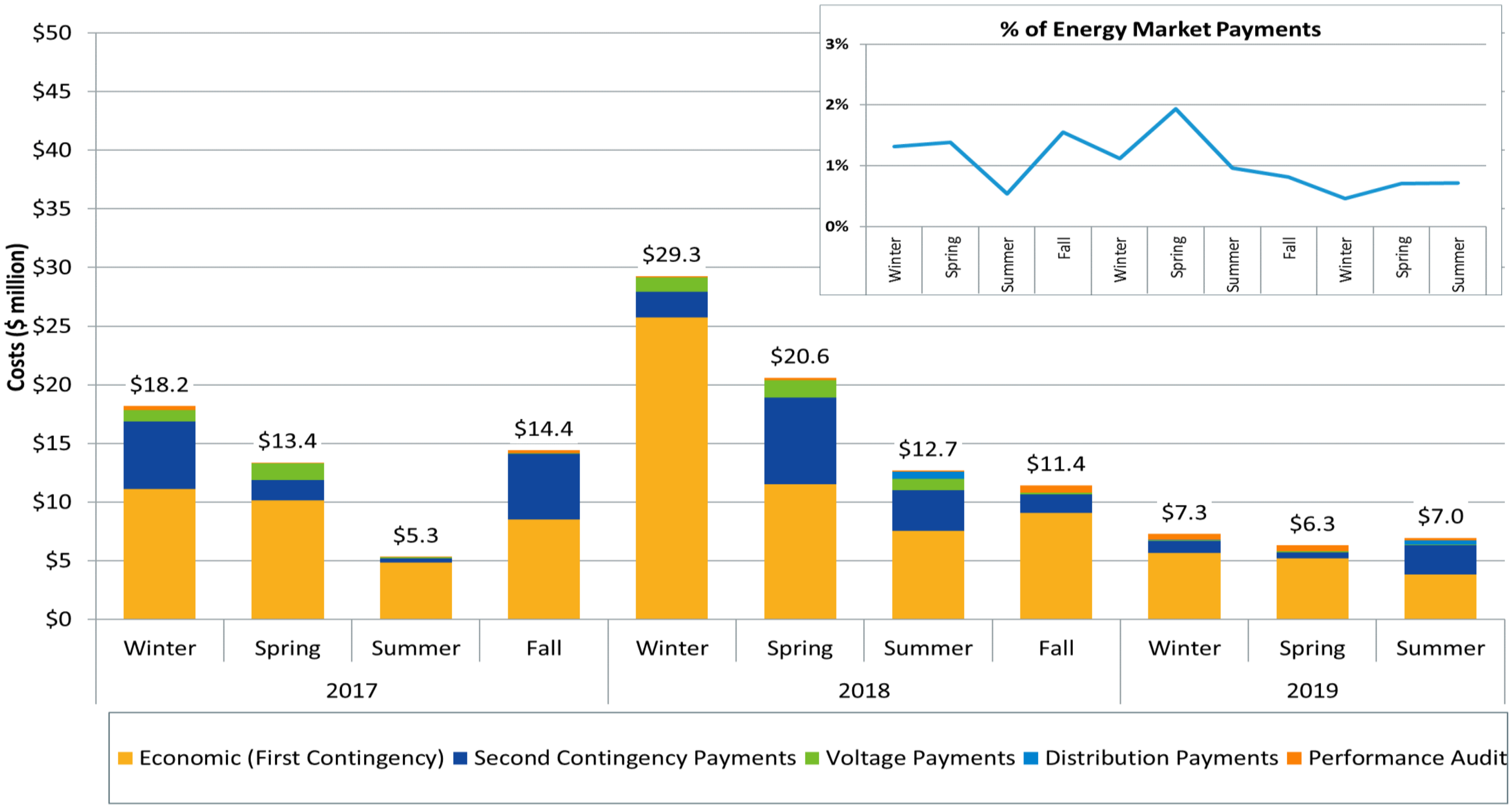
Lower NCPC driven by decreased economic payments; consistent with lower gas and energy prices



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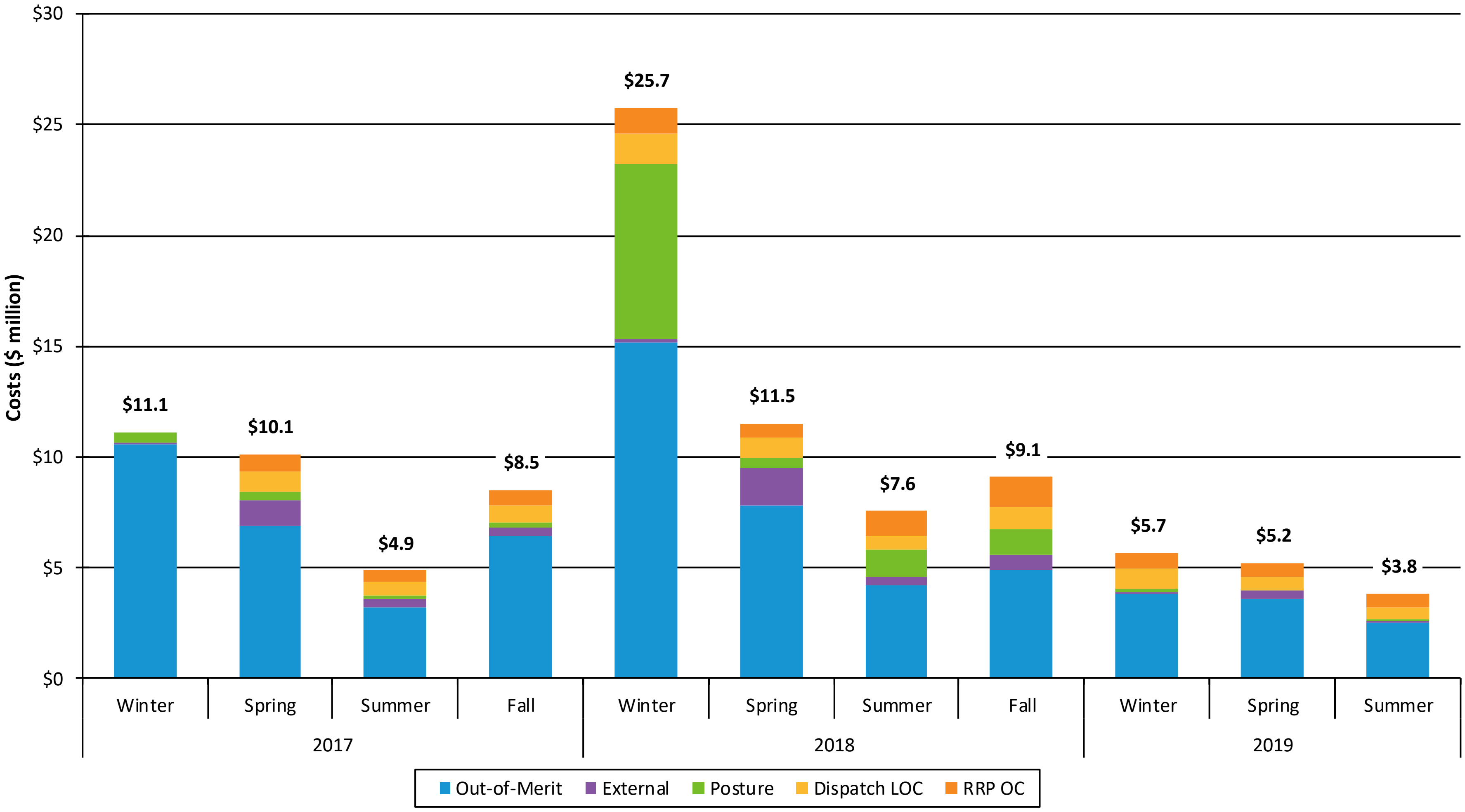
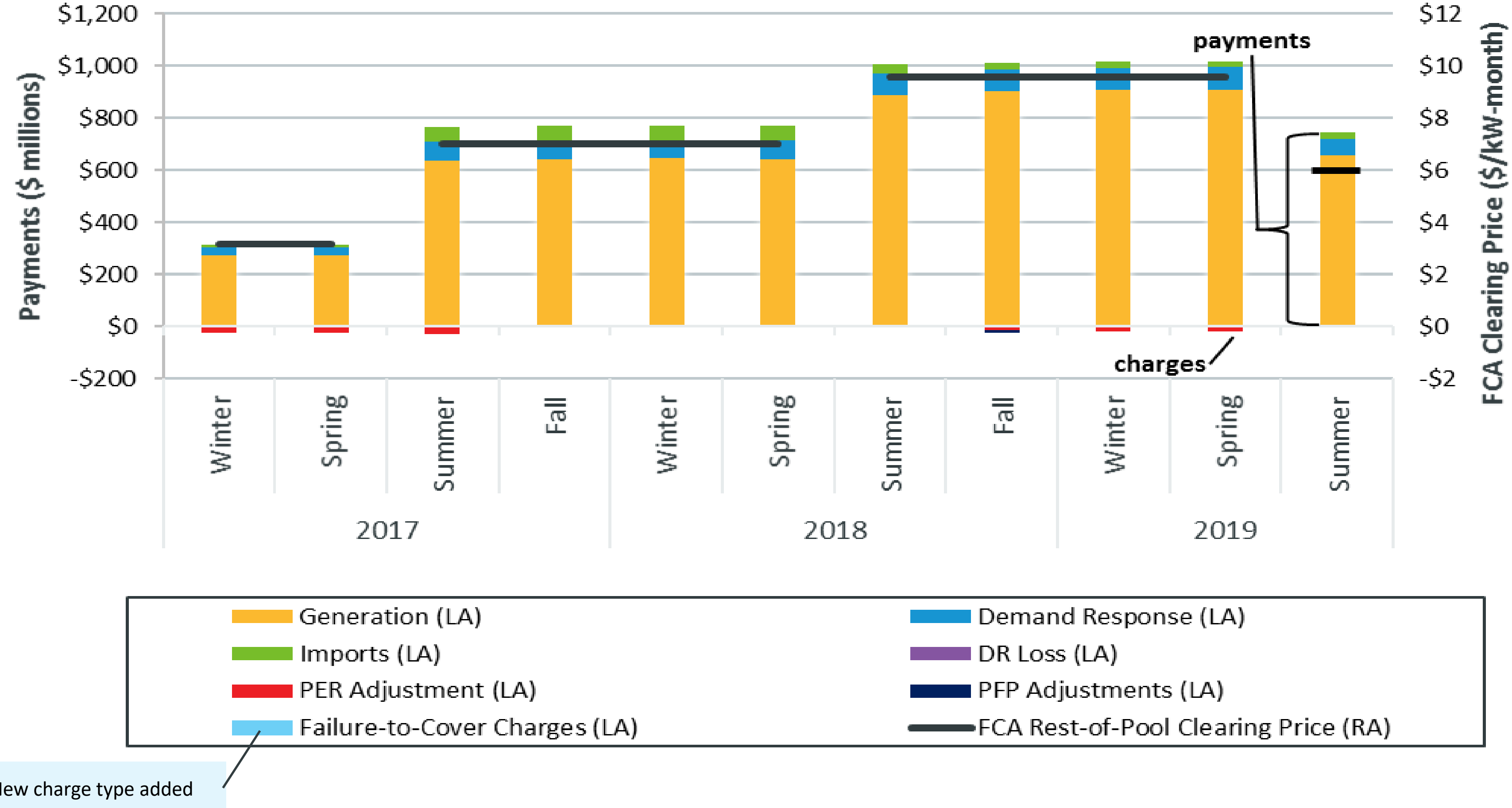
Economic NCPC payments at their lowest level over the reporting horizon



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

First quarter of FCA10; lower clearing prices

FCA 10 prices: $7.03/kW-month for all New England resources and Quebec imports; $6.26/kW-month for New York imports, $4.00/kW-month for New Brunswick imports



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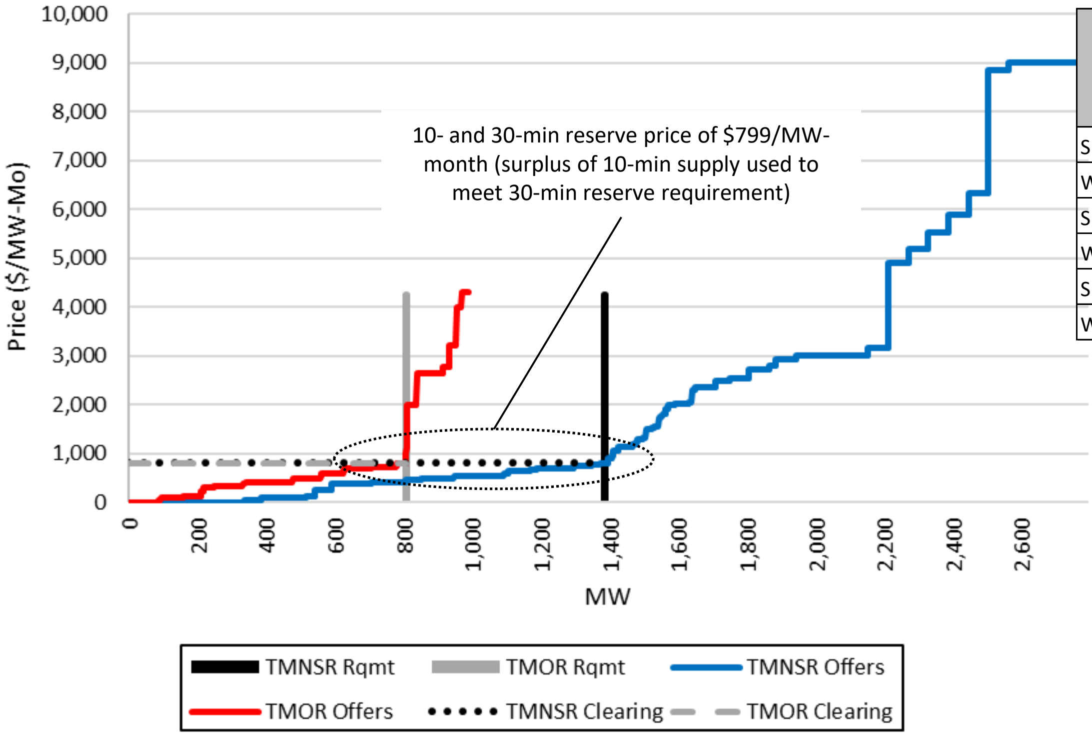
Winter 2019/20 FRM auction structurally competitive (no pivotal suppliers); prices comparable to prior winter

Supply Curves, Requirements and Clearing Prices, System-Wide TMOR & TMNSR



Offer RSI for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2017	110	197	183	N/A	21
Winter 2017-18	127	209	N/A	N/A	24
Summer 2018	112	214	438	N/A	34
Winter 2018-19	127	244	N/A	N/A	21
Summer 2019	90	204	N/A	N/A	N/A
Winter 2019-20	120	254	N/A	N/A	N/A

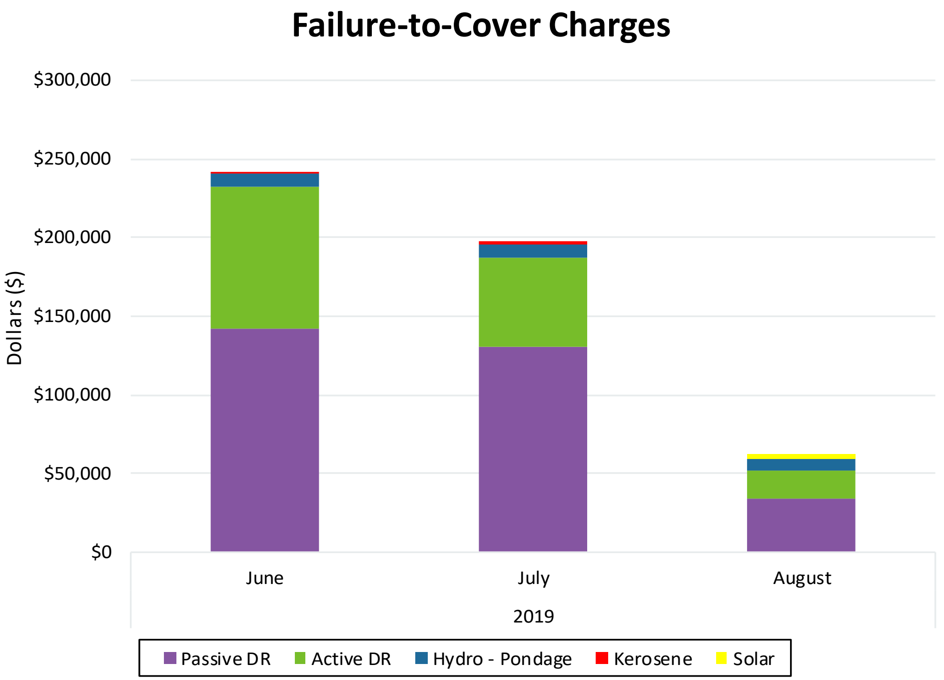
EARLY OBSERVATIONS ON NEW MARKET RULE CHANGES

Delayed Commercial Operation Rules

- In June 2019, ISO-NE implemented rules that incentivize resources to cover their CSO when they have not physically demonstrated the ability to offer capacity into the energy market.
- Rules shifted the responsibility of covering undemonstrated capacity from the ISO to the participant, who has more complete information about their resources capability to deliver.
  - also reduces negative financial impact of mandatory *annual* demand bids on resources that could satisfy their CSO for a portion of the commitment period
- Resources can cover their CSOs by shedding their obligation in secondary markets (annual and monthly). If no action is taken, resources incur a failure-to-cover charge for the "undemonstrated capacity" volume.
- Failure-to-cover charges reallocate money from resources unable to demonstrate their CSO to load customers who originally paid for the capacity.

Early observations show a market response consistent with expectations

- Over the first 3 months, 19 resources were charged $0.5m for undemonstrated capacity, predominantly demand response.
- Charges declined as resources reacted by shedding capacity obligations.
- 3 new gas-fired generators with a combined CSO of over 1,000 MW achieved commercial operation and did not incur charges [Canal 3 (333 MW), Bridgeport Harbor 5 (484 MW), and the Medway Peaker (195 MW)]

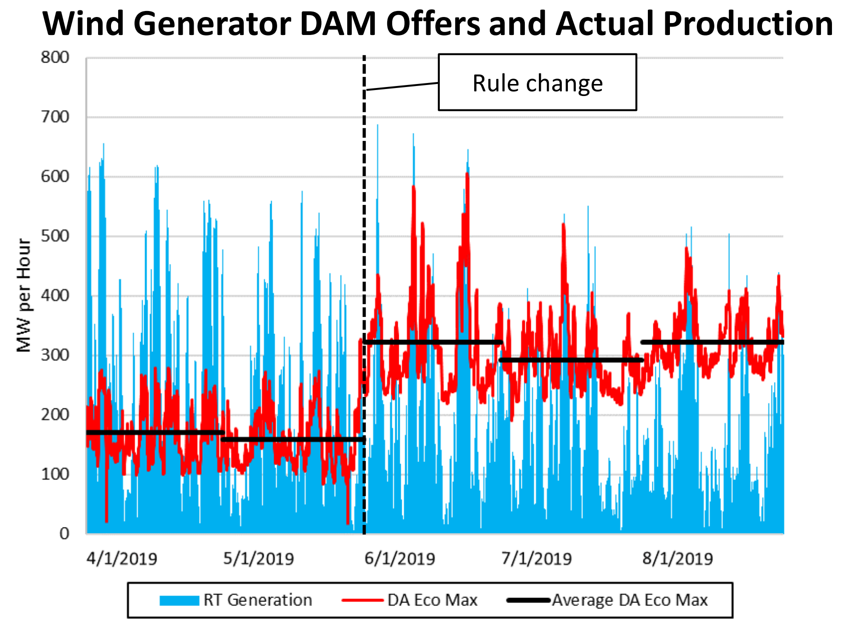


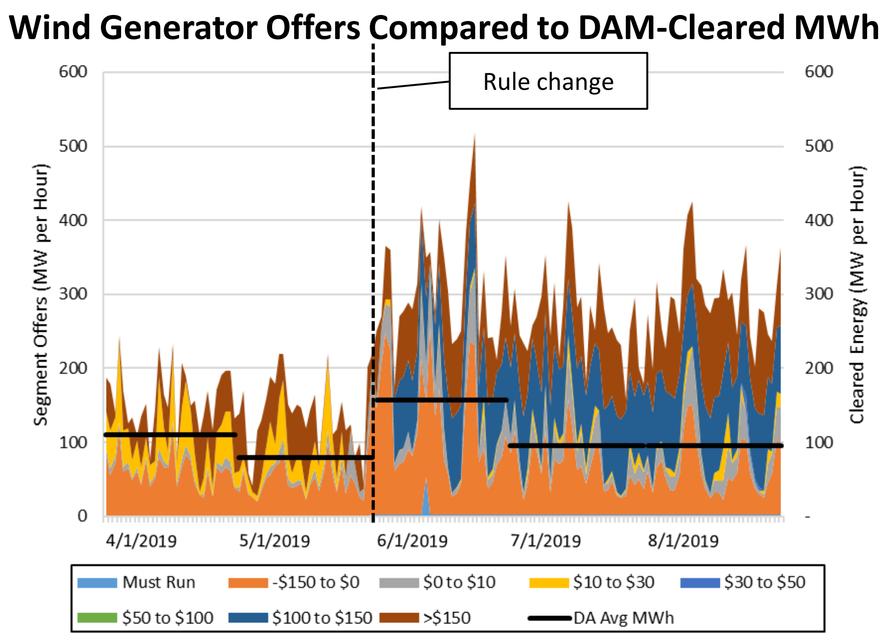
Must Offer Requirements for Wind Generation

- In June 2019, the ISO implemented day-ahead energy market offer requirements for "do not exceed" (DNE) dispatchable generators with CSOs.
  - DNE generators with CSOs are now required to offer the full hourly amount of expected real-time generation into the day-ahead market.
- The IMM reviewed day-ahead offers and clearing of wind generators affected by the requirement to determine if:
  - Offer quantities have reasonably reflected actual hourly production in real-time
  - Offer prices have changed since implementation
  - An increase in day-ahead offered generation has led to increased clearing for these generators
  - There has been a small impact on virtual supply clearing at wind generator nodes (as virtual supply has historically filled the gap left by wind generators under-clearing in the day-ahead market)

Overall, wind generation offer behavior has changed as expected

- DNE wind generators increased quantity of energy offered in the day-ahead market
- Offers reasonably reflect the expected level of real-time production
- Cleared volumes increased in the first month, but declined to pre-rule change levels as offer prices began to increase
- Cleared virtual supply at wind nodes has decreased slightly from 25% to 16% of real-time wind production (not shown)





Questions

APPENDIX

Spring 2019 Quarterly Markets Report

IMM Quarterly Markets Performance Report

Spring 2019 Report Highlights

March 2019 – May 2019 outcomes

Summary for Spring 2019

- Wholesale market costs totaled $1.91bn, a 2% increase (up $0.04bn) on Spring 2018 costs of $1.87bn
  - Higher capacity market costs were somewhat offset by lower energy costs.
- Lower energy costs driven by a decrease in natural gas prices and lower loads.
  - Avg. day-ahead and real-time Hub LMPs were $29.78/MWh and $28.89/MWh; 14% and 13% lower, respectively.
  - Avg. natural gas price was $3.04/MMBtu (or $23.71/MWh assuming a 7,800 Btu/kWh heat rate), down 21% on the Spring 2018 price of $3.86/MMBtu (or $30/MWh).
  - Avg. hourly load of ≈12,301 MW was down by 3% (≈ 430 MW), driven by milder temperatures.
- Large increase in capacity market costs, up by 30% (totaled about $1bn, up by $226m) on Spring 2018.
  - Spring 2019 was the fourth quarter of the FCA 9 commitment period, with clearing prices of $9.55/kW-month for rest-of-system, compared to an FCA 8 price of $7.03/kW-month.

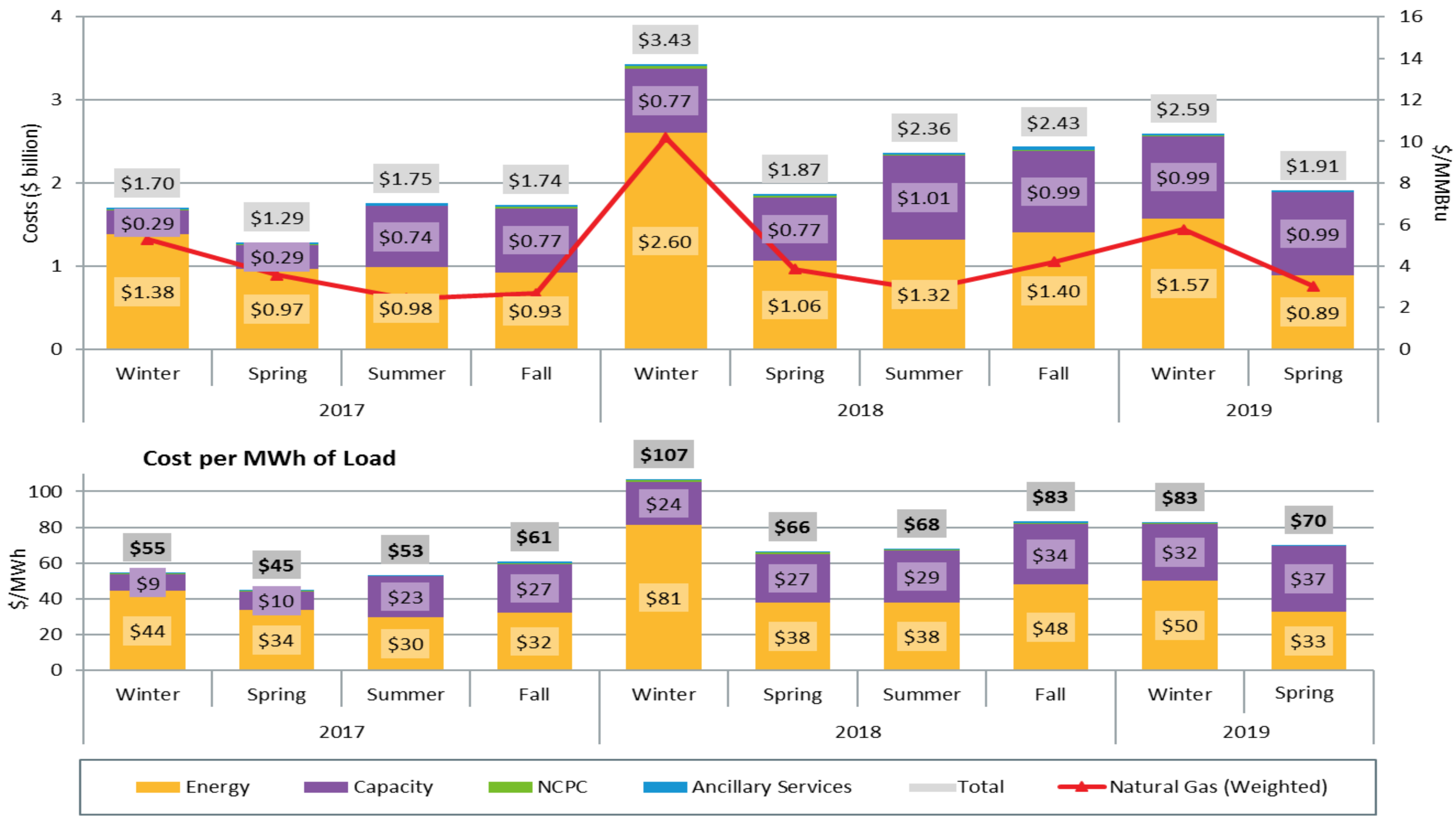
Seasons: Winter: Dec-Feb **Spring: Mar-May** Summer: Jun-Aug Fall: Sep-Nov

Summary for Spring 2019 (cont.)

- Gross real-time reserve payments totaled $2.4m, a 66% decrease from $7.1m in Spring 2018.
  - Fewer hours of non-zero reserve pricing, and a lower average spinning reserve price, reflecting lower opportunity costs.
  - All reserve payments were for spinning reserve (TMSR).
- Total regulation payments were $4.3m, down by $0.5m (11%) compared to Spring 2018.
  - Decrease in payments reflects lower real-time LMPs and opportunity costs, reduced regulation service price offers, and a small decline in scheduled regulation capacity.
- Net Commitment Period Compensation (NCPC) costs totaled $6.3m, down by 69% (by $14m) on the prior spring.
  - NCPC costs represented less than 1% of the total energy costs, down from 1.9% in Spring 2018.
  - Economic payments made up 83% ($5.2m) of the total, down by $6.3m on Spring 2018 costs.
    - Economic out-of-merit payments fell by 54%, from $7.8 million to $3.6 million.
    - External transaction payments fell by 78% to $0.4m, driven by lower payments to transactions at the New Brunswick interface that were paid due to price forecast error.
  - Local reliability payments fell by 93% to $0.5m, as a result of improved transmission availability in NEMA/Boston compared to Spring 2018.

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

Lower energy prices partially offset higher capacity costs; total cost similar to Spring 2018



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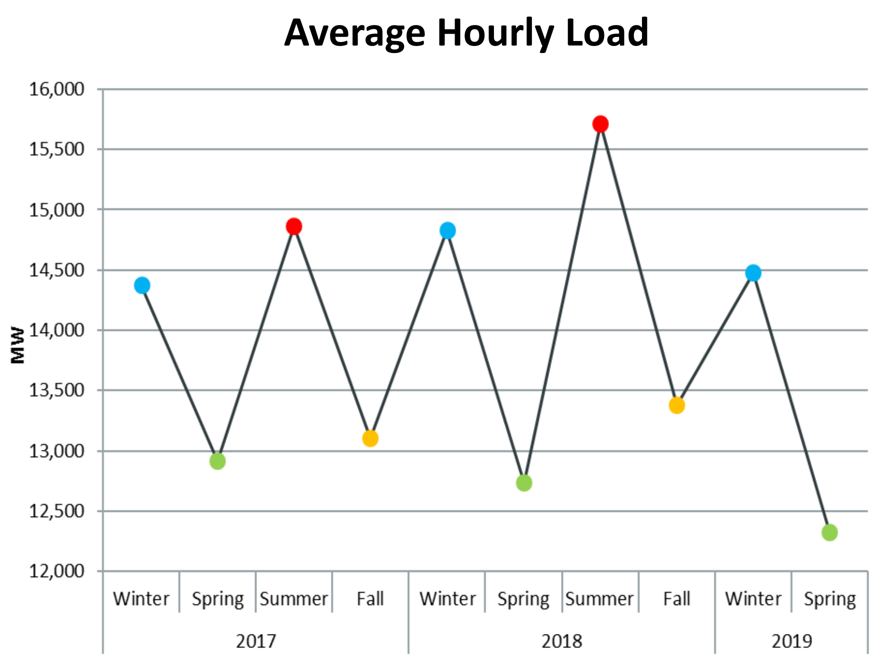
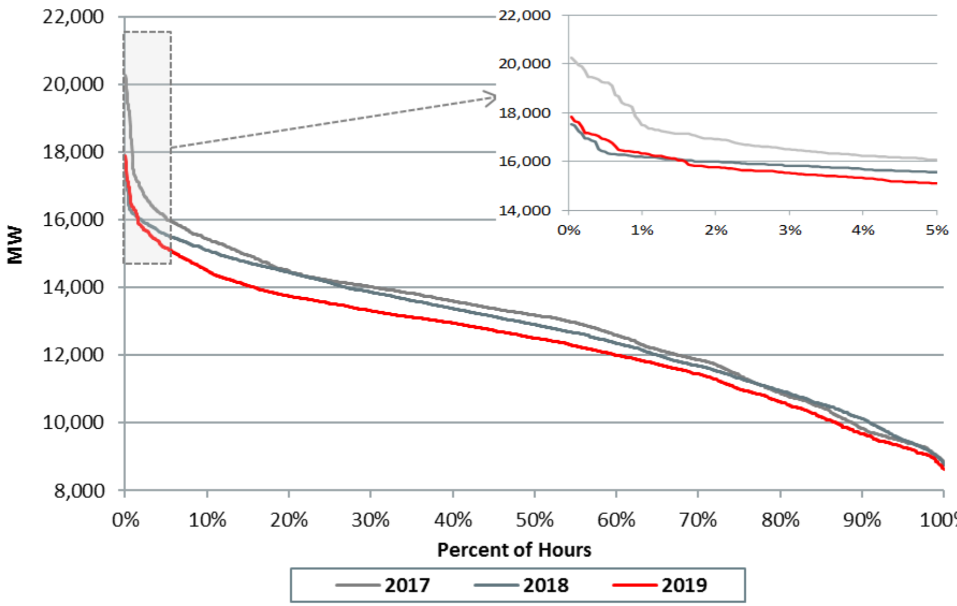
Average loads down; warmer temperatures in April and cooler temperatures in May





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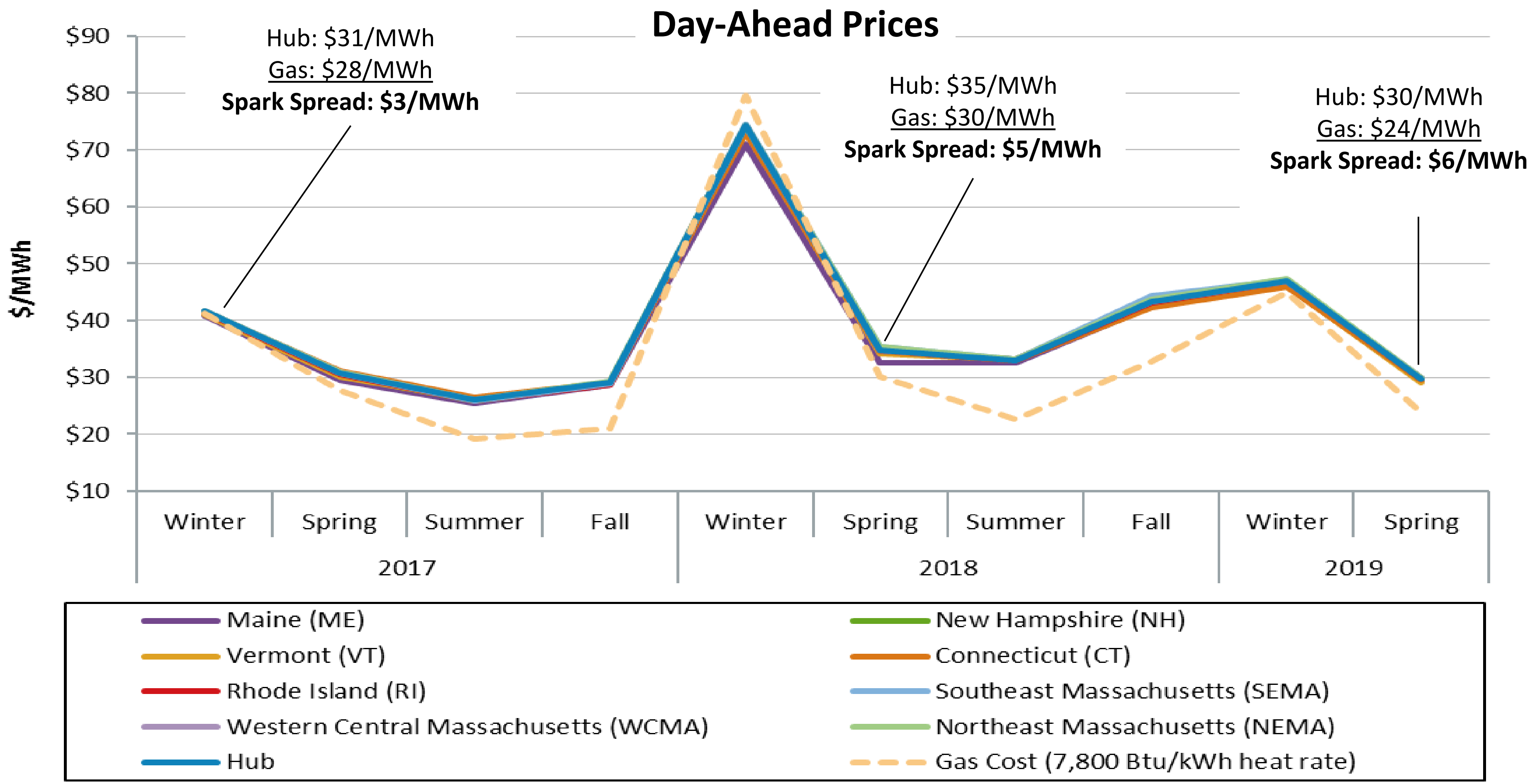
Lower gas prices drove lower energy prices; decrease partially offset by increased baseload generator outages



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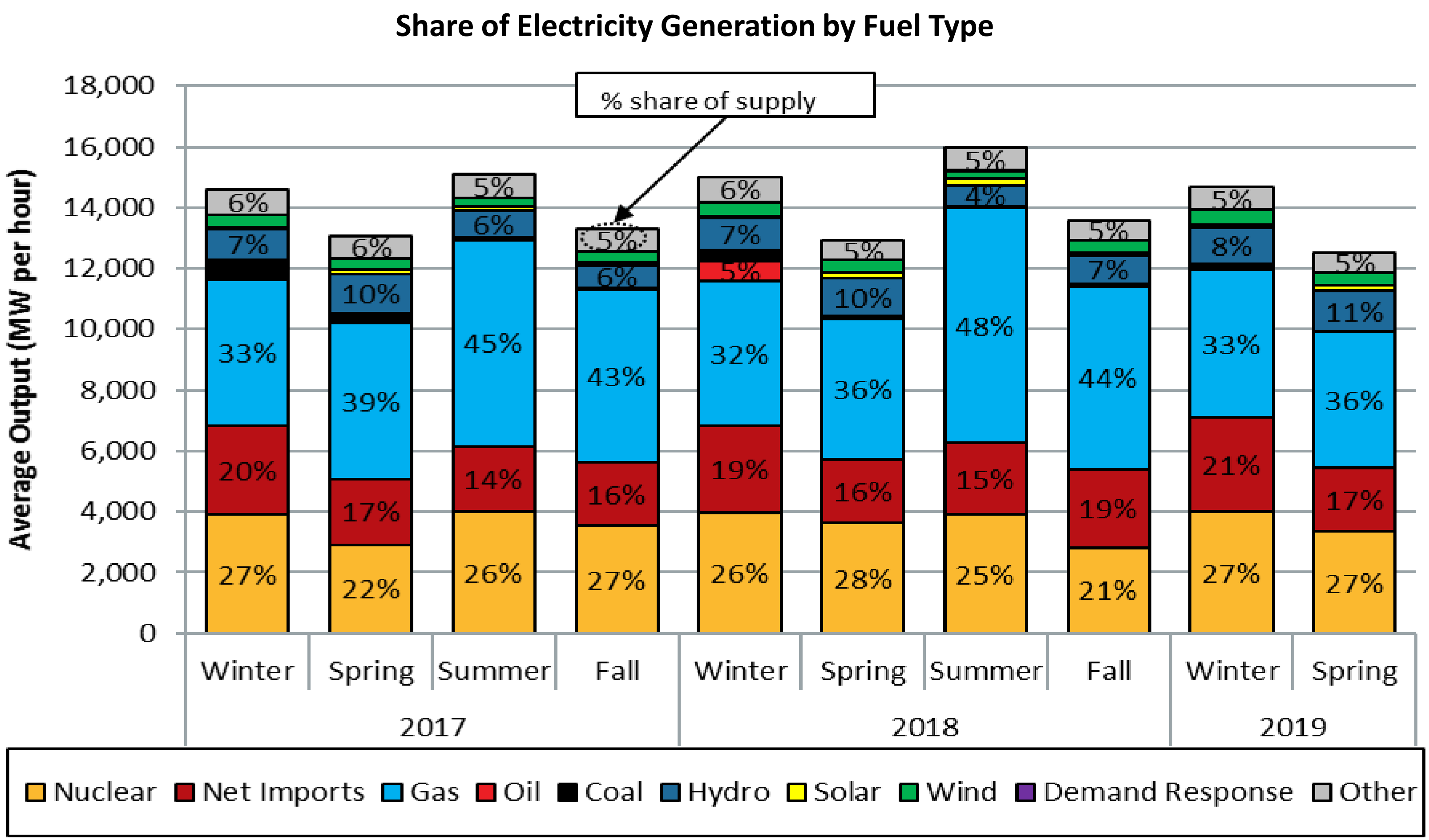
Less nuclear generation due to outages; fewer imports due to reduced transfer capability over NY interfaces



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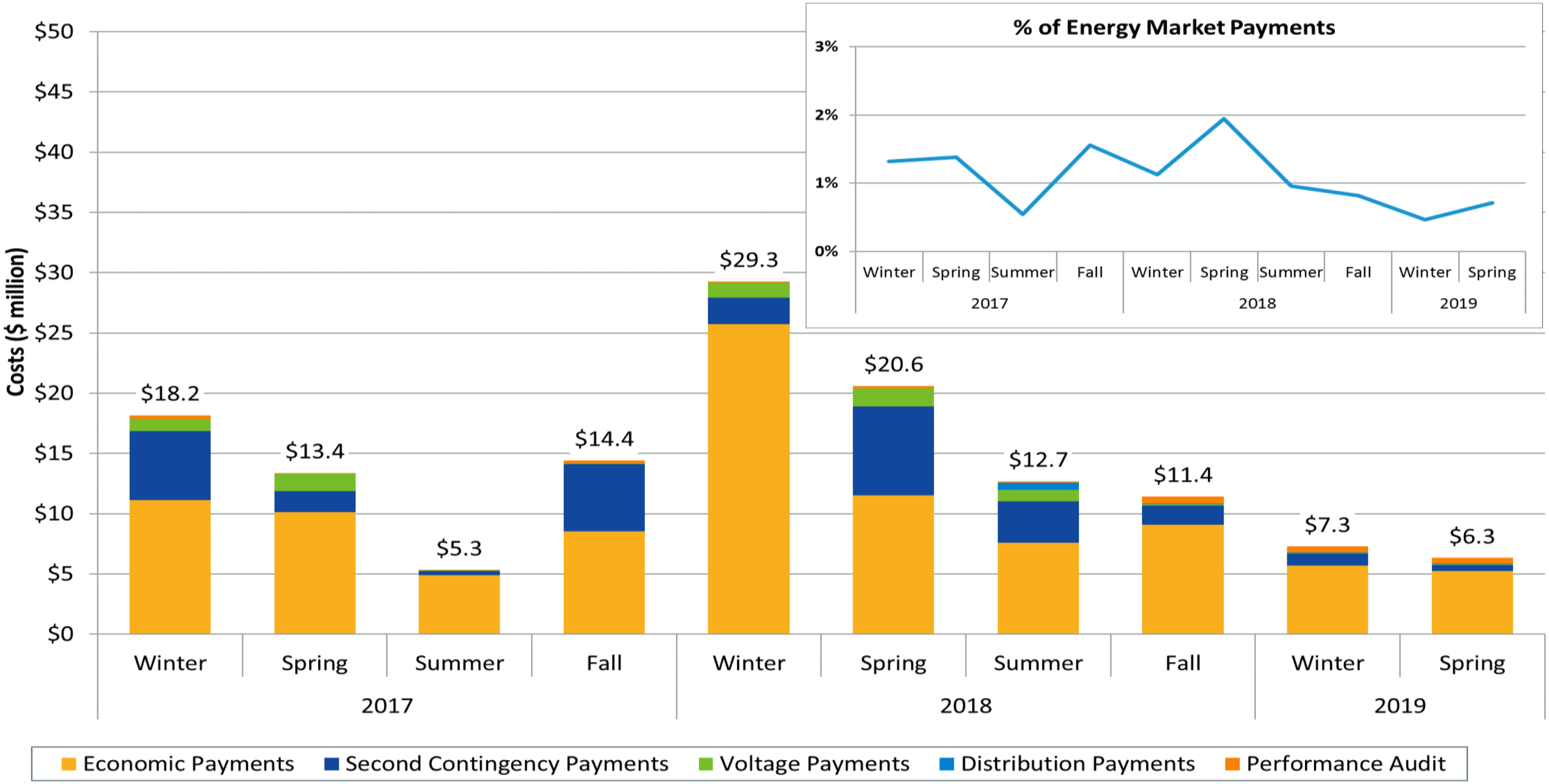
Lower NCPC driven by decreased local reliability and economic out-of-merit payments



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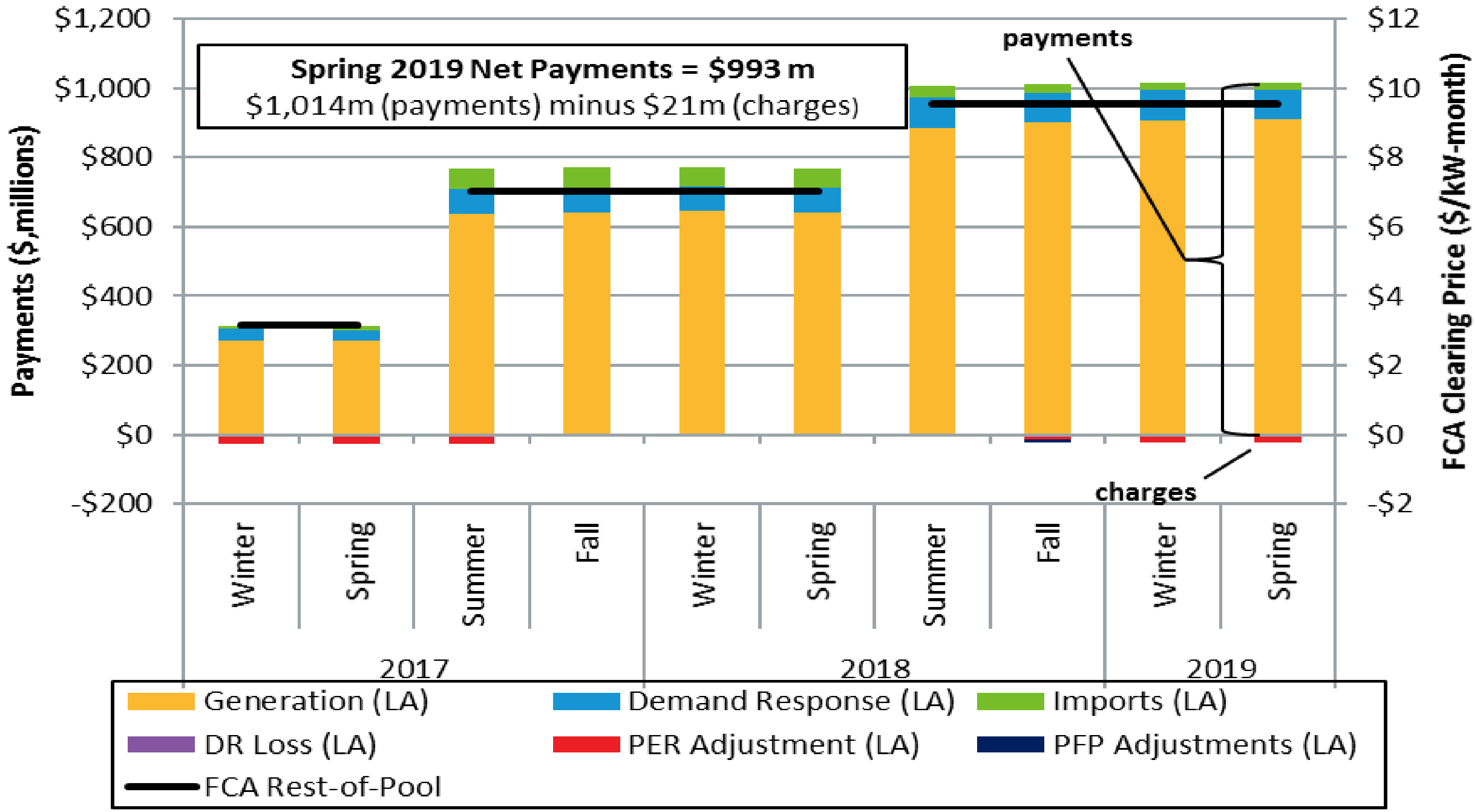
Fourth quarter of FCA9; higher clearing prices

FCA 9 prices: $9.55/kW-month for resources outside SEMA/Rhode Island; in SEMA/RI $11.08 for existing resources, $17.73 for new resources



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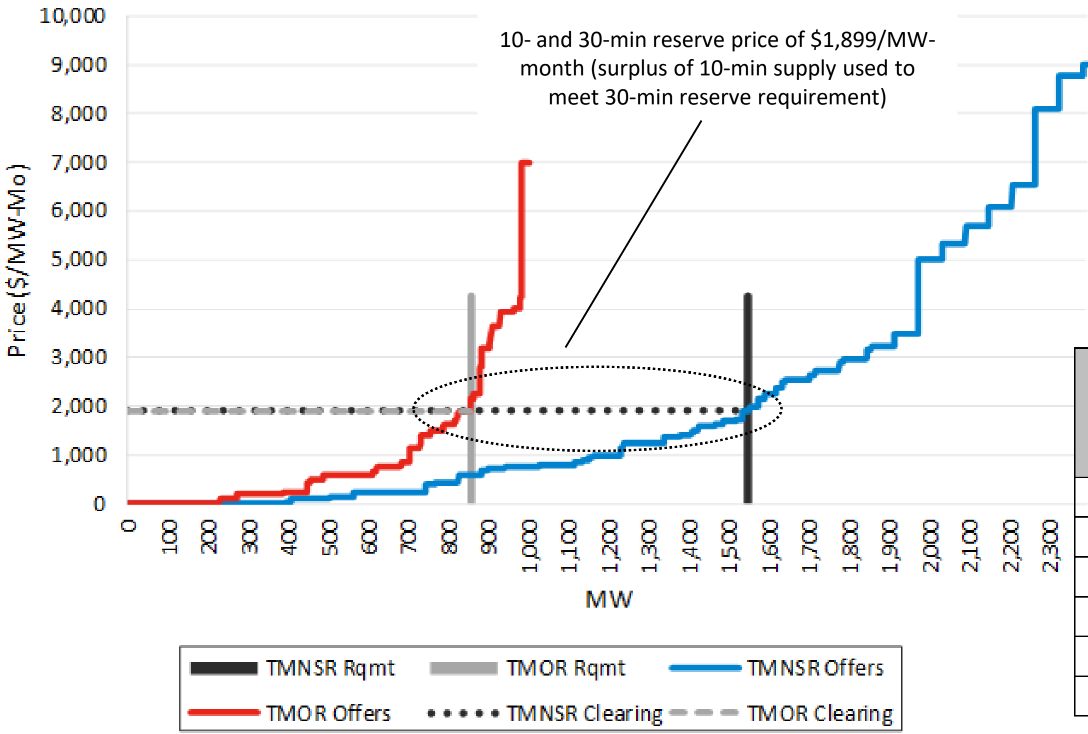
Summer 2019 FRM auction structurally competitive for system TMOR; one pivotal supplier for system TMNSR

Supply Curves, Requirements and Clearing Prices, System-Wide TMOR & TMNSR



Offer RSI for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Winter 2016-17	148	222	302	N/A	N/A
Summer 2017	110	197	183	N/A	21
Winter 2017-18	127	209	N/A	N/A	24
Summer 2018	112	214	438	N/A	34
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