Highlights of the 2018 Assessment of the ISO New England Markets

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External Market Monitor

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Introduction

- Potomac Economics serves as the External Market Monitor ("EMM") for the ISO-NE. In this role, we:
  - ✓ Evaluate and report on the competitive performance and operation of the wholesale markets operated by ISO-NE;
  - ✓ Identify and recommend necessary changes to existing and proposed market rules, tariff provisions and market design elements; and
  - ✓ Evaluate the mitigation by the Internal Market Monitor ("IMM").
- This presentation summarizes our assessment of New England's wholesale power markets in 2018, focusing on:
  - ✓ Cross-market comparison of several key market outcomes and metrics;
  - ✓ The competitive performance of the markets;
  - ✓ Market issues related to out-of-merit uplift costs;
  - ✓ Fuel security in New England; and
  - ✓ Evaluation of the Pay-for-Performance framework.
- We also present recommendations for improving the ISO's markets.

Summary of Market Outcomes

Energy Markets

- The ISO-NE markets performed competitively in 2018.
  - ✓ Strong relationship between natural gas prices and energy prices
  - ✓ Energy offers in competitive electricity markets should track input costs.
- Weather conditions, include hot temperatures in the summer led to higher average load (2 percent) and peak load (9 percent) in the summer.
- The higher load and significantly higher natural gas prices (33 percent) in 2018 led to increases in:
  - ✓ Energy prices of 28-32 percent; and
  - ✓ NCPC Uplift of 35 percent.

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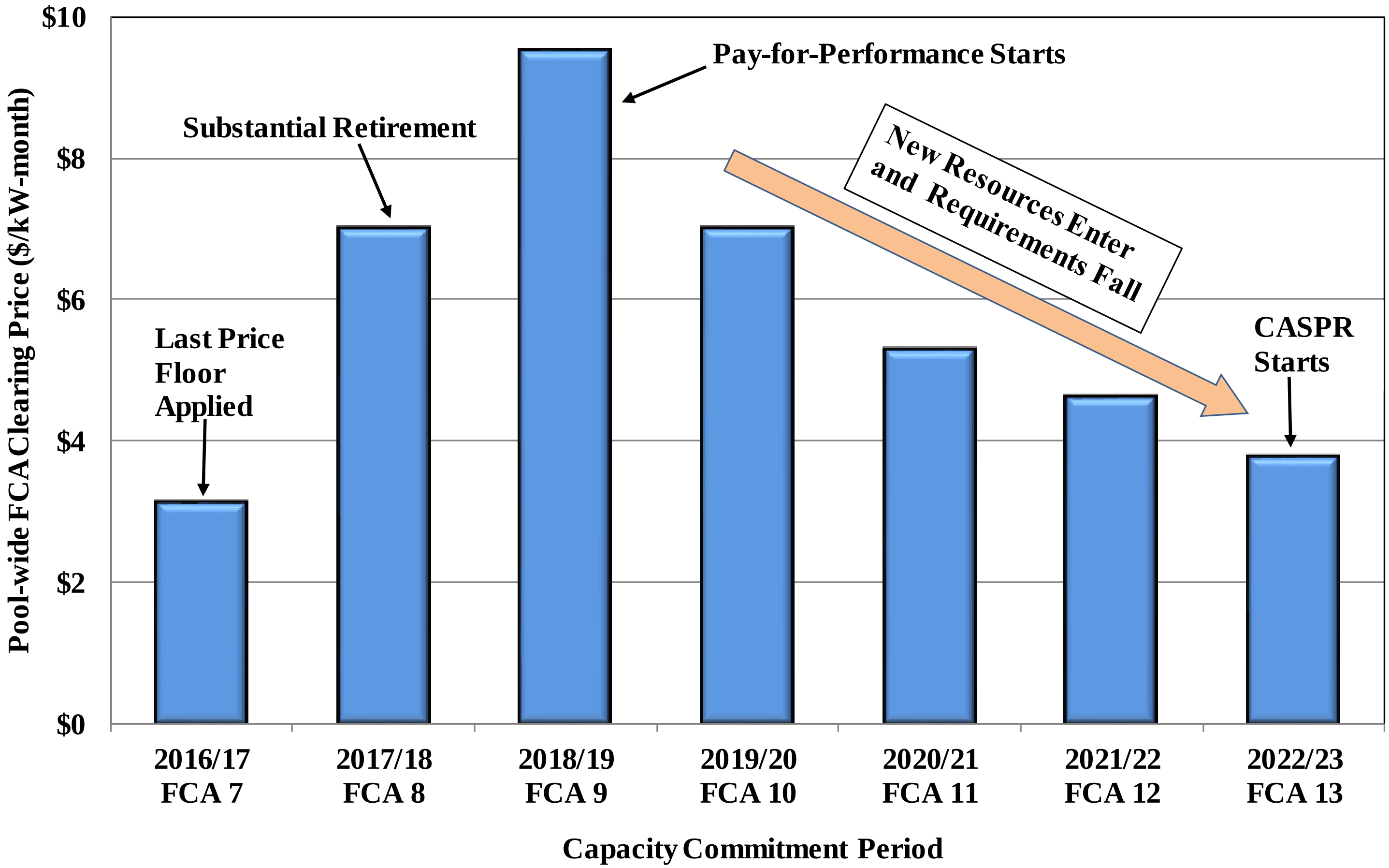
Capacity Market

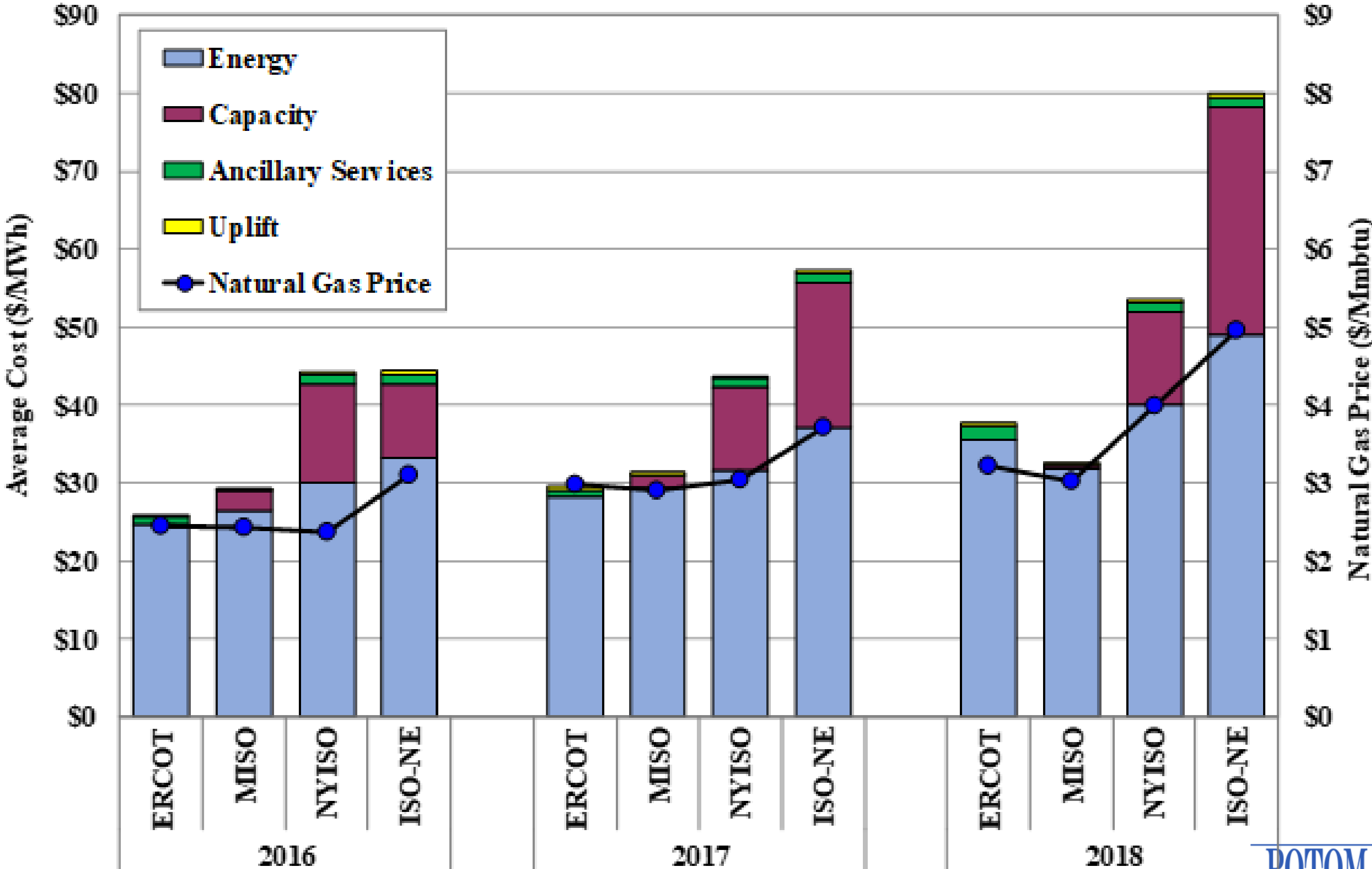


Cross-Market Comparison

Cross-Market Comparison of Key Outcomes and Metrics

- Compared to most of other RTO markets, ISO-NE has:
  - ✓ The highest energy prices because of higher natural gas prices.
  - ✓ Far less congestion (10%-20% of other RTO markets) because of substantial transmission investments in the past decade.
    - – However, transmission service costs more than doubled the average rates in other RTO markets.
  - ✓ The highest net revenues that exceeded the CONE because of higher capacity revenues.
    - – However, this is not sustainable given falling capacity prices.
  - ✓ The best performing CTS implemented so far, partly because of the RTOs’ decision not to impose charges to CTS transactions.
    - – However, forecast errors still limit the potential benefits.

All-in Prices



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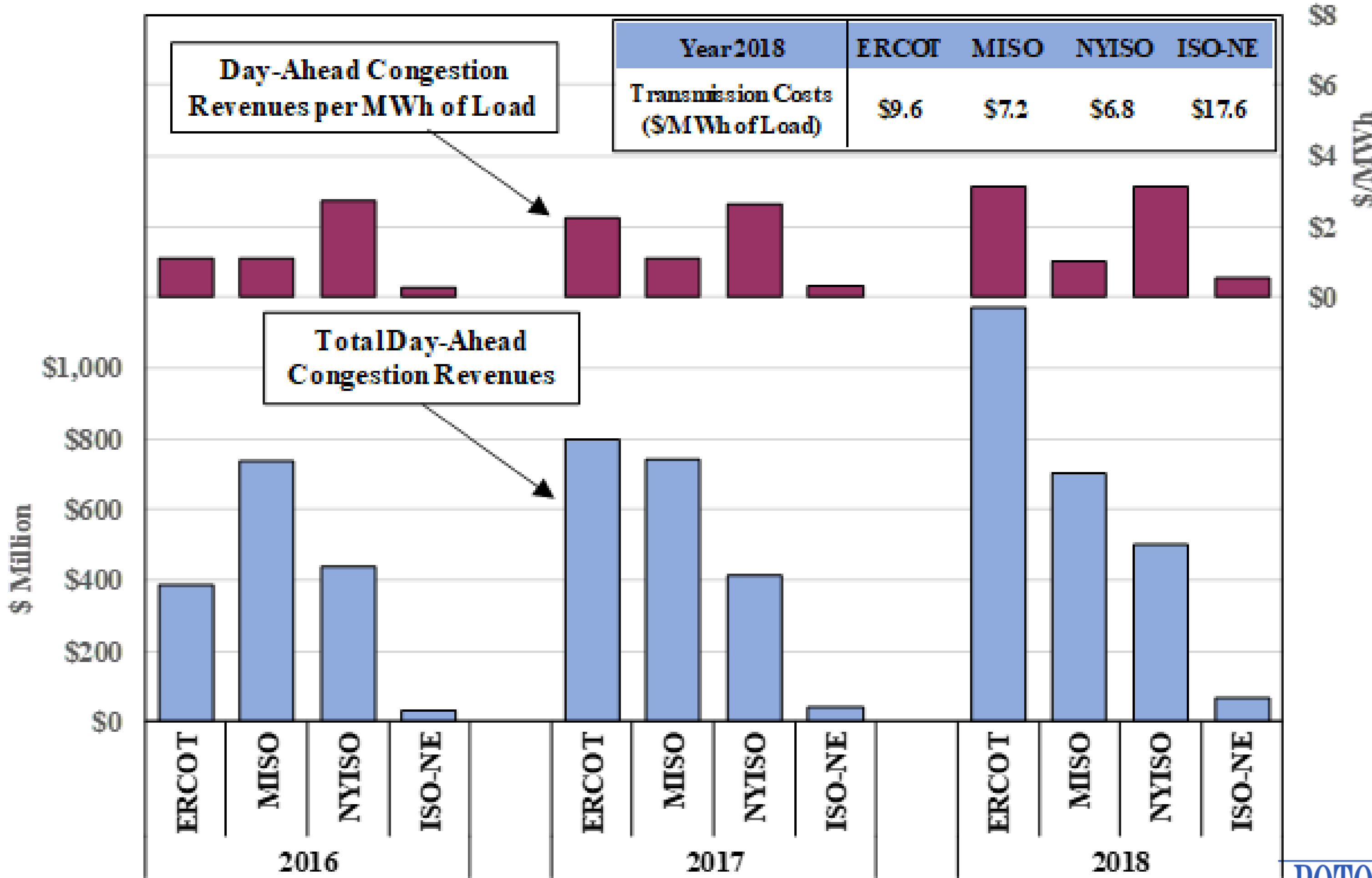
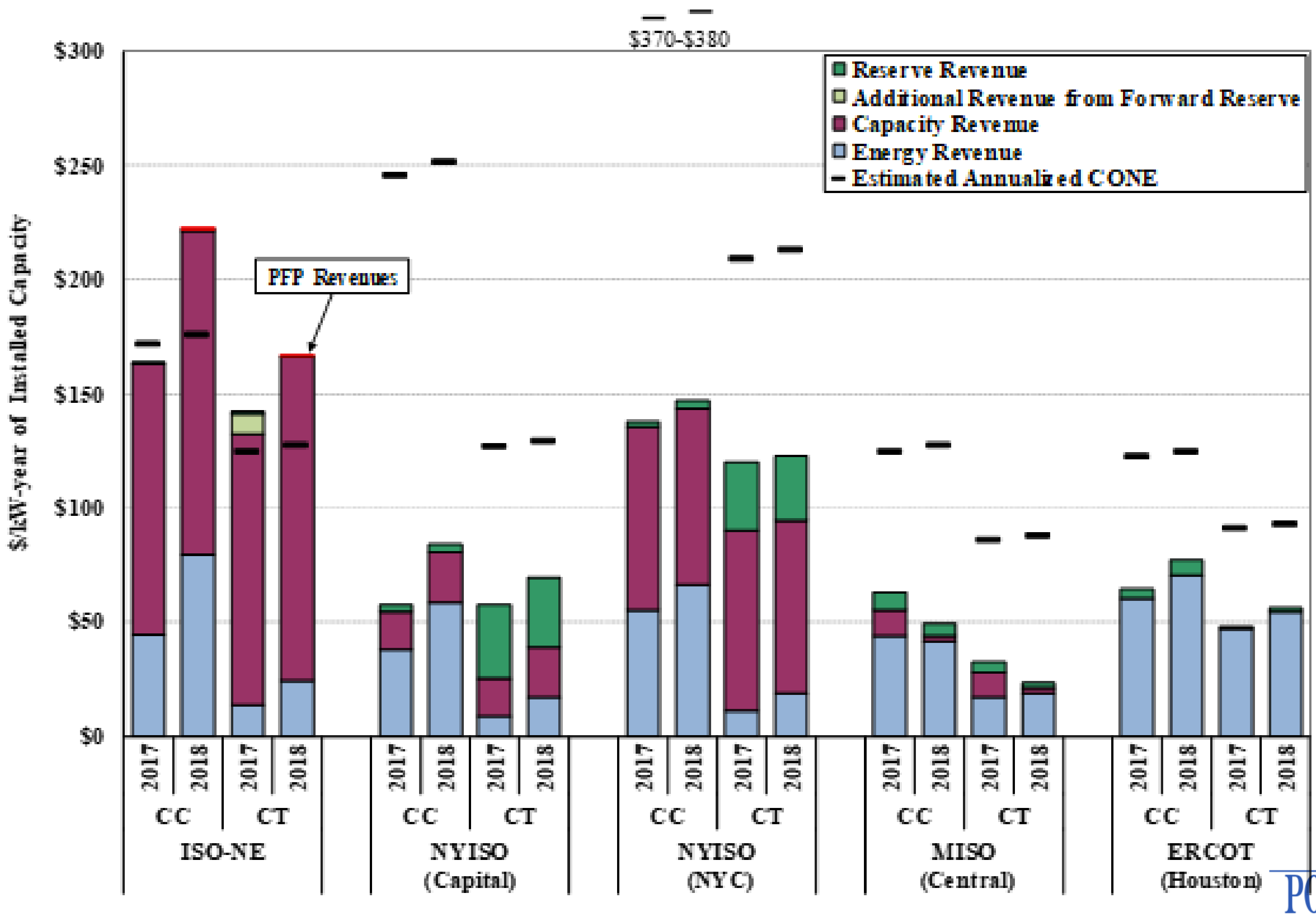
Congestion Costs



Net Revenues



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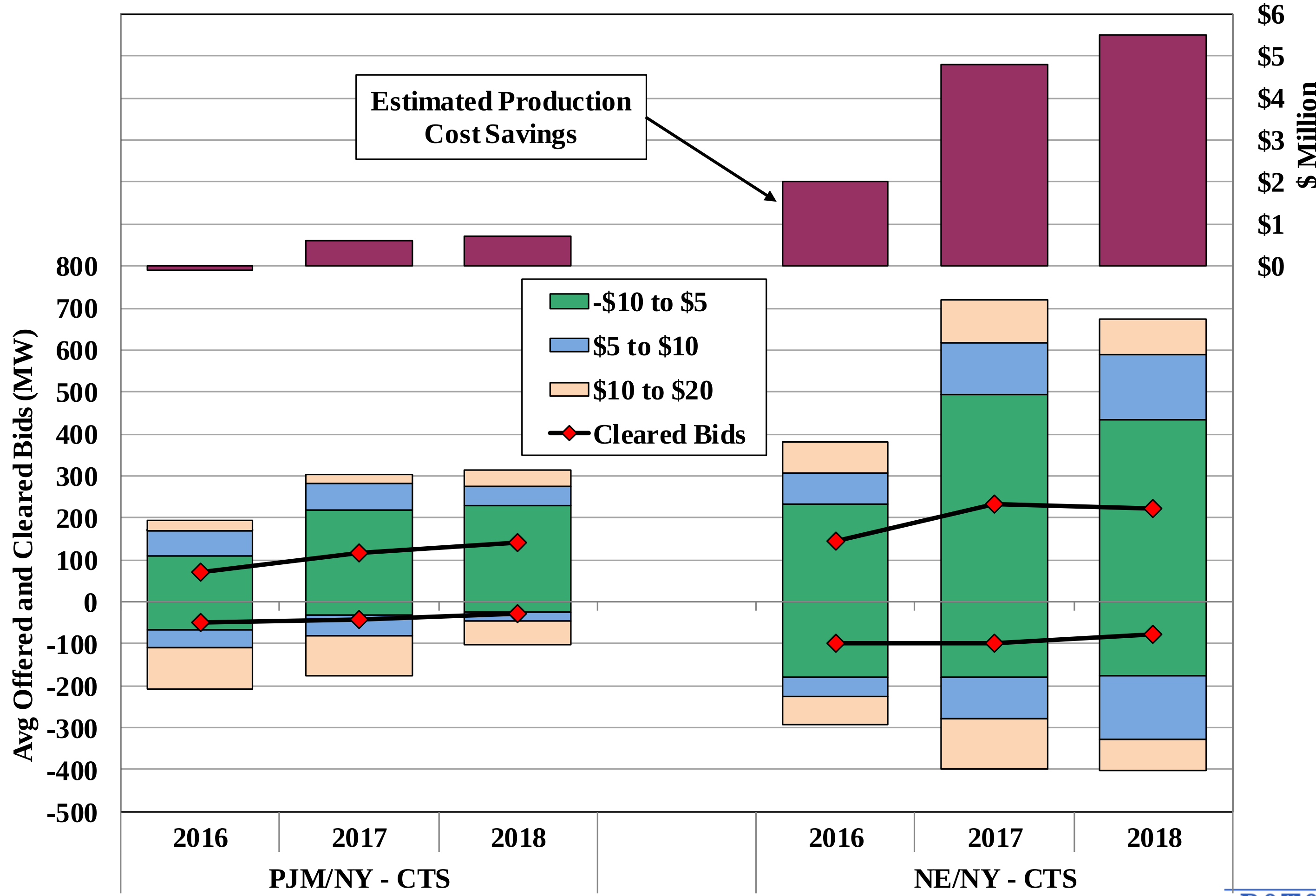
CTS Scheduling



Market Competitiveness

Evaluation of Market Competitiveness

- Our pivotal supplier analysis finds that market power concerns diminished greatly in Boston and market-wide in 2018.
- These changes are due to:
  - ✓ 1.5 GW of new CCs in the import-constrained areas;
  - ✓ Transmission upgrades in Boston; and
  - ✓ Lower market concentrations because of portfolio changes in several largest suppliers.

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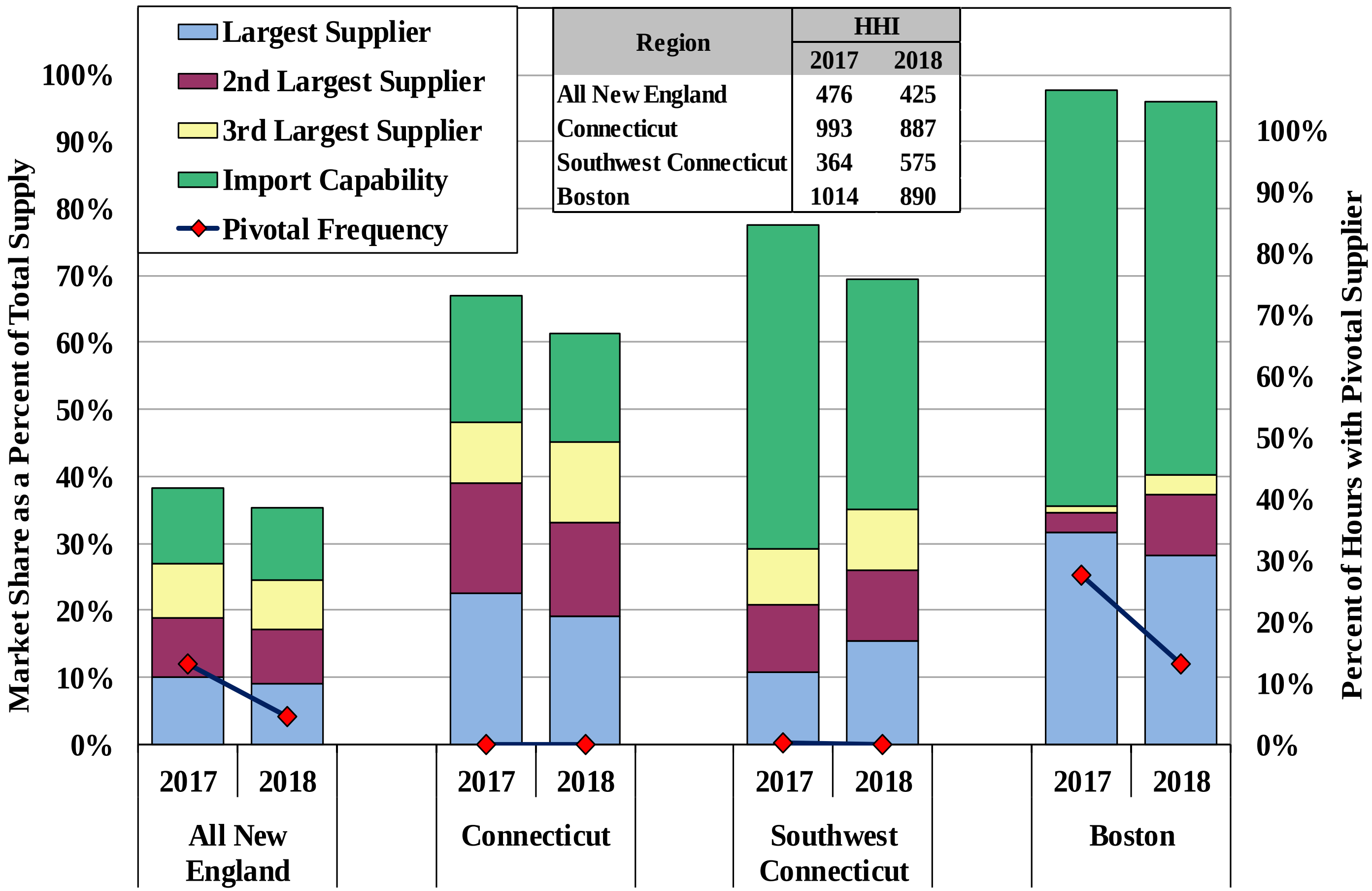
Market Power Mitigation



Region	HHI 2017	HHI 2018
All New England	476	425
Connecticut	993	887
Southwest Connecticut	364	575
Boston	1014	890

Evaluation of Market Competitiveness

- Our analyses of market participant conduct indicated that the markets performed competitively:
  - ✓ Very little evidence of economic and physical withholding, or other forms of market power abuses or manipulation.
  - ✓ Mitigation was infrequent, effective in preventing the exercise of market power, and implemented consistent with Tariff.
- However, the mitigation measures may not have been fully effective for local reliability commitment.
  - ✓ Suppliers have the incentive to operate in a higher-cost mode and receive higher NCPC payment as a result.
  - ✓ We are encouraging the ISO to consider Tariff changes as needed to expand its authority to address this concern. (See Recommendation #2)

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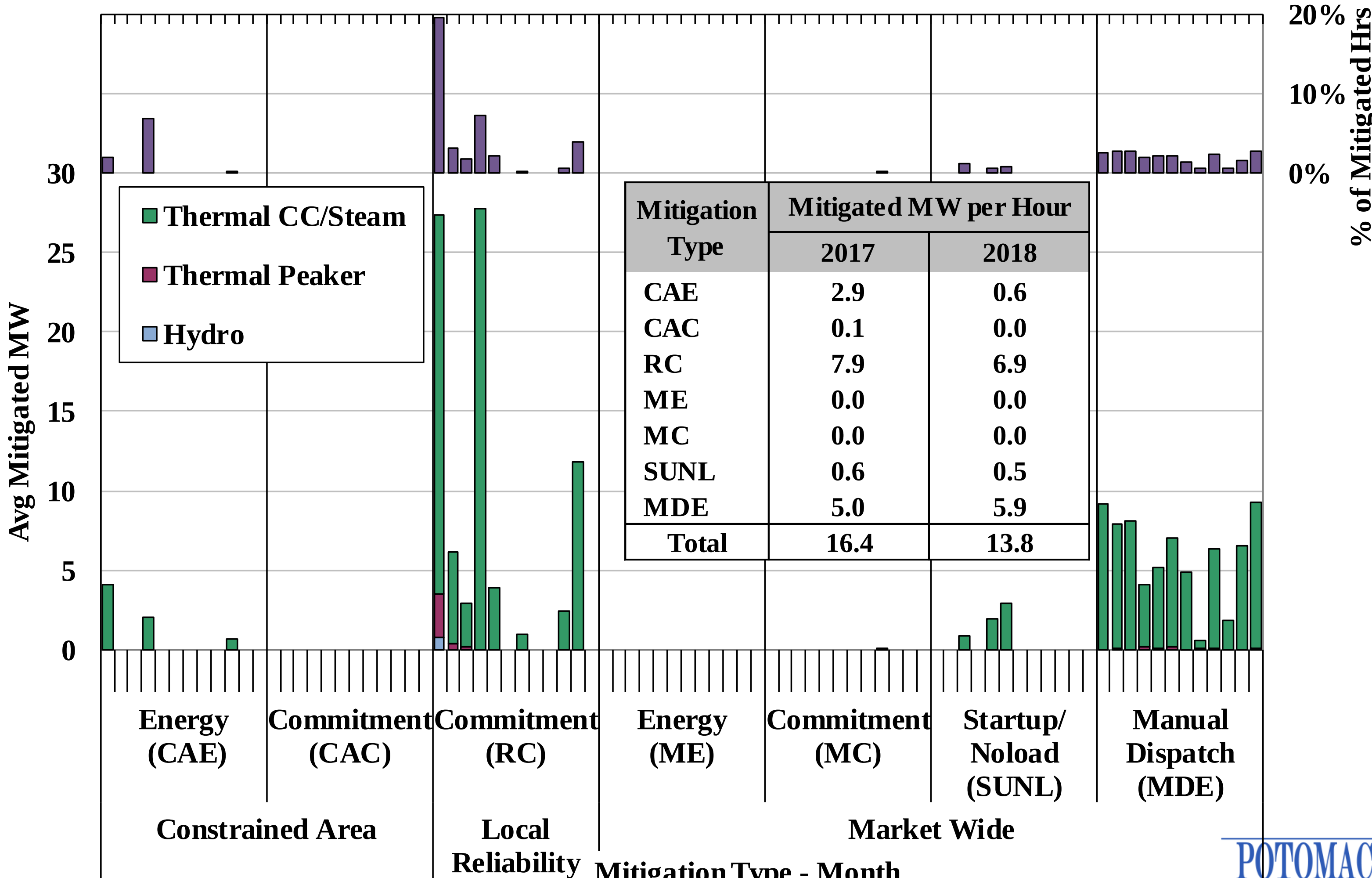
Market Power Mitigation



Mitigation Type	Mitigated MW per Hour 2017	Mitigated MW per Hour 2018
CAE	2.9	0.6
CAC	0.1	0.0
RC	7.9	6.9
ME	0.0	0.0
MC	0.0	0.0
SUNL	0.6	0.5
MDE	5.0	5.9
Total	16.4	13.8

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Operating Reserves and Uplift Costs

Uplift Cost Comparison Across RTOs

- Uplift costs, particularly in the market-wide category, remain higher than other RTOs.

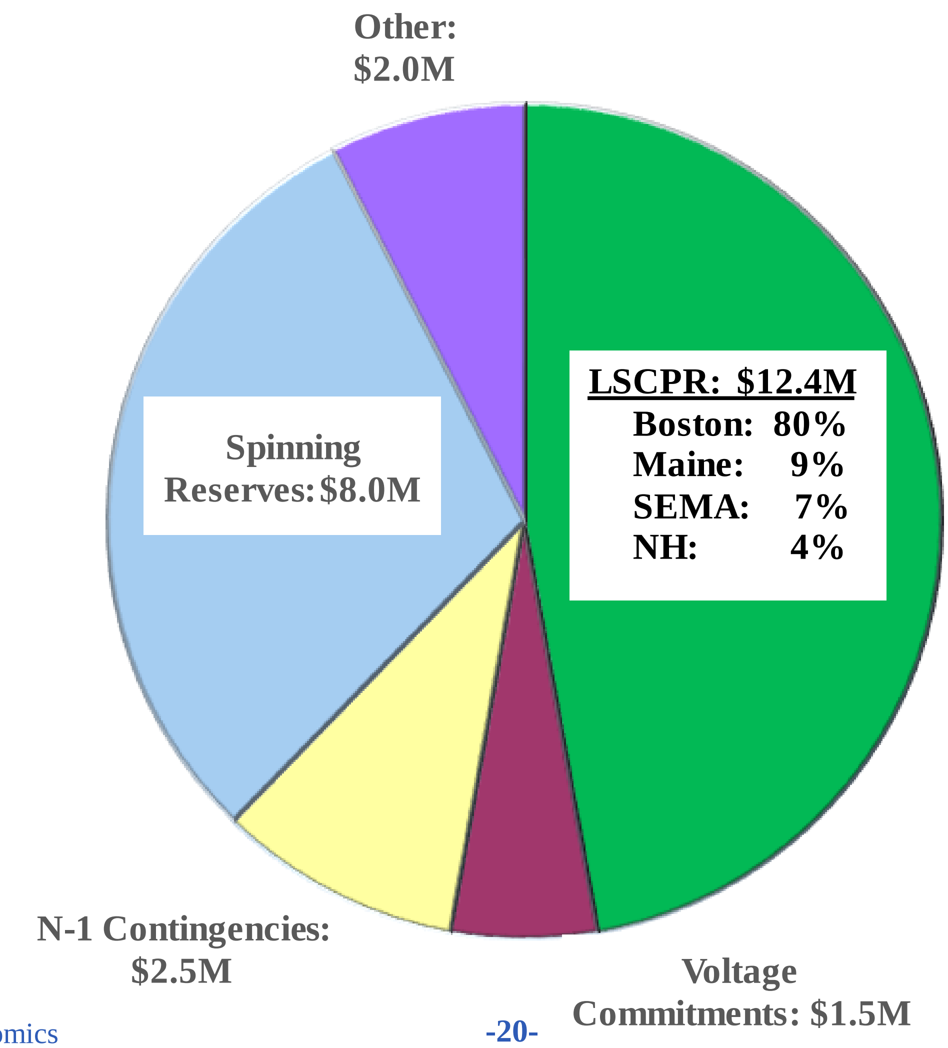
			ISO-NE			NYISO	MISO
			2016	**2017**	**2018**	**2018**	**2018**
Real-Time Uplift							
	Total	**Local Reliability ($M)**	$1	$1	$4	$23	$3
		Market-Wide ($M)	$27	$23	$40	$19	$78
	Per MWh of Load	**Local Reliability ($/MWh)**	$0.01	$0.01	$0.04	$0.14	$0.004
		Market-Wide ($/MWh)	$0.22	$0.19	$0.32	$0.12	$0.11
Day-Ahead Uplift							
	Total	**Local Reliability ($M)**	$31	$15	$14	$31	$22
		Market-Wide ($M)	$13	$13	$12	$4	$17
	Per MWh of Load	**Local Reliability ($/MWh)**	$0.25	$0.12	$0.11	$0.19	$0.03
		Market-Wide ($/MWh)	$0.10	$0.11	$0.10	$0.03	$0.03
Total Uplift							
	Total	**Local Reliability ($M)**	$33	$16	$18	$54	$25
		Market-Wide ($M)	$40	$36	$52	$23	$95
	Per MWh of Load	**Local Reliability ($/MWh)**	**$0.26**	**$0.13**	**$0.15**	**$0.33**	**$0.04**
		Market-Wide ($/MWh)	**$0.32**	**$0.29**	**$0.42**	**$0.14**	**$0.14**
		All Uplift ($/MWh)	**$0.58**	**$0.42**	**$0.57**	**$0.48**	**$0.17**

Day-Ahead NCPC Costs and Reserve Markets

Market Issues

- Most of day-ahead NCPC charges occurred because of local and system-level reserve requirements that require committing additional resources are not currently priced.
- Of total day-ahead NCPC in 2018,
  - ✓ 47% was for the second contingency protection in local areas.
    - – 60 percent of the commitments made by the DA commitment software for Boston would not have been needed if energy and reserves were to be co-optimized in the day-ahead market.
  - ✓ 30% was for the system-level 10-spinning reserve requirement.
    - – Additional units were committed to meet this requirement in nearly 4,000 hours of the year.
    - – These commitments lowered day-ahead energy prices by an estimated average of $1.0 - $1.5/MWh.

Day-Ahead NCPC Charges by Category 2018



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NCPC Costs and Day-Ahead Reserve Markets

<u>Recommendations</u>

- Introduce the day-ahead reserve markets that are co-optimized with day-ahead energy (see Recommendation #3), which would:
  - ✓ Allow the ISO to select the lowest-cost offers to simultaneously satisfy energy and reserve requirements and set prices efficiently;
  - ✓ Reduce day-ahead NCPC; and
  - ✓ Improve unit availability by scheduling reserves in a timeframe to allow suppliers to arrange fuel and staffing to be available for deployment.
- Eliminate the forward reserve market (see Recommendation #4), especially with the introduction of day-ahead reserve markets.
  - ✓ The forward reserve market has provided limited values and is largely redundant with the locational requirement in the FCM.
  - ✓ The forward procurements do not ensure that sufficient reserves will be available during the operating day.

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Real-Time NCPC and Allocations to Virtual Trading

Market Issues

- "RT deviations" caused only 14% of RT NCPC charges in 2018, but were allocated 40%.
- Virtual trades (part of RT deviations) were over-allocated RT NCPC charges, which were typically higher than in most other RTOs.
  - ✓ This has discouraged virtual trading, resulting in reduced liquidity in the DAM and less efficient resource commitment.

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2016	1.3%	$1.70	2.0%	$1.94	$1.25
	2017	2.2%	$1.98	3.6%	$2.71	$0.81
	2018	2.7%	$1.10	4.5%	$2.69	$0.94
NYISO	2018	5.7%	$1.54	12.3%	-$0.35	< $0.1
MISO	2018	9.8%	-$0.31	9.8%	$1.90	$0.64

Real-Time NCPC Charges by Category

Real-Time NCPC Category	Charges (Million $)	Share of RT NCPC
Local Reliability		
Local Second Contingency	$0.6	1%
Voltage Support	$0.4	1%
SCR	$0.6	1%
Multi-Turbine Portion	$2.7	6%
External Transactions	$2.7	6%
Market-Wide *Charged to RTLO*		
Generator Performance Audit	$1.4	3%
Dispatch LOC	$3.7	8%
Rapid Response OC	$4.0	9%
Resource Posturing	$10.1	23%
Market-Wide *Charged to RT Deviation*		
Fast Start Resources	$6.9	16%
Supplemental Commitment after DAM	$6.3	14%
Other	$4.4	10%
Total	$43.9	

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Real-Time NCPC and Allocations to Virtual Trading

Recommendations

- Modify the allocation of Economic NCPC charges to be more consistent with a "cost causation" principle.(see Recommendation #1)
  - ✓ This would largely involve not allocating NCPC costs to virtual load and other real-time deviations that do not cause it, which requires the ISO to:
    - – Identify the reason for the economic NCPC (congestion vs capacity);
    - – Quantify extent to which *net* "harming" deviations cause NCPC by:
      - Reducing total day-ahead generation schedules (e.g., virtual supply, unscheduled load); or
      - Reducing scheduled day-ahead flows over the constraint.
    - – Allocate NCPC to harming deviations in proportion to their effect.
    - – Allocate the residual to real-time load.

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Fuel Security in New England

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Winter Fuel Security

Market Issues

- In the first 13 FCAs, nearly 5 GW of nuclear, coal, and older steam turbine capacity has/will retire, and reliance on gas-fired capacity has increased.
  - ✓ Concerns heightened by potential retirement of Mystic and Distrigas.
- Our fuel security evaluation for a two-week severe winter period shows:
  - ✓ In the Baseline Scenario, very high utilization of oil inventory capacity and LNG import capability would be needed.
  - ✓ In the Pipeline Contingency Scenario or in a scenario with major reductions in availability, load shedding would occur.
- ISO's OFSA and Mystic Retirement Study also found tight fuel supply margins that could result in load shedding in winters of 2022/23 and 2023/24.

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Fuel Security Outlook for Winter 2022/23

- ISO is currently designing rules to incentivize suppliers to acquire the fuel necessary to maintain reliability during periods of gas scarcity.
  - ✓ In the long term, these changes should provide incentives for investment in fuel-secure new resources and maintenance of existing resources.
  - ✓ In the short term, these changes should improve incentives to procure fuel and fully utilize the existing resources.
- ISO's assumptions in the OFSA model are very conservative about oil tank replenishment rates and dispatch order, and are based on past experience.
- ISO reran the OFSA model with modifications to the following two default assumptions:
  - ✓ Light oil units (i.e., combined cycles) are always dispatched before heavy oil units (i.e., older steam turbines).
  - ✓ Oil-fired and dual-fuel generators will not fill their oil tanks to capacity before each winter or fully utilize refueling capacity during the winter.

Fuel Security Outlook for Winter 2022/23

Results

- Market design changes will substantially affect reliability.
  - ✓ Modifying dispatch order will eliminate all hours of load shedding and 10-minute reserve depletion.
  - ✓ Frequent refills would eliminate even 30-minute reserve depletion.
- System would be far more reliable even under contingency scenarios with significant reductions in supply.
  - ✓ None of the extraordinary contingencies considered would result in load shedding hours.
- Battery storage resources can provide considerable flexibility to the system, but they are energy limited and have very little fuel security value.

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Fuel Security Analysis with Modified Assumptions (Winter 2022/23)

Scenario Description	No.	Assumptions				Results (Hrs)		
		New Entry and Retirements	Dispatch Order	Oil Tank Refills	LNG (bcf/d)	30 Min Res Depletion	10 Min Res Depletion (< 700MW)	Load Shedding
ISO Ref + Updated Resource Mix	[1]	FCA-13 New Entry/ Retirements	ISO default	1.25	0.8	138	12	2
[1] + Modified Dispatch	[2]	FCA-13 New Entry/ Retirements	CCs after ST units	1.25	0.8	24	0	0
[2] + Modified Refills (*EMM Reference*)	[3]	FCA-13 New Entry/ Retirements	CCs after ST units	Heavy - Unlimited Light - 2	0.8	0	0	0
[3] with Batteries Replacing a ST	[4]	FCA-13 New Entry/ Retirements + 600MW of batteries in place of ST	CCs after ST units	Heavy - Unlimited Light - 2	0.8	2	0	0
Contingencies								
EMM Ref [3] - Millstone outage	[5]	FCA-13 New Entry/ Retirements - Millstone out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	36	0	0
EMM Ref [3] - Pipeline outage	[6]	FCA-13 New Entry/ Retirements - 1.2 bcf/d gas unavailable for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.8	57	1	0
EMM Ref [3] - Canaport outage	[7]	FCA-13 New Entry/ Retirements - Canaport out for 14 peak days	CCs after ST units	Heavy - Unlimited Light - 1	0.4	14	0	0

Fuel Security Outlook for Winter 2024/25

Results

- No significant fuel security issues in 2024/25 with modified dispatch order and replenishment assumptions.
- Impact of retiring the Mystic and Distrigas facilities would depend on the response from other sources of supply.
  - ✓ If the volume of LNG imports through the other two import terminals rose from 0.4 to 0.8 Bcf/day, reserve shortages would become much less frequent.
  - ✓ Increasing LNG to 0.8 Bcf/day, replacing slightly over half the supply lost from Mystic + Distrigas, eliminates 10-minute reserve depletion to 700 MW.
  - ✓ Other risks to consider upon retirement of Mystic and Distrigas:
    - Impact of large supply-side contingencies
    - Rate of entry of low fuel security resources (e.g. batteries) and exit of fuel-secure resources
- Developing a market mechanism would provide valuable incentives, and can reduce or eliminate the reliability impact of losing Mystic and Distrigas.

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Fuel Security Analysis with Retirement of the Mystic and Distrigas Facilities (Winter 2024/25)

Scenario Description	No.	Assumptions			Results (Hrs)		
		New Entry and Retirements	**Oil Tank Refills**	**LNG (bcf/d)**	**30 Min Res Depletion**	**10 Min Res Depletion (< 700MW)**	**Load Shedding**
EMM Reference 2024/25	[1]	FCA-13 New Entry/ Retirements	Heavy - Unlimited Light - 2	0.8	0	0	0
Sensitivities on LNG Injection for Mystic 8 and 9 and Distrigas LNG Retirement Scenario							
LNG Sensitivity #1 (Low Injection)	[2]	FCA-13 New Entry/ Retirements - Mystic 8 and 9 + Distrigas LNG retired	Heavy - Unlimited Light - 2	0.4	216	2	0
LNG Sensitivity #2	[3]			0.5	146	2	0
LNG Sensitivity #3	[4]			0.6	95	0	0
LNG Sensitivity #4	[5]			0.7	52	0	0
LNG Sensitivity #5 (High Injection)	[6]			0.8	23	0	0

Evaluation of the Pay-for-Performance Framework

First Pay-for-Performance Event

- Pay-for-Performance rule became effective on June 1, 2018.
- The first such event occurred on September 3 primarily due to unexpectedly high load and significant forced outages and derates.
- PFP incentives were in effect during the reserve shortage at a rate of $2,000/MWh.
  - ✓ Steam turbine units accounted for $22 million in PFP charges.
    - These units were not economic in the day-ahead market.
    - They could not respond to this real-time event because of long lead times.
  - ✓ Combined-cycle units accounted for almost $9 million in charges and more than $14 million in performance payments.
    - Although forced outages were the primary driver, several units were simply not committed in the day-ahead market.
    - Some units responded by self-scheduling in real-time but came online after the shortage ended.
  - ✓ Imports received performance payments of nearly $15 million, roughly half of which was paid to importers with no capacity obligations.

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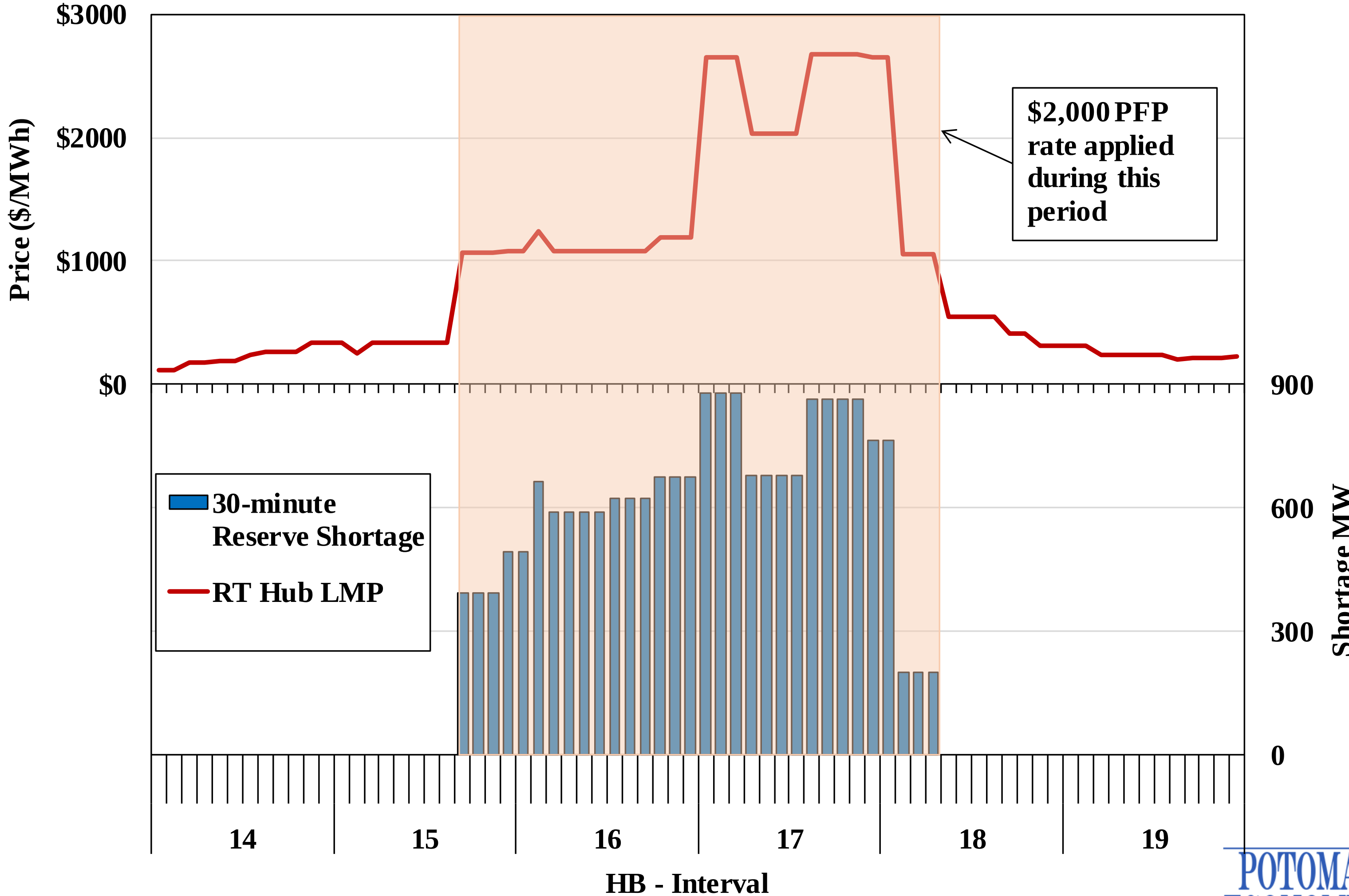
Pay-for-Performance Event
September 3, 2018



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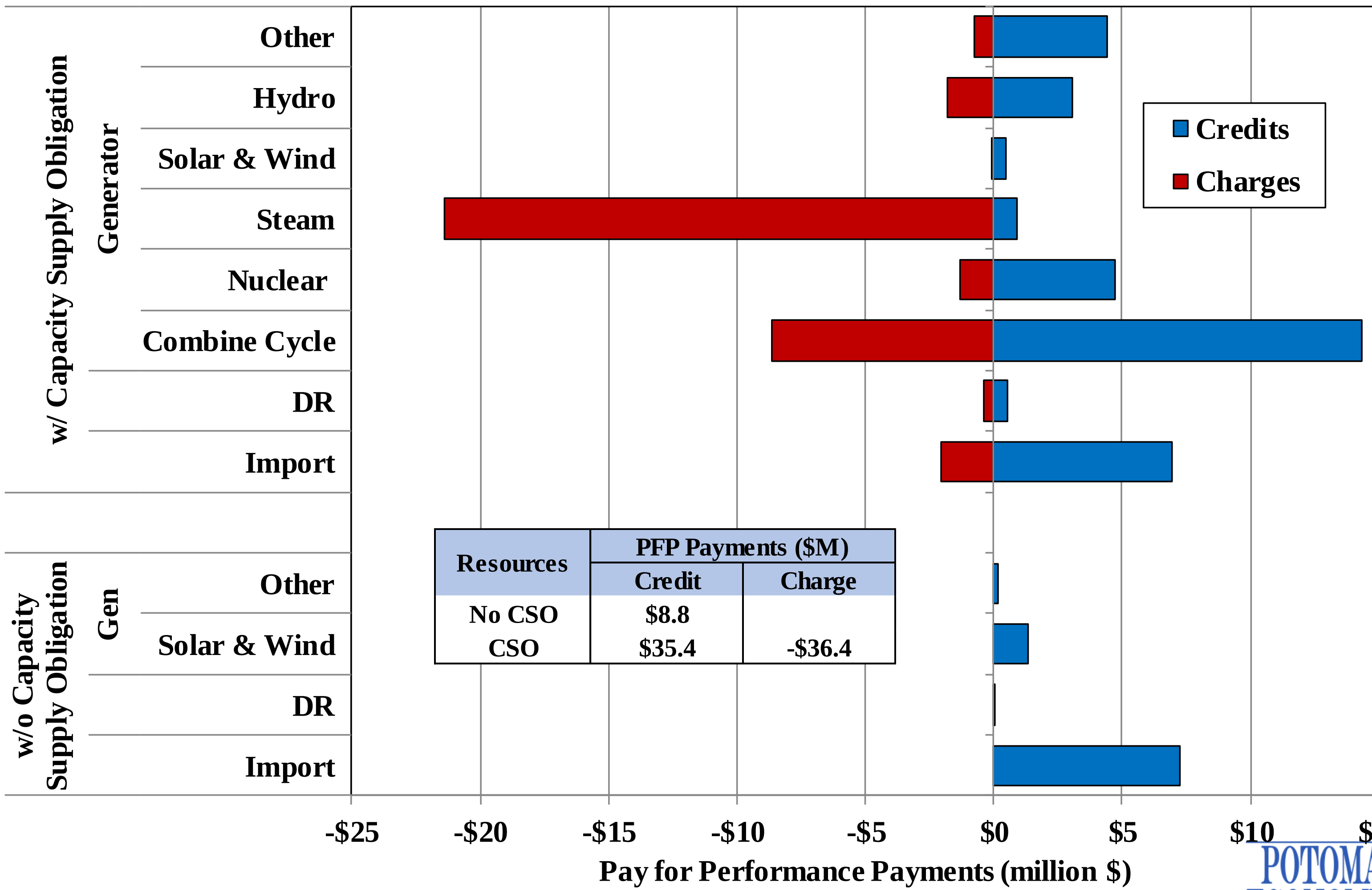
Pay-for-Performance Credits & Charges
September 3, 2018



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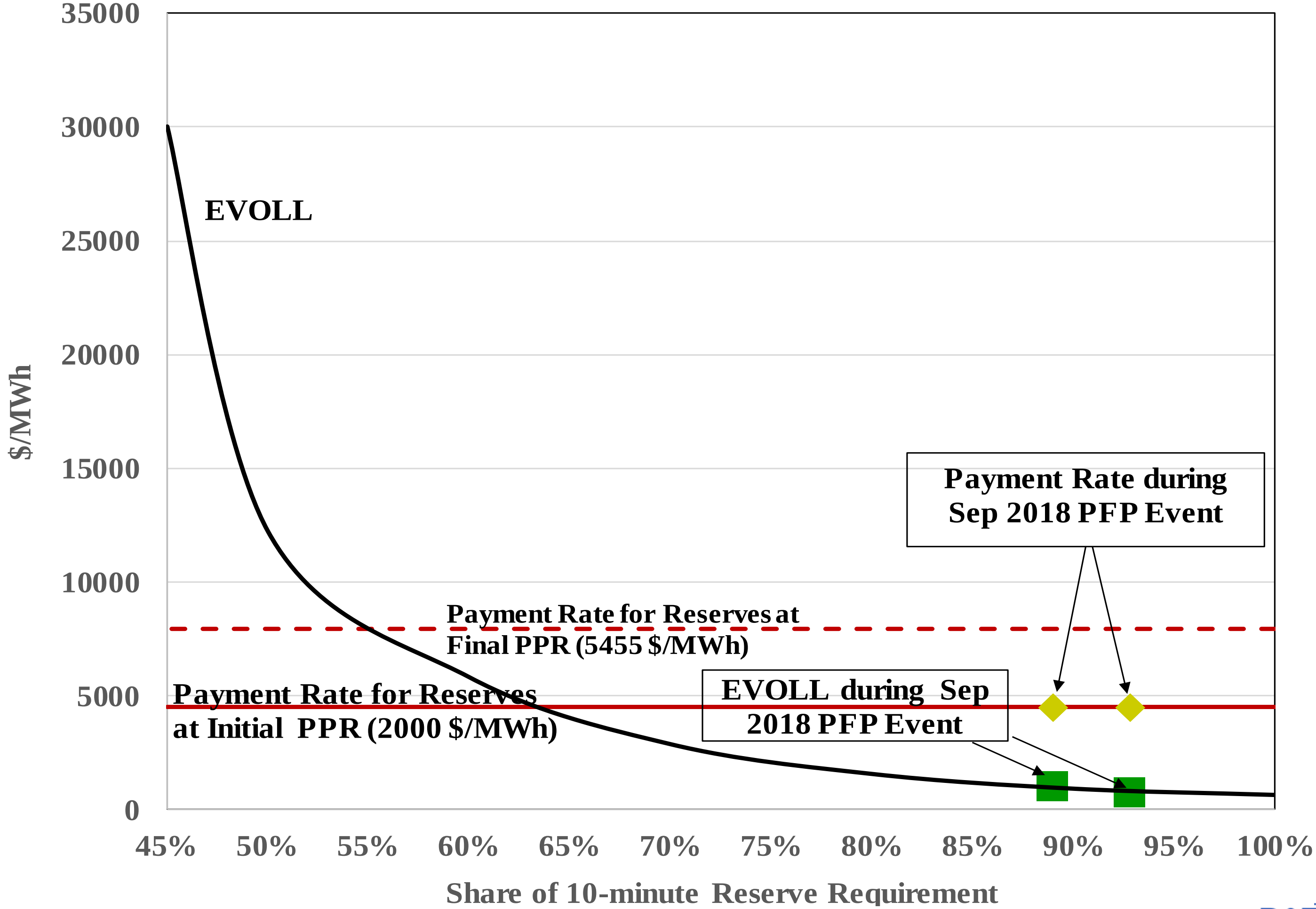
Evaluation of Pay-for-Performance Pricing

- Total incentives provided by the real-time market and the PFP were large.
  - ✓ Settlements exceeded $4700 although reserves were above 60% of requirements.
- Efficient prices during reserve shortages are key to establishing economic signals. Efficient shortage pricing should:
  - ✓ Reflect the marginal reliability value of reserves given the shortage level;
  - ✓ Depend on the risk of potential supply contingencies, including multiple simultaneous contingencies; and
  - ✓ Rise gradually as the reserve shortage increases and have no artificial discontinuities that can lead to excessively volatile outcomes.
- The marginal reliability value of reserves equals expected value of lost load (“EVOLL”), which is a product of: (a) value of lost load, and (b) the probability of losing load.
- We compared EVOLL at various reserve levels to actual settlements by:
  - ✓ assuming a high VOLL of $30,000 per MWh; and
  - ✓ using a Monte Carlo analysis based on random forced outages of generation.

Comparison of Reserve Prices to EVOLL during PFP Events



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Evaluation of Pay-for-Performance Pricing

Results

- EVOLL during the event ranged from $700 to $1,000 per MWh, far lower than the actual rate of compensation of $3000 to $4700 per MWh.
- EVOLL curve has a convex shape to it.
  - ✓ Current rate of compensation far higher than efficient price levels during shallow shortages and much lower during deep shortages.
  - ✓ PFP framework over-compensates flexible resources that resolve transient and shallow shortages, and under-compensates resources that resolve more serious shortages.

Recommendation

- Modify the PPR to rise with the reserve shortage level, and
- Do not implement the remaining planned increase in the payment rate.

Incentives for Energy Storage Resources under Pay-for-Performance

<u>Market Issues</u>

- Interest in ESRs has grown quickly in recent years, but valuing capacity, energy and operating reserves is challenging.
- We evaluate the reliability value of a 2-hour ESRs and find that such units are likely to be over-compensated.
- FCM rules allow ESRs to qualify 100 percent of their capability, but PFP rules do not provide sufficient discipline in qualifying their capacity.
  - ✓ ESRs can provide reserves for extended periods of time, unless they are required to discharge.
  - ✓ Simulations of a system at one-day-in-ten-year standard indicate that load shedding constitutes only *two percent* of reserve shortage hours.
  - ✓ Therefore, risk of PFP penalties may not be significant relative to the potential upside from higher capacity revenue.
- ESRs are likely to find it profitable to sell 100 percent of their capacity.

Incentives for Energy Storage Resources under Pay-for-Performance

<u>Results</u>

- GE-MARS simulations indicate that capacity value of a 2-hour ESR was 63 to 68 percent with 500 MW penetration.
- 2-hour ESRs would receive 117 percent of the compensation of a capacity supplier with average performance.
- ESRs are over-valued in capacity market because:
  - ✓ 2-hour ESRs are far less valuable for preventing load shedding than the average conventional resource.
  - ✓ ESRs are likely to have high rates of availability during reserve shortages and comparatively lower availability during load shedding.
- PFP construct over-compensates ESRs because PPR is the same for shallow and deep shortages, although the EVOLL is low for shallow shortages.

<u>Recommendation</u>

- Consider modifying the capacity compensation of energy limited resources to be consistent with the reliability value.

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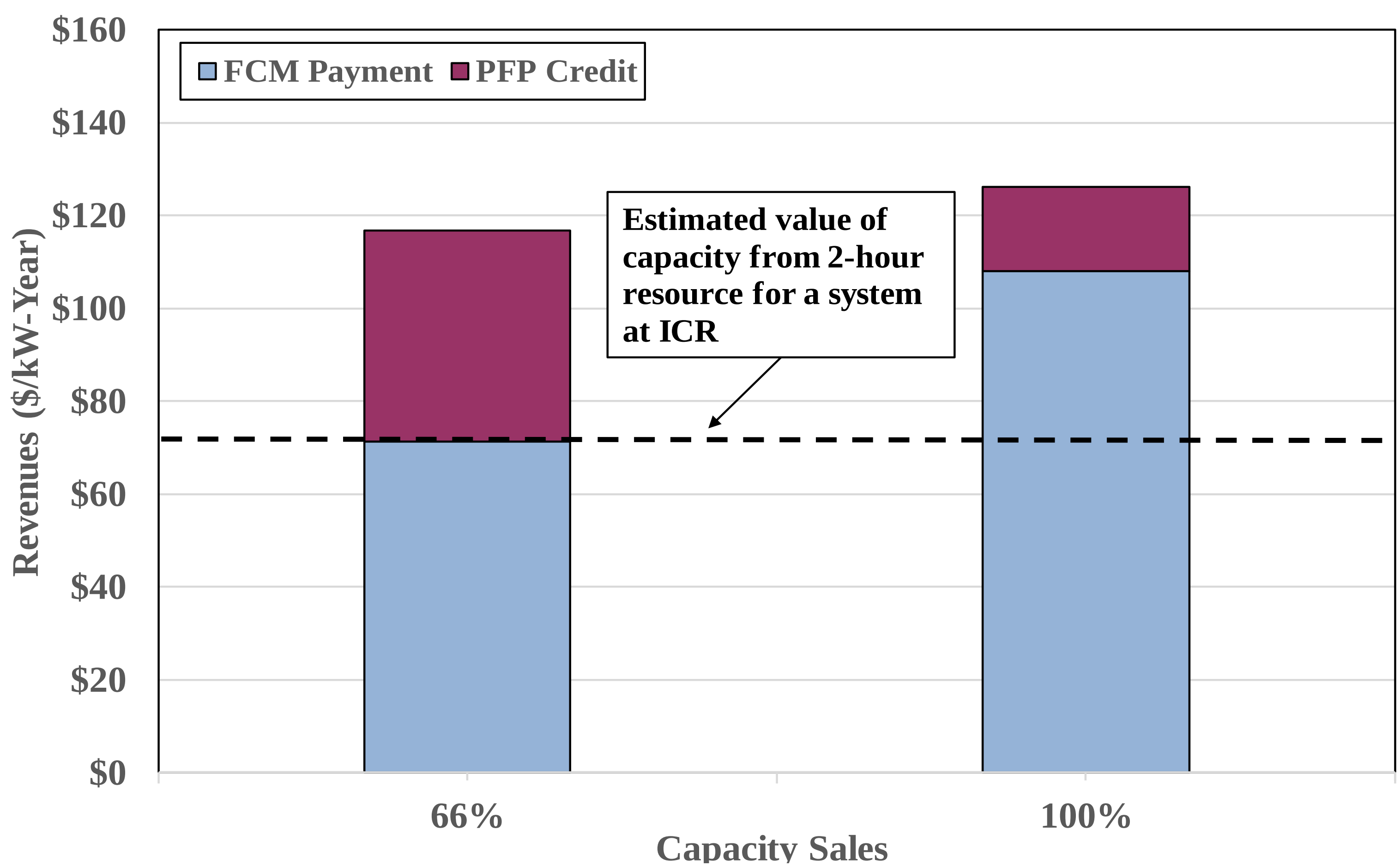
Breakdown of Revenues for a 2-Hour Battery Resource



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Full List of Recommendations

List of Recommendations

Recommendation	Wholesale Mkt Plan	High Benefit[1]	Feasible in ST[2]
Reliability Commitments and NCPC Allocation			
1. Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.	✓		✓
2. Utilize the lowest-cost fuel and/or configuration for multi-unit generators when committed for local reliability.			✓
Reserve Markets			
3. Introduce day-ahead operating reserve markets that are co-optimized with the day-ahead energy market.	✓	✓	
4. Eliminate the forward reserve market.			✓
External Transactions			
5. Pursue improvements to the price forecasting that is the basis for Coordinated Transaction Scheduling with NYISO.		✓	✓

Notes:

1. *High Benefit*: Will likely produce considerable efficiency benefits.
2. *Feasible in Short Term*: Complexity and required software modifications are likely limited.

List of Recommendations (cont.)

Recommendation	Wholesale Mkt Plan	High Benefit[1]	Feasible in ST[2]
Capacity Market			
6. Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			✓
7. Modify the PPR to rise with the reserve shortage level, and not implement the remaining planned increase in the payment rate.			
8. Consider modifying the capacity compensation of energy limited resources to be consistent with the reliability value.			
9. Improve the MOPR by: a) eliminating performance payment eligibility for units subject to the MOPR, b) capping the Minimum Offer Price at net CONE, and c) exempting competitive private investment from the MOPR.			✓