IMM Quarterly Markets Performance Report

Fall 2025 Report Highlights

September 2025 – November 2025 outcomes

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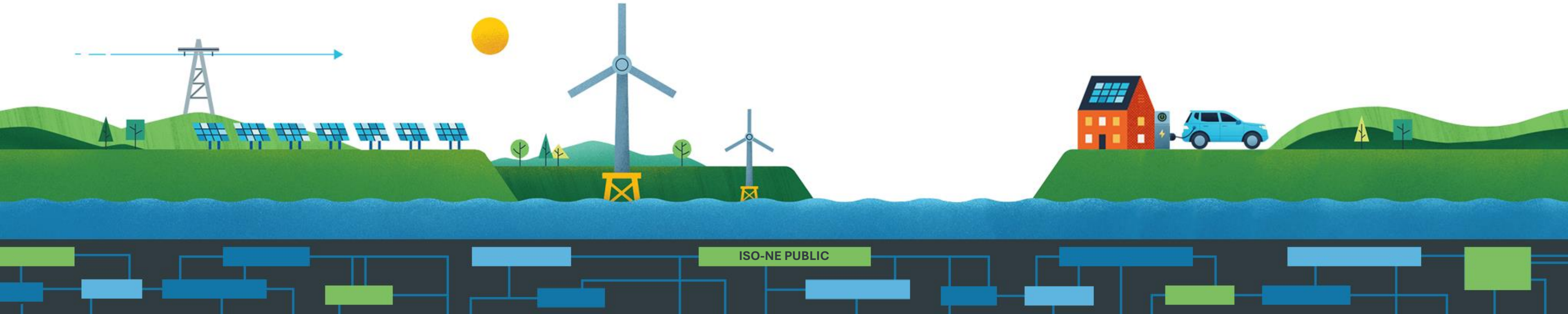
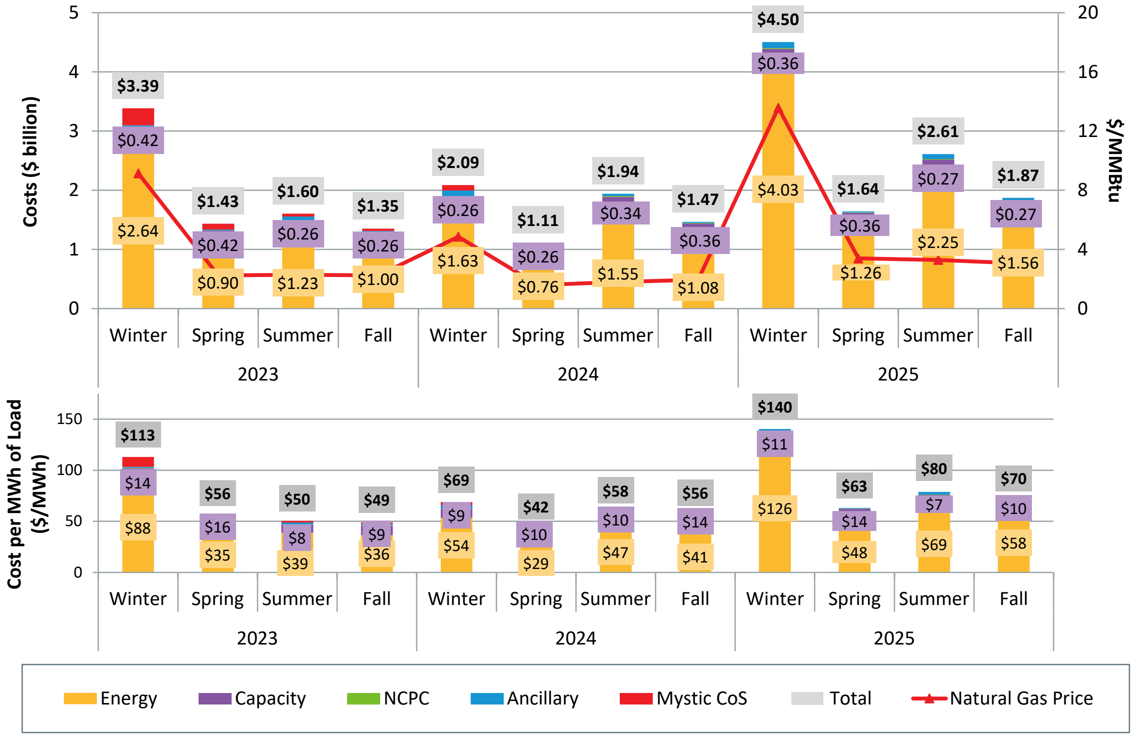
SURVEILLANCE & ANALYSIS, INTERNAL MARKET MONITOR



Wholesale electricity costs up 28% on prior fall driven by higher energy costs

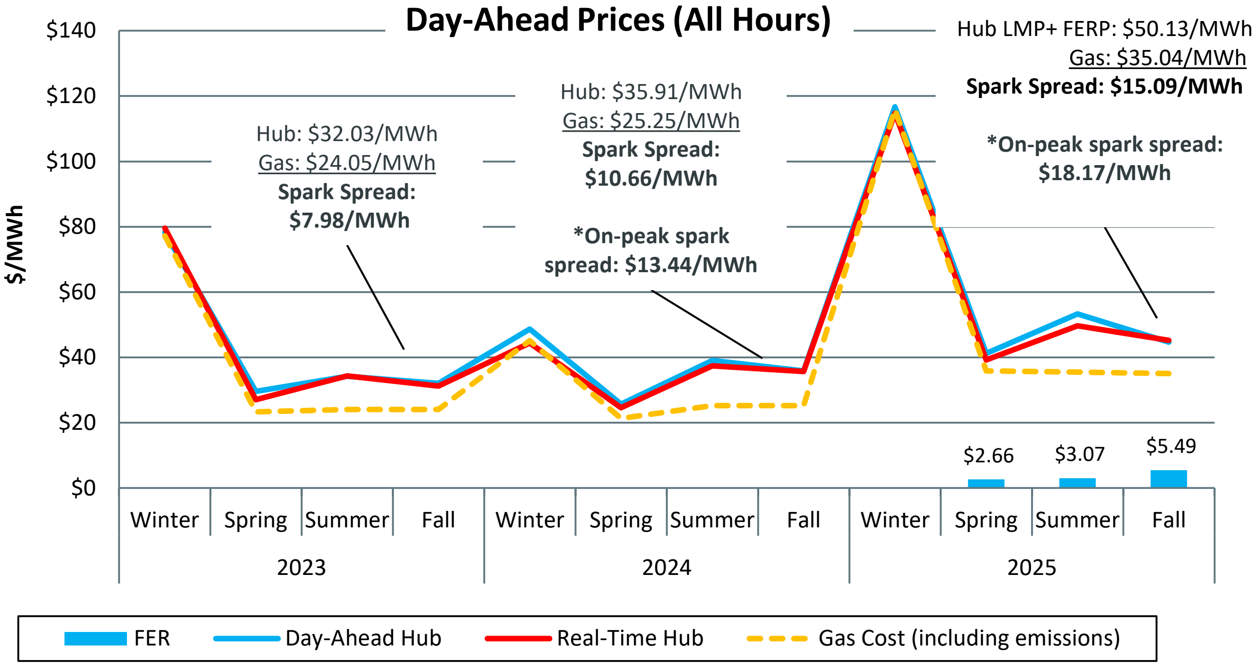
- **Wholesale electricity costs in Fall 2025 totaled $1.87 billion ($70/MWh),** up 28% from Fall 2024 due to higher energy costs, but down 28% from Summer 2025
- **Energy costs dominated wholesale costs**, totaling $1.56 billion (83% of total costs), driven primarily by a 58% year-over-year increase in natural gas prices and a 10% increase in emissions costs
- **Capacity costs were stable but lower in total**, with payments of $266 million (14% of total costs), reflecting similar FCA clearing prices but reduced cleared capacity and less zonal price separation in Southeast New England
- **Ancillary service costs increased sharply**, totaling $42.7 million (2% of total costs), largely due to $34.1 million in DA A/S costs, while NCPC costs remained small at $7.6 million (0.5% of total energy payments)



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

Higher gas prices and fewer net imports drove higher energy prices

- **Seasonal energy prices in New England continued to track natural gas generation costs**, with Fall 2025 average Hub prices of $44.64/MWh (DA) and $45.22/MWh (RT); including FER, the effective DA price for physical generation averaged $50.13/MWh
- **Energy prices rose year-over-year in line with higher gas costs**, increasing by roughly $9–$10/MWh (24%–27%) versus Fall 2024, as estimated gas generation costs rose 39% due to higher natural gas prices (+58%) and emissions costs (+10%)
- **Locational price differences were driven by transmission constraints**, with Connecticut prices averaging 2% below the Hub due to export constraints and efficient local supply, Vermont prices averaged 3% above the Hub as seasonal transmission outages caused the NW Vermont interface to bind



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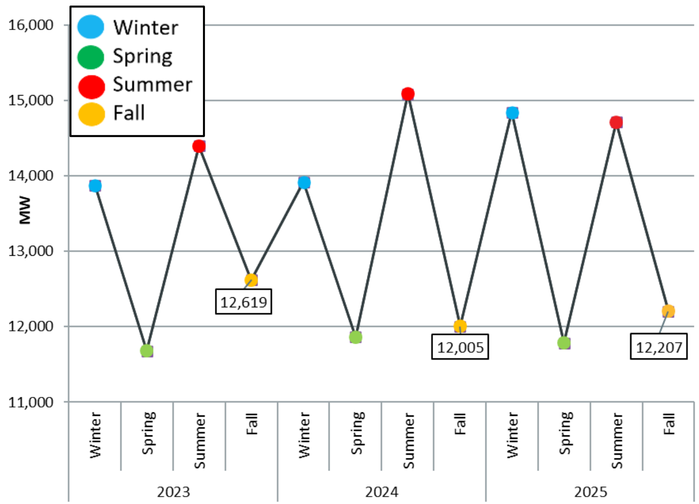
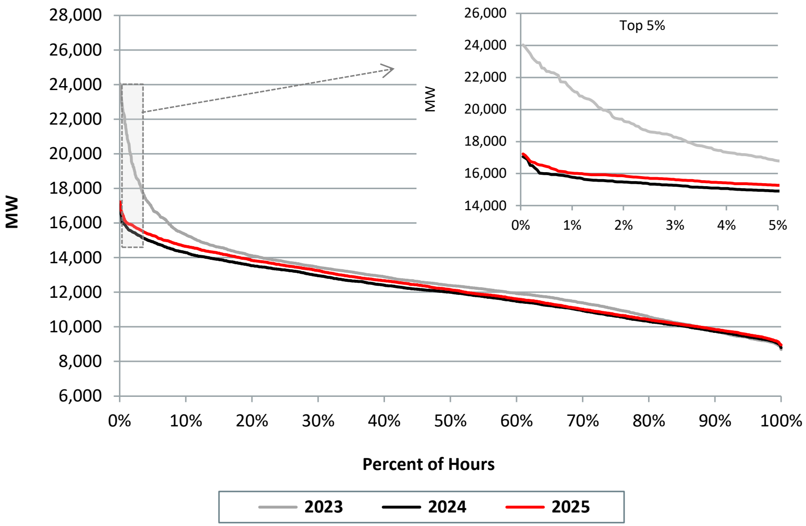
Average Fall 2025 loads increased by approximately 1.7% from Fall 2024, driven by November temperatures declining from 47°F in Fall 2024 to 44 °F in Fall 2025

Average Hourly Load



Load Duration Curves



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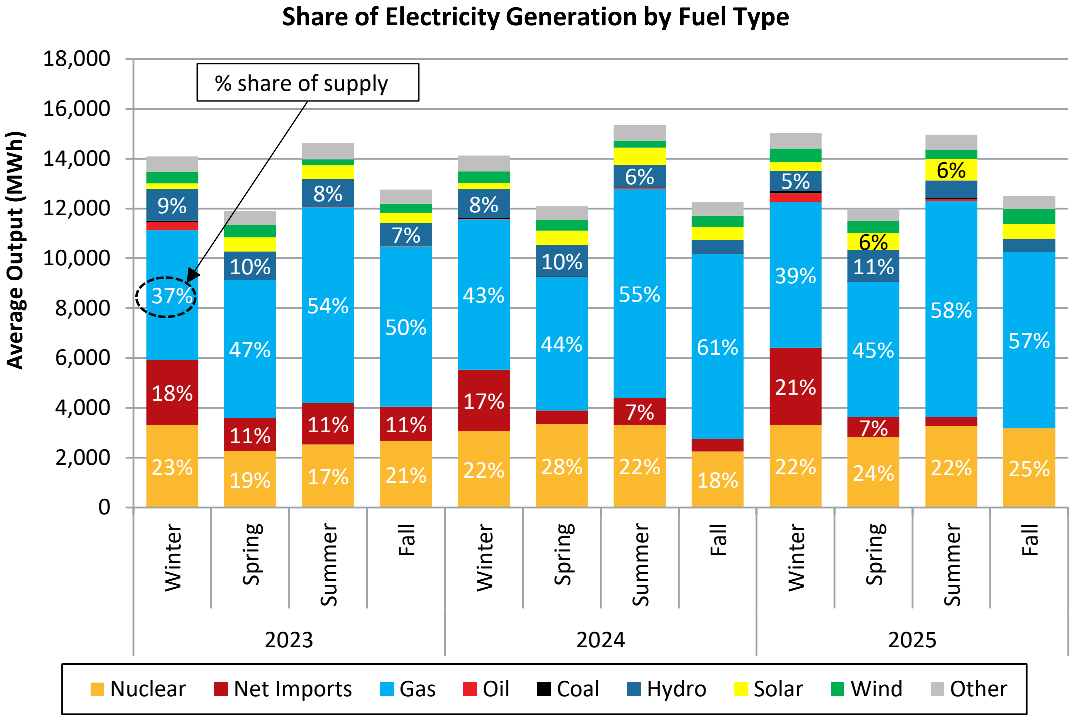
Increase in nuclear generation from Fall 2024 while net imports and gas decline

- In Fall 2025, **natural gas remained the dominant energy** source, supplying 57% of total generation on average
- **Nuclear and wind generation increased**, with the nuclear share rising from 18% to 25% due to fewer outages, and wind increasing from 4% to 5% driven by additional offshore wind capacity
- Notably, **New England became a net exporter of power** for the first time in at least two decades

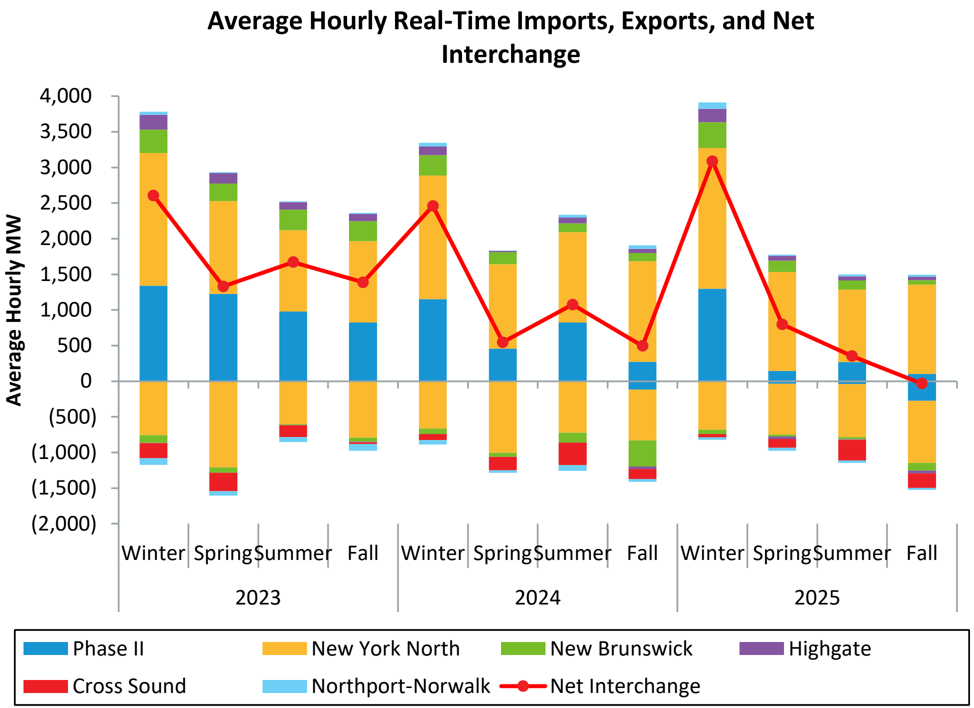


Note: the "Other" category includes energy storage, landfill gas, methane, refuse, steam, and wood

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

New England Became a Net Energy Exporter in Fall 2025

- **New England was a net exporter of energy for the first time in at least two decades**, with average net exports of 33 MW per hour, reflecting reduced imports across nearly all external interfaces
- **Exports to Canada increased materially**, averaging 207 MW per hour, driven primarily by net exports at the Phase II (Québec) interface as reduced hydro availability in Québec limited exports to New England
- **Net interchange with New York declined sharply year-over-year**, with New England remaining a net importer (174 MW per hour) but importing nearly 400 MW per hour less than in Fall 2024 due to higher New York prices
- **Exports to Long Island remained significant but constrained**, averaging 207 MW over the Cross Sound Cable as New York prices exceeded New England prices, while flows on the Northport-Norwalk interface were limited by transmission work



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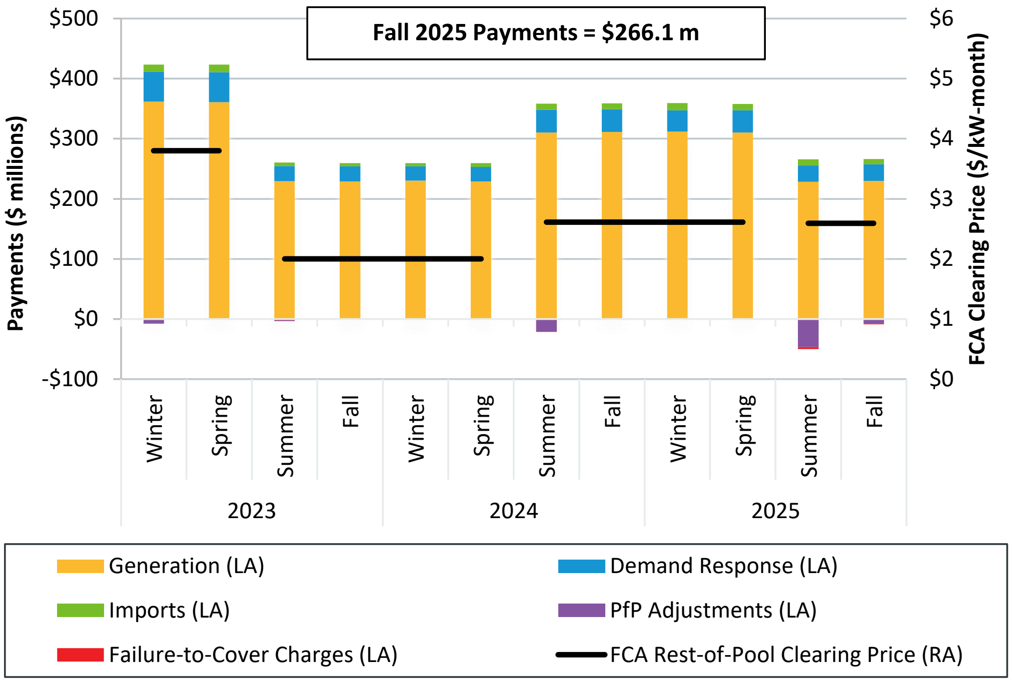
Total capacity payments in the second quarter of the FCA 16 delivery period largely driven by the primary auction clearing price

- **FCA 16 cleared with a Rest-of-Pool clearing price of $2.59/kW-month** (essentially unchanged from FCA 15) and more than 1,000 MW of capacity in excess of the Net ICR
- **Capacity payments totaled $266 million in Fall 2025, down 26% from Fall 2024**, driven by lower cleared capacity in FCA 16 and reduced price separation in the import-constrained Southeast New England zone, despite similar clearing prices
- **Pay-for-Performance transfers were modest**, with under-performing resources transferring $7.3 million to over-performing non-capacity resources following the November 23 PfP event

FCA 16 prices: $2.59/kW-month in rest of pool; similar the prior year ($2.61/kW-month)



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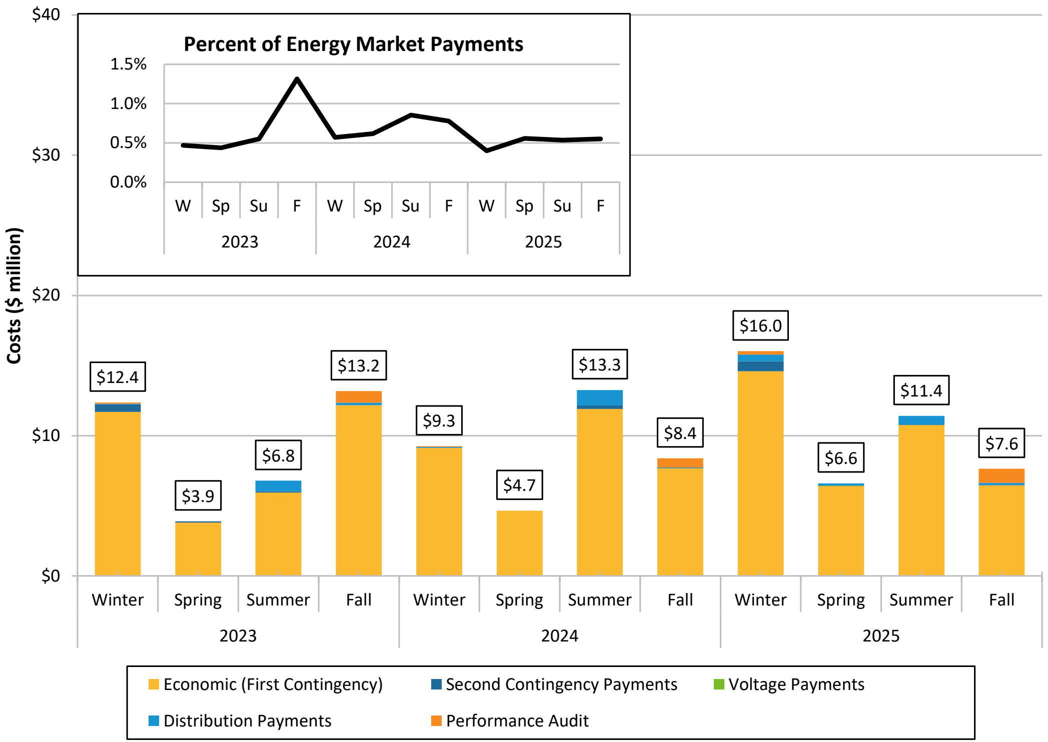
Uplift payments remained relatively low; most payments covered economic commitments and dispatch

- **NCPC payments in Fall 2025 totaled $7.6 million**, down from $8.4 million in Fall 2024, and remained a small share of total energy market payments
- **Economic uplift continued to dominate NCPC**, accounting for $6.5 million of total payments, while performance audit uplift totaled about $1.0 million, consistent with prior fall seasons



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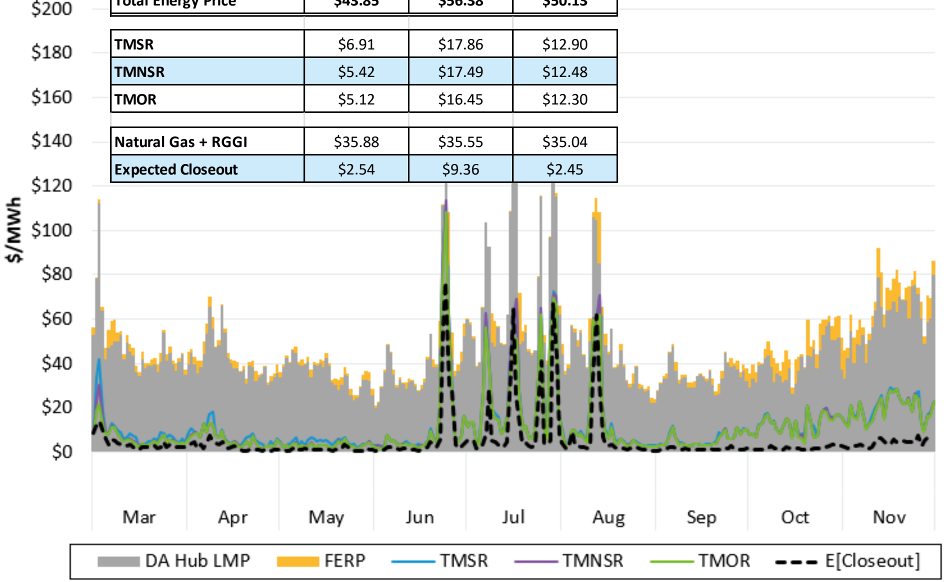
Lower day-ahead reserve clearing prices than the summer but higher FER prices

Values (Gross): Daily Average

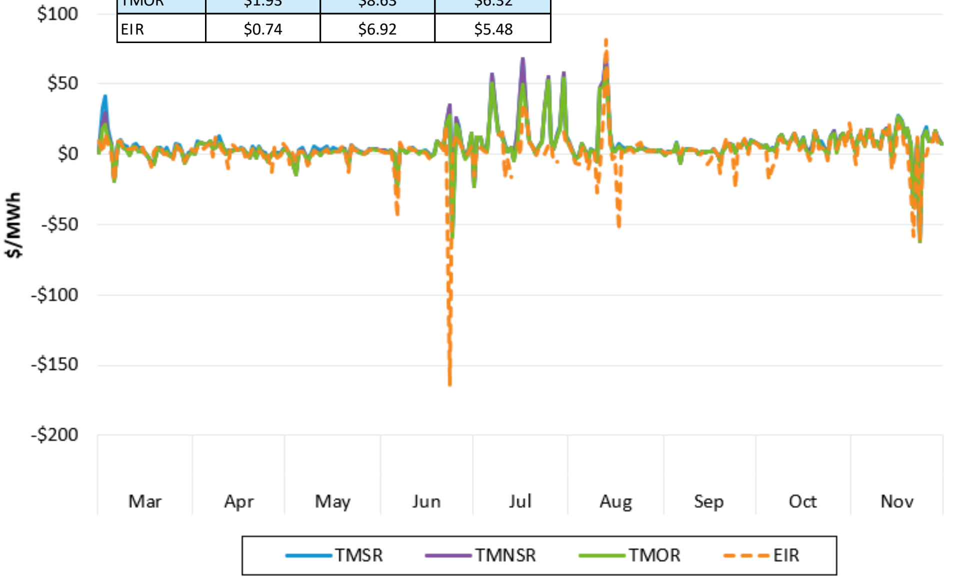
Day-Ahead Prices and Cost Summary

	Average Value ($/MWh)		
	Spring 2025	Summer 2025	Fall 2025
Hub LMP	$41.19	$53.31	$44.64
FER Price	$2.66	$3.07	$5.49
Total Energy Price	**$43.85**	**$56.38**	**$50.13**
TMSR	$6.91	$17.86	$12.90
TMNSR	$5.42	$17.49	$12.48
TMOR	$5.12	$16.45	$12.30
Natural Gas + RGGI	$35.88	$35.55	$35.04
Expected Closeout	$2.54	$9.36	$2.45



Reserve Net Clearing Prices (Net of Closeout Charges): Daily Average

	Average Value ($/MWh)		
	Spring 2025	Summer 2025	Fall 2025
TMSR	$3.71	$10.04	$6.93
TMNSR	$2.22	$9.67	$6.51
TMOR	$1.93	$8.63	$6.32
EIR	$0.74	$6.92	$5.48



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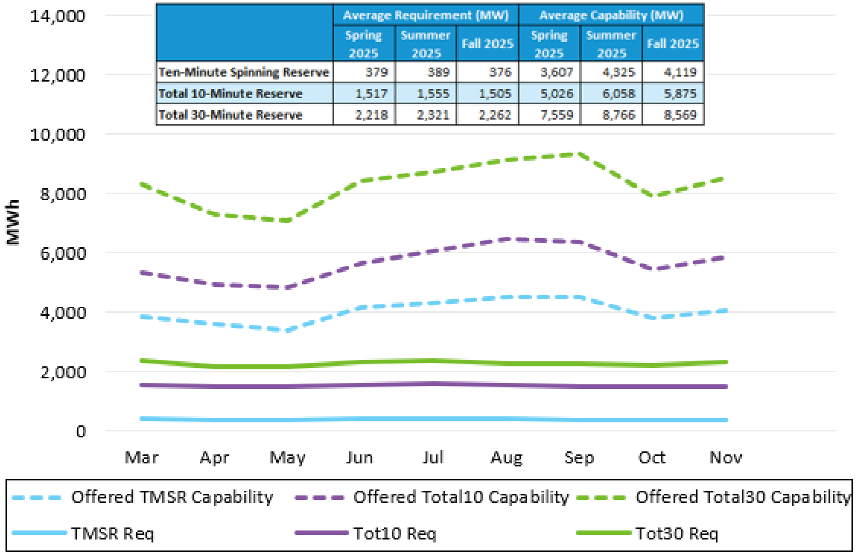
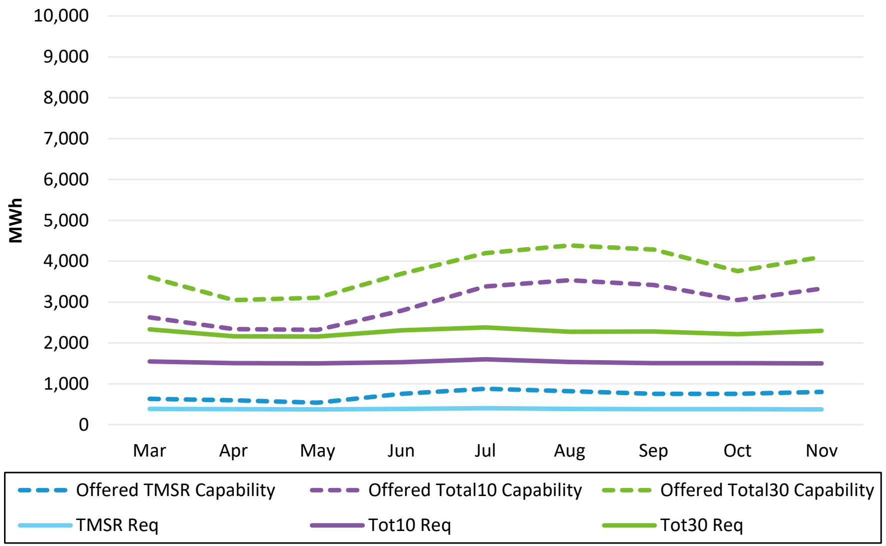
DA A/S FRS offers total many times the requirement; once energy demand and operational constraints are accounted for, FRS supply is significantly tighter

Ex-ante Requirements and Offered Capabilities



	Average Requirement (MW)			Average Capability (MW)		
	Spring 2025	Summer 2025	Fall 2025	Spring 2025	Summer 2025	Fall 2025
Ten-Minute Spinning Reserve	379	389	376	3,607	4,325	4,119
Total 10-Minute Reserve	1,517	1,555	1,505	5,026	6,058	5,875
Total 30-Minute Reserve	2,218	2,321	2,262	7,559	8,766	8,569

Ex-post Requirements and Offered Capabilities



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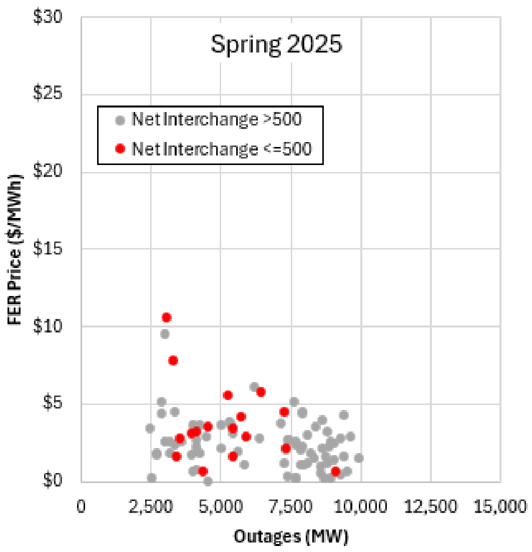
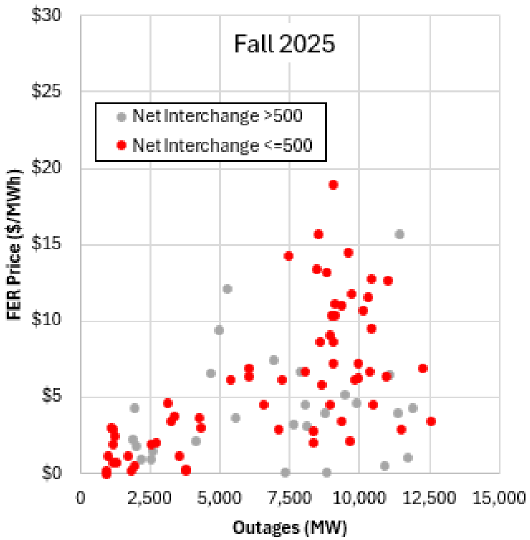
Higher outage frequency and lower imports drove higher FER prices in Fall 2025

- **Higher FER prices in Fall 2025 were driven by tighter physical supply**, primarily due to elevated generator outages and reduced day-ahead net interchange
- **Fall 2025 experienced far more high-outage days than Spring 2025**, with 17 days exceeding 10,000 MW of average daily outages compared to none in the spring
- **Lower net interchange further constrained available FER supply in the fall**, with 64 days at or below 500 MWh of daily average net interchange versus just 17 days in the spring, putting upward pressure on FER prices





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Simulations estimate an incremental DA A/S cost of $400m compared to DA energy-only market (March-November 2025)

Day-Ahead Energy-Only Market

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA Energy	**$4,842**	**$5,133**	**$291**	**6.0%**
LMP	$4,842	$4,748	-$93	-1.9%
FER Price	$0	$385	$385	
DA A/S	**$0**	**$108**	**$108**	
Credits	$0	$202	$202	
Closeouts	$0	-$94	-$94	
Total DA Charges/Credits	**$4,842**	**$5,241**	**$399**	**8.2%**
Cost of Incremental RT Energy[38]	$58.6	$59.3	$0.7	1.2%
Total Cost/Revenue Change	**$4,900**	**$5,300**	**$400**	**8.2%**

- **First 6 months totaled $258 million**, with over half ($130m) of total incremental costs occurred on a few (10) exceptionally high load days (See Summer Report)
- **$142 million in incremental costs in Fall 2025**

Note: the now-defunct Forward Reserve Market costs are not considered in the "Delta". Annual FRM costs have ranged from $19m to $101m over the last 5-year period.

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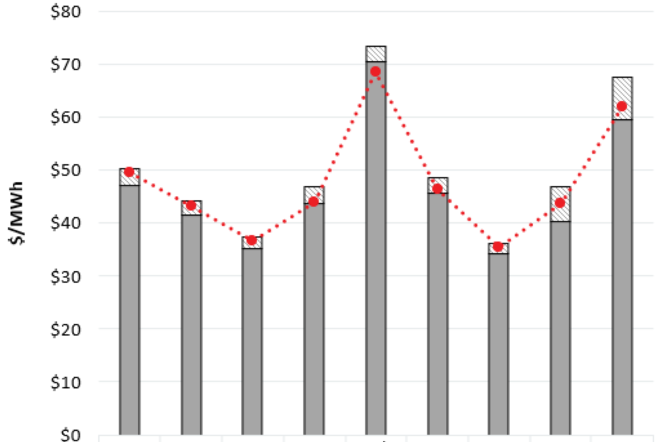
Day-Ahead LMP plus FER reflects DA marginal energy cost

- On average, DA A/S has lowered DA LMPs but increased total DA energy prices when FER is included
- Across all nine months, the combined average DA LMP and FER exceeds the estimated DA LMP under the 'No DA A/S' scenario
- The marginal cost of day-ahead energy supply is split between the DA LMP and FER price rather than recovered through the LMP alone

Comparison of Actual DA LMP and FER Price against Estimated DA LMP with no DA A/S



	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
FERP	$3.25	$2.66	$2.06	$3.15	$3.06	$3.02	$1.94	$6.50	$7.99
DA Hub LMP	$46.97	$41.41	$35.21	$43.75	$70.27	$45.58	$34.21	$40.28	$59.55
DA Hub LMP (No DA A/S)	$49.44	$43.22	$36.72	$43.80	$68.52	$46.36	$35.29	$43.63	$61.88

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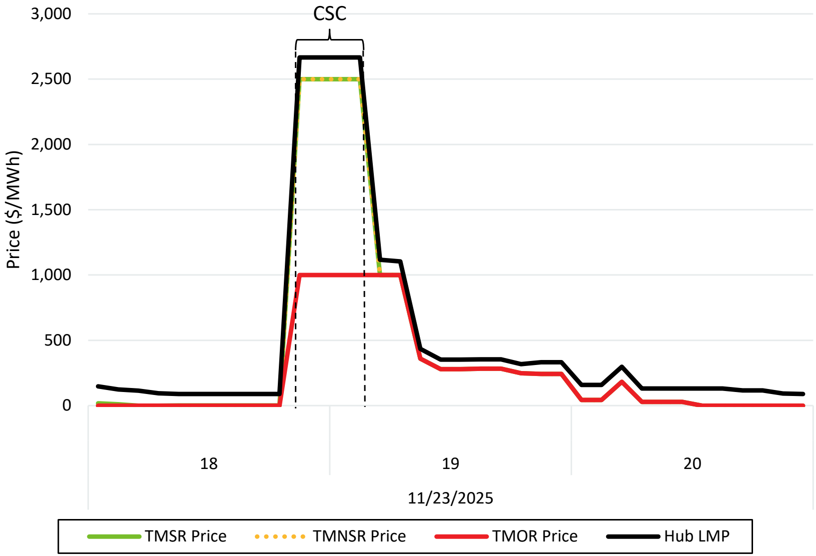
Short duration and unanticipated Sunday, November 23 Capacity Scarcity Condition (CSC)

- During the event, the average temperature was 38°F and load peaked just below 16,000 MW
- Event resulted primarily from large thermal generator (about 900 MW in total) tripping during the peak load hour; Additionally, nearly 5,000 MW of generation was out-of-service during the morning
- Real-time Hub LMP peaked at \$2,666/MWh for 17:50 – 18:05 (4 5-minute intervals)



Reserve Acronyms:
TMSR: ten-minute spinning reserve
TMNSR: ten-minute non-spinning reserve
TMOR: thirty-minute operating reserve

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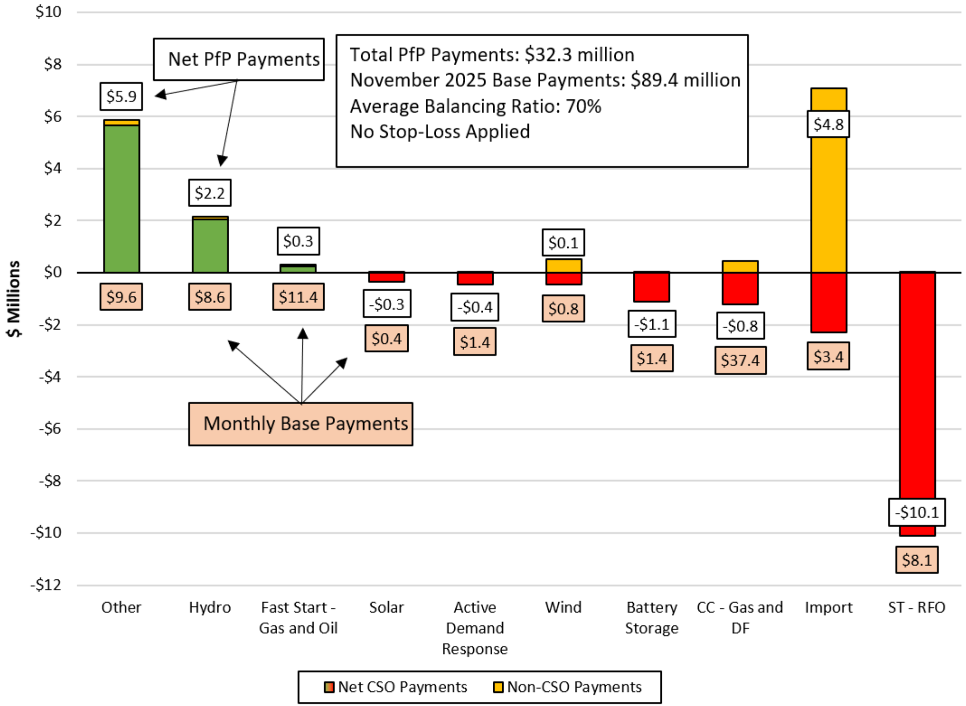
November 23 Pay For Performance credits totaled $32.3m

- Pay for Performance (PfP) credits totaled $32.3 million, based on a PPR of $9,337/MWh
- Balancing Ratio (BR) averaged 70% during the event
- The best-performing generator types included flexible hydro and fast-start units, and other non-fossil fuel units that were generally already online before the event
- Contracted imports underperformed their obligations, but uncontracted imports provided over 1,400 MW on average and earned over $7 million in credits



Notes: “Other” includes nuclear, biomass, fuel cells, and other uncategorized units. “Hydro” includes both traditional hydro and pumped storage units.

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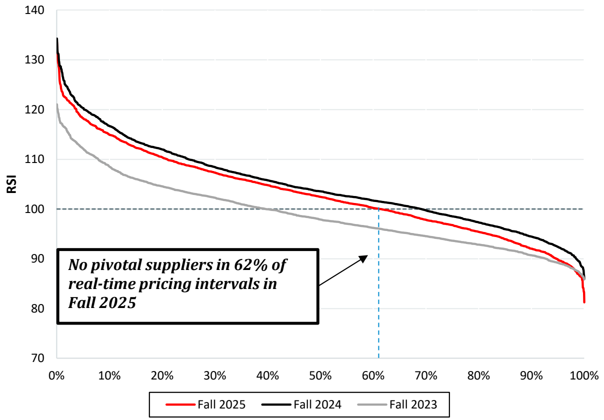
Energy Market Competitiveness

- **At least one pivotal supplier present in the real-time market for 39% of 5-minute intervals in Fall 2025** (vs 31% the previous fall)
- **Presence of structural market power slightly higher than that of Fall 2024**; fewer net imports and higher loads
- **The residual supply index for the real-time market in Fall 2025 was 103.0**, 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 w/Pivotal Suppliers (RT)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%
Fall 2024	104.7	31%
Winter 2025	101.3	47%
Spring 2025	105.7	25%
Summer 2025	104.4	31%
Fall 2025	103.0	39%

System-Wide Residual Supply Index Duration Curves



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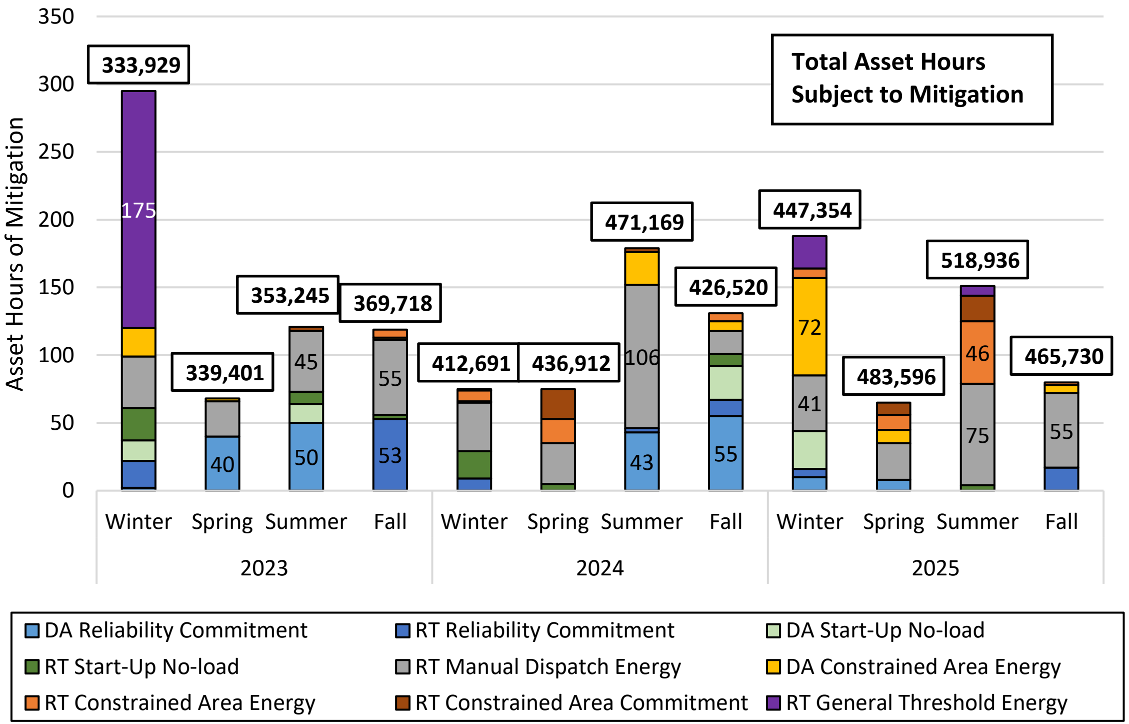
Market Power Mitigation in the Energy Market remained low

- **Mitigation activity in Fall 2025 was limited**, with **80 total mitigation asset hours**—lower than in Fall 2024—and no day-ahead reliability commitments or SUNL or GTE mitigations
- **Reliability and constrained-area mitigation were minimal**, including 17 real-time reliability commitment mitigation hours and eight constrained-area mitigation hours, split between Maine (day-ahead, September 9) and Vermont (real time, October 27–28)
- **Manual dispatch energy accounted for most mitigation activity**, with 55 asset hours of MDE mitigation, primarily affecting gas and dual-fuel units, which represented roughly 80% of all manual dispatch hours during the fall



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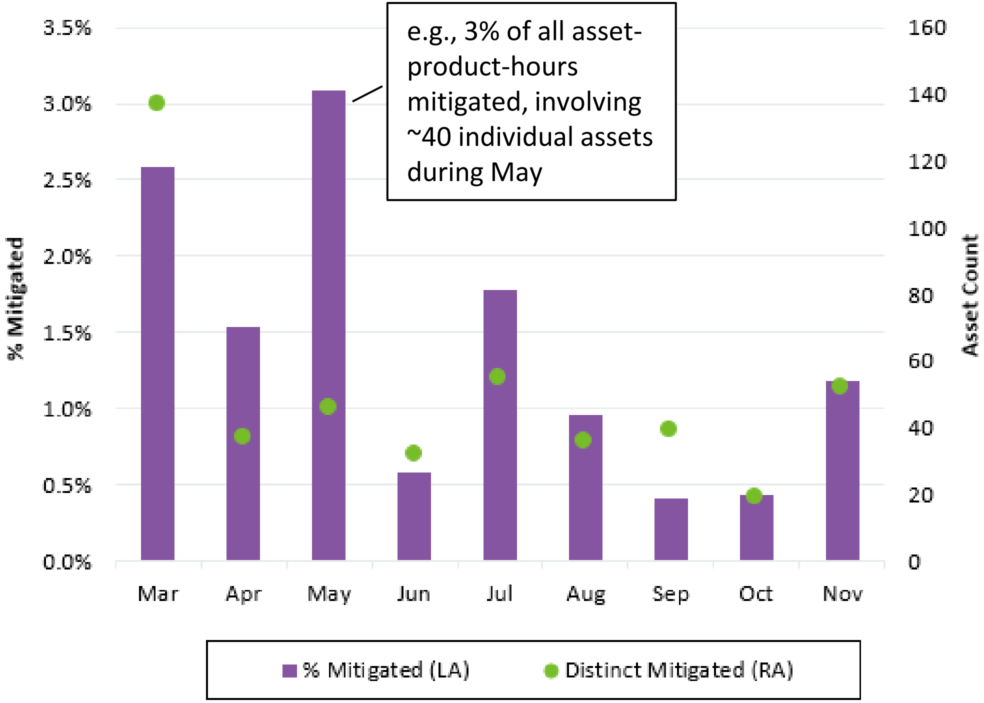
Instances of DA A/S offer mitigation continued to trend downwards in the fall

- **DA A/S mitigation applies when offers fail both conduct and price impact tests**, with a unique design feature allowing mitigation in any hour of a day if an offer fails the conduct test in that hour and causes a price impact failure in <u>*any*</u> other hour that same day
- **DA A/S mitigation has declined over time**, with the share of mitigated asset-product-hours falling from 1.1% in Summer 2025 to 0.7% in Fall 2025
- **The number of distinct mitigated assets has stabilized**, ranging between 19 and 55 over the past eight months after peaking at 137 in March, likely reflecting increased participant familiarity with the DA A/S market design



“LA” Left Axis, “RA” Right Axis

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Questions