Analysis of a New York Carbon Charge

PRESENTED TO
IPPTF Stakeholders

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THE Brattle GROUP

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Agenda

Assessment of the Effects of Carbon Charges on Customer Costs (NYCA-wide)

- Study motivation, scope, and approach
- Conclusions about customer costs
- Drivers and trends

Analytical Details

Next Presentation: Zonal Effects and Seams

Introduction

Recap: Motivation for Carbon Pricing

- Provide transparent price signal reflecting carbon externality, to help achieve New York State decarbonization goals efficiently within the wholesale market
  - Align commitment and dispatch with state policy goals
  - Signal investment for reducing carbon, including from diverse and innovative solutions beyond CES
  - Fine-tune the solutions with granular prices, e.g., location of new renewables, operation of storage
- Provide a market-oriented approach to bridging state policies and federally regulated wholesale markets
  - Addresses negative energy pricing from renewables as penetration increases, lessening pressure for out-of-market incentives for non-renewable resources
  - Minimize calls for more aggressive buyer-side mitigation measures that could deter policy-supported resources and/or lead to costly excess capacity

Hence, NYISO presented a Carbon Pricing Straw Proposal

- Add a carbon charge to NYISO's commitment, dispatch, and settlement
- Carbon price determined by the NYPSC (presumably consistent w/ its social cost of carbon)
- Return residuals from emitting resources to customers

But would carbon pricing substantially increase customer costs?

Study Scope and Approach

IPPTF Issue Track 5 Scope: Estimate Effects of Carbon Pricing

- Estimate effects on customer costs and emissions from Carbon Pricing Straw Proposal (as discussed within the IPPTF)
- NYISO retained Brattle to help conduct the analysis

Analytical Approach

- NYISO staff to run GE-MAPS to evaluate effects on dispatch, emissions, and LBMPs
- Base case reflects "most likely" conditions with CES and RGGI and other existing policies (alternative scenarios shown at end)
- Freeze hourly external transactions (MWh) from base case, consistent with Straw Proposal, to make the economics of external transactions unaffected by carbon
- Evaluate 2020, 2025 and 2030; 2020 was chosen before the NYISO concluded that carbon pricing would not be implemented before Q2 2021; 2020 analysis can be interpreted as an approximation of when carbon pricing is first implemented
- Include dynamic supply responses
- Compare change cases with carbon charge to base case without carbon charge

Study Conclusions

Although LBMPs increase with a carbon charge, there are several offsetting customer benefits quantified

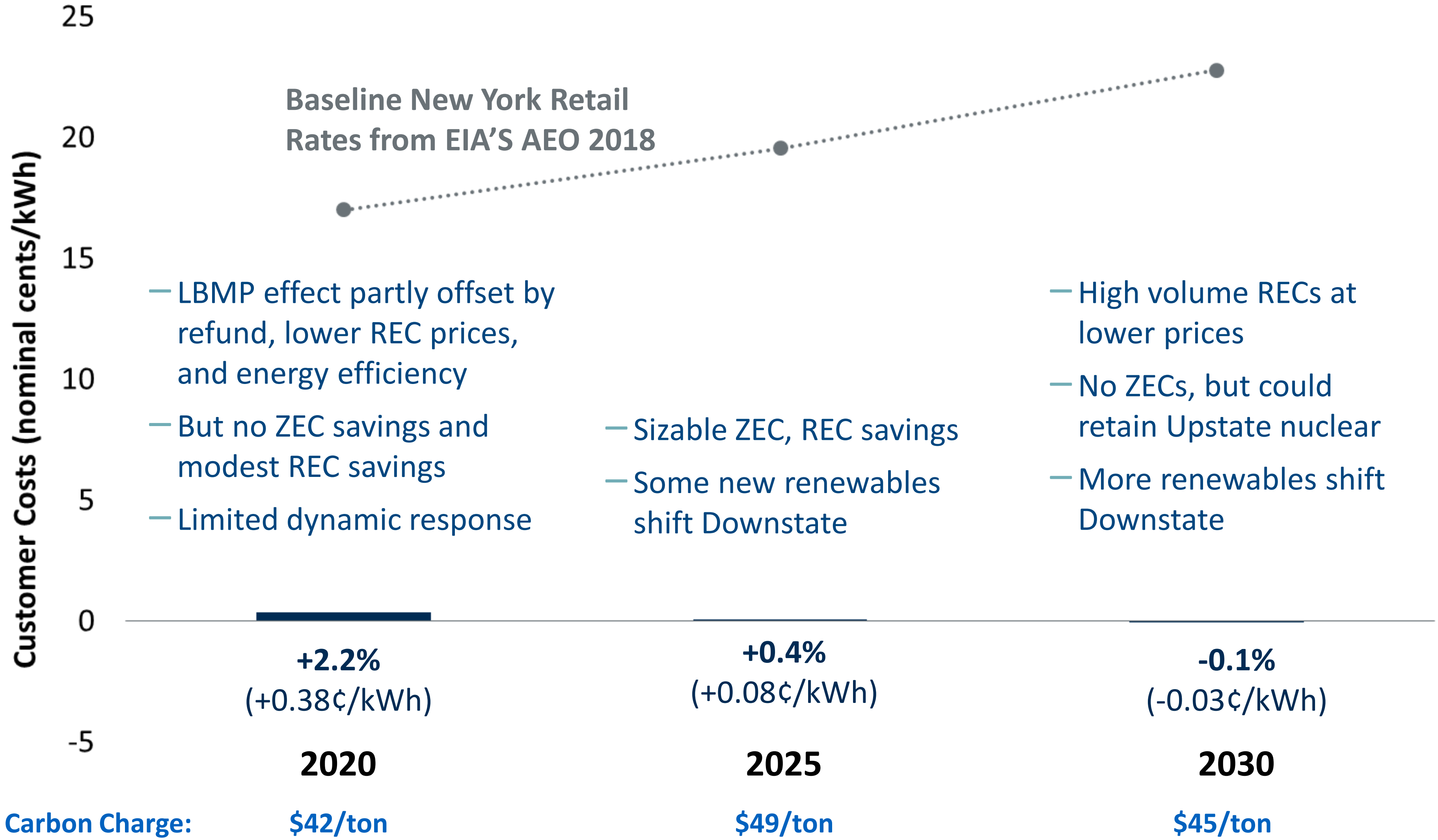
- Customer credit from emitting resources
- Lower REC and ZEC prices
- Increased value of TCCs
- Shift of new renewables to regions with higher CO_2 emissions to displace
- Possible retention of some Upstate nuclear in 2030
- Possible incremental investment in renewables
- Some incremental energy efficiency and conservation

On net, we estimate that a carbon charge would have a minor effect on customer costs, especially in the long run as supplies adjust

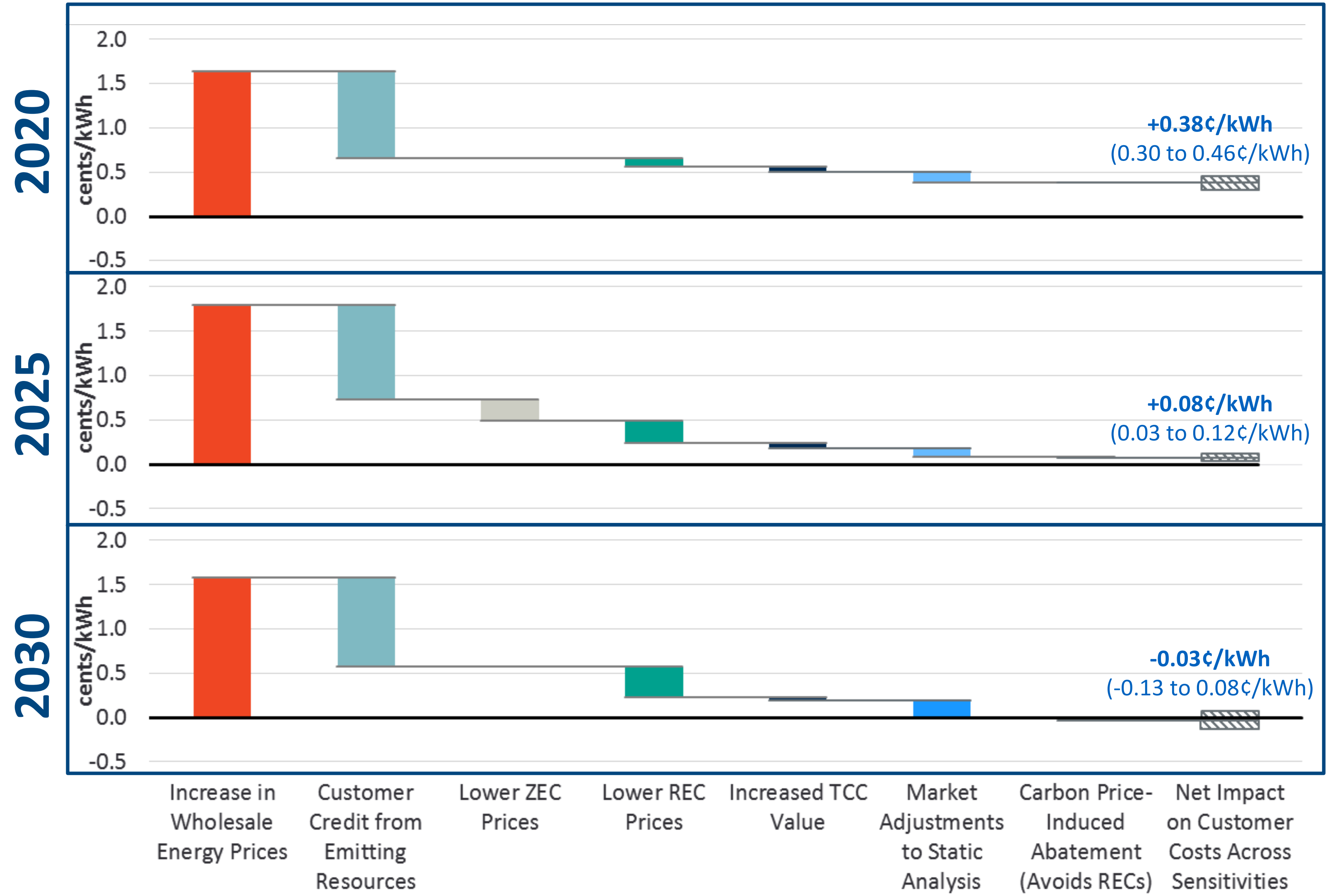
Benefits could increase with more innovative emissions reductions the market might produce in response to prices (but not captured in the analysis), such as:

- Increased investment in low-cost renewable generation as technologies evolve
- Increased investment and activity of storage to move load from high to low-emitting hours
- Efficiency improvements to the existing fleet, and in any new investment in fossil generation

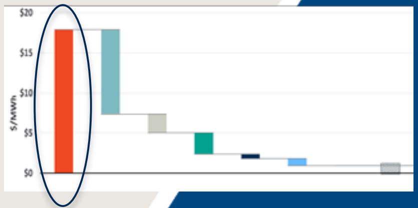
Effects on Customer Costs
compared to existing policies alone



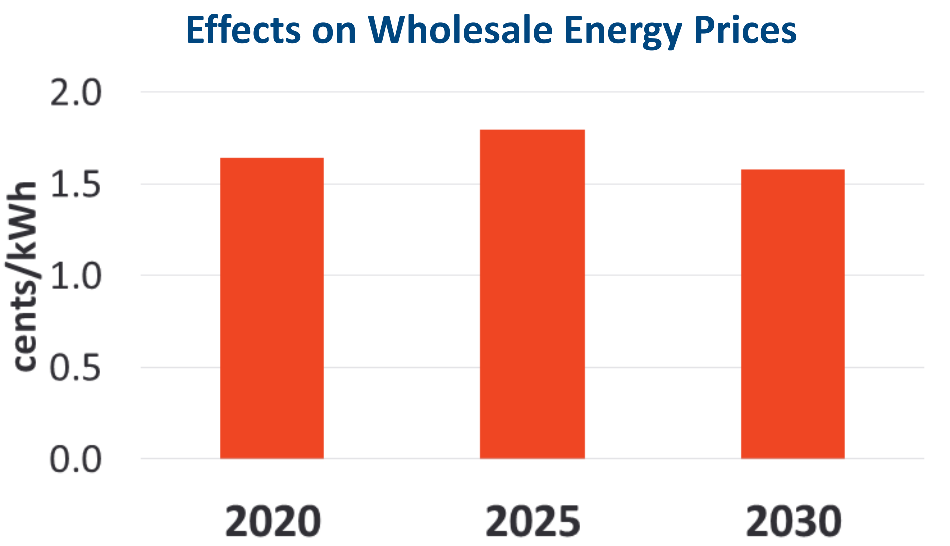
Effects on Customer Costs



Effects on Wholesale Energy Prices

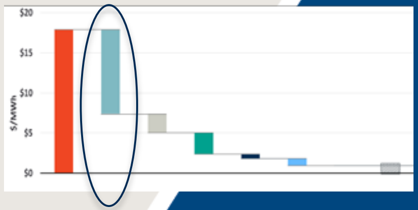


- LBMPs increase with carbon charges *times* marginal emission rates (MERs)
- MERs decline over time with greater renewable generation and declining load
  - 2020: 0.35 ton/MWh Upstate; 0.42 Downstate
  - 2025: 0.31 ton/MWh Upstate; 0.39 Downstate
  - 2030: 0.30 ton/MWh Upstate; 0.37 Downstate
- Carbon charges are fairly steady with rising SCC offset by rising RGGI prices (per current CARIS assumptions)
  - 2020: \$47 SCC – \$6 RGGI = \$42/ton
  - 2025: \$57 SCC – \$8 RGGI = \$49/ton
  - 2030: \$69 SCC – \$24 RGGI = \$45/ton
- Modest direct effect on commitment and dispatch due to limited fuel switching and locked imports (before dynamic effects)



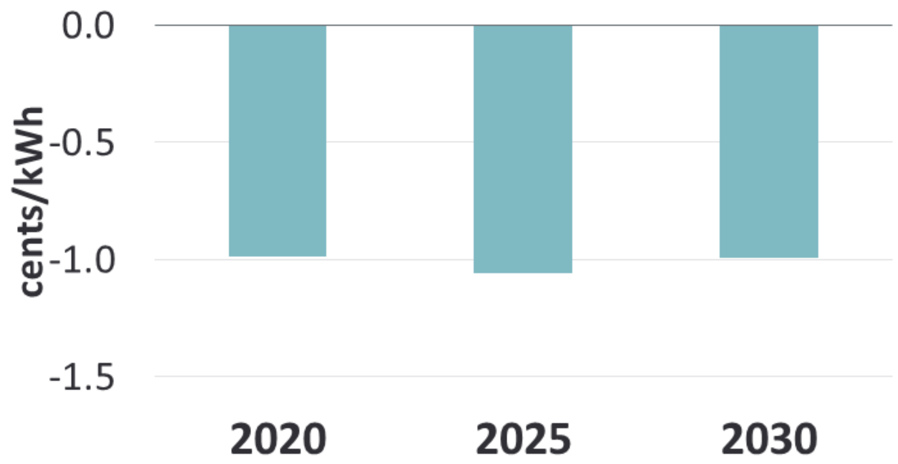
Note: The RGGI prices assumed in our analysis (based on CARIS assumptions) are similar in 2020 and 2025 to those included in NYISO's Carbon Pricing Draft Recommendations report (projected by RGGI, Inc.) but much higher in 2030 (\$24/ton versus \$13/ton).

Customer Credits from Emitting Resources

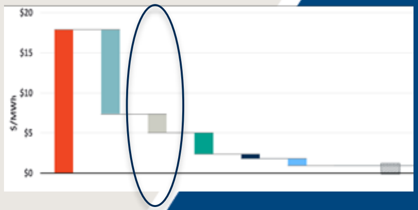


- Customer credit reflects carbon charge *times* total emissions
  - 2020: \$42/ton × 29 million tons
  - 2025: \$49/ton × 25 million tons
  - 2030: \$45/ton × 21 million tons
- Amounts trend similarly to changes in LBMPs, offsetting ~60% of wholesale price effect
  - Reflects total or average fleet emission rates, which are less than marginal rates, due to non-emitting generation
  - 2020 to 2025 increases slightly as rising carbon charge is partially offset by lower total emissions
  - Decrease by 2030 due to CES renewable additions and declining load
- Translates to bill savings by dividing total residuals among all 144-156 TWh of annual energy consumption
  (we express all savings categories this way)

Customer Credit from Emitting Resources

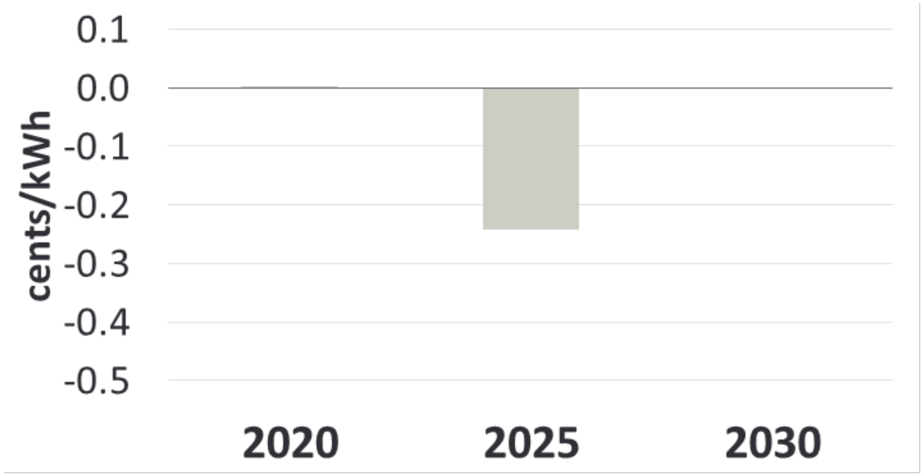


Lower ZEC Prices



- ZEC savings only occur in 2025
- 2020 prices (LBMPs+ capacity) are less than the $39/MWh threshold even with a carbon charge, so no indexing of ZEC prices to changes in LBMPs
- 2025 prices rise from $38/MWh to $52/MWh with carbon charge, reducing ZEC prices by $13/MWh
- ZEC program expires after 2029

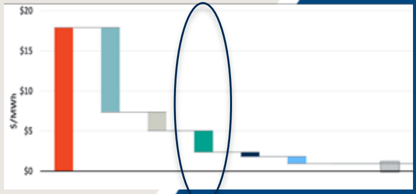
Customer Benefit from Lower ZEC Prices



Clean Energy Standard ZEC Price Equation

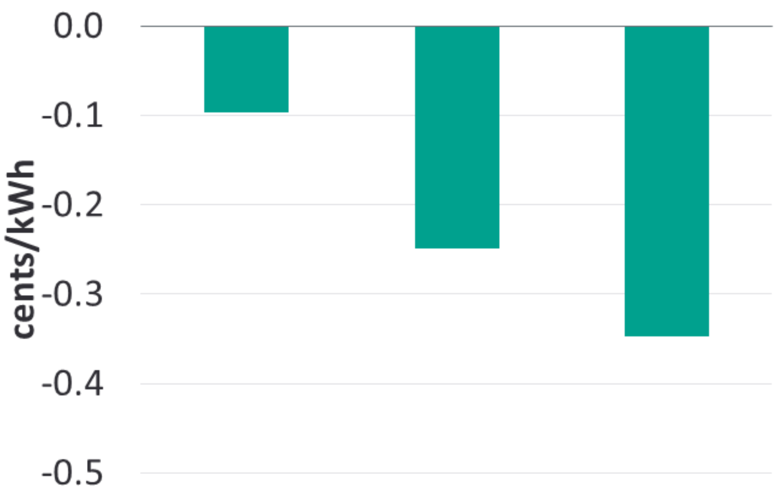
Social Cost of Carbon - **Baseline RGGI Effect** - **Amount Zone A Forecast Energy Price and ROS Forecast Capacity Price combined exceeds $39/MWh** = **ZEC Price ($/MWh)**

Lower REC Prices



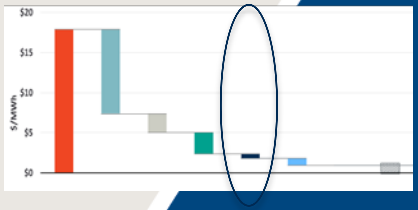
- REC savings reflect REC purchases *times* the change in REC price due to carbon charge
- This adjustment applies in one form or another to all renewables except those whose REC contracts have expired
  - 9 TWh in 2020
  - 21 TWh in 2025
  - 32 TWh in 2030
- Carbon charges reduce REC prices from base case REC prices of $22-28/MWh
  - -$19/MWh in 2020 and 2025
  - -$16/MWh in 2030

Customer Benefit from Lower REC Prices



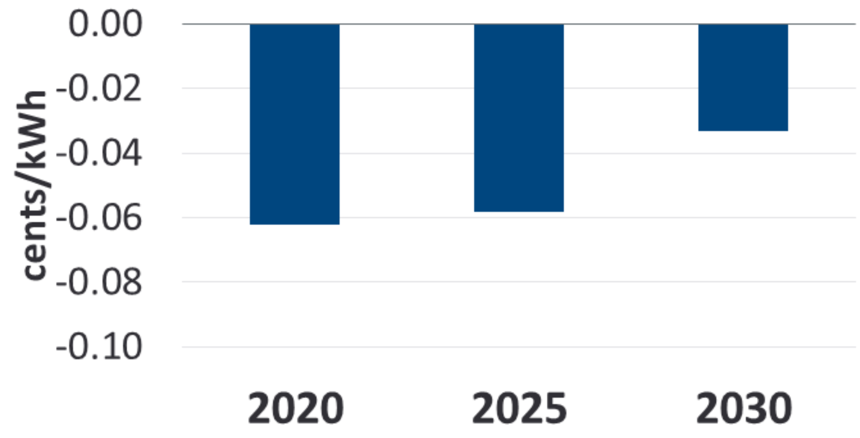
Sources and notes: Pre-2020 REC contract expiration based on NYSERDA, New York State Renewable Portfolio Standard: Annual Performance Report Through December 31, 2016 Final Report, Appendix B, March 2017. Shows 2.8 TWh expired by 2020 and 4.9 TWh by 2025 and 2030.
See slide 26 for more details on REC quantities that are assumed to be subject to offsets.

Increased Value of TCCs



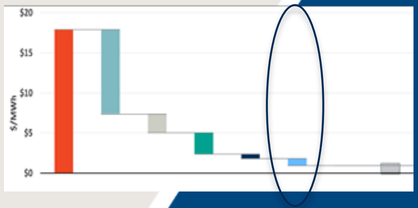
- Value of TCC contracts reflect change in NYISO congestion with carbon charge
- Base Case Congestion on Central East is steady at $290-$320 million, similar to historical congestion, due to several offsetting factors:
  - Growing Upstate renewable generation and declining load more than offset by loss of nuclear in Ontario and Upstate (reducing the difference in Market Heat Rate across Central East)
  - But rising gas prices increase the shadow price when Central East binds
- With carbon pricing applied to declining MER differential across CE, the effect of carbon pricing on Up-Down differentials and TCC values decreases over time
- Assume all congestion rents accrue to load

Customer Benefit from Increased TCC Value



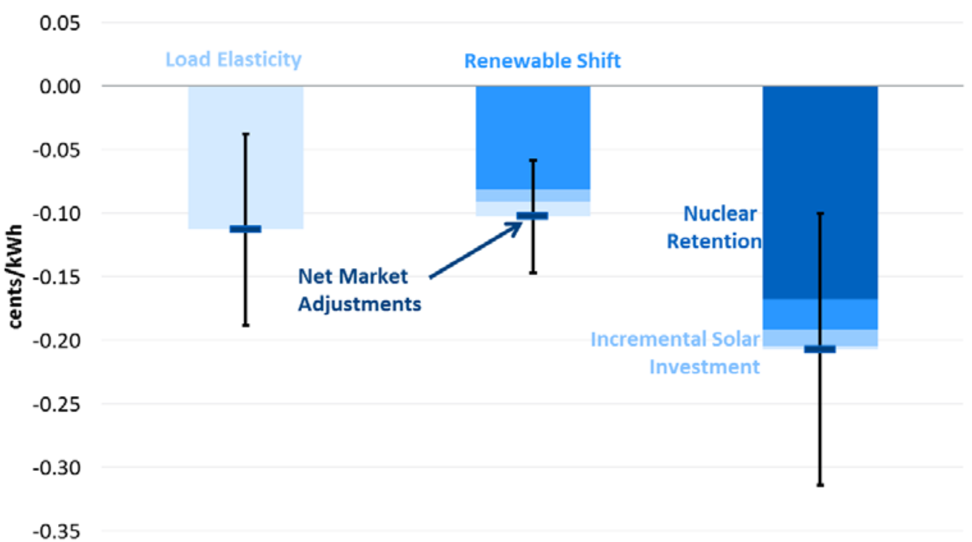
Source: total congestion costs on all NY constraints in GE-MAPS runs

Dynamic Market Adjustments



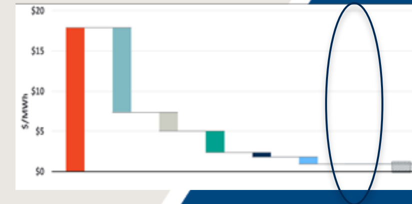
- In 2020, higher prices induce energy efficiency and conservation, reducing peak load by 320 MW and total demand by 1.5 TWh
- In 2025, assume 75% chance that 1.9 TWh of renewables (equiv. to ~1,400 MW PV) shift Downstate to re-equilibrate from increase in Downstate premium; 10% chance additional 600 MW PV enter
- In 2030, 50% chance carbon charge retains Upstate nuclear; 75% chance 2.5 TWh of renewables (~1,900 MW PV) shift Downstate; 20% chance additional 580 MW PV enter

Customer Benefit from Dynamic Adjustments



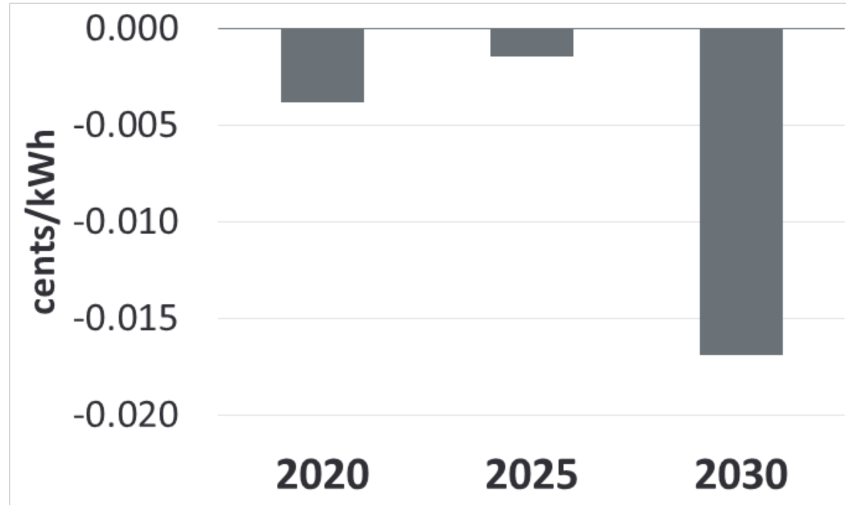
Notes: Details shown on slides 22-23.
To avoid overstating the effects, we analyze each sequentially given the expected value of prior effects (which diminishes the remaining price signal for subsequent adjustments).
Estimates account for effects on not only energy and capacity prices, but also secondary reductions in customer credits from emitting resources and from REC, ZEC, and TCC effects.
Error bars reflect a range of assumptions regarding induced changes to the supply mix and demand elasticity, as shown on slide 23.

Incremental Emissions Reductions or Avoided RECs

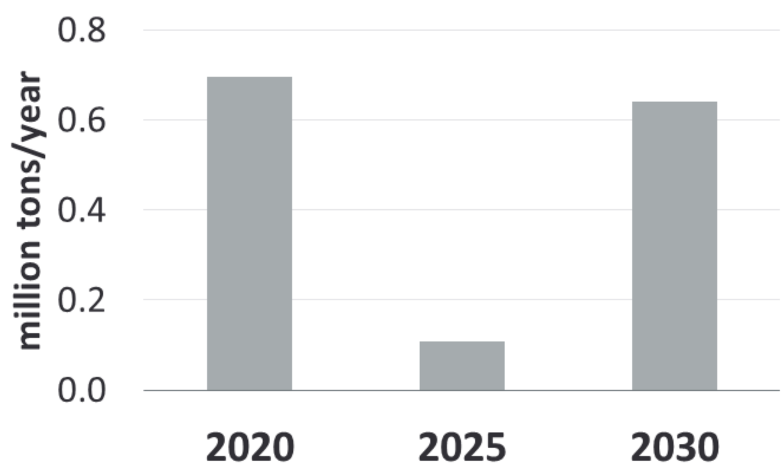


- Carbon charges lead to incremental internal emissions reductions of 3% by 2030 (-0.6 million tons from a baseline of 21 million tons internal emissions)
  - Limited fuel switching in MAPS runs due to addition of carbon charge
  - Most emission reductions from dynamic effects, including price-responsive load, renewable shifts, and possible nuclear retention
  - Reductions could be greater if the market finds innovative solutions we did not model (e.g., more low-cost renewables and storage, efficiency gains in the fossil fleet)
- Can translate avoided emissions into customer savings if they are going beyond CES to meet decarbonization goals, and now they can buy fewer RECs
- REC prices with carbon charges are \$3/MWh in 2020, \$7 in 2025, and \$12 in 2030

Customer Benefit from Reduced RECs



Emissions Reductions from Carbon Charge



Agenda

Assessment of the Effects of Carbon Charges on Customer Costs (NYCA-wide)

Analytical Details

- Analytical approach
- Key inputs
- Snapshot of market prices before adding carbon charge
- Static and dynamic effects of a carbon charge
- Summary of costs and other metrics

Next Presentation: Zonal Effects and Seams

Framework for Analysis

Difference shows the *static effect* of a carbon charge on dispatch, prices, and emissions

Base Case

From CARIS data, updated and extended

Static Carbon Charge Case

Add carbon charge of \$42 - \$49/ton (based on SCC and RGGI prices)

Dynamic Carbon Charge Case

Add assumed changes to fleet & load (based on offline analysis and MAPS results)

Difference shows the total effect of a carbon charge, including *dynamic effects*

Key Assumptions
(for Base Cases, before adding carbon charges)

Assumptions based primarily on CARIS, with a few differences to produce a "most likely" scenario

Year	New Renewable Resources	Nuclear Plants
2020	CARIS, mostly onshore renewables	Indian Point retired in 2020/21
2025	400 MW off-shore wind, assume fewer new on-shore renewables	Indian Point retired in 2020/21
2030	1,300 MW off-shore wind	2,700 MW of Upstate nuclear retire by 2030

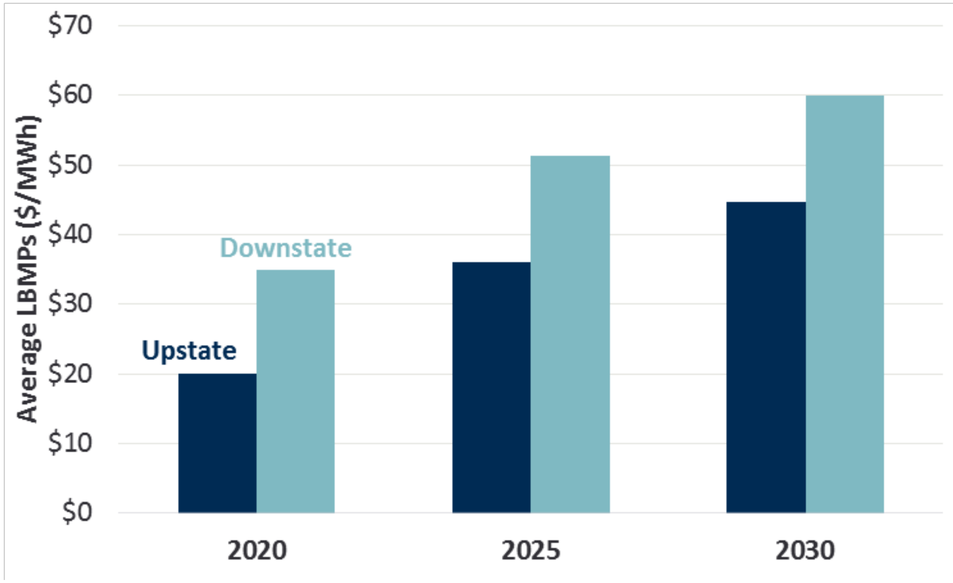
Also analyzed alternative scenarios as discussed with IPPTF5

- **2025 with alternative low and high load**
- **2030 with alternative assumptions re offshore wind (OSW) and Upstate nuclear**
  - A. 250 MW OSW ; all Upstate nuclear plants online ("Lo OSW / Hi Nuclear")
  - B. 2,400 MW OSW; all Upstate nuclear plants online ("Hi OSW / Hi Nuclear")
  - C. 250 MW OSW; NMP2 & Fitz online; Ginna & NMP1 retired ("Lo OSW / Med Nuclear")

Snapshot of Energy Market
(before adding carbon charges)

- Base case energy prices increase over time with rising gas prices
- Other factors are nuclear retirements, Ontario imports, and new renewables, and declining load, but these partially offset each other (see slide 26)

Average LBMPs by Region and Scenario ($/MWh)



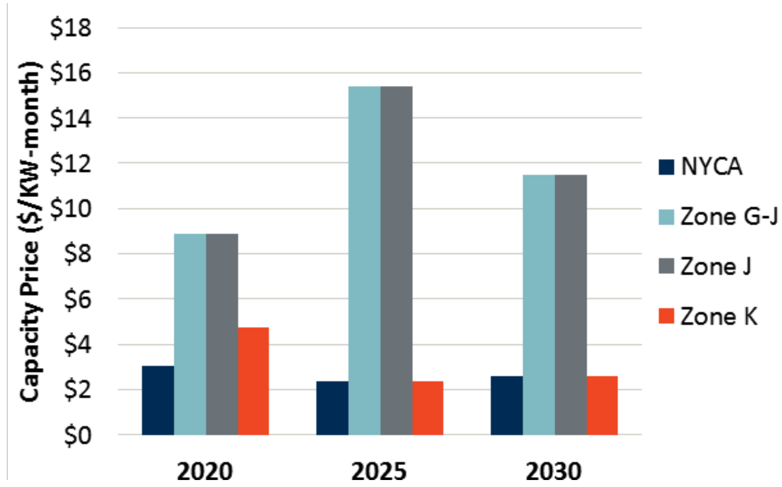
Source and Notes: Based on results from GE-MAPS runs. Prices are simple averages of hourly prices for each zone that are then weighted by load across Upstate (A-E) and Downstate (F-K) zones.

Snapshot of Capacity, RECs, and ZECs
(before adding carbon charges)

Capacity Prices

- NYCA prices remain low around $2/kW-mo
- Prices rise in G-J following Indian Point retirements, but remain lower than CC Net CONE
- Excludes capacity price effects of Downstate retirements due to pending DEC NOx rule

Capacity Price by Region and Year



REC and ZEC Prices

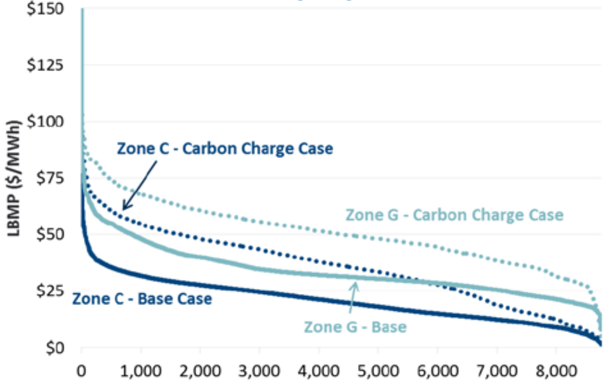
- 2018-2020 REC prices are about $18-22/MWh
- NYSERDA assumes $24-25/MWh RECs in 2024;[1] we assume this value remains constant in real terms through 2030
- Projected ZECs prices of $20-25/MWh based on energy and capacity prices in Zone A and projected RGGI prices

Sources: 1. NYSERDA, Offshore Wind Policy Options Paper, Jan 29, 2018.

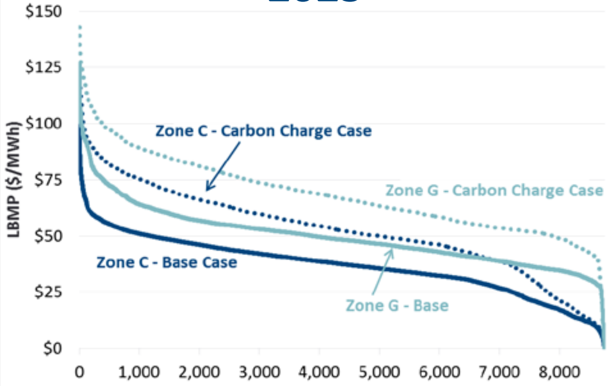
Static Price Effects of Carbon Charges

Price Duration Curves for Zones C & G for Base Case and Carbon Charge Case

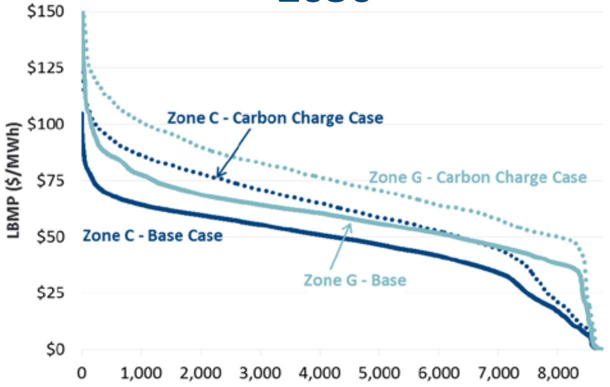
2020



2025



2030



Dynamic Market Adjustments

We evaluated four changes in the resource mix and demand due to the carbon charge

Dynamic Effect	Concept	Analytical Approach
Nuclear Retention	Increased Upstate prices could retain nuclear plant in 2030	• Value quantified as difference in customer costs in MAPS runs with and without nuclear units • Assume 50% likelihood of nuclear retention due to carbon charge
Shift Renewables Downstate	Increased Downstate energy price premium causes some new renewables to shift from Upstate	• Observe how much a carbon charge plus the expected effect of nuclear retention increases the Downstate energy price premium • Shift sufficient capacity to erode the increase using MAPS to inform the changes in LBMPs from shifting capacity • Assume 75% likelihood of investment shift in 2025 and 2030
Incremental Solar Investment	If solar becomes so economic that REC prices fall to/near zero, a carbon charge could induce investment of solar beyond the amount mandated by the CES	• Observe how much a carbon charge plus the expected effects of the nuclear retention and renewable shift increase solar revenues in Zone G • Assume some of the increased solar revenues reduce REC prices to zero and then provide an extra profit of $5/MWh • Add enough incremental PV to erase that gain using MAPS to inform the changes in LBMPs from adding incremental solar capacity in Zone G • Assume 10% chance in 2025 and 20% in 2030 of PV being sufficiently economic w/o RECs
Load Elasticity	Customers adjust consumption due to higher/lower rates with a carbon charge	• Observe the change in customer costs, net of expected dynamics; assume all costs/credits apply to all customers on a per-kWh basis • Assume customers' average elasticity of demand is -0.3 • Estimate reduction in LBMPs based on 2025 high/low load MAPS runs

Dynamic Effects (cont.)

Dynamic Effect	Year	Change due to Carbon Charge and prior Dynamic Effects	Market Adjustment (Change in Capacity/Load)	Uncertainty Range
Nuclear Retention	2030	Nuclear Revenues +$107/kW-year	50% likelihood of retaining 880 MW of Upstate nuclear *(440 MW expected value*)	25 to 75% likelihood
Shift Renewables Downstate	2025	Downstate Premium +$4/MWh	75% likelihood of shifting 1.9 TWh Downstate *(1.4 TWh expected value*)	50 to 100% likelihood
	2030	Downstate Premium +$6/MWh	75% likelihood of shifting 2.5 TWh Downstate (*1.8 TWh expected value)*	
Incremental Solar Investment	2025	Zone G Solar Revenues +$18/MWh	10% likelihood of an incremental 604 MW of PV *(60 MW expected value)*	0 to 2x
	2030	Zone G Solar Revenues +$16/MWh	20% likelihood of an incremental 579 MW of PV *(116 MW expected value*)	
Load Elasticity	2020	Customer Costs +0.50 ¢/kWh	-0.3 elasticity lowers system peak 323 MW, energy 1,470 GWh	-0.1 to -0.5 elasticity of demand
	2025	Customer Costs +0.09 ¢/kWh	-0.3 elasticity lowers system peak 54 MW, energy 220 GWh	
	2030	Customer Costs -0.01 ¢/kWh	-0.3 elasticity *raises* system peak 3 MW, energy 40 GWh	

Dynamic Effects (cont.)

Other dynamic effects are possible but not quantified here:

- Innovations that market prices may stimulate but we cannot anticipate
- Increased investment in efficient new CCs vs. existing/new CTs
  - Our analysis indicates that carbon charges provide only a small increase in CC net revenues, but that could depend on location-specific gas prices and market heat rates
  - Investment more likely in combination with pending NOx rule
- Increased investment in and utilization of energy storage
- Efficiency improvements in the existing fleet

Summary of Customer Cost Effects

	2020	2025	2030
STATIC ANALYSIS (cents/kWh of load)			
I. Increase in Wholesale Energy Prices	**1.64**	**1.79**	**1.58**
II. Customer Credit from Emitting Resources	**(0.99)**	**(1.06)**	**(0.99)**
III. Lower ZEC Prices	**0.00**	**(0.24)**	**0.00**
IV. Lower REC Prices	**(0.10)**	**(0.25)**	**(0.35)**
V. Increased TCC Value	**(0.06)**	**(0.06)**	**(0.03)**
Subtotal	**0.50**	**0.18**	**0.20**
DYNAMIC ADJUSTMENTS (cents/kWh of load)			
VI. Market Adjustments to Static Analysis	**(0.11)**	**(0.10)**	**(0.21)**
A. Nuclear Retention	**0.00**	**0.00**	**(0.17)**
Retained Nuclear (MW)	*0*	*0*	*882*
Assumed Likelihood	*0%*	*0%*	*50%*
B. Renewable Shift Downstate	**0.00**	**(0.08)**	**(0.02)**
RE Shift Downstate (TWh)	*0.0*	*1.9*	*2.5*
Assumed Likelihood	*0%*	*75%*	*75%*
C. Incremental Renewable Entry	**(0.00)**	**(0.01)**	**(0.01)**
Incremental PV Entry (MW)	*0*	*604*	*579*
Assumed Likelihood	*0%*	*10%*	*20%*
D. Load Elasticity	**(0.11)**	**(0.01)**	**(0.00)**
Peak Load Reduction (Increase) (MW)	*323*	*54*	*(3)*
Annual Load Reduction (Increase) (GWh)	*1,469*	*218*	*(41)*
Assumed Likelihood	*100%*	*100%*	*100%*
VII. Carbon Price-Induced Abatement (Avoided RECs)	**(0.00)**	**(0.00)**	**(0.02)**
million tons of abatement	*0.7*	*0.1*	*0.6*
Subtotal	**(0.12)**	**(0.10)**	**(0.23)**
TOTAL EFFECT (cents/kWh of load)			
Net Change in Customer Costs	**0.38**	**0.08**	**(0.03)**
Range Accounting for Uncertainty in Dynamic Effects	**0.3 to 0.46**	**0.03 to 0.12**	**-0.13 to 0.08**

Summary of Key Metrics

	2020	2025	2030
KEY ASSUMPTIONS & OUTPUTS			
SCC ($/ton)	$47	$57	$69
RGGI Price ($/ton)	$6	$8	$24
Carbon Charge ($/ton), >25MW	$42	$49	$45
NYCA Load (TWh)	156.1	150.1	143.9
Upstate Nuclear (TWh)	26.1	27.4	9.7
Downstate Nuclear (TWh)	10.9	0.0	0.0
Total Renewables (TWh)	12.1	26.1	37.0
Upstate Wind/Solar (TWh)	8.0	18.3	22.1
Downstate Wind/Solar (TWh)	0.6	2.9	9.4
Pre-2020 REC Contracts Not Receiving Carbon LBMP (TWh)	4.6	2.7	2.6
Distributed PV with Offsets to Carbon LBMP (TWh)	2.8	4.0	4.6
Renewables Added After 2020 with Indexed REC (TWh)	1.8	14.5	24.8
Net Imports (TWh)	24.6	19.7	29.5
Upstate LBMP, base case ($/MWh)	$20	$36	$45
Downstate LBMP, base case ($/MWh)	$35	$51	$60
Central East Congestion, base ($ million)	$289	$314	$317
Central East Congestion, simple change ($ million)	$344	$364	$343
ZEC price, before carbon charge ($/MWh)	$20	$25	$0
ZEC price, after carbon charge ($/MWh)	$20	$12	$0
REC price, before carbon charge ($/MWh)	$22	$25	$28
REC price, after carbon charge ($/MWh)	$3	$7	$12
NYCA CO2 Emissions, base case (million tons)	29.0	25.4	21.2
NYCA CO2 Emissions, simple change case (million tons)	28.5	25.3	21.2
System CO2 Emissions, base case (million tons)	348.3	446.6	448.0
System CO2 Emissions, simple change case (million tons)	348.2	445.1	446.7

Analysis of Alternative Scenarios

	2020	2025			2030			
	Reference	Reference	Lo Load	Hi Load	Reference	Lo OSW / Hi Nuclear	Hi OSW / Hi Nuclear	Lo OSW / Med Nuclear
STATIC ANALYSIS (cents/kWh of load)								
I. Increase in Wholesale Energy Prices	1.64	1.79	1.76	1.81	1.58	1.36	1.34	1.50
II. Customer Credit from Emitting Resources	(0.99)	(1.06)	(1.04)	(1.07)	(0.99)	(0.80)	(0.76)	(0.91)
III. Lower ZEC Prices	0.00	(0.24)	(0.25)	(0.26)	0.00	0.00	0.00	0.00
IV. Lower REC Prices	(0.10)	(0.25)	(0.22)	(0.29)	(0.35)	(0.27)	(0.32)	(0.32)
V. Increased TCC Value	(0.06)	(0.06)	(0.06)	(0.07)	(0.03)	(0.19)	(0.14)	(0.12)
Subtotal	0.50	0.18	0.20	0.12	0.20	0.11	0.12	0.15
DYNAMIC ADJUSTMENTS (cents/kWh of load)								
VI. Market Adjustments to Static Analysis	(0.11)	(0.10)	(0.08)	(0.08)	(0.21)	(0.18)	(0.12)	(0.26)
A. Nuclear Retention	0.00	0.00	0.00	0.00	(0.17)	0.00	0.00	(0.09)
Retained Nuclear (MW)	0	0	0	0	882	0	0	1,871
Assumed Likelihood	0%	0%	0%	0%	50%	0%	0%	15%
B. Renewable Shift Downstate	0.00	(0.08)	(0.06)	(0.06)	(0.02)	(0.17)	(0.10)	(0.16)
RE Shift Downstate (TWh)	0.0	1.9	1.3	1.6	2.5	3.5	2.0	3.4
Assumed Likelihood	0%	75%	75%	75%	75%	75%	75%	75%
C. Incremental Renewable Entry	(0.00)	(0.01)	(0.01)	(0.01)	(0.01)	(0.02)	(0.02)	(0.02)
Incremental PV Entry (MW)	0	604	638	638	579	358	311	358
Assumed Likelihood	0%	10%	10%	10%	20%	20%	20%	20%
D. Load Elasticity	(0.11)	(0.01)	(0.02)	(0.01)	(0.00)	0.01	(0.00)	0.01
Peak Load Reduction (Increase) (MW)	323	54	73	32	(3)	(33)	4	(54)
Annual Load Reduction (Increase) (GWh)	1,469	218	311	123	(41)	(167)	(8)	(265)
Assumed Likelihood	100%	100%	100%	100%	100%	100%	100%	100%
VII. Carbon Price-Induced Abatement (Avoided RECs)	(0.00)	(0.00)	(0.00)	(0.00)	(0.02)	(0.02)	(0.01)	(0.02)
million tons of abatement	0.7	0.1	0.3	0.3	0.6	0.4	0.3	0.5
Subtotal	(0.12)	(0.10)	(0.09)	(0.08)	(0.23)	(0.20)	(0.13)	(0.28)
TOTAL EFFECT (cents/kWh of load)								
Net Change in Customer Costs	0.38	0.08	0.11	0.04	(0.03)	(0.10)	(0.01)	(0.13)
Range Accounting for Uncertainty in Dynamic Effects	0.3 to 0.46	0.03 to 0.12	0.07 to 0.15	0.01 to 0.08	-0.13 to 0.08	-0.17 to -0.02	-0.07 to 0.05	-0.25 to -0.02

Notes: scenario descriptions provided on slide 18; dynamic effects explained on slides 14 and 22-23. Costs are expressed in nominal terms.

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