Benefit-Cost Analysis of Proposed New York AC Transmission Upgrades

PRESENTED TO

NYISO and DPS Staff

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I. Problem Statement
Motivation for AC Transmission Upgrades

Needs identified: Recent studies have highlighted the need for the NY transmission system to be upgraded to replace aging infrastructure and to increase transfer capability into SENY

Benefits not fully addressed by CARIS: The existing approach for identifying economic projects through the NYISO Congestion Assessment and Resource Integration Study (CARIS) has not identified projects to be built due to its limited scope of benefits considered

- CARIS considers a narrow range of benefits, focusing solely on base case production cost savings over only a 10-year time horizon
- Some other benefits (i.e., reduced losses, capacity value, emissions reductions) are calculated but not incorporated into the benefit-cost analysis
- Evaluating new transmission beyond standard reliability planning criteria requires a consideration of a wide-range of benefits that transmission can provide to the system (*see 2013 WIRES report*)

Do transmission (Tx) projects provide net economic benefits if benefits are evaluated more broadly?

Source: Chang, Pfeifenberger, and Hagerty, " The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," WIRES and The Brattle Group, July 2013, online at: http://www.wiresgroup.com/res_benefits_of_transmission.html ("2013 WIRES Report")

I. Problem Statement
PSC AC Transmission Initiative

Public Service Commission (PSC) initiated a proceeding to examine potential transmission solutions to congestion identified at the Central East and UPNY-SENY bulk electric system interfaces

- In August 2014, the PSC identified a wide-range of benefits to be considered and solicited proposals from stakeholders
- In September 2014, the solicitation resulted in the submissions of transmission portfolios intended to meet the needs identified by the PSC with the capability of adding 1,000 to 1,200 MW of transfer capability to the UPNY/SENY interface as identified by the PSC
- In July 2015, the Department of Public Services (DPS) Trial Staff filed an interim report with the PSC that analyzed the 22 proposed portfolios based on their *environmental compatibility* and *electric system impacts* and identified 7 portfolios for further evaluation

DPS asked NYISO and The Brattle Group to help evaluate the benefits and costs of the proposed transmission portfolios

Overview of Benefit-Cost Analysis

We developed a framework for calculating the benefits and costs of the proposed transmission portfolios and two non-transmission alternatives against a "do nothing" Business-as-Usual case

Scope of solutions considered:

- Transmission portfolios proposed through solicitation process
- A comparable generation solution based on an approach similar to CARIS
- A portfolio of resources pursued through the Reforming the Energy Vision (REV) proceedings

Solutions evaluated:

- We initially evaluated the benefits of all 22 proposed Tx portfolios, the Generation solution, and the REV portfolio prior to the release of the DPS interim report and the CPV Valley announcement in July 2015
- Since the release of the interim report, we updated the analysis to focus on 9 portfolios selected by DPS (7 from interim report plus 2 additional portfolios requested by DPS) and the REV resources, accounting for the expected addition of 670 MW CPV Valley in Zone G
- The Generation solution showed minimal benefits during the initial analysis without CPV Valley, therefore the analysis was not updated with CPV Valley

In this report, we provide the updated results (*with CPV Valley*) in the main body of the report and the prior results (*without CPV Valley*) in the Appendix

I. Problem Statement

Scope of Benefit-Cost Analysis

Costs and benefits considered

- We analyzed a wide range of potential benefits for each solution compared to "no action"
- DPS provided capital cost and revenue requirement (RevReq) estimates for the Tx portfolios; we calculated generation costs based on NYISO's last demand curve reset, and REV costs based on a recent report done for DPS

Types of evaluation metrics

- From a societal perspective, we calculate benefits and costs based on the total costs either incurred or avoided (e.g., production costs savings, not LBMP impacts); for quantified benefits and costs, we present an NPV and benefit-to-cost ratio ("B:C ratio") over the economic life of each solution
- From a ratepayer perspective, we calculate benefits and costs based on the additional transmission revenue requirements added to ratepayers bills, and the impacts on generation charges accounting for wholesale energy and capacity market impacts

Scenarios and sensitivities

- Calculated the sensitivity of our analysis to key assumptions for each benefit analyzed
- Potential retirement of Indian Point (and other potential retirements) handled as a separate scenario

All present value calculations in this presentation are shown in 2015 dollars.

All other monetary values discussed are in nominal dollars unless stated otherwise.

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II. Solutions Analyzed

Transmission Portfolios Evaluated

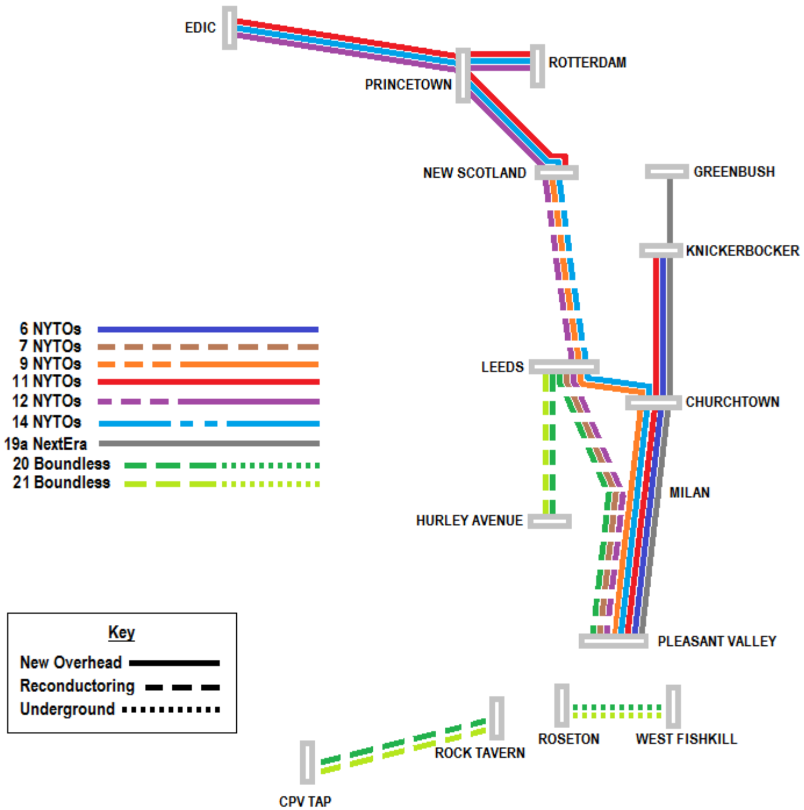
DPS requested detailed cost-benefit analysis of the 9 Tx portfolios listed below following the release of the interim report in July 2015

Summary of Transmission Portfolio Characteristics

Portfolio	Components	UPNY-SENY Normal N-1 Impact	UPNY-SENY Emergency N-1 Impact	Central East Voltage Impact
P6 - NYTO	KN-PV	918	1,686	50
P7 - NYTO	LD-PV reconductor	352	1,404	25
P9 - NYTO	NS-LD reconductor, LD-PV	1,038	2,091	50
P11 - NYTO	Edic-NS, KN-PV	939	1,621	375
P12 - NYTO	Edic-NS, NS-LD reconductor, LD-PV reconductor	432	1,341	375
P14 - NYTO	Edic-NS, NS-LD reconductor, LD-PV	1,136	2,286	375
P19a - NextEra	GB-KN-CH-PV	961	1,747	50
P20 - Boundless	NS-LD SR, (LD-PV, L-H, CPV-RT reconductor), LD-HA-R SC, RS-EF two cables	15	1,753	-25
P21 - Boundless	P20 minus LD-PV reconductor	-81	1,433	-25

Note: At request of DPS, we assume Athens SPS is removed in 2019 once the new facilities are energized. While Athens SPS is in effect, Leeds-PV and Athens-PV can reach their STE ratings following the loss of a parallel circuit, assuming there is sufficient Athens generation to guarantee flows return to or below their LTE ratings within 15 minutes.

Schematic of Transmission Portfolios



(*See Appendix for acronym definitions*)

II. Solutions Analyzed

Generation Solution

Developed alternative generation solution based on 2013 CARIS approach, with capacity similar to the increase in UPNY/SENY transfer capability provided by the Tx portfolios of 1,000 MW – 1,200 MW

- Added four 330 MW Combined Cycle units, for a total of 1,320 MW
  - 330 MW units are used for generic CC units in 2013 CARIS
- Units spread across Zone G high load buses
- 7,000 Btu/kWh full load heat rate
- 25-year economic life

Alternative 45-Year economic life case: Evaluated an alternative 45-year economic life case that assumes fixed O&M costs continue at the same annual rate (although they would typically be expected to increase) for an additional 20 years, while enjoying 20 more years of benefits

Note: The Generation solution was only analyzed for the case without CPV Valley and showed negative net benefits. It is anticipated that with CPV Valley, net benefits would not be better and therefore we did not re-analyze the Generation solution with CPV Valley. We thus present only the without-CPV Valley analysis results in the Appendix.

II. Solutions Analyzed

REV Resources Solution

Identified portfolio of REV resources capable of reducing SENY peak load by 1,200 MW based primarily on Generic Environmental Impact Statement (GEIS) "Lower" scenario

- Distributed REV resources among Zones G-J based on current penetration and potential for future growth
  - Started with near- to mid-term potential of REV resources from GEIS and distributed each resource across NY zones based on current and forecast levels of capacity impact from Gold Book long-term forecast and other sources (using the current capacity impact only if a forecast was not available)
  - Resulting capacity grossed up to 1,200 MW, keeping resource mix and distribution among zones constant
- Energy savings based on LBMPs from GE-MAPS Base Case (with CPV Valley) and capacity factors from GEIS analysis; the EE capacity factor in GEIS (~75%) is higher than capacity factor implied for Zone J "energy program impacts" in Gold Book (~65%), likely overstating energy savings
- We assume resources will be phased in from 2016 – 2020 (20% of total each year, consistent with GEIS assumptions) and remain in operation over reasonable measure life

REV Portfolio Summary by Resource Type and Zone

	Capacity Savings (MW)					Annual Energy Savings (GWh)					Measure Life
Resource Type	G	H	I	J	**Total**	G	H	I	J	**Total**	years
Energy Efficiency	91	23	50	673	**838**	598	154	328	4,417	**5,497**	12
Customer-sited Renewables	23	6	5	40	**73**	31	8	7	53	**98**	25
Combined Heat & Power	1	0	0	27	**28**	4	0	0	190	**195**	20
Demand Response	7	1	5	76	**89**	0	0	0	0	**0**	10
Fossil Fuel Distributed Generation	0	0	0	0	0	0	0	0	0	0	--
Grid Integrated Vehicles	2	1	1	11	**15**	0	0	0	-1	**-2**	10
Storage (flywheel and battery)	6	2	4	29	**40**	-1	0	0	-3	**-5**	15
Rate Structures	9	2	6	100	**117**	0	0	0	0	**0**	15
Total	**139**	**34**	**71**	**956**	**1,200**	**632**	**161**	**335**	**4,656**	**5,783**	

Sources: REV GEIS. See slide 51 for sources supporting resource distribution and economic life estimates

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B. Ratepayer Impacts Analysis

C. Indian Point Retirement Scenario

D. Benefits by Project

IV. Detailed Cost Information

V. Detailed Benefit Analysis

III.A. Benefit-Cost Analysis Results: Societal Impacts

Net Benefits in Change Cases vs. Base Case

Compared Change Case with each proposed Transmission portfolio, Generation or REV Resources to a business-as-usual Base Case

- Costs reflect estimated capital costs of each portfolio, and the associated revenue requirements
- Benefits include any avoided costs and in-state tax receipts that differ from Base Case
- Costs and benefits analyzed over life of assets (45 years for Tx) and discounted to present value by applying a discount rate of 9.13% (corresponding to a pre-tax WACC) as requested by DPS
  - *Note*: The Brattle team members typically use an after-tax WACC, which would be 5.6% based on consistent assumptions; DPS's use of a higher discount rate will show lower NPV of Tx projects, since benefits tend to increase and costs tend to decrease over time (*see sensitivity analysis on slide 17*)

Summary of Base Case and Change Case Key Assumptions

	Base Case	Change Case
Transmission	Aging facilities refurbished over next 20 years (including several lines in 2020) based on 2012 STARS Report	New Tx facilities energized in 2019; may accomplish or facilitate needed refurbishments or upgrade existing lines
Generation	Capacity based on 2014 Gold Book with adjustments for recent announcements (incl. CPV Valley and capacity sales into ISO-NE); generic entry occurs when ICAP prices reach Net CONE in each capacity zone	Generation re-dispatched; no major change in supply capacity but ICAP analysis recognizes lower LCRs affecting future entry/exit locations & timing
Demand	Grows as forecasted by 2015 Gold Book through 2024 and extrapolated through 2063 at annual growth rate for 2020 – 2025	Same as Base Case
Athens SPS	Expires in 2024	Expires earlier in 2019 only with addition of Tx portfolios; same as Base Case for Generation and REV

III.A. Benefit-Cost Analysis Results: Societal Impacts

Wide Range of Benefits Considered

Analyzed a wide range of potential benefits and quantified majority of benefits considered (mostly monetarily) and provided qualitative description for benefits not easily quantified

- **Monetized benefits**: production cost savings incl. emission allowances and factors not captured in MAPS; avoided refurbishment costs of aging Tx; capacity resource cost savings due to reduced LCRs enabling the exit of existing capacity and the delay and shift of new construction; reduced net cost of RPS goals; and tax receipts (just offsetting the tax cost)
- **Quantified (but not monetized) benefits**: employment impacts, generation retirement preparedness
- **Benefits described qualitatively**: reliability, storm resiliency, planning/operational flexibility, future capacity options on existing ROW, synergies w/other future transmission projects, relieving gas transport constraints, market competition & liquidity, employment, and environmental externalities (plus and minus)

Benefit Category	Benefit Type	Monetized	Quantified	Described	Little Impact
Production Cost Savings	Traditional Production Cost Savings (PCS)	✓			
	PCS from Reduced Energy Losses	✓			
	PCS from Factors Not Modeled in MAPS	✓			
	Reduced Ancillary Service Requirements				✓
	Mitigation of Non-Market Measures				✓
Avoided Tx Refurbishment Costs	Avoided Refurbishment Costs of Aging Lines	✓			
	Addition of Parallel Path Reduces Congestion during Refurbishment of Aging Lines	✓			
Capacity Resource Cost Savings	Reduced Installed Reserve Margin (IRM)				✓
	Reduced Local Capacity Requirement (LCR)	✓			
	Generation Retirement Preparedness		✓		
RPS/CO_2 Goals	Reduced Net Cost of Meeting RPS Goals	✓			
Tax Receipts	Increased Tax Receipts	✓			
Environmental	Reduced Emissions of Air Pollutants		✓		
Economic	Employment Impact		✓		
Other Benefits	Market Benefits, Storm Hardening, Resiliency, etc.			✓	

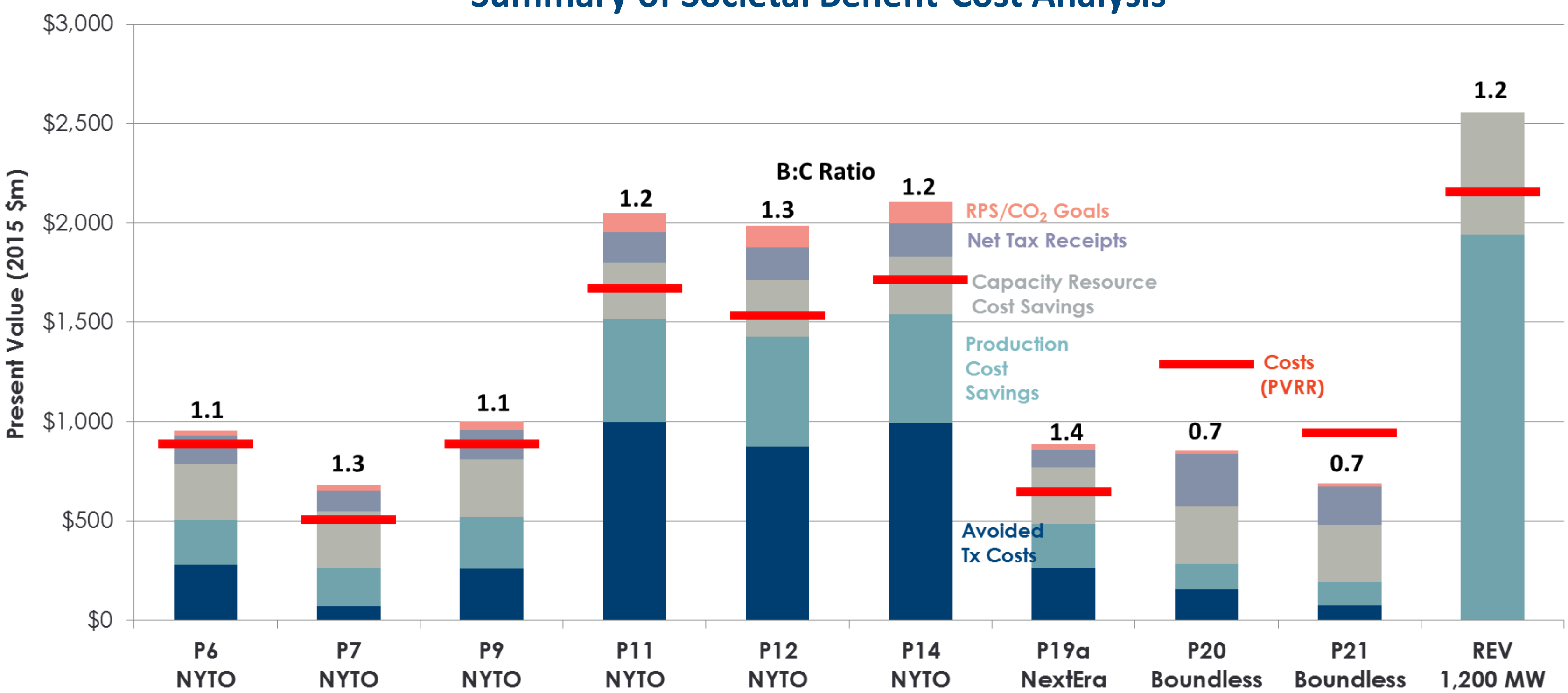
See: Chang, Pfeifenberger, and Hagerty, "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments," WIRES and The Brattle Group, July 2013, online at: http://www.wiresgroup.com/res_benefits_of_transmission.html

Societal Benefit-Cost Analysis Results

Our analysis found net societal benefits for 7 Tx portfolios and the REV resources

- P19a has the highest B:C ratio of 1.4; P12 has the highest NPV of $451m
- These projects reduce economy-wide costs to serve load and meet reliability and environmental objectives; they save fuel costs and capacity resource costs in excess of their own costs (based on DPS estimates)
- Accounting for non-monetized benefits (*see slide 16*) and a lower discount rate (*see slide 17*) would further increase net benefits of all Tx portfolios

Summary of Societal Benefit-Cost Analysis



Notes: Tx PVRRs are based on DPS's estimated 2015 capital costs, which differ from proponents' claimed costs (*see following slides*). State and local taxes shown on the benefits side cancel the non-federal taxes included in the PVRR of Tx portfolios.

Detailed Societal Results with DPS Costs

The costs and benefits of the various portfolios differ as follows:

- Portfolios that extend through Central East (P11, P12, P14) have the highest NPVs ($380– 450 million). Although they cost the most, they provide the greatest Production Cost Savings (PCS) and Avoided Tx Costs (by retiring Porter-Rotterdam, which is assumed in the Base Case to be refurbished in 2020).
- Portfolios that only add capacity along the Leeds-PV corridor (P6, P7, P9, P19a) have lower costs and lower benefits, but P19a has the highest B:C ratio of 1.4. Compared to larger projects, they provide less PCS and Avoided Tx Costs but similar Capacity Resource savings. All proposed portfolios provide similar increases in UPNY/SENY transfer capability (and those that provide slightly less prevent the G-J LCR from binding over the study period, so those that further expand transfer capability offer little incremental capacity value).
- The Boundless projects (P20, P21) achieve similar levels of benefits as the Leeds-PV upgrades but tend to be more expensive, resulting in negative NPVs

Societal Benefit-Cost Analysis assuming DPS's Costs Estimates

Portfolio	DPS Estimated Capital Cost (2015 $m)	PVRR (2015 $m)	Production Cost Savings (2015 $m)	Capacity Resource Savings (2015 $m)	Avoided Tx Costs (2015 $m)	Net RPS Costs (2015 $m)	Total Tax Benefit (2015 $m)	Total Benefits (2015 $m)	NPV (2015 $m)	B/C Ratio
P6 - NYTO	$631	$887	$221	$284	$281	$27	$142	$956	$68	1.1
P7 - NYTO	$361	$508	$194	$284	$70	$31	$104	$683	$175	1.3
P9 - NYTO	$631	$887	$262	$286	$260	$41	$151	$1,001	$114	1.1
P11 - NYTO	$1,189	$1,671	$516	$286	$998	$97	$151	$2,049	$377	1.2
P12 - NYTO	$1,090	$1,533	$554	$286	$873	$108	$163	$1,984	$451	1.3
P14 - NYTO	$1,218	$1,713	$547	$286	$995	$108	$169	$2,105	$392	1.2
P19a - NextEra	$461	$648	$221	$285	$264	$27	$87	$884	$236	1.4
P20 - Boundless	$918	$1,291	$128	$288	$157	$17	$264	$854	-$436	0.7
P21 - Boundless	$671	$944	$115	$288	$76	$17	$193	$690	-$254	0.7

Note: See slides 46-47 for the relationship between capital cost and PVRR. See Section V for the analysis of benefits.

Detailed Societal Results with Proponent Costs

Assuming proponents' cost estimates instead of DPS's slightly increases net benefits of non-NYTO projects

- B:C ratio of NextEra's portfolio P19a increases from 1.4 to 1.6
- P21's B:C ratios increases by 0.1, but both Boundless projects remain less than 1.0
- A summary of the DPS and Proponent cost estimates is shown on slide 45
- *Note*: Other than the table below, the rest of this presentation uses DPS's estimates

Societal Benefit-Cost Analysis assuming Proponents' Cost Estimates

Portfolio	Proponent Estimated Capital Cost (2015 $m)	PVRR (2015 $m)	Production Cost Savings (2015 $m)	Capacity Resource Savings (2015 $m)	Avoided Tx Costs (2015 $m)	Net RPS Costs (2015 $m)	Total Tax Benefit (2015 $m)	Total Benefits (2015 $m)	NPV (2015 $m)	B/C Ratio
P6 - NYTO	$617	$867	$221	$284	$279	$27	$138	$949	$82	1.1
P7 - NYTO	$359	$505	$194	$284	$69	$31	$103	$682	$177	1.3
P9 - NYTO	$635	$893	$262	$286	$260	$41	$153	$1,002	$109	1.1
P11 - NYTO	$1,194	$1,679	$516	$286	$998	$97	$153	$2,050	$371	1.2
P12 - NYTO	$1,105	$1,553	$554	$286	$870	$108	$167	$1,984	$431	1.3
P14 - NYTO	$1,239	$1,741	$547	$286	$991	$108	$175	$2,106	$365	1.2
P19a - NextEra	$386	$543	$221	$285	$251	$27	$66	$849	$306	1.6
P20 - Boundless	$737	$1,036	$128	$288	$112	$17	$212	$757	-$278	0.7
P21 - Boundless	$510	$716	$115	$288	$38	$17	$147	$605	-$112	0.8

Note: See slides 46-47 for the relationship between capital cost and PVRR. See Section V for the analysis of benefits.

Non-Quantified Societal Benefits

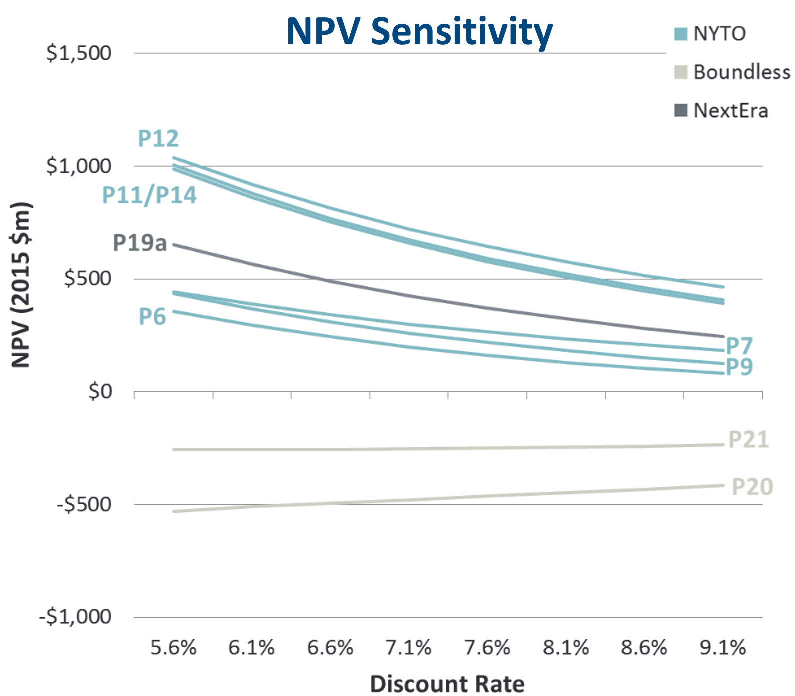
Benefit Category	Transmission	Generation	REV Resources
Protection against Extreme Conditions, including short-term operating events and long-term planning scenarios (accounting for these could increase the *expected value* of projects and the *insurance value* to risk-averse stakeholders)	Helps prevent or limit reliability and price-spike events and long term outages downstate; expected value conceptually included thru PCS multipliers, but they may not capture all possibilities; insurance value not quantified in our analysis.	Generation may also help during similar events, but provides less flexibility than Tx to rely on wide range of resources to limit cost excursions	Also protects against extremes; reducing net load is at least as good at balancing supply and demand as transmission that expands supply options
Market Benefits, including increased competition and liquidity	All projects increase competition and liquidity (access to trading Hubs)	May increase competition, depending on ownership	Net load reductions increase competition among suppliers
Storm Hardening and Resiliency	New facilities increase system resiliency due to updated construction standards; parallel path benefit may be limited for projects on existing ROW	Local resources may mitigate loss of T or G	Local load reductions and DG may mitigate loss of T or G
Maximizing Future Capacity Options on Existing ROW, e.g., by upsizing a circuit or making space for a 2nd future circuit	Most portfolios add more capacity than currently "needed" for reliability or congestion relief on existing ROW; none add space for future circuits	N/A	N/A
Synergies with Other Future Tx Projects, e.g., to deliver renewables or meet load growth	Projects extending north and west provide the most possibilities	May reduce the need for future Tx projects	May reduce the need for future transmission projects
Relieving Gas Transport Constraints	Few gas constraints in current system, but more Tx capacity may help in contingencies and in a future with more gas demand and changing flow patterns	Additional local gas demand may result in additional costs on a constrained system	If gas becomes constrained downstate, reduced electric/gas demand would help
Help Meet EPA Clean Power Plan Goals, by providing more flexibility for generation retirements	Reduces reliability and economic challenges with downstate retirements and provides additional capacity to connect remote resources with load	New CC will meet new source standard; does not impact existing source standard	Reduces consumption and emissions

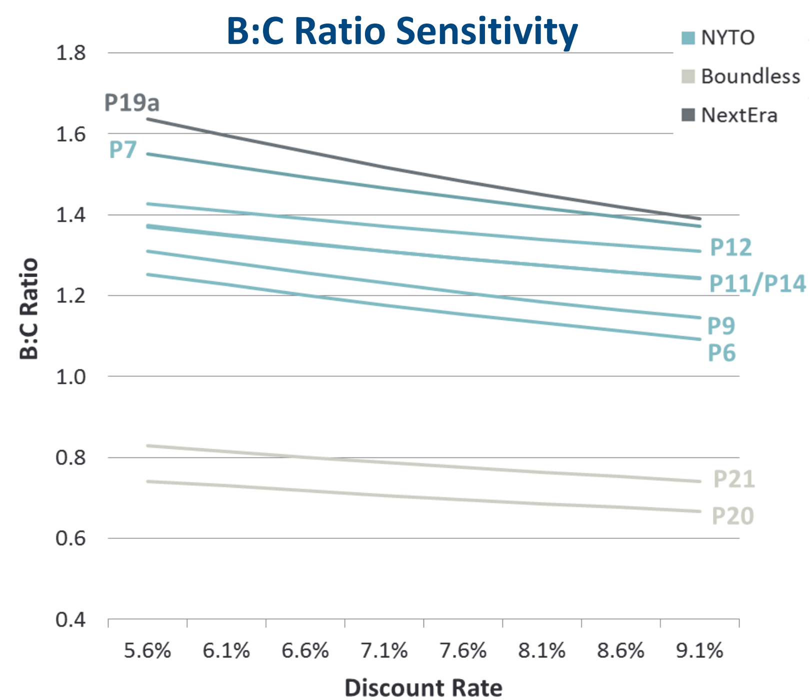
III.A. Benefit-Cost Analysis Results: Societal Impacts

Discount Rate Sensitivity Analysis

Analyzed impact of discount rate on NPV and B:C ratio by reducing DPS-recommended assumption of 9.13% at the high end to 5.6% (reflecting utility ATWACC) at the low end

- Lower discount rate increases NPV of most portfolios by $300 – 700m, but decreases NPV of P20 and P21 by $100– 200m due to benefits being small relative to its PVRR
- Due to back-weighted benefits of Tx projects, lower discount rates increase B:C ratios by 0.1 – 0.3
- The different composition of benefits (front-weighted vs. back-weighted) for each portfolio causes the slopes to differ by portfolio



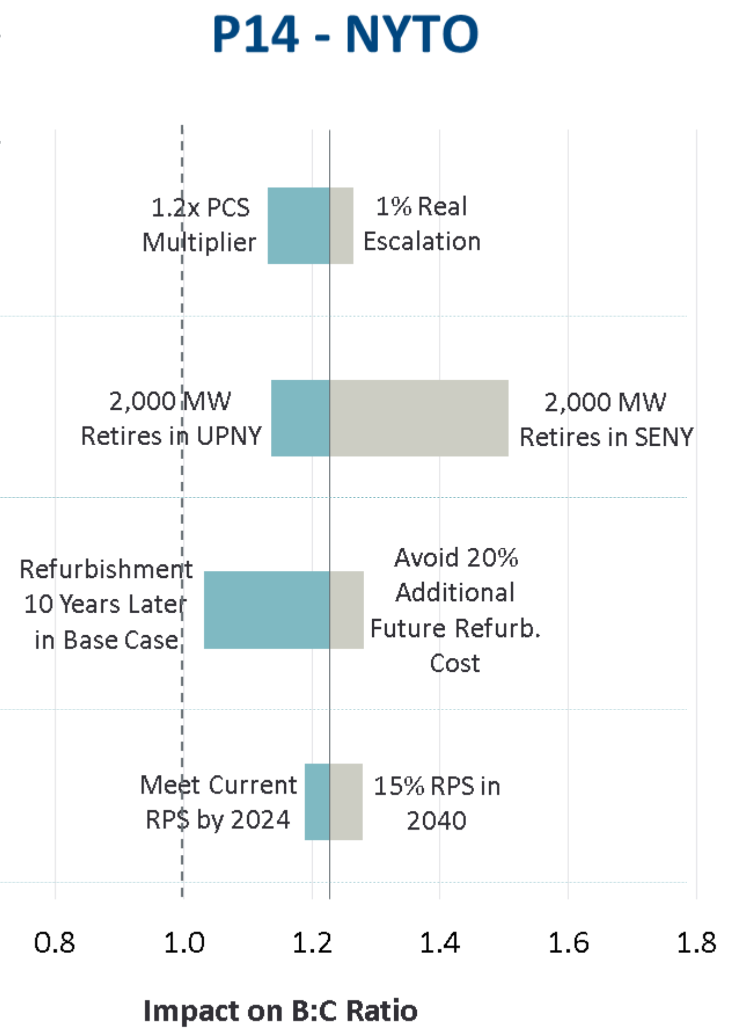


III.A. Benefit-Cost Analysis Results: Societal Impacts

B:C Ratio Sensitivity Analysis of Benefit Assumptions

Sensitivity Analysis Assumptions

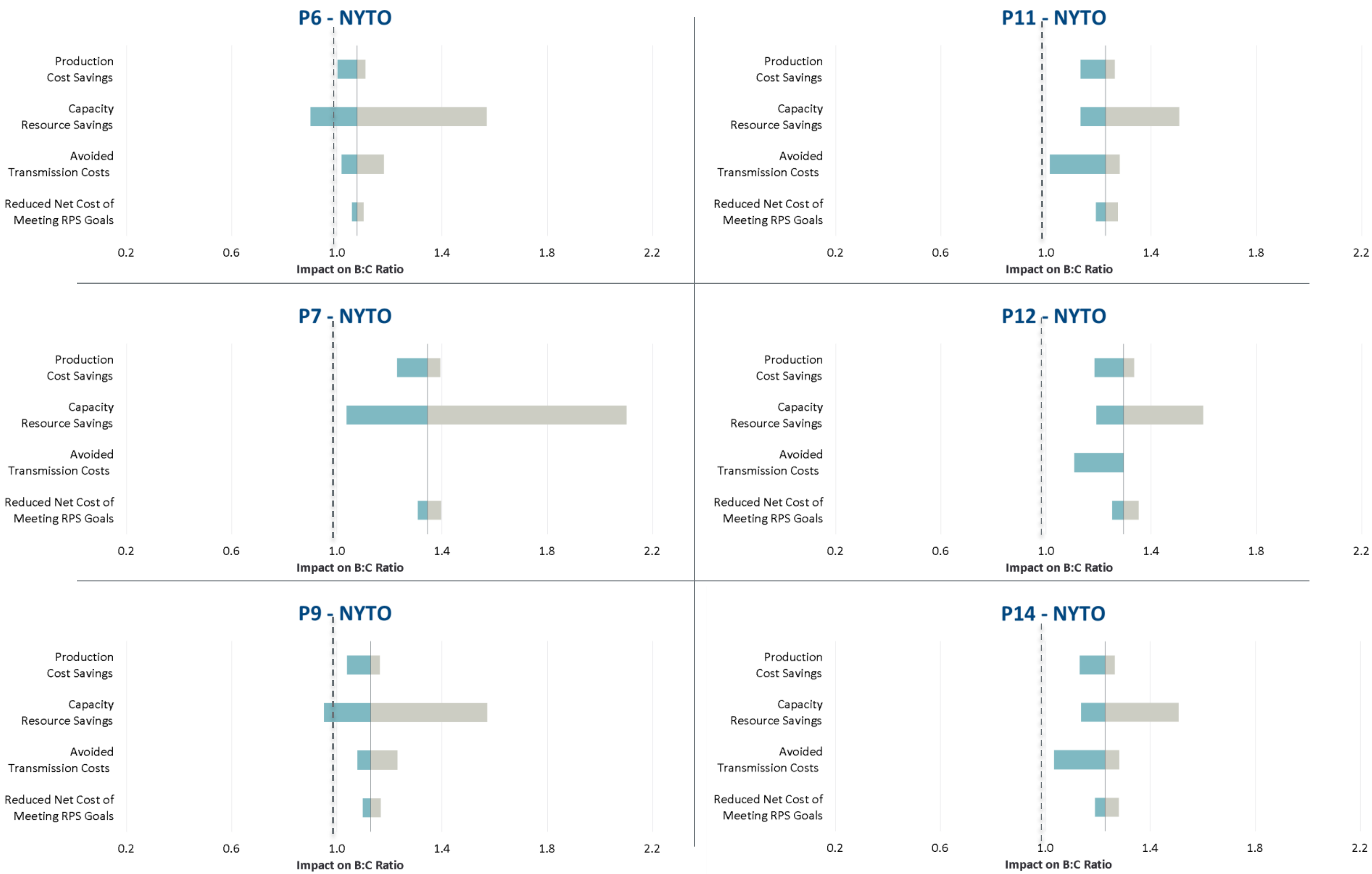
Benefit Category	Lower Value Case	Primary Assumption	Higher Value Case
Production Cost Savings (PCS)	Reduce PCS multiplier to 1.2x	Multiply MAPS PCS by 1.6 to account for factors not modeled in Base Case; escalate post-2024 PCS at inflation	Post-2024 PCS escalates at inflation + 1%
Capacity Resource Savings	2,000 MW retires in UPNY (with or w/o new Tx)	No exit of existing/planned supply, except in response to reduced LCRs	2,000 MW retires in SENY (with or w/o new Tx)
Avoided Transmission Costs	Refurbishment could be delayed 10 years	Projects that *refurbish* aging facilities get a "credit" based on the latest date indicated in STARS; projects that *facilitate* future refurbishments NOT credited for reducing future construction costs	Projects that add a parallel path to aging facilities reduce future refurbishment costs 20% (by avoiding extended construction)
Reduced Net Cost of Meeting RPS Goals	Meet current RPS by 2024 and no more thereafter	RPS increases in 2030 to 2x the 2024 RPS	15% RPS in 2040



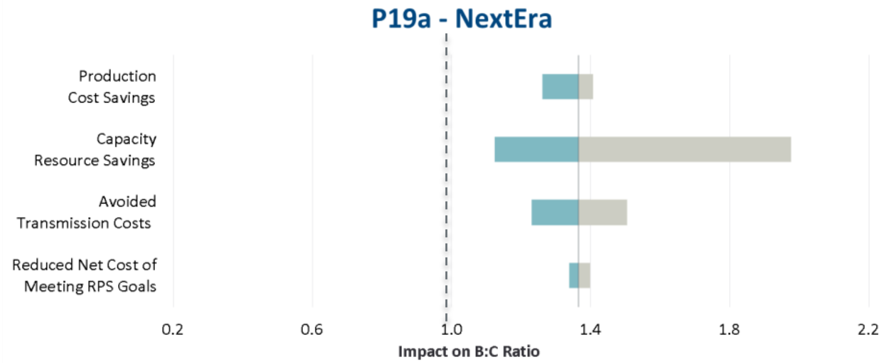
Note: These cases represent the outer envelope of a larger set of sensitivities we considered; we did not test the sensitivity to uncertainty in project cost assumptions

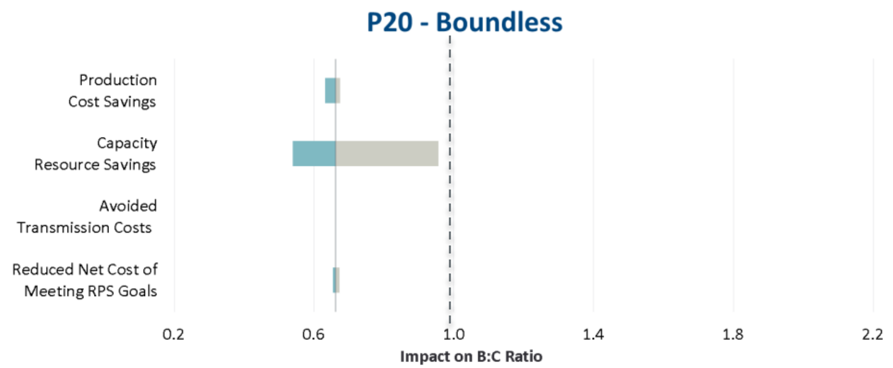
III.A. Benefit-Cost Analysis Results: Societal Impacts

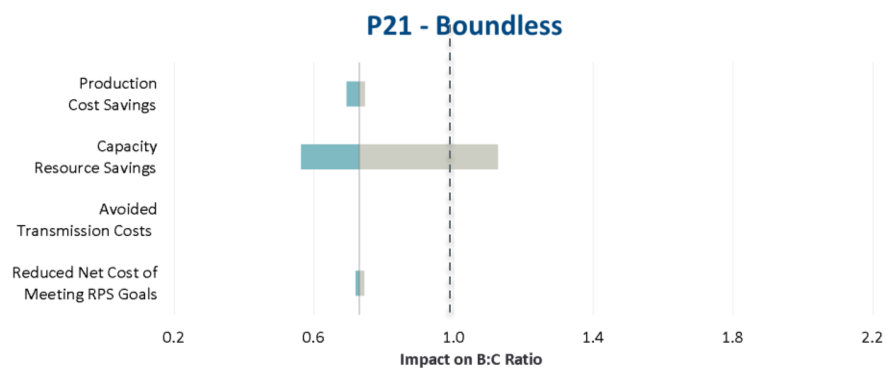
B:C Ratio Sensitivities Across Tx Portfolios



B:C Ratio Sensitivities Across Tx Portfolios







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- A. Societal Impacts Analysis
- B. Ratepayer Impacts Analysis
- C. Indian Point Retirement Scenario
- D. Benefits by Project

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V. Detailed Benefit Analysis

Ratepayer Impact Analysis

Cost Allocation: Assume 90% of transmission RevReq allocated to SENY and 10% to UPNY

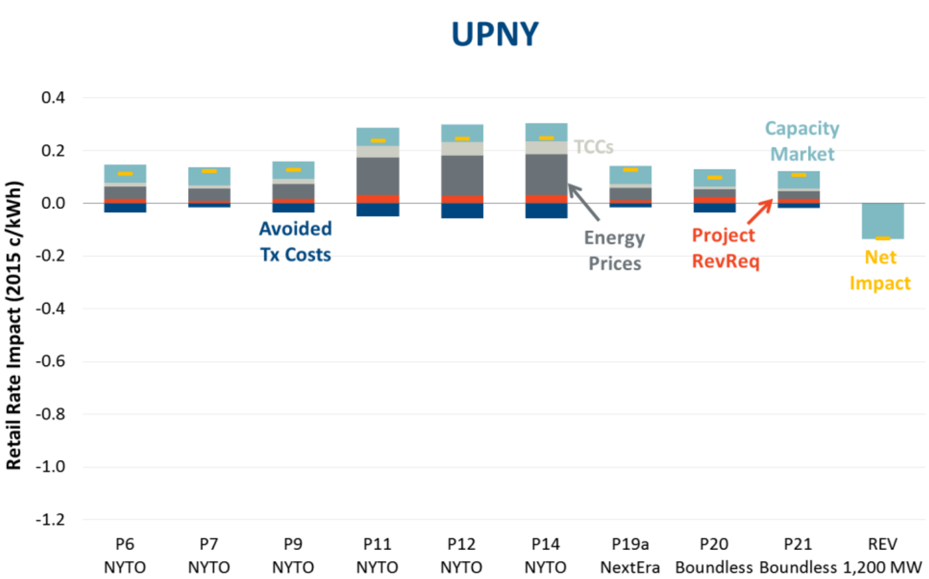
- PSC Order (Dec 2014) states, "75% of project costs are allocated to the economic beneficiaries of reduced congestion, while the other 25% of the costs are allocated to all customers on a load-ratio share"
- Order assumes majority of benefits occur SENY resulting in 90/10 split
- Generation and REV resource costs allocated 100% to SENY

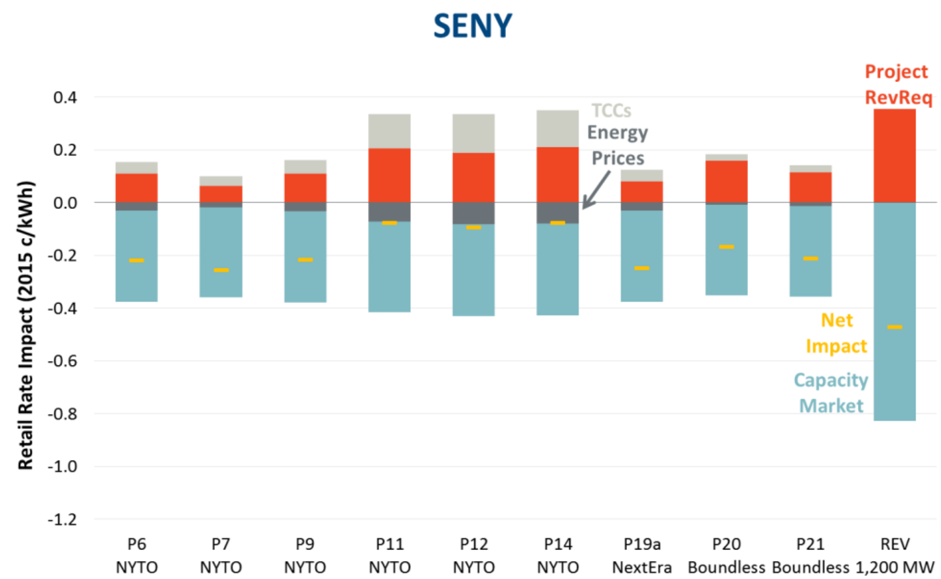
Rate Impacts of Quantified Benefits:

- *Energy Costs and Congestion Rents*:
  - Change in load*LBMP minus change in TCCs from MAPS, assuming 80% of TCC revenues accrue to Downstate ratepayers (based on 2014 data indicating 80% of TCC revenues are on TCCs sinking in SENY)
  - Change in TCC revenues multiplied by 0.9x (as defined in NYISO Economic Planning Process Manual)
  - Change in energy payments and TCC revenues increased by 1.6x to account for factors not modeled in MAPS, similar to production cost savings (*see slides 84– 87 for explanation of this multiplier*)
  - *Note*: REV analysis does not include a measure of energy/TCC impacts because this case was not modeled in MAPS
- *Capacity Costs*: Change in zonal prices and cleared quantities from ICAP model; accounts for changes in energy prices affecting Net CONE
- *Avoided Transmission Costs*:
  - Calculated based on the year refurbishment costs would have been incurred in the Base Case
  - Apply same RevReq formula as the portfolio costs
  - Allocate savings to UPNY based on location of lines considered in our analysis

Tax Receipts: We note distribution of property and state income taxes to UPNY and SENY, even though the proceeds won't be included in ratepayer bills, and we provide examples illustrating our calculations

2019 Ratepayer Impacts





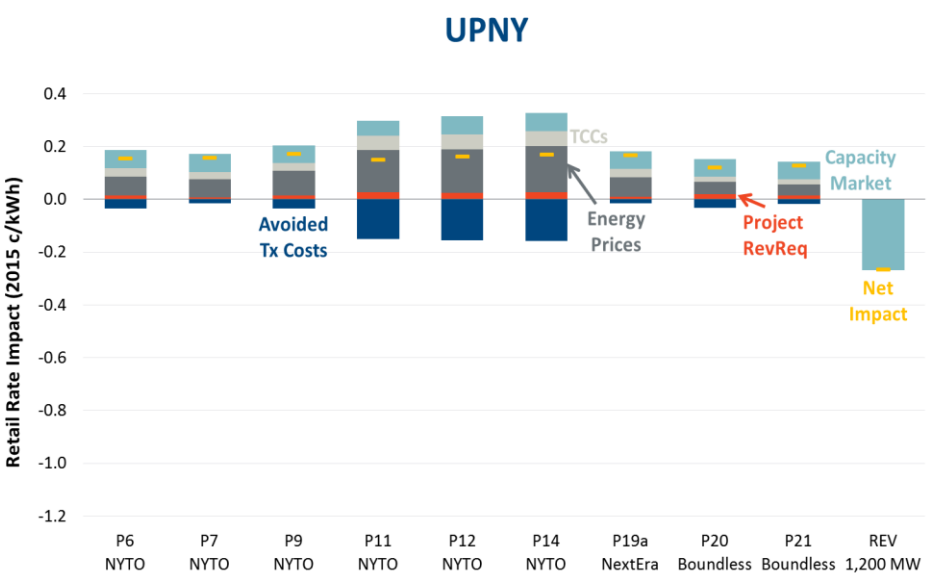
Net Tax Receipts in 2019 - UPNY

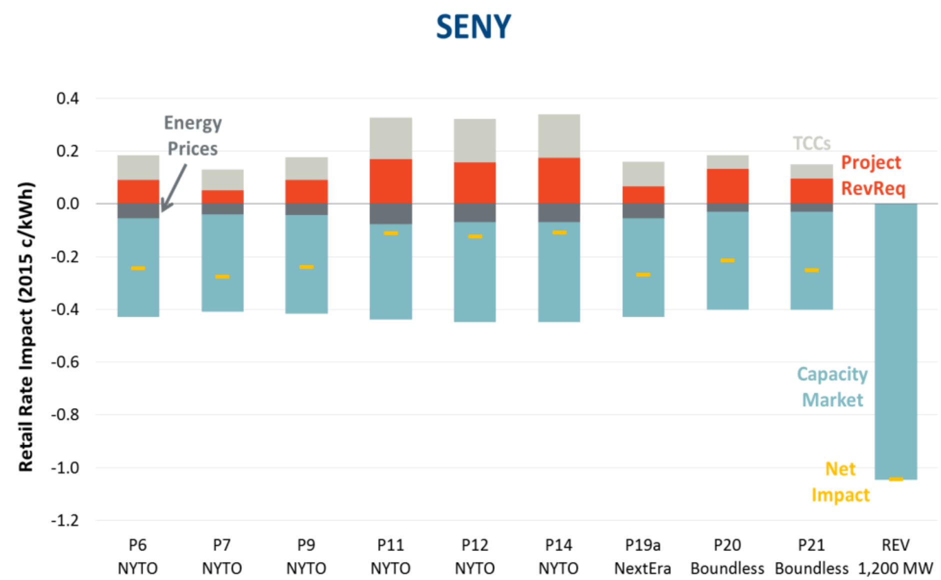
	P6	P7	P9	P11	P12	P14	P19a	P20	P21	REV
2015 $m	6	3	6	17	12	16	6	8	7	-
c/kWh	0.01	0.00	0.01	0.03	0.02	0.02	0.01	0.01	0.01	0.00

Net Tax Receipts in 2019 - SENY

	P6	P7	P9	P11	P12	P14	P19a	P20	P21	REV
2015 $m	5	4	5	7	7	7	4	12	10	-
c/kWh	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.00

2024 Ratepayer Impacts





Net Tax Receipts in 2024 - UPNY

	P6	P7	P9	P11	P12	P14	P19a	P20	P21	REV
2015 $m	5	3	5	9	5	8	6	7	6	-
c/kWh	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00

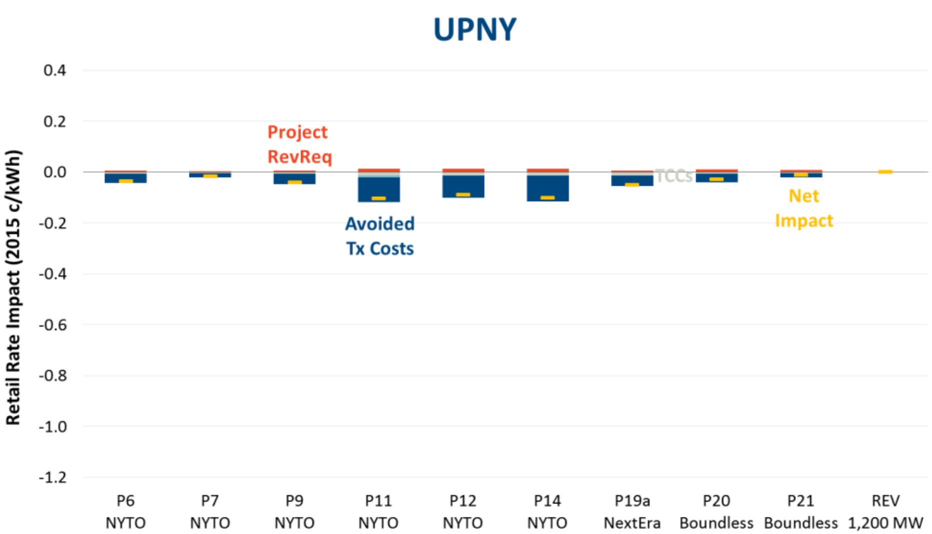
Net Tax Receipts in 2024 - SENY

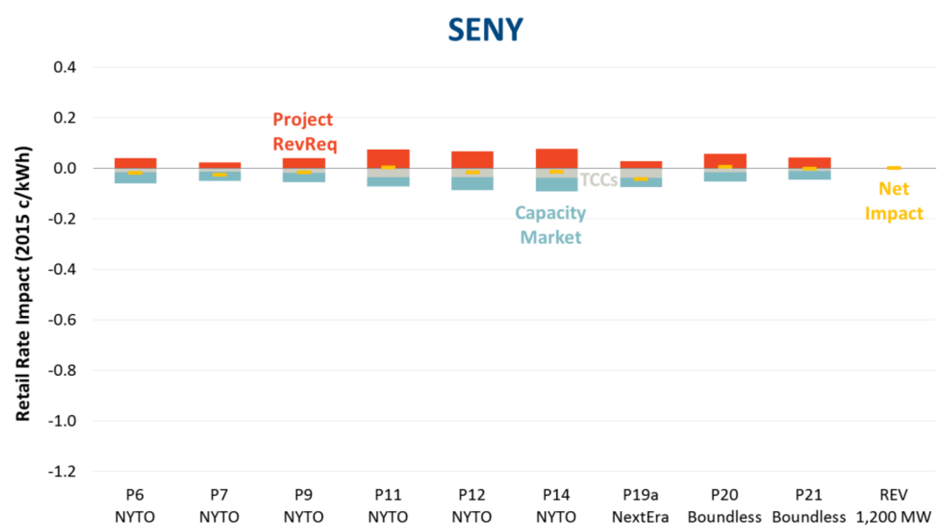
	P6	P7	P9	P11	P12	P14	P19a	P20	P21	REV
2015 $m	4	4	4	2	2	2	3	10	8	-
c/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00

Long-Term Rate Impacts

Long-term rate impact analysis assumes market returns to Base Case price differentials

- Retirements, load growth, and new builds (more tilted to UPNY due to new transmission) eventually will fill up the additional transfer capacity until prices revert to base case levels
- By then, there is no energy price impact, but TCC revenues increase with increased flow
- We use simulated production cost savings as a proxy for the incremental TCC value (e.g., if the prices are $40 in UPNY and $50 in SENY with an additional 1,000 MW flow, the production cost savings and the incremental TCC values will both be $10 x 1,000 MW)
- Tax receipts would continue as well, though not shown on this slide
- Similarly, for the capacity market part of this analysis, we assume each zone reaches long-term equilibrium with prices at local Net CONE (but with lower LCR in SENY)

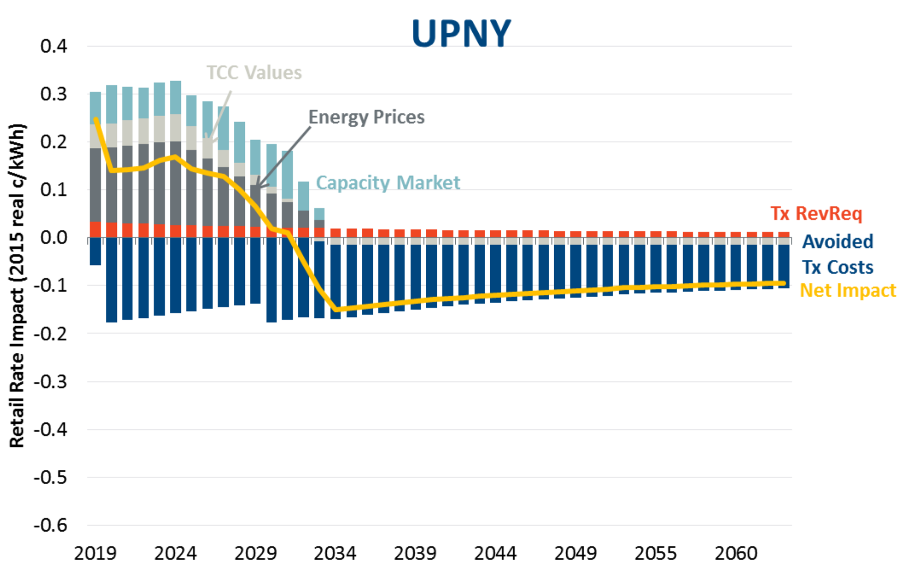


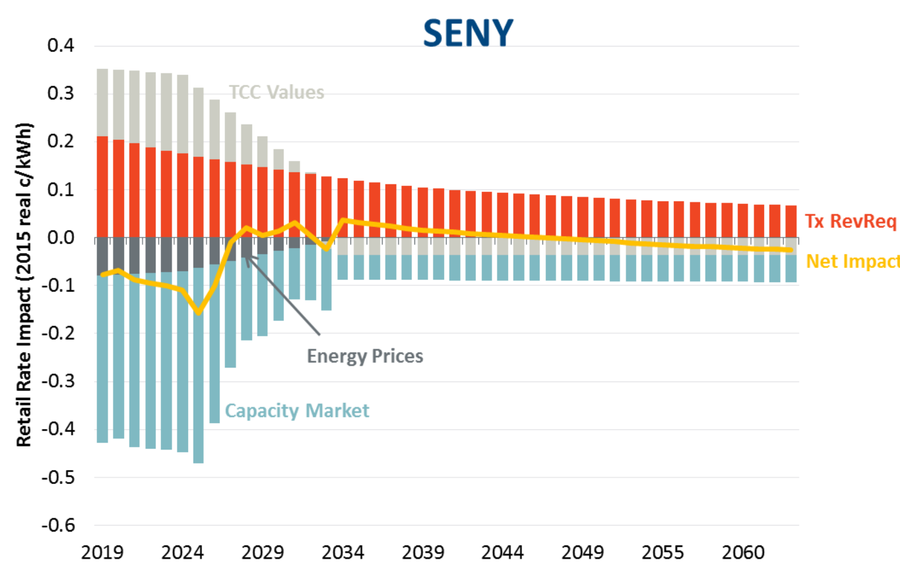


Annual Rate Impacts (P14 example)

Projected rate impacts depend on how long it takes to reach the "long-term" conditions described on the prior slide; for that reason, we present a "what-if" scenario below for P14, assuming it takes 15 years (to 2034)

- Energy Price and TCC Value impacts are linearly interpolated for 2020-2023 and 2025-2033 and then held constant in real terms beyond 2034
- Capacity Market impacts in 2034 and later assume price equals Net CONE
- Tx RevReq and Avoided Future Refurbishments calculated from RevReq analysis
- Tax receipts would continue as well over this 45-year timeframe (*see slide 28*)

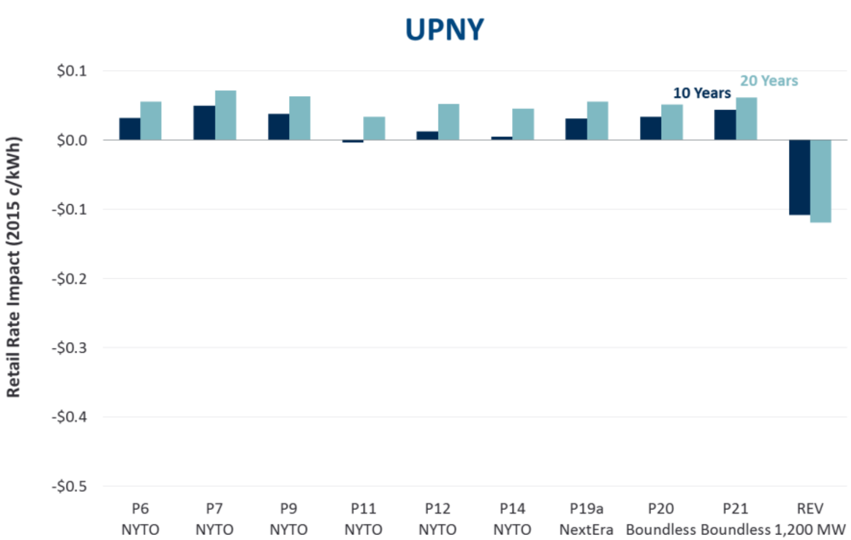


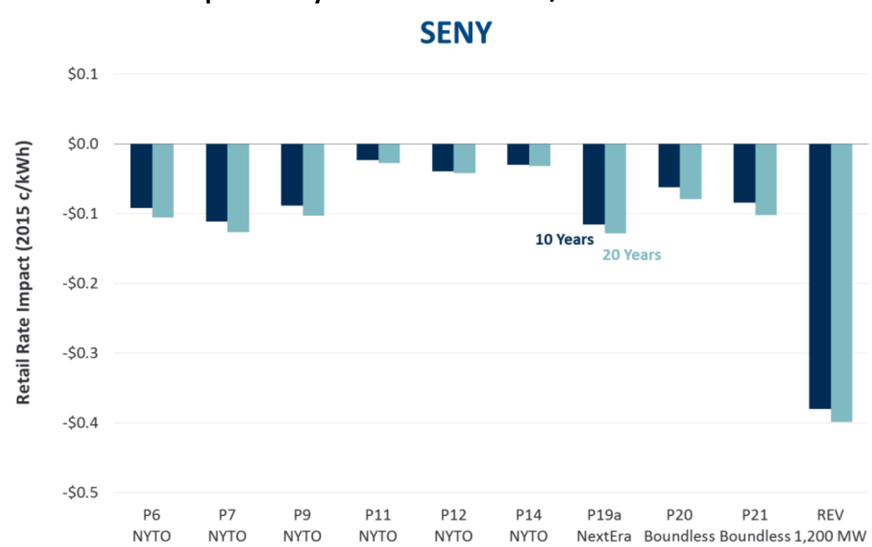


Levelized Rate Impacts

We calculated a levelized long-term rate impact for each project over 45 years

- Reflects a fixed rate (in real dollars) that if paid/saved annually over 45 years would have the same PV as the annual rate calculated for each project
- Levelized rate impact depends on how long it takes to reach equilibrium; chart below shows two "what-if" scenarios of reaching equilibrium in 10 or 20 years with rate impacts calculated by linearly interpolating between 2024 and either 2029 or 2039
- Based on the assumed cost allocation approach (with 10% of RevReq allocated to UPNY and 90% to SENY), most projects slightly increase levelized rates in UPNY and decrease them in SENY
- Adjusting the time-to-equilibrium from 10 to 20 years increases UPNY levelized rate impact by 0.02 – 0.04 c/kWh and decreases SENY levelized rate impact by 0.00 - 0.02 c/kWh





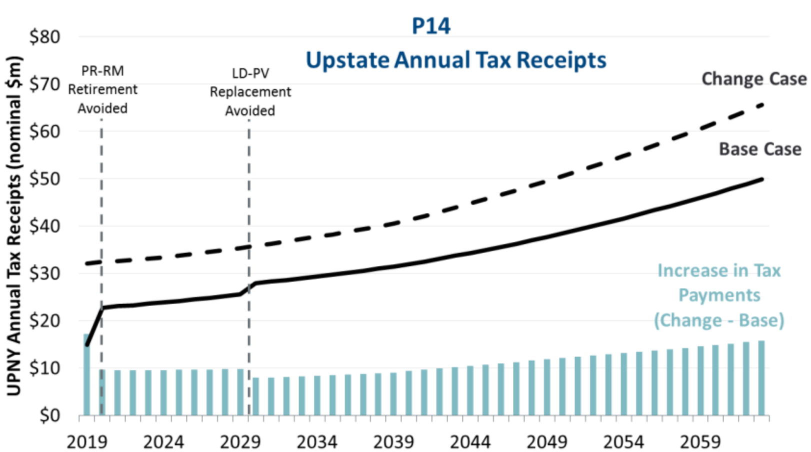
Projected UPNY Tax Receipt Impacts

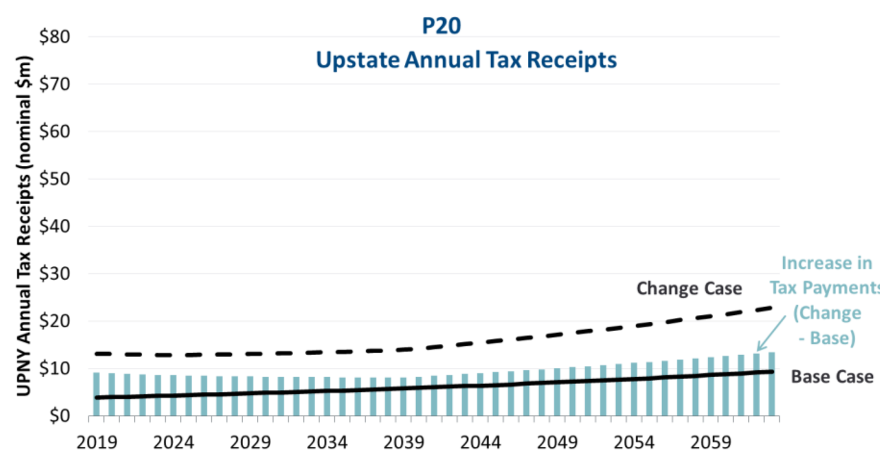
Tx portfolios increase tax receipts for UPNY municipalities

- New portfolios increase tax receipts based on the property taxes included in the portfolio's RevReq
- Increases offset by replacing existing facilities that would otherwise continue to pay taxes and by avoiding future refurbishments that would have increased tax payments and

Expected taxes paid in UPNY for P14 and P20 are shown for Base and Change Cases to demonstrate when and by how much tax payments are expected to change

- P14: Reconductors NS-LD, retires PT-RM, and replaces LD-PV
  - *Base Case*: Existing NS-LD line continues paying taxes, refurbishment of PT-RM increases taxes in 2020, and refurbishment of LD-PV increases taxes in 2030
  - *Change Case*: Addition of P14 portfolio increases taxes starting in 2019
- P20: Reconductors LD-PV, HA-LD, and CPV-RT
  - *Base Case*: Existing LD-PV, HA-LD, and CPV-RT lines continue paying taxes
  - *Change Case*: Addition of P20 portfolio increases taxes starting in 2019





Agenda

Indian Point Retirement Scenario Overview

The possibility of Indian Point retiring (or other SENY retirements) would increase the value of new transmission into SENY

We analyzed benefits under a 2019 surprise retirement of Indian Point, comparing:

- The addition of new AC transmission portfolio
- Without new transmission, compensating generation must be added for reliability

MAPS Assumptions	IP-Out Base Case with Compensating Generation	IP-Out with Tx Solution
Generation	3 years with no additional generation, compensating generation online by 2022 sufficient to maintain reliability	No additional generation needed to maintain reliability
Transmission	No new additions	New Tx facilities energized in 2019

Societal benefits calculated as follows:

- <u>Production cost savings</u> calculated based on difference in production costs between the two cases described above with P14 as a representative Tx project
- <u>Capacity resource cost savings</u> based on 2,000 MW SENY retirement sensitivity; assume entry occurs at Net CONE as needed, starting in 2019 both with and without new transmission (*Note*: Tx benefits may be higher if it avoids adding more expensive compensating MW in the short-term)
- <u>Avoided refurbishment costs</u>, <u>tax receipts</u> and <u>net cost of RPS goals</u> are assumed to be equivalent to scenario with Indian Point operating

IP Retirement Production Cost and ICAP Impact

Production Cost Changes: While IP Retirement increases production costs in all cases, both Tx and Generation solutions mitigate production cost increases, with greater savings from Tx

- NYCA Adjusted Production Costs increase by $700m in 2019 and $900m in 2024 with the retirement of Indian Point and no additional Tx or generation
- Additional generation or transmission lowers production costs compared to the IP out Base Case
- Tx solution has lower production costs than Generation solution by $50m in 2019, $46m in 2024

ICAP Changes: Capacity in G-J decreases, but Tx Solution increases transfers into SENY

- Capacity decreases by **2,000 MW** with retirement of IP, assuming no additional Tx or Generation
- Tx solution results in **1,100 MW** less new capacity in G-J than in the Compensating Gen case (assuming new entry at net CONE)

Scenario	Production Costs ($m)		G-J Capacity (MW)	
	2019	2024	2019	2024
Base Case	$3,511	$4,277	16,548	16,548
IP-Out Base Case (no Compensating Generation)	$4,208	$5,187	14,548	14,548
IP-Out Base Case with Compensating Generation	$4,208	$5,169	15,555	16,014
IP-Out with Tx Solution	$4,159	$5,123	14,449	14,912
IP Out Delta (Tx Solution – Generation Solution)	**(50)**	**(46)**	**(1,106)**	**(1,102)**

Net Increase in Tx Value with IP Retirement

Societal value of Tx portfolios increase in the Indian Point retirement scenario. Compared to the value of Tx with IP in:

Scenario	Production Costs (NPV $m)
"Scenario A" – IP in, with Tx	$38,583
"Scenario B" – IP out, with Tx	$46,444
"Scenario C" – IP in, no Tx	$39,129
"Scenario D" – IP out, no Tx	$47,194
Production Cost Savings of Tx with IP: Scenario A – Scenario C	**$547**
Production Cost Savings of Tx without IP: Scenario B – Scenario D	**$749**
Higher Production Cost Savings Value of Line if IP Retires	**$202**

- Production cost savings by Tx will *increase* by $202m without IP
- Capacity cost savings *increase* by $380–480m in NPV (depending on the project) due to short-term need for capacity in SENY; transmission allows delay and shift to UPNY
- Net impact for the Tx portfolio (using P14 as a representative)* is an increase in NPV of $680m (increases B:C ratio to 1.6)

**Note*: This analysis shows only P14 under an IP retirement scenario. The value of other portfolios likely to increase by a similar amount w/IP retirement.

Agenda

III.D. Benefit-Cost Analysis Results: Benefits by Project

P6 NYTO

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $631m	**PVRR = -$887m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $8m in 2019; $17m in 2024 Multiplier for Other Factors = 1.6x	**$221m**	-$67m with lower 1.2x multiplier to +$28m with 1% real escalation
Avoided Transmission Costs	See later slides	**$281m**	-$53m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1017 MW in G-J, 213 MW in J, 125 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $28m in 2024 Variant 2 = $139m in 2019; $164m in 2024	**Resource Cost Svgs = $284m** Variant 1 = $306m Variant 2 = $857m	-$157m if 2,000 MW retires in UPNY to +$438m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.3/MWh in 2019, $0.4/MWh in 2024 Saves: $0.6m in 2019; $2.3m in 2024	**$27m**	-$17m to just meet 2024 RPS to +$22m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$7m in 2019; $8m in 2024	**$142m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$68m** **B/C Ratio = 1.1**	
Annual Emissions Impacts	Total System CO2: -0.01 % in 2019; 0.02 % in 2024 Total System NOx: -0.05% in 2019; -0.02 % in 2024 Total System SO2: -0.5% in 2019; 0.23 % in 2024	NYCA CO2: -0.51 % in 2019; -0.28 % in 2024 NYCA NOx: -0.42% in 2019; -1.49 % in 2024 NYCA SO2: -3.21% in 2019; -1.59 % in 2024	
Employment During Construction	4200 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1140 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

III.D. Benefit-Cost Analysis Results: Benefits by Project

P7 NYTO

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $361m	**PVRR = -$508m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $7m in 2019; $15m in 2024 Multiplier for Other Factors = 1.6x	**$194m**	-$59m with lower 1.2x multiplier to +$24m with 1% real escalation
Avoided Transmission Costs	See later slides	**$70m**	N/A
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 911 MW in G-J, 209 MW in J, 123 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $29m in 2024 Variant 2 = $138m in 2019; $168m in 2024	**Resource Cost Svgs = $284m** Variant 1 = $305m Variant 2 = $876m	-$157m if 2,000 MW retires in UPNY to +$384m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.3/MWh in 2019, $0.5/MWh in 2024 Saves: $0.7m in 2019; $2.7m in 2024	**$31m**	-$19m to just meet 2024 RPS to +$26m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$4m in 2019; $5m in 2024	**$104m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$175m** **B/C Ratio = 1.3**	
Annual Emissions Impacts	Total System CO_2: -0.02 % in 2019; -0.01 % in 2024 Total System NO_x: -0.02% in 2019; 0.01 % in 2024 Total System SO_2: -0.26% in 2019; -0.34 % in 2024	NYCA CO_2: -0.3 % in 2019; -0.05 % in 2024 NYCA NO_x: -0.25% in 2019; -1.01 % in 2024 NYCA SO_2: -1.55% in 2019; -1.72 % in 2024	
Employment During Construction	2400 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1030 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

III.D. Benefit-Cost Analysis Results: Benefits by Project

P9 NYTO

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $631m	**PVRR = -$887m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $9m in 2019; $20m in 2024 Multiplier for Other Factors = 1.6x	**$262m**	-$80m with lower 1.2x multiplier to +$32m with 1% real escalation
Avoided Transmission Costs	See later slides	**$260m**	-$45m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 932 MW in G-J, 213 MW in J, 125 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $28m in 2024 Variant 2 = $140m in 2019; $167m in 2024	**Resource Cost Svgs = $286m** Variant 1 = $307m Variant 2 = $869m	-$157m if 2,000 MW retires in UPNY to +$394m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.4/MWh in 2019, $0.7/MWh in 2024 Saves: $0.9m in 2019; $3.6m in 2024	**$41m**	-$26m to just meet 2024 RPS to +$34m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$7m in 2019; $8m in 2024	**$151m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$114m** **B/C Ratio = 1.1**	
Annual Emissions Impacts	Total System CO_2: -0.01 % in 2019; -0.01 % in 2024 Total System NO_x: -0.02% in 2019; -0.07 % in 2024 Total System SO_2: -0.43% in 2019; -0.12 % in 2024	NYCA CO_2: -0.47 % in 2019; -0.12 % in 2024 NYCA NO_x: -0.31% in 2019; -1.16 % in 2024 NYCA SO_2: 0.82% in 2019; -0.99 % in 2024	
Employment During Construction	4200 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1060 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

III.D. Benefit-Cost Analysis Results: Benefits by Project

P11 NYTO

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $1189m	**PVRR = -$1671m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $28m in 2019; $36m in 2024 Multiplier for Other Factors = 1.6x	**$516m**	-$157m with lower 1.2x multiplier to +$60m with 1% real escalation
Avoided Transmission Costs	See later slides	**$998m**	-$352m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1087 MW in G-J, 217 MW in J, 127 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $28m in 2024 Variant 2 = $141m in 2019; $167m in 2024	**Resource Cost Svgs = $286m** Variant 1 = $309m Variant 2 = $883m	-$159m if 2,000 MW retires in UPNY to +$469m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $1.4/MWh in 2019, $1.6/MWh in 2024 Saves: $3.4m in 2019; $8.3m in 2024	**$97m**	-$61m to just meet 2024 RPS to +$80m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$14m in 2019; $15m in 2024	**$151m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$377m** **B/C Ratio = 1.2**	

Annual Emissions Impacts	Total System CO_2: 0.02 % in 2019; -0.02 % in 2024 Total System NO_x: 0.09% in 2019; -0.04 % in 2024 Total System SO_2: -0.27% in 2019; 0.02 % in 2024	NYCA CO_2: -0.65 % in 2019; -0.25 % in 2024 NYCA NO_x: 0.19% in 2019; -0.98 % in 2024 NYCA SO_2: 3.96% in 2019; 0.4 % in 2024
Employment During Construction	7800 FTE (60% direct; 40% indirect and induced)	
Retirement Preparedness	Able to accommodate 1210 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*	

III.D. Benefit-Cost Analysis Results: Benefits by Project

P12 NYTO

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $1090m	**PVRR = -$1533m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $30m in 2019; $39m in 2024 Multiplier for Other Factors = 1.6x	**$554m**	-$168m with lower 1.2x multiplier to +$64m with 1% real escalation
Avoided Transmission Costs	See later slides	**$873m**	-$286m if Refurbishment Required 10 Years Later in the Base CaseN/A
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1079 MW in G-J, 217 MW in J, 127 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $28m in 2024 Variant 2 = $141m in 2019; $168m in 2024	**Resource Cost Svgs = $286m** Variant 1 = $308m Variant 2 = $894m	-$158m if 2,000 MW retires in UPNY to +$465m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $1.6/MWh in 2019, $1.8/MWh in 2024 Saves: $3.8m in 2019; $9.2m in 2024	**$108m**	-$67m to just meet 2024 RPS to +$89m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$13m in 2019; $14m in 2024	**$163m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$451m** **B/C Ratio = 1.3**	
Annual Emissions Impacts	Total System CO_2: 0.04 % in 2019; -0.03 % in 2024 Total System NO_x: 0.05% in 2019; -0.1 % in 2024 Total System SO_2: -0.18% in 2019; -0.45 % in 2024	NYCA CO_2: -0.75 % in 2019; -0.07 % in 2024 NYCA NO_x: 0.26% in 2019; -0.64 % in 2024 NYCA SO_2: 3.07% in 2019; 0.18 % in 2024	
Employment During Construction	7200 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1210 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

III.D. Benefit-Cost Analysis Results: Benefits by Project

P14 NYTO

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $1218m	**PVRR = -$1713m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $30m in 2019; $39m in 2024 Multiplier for Other Factors = 1.6x	**$547m**	-$166m with lower 1.2x multiplier to +$63m with 1% real escalation
Avoided Transmission Costs	See later slides	**$995m**	-$336m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1107 MW in G-J, 217 MW in J, 127 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $28m in 2024 Variant 2 = $141m in 2019; $168m in 2024	**Resource Cost Svgs = $286m** Variant 1 = $309m Variant 2 = $896m	-$159m if 2,000 MW retires in UPNY to +$478m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $1.6/MWh in 2019, $1.8/MWh in 2024 Saves: $3.7m in 2019; $9.2m in 2024	**$108m**	-$67m to just meet 2024 RPS to +$88m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$14m in 2019; $15m in 2024	**$169m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$392m** **B/C Ratio = 1.2**	

Annual Emissions Impacts	Total System CO2: 0.03 % in 2019; -0.02 % in 2024 Total System NOx: 0.03% in 2019; -0.01 % in 2024 Total System SO2: -0.29% in 2019; 0.01 % in 2024	NYCA CO2: -0.87 % in 2019; -0.11 % in 2024 NYCA NOx: -0.11% in 2019; -0.77 % in 2024 NYCA SO2: 0.83% in 2019; 1.52 % in 2024
Employment During Construction	8000 FTE (60% direct; 40% indirect and induced)	
Retirement Preparedness	Able to accommodate 1230 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*	

III.D. Benefit-Cost Analysis Results: Benefits by Project

P19a NextEra

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $461m	**PVRR = -$648m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $8m in 2019; $17m in 2024 Multiplier for Other Factors = 1.6x	**$221m**	-$67m with lower 1.2x multiplier to +$28m with 1% real escalation
Avoided Transmission Costs	See later slides	**$264m**	-$86m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 935 MW in G-J, 213 MW in J, 125 MW in K Resource Cost Svgs = $15m in 2019; $25m in 2024 Variant 1 = $18m in 2019; $28m in 2024 Variant 2 = $139m in 2019; $164m in 2024	**Resource Cost Svgs = $285m** Variant 1 = $305m Variant 2 = $839m	-$156m if 2,000 MW retires in UPNY to +$397m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.3/MWh in 2019, $0.4/MWh in 2024 Saves: $0.6m in 2019; $2.3m in 2024	**$27m**	-$17m to just meet 2024 RPS to +$22m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$5m in 2019; $6m in 2024	**$87m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$236m** **B/C Ratio = 1.4**	

Annual Emissions Impacts	Total System CO_2: -0.01 % in 2019; 0.02 % in 2024 Total System NO_x: -0.05% in 2019; -0.02 % in 2024 Total System SO_2: -0.5% in 2019; 0.23 % in 2024	NYCA CO_2: -0.51 % in 2019; -0.28 % in 2024 NYCA NO_x: -0.42% in 2019; -1.49 % in 2024 NYCA SO_2: -3.21% in 2019; -1.59 % in 2024
Employment During Construction	3000 FTE (60% direct; 40% indirect and induced)	
Retirement Preparedness	Able to accommodate 1060 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*	

III.D. Benefit-Cost Analysis Results: Benefits by Project

P20 Boundless

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $918m	**PVRR = -$1291m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $3m in 2019; $10m in 2024 Multiplier for Other Factors = 1.6x	**$128m**	-$39m with lower 1.2x multiplier to +$16m with 1% real escalation
Avoided Transmission Costs	See later slides	**$157m**	N/A
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 904 MW in G-J, 211 MW in J, 124 MW in K Resource Cost Svgs = $15m in 2019; $26m in 2024 Variant 1 = $18m in 2019; $29m in 2024 Variant 2 = $140m in 2019; $171m in 2024	**Resource Cost Svgs = $288m** Variant 1 = $308m Variant 2 = $894m	-$158m if 2,000 MW retires in UPNY to +$380m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.1/MWh in 2019, $0.3/MWh in 2024 Saves: $0.3m in 2019; $1.5m in 2024	**$17m**	-$11m to just meet 2024 RPS to +$14m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$11m in 2019; $12m in 2024	**$264m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = -$436m** **B/C Ratio = 0.7**	

Annual Emissions Impacts	Total System CO2: -0.02 % in 2019; 0 % in 2024 Total System NOx: -0.01% in 2019; -0.03 % in 2024 Total System SO2: -0.21% in 2019; -0.18 % in 2024	NYCA CO2: -0.21 % in 2019; 0.27 % in 2024 NYCA NOx: -0.18% in 2019; -0.61 % in 2024 NYCA SO2: -0.27% in 2019; 0.26 % in 2024
Employment During Construction	6100 FTE (60% direct; 40% indirect and induced)	
Retirement Preparedness	Able to accommodate 1030 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*	

III.D. Benefit-Cost Analysis Results: Benefits by Project

P21 Boundless

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $671m	**PVRR = -$944m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $3m in 2019; $9m in 2024 Multiplier for Other Factors = 1.6x	**$115m**	-$35m with lower 1.2x multiplier to +$15m with 1% real escalation
Avoided Transmission Costs	See later slides	**$76m**	N/A
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 895 MW in G-J, 211 MW in J, 124 MW in K Resource Cost Svgs = $15m in 2019; $26m in 2024 Variant 1 = $18m in 2019; $29m in 2024 Variant 2 = $140m in 2019; $171m in 2024	**Resource Cost Svgs = $288m** Variant 1 = $308m Variant 2 = $892m	-$157m if 2,000 MW retires in UPNY to +$375m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.2/MWh in 2019, $0.3/MWh in 2024 Saves: $0.4m in 2019; $1.5m in 2024	**$17m**	-$11m to just meet 2024 RPS to +$14m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$8m in 2019; $8m in 2024	**$193m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = -$254m** **B/C Ratio = 0.7**	
Annual Emissions Impacts	Total System CO_2: -0.01 % in 2019; -0.05 % in 2024 Total System NO_x: -0.02% in 2019; -0.03 % in 2024 Total System SO_2: -0.24% in 2019; -0.02 % in 2024	NYCA CO_2: -0.15 % in 2019; 0.25 % in 2024 NYCA NO_x: -0.13% in 2019; -0.53 % in 2024 NYCA SO_2: -0.4% in 2019; 2.18 % in 2024	
Employment During Construction	4400 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1020 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

REV Resources Benefit-Cost Analysis

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $2629m	**PVRR = -$2156m**	N/A
Production Cost Savings, including multiplier (model vs. futures LBMPs)	MAPS: $208m in 2019; $331m in 2024 Multiplier for Other Factors = 1.03x in Zones GHI, 1.06x in Zone J	**$1943m**	-$259m if EE capacity factor is reduced to 65%to + $90m if based on load-weighted average LMP
Avoided Transmission Costs	None	N/A	N/A
Capacity Resource Cost Savings from avoided new construction	Resource Cost Svgs = $57m in 2019; $91m in 2024 Variant 1 = $67MM in 2019; $107MM in 2024 Variant 2 = $440MM in 2019; $649MM in 2024	**Resource Cost Svgs = $613m** Variant 1 = $692m Variant 2 = $3468m	$136m if 2,000 MW retires in UPNY to +$393m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	None	N/A	N/A
Tax Receipts from property tax and state income tax in RevReq	None	N/A	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$400m** **B/C Ratio = 1.2**	
Annual Emissions Impacts	NYCA CO_2: -1,231 thousand tons in 2019; -1,538 thousand tons in 2024 NYCA NO_x: -1,438 tons in 2019; - 1,797 tons in 2024 NYCA SO_2: -1,725 tons in 2019; -2,157 tons in 2024		
Employment During Construction	2000 to 16000 FTE (4% to 80% direct, depending on type of measure)		
Retirement Preparedness	Able to accommodate 1200 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Market Benefits, Storm Resiliency, Relieving Gas Transport Constraints *(see following slides)*		

Note: Emissions reductions based on REV GEIS.

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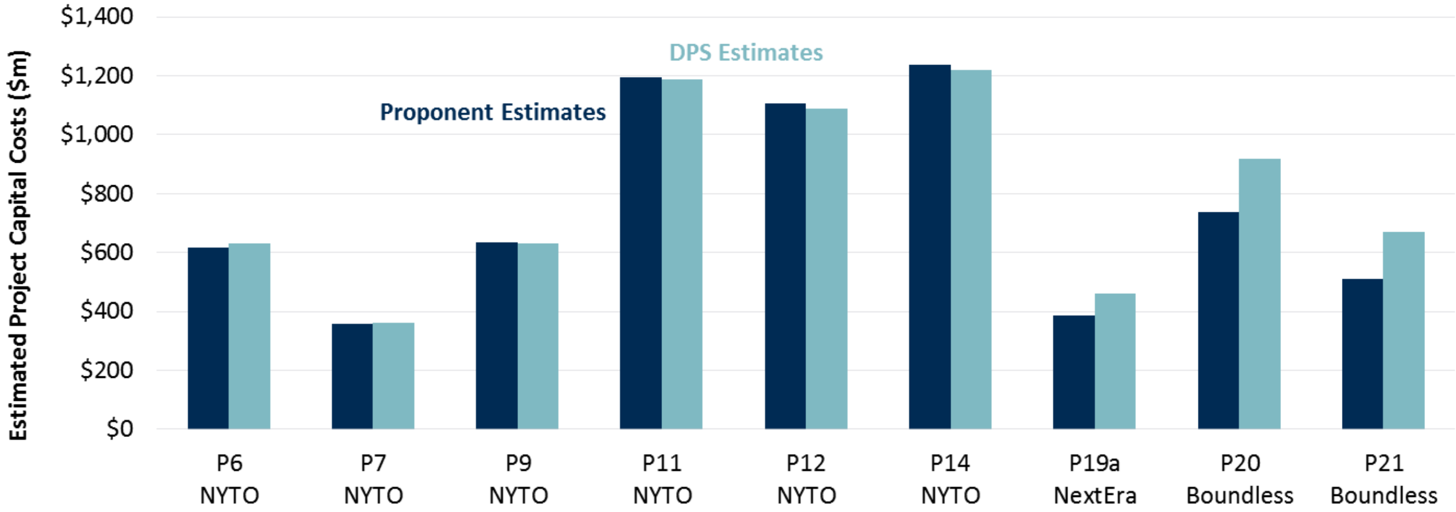
Estimated Overnight Capital Costs

DPS staff developed two capital cost estimates for each Tx portfolio based on their analysis of the project components ("DPS Estimates") and a review of proponent cost estimates ("Proponent Estimates")

- Cost estimates represent overnight capital costs as of mid-2015
- We calculated NPV and B:C ratio using both cost estimates on slides 14 and 15
- All other analyses in this report use the DPS Estimates

Comparison of DPS and Proponent Capital Cost Estimates



Translating Costs to Revenue Requirements

DPS provided workbook to estimate 45-year RevReq for $100m capital investment

- Workbook calculates annual revenue requirements beginning in Year-1 (assume in-service date of Jan 2019 and total 2019 revenues received at mid-year on average), based on investment costs as of Year-0 (as of mid-2018)
- Discounting annual RevReq at 9.13% (as requested by DPS) yields a Year-0 PVRR of 1.65x the Year-0 capital investment costs
- See next slide for treatment of cost escalation, interest during construction, and discounting
- There is significant uncertainty in RevReq calculation due to assumptions required in developing actual project costs and the assumed FERC ROE (8.7% in DPS analysis)

AC Transmission Upgrade Case 12-T-0502 et al.
Analysis of Revenue Requirement needed assuming $100 M Investment

Investment	$ 100,000,000	
PTROR (w/adder)	9.97%	
Depreciation Rate	2.26%	(44.25 years)
Property Tax	2.18%	

Rate of Inflation 2.00%

MULTIPLIER FACTOR

Investment	Total Cost PV
$1=	**$1.65**
Discount Rate:	9.13%

	O&M, Property Taxes and Depreciation Expense				Rate Base								
Year	O&M Exp - Transmission	Property Taxes	Book Depreciation	Total Exp	Initial Investment	Accumulated Depreciation	Net Plant	AVG Net Plant	Deferred Tax	Prepayments, M&S Working Capital	Rate Base	Return on Investment	Revenue Requirement
1	2,861,617	2,183,334	2,260,000	7,304,951	100,000,000	2,260,000	97,740,000	98,870,000	298,000	1,786,641	100,358,641	10,005,757	17,310,707
2	2,918,849	2,227,001	2,260,000	7,405,850	100,000,000	4,520,000	95,480,000	96,610,000	1,587,800	1,793,796	96,815,996	9,652,555	17,058,404
3	2,977,226	2,271,541	2,260,000	7,508,767	100,000,000	6,780,000	93,220,000	94,350,000	3,463,000	1,801,093	92,688,093	9,241,003	16,749,770
4	3,036,770	2,316,972	2,260,000	7,613,742	100,000,000	9,040,000	90,960,000	92,090,000	5,129,800	1,808,536	88,768,736	8,850,243	16,463,985
5	3,097,506	2,363,311	2,260,000	7,720,817	100,000,000	11,300,000	88,700,000	89,830,000	6,603,800	1,816,128	85,042,328	8,478,720	16,199,537
6	3,159,456	2,410,577	2,260,000	7,830,033	100,000,000	13,560,000	86,440,000	87,570,000	7,899,400	1,823,871	81,494,471	8,124,999	15,955,032
7	3,222,645	2,458,789	2,260,000	7,941,434	100,000,000	15,820,000	84,180,000	85,310,000	9,030,000	1,831,770	78,111,770	7,787,743	15,729,177
8	3,287,098	2,507,965	2,260,000	8,055,063	100,000,000	18,080,000	81,920,000	83,050,000	10,008,000	1,839,827	74,881,827	7,465,718	15,520,781
9	3,352,840	2,558,124	2,260,000	8,170,964	100,000,000	20,340,000	79,660,000	80,790,000	10,900,800	1,848,044	71,737,244	7,152,203	15,323,167
10	3,419,897	2,609,286	2,260,000	8,289,183	100,000,000	22,600,000	77,400,000	78,530,000	11,781,400	1,856,426	68,605,026	6,839,921	15,129,104
11	3,488,295	2,661,472	2,260,000	8,409,767	100,000,000	24,860,000	75,140,000	76,270,000	12,662,000	1,864,976	65,472,976	6,527,656	14,937,422
12	3,558,061	2,714,701	2,260,000	8,532,762	100,000,000	27,120,000	72,880,000	74,010,000	13,542,600	1,873,697	62,341,097	6,215,407	14,748,169
13	3,629,222	2,768,995	2,260,000	8,658,217	100,000,000	29,380,000	70,620,000	71,750,000	14,423,200	1,882,592	59,209,392	5,903,176	14,561,394
14	3,701,806	2,824,375	2,260,000	8,786,182	100,000,000	31,640,000	68,360,000	69,490,000	15,303,800	1,891,665	56,077,865	5,590,963	14,377,145
15	3,775,842	2,880,863	2,260,000	8,916,705	100,000,000	33,900,000	66,100,000	67,230,000	16,184,400	1,900,920	52,946,520	5,278,768	14,195,473
16	3,851,359	2,938,480	2,260,000	9,049,839	100,000,000	36,160,000	63,840,000	64,970,000	17,065,000	1,910,359	49,815,359	4,966,591	14,016,431
17	3,928,386	2,997,250	2,260,000	9,185,636	100,000,000	38,420,000	61,580,000	62,710,000	17,945,600	1,919,988	46,684,388	4,654,433	13,840,070
18	4,006,954	3,057,195	2,260,000	9,324,149	100,000,000	40,680,000	59,320,000	60,450,000	18,826,200	1,929,809	43,553,609	4,342,295	13,666,444
19	4,087,093	3,118,339	2,260,000	9,465,432	100,000,000	42,940,000	57,060,000	58,190,000	19,706,800	1,939,826	40,423,026	4,030,176	13,495,608
20	4,168,835	3,180,705	2,260,000	9,609,541	100,000,000	45,200,000	54,800,000	55,930,000	20,587,400	1,950,044	37,292,644	3,718,077	13,327,617

Sources and notes: Figure illustrates first 20 years from AC Transmission Revenue Requirement Spreadsheet provided by DPS .

IV.A. AC Transmission Cost Estimates

Cost Escalation, AFUDC, and Discounting

Calculated the present value of the revenue requirements (PVRR) based on the 2015 overnight capital costs provided by DPS, using the following approach:

1. Calculate Total Investment Costs as of mid-2018:
   a) Assuming construction occurs in 2017 and 2018 with costs occurring in Jan 2018 on average, escalate mid-2015 overnight capital costs 2.5 years to Jan 2018 at 2.4% per year (0.4% above inflation);
   b) Then add one year of AFUDC at 9.13% to calculate total investment costs as of Jan 2019 in-service date;
   c) Finally, discount 0.5 year back to mid-2018 to be consistent with DPS RevReq analysis on prior slide;
   d) Results in total investment costs as of mid-2018 being 1.11x the mid-2015 overnight costs
2. Convert mid-2018 investment costs to mid-2018 PVRR using 1.65x PVRR multiplier from prior slide
3. Discount mid-2018 PVRR to mid-2015 PVRR 3 years at DPS's 9.13%; results in a discount factor of 0.77

Overall ratio of PVRR in 2015$ to Overnight Capital Costs in 2015$ is 1.41

Portfolios	Overnight Costs as of Mid-2015 (2015 $m)		Investment Costs as of Mid-2018 (2018 $m)		PVRR as of Mid-2018 (2018 $m)		PVRR as of Mid-2015 (2015 $m)
P6 NYTO	$631	x1.11	$700	x1.65	$1,153	x0.77	$887
P7 NYTO	$361	x1.11	$400	x1.65	$660	x0.77	$508
P9 NYTO	$631	x1.11	$699	x1.65	$1,153	x0.77	$887
P11 NYTO	$1,189	x1.11	$1,318	x1.65	$2,172	x0.77	$1,671
P12 NYTO	$1,090	x1.11	$1,208	x1.65	$1,992	x0.77	$1,533
P14 NYTO	$1,218	x1.11	$1,350	x1.65	$2,226	x0.77	$1,713
P19a NextEra	$461	x1.11	$511	x1.65	$842	x0.77	$648
P20 Boundless	$918	x1.11	$1,017	x1.65	$1,677	x0.77	$1,291
P21 Boundless	$671	x1.11	$744	x1.65	$1,227	x0.77	$944

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Generation Costs

Variable costs: Assume 7,000 Btu/kWh heat rate and $7.01/MWh VOM (2019$)

Capital and fixed O&M costs: Utilized analysis completed for NYISO 2013 Demand Curve Reset (DCR) for estimating the capital and annual fixed O&M costs of the generation solution

- In the 2013 DCR, the estimated capital costs of a 311 MW Combined Cycle plant in Zone G is $501m, or **$1,573/kW** (grossed up to 2015$)
- We assume an equivalent per-kW cost for the 1,320 MW generation solution, which results in **capital costs of $2,077m** (includes $69m for gas/electric interconnection)
- Fixed O&M costs are assumed to be equivalent to DCR at **$51/kW-yr** or $67 million/yr
- Assuming utility-based cost of capital under a PPA, we calculate **PVRR of $3,332m** over 25-year economic life assumed in DCR (and evaluate benefits over the same time)

Alternative 45-Year case: Assume fixed O&M costs continue at the same annual rate (although they would be expected to increase) for an additional 20 years

Source: NERA, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, August 2, 2013.

REV Resource Costs

Using unit total resource costs from the GEIS analysis, we estimate capital costs of REV portfolio to be $2,629m

- GEIS cost estimates represents the total resource costs, including initial and ongoing costs, which we assume are incurred in the year the resource is installed
- 60% of costs are assumed to be utility programs costs, remaining 40% paid by customers

REV costs in GEIS may be optimistic, but in any case are uncertain

- Assumes statewide average EE costs can be improved to match best-performing utilities and sectors from 2013
- Assumes effectiveness of future spending on EE measures will increase by 10 – 20%

REV Resource	Capacity (MW)	Costs ($/kW)	Costs ($m)
Energy Efficiency	838 MW	$2,100	$1,771
Customer-Sited Renewables	73 MW	$8,600	$627
Demand Response	89 MW	$600	$55
Combined Heat & Power	28 MW	$3,800	$105
Rate Structure	117 MW	---	---
Grid Integrated Vehicles	15 MW	$600	$10
Storage	40 MW	$1,500	$61
Total	**1,200 MW**	**---**	**$2,629**

Source: REV GEIS. See next slide for sources supporting resource distribution and economic life estimates.

REV Sources

REV Resource Distribution

- Final Generic Impact Statement in Case 14-M-0101 – Reforming the Energy Vision and Case 14-M-0094 – Clean Energy Fund
- NYSERDA Energy Efficiency and Renewable Energy Potential Study of New York State (EE)
- 2015 Gold Book Draft Long-Term Forecast (EE, solar PV, fossil fuel DG, grid-integrated vehicles, storage)
- NYISO Power Trends 2014 (DR and rate structures)
- U.S. DOE Combined Heat and Power Installation Database (CHP)

REV Resource Measure Life Estimates

- NYSERDA Energy Efficiency and Renewable Energy Potential Study of New York State (EE)
- PSCo DSG study; Min VOS Austin Energy and Minnesota VOS study; PacifiCorp VOS (solar PV)
- http://www.brattle.com/system/publications/pdfs/000/005/013/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT_Part_III_Shavel_Weiss_Fox-Pennerf.pdf?1401907416 (CHP)
- http://www.hybridcars.com/how-long-will-an-evs-battery-last/ (grid-integrated vehicles)
- http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf (storage)
- http://www.emfwise.com/smartmeters.php (rate structures - typical life span of smart meters)

Summary of Cost Estimates

Tx Solution	Added Capacity or STE Transfer Limit Impact into SENY (MW)*	Estimated Capital Cost (2015 $m)	Estimated Capital Cost ($/kW)	Estimated PVRR (2015 $m)
P6 NYTO	1,686	$631	$374	$887
P7 NYTO	1,404	$361	$257	$508
P9 NYTO	2,091	$631	$302	$887
P11 NYTO	1,621	$1,189	$733	$1,671
P12 NYTO	1,341	$1,090	$813	$1,533
P14 NYTO	2,286	$1,218	$533	$1,713
P19a NextEra	1,747	$461	$264	$648
P20 Boundless	1,753	$918	$524	$1,291
P21 Boundless	1,433	$671	$469	$944
Generation (25 years)	1,320	$2,077	$1,573	$3,332
Generation (45 years)	1,320	$2,077	$1,573	$3,473
REV Resources	1,200	$2,629	$2,191	$2,156

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Overview of MAPS Analysis

Quantify impact of each solution on **production costs, LBMPs,** and **emissions** in 2019 and 2024 and use results to interpolate impacts in 2020 – 2023 and to extrapolate impacts to 2063

- **Base Case:** Reflects the business-as-usual view of the future with currently forecasted load growth, no unplanned additions or retirements, fuel prices corresponding to futures, and Athens SPS expiring in 2024
- **Change Case**
  - For Tx and Generation, adjust the Base Case in MAPS by adding either one of the Tx portfolios or generic generation
  - Athens SPS expires in 2019 for Tx Change Cases (not in Gen case)
  - For REV, we did not run a separate case in MAPS but calculated production cost savings based on the average LBMPs from our MAPS Base Case (savings likely to be trivially smaller if ran in MAPS and observed slight price decrease)
- **Scenarios and sensitivities**
  - Limited time in this study for other scenarios to capture value of solutions due to uncertainty in Tx and generation outages, load forecasts, and real-time conditions
  - We partly addressed through production cost savings “multipliers” discussed further in the next section
  - Analyzed three Indian Point retirement cases

Development of MAPS Base Case

Started with the most recent CARIS and input received from NYISO

- The starting point for developing the 2019 and 2024 Base Cases for our analysis was the Base Case from the 2013 CARIS
- NYISO adjusted generation capacity from 2014 Gold Book based on recent announcements concerning CPV Valley (*added*), Danskammer (*added*), Ravenswood 3-4 (*added*), Binghamton Cogen (*added*), Astoria 20 (*added*), Ravenswood 3-3 (*mothballed*), Bowline 2 (*uprated*), Dunkirk (*repowered*), and addition of 1,000 MW wind by 2024 to meet RPS requirements
- Later slides refer to this case as the “NYISO Base Case”

We implemented additional changes to reflect the most up-to-date market information in the MAPS analysis to produce a “Brattle Base Case”

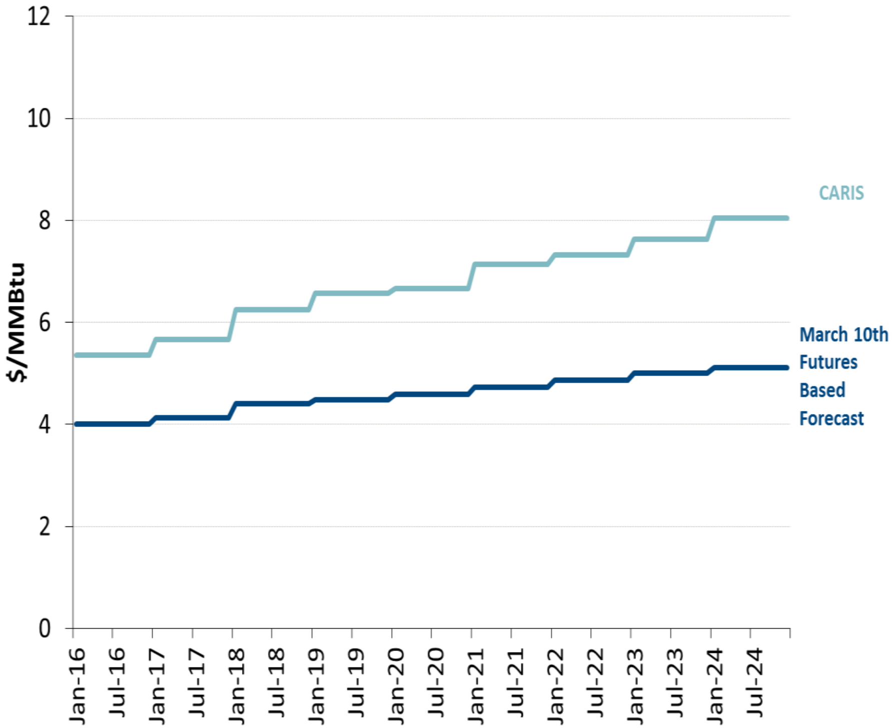
- Lower gas/oil prices consistent with current futures as of March 2015
  - Gas prices about \$2-3/MMBtu lower than 2013 CARIS assumptions
  - Oil prices about \$5-6/MMBtu lower than 2013 CARIS assumptions
  - No change to coal prices
- NYISO load forecast based on 2015 Gold Book, which is lower than 2014 Gold Book forecast by about 3% in 2019 and 2024
- Updated supply/demand in PJM, ISO-NE, and IESO, including the addition of 2 GW of CC/CT to PJM and 1 GW of CC/CT to ISO-NE

Natural Gas Price Input Assumptions

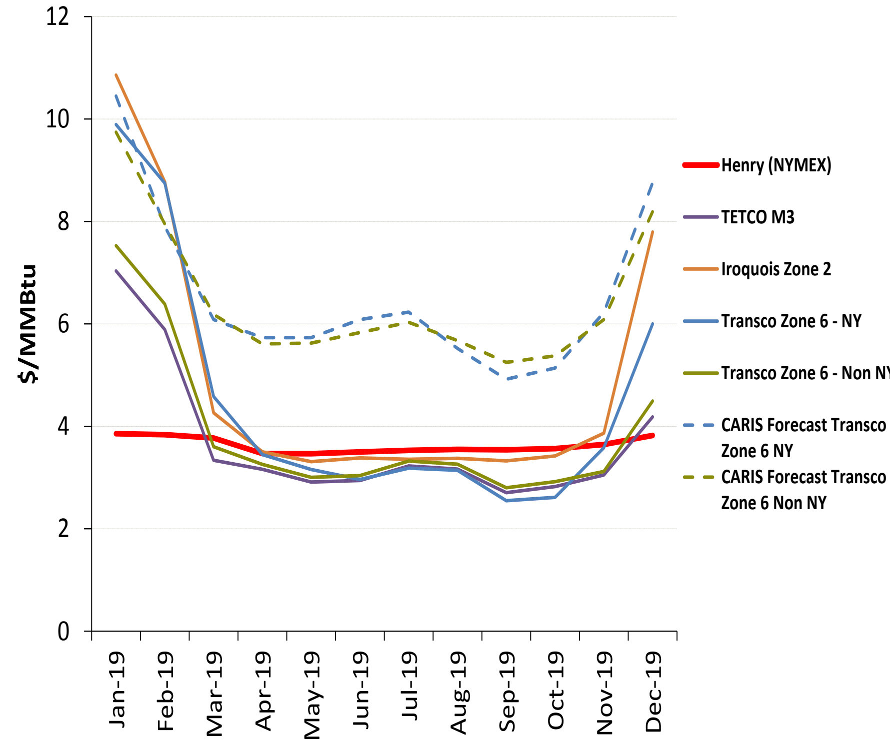
Natural Gas Price Forecasts

- Updated forecasts are consistent with current NYMEX and ICE futures (as of March 10, 2015)
- Updated prices are much lower but have more seasonality in basis differentials

Transco Zone 6 Forecast Comparison



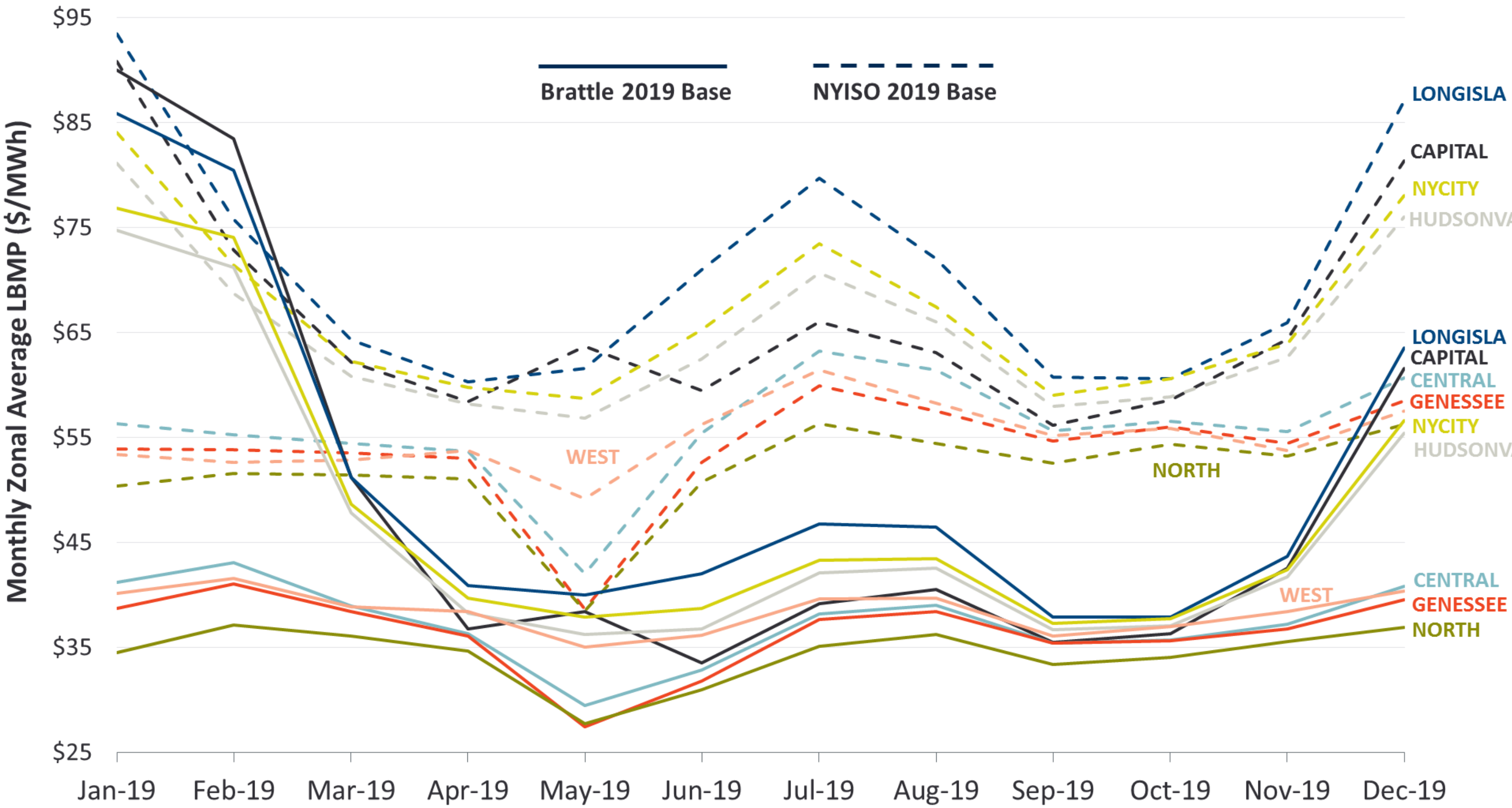
Updated 2019 NY Gas Forecasts



Source: Henry Hub Forecasts based on NYMEX data, all other hubs based on ICE data as of March 10, 2015

V.A.1. MAPS Analysis of Production Cost Savings: Base Case

MAPS Monthly Average LBMPs in 2019



Source: Monthly Area Spot Price outputs NYISO 2019 Base Run and Brattle 2019 Base Run in MAPS

Notes: Prices for Dunwoodie (I), Hudson Valley (G), and Millwood (H) are closely aligned (both in the NYISO Base Run and Brattle Run 1). Only Hudson Valley is shown for the sake of clarity. Similarly, prices for Central (C) and Mohawk Valley (E) are closely aligned in both sets of outputs, so only Central is shown for the sake of clarity. The Brattle 2019 Base Case MAPS run shown here is without CPV Valley as it was completed in March 2015, prior to the CPV Valley announcement.

MAPS LBMPs Compared to Futures

NYISO Zonal LBMP Futures Compared to MAPS Runs ($/MWh)

	NYMEX Futures			
Zone	Contract Months 05/2015 - 04/2016	Contract Months 05/2016 - 04/2017	Contract Months 05/2017 - 04/2018	Brattle 2019 Base Run*
WEST - A	$36.7	$36.6	$35.9	$38.0
GENESSEE - B	-	-	-	$35.8
CENTRAL - C	$37.4	-	-	$36.8
NORTH - D	-	-	-	$34.3
MOHAWKVA - E	-	-	-	$36.5
CAPITAL - F	-	-	-	$47.0
HUDSONVA - G	$46.9	$46.5	$46.3	$44.6
MILLWOOD - H	-	-	-	$45.0
DUNWOODI - I	-	-	-	$44.9
NYCITY - J	$49.0	$48.6	$48.3	$45.5
LONGISLA - K	-	-	-	$48.8

Sources: NYMEX 5 MW Peak and Off-Peak Calendar Month Day-Ahead LMP Futures by NYISO zone (from SNL). Annual Average Area Spot Price outputs from MAPS, Brattle 2019 Base Run without CPV Valley .

Notes: The weighted average price is taken over futures contracts for the periods 5/2015 - 4/2016 (1-12 months forward), 5/2016 - 4/2017 (13-24 months forwards), and 5/2017 to 4/2018 (25-26 months forward) only if all contract months within the period are traded for a given zone, using prices from past 30 trade days. Weighted averages are taken using 48% on-peak and 52% off-peak prices.

* The Brattle 2019 Base Case MAPS run shown here is without CPV Valley. This is to maintain consistency with the NYMEX data from March 2015, our fuel price assumptions, and our development of production cost savings multipliers (see slides 84-87). CPV Valley announced its decision to enter the market on July 15, 2015, with an anticipated online date in early 2018. The NYMEX futures shown above would not likely account for any impact CPV Valley may have.

Congestion Rents in Brattle vs. NYISO Base Case

Ranked by Brattle Congestion Rents

Constraints	2019 Brattle Base	2019 Delta to NYISO Base
CENTRAL EAST	306,077	48,883
HUNTLEY PACKARD	49,083	(16,019)
VOLNEY SCRIBA	29,874	(116,825)
DUNWOODIE SHORE ROAD	25,050	(2,673)
LEEDS PLEASANT VALLEY	23,587	(12,140)
Ramapo PAR	18,322	1,048
VLY STRM2 138.00-E.G.C.-2 138.00	9,816	(11,219)
GARDV230 230.00-STOLE230 230.00	5,614	5,491
GREENWOOD	5,150	(2,759)
BURNS138 138.00-WHAV138 138.00	2,500	1,018
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont	**1,371,739**	**(506,251)**

Ranked by Congestion Rent Differences

Constraints	2019 Brattle Base	2019 Delta to NYISO Base
CENTRAL EAST	306,077	48,883
GARDV230 230.00-STOLE230 230.00	5,614	5,491
NEW SCOTLAND LEEDS	2,185	2,185
CLAY 345.00-CLAY 115.00	71	(2,407)
DUNWOODIE SHORE ROAD	25,050	(2,673)
GREENWOOD	5,150	(2,759)
VLY STRM2 138.00-E.G.C.-2 138.00	9,816	(11,219)
LEEDS PLEASANT VALLEY	23,587	(12,140)
HUNTLEY PACKARD	49,083	(16,019)
VOLNEY SCRIBA	29,874	(116,825)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont	**1,371,739**	**(506,251)**

Note: The Brattle 2019 Base Case MAPS run listed here is without CPV Valley as it was completed in March 2015, prior to the CPV Valley announcement.

V.A.1. MAPS Analysis of Production Cost Savings: Base Case

Forecasted Congestion vs. Historical

Top Historical NYCA Constraints – Historical and Forecasted Congestion Rent

Rank	Constrained Path	Annual Congestion Rent ($m)												
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	**Historical Average**	2019	2024
1	CENTRAL EAST - VC	$24	$58	$177	$348	$128	$146	$105	$77	$318	$334	**$171**	$306	$295
2	NEW SCOTLAND PLEASANT VALLEY	$56	$133	$142	$228	$59	$75	$95	$41	$48	$16	**$89**	$26	$67
3	DUNWOODIE SHORE ROAD	$82	$124	$68	$47	$29	$40	$47	$49	$60	$33	**$58**	$25	$30
4	GREENWOOD VERNON	$9	$16	$15	$15	$25	$34	$30	$12	$27	$1	**$18**	$1	$1
5	FRESHKILLS WILLOWBROOK	$23	$25	$14	$32	$10	$18	$16	$14	$13	$1	**$17**	$3	$1
6	MOTTHAVEN RAINEY	$0	$0	$13	$76	$14	$8	$5	$1	$0	$0	**$12**	$2	$0
	Historical Top 6 Constraints Total	$193	$355	$429	$746	$266	$322	$297	$195	$466	$386	**$365**	$362	$394
	TCC Fund Annual Total	$737	$601	$577	$985	$380	$414	$406	$295	$661	$558	**$561**		
	Historical Top 6 Constraints % of Total	*26%*	*59%*	*74%*	*76%*	*70%*	*78%*	*73%*	*66%*	*71%*	*69%*	***66%***		

Sources: NYISO hourly DAM limiting constraint data (shadow prices) for 2005-2014. Line and interface limits, forecasted congestion rents MAPS. NYISO annual congestion data summaries for 2005-2014 (TCC Fund annual totals).

Fundamental reasons for lower congestion today and going forward relative to historical congestion:

- Downstate's efficient CCs capacity grew from ~1,000 MW 10 years ago to nearly 4,000 MW today
  - SENY no longer relies as heavily on old, inefficient steam turbines and combustion turbines
  - SENY not short on capacity (until 2025 in Zone J)
- Upstate no longer has as much baseload coal generation
  - 10 years ago, UPNY had ~3,000 MW capacity and ~17,000 GWh annual generation
  - More recently, this declined to ~1,500 MW capacity and ~4,500 GWh annual generation

Note: The Brattle 2019 Base Case MAPS run listed here is without CPV Valley as it was completed in March 2015, prior to the CPV Valley announcement.

Agenda

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases

P6 NYTO

Input Changes:

- Topology: add new lines from Knickerbocker to Pleasant Valley
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Ratings increases on other lines binding in Base Case:
  - 2019 & 2024: CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW
- Central East limits: increase by 50 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	304,699	11,839	283,680	13,803
HUNTLEY PACKARD	A	A	47,704	2,317	74,237	(6,391)
KNICKERBOCK 345.00-N.SCOT77 345.00	F	F	N/A	2,148	N/A	2,790
DUNWOODIE SHORE ROAD	I	K	27,558	687	31,945	2,728
Ramapo PAR	G	G	15,149	154	6,459	2,485
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(22)	36,663	(2,647)
CLAY 345.00-CLAY 115.00	C	C	280	(158)	3,317	(2,909)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,815)	18,288	(17,536)
VOLNEY SCRIBA	C	C	45,074	(18,742)	63,524	(34,038)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(34,375)	50,103	(44,283)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(19,126)**	**1,953,340**	**(70,509)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.43	0.32	51.71	0.26
GENESSEE (B)	35.23	0.23	47.04	0.58
CENTRAL (C)	36.19	0.21	48.28	0.36
NORTH (D)	33.78	0.22	45.70	0.49
MOHAWKVA (E)	35.82	0.28	47.82	0.54
CAPITAL (F)	46.52	0.19	57.79	0.54
HUDSONVA (G)	44.23	(0.26)	56.54	(0.39)
MILLWOOD (H)	44.52	(0.21)	56.89	(0.39)
DUNWOODI (I)	44.47	(0.22)	56.92	(0.43)
NYCITY (J)	45.02	(0.15)	57.44	(0.35)
LONGISLA (K)	48.69	(0.10)	61.86	(0.03)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,511	(8)	4,277	(17)
Total System	29,736	(10)	41,023	(11)

Source: The Brattle Group analysis using MAPS

P7 NYTO

Input Changes:

- Topology: Leeds-PV reconductor
- Leeds-PV limit on existing line: pre-2024 limit increased by 523 MW
- Ratings increases on other lines binding in Base Case:
  - 2019 & 2024: CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW
- Central East limits: increase by 25 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	304,699	9,237	283,680	7,295
NEW SCOTLAND LEEDS	F	F	878	4,925	1,438	11,190
HUNTLEY PACKARD	A	A	47,704	1,963	74,237	(3,036)
DUNWOODIE SHORE ROAD	I	K	27,558	1,115	31,945	2,383
Ramapo PAR	G	G	15,149	692	6,459	3,084
CLAY 345.00-CLAY 115.00	C	C	280	(208)	3,317	(2,892)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(675)	36,663	(2,985)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(18,288)
VOLNEY SCRIBA	C	C	45,074	(13,987)	63,524	(23,713)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(33,481)	50,103	(43,587)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(17,906)**	**1,953,340**	**(44,893)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.43	0.35	51.71	0.42
GENESSEE (B)	35.23	0.29	47.04	0.63
CENTRAL (C)	36.19	0.27	48.28	0.44
NORTH (D)	33.78	0.24	45.70	0.51
MOHAWKVA (E)	35.82	0.31	47.82	0.57
CAPITAL (F)	46.52	0.18	57.79	0.29
HUDSONVA (G)	44.23	(0.16)	56.54	(0.24)
MILLWOOD (H)	44.52	(0.09)	56.89	(0.19)
DUNWOODI (I)	44.47	(0.12)	56.92	(0.25)
NYCITY (J)	45.02	(0.05)	57.44	(0.21)
LONGISLA (K)	48.69	0.04	61.86	0.09

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,511	(7)	4,277	(15)
Total System	29,736	(5)	41,023	(11)

Source: The Brattle Group analysis using MAPS

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases

P9 NYTO

Input Changes:

- Topology: add a third path from Leeds to PV, NS-Leeds reconductor
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Ratings increases on other lines binding in Base Case:
  - 2019 & 2024: New Scotland Leeds increases 616 MW, CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW.
- Central East limits: increase by 50 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	304,699	3,332	283,680	5,596
MOTTHAVEN RAINEY	J	J	1,456	1,577	345	611
HUNTLEY PACKARD	A	A	47,704	1,425	74,237	(5,833)
DUNWOODIE SHORE ROAD	I	K	27,558	1,320	31,945	3,148
Ramapo PAR	G	G	15,149	478	6,459	3,882
CLAY 345.00-CLAY 115.00	C	C	280	(215)	3,317	(2,957)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(798)	36,663	(3,063)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(18,288)
VOLNEY SCRIBA	C	C	45,074	(15,204)	63,524	(23,376)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(33,076)	50,103	(41,431)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(23,760)**	**1,953,340**	**(40,556)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	**Base**	**Impact**	**Base**	**Impact**
WEST (A)	37.43	0.41	51.71	0.51
GENESSEE (B)	35.23	0.40	47.04	0.82
CENTRAL (C)	36.19	0.37	48.28	0.62
NORTH (D)	33.78	0.40	45.70	0.74
MOHAWKVA (E)	35.82	0.43	47.82	0.77
CAPITAL (F)	46.52	0.12	57.79	0.50
HUDSONVA (G)	44.23	(0.33)	56.54	(0.32)
MILLWOOD (H)	44.52	(0.29)	56.89	(0.31)
DUNWOODI (I)	44.47	(0.28)	56.92	(0.34)
NYCITY (J)	45.02	(0.18)	57.44	(0.28)
LONGISLA (K)	48.69	(0.09)	61.86	0.10

Impacts on Production Costs ($m)

	2019		2024	
	Base	**Impact**	**Base**	**Impact**
NYCA+Imports-Exports	3,511	(9)	4,277	(20)
Total System	29,736	(18)	41,023	(18)

Source: The Brattle Group analysis using MAPS

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases

P11 NYTO

Input Changes:

- Topology: new line from Edic to New Scotland; add new lines from Knickerbocker to Pleasant Valley
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Rating increases on other lines binding in Base Case:
  - 2019 & 2024: CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW.
- Central East limits: increase by 375 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
NEW SCOTLAND LEEDS	F	F	878	4,892	1,438	6,465
KNICKERBOCK 345.00-N.SCOT77 345.00	F	F	N/A	2,261	N/A	3,475
DUNWOODIE SHORE ROAD	I	K	27,558	1,891	31,945	3,802
HUNTLEY PACKARD	A	A	47,704	592	74,237	(8,989)
CLAY 345.00-CLAY 115.00	C	C	280	(280)	3,317	(3,317)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(1,891)	36,663	(6,769)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(16,974)
VOLNEY SCRIBA	C	C	45,074	(31,519)	63,524	(42,942)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(35,016)	50,103	(47,637)
CENTRAL EAST	D/E/F	NE/F	304,699	(54,092)	283,680	(43,435)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(120,066)**	**1,953,340**	**(137,668)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	**Base**	**Impact**	**Base**	**Impact**
WEST (A)	37.43	1.23	51.71	1.06
GENESSEE (B)	35.23	1.39	47.04	1.72
CENTRAL (C)	36.19	1.31	48.28	1.43
NORTH (D)	33.78	1.75	45.70	1.92
MOHAWKVA (E)	35.82	1.57	47.82	1.79
CAPITAL (F)	46.52	(1.50)	57.79	(0.92)
HUDSONVA (G)	44.23	(0.65)	56.54	(0.61)
MILLWOOD (H)	44.52	(0.61)	56.89	(0.60)
DUNWOODI (I)	44.47	(0.59)	56.92	(0.61)
NYCITY (J)	45.02	(0.48)	57.44	(0.51)
LONGISLA (K)	48.69	(0.28)	61.86	(0.06)

Impacts on Production Costs ($m)

	2019		2024	
	Base	**Impact**	**Base**	**Impact**
NYCA+Imports-Exports	3,511	(39)	4,277	(24)
Total System	29,736	(35)	41,023	(23)

Source: The Brattle Group analysis using MAPS

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases

P12 NYTO

Input Changes:

- Topology: new line from Edic to New Scotland; reconductor NS-Leeds-PV
- Leeds-PV limit on existing line : pre-2024 limit increased by 523 MW with Leeds-PV reconductor
- Rating increases on other lines binding in Base Case:
  - 2019 & 2024: New Scotland Leeds increases 616 MW, CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW.
- Central East limits: increase by 375 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
DUNWOODIE SHORE ROAD	I	K	27,558	2,587	31,945	4,061
MOTTHAVEN RAINEY	J	J	1,456	1,522	345	726
HUNTLEY PACKARD	A	A	47,704	678	74,237	(10,139)
Ramapo PAR	G	G	15,149	294	6,459	3,672
CLAY 345.00-CLAY 115.00	C	C	280	(280)	3,317	(3,307)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(2,582)	36,663	(8,784)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(18,288)
VOLNEY SCRIBA	C	C	45,074	(30,064)	63,524	(41,231)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(31,499)	50,103	(39,627)
CENTRAL EAST	D/E/F	NE/F	304,699	(63,281)	283,680	(49,165)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(141,831)**	**1,953,340**	**(145,200)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.43	1.40	51.71	1.15
GENESSEE (B)	35.23	1.60	47.04	1.95
CENTRAL (C)	36.19	1.50	48.28	1.62
NORTH (D)	33.78	1.97	45.70	2.14
MOHAWKVA (E)	35.82	1.74	47.82	1.95
CAPITAL (F)	46.52	(1.66)	57.79	(1.02)
HUDSONVA (G)	44.23	(0.67)	56.54	(0.50)
MILLWOOD (H)	44.52	(0.64)	56.89	(0.50)
DUNWOODI (I)	44.47	(0.64)	56.92	(0.54)
NYCITY (J)	45.02	(0.53)	57.44	(0.45)
LONGISLA (K)	48.69	(0.24)	61.86	0.04

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,511	(30)	4,277	(39)
Total System	29,736	(32)	41,023	(25)

Source: The Brattle Group analysis using MAPS

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases

P14 NYTO

Input Changes:

- Topology: new line from Edic to New Scotland; reconductor NS-Leeds-PV
- Leeds-PV limit on existing line : pre-2024 limit tightened by 93 MW
- Rating increases on other lines binding in Base Case:
  - 2019 & 2024: New Scotland Leeds increases 616 MW, CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW
- Central East limits: increase by 375MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
DUNWOODIE SHORE ROAD	I	K	27,558	2,726	31,945	4,008
MOTTHAVEN RAINEY	J	J	1,456	1,745	345	687
Ramapo PAR	G	G	15,149	743	6,459	3,628
HUNTLEY PACKARD	A	A	47,704	201	74,237	(9,770)
CLAY 345.00-CLAY 115.00	C	C	280	(280)	3,317	(3,317)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(2,418)	36,663	(8,649)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(18,288)
VOLNEY SCRIBA	C	C	45,074	(30,051)	63,524	(41,554)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(32,970)	50,103	(42,368)
CENTRAL EAST	D/E/F	NE/F	304,699	(58,230)	283,680	(45,082)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(132,738)**	**1,953,340**	**(139,574)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	**Base**	**Impact**	**Base**	**Impact**
WEST (A)	37.43	1.35	51.71	1.14
GENESSEE (B)	35.23	1.56	47.04	1.92
CENTRAL (C)	36.19	1.47	48.28	1.62
NORTH (D)	33.78	1.92	45.70	2.12
MOHAWKVA (E)	35.82	1.72	47.82	1.96
CAPITAL (F)	46.52	(1.49)	57.79	(0.84)
HUDSONVA (G)	44.23	(0.70)	56.54	(0.57)
MILLWOOD (H)	44.52	(0.68)	56.89	(0.58)
DUNWOODI (I)	44.47	(0.66)	56.92	(0.60)
NYCITY (J)	45.02	(0.55)	57.44	(0.50)
LONGISLA (K)	48.69	(0.24)	61.86	(0.01)

Impacts on Production Costs ($m)

	2019		2024	
	Base	**Impact**	**Base**	**Impact**
NYCA+Imports-Exports	3,511	(30)	4,277	(39)
Total System	29,736	(34)	41,023	(24)

Source: The Brattle Group analysis using MAPS

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases
P19a NextEra

Input Changes:

- Topology: add new lines from Knickerbocker to Pleasant Valley
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Ratings increases on other lines binding in Base Case:
  - 2019 & 2024: CPV_VLY 345.00-ROCK TAV 345.00 increases 352 MW
- Central East limits: increase by 50 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	304,699	11,839	283,680	13,803
HUNTLEY PACKARD	A	A	47,704	2,317	74,237	(6,391)
KNICKERBOCK 345.00-N.SCOT77 345.00	F	F	N/A	2,148	N/A	2,790
DUNWOODIE SHORE ROAD	I	K	27,558	687	31,945	2,728
Ramapo PAR	G	G	15,149	154	6,459	2,485
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(22)	36,663	(2,647)
CLAY 345.00-CLAY 115.00	C	C	280	(158)	3,317	(2,909)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,815)	18,288	(17,536)
VOLNEY SCRIBA	C	C	45,074	(18,742)	63,524	(34,038)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(34,375)	50,103	(44,283)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**(19,126)**	**1,953,340**	**(70,509)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	**Base**	**Impact**	**Base**	**Impact**
WEST (A)	37.43	0.32	51.71	0.26
GENESSEE (B)	35.23	0.23	47.04	0.58
CENTRAL (C)	36.19	0.21	48.28	0.36
NORTH (D)	33.78	0.22	45.70	0.49
MOHAWKVA (E)	35.82	0.28	47.82	0.54
CAPITAL (F)	46.52	0.19	57.79	0.54
HUDSONVA (G)	44.23	(0.26)	56.54	(0.39)
MILLWOOD (H)	44.52	(0.21)	56.89	(0.39)
DUNWOODI (I)	44.47	(0.22)	56.92	(0.43)
NYCITY (J)	45.02	(0.15)	57.44	(0.35)
LONGISLA (K)	48.69	(0.10)	61.86	(0.03)

Impacts on Production Costs ($m)

	2019		2024	
	Base	**Impact**	**Base**	**Impact**
NYCA+Imports-Exports	3,511	(8)	4,277	(17)
Total System	29,736	(10)	41,023	(11)

Source: The Brattle Group analysis using MAPS

P20 Boundless

Input Changes:

- Topology: NS-LD SR, (LD-PV, LD-HA, CPV-RT reconductor), LD-HA-R SC, RS-EF two cables
- Leeds-PV limit on existing line: pre-2024 limit increased by 551 MW with Leeds-PV reconductor
- Ratings increases on other lines binding in Base Case:
  - 2019 & 2024: CPV_VLY 345.00-ROCK TAV 345.00 increases 1050MW
- Central East limits: *decrease* by 25 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
HURLEYSC 345.00-ROSETON 345.00	G	G	N/A	15,456	N/A	29,693
CENTRAL EAST	D/E/F	NE/F	304,699	13,941	283,680	12,703
HUNTLEY PACKARD	A	A	47,704	1,587	74,237	(3,963)
DUNWOODIE SHORE ROAD	I	K	27,558	509	31,945	2,043
Ramapo PAR	G	G	15,149	340	6,459	3,256
CLAY 345.00-CLAY 115.00	C	C	280	(168)	3,317	(2,627)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(372)	36,663	(1,664)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(18,288)
VOLNEY SCRIBA	C	C	45,074	(10,917)	63,524	(16,668)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(35,636)	50,103	(50,103)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**4,910**	**1,953,340**	**(15,711)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.43	0.18	51.71	0.21
GENESSEE (B)	35.23	0.13	47.04	0.39
CENTRAL (C)	36.19	0.12	48.28	0.24
NORTH (D)	33.78	0.07	45.70	0.27
MOHAWKVA (E)	35.82	0.16	47.82	0.36
CAPITAL (F)	46.52	0.44	57.79	0.51
HUDSONVA (G)	44.23	(0.13)	56.54	(0.28)
MILLWOOD (H)	44.52	(0.08)	56.89	(0.20)
DUNWOODI (I)	44.47	(0.09)	56.92	(0.24)
NYCITY (J)	45.02	(0.05)	57.44	(0.21)
LONGISLA (K)	48.69	(0.00)	61.86	0.06

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,511	(3)	4,277	(10)
Total System	29,736	(9)	41,023	(12)

Source: The Brattle Group analysis using MAPS

P21 Boundless

Input Changes:

- Topology: NS-LD SR, (LD-HA, CPV-RT reconductor), LD-HA-R SC, RS-EF two cables
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW
- Ratings increases on other lines binding in Base Case :
  - 2019 & 2024: CPV_VLY 345.00-ROCK TAV 345.00 increases 1050MW
- Central East limits: *decrease* by 25 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO, in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
HURLEYSC 345.00-ROSETON 345.00	G	G	N/A	17,543	N/A	32,512
CENTRAL EAST	D/E/F	NE/F	304,699	10,301	283,680	10,613
HUNTLEY PACKARD	A	A	47,704	1,651	74,237	(4,794)
Ramapo PAR	G	G	15,149	458	6,459	3,130
DUNWOODIE SHORE ROAD	I	K	27,558	376	31,945	1,738
CLAY 345.00-CLAY 115.00	C	C	280	(169)	3,317	(2,592)
GARDV230 230.00-STOLE230 230.00	A	A	7,130	(514)	36,663	(1,645)
LEEDS PLEASANT VALLEY	F	G	4,859	(4,859)	18,288	(18,288)
VOLNEY SCRIBA	C	C	45,074	(10,227)	63,524	(15,683)
CPV_VLY 345.00-ROCK TAV 345.00	G	G	35,636	(35,636)	50,103	(50,103)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,381,332**	**3,572**	**1,953,340**	**2,330**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	**Base**	**Impact**	**Base**	**Impact**
WEST (A)	37.43	0.20	51.71	0.19
GENESSEE (B)	35.23	0.15	47.04	0.40
CENTRAL (C)	36.19	0.15	48.28	0.24
NORTH (D)	33.78	0.10	45.70	0.27
MOHAWKVA (E)	35.82	0.18	47.82	0.36
CAPITAL (F)	46.52	0.35	57.79	0.45
HUDSONVA (G)	44.23	(0.15)	56.54	(0.28)
MILLWOOD (H)	44.52	(0.08)	56.89	(0.19)
DUNWOODI (I)	44.47	(0.09)	56.92	(0.22)
NYCITY (J)	45.02	(0.06)	57.44	(0.19)
LONGISLA (K)	48.69	(0.03)	61.86	0.03

Impacts on Production Costs ($m)

	2019		2024	
	Base	**Impact**	**Base**	**Impact**
NYCA+Imports-Exports	3,511	(3)	4,277	(9)
Total System	29,736	(6)	41,023	(9)

Source: The Brattle Group analysis using MAPS

P20 and P21 Boundless and Central East

Impact on Central East Limits

- Production Costs savings are smaller with P20 and P21 because the Central East limit *decreases* (by 25 MW) with these portfolios, compared to others where they increase
  - Benefits of UPNY-SENY limit increase is not as utilized as other cases; lower downstate LBMP and higher upstate LBMP, but price impacts are generally smaller

P20 Impacts on LBMPs

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.43	0.18	51.71	0.21
GENESSEE (B)	35.23	0.13	47.04	0.39
CENTRAL (C)	36.19	0.12	48.28	0.24
NORTH (D)	33.78	0.07	45.70	0.27
MOHAWKVA (E)	35.82	0.16	47.82	0.36
CAPITAL (F)	46.52	0.44	57.79	0.51
HUDSONVA (G)	44.23	(0.13)	56.54	(0.28)
MILLWOOD (H)	44.52	(0.08)	56.89	(0.20)
DUNWOODI (I)	44.47	(0.09)	56.92	(0.24)
NYCITY (J)	45.02	(0.05)	57.44	(0.21)
LONGISLA (K)	48.69	(0.00)	61.86	0.06

P21 Impacts on LBMPs

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.43	0.20	51.71	0.19
GENESSEE (B)	35.23	0.15	47.04	0.40
CENTRAL (C)	36.19	0.15	48.28	0.24
NORTH (D)	33.78	0.10	45.70	0.27
MOHAWKVA (E)	35.82	0.18	47.82	0.36
CAPITAL (F)	46.52	0.35	57.79	0.45
HUDSONVA (G)	44.23	(0.15)	56.54	(0.28)
MILLWOOD (H)	44.52	(0.08)	56.89	(0.19)
DUNWOODI (I)	44.47	(0.09)	56.92	(0.22)
NYCITY (J)	45.02	(0.06)	57.44	(0.19)
LONGISLA (K)	48.69	(0.03)	61.86	0.03

P20 Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,511	(3)	4,277	(10)
Total System	29,736	(9)	41,023	(12)

P21 Impacts on Production Costs ($m)

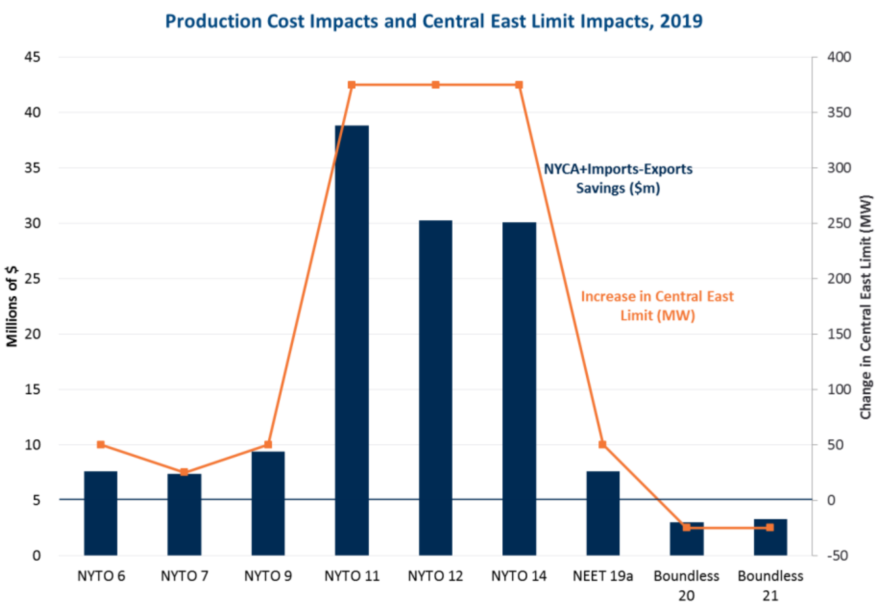
	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,511	(3)	4,277	(9)
Total System	29,736	(6)	41,023	(9)

Source: The Brattle Group analysis using MAPS

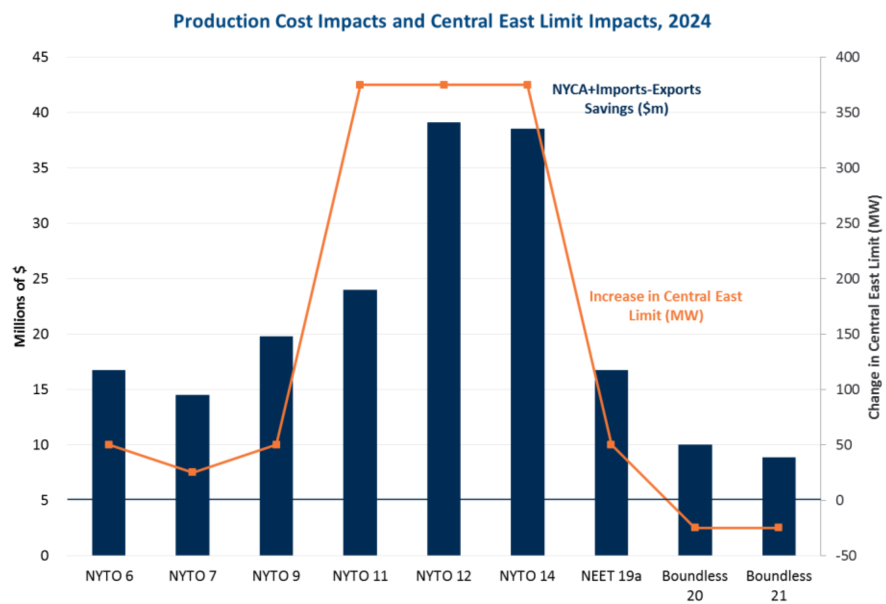
Production Cost and C/E Limit Changes

Production cost savings are correlated to changes in Central East Interface limit

- Significant increases to the Central East limit can improve the PCS associated with UPNY/SENY upgrades
- Once UPNY/SENY is upgraded (and no longer constrained), higher Central East limit enables more flow from upstate to downstate



Source: GE MAPS output files.

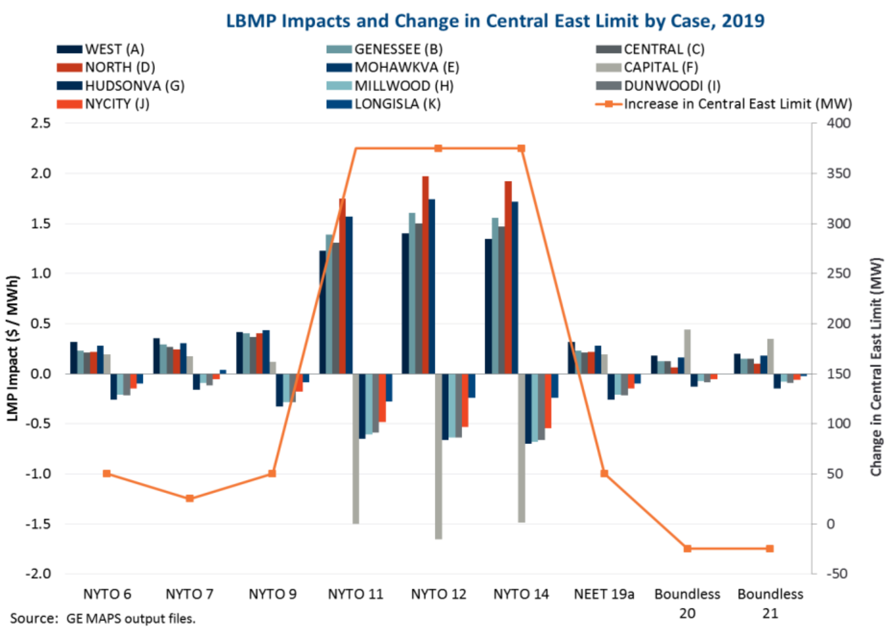


Source: GE MAPS output files.

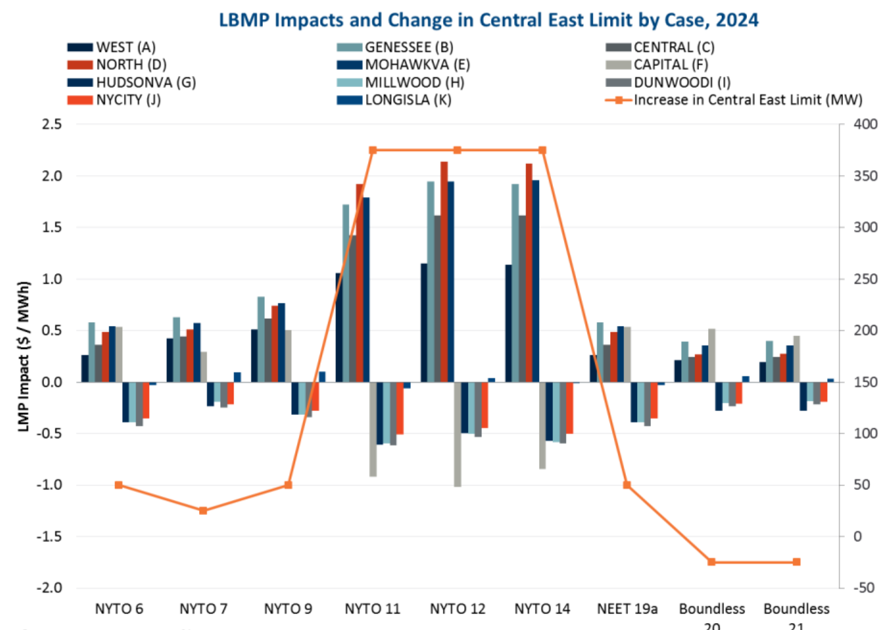
LBMP Impacts and C/E Limit Changes

Central East limits impact zonal LBMP patterns

- Higher Central East limits for P11, P12, and P14 lowers LBMP for Zone F, while other portfolios with smaller increase in Central East limits show higher LBMPs for Zone F
- This indicates that P11, P12, and P14 may have additional production cost savings benefits from increasing UPNY/SENY transfer limits further (i.e., UPNY/SENY is the limiting factor for these portfolios while Central East is limiting for other portfolios)



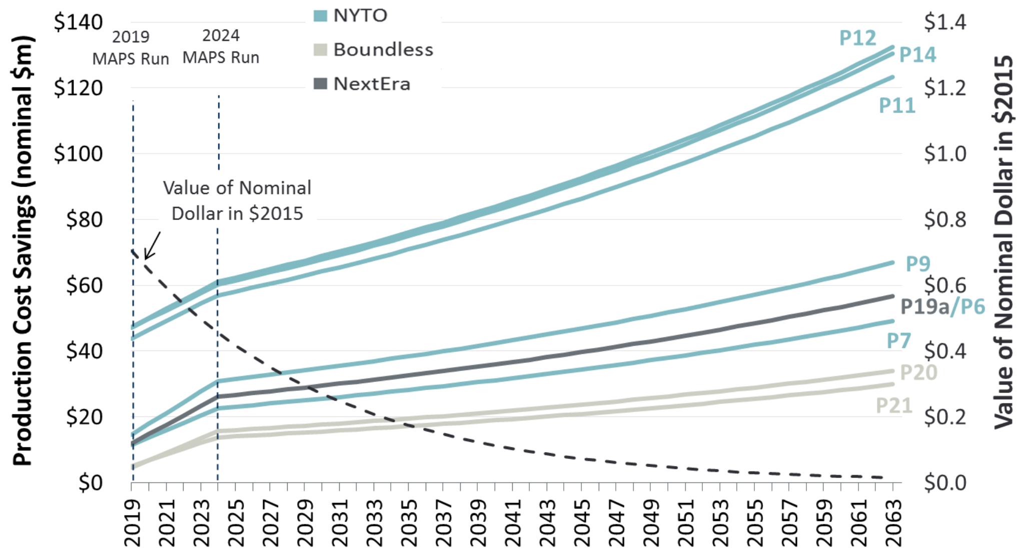
Source: GE MAPS output files.

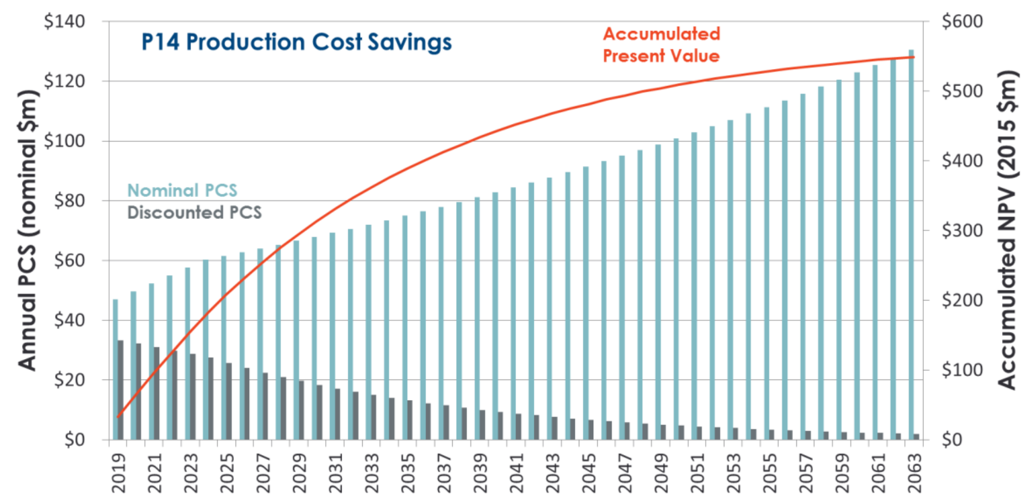


Source: GE MAPS output files.

Production Cost Savings from MAPS

- Production cost savings from MAPS for 2019 and 2024 used to estimate savings over physical life of assets
  - <u>2020 – 2023</u>: Interpolate linearly between 2019 and 2024 results in nominal terms
  - <u>2024 – 2063</u>: Escalate 2024 results by 2% per year to remain constant in real terms
  - *Note*: REV resources not shown here due to significantly higher annual production cost savings of $208m in 2019 and $331m in 2024
- Calculate NPV of production cost savings by discounting future savings back to 2015 dollars using 9.13% discount rate recommended by DPS
- NPV of production cost savings for P14 shown here for demonstration purposes





Production Cost Savings for REV Resources

REV alternative reduces the NPV of production costs by ~$1.9 billion

- PCS are calculated in 2019 and 2024 using zonal average LBMPs from MAPS
- REV resources are assumed to be phased in from 2016-2020 (20% of total each year); GWh savings shown below apply to years in which full 1,200 MW peak reduction is achieved
- Savings are likely optimistic due to assumption that avoided production costs are equal to LBMP *times* Energy Savings and the high assumed capacity factor of EE (offset somewhat by assuming average LBMPs, instead of load-weighted LBMPs)

Estimated Production Cost Savings of the REV Alternative

	Annual GWh Energy Savings by Zone					Nominal 2019 Savings ($m)	Nominal 2024 Savings ($m)	Measure Life	NPV
Resource Type	G	H	I	J	Total	G-J	G-J	(years)	**(2015 $m)**
Energy Efficiency	598	154	328	4,417	**5,497**	$197	$315	12	$1,809
Customer-sited Renewables	31	8	7	53	**98**	$4	$6	25	$48
Combined Heat & Power	4	0	0	190	**195**	$7	$11	20	$88
Demand Response	0	0	0	0	**0**	$0	$0	10	$0
Fossil Fuel Distributed Generation	0	0	0	0	**0**	$0	$0	--	$0
Grid Integrated Vehicles	(0)	(0)	(0)	(1)	**(2)**	($0.1)	($0.1)	10	($0)
Storage (flywheel and battery)	(1)	(0)	(0)	(3)	**(5)**	($0.2)	($0.3)	15	($2)
Rate Structures	0	0	0	0	**0**	$0	$0	15	
Total	**632**	**161**	**335**	**4,656**	**5,783**	**$208**	**$331**		**$1,943**

Sources: REV GEIS. See slide 51 for sources supporting resource distribution and economic life estimates.

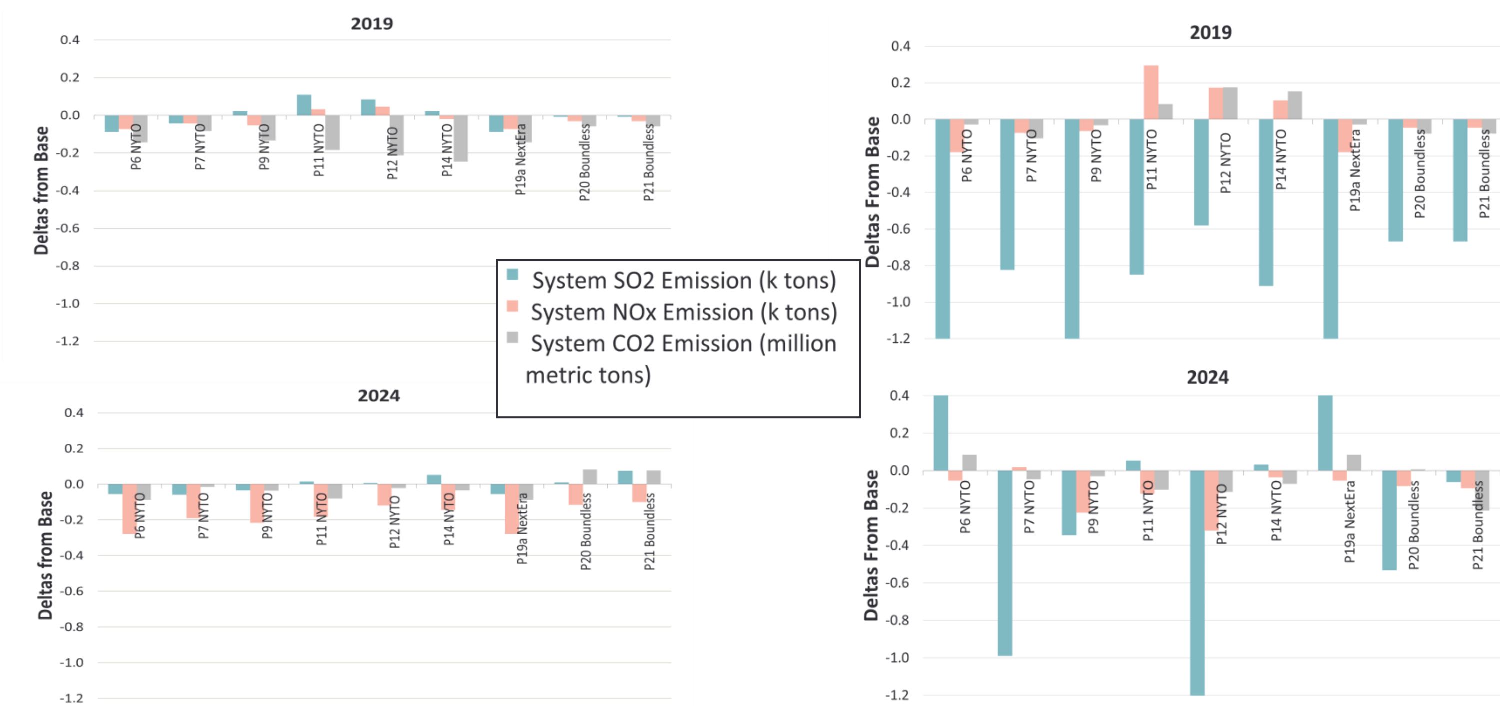
* REV case was not modeled in MAPS, although PCS are calculated using LBMPs from MAPS

Emissions Impacts from MAPS

No clear patterns among various portfolios

- Emission allowance prices have small impact on the marginal cost of generation
- CO_2 emission reduction for NYCA across all Change Cases indicates a more efficient dispatch (less fossil fuel usage) with transmission upgrades
- Change in coal unit dispatch (Huntley and Somerset) largely explains the NYCA-wide emissions changes, as described in the following slides

NYCA-wide Change in Emissions | System-wide Change in Emissions

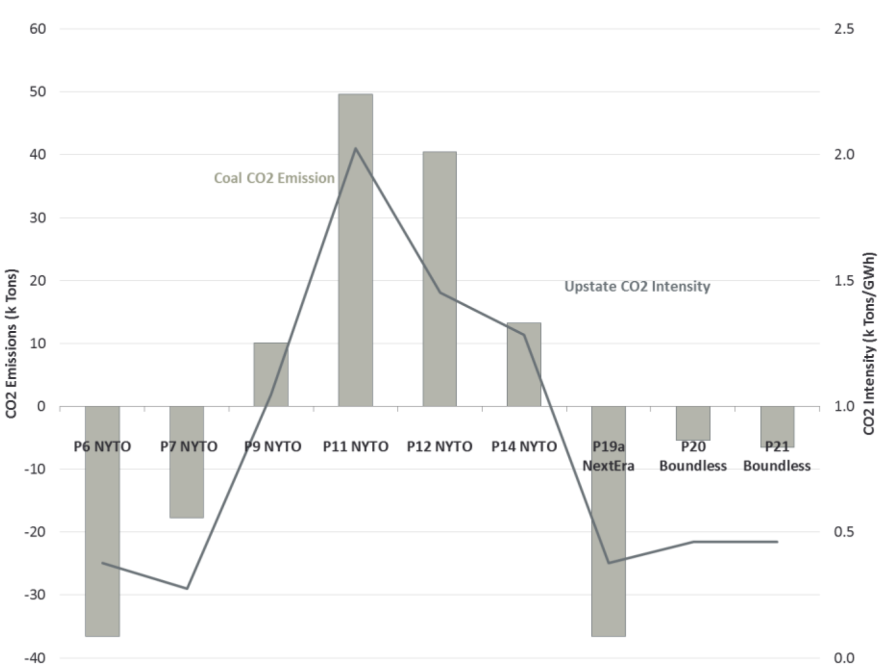


CO_2 Emissions Impacts

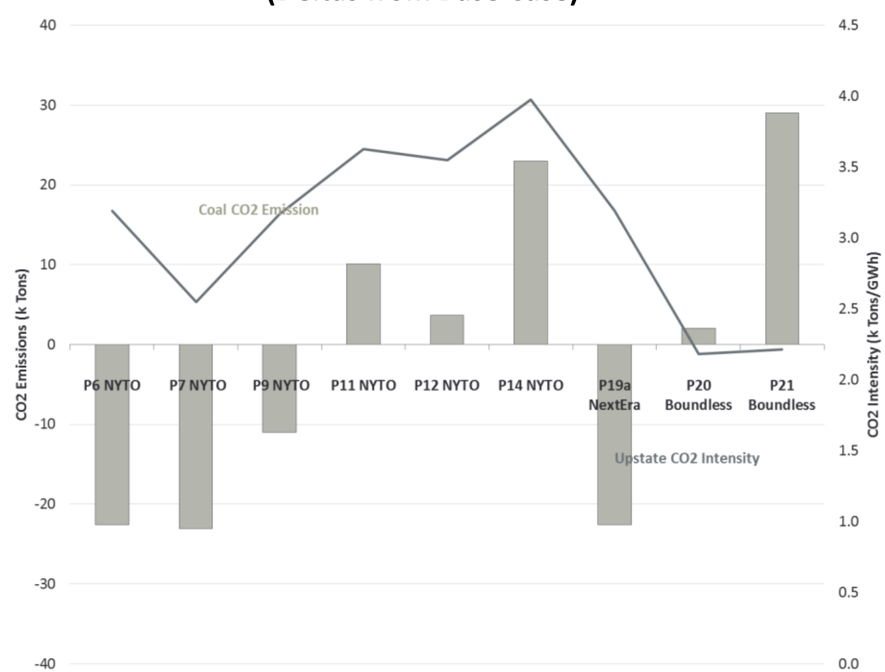
Trends in emissions can be explained largely by changes in generation from coal plants

- Upstate CO_2 intensity (shown as line in figures below) mostly follows changes in emissions from two upstate coal plants - Huntley and AES Somerset (shown as bars in figures below)
- Downstate CO_2 intensity is less than the Base Case in all Change Cases (not shown here)

2019 Coal CO_2 Emissions and Upstate CO_2 Intensity (Deltas from Base Case)



2024 Coal CO_2 Emissions and Upstate CO_2 Intensity (Deltas from Base Case)

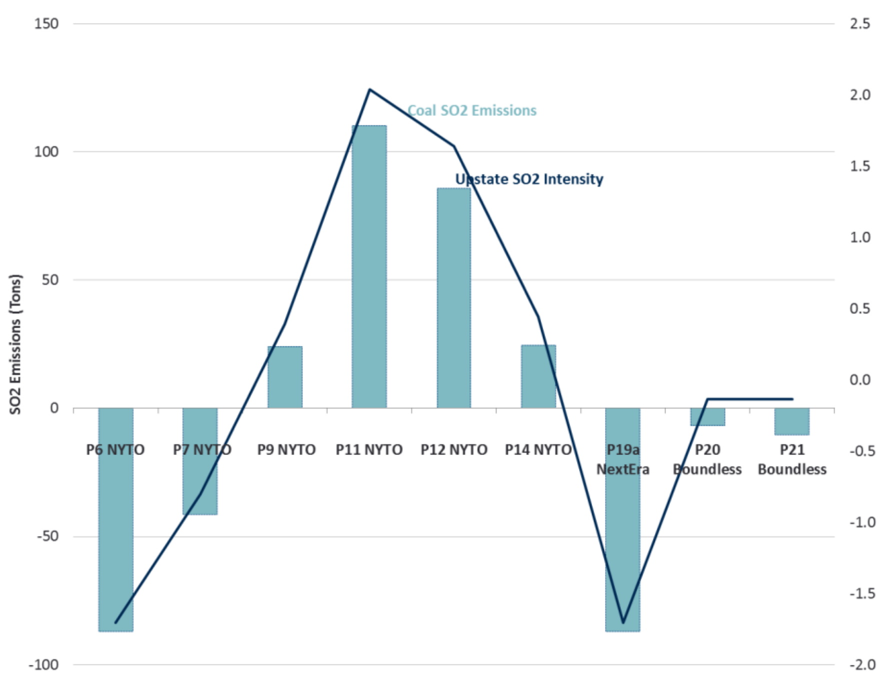


SO_2 Emissions Impacts

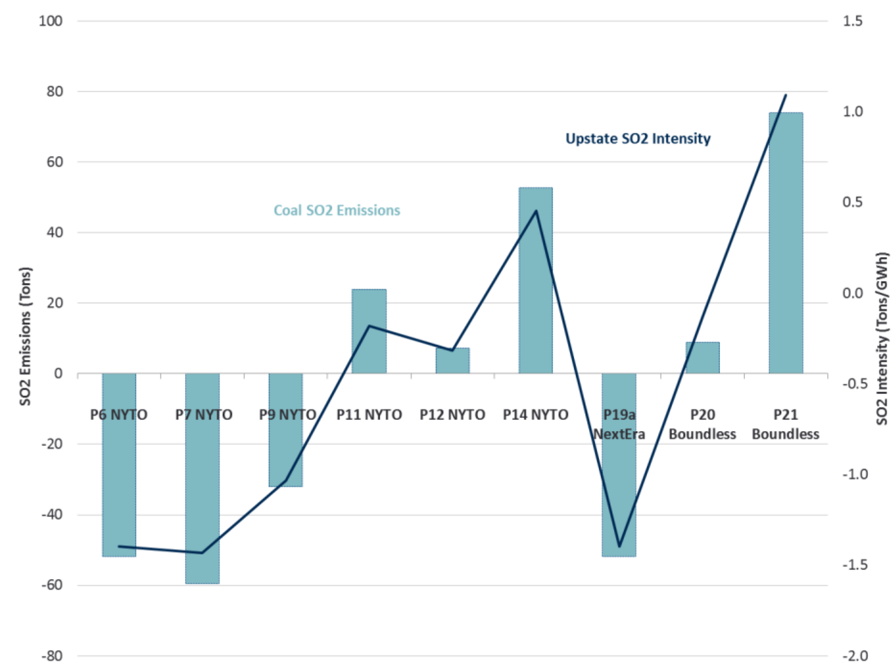
Trends in emissions can largely be explained by changes in generation from coal plants

- Upstate SO_2 intensity (shown as line in figures below) mostly follows changes in emissions from two upstate coal plants - Huntley and AES Somerset (shown as bars in figures below)
- Downstate SO_2 intensity is generally the same as the Base Case (not shown here)

2019 Coal SO_2 Emissions and Upstate SO_2 Intensity (Deltas from Base Case)



2024 Coal SO_2 Emissions and Upstate SO_2 Intensity (Deltas from Base Case)

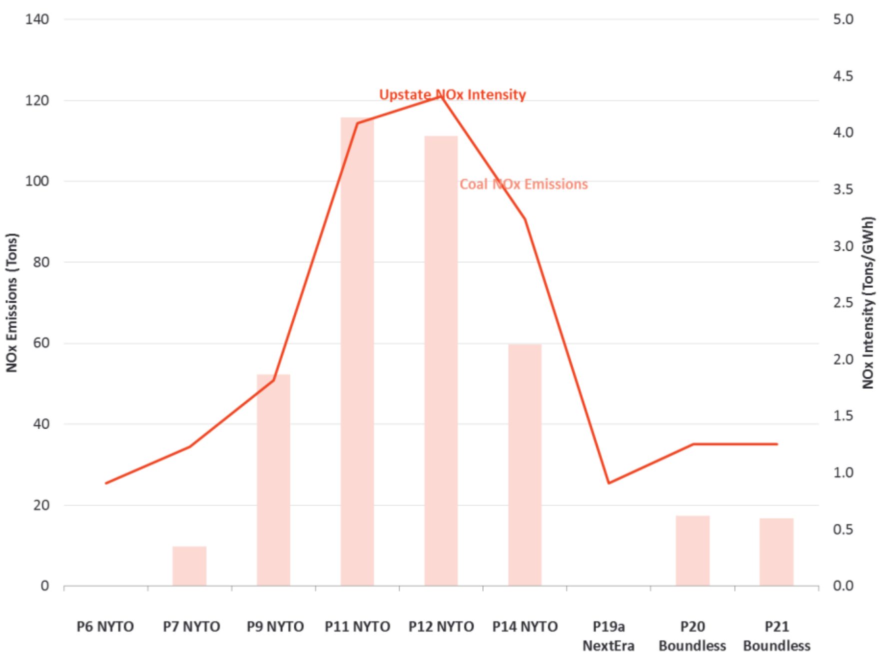


NOx Emissions Impacts

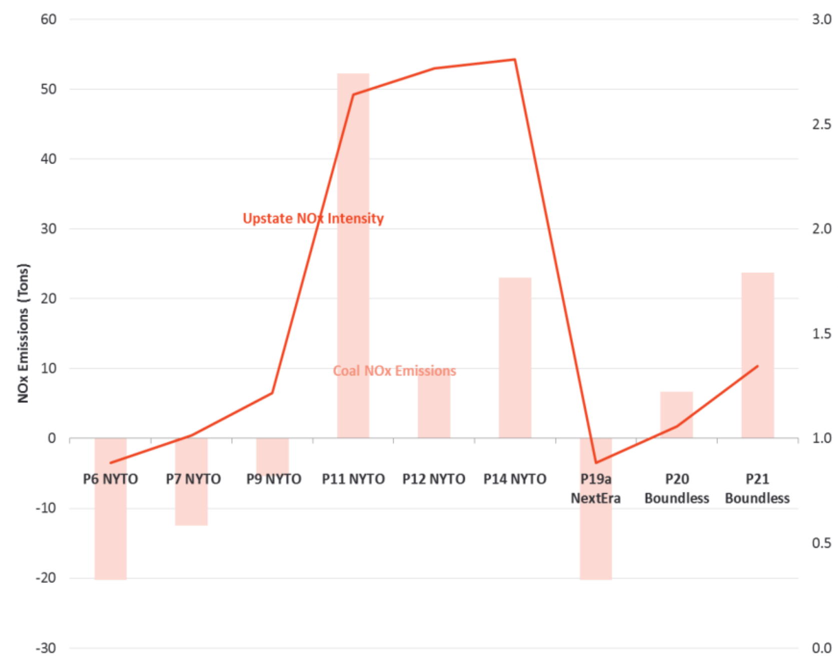
Trends in emissions can be explained largely by changes in generation from coal plants

- Upstate NOx intensity (shown as line in figures below) mostly follows changes in emissions from two upstate coal plants - Huntley and AES Somerset (shown as bars in figures below)
- Downstate NOx intensity is less than the Base Case in all Change Cases (not shown here)

2019 Coal NOx Emissions and Upstate NOx Intensity (Deltas from Base Case)



2024 Coal NOx Emissions and Upstate NOx Intensity (Deltas from Base Case)



Note: Delta to Base NOx emissions in P6 and P19a virtually zero out when summing over Huntley (-98 compared to base) and Somerset (+98 compared to Base)

V.A.2. MAPS Analysis of Production Cost Savings: Change Cases

Summary of CARIS Metrics

	units	Base Case 2019	Base Case 2024	NYTO 6 2019	NYTO 6 2024	NYTO 7 2019	NYTO 7 2024	NYTO 9 2019	NYTO 9 2024	NYTO 11 2019	NYTO 11 2024	NYTO 12 2019	NYTO 12 2024	NYTO 14 2019	NYTO 14 2024	NEET 19a 2019	NEET 19a 2024	Boundless 20 2019	Boundless 20 2024	Boundless 21 2019	Boundless 21 2024	REV 2019	REV 2024
		Absolute		*delta*		*delta*		*delta*		*delta*		*delta*		*delta*		*delta*		*delta*		*delta*		*delta*	
Production Costs (PC)																							
NYCA Adjusted PC	*$m*	3,511	4,277	-8	-17	-7	-15	-9	-20	-39	-24	-30	-39	-30	-39	-8	-17	-3	-10	-3	-9		
Total System PC	*$m*	29,736	41,023	-10	-11	-5	-11	-18	-18	-35	-23	-32	-25	-34	-24	-10	-11	-9	-12	-6	-9		
Payments																							
NYCA Generator	*$m*	5,475	7,491	35	70	33	73	30	87	72	130	77	149	77	148	35	70	19	57	20	53		
NYCA Load Payments	*$m*	6,835	8,915	2	-2	9	7	6	18	19	27	17	35	21	39	2	-2	8	3	5	0		
Congestion Rents																							
NYCA Congestion	*$m*	844	1,080	-39	-85	-33	-72	-44	-78	-111	-143	-125	-152	-120	-152	-39	-85	-22	-48	-23	-47		
Emissions																							
NYCA CO2	*1000 tons*	28,274	31,208	-144	-87	-84	-15	-134	-36	-184	-79	-213	-22	-246	-34	-144	-87	-58	83	-42	78	-1,231	-1,538
	%			-0.5%	-0.3%	-0.3%	0.0%	-0.5%	-0.1%	-0.7%	-0.3%	-0.8%	-0.1%	-0.9%	-0.1%	-0.5%	-0.3%	-0.2%	0.3%	-0.1%	0.2%		
NYCA SOX	*tons*	2,754	3,379	-88	-54	-43	-58	23	-34	109	14	85	6	23	51	-88	-54	-7	9	-11	74	-1,725	-2,157
	%			-3.2%	-1.6%	-1.5%	-1.7%	0.8%	-1.0%	4.0%	0.4%	3.1%	0.2%	0.8%	1.5%	-3.2%	-1.6%	-0.3%	0.3%	-0.4%	2.2%		
NYCA NOX	*tons*	17,207	18,665	-73	-278	-43	-189	-53	-217	32	-183	45	-119	-19	-144	-73	-278	-32	-115	-22	-100	-1,438	-1,797
	%			-0.4%	-1.5%	-0.3%	-1.0%	-0.3%	-1.2%	0.2%	-1.0%	0.3%	-0.6%	-0.1%	-0.8%	-0.4%	-1.5%	-0.2%	-0.6%	-0.1%	-0.5%		
Total System CO2	*1000 tons*	482,635	445,620	-29	84	-104	-46	-32	-29	84	-102	175	-115	153	-71	-29	84	-78	6	-33	-213		
	%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%		
Total System SOX	*tons*	316,731	288,491	-1,589	657	-824	-990	-1,366	-345	-849	53	-580	-1,293	-912	31	-1,589	657	-669	-532	-771	-61		
	%			-0.5%	0.2%	-0.3%	-0.3%	-0.4%	-0.1%	-0.3%	0.0%	-0.2%	-0.4%	-0.3%	0.0%	-0.5%	0.2%	-0.2%	-0.2%	-0.2%	0.0%		
Total System NOX	*tons*	329,019	307,225	-180	-54	-74	17	-64	-225	296	-123	173	-321	103	-35	-180	-54	-46	-83	-50	-94		
	%			-0.1%	0.0%	0.0%	0.0%	0.0%	-0.1%	0.1%	0.0%	0.1%	-0.1%	0.0%	0.0%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%		

Notes:

Red values indicate adverse impacts (such as increasing costs or greater emissions)

NYCA Adjusted Production Cost Savings is defined as Total NYCA+Imports-Exports, with Imports and Exports valued at border LBMPs

ICAP Savings not shown here; see next section of this presentation

REV metrics calculated using MAPS base case LBMPs; emissions from EIS report

IP Retirement: Assumptions

What would be the production cost savings of new transmission if Indian Point retired in 2019 without forewarning? Compare two scenarios:

- **IP-Out Base Case with Compensating Generation**
  - No need for any compensating generation through 2021.
  - 330 MW CC online by 2022 (330 MW is consistent with CARIS assumptions) to meet reliability standards (7,000 Btu/kWh full load heat rate and $7/MWh VOM, distributed among high voltage buses in Zone G)

Adjusted Compensatory MW (Zones G-J)

	Compensating MW Needed with Indian Point Retirement						
	2016 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)
2014 CRP Compensatory MW	500						
2014 Gold Book G-J Non-Coincident Summer Peak Load	16,749						
2015 Gold Book G-J Non-Coincident Summer Peak Load	16,441	16,800	16,867	16,957	17,053	17,158	17,263
Change in Load (relative to 2016 in 2014 Gold Book)	-308	51	118	208	304	409	514
Compensatory MW Needs (without CPV Valley)	192	551	618	708	804	909	1,014
Compensating MW Needs with CPV Valley (760 MW)	-568	-209	-142	-52	44	149	254

Sources: 2014 CRP (p. 23); 2014 Gold Book (p. 14); 2015 Long Term Forecast from NYISO .

- **IP-Out with Tx Solution** (modeling in MAPS one representative Tx portfolio)
  - Tx in service prior to IP surprise retirement
  - No compensating generation needed for reliability since Tx provides adequate imports to SENY

While these scenarios relate to the retirement of Indian Point, similar (though less extreme) conclusions could be drawn about other large potential retirements

IP Retirement: Production Cost and LBMP Impacts

- NYCA-wide production cost savings from the **IP-Out with Tx Solution** scenario as compared to the **IP-Out Base Case with Compensating Generation** scenario are $749m in NPV terms
- 21% of the PV of production cost savings occur in the 3 years w/o compensating generation
  - The addition of CPV limits the benefits of the Tx solution as compared to the compensating generation solution, as less generation is needed to meet reliability with the retirement of Indian Point (only 330 MW needs to be added in 2022 to meet reliability).

Production Costs Savings from Transmission

Production Cost Savings	NPV ($m)	Percent of Total
No Compenating Generation (2019 - 2021)	160	21%
With Compenating Generation (2022 - 2063)	590	79%
Total (2019 - 2063)	749	100%

- Zone G LBMP impact of the **IP-Out with Tx Solution** (compared to the IP-Out Base Case with Compensating Generation starting in 2022) is **-$0.88** in in 2019 but **+$0.00** in 2024
- LBMP Impact changes more significantly in Zone G from 2019 to 2024 than in surrounding areas.

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	IP-Out Base Case with Compensating Generation	Impact of Tx with IP Out (and no compensating Gen)	IP-Out Base Case with Compensating Generation	Impact of Tx with IP Out (and no compensating Gen)
WEST (A)	38.23	1.67	51.44	2.11
GENESSEE (B)	36.08	1.91	47.37	2.66
CENTRAL (C)	37.14	1.82	48.65	2.43
NORTH (D)	34.59	2.20	45.96	2.86
MOHAWKVA (E)	36.72	2.14	48.14	2.85
CAPITAL (F)	48.68	(0.88)	59.13	0.00
HUDSONVA (G)	47.39	(0.96)	59.54	(0.88)
MILLWOOD (H)	47.65	(0.87)	60.02	(0.95)
DUNWOODI (I)	47.71	(0.96)	60.20	(1.11)
NYCITY (J)	47.92	(0.85)	60.46	(1.00)
LONGISLA (K)	50.01	(0.37)	63.32	(0.42)

Agenda

I. Problem Statement

II. Solutions Analyzed

III. Benefit-Cost Analysis Results

IV. Detailed Cost Information

V. Detailed Benefit Analysis

A. MAPS Analysis of Production Cost Savings

B. Additional Production Cost Savings Not Captured in MAPS

C. ICAP Analysis of Capacity Value

D. Avoided Transmission Costs

E. Reduced Cost of Meeting Future RPS Goals

F. Tax Receipts

G. Employment and Economic Activity

H. Non-Quantified Benefits

Additional Production Cost Related Benefits

MAPS represents operation of the power system under ideal, normalized conditions that is useful for analyzing impacts of changes to the system, but provides an incomplete picture of the operation of the real-world power system

- MAPS assumes no transmission outages, and no *uncertainty* in load forecasts, wind/solar output, or generation outages
- Normalized future conditions will not capture full range of circumstances (e.g., hot summers, gas shortages, major retirements) that are likely to stress the system in future years
- 2013 CARIS report highlights this issue, noting that congestion modeled in MAPS tends to be significantly lower than the historical system congestion

These factors could be included in MAPS by running many scenarios but there was insufficient time to do so during this study

We therefore relied on multipliers to the MAPS-generated production cost savings (PCS) to capture the additional value provided by Tx, Gen, and REV in the real-world power system

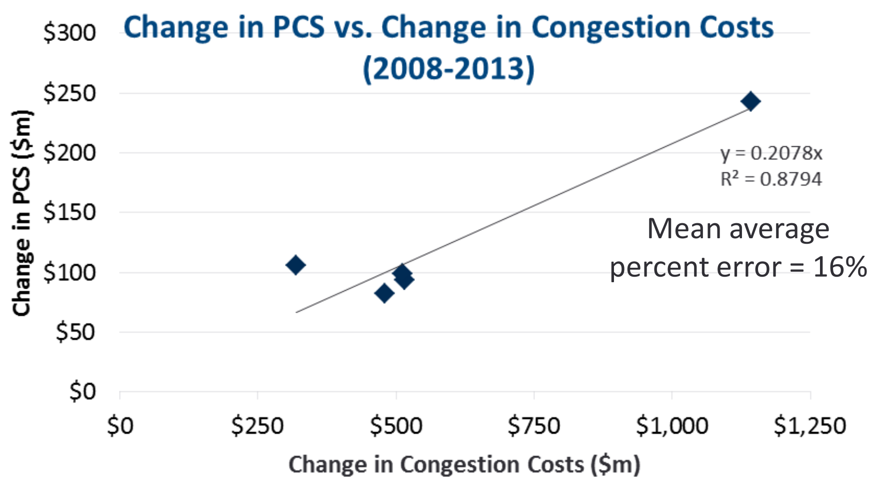
- For Tx portfolios, we apply 1.56 multiplier based on a comparison of zonal LBMP differentials in MAPS to zonal LBMP differentials in recent electricity futures contracts (Zone A vs. G)
- For Generation, we apply 1.24 multiplier based on the ratio of market heat rate spreads (MHR – CC HR of 7,000 Btu/kWh) between modeled results and futures (for Zone G)
- For REV resources, we apply 1.03 (Zones GHI) or 1.06 (Zone J) multiplier based on difference in zonal LBMPs between modeled results and futures and resource location

Our approach for developing these PCS multipliers is discussed in the following slides

Approach for Developing PCS Multipliers for Tx

Adding transmission capacity lowers production costs by relieving congestion, which MAPS understates

We estimate that production costs vary linearly with congestion costs based on CARIS analysis of 2008-2013, where NYISO re-ran market software with Tx constraints removed; showed that production cost savings was a nearly constant multiple of congestion costs, i.e., a change in congestion costs produces the same % change in production cost savings



Source: CARIS 2013, Table 5-3. Note that TCC payments represent congestion costs.

Therefore, we can estimate the full production cost impact by applying a congestion cost multiplier to modeled PCS; we can derive congestion cost multipliers by comparing LBMP differentials in MAPS to futures markets (*see next slide*)

PCS Multipliers from Energy Futures Prices

Market expectations relative to MAPS: Calculated multipliers for each solution based on zonal electricity (LBMP) futures prices, which theoretically reflect the full range of extreme conditions anticipated by the market, including extremes not experienced during the 2005-2014 period over which we examined historical costs

- Tx PCS multiplier calculated based on comparison of the differential between Zone A and Zone G LBMPs in MAPS 2019 Base Case to the price differential in futures for 2017/18 (Note: Zones A and G were selected for assessing the impact of UPNY/SENY, which is roughly Zone F to Zone G, and LBMP futures are not available for all zones)
- Generation PCS multiplier calculated based on ratio of market heat rate spreads (MHR – 7,000 Btu/kWh) between modeled results and futures for Zone G
- REV PCS multipliers calculated based on difference in LBMPs between modeled results and futures prices for Zones GHI or for Zone J (depending on resources' locations)

Source	Transmission Multiplier			Gen Multiplier	REV Multiplier	
	Zone A LBMP ($/MWh)	Zone G LBMP ($/MWh)	Differential ($/MWh)	MHR Spread (Btu/kWh)	REV Avg LBMP ($/MWh) Zone GHI	Zone J
Futures (2017/18)	$35.9	$46.3	$10.4	~4,040	$46.3	$48.3
MAPS (2019)	$38.0	$44.6	$6.6	~3,250	$44.6	$45.5
Futures/MAPS Ratio			**1.56**	**1.24**	**1.03**	**1.06**

Note: The Base Case MAPS run shown here is without CPV Valley, as our "multiplier" analysis was completed in March 2015, before CPV's announcement.

Historical Data Alternative Approach to Tx PCS Multiplier

As a check, we compared historical congestion costs under normal/idealized system conditions to congestion costs under a range of circumstances

To account for the fact that MAPS does not include transmission outages or departures from normalized future conditions, we evaluated:

- Effect of Transmission Outages
  - Compared MAPS 2013 backcasts with and without transmission outages
  - An accurate representation of transmission outages results in an 18% increase in demand congestion (multiplier of **1.18**)
- Effects of Extremes
  - Calculated how much the average of the annual TCC Fund increases with the inclusion of years with “extreme” supply/demand/transmission congestion conditions
  - Data on drivers of congestion costs over 2005-2014 suggest that 2007, 2008, and 2012 should be excluded from the “normal” years’ average
    - Average annual TCC Fund (congestion rents) over 2005-2014 was $561 m
    - The average excluding 2007, 2008, and 2012 was $484 m
  - This yields a multiplier of $561 m/ $484 m= **1.16**
- Combined Historical-Based PCS Multiplier= **1.18 x 1.16 = 1.4**

…but we used the slightly higher futures-based multiplier to be consistent with the multipliers for generation and REV; we examine lower multipliers in sensitivity analyses

V.B. Additional Production Cost Savings

PCS Sensitivities

We assessed the sensitivity of the estimated production cost savings to variation in the multiplier and to the assumed growth rate of savings beyond 2024

For transmission and generation:

- Higher value sensitivity: Increased PCS annual escalation rate by 1% after 2024 to capture potential effect of fuel escalation and tightening markets beyond what is conservatively included in MAPS analysis
  - Multiplier is based on first 5 years, when system is not as tight as projected in the future
  - Future likely more sensitive to Tx outages/other extremes, compounded by higher RCPFs
  - Calculated multiplier based on whole LBMP differential, rather than just the MCC differential
- Lower value sensitivity: Reduced PCS multipliers on MAPS results
  - 1.2x multiplier for transmission, representing only the Tx outage effect
  - This lower multiplier could also account for the uncertain relationship between PCS and congestion savings (the mean average percentage error in that relationship is 16%)
  - Scaled generation PCS multiplier by similar ratio to ~1.09

For REV resources:

- Higher value sensitivity: used load-weighted average instead of simple average LBMPs
- Lower value sensitivity: reduced energy savings to reflect 65% capacity factor (closer to that implied for Zone J “energy program impacts” in Gold Book), rather than ~75% assumed in GEIS

Present Value of Production Cost Savings

Solution	MAPS 2019 PCS ($m)	MAPS 2024 PCS ($m)	PCS Multiplier	Total 2019 PCS ($m)	Total 2024 PCS ($m)	Production Cost Savings (2015 $m)
P6 NYTO	$8	$17	x 1.56	$12	$26	$221
P7 NYTO	$7	$15	x 1.56	$12	$23	$194
P9 NYTO	$9	$20	x 1.56	$15	$31	$262
P11 NYTO	$28	$36	x 1.56	$44	$57	$516
P12 NYTO	$30	$39	x 1.56	$47	$61	$554
P14 NYTO	$30	$39	x 1.56	$47	$60	$547
P19a NextEra	$8	$17	x 1.56	$12	$26	$221
P20 Boundless	$3	$10	x 1.56	$5	$16	$128
P21 Boundless	$3	$9	x 1.56	$5	$14	$115
REV Resource	$208	$331	GHI: x 1.03 J: x 1.06	$218	$348	$1,943

Note: MAPS PCS listed here are NYCA-wide Adjusted Production Costs savings

Agenda

V.C.1. Capacity Value: Approach

Overview of ICAP Analysis

Quantify impacts to capacity costs, prices, and payments over the life of the facilities

- **Base Case**
  - Reflects planned capacity additions and retirements in MAPS through 2024, including updated "Net Purchases" from 2015 Gold Book and likely market response to CPV Valley addition in Zone G (*see next slide*)
  - Adds new capacity when market prices rise to CT Net CONE specific to the capacity zone, such that LCRs and IRM are achieved in all years modeled (*see slide 94*)
  - Models every year over expected lifetime of proposed solutions (up to 45 years)
- **Change Cases to analyze solutions**
  - Key assumptions for each solution type:
    - For <u>Transmission</u>, we adjust the LCRs within the import-constrained zones based on NYISO evaluation of each solution (we made no adjustments to IRM)
    - For <u>Generation</u>, we increase supply in Zone G by 1,320 MW
    - For <u>REV</u>, we reduced the peak load forecast in each zone (*see slide 9*)
  - Methodology for estimating Change Case clearing prices/quantities for each resource over time is described on slide 95
- **Scenarios and sensitivities**
  - Evaluated sensitivity of results to several factors, including supply uncertainty, supply curve slope assumptions, and discount rate (discount rate has largest impact on results)
  - Sensitivity case of 1,000 MW and 2,000 MW retirement in SENY is similar to near-term potential retirement scenarios

V.C.1. Capacity Value: Approach
Base Case Supply Adjustments

In addition to the adjustments to 2014 Gold Book supply described in the MAPS section (*see slide 55*), we incorporated additional adjustments for ICAP modeling, including updates to capacity exports to ISO-NE and the supply response to the introduction of CPV Valley

Capacity Exports to ISO-NE:

- Projection of Net Purchases/Sales of capacity with neighboring regions in 2014 Gold Book did not account for NY resources selling their capacity into ISO-NE's Forward Capacity Market
- 2015 Gold Book projects about 1,000 MW lower Net Purchases/Sales in 2015-2018 than the 2014 version after accounting for NY resources selling into ISO-NE through 2018/19 (FCA9)
- Based on ISO-NE capacity supply obligation data for FCA9, we assume in 2019 (and each subsequent year) that there will be 510 MW less supply in Zone G-J (due to Roseton's capacity supply obligation in ISO-NE) and 540 MW less supply in UPNY

Price Response to CPV Valley:

- Adding 670 MW in zone G will reduce capacity prices in both G-J and NYCA and likely result in the retirements of existing units
- To estimate the response to lower prices, we modeled an additional 670 MW of supply in Zone G, letting the market re-equilibrate where a shifted (but sloped) supply curve intersects demand
- This indicates the exit of 150 MW in G-J and 160 MW in UPNY, which we assume exits permanently
- We incorporate this response into our ICAP Base Case from which we estimate the impacts of new Tx

Sources for Capacity Exports: 2014 Gold Book, Table V-1: Summary of Transactions External to NYCA, p. 73; 2015 Gold Book, Table V-1: Summary of Net Purchases from External Control Areas, p. 77.

V.C.1. Capacity Value: Approach

Quantifying ICAP Value – Metrics

CARIS ICAP Metrics: Calculated Variant 1 and Variant 2 metrics based on the approach used in CARIS**,** which represents potential impact on capacity payments

- *Variant 1*: From a long-term perspective, assumes supply is perfectly elastic such that the market will clear at the same price but at a lower quantity
- *Variant 2*: From a short-term perspective, assumes supply is perfectly inelastic such that quantity is constant but the prices fall

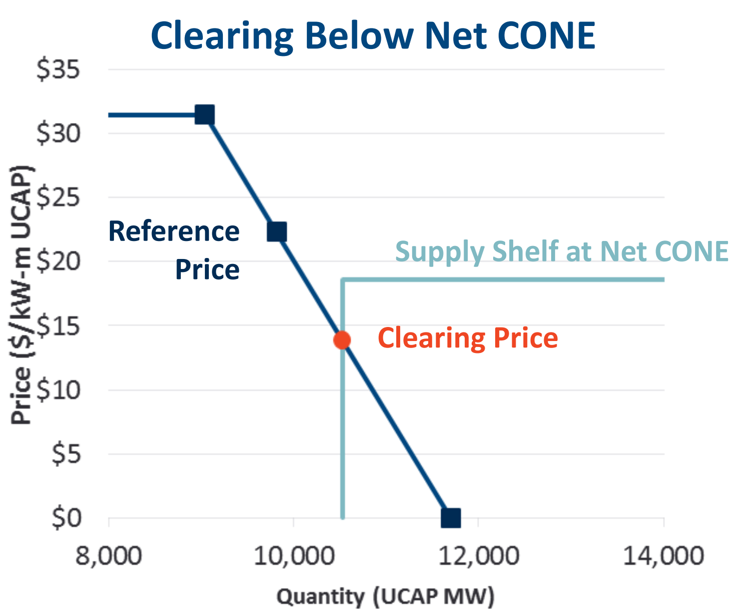
Capacity Resource Cost Savings: Developed additional metric for quantifying capacity resource cost savings in the ICAP market (not treating price suppression as a benefit or price increases as a dis-benefit) that is consistent with (and additive to) the production cost savings benefits in the energy market

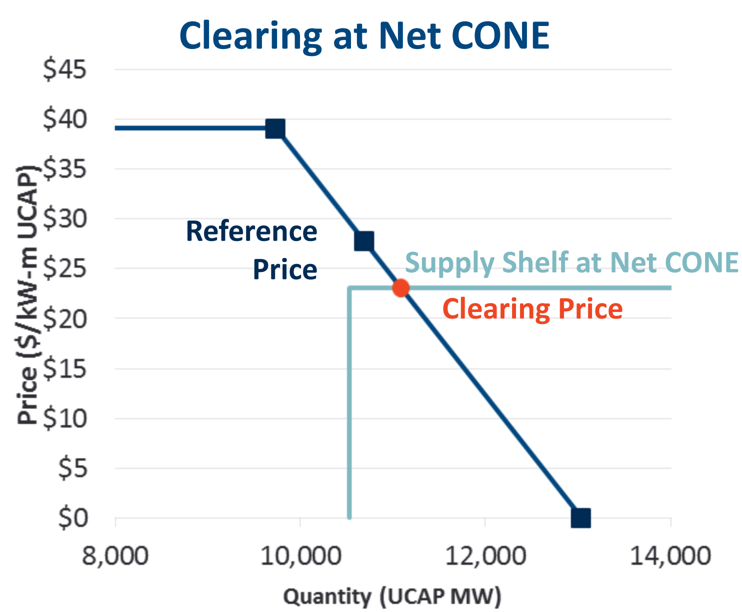
- Capacity resource cost savings arises from being able to:
  - Maintain less existing capacity in SENY, valued at quantity released times the cost of maintaining such resources (with a slight offset by adding a little UPNY capacity at the margin and incurring resource costs)
  - Delay new construction in SENY by better utilizing UPNY surplus, valued at the quantity of new construction avoided times the Net CONE in SENY (again, with a slight offset for UPNY capacity)
  - When new construction is needed, some new construction shifted to UPNY where Net CONE is lower, valued at the Net CONE differential times the quantity shifted
- Estimated using a detailed multi-zonal clearing model of the ICAP market
- Result is similar to Variant 1, but slightly lower because it accounts for diminishing marginal value of reducing capacity and NYCA clearing slightly more capacity when SENY capacity contracts

V.C.1. Capacity Value: Approach
Approach to ICAP Base Case

Modeled the NYISO ICAP market under the Base Case assuming inelastic supply until prices reach Net CONE

- Demand curves use the current IRM/LCR percentages and the latest NYISO load forecast
- Supply curve is vertical based on projected capacity in Base Case with shelf at Net CONE
- Model clears the market based on the supply and demand curves, while accounting for nested zonal structure (for example, prices in subzones cannot fall below the parent zone)
- We adjust parent zone supply following years in which supply is added to nested zones to meet LCR to be consistent with Change Case



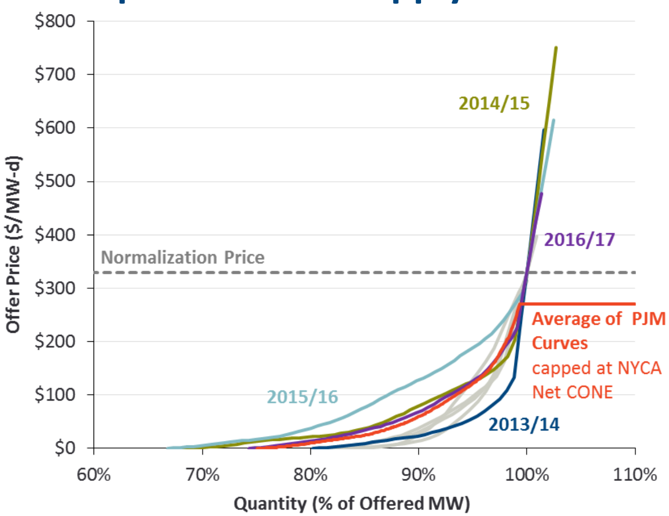


Modeling Change Cases

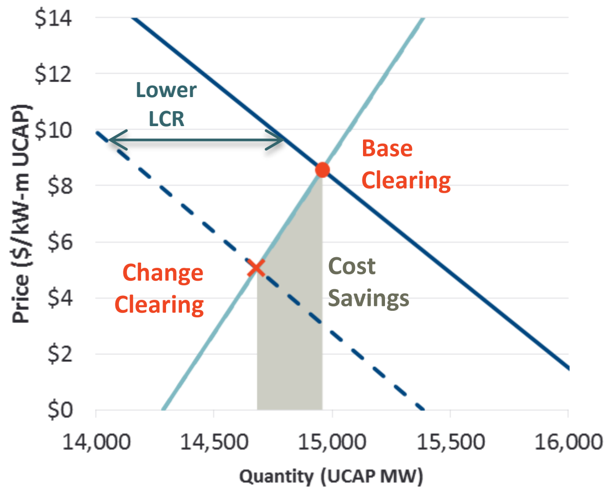
Change Cases result in different outcomes in the ICAP market due to shifts in the demand curve (for transmission and REV solutions) and the supply curve (for generation) and the assumed slope of the supply curve

- *Supply Curves*: Generated representative curve based on bids from past three PJM auctions
- *Transmission/REV*: Demand curve shifts to the left based on LCR impact or peak load reduction, resulting in lower prices, reduced capacity procured, and capacity cost savings
- *Generation*: Treated as inframarginal supply shifting curve right, which lowers prices and quantities procured from other resources (*Note: we do not add generation into the ICAP market until price reaches Net CONE, due to buyer-side mitigation)

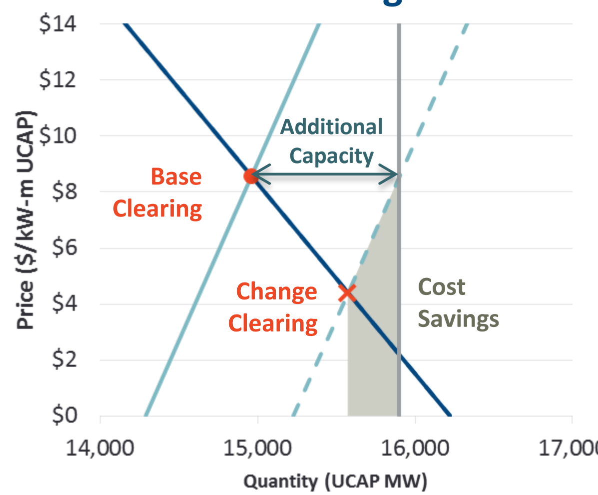
Representative Supply Curves



Transmission/REV Change Cases



Generation Change Case*



V.C.1. Capacity Value: Approach

Other ICAP Model Assumptions

Annual vs. Seasonal Markets: Created a single annual market using the average of summer/winter ICAP/UCAP translation factors to draw demand curve

Demand Curve Slopes: Assume demand curve slopes do not change after 2015

Peak Load Growth: For 2025 – 2063, we assume peak load in each zone grows at the average projected annual growth rate for 2020 – 2025

No Attrition of Existing Supply except in response to lower capacity prices in the Change Case or in response to capacity addition in sub-zones

Impact energy losses on peak load: Analysis of changes in energy losses during the top 100 load hours resulted in an inconclusive pattern of changes across portfolios; therefore, assume no impact of energy losses on peak load and IRM

Impact of changes in E&AS revenues on Net CONE: Adjusted E&AS margins by -$0.2/kW-mo to +$0.1/kW-mo (depending on zone and portfolio/resource) based on changes in CT revenues from 2019 and 2024 MAPS results; assume Net CONE is constant in real terms after 2024

V.C.1. Capacity Value: Approach

ICAP MW Impact of Tx Portfolios

With NYISO staff, we developed an approach to estimate the Tx portfolios' impacts on LCRs

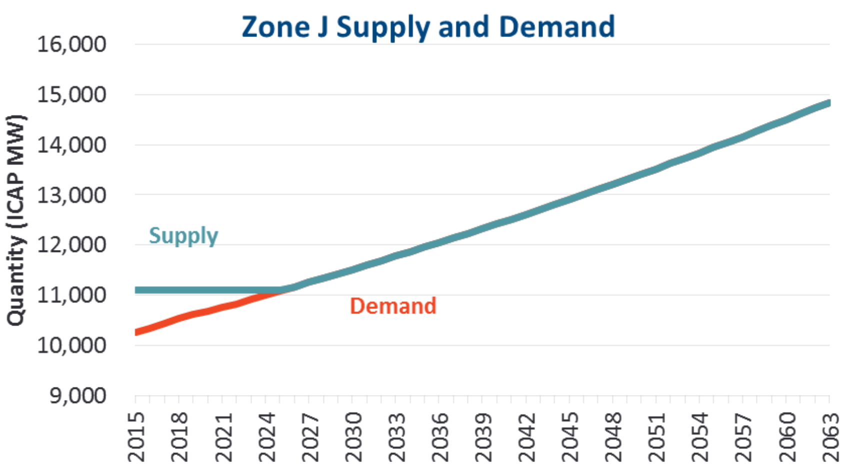
- Using GE-MARS, start with a 2024 base case, note the LOLEs (close to 0.1), then increase interface limits
- For J and K's LCR impacts, follow the CARIS tariff method by proportionally removing capacity from all zones until LOLE returns to the base level; the amount removed from J & K provides a reasonable and conservative approximation of the LCR impact the more detailed TAN45 method would produce; NYSRC's IRM process also uses this methodology to analyze sensitivities
- For G-J's LCR impacts, hold J and K at the capacities from the prior step but restore zones A-I to the base level; then shift capacity proportionally from GHI to A-F until LOLE returns to the base level; the amount of capacity shifted out of GHI in this step plus capacity removed from J in the prior step indicates the transmission portfolio's ability to lower the G-J LCR
- For NYCA's IRM, we conservatively assume no impact based on previous NYISO analysis of similar transmission projects using the TAN45 method

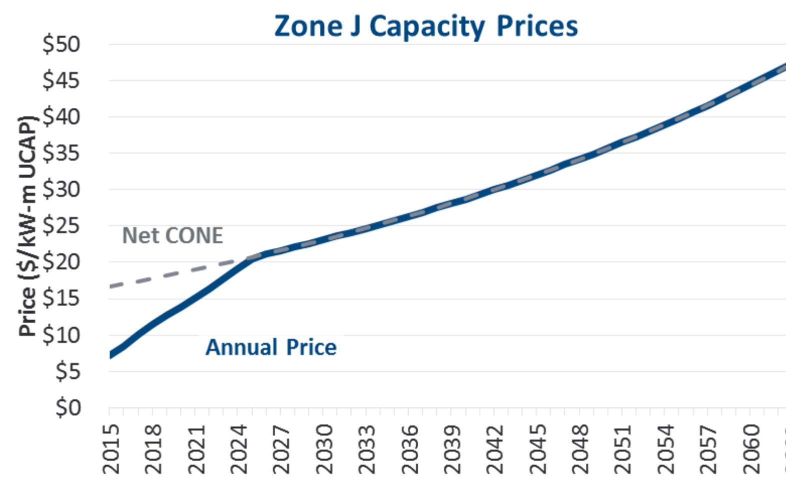
Proposed Solution	UPNY/SENY Emergency N-1 Impact (MW)	NYCA IRM Impact (MW)	Zone G-J LCR Impact (MW)	Zone J LCR Impact (MW)	Zone K LCR Impact (MW)
P6 NYTO	+1,686	0	-1,017	-213	-125
P7 NYTO	+1,404	0	-911	-209	-123
P9 NYTO	+2,091	0	-932	-213	-125
P11 NYTO	+1,621	0	-1,087	-217	-127
P12 NYTO	+1,341	0	-1,079	-217	-127
P14 NYTO	+2,286	0	-1,107	-217	-127
P19a NextEra	+1,747	0	-935	-213	-125
P20 Boundless	+1,753	0	-904	-211	-124
P21 Boundless	+1,433	0	-895	-211	-124

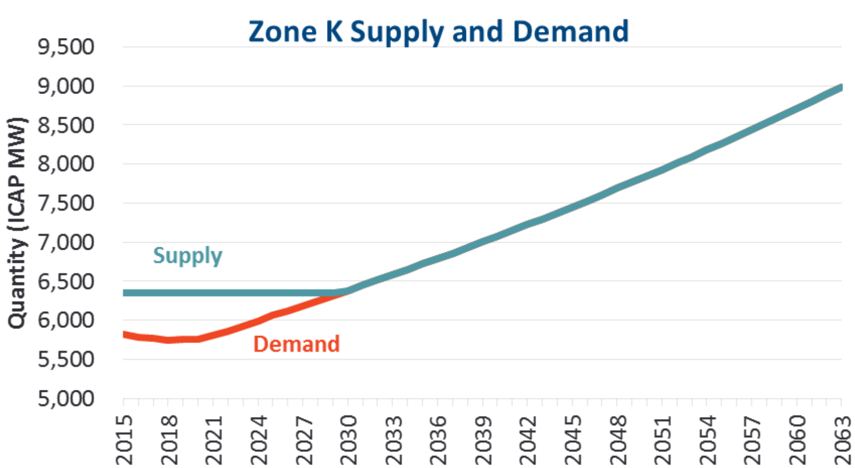
Agenda

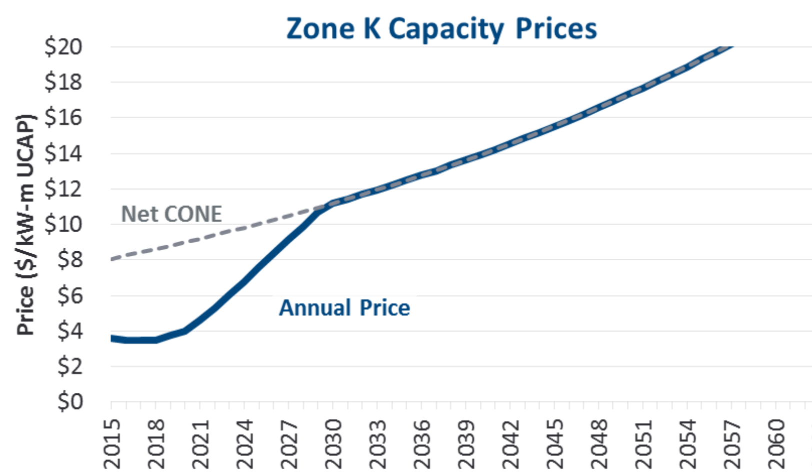
V.C.2. Capacity Value: Results

Base Case Supply, Demand & Prices





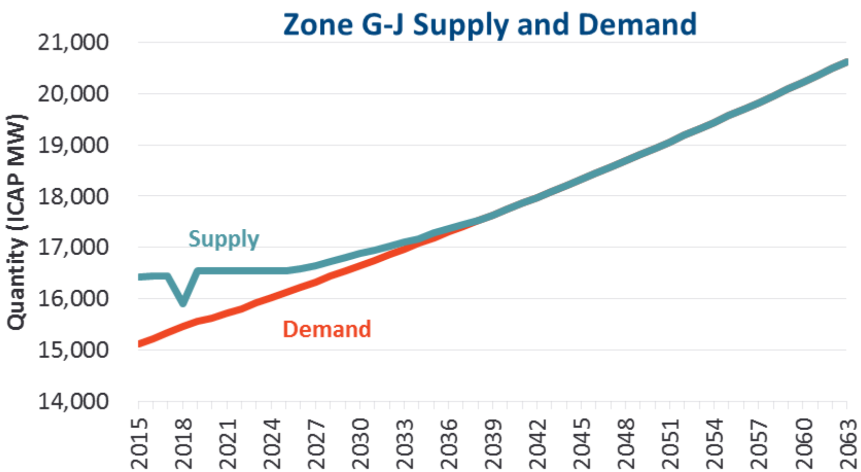


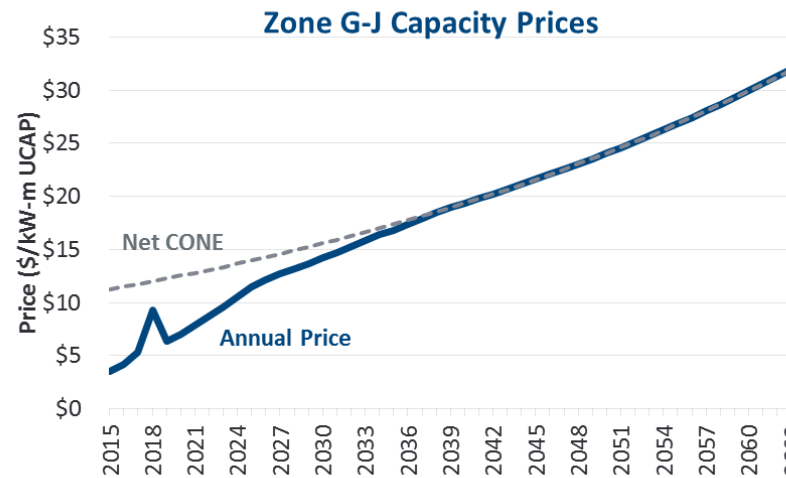


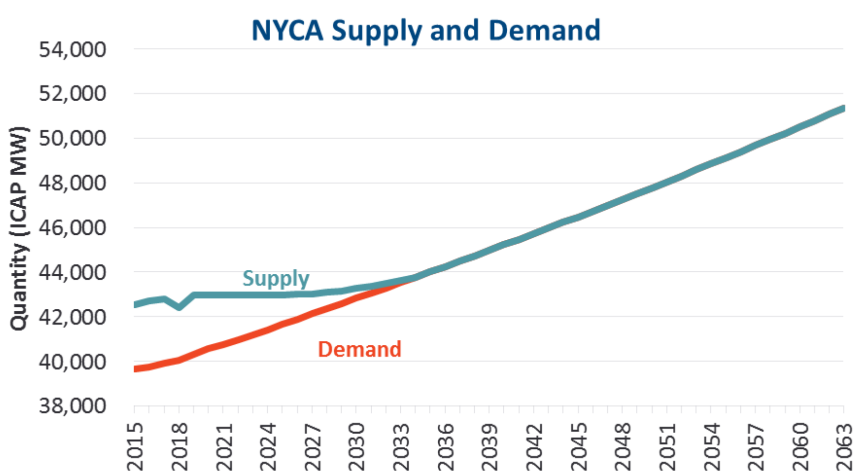
Note: "Demand" indicates the quantity where price is Net CONE, which is above the LCR

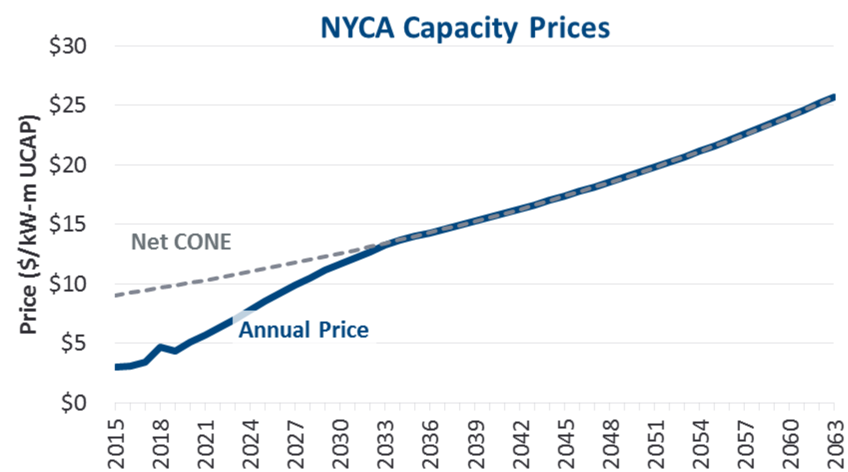
V.C.2. Capacity Value: Results

Base Case Supply, Demand & Prices (cont.)







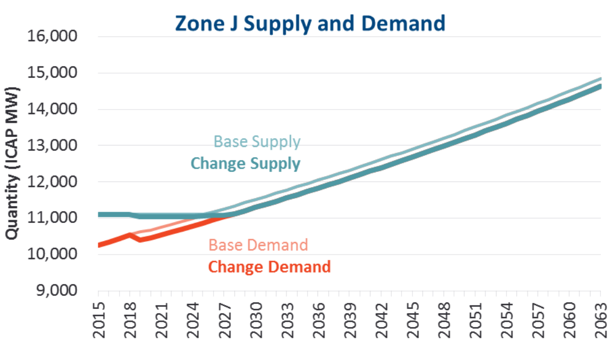


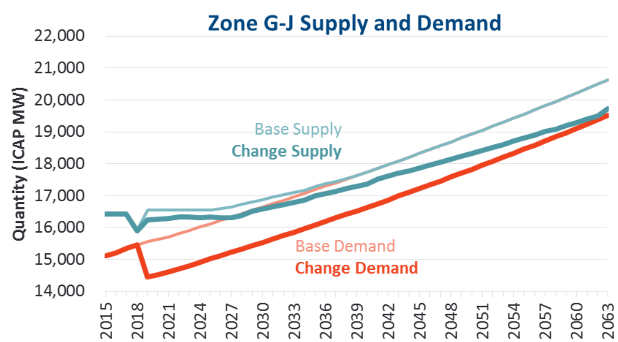
Note: "Demand" indicates the quantity where price is Net CONE, which is above the LCR

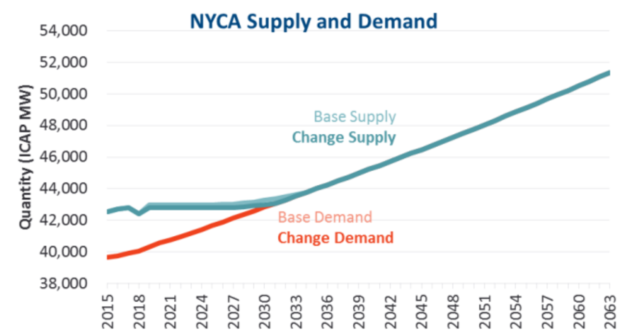
Change Case Supply, Demand & Prices

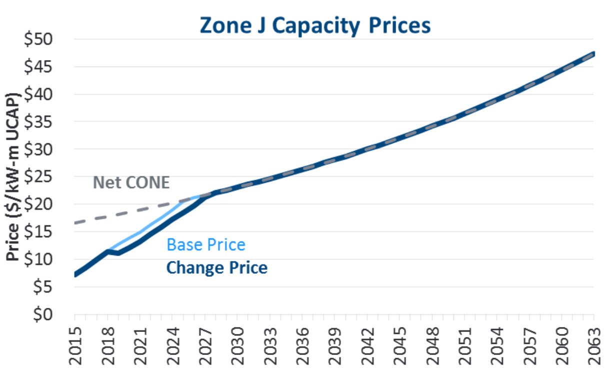
To demonstrate the Change Case, we show that P14, for example, has the following impacts on clearing prices and capacity:

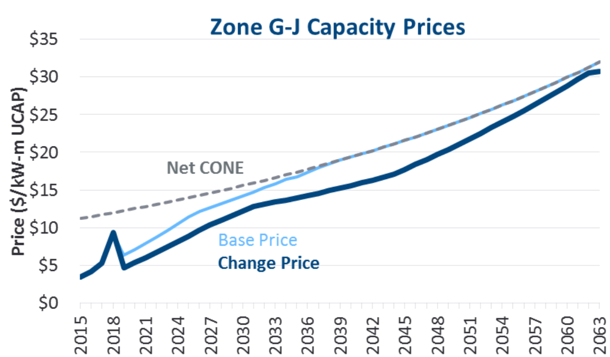
- Decreased demand in Zones J, G-J and K (not shown) results in lower prices and capacity cleared
- Reduced SENY capacity results in higher prices in NYCA and increased capacity in rest-of-NYCA

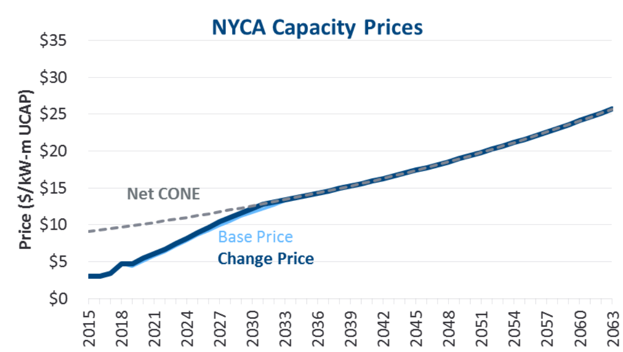








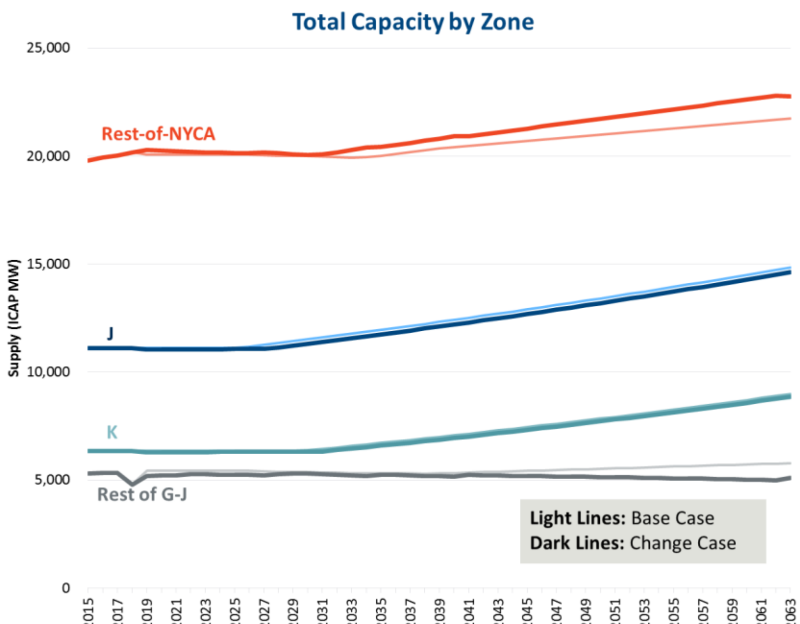


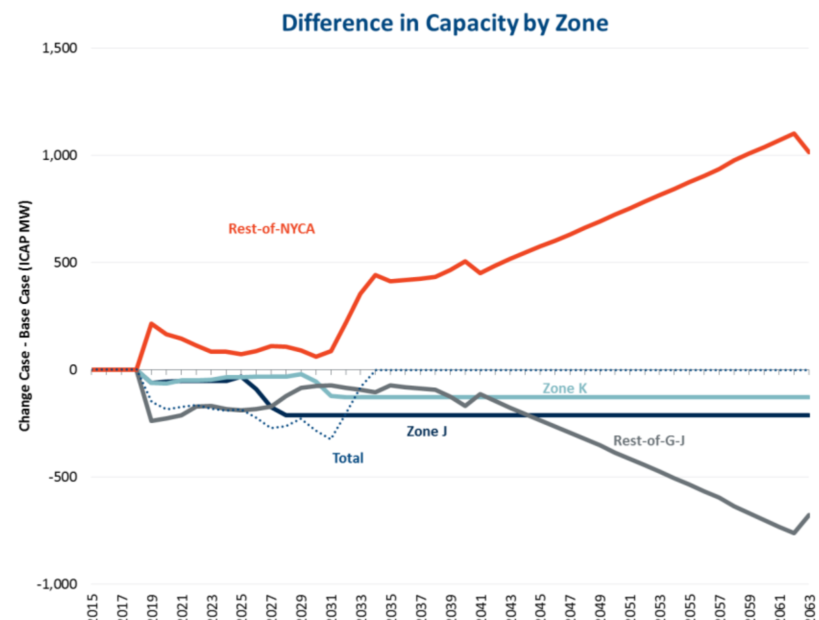


Supply in Base and Change Cases

To better demonstrate the differences in Base and Change Case in ICAP, we show total capacity and change in capacity by area (isolating "Rest-of-NYCA" and "Rest of G-J")

- As expected, capacity in SENY areas decreases and capacity in UPNY increases
- Total capacity is lower in the Change Case until both cases in 2034 reach Net CONE in NYCA
- After 2034, high-cost capacity in G-J is replaced 1-for-1 by low-cost capacity in Rest-of-NYCA
- Capacity cost savings are achieved due to the change in the amount and location of supply resources in the Change Case



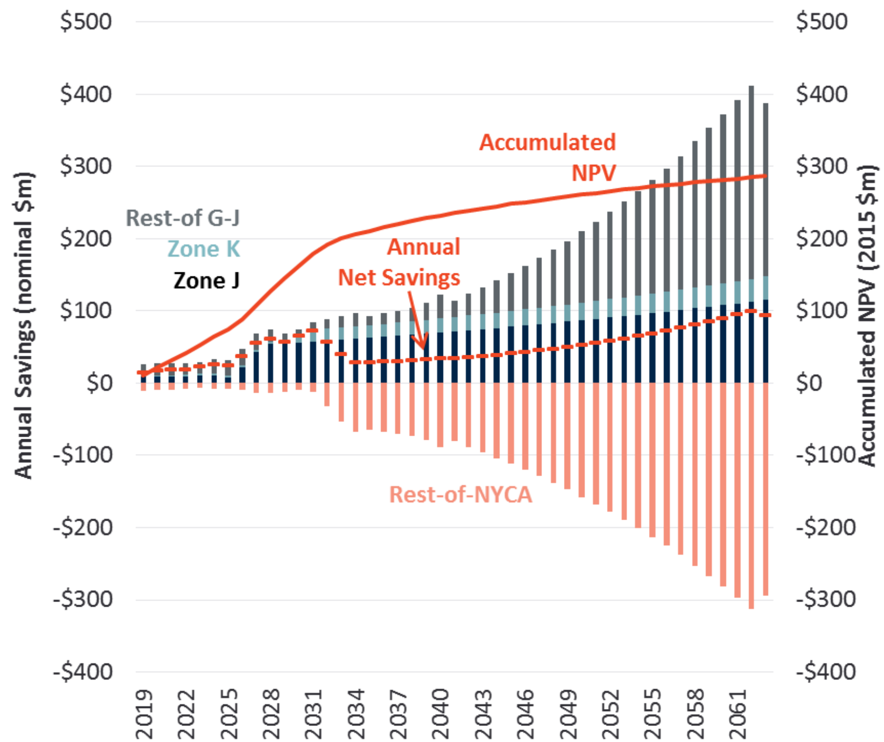


Note: Diagrams show adding ~1,000 MW of transfer capacity into G-J results in 450 MW shift in capacity from SENY to UPNY, based on the assumed slope of the supply curves. If in fact SENY has more expensive capacity that leaves (and reaches equilibrium faster, as assumed in the ratepayer impact analysis), the resource shifts between G-J and NYCA would be greater than shown in this analysis and result in greater resource cost savings.

Transmission Solution Capacity Value

We estimated NPV of capacity cost savings for the P14 NYTO to be $286m

- In Zone J, the lower LCR leads to capacity savings of $8m in 2019 due to reduced capacity cleared
- The transmission solution has a similar impact on Zone K, resulting in $2m in 2019 savings
- In G-J, less capacity is needed because of the lower LCR (which is offset slightly by reduced supply in Zone J) which leads to 2019 savings of $15m
- To make up for lost G-J capacity and still maintain IRM, capacity must be added in Rest-of-NYCA, which offsets the savings in other zones by $11m in 2019



We estimated the capacity value of the other Tx portfolios, Generation and REV Resources in a similar way

Summary of Capacity Value

For each proposed solution, we also calculated the CARIS Variant 1 and Variant 2 metrics following the approach outlined in CARIS Appendix E

Solution	Capacity Resource Cost Savings (2015 $m)	CARIS Variant 1 (2015 $m)	CARIS Variant 2 (2015 $m)
P6 NYTO	$284	$306	$857
P7 NYTO	$284	$305	$876
P9 NYTO	$286	$307	$869
P11 NYTO	$286	$309	$883
P12 NYTO	$286	$308	$894
P14 NYTO	$286	$309	$896
P19a NextEra	$285	$305	$839
P20 Boundless	$288	$308	$894
P21 Boundless	$288	$308	$892
Generation (25 yr)*	$89	$94	$45
REV Resource Solution	$613	$692	$3,468

Note: Generation capacity value is reduced due to the MOPR

V.C.2. Capacity Value: Results

Sensitivity of Capacity Value

The capacity value of the proposed solutions depends on assumptions about the supply curves and the discount rate used to calculate NPV

- **Supply Curve Slope**: Adjusting the estimated slopes of the supply curves by +/- 25% impacts the results for Tx portfolios by **-$11m to +$16m** (-4% to + 6%) on average
- **Discount Rate:** Applying a discount rate of 5.58% increases the value by **$230m**(+79%) on average for the Tx portfolios

Uncertain Capacity Retirements: Capacity value of new Tx depends on excess UPNY capacity being available as well as the difference in Net CONE between UPNY and SENY; for this reason, we analyzed the change in capacity value across the following conditions

Scenario	Average Impact on Capacity Value ($m)
2,000 MW Retires in SENY	+$420
1,000 MW Retires in SENY	+$245
1,000 MW Retires in UPNY	-$100
2,000 MW Retires in UPNY	-$160

Response to CPV Valley: If a 500 MW generation facility in Zone G retires in response to the announced addition of CPV Valley *instead of* the response we estimated (*see slide 92*), the transmission portfolios would save *an additional* $70m in capacity resource costs

Capacity Market Ratepayer Impacts

Calculated ratepayer impacts based on results of ICAP market model

- Model projects changes in cleared quantity and prices due to Tx solutions, which for 2019 finds:
  - NYCA: Increased capacity cleared at higher prices results in increased payments
  - SENY Zones: Decreased capacity cleared at lower prices results in decreased payments
- NYCA payments allocated to UPNY and SENY ratepayers based on load ratio share
- All other zones 100% allocated to SENY ratepayers

2019 ratepayer impact for P14 is:

- UPNY: *Increases* by 0.073 c/kWh
- SENY: *Decreases* by 0.370 c/kWh

2019 Capacity Market Ratepayer Impact for P14

Region Case	Cleared Quantity *MW*	Cleared Price *$/kW-mo*	Cleared Payments *$m*	UPNY Payments *$m*	SENY Payments *$m*
NYCA					
Base Case	17,980	$4.4	$942	$718	$224
Change Case	18,184	$4.7	$1,021	$766	$254
Difference	**204**	**$0.3**	**$79**	**$49**	**$30**
Zone G-J					
Base Case	5,104	$6.4	$390	-	$390
Change Case	4,879	$4.7	$274	-	$274
Difference	**-225**	**-$1.7**	**-$116**	**$0**	**-$116**
Zone J					
Base Case	10,524	$12.8	$1,611	-	$1,611
Change Case	10,465	$11.1	$1,396	-	$1,396
Difference	**-59**	**-$1.6**	**-$216**	**$0**	**-$216**
Zone K					
Base Case	5,839	$3.8	$265	-	$265
Change Case	5,781	$3.3	$226	-	$226
Difference	**-58**	**-$0.5**	**-$40**	**$0**	**-$40**
Total Payments ($m)				**$49**	**-$342**
Ratepayer Impact (c/kWh)				**0.073**	**-0.370**

Note: Cleared Quantity represents capacity that is specific to each region, such that NYCA's Cleared Quantity only accounts for capacity that did not clear in G-J, J, or K.

Maintaining Reliability with Major Retirements

In addition to reduced capacity costs, the additional transfer capability into SENY provided by the Tx solutions will increase the flexibility to accommodate generation retirements without falling below LCRs

Additional Capacity Retirement Flexibility of Proposed Solutions (MW)

Proposed Solution	Zone G-J (MW)	Zone J (MW)	Zone K (MW)	Total (MW)
P6 NYTO	1,017	213	125	**1,142**
P7 NYTO	911	209	123	**1,034**
P9 NYTO	932	213	125	**1,057**
P11 NYTO	1,087	217	127	**1,214**
P12 NYTO	1,079	217	127	**1,206**
P14 NYTO	1,107	217	127	**1,234**
P19a NextEra	935	213	125	**1,060**
P20 Boundless	904	211	124	**1,028**
P21 Boundless	895	211	124	**1,019**

Note: Total is calculated based on sum of G-J and K since J is nested in G-J.

Agenda

I. Problem Statement
II. Solutions Analyzed
III. Benefit-Cost Analysis Results
IV. Detailed Cost Information
V. **Detailed Benefit Analysis**
   A. MAPS Analysis of Production Cost Savings
   B. Additional Production Cost Savings not captured in MAPS
   C. ICAP Analysis of Capacity Value
   D. **Avoided Future Transmission Costs**
      1. Existing Line Upgrades
      2. Early Retirement of Aging Lines
      3. Avoided Congestion Costs
      4. Construction Cost Savings
   E. Reduced Cost of Meeting Future RPS Goals
   F. Tax Receipts
   G. Employment and Economic Activity
   H. Non-Quantified Benefits

Types of Avoided Transmission Costs

Concept: Proposed projects may avoid future Tx costs in four ways:

1. Upgrading Existing Lines: Projects that reconductor, retire, rebuild, or replace existing lines incur new O&M and property taxes, but if counting those has "new" costs, need to recognize that the "old" costs associated with existing facilities go away
2. Early Refurbishments of Aging Lines: Projects that replace aging lines identified in STARS and confirmed by project proponents avoid the cost of replacing those lines in the future
3. Parallel Facilities Could Reduce Congestion Costs During Refurbishment: Projects that add new parallel paths to aging lines will reduce congestion and production costs during construction
4. Parallel Facilities Reduce Refurbishment Costs: Projects that add new parallel lines to aging lines will also lower the cost of future refurbishments by avoiding expensive construction scheduling when taking the existing lines out of service for construction. (We analyze this only as a sensitivity.)

Approach: Benefits of each portfolio depend on whether they replace existing or aging facilities and/or provide additional parallel path to aging facilities:

- All nine Tx portfolios include an upgrade of existing lines that will avoid future costs
- P6, P9, P11, P12, P14, and P19a replace aging facilities, avoiding future costs; also likely to cause congestion during construction, but similar to Base Case (therefore, no net "dis-benefit")
- P4, P9, P17, P19a provide additional parallel paths, which could avoid congestion costs (depending on the aging lines); they could also avoid a premium on extended refurbishment schedule, but we include this benefit only as a sensitivity

Summary of Avoided Transmission Costs

Type of Project Elements	Avoided "Base Case" Cost*	Approach to Quantifying	P6 NYTO ($m)	P7 NYTO ($m)	P9 NYTO ($m)	P11 NYTO ($m)	P12 NYTO ($m)
Project Elements Upgrade Existing Lines	Ongoing O&M costs	Credit equals the present value of the avoided revenue requirements of existing lines upgraded (*Note: Cost only avoided until date line planned to be refurbished in Base Case, if refurbished at all.*)	**$87m** Replace KN-PV	**$70m** Reconductor LD-PV	**$112m** Reconductor NS-LD and replaces LD-PV	**$65m** Retire PT-RM and replaces LD-PV	**$135m** Retire PT-RM and reconductor NS-LD and LD-PV
Project Elements Replace Aging Lines that will have to be replaced anyway	Future Refurbishment costs	Credit equals the present value of future revenue requirements for refurbishments. (*Note: Date indicates when we assume refurbishment would occur in Base Case.*)	**$195m** Replace KN-PV (2030)	-	**$148** Replace LD-PV (2030)	**$933** Retire PT-RM (2020) and replace LD-PV (2030)	**$739** Retire PT-RM (2020)
Project Elements Provide Parallel Paths to Aging Lines that will have to be replaced in the future	Congestion during Construction	Aging lines are predominantly 115 kV rated, and were expected to have very low production cost/congestion impact	–	–	–	–	–
	Construction Costs due to Extended Construction Schedule	**Base Analysis** conservatively assume no costs avoided	**$0**	**$0**	**$0**	**$0**	**$0**
		Sensitivity Analysis avoid 20% of costs due to normal construction schedule; credit equals the present value of future revenue requirements for refurbishments	**$91** Avoids costly constr. of 6 115kV Lines in LD-PV Corridor	–	**$91** Avoids costly constr. of 6 115kV Lines in LD-PV Corridor	**$91** Avoids costly constr. of 6 115kV Lines in LD-PV Corridor	–

[*] Assumes "Base Case" world needs to refurbish aging lines in the latest years indicated in STARS, incurring capital costs at that time; Project change cases show differences in costs from that Base Case

Summary of Avoided Transmission Costs (2)

Type of Project Elements	Avoided "Base Case" Cost*	Approach to Quantifying	P14 NYTO ($m)	P19a NextEra ($m)	P20 Boundless ($m)	P21 Boundless ($m)
Project Elements Upgrade Existing Lines	Ongoing O&M costs	Credit equals the present value of the avoided revenue requirements of existing lines (*Note: Cost only avoided until date line planned to be refurbished in Base Case, if refurbished at all.*)	**$108m** Retire PT-RM, reconductor NS-LD and replace CH-PV	**$41m** Replace GB-PV	**$157m** Reconductor LD-PV, HA-LD, and CPV-RT	**$76m** Reconductor HA-LD, and CPV-RT
Project Elements Replace Aging Lines that will have to be replaced anyway	Future Refurbishment costs	Credit equals the present value of future revenue requirements for refurbishments (*Note: Date indicates when we assume refurbishment would occur in Base Case.*)	**$887** Retire PT-RM (2020) and replace LD-PV (2030)	**$223m** Replace GB-PV (2030)	-	-
Project Elements Provide Parallel Paths to Aging Lines that will have to be replaced in the future	Congestion during Construction	Aging lines are predominantly 115 kV rated, and were expected to have very low production cost/congestion impact	–	–	–	–
	Construction Costs due to Extended Construction Schedule	**Base Analysis** conservatively assume no costs avoided	**$0**	**$0**	**$0**	**$0**
		Sensitivity Analysis avoid 20% of costs due to normal construction schedule; credit equals the present value of future revenue requirements for refurbishments	**$91** Avoids costly constr. of 6 115kV Lines in LD-PV Corridor	**$91** Avoids costly constr. of 6 115kV Lines in LD-PV Corridor	–	–

[*] Assumes "Base Case" world needs to refurbish aging lines in the latest years indicated in STARS, incurring capital costs at that time; Project change cases show differences in costs from that Base Case

V.D.1. Avoided Transmission Costs: Existing Lines

Upgrades to Existing Lines

Portfolios should be credited for upgrading existing facilities

- Many of the portfolios upgrade existing facilities by either reconductoring, rebuilding, or replacing them
- Although the upgrades may not be "needed," the ongoing RevReqs for those facilities to cover O&M costs and property taxes will be replaced by the RevReqs for the proposed facilities
- For that reason, we include the RevReq of the existing facilities proposed to be upgraded as avoided costs and include them as a benefit

Approach to calculating the credit (to partially offset the full cost of the portfolio that is taking over the existing facility)

- DPS identified the existing lines that are proposed to be upgraded and provided the replacement costs for each line segment
- We calculated avoided O&M costs by multiplying the existing line replacement costs by 2.9%, the assumed O&M costs as a percentage of capital costs in the RevReq workbook provided by DPS (*see slide 46*)
- We calculated avoided property taxes by converting replacement costs to assessed value and multiplying by the assumed property tax of 2.18% (*see slide 46*)
  - For societal benefit-cost analysis, the avoided taxes net to zero against reduced receipts
  - For the ratepayer impact analysis, we recognize the avoided tax burden

V.D.1. Avoided Transmission Costs: Existing Lines

Existing Lines Proposed to be Upgraded

Tx Portfolio	Facility Upgraded	Type of Upgrade	Assumed Refurbishment Year	Replacement Costs (2015 $m)	PVRR of Avoided Costs (2015 $m)
P6 NYTO	KN - PV 115 kV	Replaced	2030	$484	**$87**
P7 NYTO	LD - PV 115 kV	Reconductor	N/A	$214	**$70**
P9 NYTO	NS - LD 115 kV	Reconductor	N/A	$171	**$112**
	LD - PV 115 kV	Replaced	2030	$313	
P11 NYTO	PT - RM 230 kV	Retired	2020	$396	**$65**
	LD - PV 115 kV	Replaced	2030	$313	
P12 NYTO	PT - RM 230 kV	Retired	2020	$396	**$135**
	NS - LD 115 kV	Reconductor	N/A	$171	
	LD - PV 115 kV	Reconductor	N/A	$214	
P14 NYTO	PT - RM 230 kV	Retired	2020	$396	**$108**
	NS - LD 115 kV	Reconductor	N/A	$171	
	CH - PV 115 kV	Replaced	2030	$242	
P19a NextEra	GB - PV 115 kV	Replaced	2030	$230	**$41**
P20 Boundless	LD - PV 115 kV	Reconductor	N/A	$246	**$157**
	HA - LD 115 kV	Reconductor	N/A	$128	
	CPV - RT 115 kV	Reconductor	N/A	$107	
P21 Boundless	HA - LD 115 kV	Reconductor	N/A	$128	**$76**
	CPV - RT 115 kV	Reconductor	N/A	$107	

Notes:

Assume RevReq for existing lines would be required through 2063 unless the line is aging and projected to be refurbished in year shown (see next section for more details).

PVRR of avoided costs calculated by reducing O&M costs in RevReq workbook proportional to 1 minus the ratio of Replacement Costs over Portfolio Capital Costs and calculating the change in the RevReq.

Early Refurbishment of Aging Lines

Concept:

- Many of the proposed projects address the need to upgrade aging transmission facilities by making early refurbishments of specific aging facilities, and thus avoiding future refurbishment costs
- We count these avoided costs (and associated revenue requirements) as benefits

Approach to Quantifying Savings :

- Identify old facilities that each project would refurbish, by reviewing proposals
- Cross reference with the 2012 STARS report to see estimated time-to-replacement
- Use DPS's estimate of the capital costs avoided at that time; then calculate present value of avoided costs and avoided RevReq
  - The costs include the cost of rebuilding an existing aging line – identified by project proponents – that would have to be refurbished in the Base Case within the next 10 – 30 years
  - The benefit credit reflects the PV of savings from not having to refurbish the line later at the estimated capital cost (from DPS)

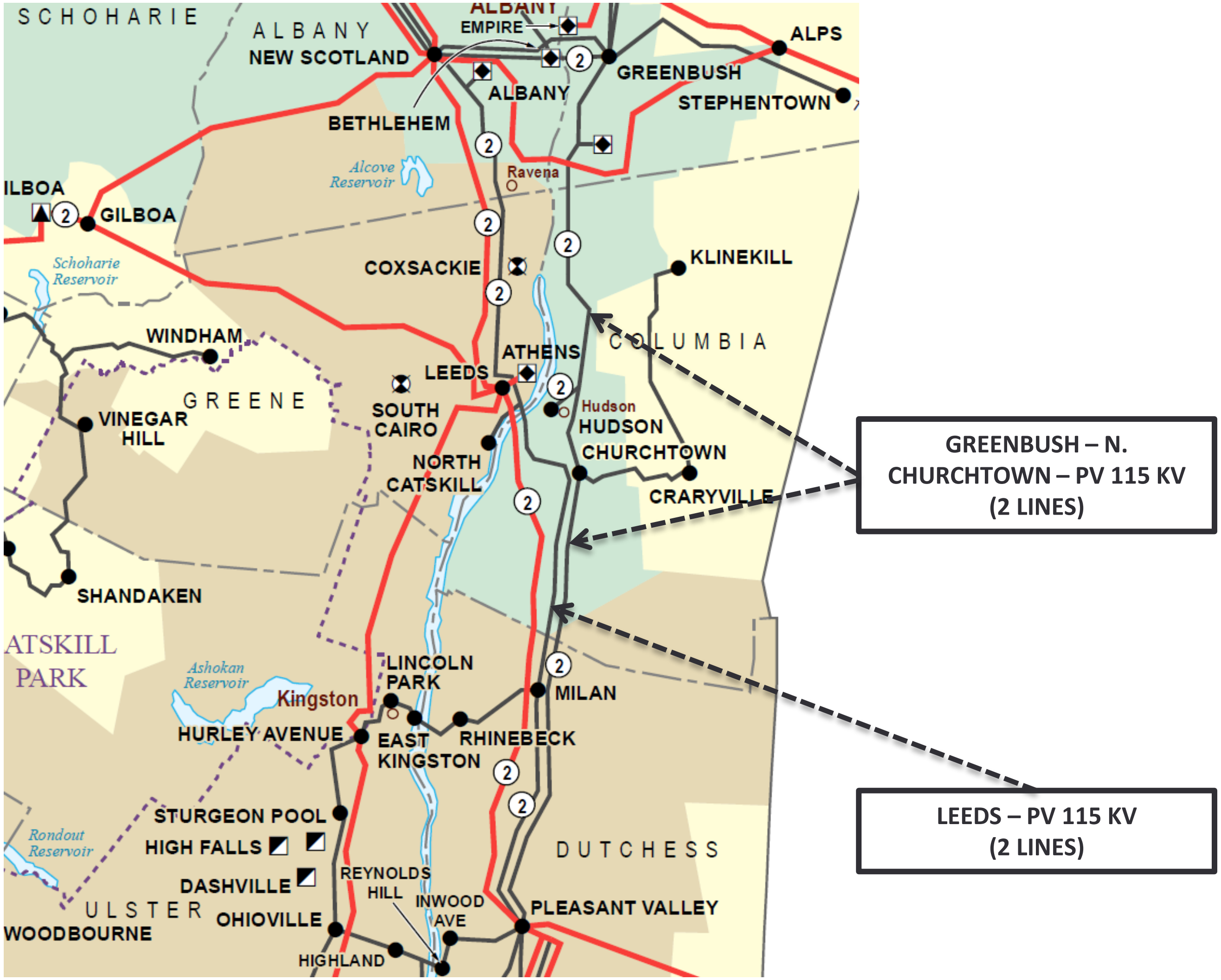
Key Assumptions

- STARS Report identifies aging transmission facilities based on an age criteria; it notes that a condition assessment would need to be conducted to ascertain which facilities would actually need to be refurbished
- We assumed that the project proponents have performed cursory level condition assessments to identify the facilities (lines and structures) needing refurbishment
  - Therefore, we relied on the Project Applications to identify aging facilities whose refurbishments would result in Avoided Costs
  - Only aging facilities rated 115 kV and 230 kV were identified by project proponents as facilities needing refurbishment
  - For e.g., TRANSCO's Leeds-PV Reconductoring project refurbishes 345 kV lines in the Leeds-PV corridor, which are identified by STARS report as aging, however, the TRANSCO application does not indicate those facilities need refurbishment (see quote from p. 12 of the TRANSCO Application below)

"The LD-PV Reconductoring Project increases UPNY/SENY transfers at a lower cost with few construction and environmental impacts. The Project by itself meets the full 1000 MW of UPNY/SENY transfer, though it does not improve the transfers across the Central-East interface. <u>The Project does not address any of the aging infrastructure issues nor does it add to system resiliency</u>."

V.D.2. Avoided Transmission Costs: Aging Lines

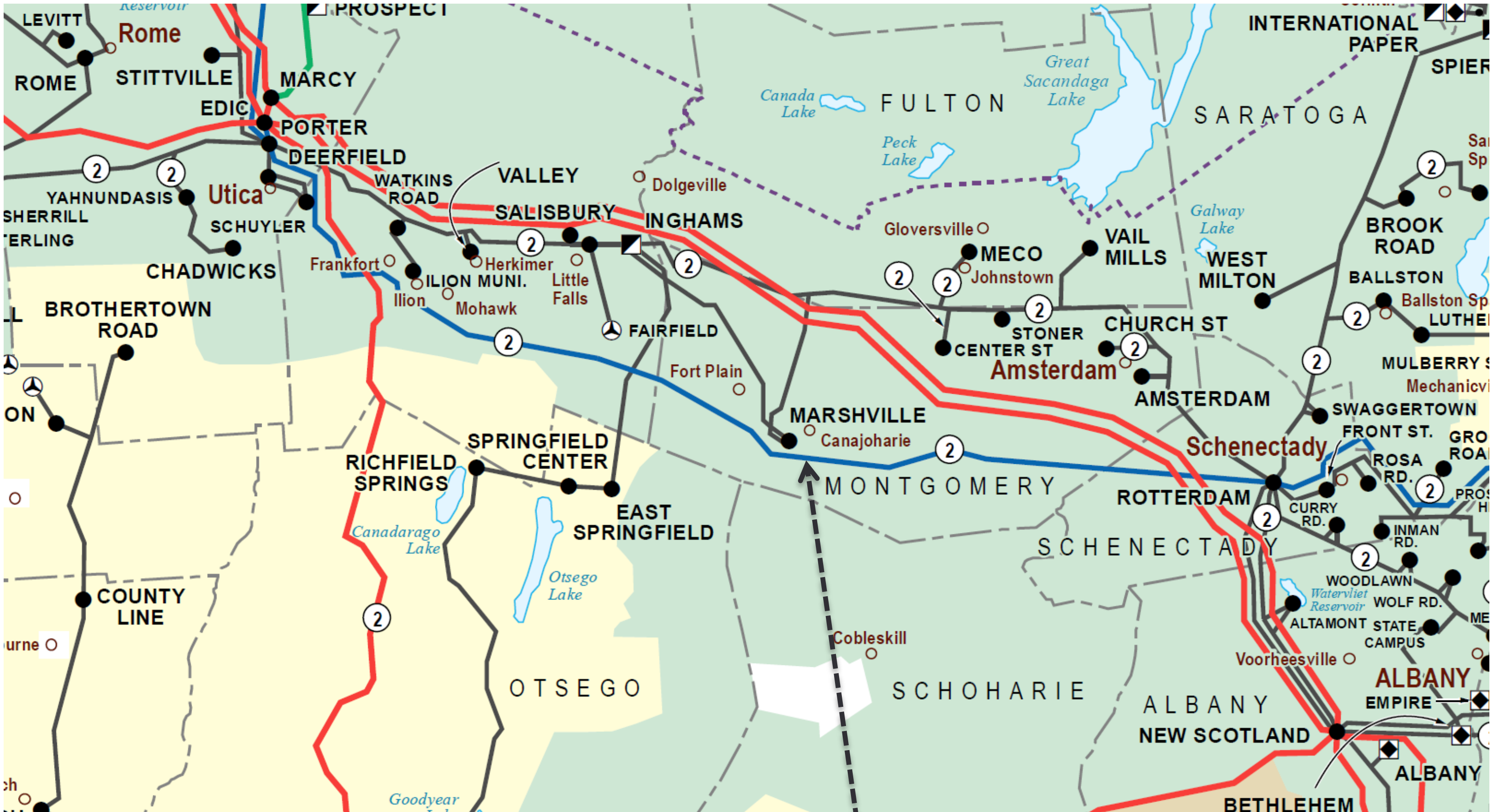
New Scotland-Leeds-Pleasant Valley Corridor



Source: NYISO 2013 Electric System Map

V.D.2. Avoided Transmission Costs: Aging Lines

Central East



PORTER – ROTTERDAM 230 KV (2 LINES)

Source: NYISO 2013 Electric System Map

Avoided Costs of Refurbishing Aging Lines

Project	Aging Transmission Facility (identifed in STARS 2012 Report)	Estimated Year of Refurbishment	Proposed Refurbishment	Refurbishment Mileage	Avoided Capital Costs (mid-2015 $m)	Avoided Investment Cost (Mid-Year before Investment $m)	Avoided PVRR (Mid-Year before Investment $m)	Avoided PVRR (mid-2015 $m)
P6 – NYTO	Knickerbocker - Pleasant Valley 115 KV (2 lines)	2030	Replacement	108	**$279**	**$401**	**$661**	**$195**
P7 - NYTO	None		None		-	-	-	-
P9 - NYTO	Leeds - Pleasant Valley 115 kV (2 Lines)	2030	Replacement	82	**$212**	**$305**	**$502**	**$148**
P11 – NYTO	Porter - Rotterdam 230 kV (2 Lines)	2020	Retirement	140	**$560**	**$636**	**$1,048**	**$739**
	Knickerbocker - Pleasant Valley 115 KV (2 lines)	2030	Replacement	108	**$279**	**$401**	**$661**	**$195**
	Total				**$839**			**$933**
P12 – NYTO	Porter - Rotterdam 230 kV (2 Lines)	2020	Retirement	140	**$560**	**$636**	**$1,048**	**$739**
P14 – NYTO	Porter - Rotterdam 230 kV (2 Lines)	2020	Retirement	140	**$560**	**$636**	**$1,048**	**$739**
	Leeds - Pleasant Valley 115 kV (2 Lines)	2030	Replacement	82	**$212**	**$305**	**$502**	**$148**
	Total				**$772**			**$887**
P19a – NextEra	Greenbush - N. Churchtown - Pleasant Valley 115 kV (2 lines)	2030	Retirement	124	**$319**	**$459**	**$757**	**$223**
P20 – Boundless	None		None		-	-	-	-
P21 – Boundless	None		None		-	-	-	-

Notes:

Assumed lines to be replaced in STARS report in 0 – 10 years occur in 2020 and 11 – 20 years occur in 2030.

Assumed all identified aging facilities will require a full rebuild to calculate the avoided capital cost; used generic equipment cost of $2.6m for a 115 kV Tx rebuild to calculate avoided capital cost for 115 kV Lines.

See slides 46 – 47 for an explanation of how we convert 2015 overnight costs to PVRR in 2015$.

Avoided Congestion Costs

Many proposed projects add new transmission parallel to aging 115kV and 230kV lines; parallel paths could enable reduced congestion and production costs during future refurbishment of aging facilities

- We estimated that the aging 115 kV lines, which are all in the Leeds-Pleasant Valley corridor, will have very low congestion and production cost impacts
  - This was based on our MAPS analysis to estimate the congestion impact of outage of major 345kV facilities in the Leeds-PV corridor (see Appendix); congestion impact of major 345kV lines was low, at less than $2m; therefore, expected the impact of 115kV outages to be even lower
- We evaluated avoided congestion costs for the 230kV lines by modeling outages of the Porter-Rotterdam (PT-RM) 230kV aging lines in MAPS (without any parallel paths), and compared the congestion impact with our base case (the base case, which modeled the current system without outages, also represents an outage during refurbishment in the presence of a new parallel path)
- However, we do not credit projects retiring PT-RM lines with any avoided congestion cost benefits, since with the new Tx, PT-RM must be removed during construction to accommodate new lines on the same ROW; without it, PT-RM must be taken out of service during refurbishment anyway

Avoided Congestion Costs

- To estimate congestion impact during refurbishment of major 345kV lines in the Leeds-PV corridor, we modeled the outage of Athens-Pleasant Valley 345kV line in MAPS
  - 345kV lines in the LD-PV corridor were identified in the STARS report as potentially needing refurbishment, subject to more detailed condition assessments (note that project proponents however do not identify these facilities as aging; therefore, we do not count these as avoided congestion costs in our benefits analysis)
- We assumed outages of Leeds – Pleasant Valley and New Scotland – Leeds 345kV lines would have similar impacts as the Athens – Pleasant Valley outage
- In Central East, we modeled the outage of Porter – Rotterdam 230 kV lines, as some projects propose to retire these facilities
- Results indicate that congestion and production cost impacts of these outages are very low

Elements being Outaged for Replacement	Assumed Outage Required	Outage Period Assumed (modeled in MAPS)	2019 NYCA-wide APC Impact ($m)
Athens – Pleasant Valley 345 (part of UPNY/SENY)	**23 weeks (~ 6 months)**	A1. February through April	$1.60
		A2. October through December	$0.24
		Total (A1 + A2)	**$1.84**
Porter – Rotterdam 230 (part of Central East)	**10 weeks in fall, 10 weeks in spring, 6 weeks in fall**	B1. March through Mid-May	$2.69
		B2. September through Mid-November	$0.24
		Total (B1 + B2 * 1.6)	**$3.07**

V.D.4. Avoided Transmission Costs: Construction Costs

New Parallel Lines Reduce Future Refurbishment Costs

Projects that provide parallel paths to existing aging lines lower the cost of future refurbishments by avoiding expensive construction scheduling when taking existing lines out of service for construction

- In the short-term, parallel lines provide flexibility to schedule maintenance outages, which we have aimed to capture already under production cost related benefits
- In the long-term, new parallel lines could reduce the construction cost of future refurbishment of aging lines
- In the New Scotland–Pleasant valley corridor, we estimate that projects might avoid 20% cost premium associated with costly extended refurbishment schedules; <u>cost premium savings are uncertain, therefore we treat this as an added benefit only in our sensitivity analysis</u>
- Even though some projects propose new parallel lines in Central-East, they require existing aging lines to be removed to accommodate new lines on the same ROW; therefore, no construction cost savings occur due to these parallel lines

Avoided Construction Costs by Adding Parallel Line

5 of the 9 projects propose to build a new transmission line in the New Scotland–Leeds–Pleasant Valley corridor that will enable refurbishment of up to 3 aging lines

Portfolio	Facilities Proposed	Aging Lines whose Refurbishment is Enabled by Proposed Facility	Proposed Refurbishment	Estimated Year of Refurbishment	Refurbishment Mileage	Estimated Cost of Refurbishment (mid-2015 $m)	20% of Estimated Refurbishment Costs (mid-2015 $m)	Avoided Investment Costs (Mid-Year before Investment $m)	Avoided PVRR (Mid-Year before Investment $m)	Avoided PVRR (mid-2015 $m)
P6 – NYTO	**Knickerbocker - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P7 – NYTO	**None**	-	-	-	-	-	-		-	-
P9 – NYTO	**Leeds - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P11 – NYTO	**Knickerbocker - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P12 – NYTO	**None**	-	-	-	-	-	-	-	-	-
P14 – NYTO	**Leeds - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P19a – NextEra	**Greenbush - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P20 – Boundless	**None**	-	-	-	-	-	-	-	-	-
P21 – Boundless	**None**	-	-	-	-	-	-	-	-	-

Notes:

Assumed lines to be replaced in 11 – 20 years in STARS report occur in 2030.

Assumed all identified aging facilities will require a full rebuild to calculate the avoided capital cost; used generic equipment cost of $2.6m for a 115 kV Tx rebuild to calculate avoided capital cost for 115 kV Lines.

See slides 46 – 47 for an explanation of how we convert 2015 overnight costs to PVRR in 2015$.

Agenda

RPS/CO_2 Benefits of Transmission

Approach: We estimated potential cost reductions for achieving future wind capacity goals from the addition of the proposed transmission solutions

- The cost of meeting a specific MWh renewables policy goal is estimated as the additional "REC" payments required to attract new wind generation
- REC cost savings may occur due to higher LBMPs and/or reductions in curtailments
- Neither of the alternative solutions are expected to provide benefits to future renewable capacity development

Impact of transmission on wind revenues: We used findings from the 2010 Growing Wind report and the MAPS production cost analysis to estimate the impact of the proposed transmission solutions

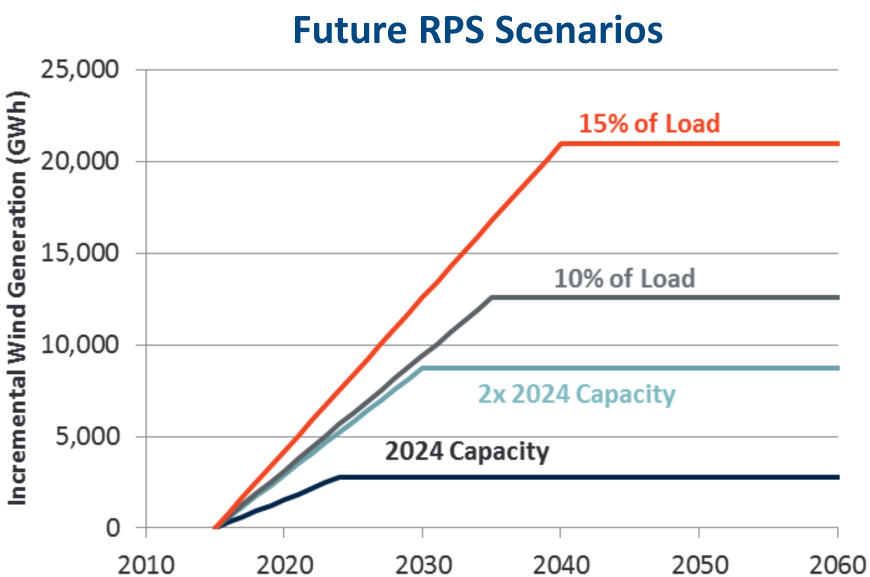
- We assume curtailment impact is negligible since most curtailments are due to local constraints that are not resolved by the proposed solution
- Based on MAPS modeling of the proposed solutions, the LBMPs in zones in which new wind capacity is expected to be built increase by the following amounts:

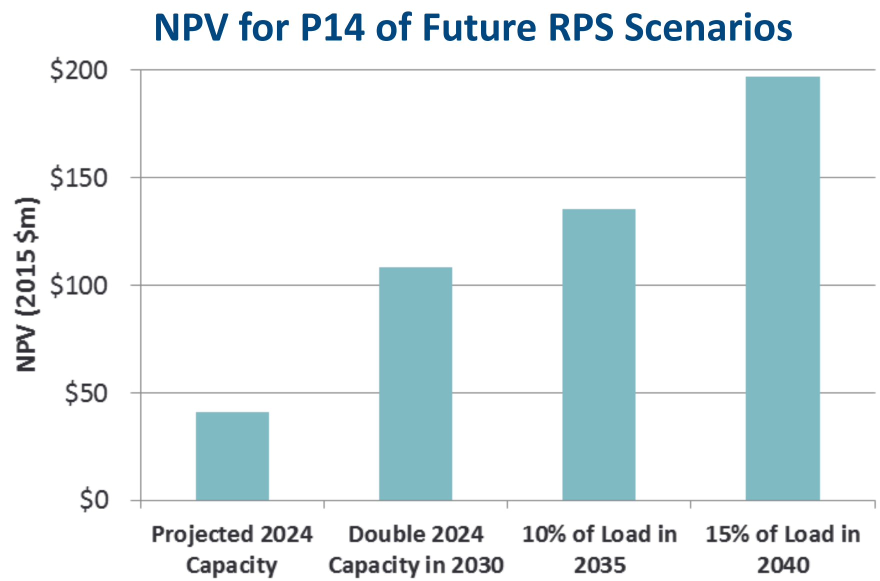
UPNY LBMP Impact of Transmission Solutions ($/MWh)

Year	P6	P7	P9	P11	P12	P14	P19a	P20	P21
2019	$0.25	$0.29	$0.40	$1.45	$1.65	$1.60	$0.25	$0.13	$0.16
2024	$0.45	$0.52	$0.69	$1.58	$1.76	$1.75	$0.45	$0.29	$0.29

Summary of RPS/CO_2 Benefits

Depending on the assumed goals, the savings for P14 in 2024 could be \$5m to \$13m with an NPV of \$41m to \$197m in benefits with an average of \$120m





RPS/CO2 Benefits of Transmission Portfolios ($m)

RPS	P6	P7	P9	P11	P12	P14	P19a	P20	P21
Low	$10	$11	$15	$37	$41	$41	$10	$6	$6
2x 2024	**$27**	**$31**	**$41**	**$97**	**$108**	**$108**	**$27**	**$17**	**$17**
High	$49	$56	$75	$177	$197	$196	$49	$32	$32

Agenda

I. Problem Statement
II. Solutions Analyzed
III. Benefit-Cost Analysis Results
IV. Detailed Cost Information
V. Detailed Benefit Analysis
  A. MAPS Analysis of Production Cost Savings
  B. Additional Production Cost Savings not captured in MAPS
  C. ICAP Analysis of Capacity Value
  D. Avoided Transmission Costs
  E. Reduced Cost of Meeting Future RPS Goals
  F. Tax Receipts
  G. Employment and Economic Activity
  H. Non-Quantified Benefits

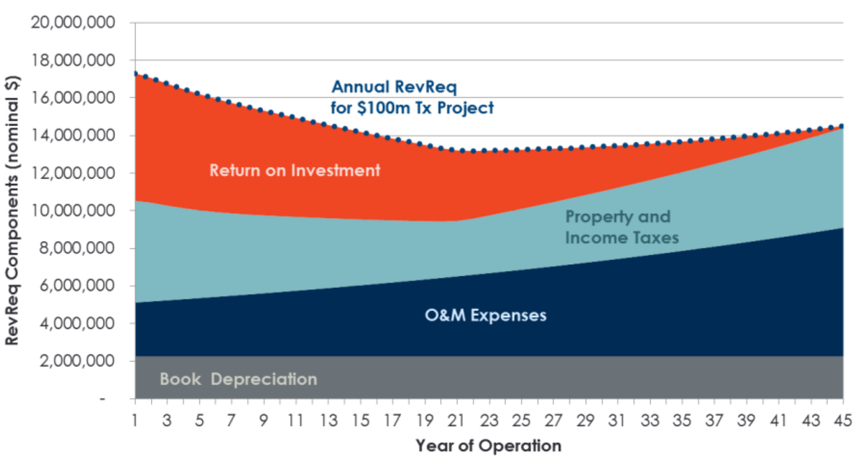
State and Local Taxes

Taxes as a cost and benefit: While property and state income taxes are a transfer between entities within NY, we include them in our analysis as a benefit to offset their inclusion in the RevReq calculation; account for 28% of PVRR

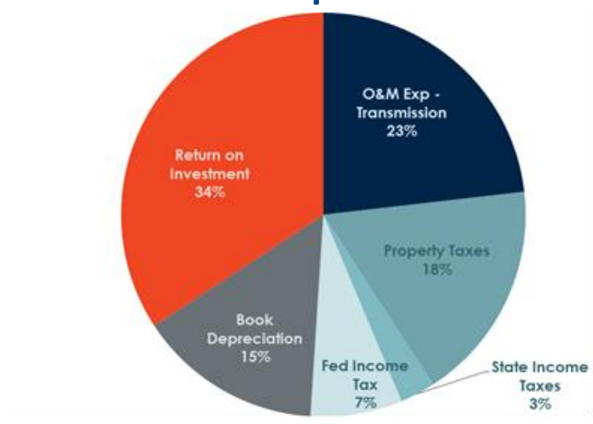
- Property tax rate of 2.18% is included in RevReq analysis for transmission and constitutes 18% of PVRR due to DPS assumption that taxes escalate at inflation over 45 year life
- Total effective income tax rate of 40% is assumed in RevReq analysis, including 7.1% state income taxes; state income taxes add 3% to PVRR
- Federal income taxes are not included in the analysis since NY ratepayers are not likely to receive a direct benefit from the amount paid; add 7% to PVRR

For ratepayer analysis, we estimated UPNY/SENY tax receipts assuming property taxes are received by proximate localities and income taxes distributed by load

Annual RevReq Components



Contribution of Components to PVRR



Accounting for Tax Payments and Receipts

In addition to taxes paid and received from proposed Tx portfolios, we also accounted for changes in taxes due to the upgrade and refurbishment of existing lines

- Existing Line Upgrades:
  - Similar to our approach for calculating avoided O&M costs of existing lines (*see slide 112*), we account for property taxes paid and received from existing lines
  - In societal analysis, we place both taxes paid and received in "Tax Receipts" category such that they cancel each other out
  - In ratepayer analysis, we include taxes no longer paid in Avoided Tx Costs and taxes no longer received separately in the taxpayer impact analysis
- Avoided Refurbishment Projects:
  - Taxes that are avoided by removing need to refurbish lines are included as a benefit with the rest of the avoided RevReq in the Avoided Tx Costs category
  - Tax that will not be received are counted as an offset to increased taxes paid by the proposed Tx portfolios in the Tax Receipts category

See examples on slide 28

Agenda

I. Problem Statement

II. Solutions Analyzed

III. Benefit-Cost Analysis Results

IV. Detailed Cost Information

V. Detailed Benefit Analysis

A. MAPS Analysis of Production Cost Savings

B. Additional Production Cost Savings not captured in MAPS

C. ICAP Analysis of Capacity Value

D. Avoided Transmission Costs

E. Reduced Cost of Meeting Future RPS Goals

F. Tax Receipts

G. Employment and Economic Activity

H. Non-Quantified Benefits

Increased Employment During Construction

Investment in new transmission facilities will have employment impacts in the regions in which the facilities are built

- Based on previous analysis using NREL's JEDI model, every $1m in transmission investment results in 6.6 full-time equivalent ("FTE") jobs during construction
- 60% of jobs are directly associated with the project and the remaining 40% indirect or induced
- The capital costs of the proposed solutions range from $360 to $1,200m, which would be expected to result in 2,400 to 8,000 FTEs

This does not account for the effects of rate impacts on customer spending and associated economic activity

Also, does not include employment benefits from ongoing transmission maintenance and improved viability of upstate generators

- Near term, we project upstate generator revenues to increase by $1 – 2/kW-mo
- Long term, we project 800 – 1,000 MW of additional UPNY capacity

Increased Revenues to Upstate Generators ($/kW-mo)

Unit Type	Capacity Factor	LBMP Impact $1/MWh	LBMP Impact $2/MWh	Capacity Revenues	Total
Nuclear	95%	$0.7	$1.4	$0.5 - 1.0	$1.2 - 2.4
CC	60%	$0.4	$0.9	$0.5 - 1.0	$0.9 - 1.9
Oil/Gas Steam	40%	$0.3	$0.6	$0.5 - 1.0	$0.8 - 1.6

Agenda

Transmission Value under Extreme Conditions

Transmission Value under Extremes Conditions: The additional transfer capacity provided by transmission lines can avoid or limit the effects of extreme conditions that are not to be expected (and not modeled) but are also not uncommon during short term operations and longer term

- *Extreme conditions that affect operations in the short term:*
  - Fluctuations in uncertain variables (including fuel prices, transmissions and generation availability, and load) occurring simultaneously can result in extremely high cost events that may be avoided with additional transmission;
  - Examples from NY or other markets: 2014 Polar Vortex; 2011 Feb & summer in TX
- *Extreme scenarios that can affect costs and reliability for longer periods:*
  - Changes in the availability of large transmission or generation facilities over an extended period of time (due to equipment failure or environmental restrictions) can result in sustained high costs that may be avoided with additional transmission
  - Examples from NY or other markets: the San Onofre nuclear unit shut down in CA; preparing for federal CO_2 restrictions that may limit operation hours of local resources

Source: Pfeifenberger, Chang, and Sheilendranath, Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid, Prepared for WIRES, April 2015.

Expected versus Insurance Value

Value that Tx may provide by protecting against extremes can be captured both through the *expected value* of costs avoided (e.g., production costs) and the *insurance value* of limiting such costly events from occurring due to the addition of new Tx

Effects of mitigating extremes on the *expected value* of new transmission:

- Conceptually, should account for a range of conditions/scenarios weighted by probabilities
- We aimed to include the effect of extremes conditions on the expected value by multiplying our modeled PCS by the "multipliers" described on slides 84-87, but this approach may not capture all possibilities affecting the expected value
- We did not include effects of extreme scenarios on capacity costs, except as sensitivity analyses (and our IP-Out scenario was also only a sensitivity analysis)

The insurance value concept:

- Risk-averse stakeholders may be willing to pay a slight expected premium to avoid exposure to extremes
- We have not quantified the insurance value Tx provides in our analysis
- Including the insurance value in the evaluation of additional transmission capacity could in some cases result in a more "conservative" approach to planning than the more common outcome of avoiding high capital cost projects

V.H. Non-Quantified Benefits

Market Benefits and Future Capacity Options

Market Benefits: Increased competition and market liquidity can reduce costs to NY ratepayers due to more competitive bids into the energy market, reduced transaction costs, and improved information for long-term planning and investment decisions

- Although not quantified, all Tx projects increase competition and liquidity by providing additional access to trading hubs
- Additional generation capacity may increase competition depending on ownership
- Net load reductions of REV resources increase competition by reducing pivotality

Maximizing Future Capacity Options on Existing ROW: New Tx facilities can be "upsized" beyond the capacity required to meet reliability standards or make space for 2nd circuit

- Most proposals add more capacity than currently "needed" for reliability or congestion relief
- Although no proposals add space for future circuits, one proponent (NAT) requested guidance from DPS on whether to build their lines to provide the option for future double circuit capability

V.H. Non-Quantified Benefits

Resiliency and Synergies with Future Projects

Storm Hardening and Resiliency: Transmission towers and substations built with current technology and to current standards provide a more resilient system during storms

- Projects re-building (P12), replacing (P12), or re-conductoring (P9/P12/P20) existing lines will increase system resiliency due to updated construction standards
- Parallel path benefit may be limited for projects on existing ROW
- For example, Boundless notes that many existing lines do not meet current ice loading standards; new facilities will meet the standards and increase system resilience
- Generation and REV resources both provide additional local resources or reduce demand that may mitigate loss of Tx and generation facilities

Synergies with Other Future Transmission Projects: Transmission lines built to serve other needs (e.g., policy upgrades) can create low-cost options to quickly increase load-serving capability or increase access to renewables

- Tx projects extending north and west provide the most possibilities, including providing lower cost upgrades to accommodate increased industrial capacity and load growth north of Albany
- STARS and Wind Vision reports identified need for further upgrades to replace aging infrastructure and to serve additional renewable development
- Generation and REV resources may reduce the need for future transmission projects

Relieving Gas Constraints

Relieving Gas Transport Constraints: additional Tx capacity can relieve gas transport constraints by changing the location where NG is used for generation

- Few gas constraints in current system, but more Tx capacity may help in contingencies and in a future with more gas demand and changing flow patterns
- Relieving gas transport constraints could potentially reduce fuel switching from gas to oil and avoid higher production costs and higher emission from burning oil
- Generation will add local demand that may result in additional costs on a constrained system
- Reduced demand due to REV resources will help if downstate gas becomes constrained
- The combination of fewer transmission constraints and gas transport constraints will increase potential sites for developing new generators. Some of these sites may have fewer scheduling constraints for construction, providing “speediness” benefits (e.g., build a new plant upstate in 2 years vs take 3 years downstate)

Appendices

Appendix A: Analysis Without CPV Valley

A1. Solutions Analyzed

A2. Benefit-Cost Analysis Results

A3. Detailed Cost Information

A4. Detailed Benefit Analysis

A1. Solutions Analyzed
Proposed Transmission Portfolios

- Started with 21 Tx portfolios proposed by 4 developers, plus 1 add-on portfolio (P19a) requested by DPS
- For efficiency purposes, DPS selected 6 representative portfolios for detailed analysis (reps are highlighted in the table)
  - The 6 include at least one from each of 5 groups NYISO identified based on electrical similarities
  - The 6 include a project from each developer
  - The 6 are used to extrapolate benefits to the other 16

(*See appendix for acronym definitions*)

Group A	Hudson Valley reconductoring, PARs, or series comp
P7 - NYTO	LD-PV reconductor
P8 - NYTO	Hurley PARs
P13 - NYTO	Edic-NS, NS-LD reconductor, Hurley PARs
P20 - Boundless	**NS-LD SR, (LD-PV, LD-HA, CPV-RT reconductor), LD-HA-R SC, RS-EF two cc**
P21 - Boundless	P20 minus LD-PV reconductor
Group B	**Hudson Valley additional transmission**
P6 - NYTO	KN-PV
P9 - NYTO	**NS-LD reconductor, LD-PV**
P19 - NextEra	O-FR, KN-PV
P19a - NextEra	**GB-KN-CH-PV**
Group C	**Hudson Valley reconductoring plus Central East**
P12 - NYTO	**Edic-NS, NS-LD reconductor, LD-PV reconductor**
Group D	**Hudson Valley additional transmission plus Central East**
P10 - NYTO	O-FR, Edic-NS, KN-PV
P11 - NYTO	Edic-NS, KN-PV
P14 - NYTO	Edic-NS, NS-LD reconductor, LD-PV
P15 - NextEra	O-FR, Edic-LD-PV
P16 - NextEra	O-FR, Marcy-Princetown, KN-PV
P17 - NextEra	**O-FR, Marcy-Princetown-NS-KN-PV**
P18 - NextEra	O-FR, Marcy-NS, KN-PV
Group E	**Hudson Valley additional transmission plus Marcy South**
P1 - NAT	Edic-Fraser, NS-LD-PV
P2 - NAT	Edic-Fraser, NS-LD-PV Alt
P3 - NAT	Edic-Fraser, NS-LD-PV, FR-G SC, Fraser tie M-CC
P4 - NAT	**Edic-Fraser, NS-PV, FR-G SC, Fraser tie M-CC, M/E-NS SC**
P5 - NAT	Edic-Fraser, KN-PV, FR-G SC, Fraser tie M-CC, ED-Princetown-KN

A1. Solutions Analyzed

Tx Portfolios Selected for Detailed Analysis

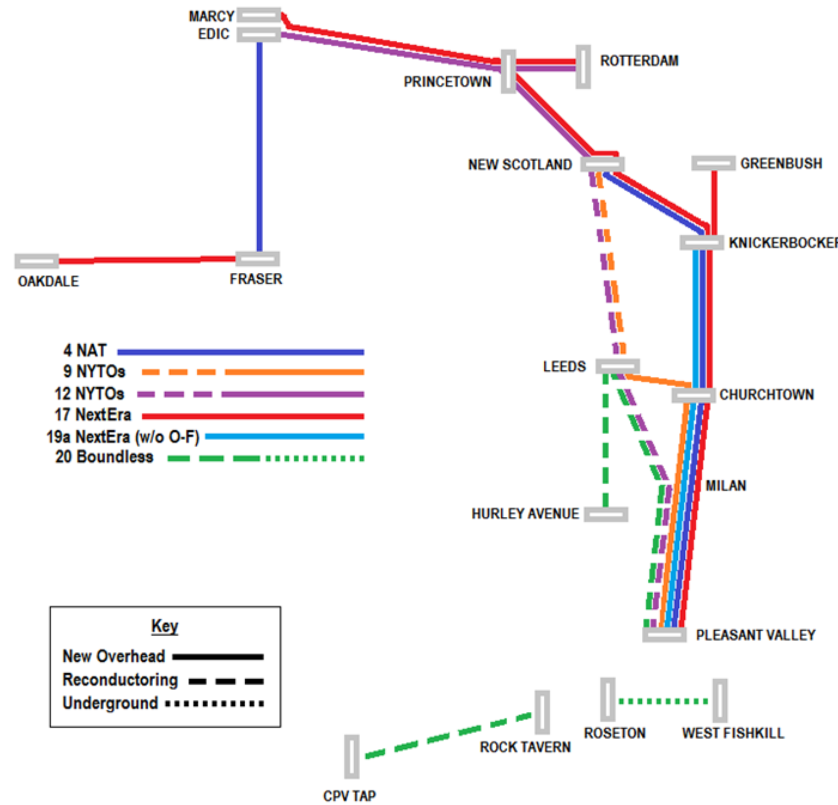
The projects were grouped by similarity and we analyzed the benefits and costs of the 6 selected transmission portfolios as representative of the groups

Representative Projects Selected for Detailed Analysis

GROUPINGS							
A	7 NYTOs	8 NYTOs	13 NYTOs	20 Boundless	21 Boundless		
B	6 NYTOs	9 NYTOs	19 NextEra	19a * NextEra			
C	12 NYTOs						
D	10 NYTOs	11 NYTOs	14 NYTOs	15 NextEra	16 NextEra	17 NextEra	18 NextEra
E	1 NAT	2 NAT	3 NAT	4 NAT	5 NAT		

* = To be modeled without the Oakdale - Fraser Segment

Schematic of Selected Projects



Impacts on Major Interface Limits (MW)

Portfolio	SENY N-1-1	UPNY-SENY Normal N-1	UPNY-SENY Emergency N-1	Central East Voltage	Central East Limit	ISO-NE Import
P4 - NAT	1,048	933	1,203	300	420	-186
P9 - NYTO	1,198	1,351	1,598	25	292	-58
P12 - NYTO	1,228	1,200	1,200	350	617	-11
P17 - NextEra	1,123	817	1,653	350	617	-131
P19a - NextEra	1,106	679	1,528	50	317	-73
P20 - Boundless	601	588	588	-50	217	-31

Note: At request of DPS, we assume Athens SPS is removed in 2019 once the new transmission facilities are energized. While Athens SPS is in effect, Leeds-PV and Athens-PV can reach their STE ratings following the loss of a parallel circuit, assuming there is sufficient Athens generation to guarantee flows return to or below their LTE ratings within 15 minutes.

A1. Solutions Analyzed

Non-Transmission Alternatives

For a description of the Generation solution and REV resource included in this analysis, see the following slides:

- Generation: Slide 8
- REV Resources: Slide 9

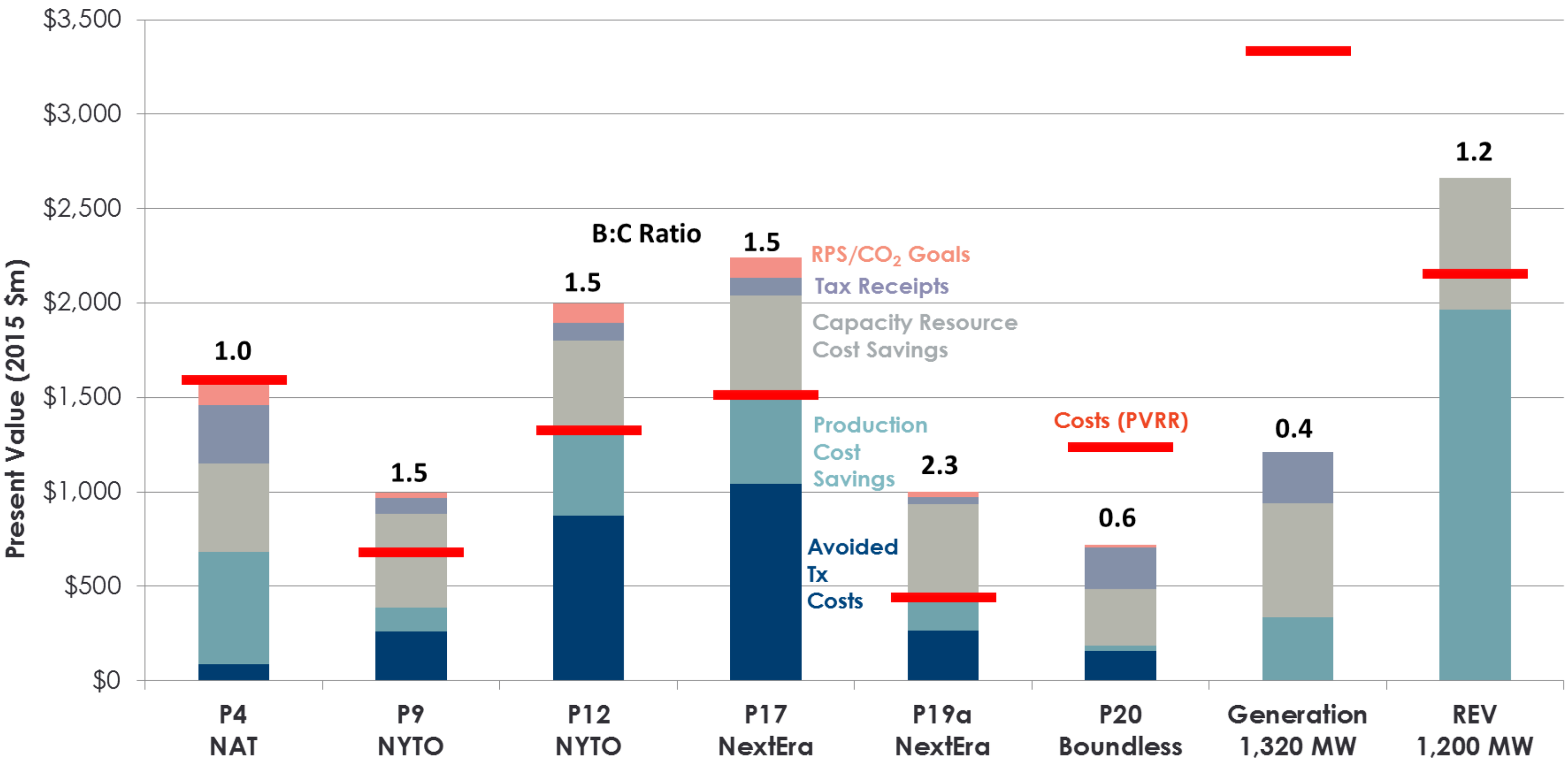
Appendix A: Analysis Without CPV Valley

Societal Benefit-Cost Analysis Results

Analysis without CPV Valley found net societal benefits for 4 Tx portfolios and the REV resources

- P19a has the highest B:C ratio of 2.3; P17 has the highest NPV of $729m
- Generation has the lowest B:C ratio of 0.4

Summary of Societal Benefit-Cost Analysis



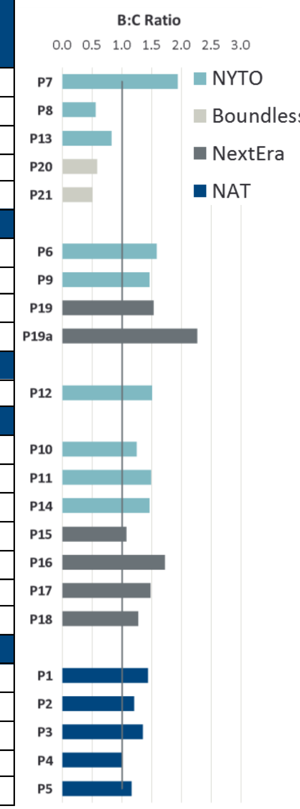
Notes: Tx PVRRs are based on DPS's estimated 2015 capital costs, which differ from proponents' claimed costs (*see following slides*). State and local taxes shown on the benefits side cancel the non-federal taxes included in the PVRR of projects.

Benefit-Cost Analysis for All Proposed Portfolios

Analysis of all 22 portfolios identified 18 Tx portfolios with net benefits

- P19a has the highest B:C ratio of 2.3
- P16 has the highest NPV of $909m

Group A	DPS Estimated Capital Cost (2015 $m)	PVRR (2015 $m)	Production Cost Savings (2015 $m)	Capacity Resource Savings (2015 $m)	Avoided Refurb PVRR (2015 $m)	Net RPS Costs (2015 $m)	Tax Receipts (2015 $m)	Total Benefits (2015 $m)	NPV (2015 $m)	B/C Ratio
P7 - NYTO	$214	$301	$28	$423	$70	$15	$47	$583	$282	1.9
P8 - NYTO	$79	$112	$0	$39	$0	$0	$23	$62	-$49	0.6
P13 - NYTO	$676	$950	$0	$0	$748	$0	$41	$789	-$161	0.8
P20 - Boundless	**$879**	**$1,236**	**$28**	**$300**	**$157**	**$15**	**$221**	**$720**	**-$515**	**0.6**
P21 - Boundless	$632	$889	$28	$164	$76	$15	$166	$450	-$439	0.5
Group B										
P6 - NYTO	$484	$681	$178	$513	$281	$27	$82	$1,082	$401	1.6
P9 - NYTO	**$484**	**$681**	**$128**	**$494**	**$260**	**$28**	**$86**	**$996**	**$316**	**1.5**
P19 - NextEra	$498	$701	$178	$513	$264	$27	$89	$1,072	$371	1.5
P19a - NextEra	**$314**	**$441**	**$178**	**$493**	**$264**	**$27**	**$36**	**$999**	**$557**	**2.3**
Group C										
P12 - NYTO	**$943**	**$1,326**	**$460**	**$470**	**$873**	**$103**	**$93**	**$1,999**	**$672**	**1.5**
Group D										
P10 - NYTO	$1,292	$1,817	$485	$513	$998	$107	$167	$2,270	$453	1.2
P11 - NYTO	$1,042	$1,465	$485	$500	$998	$107	$95	$2,185	$721	1.5
P14 - NYTO	$1,071	$1,506	$485	$513	$995	$107	$105	$2,204	$697	1.5
P15 - NextEra	$902	$1,269	$485	$513	$0	$107	$260	$1,364	$96	1.1
P16 - NextEra	$894	$1,257	$485	$513	$1,012	$107	$50	$2,166	$909	1.7
P17 - NextEra	**$1,076**	**$1,513**	**$485**	**$513**	**$1,041**	**$107**	**$96**	**$2,242**	**$729**	**1.5**
P18 - NextEra	$861	$1,211	$485	$489	$264	$107	$194	$1,538	$328	1.3
Group E										
P1 - NAT	$711	$999	$594	$513	$0	$125	$205	$1,436	$437	1.4
P2 - NAT	$874	$1,229	$594	$513	$0	$125	$252	$1,483	$255	1.2
P3 - NAT	$765	$1,075	$594	$513	$0	$125	$220	$1,452	$377	1.4
P4 - NAT	**$1,134**	**$1,595**	**$594**	**$469**	**$87**	**$125**	**$309**	**$1,583**	**-$11**	**1.0**
P5 - NAT	$1,077	$1,515	$594	$513	$281	$125	$253	$1,765	$251	1.2



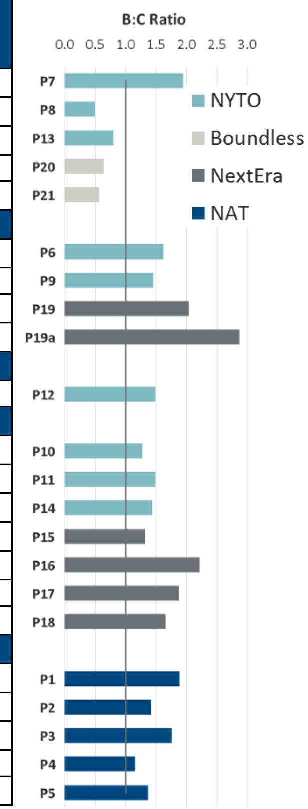
Projects in bold are the 6 selected transmission portfolios analyzed in detail as representatives of the groups

A2. Benefit-Cost Analysis Results: Societal Impacts

Benefit-Cost Analysis with Proponent Costs

Using the proponent's cost estimates tends to increase the NPV due to the lower estimated cost of the portfolios (*see slide 166 for a comparison of cost estimates*)

Group A	Proponent Estimated Capital Cost (2015 $m)	PVRR (2015 $m)	Production Cost Savings (2015 $m)	Capacity Resource Savings (2015 $m)	Avoided Refurb PVRR (2015 $m)	Net RPS Costs (2015 $m)	Tax Receipts (2015 $m)	Total Benefits (2015 $m)	NPV (2015 $m)	B/C Ratio
P7 - NYTO	$212	$299	$28	$423	$69	$15	$47	$582	$284	1.9
P8 - NYTO	$95	$134	$0	$39	$0	$0	$27	$67	-$67	0.5
P13 - NYTO	$701	$986	$0	$0	$746	$0	$49	$795	-$191	0.8
P20 - Boundless	**$698**	**$981**	**$28**	**$300**	**$112**	**$15**	**$178**	**$633**	**-$348**	**0.6**
P21 - Boundless	$471	$662	$28	$164	$38	$15	$128	$373	-$289	0.6
Group B										
P6 - NYTO	$470	$661	$178	$513	$279	$27	$78	$1,075	$415	1.6
P9 - NYTO	**$488**	**$686**	**$128**	**$494**	**$260**	**$28**	**$87**	**$998**	**$311**	**1.5**
P19 - NextEra	$355	$500	$178	$513	$251	$27	$51	$1,020	$520	2.0
P19a - NextEra	$239	**$336**	**$178**	**$493**	**$251**	**$27**	**$17**	**$967**	**$630**	**2.9**
Group C										
P12 - NYTO	**$958**	**$1,347**	**$460**	**$470**	**$870**	**$103**	**$97**	**$2,000**	**$654**	**1.5**
Group D										
P10 - NYTO	$1,258	$1,768	$485	$513	$998	$107	$158	$2,260	$491	1.3
P11 - NYTO	$1,047	$1,472	$485	$500	$998	$107	$97	$2,187	$714	1.5
P14 - NYTO	$1,092	$1,535	$485	$513	$991	$107	$111	$2,206	$671	1.4
P15 - NextEra	$704	$990	$485	$513	$0	$107	$203	$1,307	$317	1.3
P16 - NextEra	$671	$943	$485	$513	$996	$107	-$11	$2,090	$1,146	2.2
P17 - NextEra	**$812**	**$1,142**	**$485**	**$513**	**$1,019**	**$107**	**$25**	**$2,149**	**$1,007**	**1.9**
P18 - NextEra	$627	$881	$485	$489	$251	$107	$129	$1,460	$579	1.7
Group E										
P1 - NAT	$522	$734	$594	$513	$0	$125	$150	$1,382	$648	1.9
P2 - NAT	$718	$1,009	$594	$513	$0	$125	$207	$1,438	$429	1.4
P3 - NAT	$563	$792	$594	$513	$0	$125	$162	$1,394	$602	1.8
P4 - NAT	**$930**	**$1,308**	**$594**	**$469**	**$79**	**$125**	**$252**	**$1,518**	**$210**	**1.2**
P5 - NAT	$887	$1,246	$594	$513	$273	$125	$199	$1,704	$457	1.4

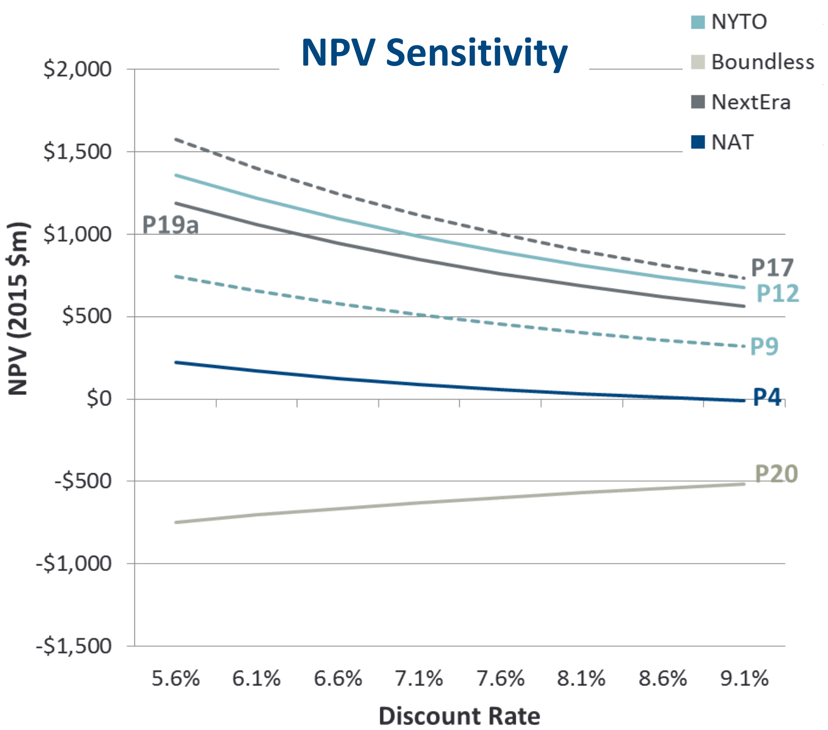


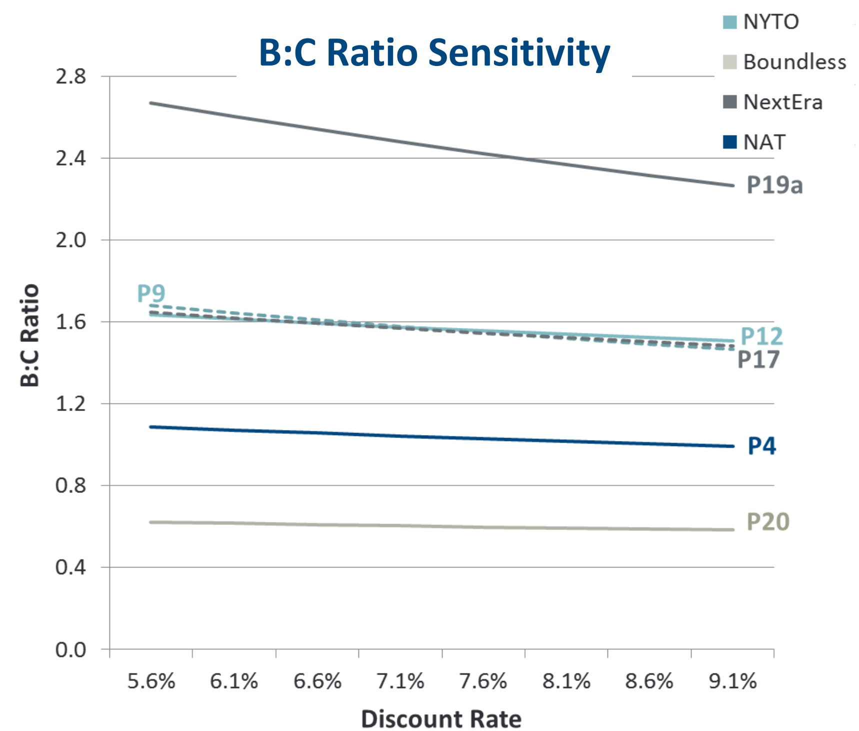
Projects in bold are the 6 selected transmission portfolios analyzed in detail as representatives of the groups

Discount Rate Sensitivity Analysis

Analyzed impact of discount rate on NPV and B:C ratio by reducing DPS recommended assumption of 9.13% at the high end to 5.6% (reflecting utility ATWACC) at the low end

- Lower discount rate increases NPV of most portfolios by $200-800m (but decreases NPV of P20 by $200m due to its benefits being small relative to its PVRR)
- Due to back-weighted benefits, lower discount rates increase B:C ratios by 0.0– 0.4





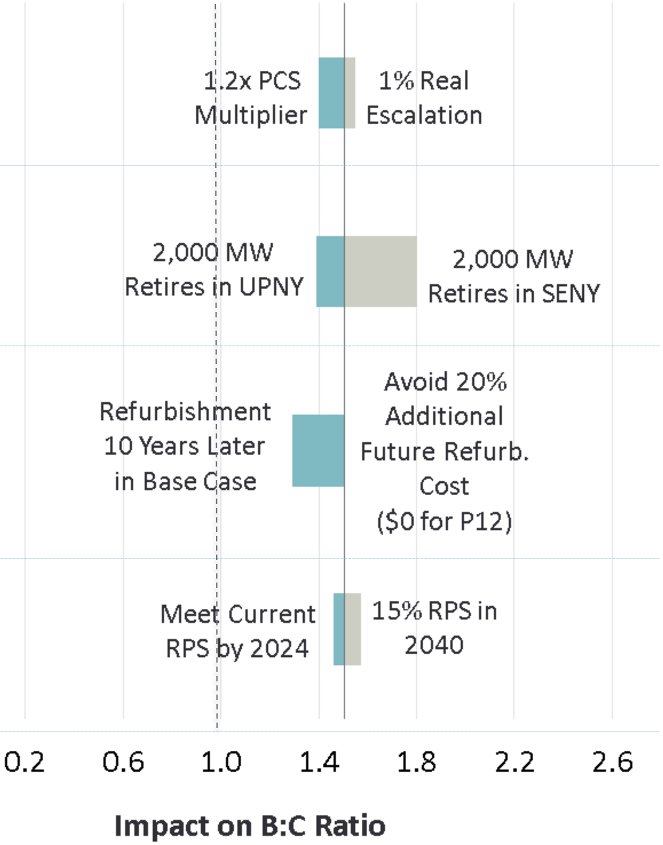
A2. Benefit-Cost Analysis Results: Societal Impacts

B:C Ratio Sensitivity Analysis of Benefit Assumptions

Sensitivity Analysis Assumptions

Benefit Category	Lower Value Case	Primary Assumption	Higher Value Case
Production Cost Savings (PCS)	Reduce PCS multiplier to 1.2x	Multiply MAPS PCS by 1.6 to account for factors not modeled in Base Case; escalate post-2024 PCS at inflation	Post-2024 PCS escalates at inflation + 1%
Capacity Resource Savings	2,000 MW retires in UPNY (with or w/o new Tx)	No exit of existing/planned supply, except in response to reduced LCRs	2,000 MW retires in SENY (with or w/o new Tx)
Avoided Transmission Costs	Refurbishment could be delayed 10 years	Projects that *refurbish* aging facilities get a "credit" on the latest date indicated in STARS; projects that *facilitate* future refurbishments NOT credited for reducing future construction costs	Projects that add a parallel path to aging facilities reduce future refurbishment costs 20% (by avoiding extended construction)
Reduced Net Cost of Meeting RPS Goals	Meet current RPS by 2024 and no more thereafter	RPS increases in 2030 to 2x the 2024 RPS	15% RPS in 2040

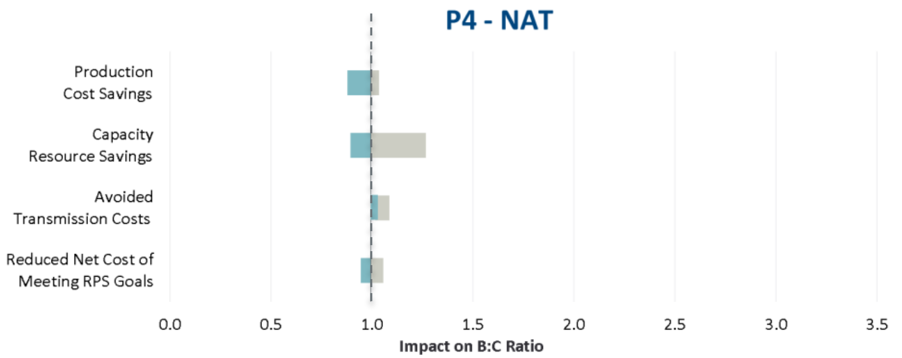
P12 - NYTO

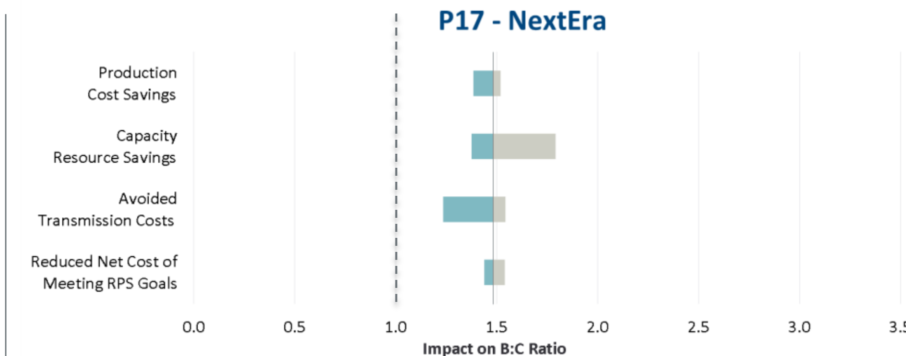


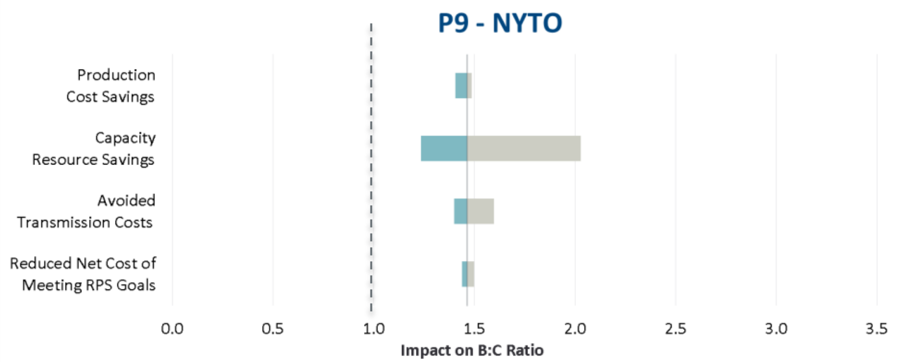
Note: These cases represent the outer envelope of a larger set of sensitivities we considered; we did not test the sensitivity to uncertainty in project cost assumptions

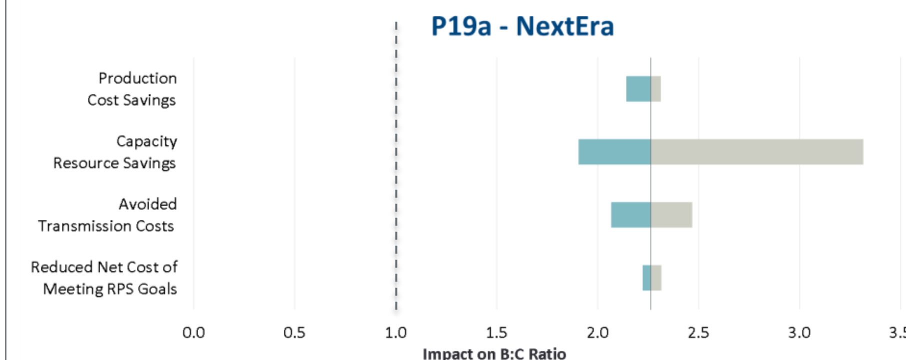
A2. Benefit-Cost Analysis Results: Societal Impacts

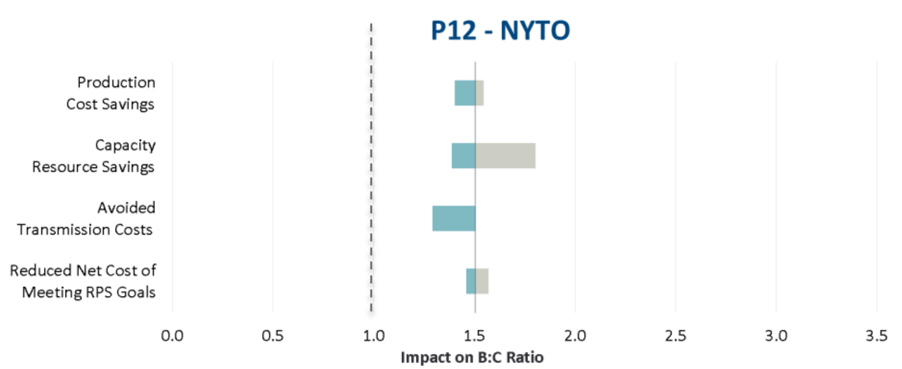
B:C Ratio Sensitivities Across Tx Portfolios

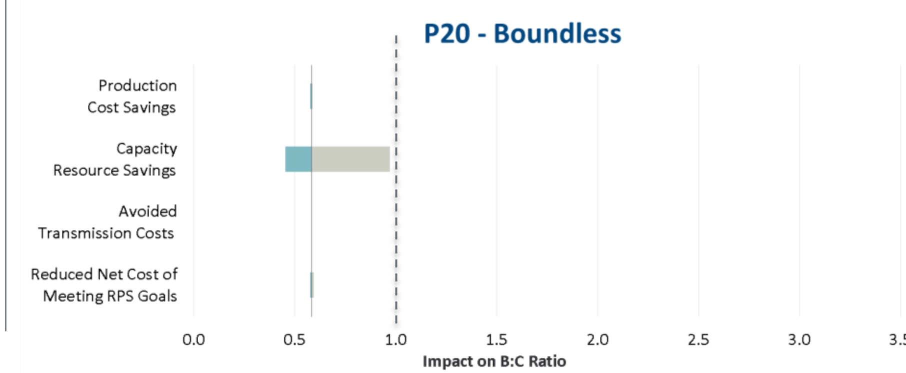






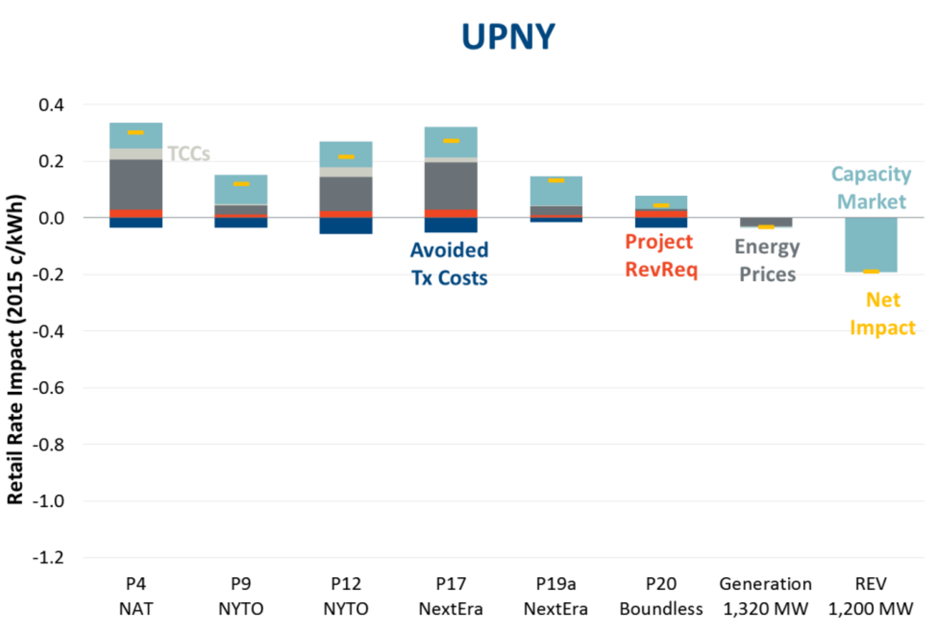


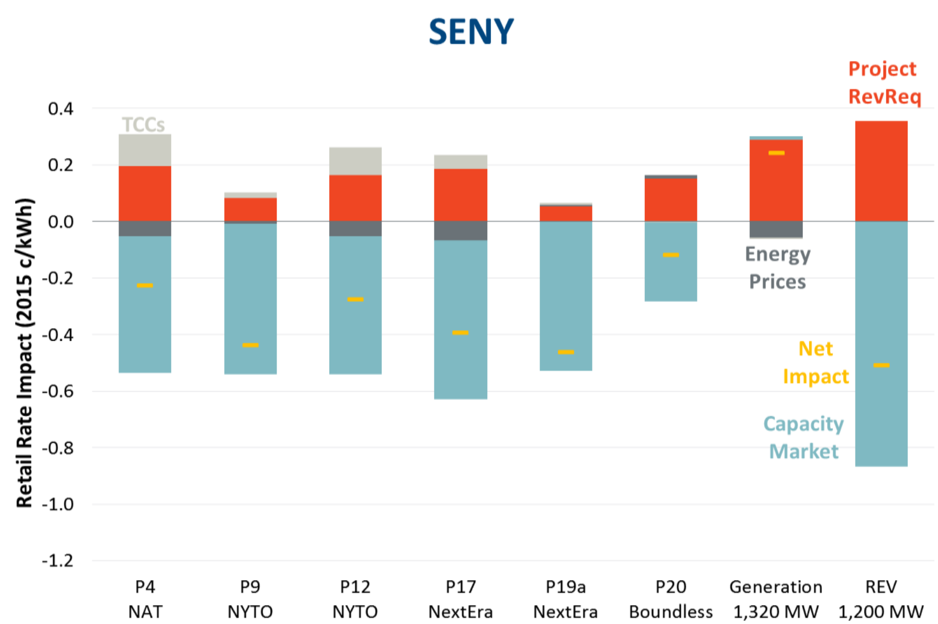




A2. Benefit-Cost Analysis Results: Ratepayer Impacts

2019 Ratepayer Impacts





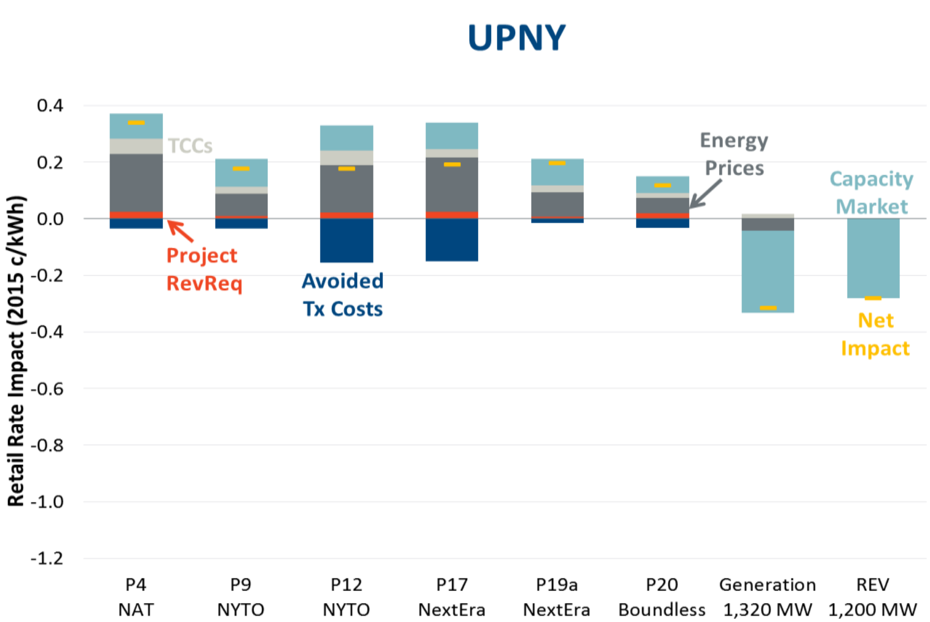
Net Tax Receipts in 2019 - UPNY

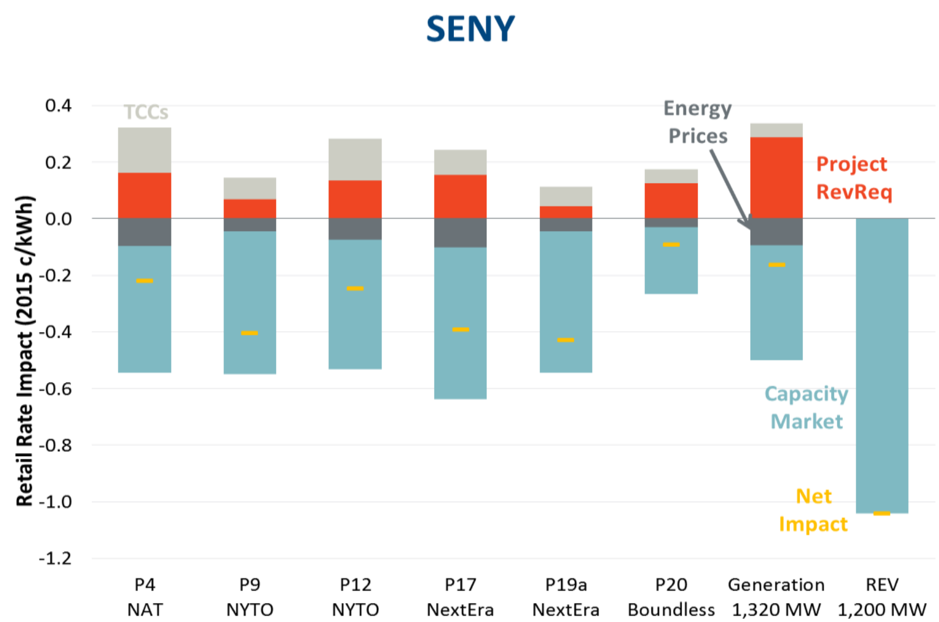
	P4	P9	P12	P17	P19a	P20	Gen	REV
$m	18	3	9	14	3	8	--	--
c/kWh	0.03	0.00	0.01	0.02	0.00	0.01	0.00	0.00

Net Tax Receipts in 2019 - SENY

	P4	P9	P12	P17	P19a	P20	Gen	REV
$m	8	3	6	6	2	11	16	
c/kWh	0.01	0.00	0.01	0.01	0.00	0.01	0.02	0.00

2024 Ratepayer Impacts





Net Tax Receipts in 2024 - UPNY

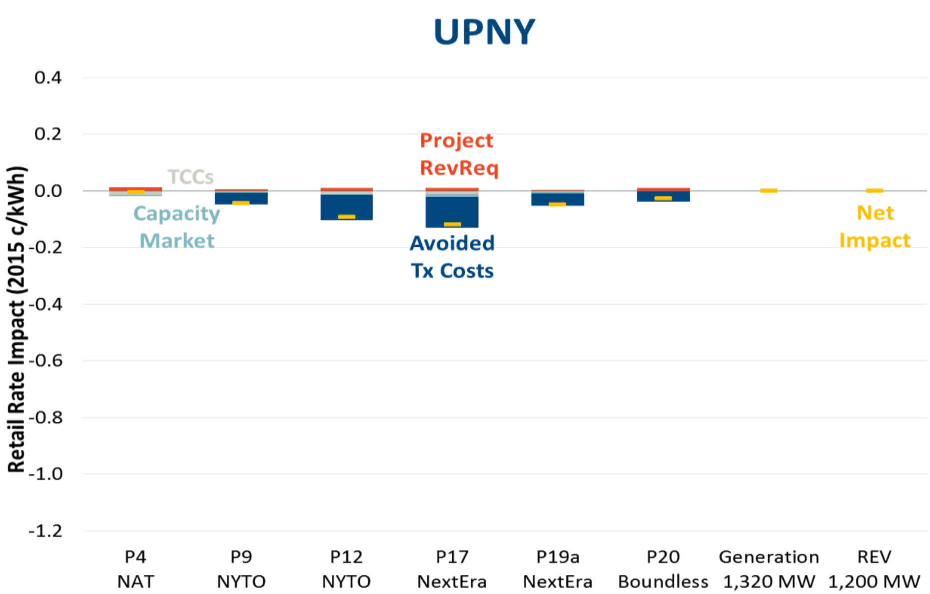
	P4	P9	P12	P17	P19a	P20	Gen	REV
$m	17	2	2	6	3	7	--	--
c/kWh	0.03	0.00	0.00	0.01	0.00	0.01	0.00	0.00

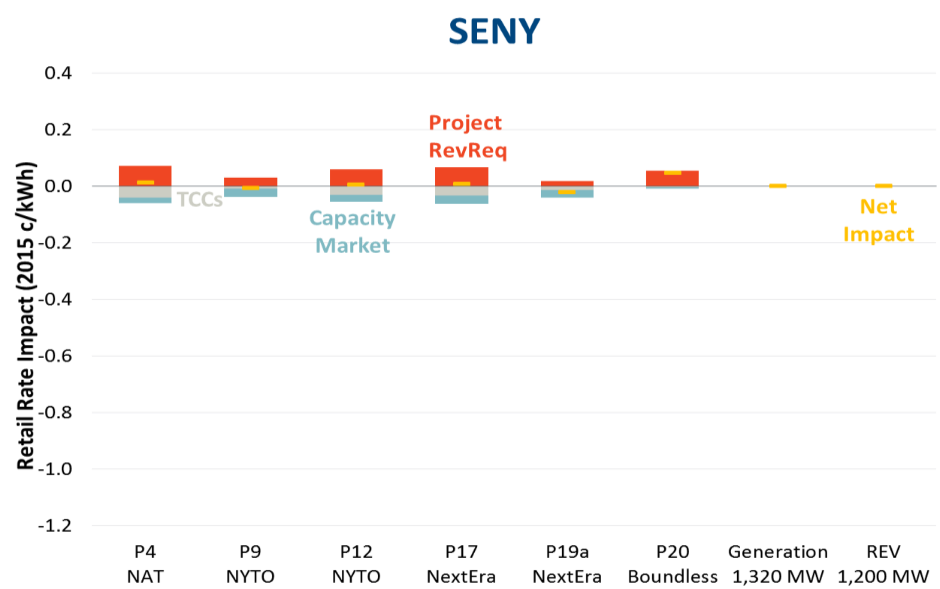
Net Tax Receipts in 2024 - SENY

	P4	P9	P12	P17	P19a	P20	Gen	REV
$m	6	2	1	2	2	9	16	--
c/kWh	0.01	0.00	0.00	0.00	0.00	0.01	0.02	0.00

A2. Benefit-Cost Analysis Results: Ratepayer Impacts
Long-Term Rate Impacts

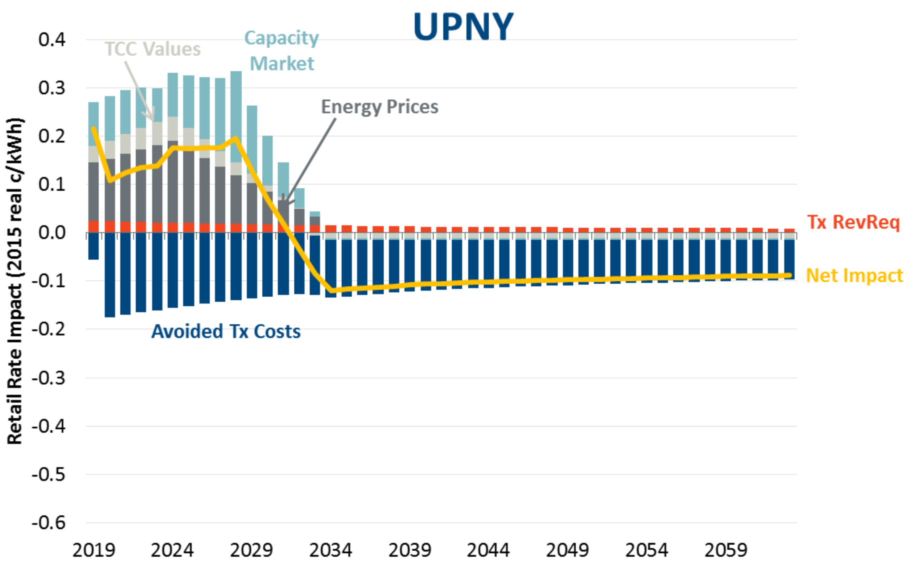
See slide 25 for a summary of the long term rate impact assumptions

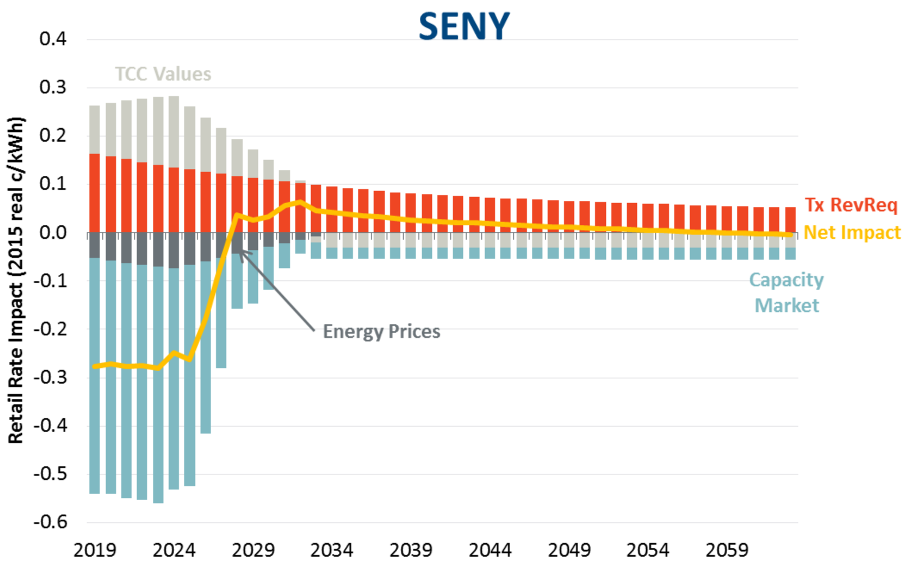




Annual Rate Impacts (P12 example)

See slide 26 for a summary of the annual rate impact assumptions

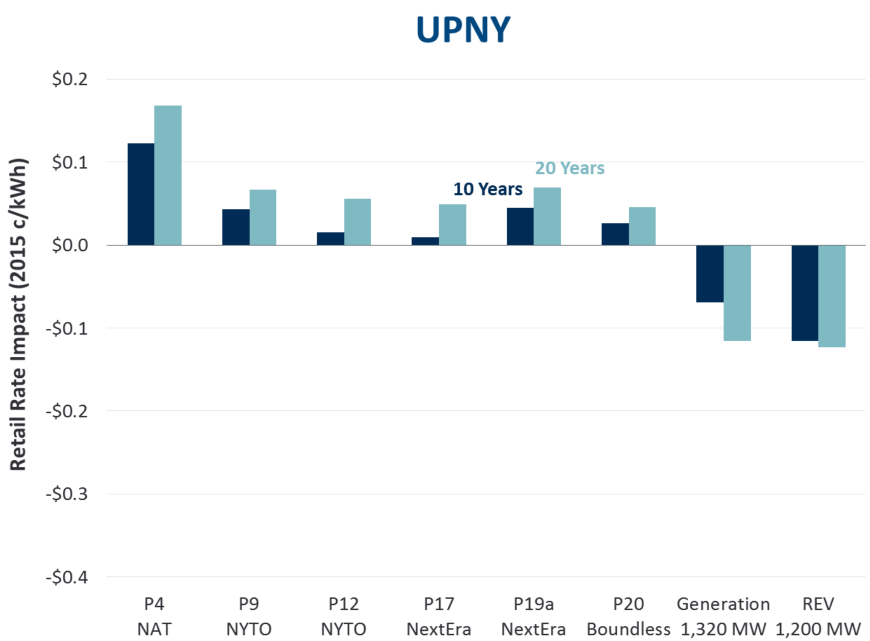


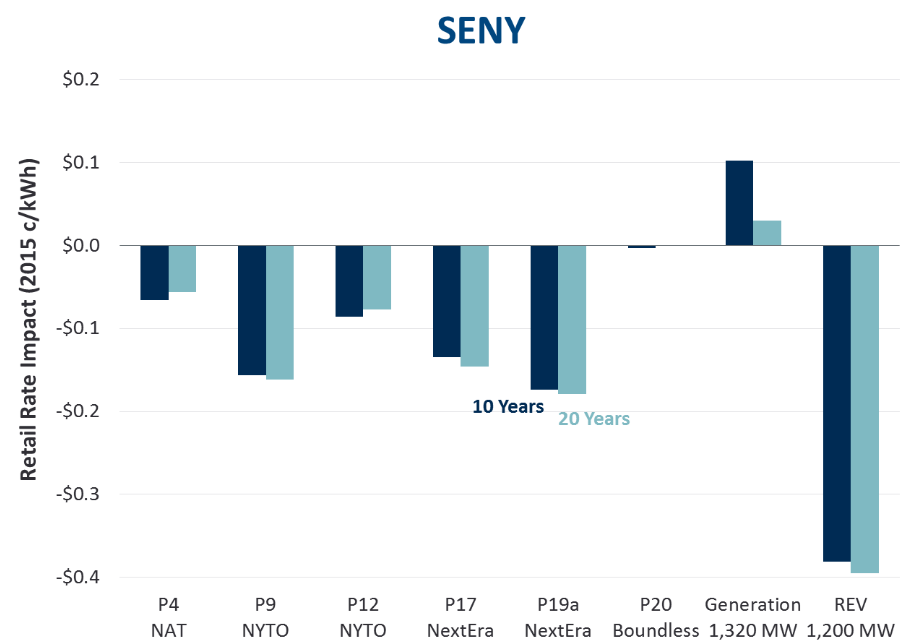


A2. Benefit-Cost Analysis Results: Ratepayer Impacts

Levelized Rate Impacts

See slide 27 for a summary of the levelized rate impact calculations





A2. Benefit-Cost Analysis Results: Indian Point Retirement

IP Retirement MAPS and ICAP Impact

MAPS Results: While IP Retirement increases production costs in all cases, both Tx and Generation additions mitigate production cost increases, with greater savings associated with Tx

- NYCA Adjusted Production Costs increase by $700m in 2019 and $900m in 2024 with the retirement of Indian Point and no additional Tx or generation
- Additional generation or transmission lowers production costs compared to the IP out Base Case
- Tx solution has lower production costs than Generation by $56m in 2019, and $8m in 2024

ICAP Results: Capacity in G-J decreases, but Tx Solution increases transfers into SENY

- Capacity decreases by 2,000 MW with the retirement of IP, assuming no additional Tx or Generation
- Tx solution results in 871 MW less new capacity in G-J than in the Compensating Gen case (assuming new entry at net CONE)

Scenario	Production Costs ($m)		G-J Capacity (MW)	
	2019	2024	2019	2024
Base Case	$3,561	$4,339	15,903	16,014
IP-out Base Case (no Compensating Generation)	$4,273	$5,242	13,903	14,014
IP-Out Base Case with Compensating Generation	$4,256	$5,196	15,555	16,014
IP-Out with Tx Solution	$4,217	$5,188	14,683	15,143
IP Out Delta (Tx Solution – Generation Solution)	**($56)**	**($8)**	**-872**	**-871**

Note: Results reflect analysis of P12 in IP retirement scenario. Similar results are expected for other Tx solutions.

IP Retirement Results

Societal value of Tx portfolios increase in the Indian Point retirement scenario. Compared to the value of Tx with IP in:

- Production cost savings *decrease* by $280m (but still positive) for P12 since the no-Tx Compensating Generation alternative assumed to add new, efficient CCs in SENY (although Tx savings would be very high with IP out, absent compensating generation)
- Capacity cost savings *increase* by $120–450m in NPV (depending on the project) due to short-term need for capacity in SENY; transmission allows delay and shift to Upstate
- Net impact for P12 is an increase in NPV of $70m (increasing B:C ratio to 1.6)

A2. Benefit-Cost Analysis Results: Benefits by Project

P4 NAT (Group E)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $1134m	**PVRR = -$1595m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $34m in 2019; $42m in 2024 Multiplier for Other Factors = 1.6x	**$594m**	-$181m with lower 1.2x multiplier to +$68m with 1% real escalation
Early Refurbishment Credits	See later slides	**$87m**	+$39m if Refurbishment Required 10 Years Later in the Base Case +$112m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 867 MW in G-J, 278 MW in J, 163 MW in K Resource Cost Svgs = $25m in 2019; $40m in 2024 Variant 1 = $31m in 2019; $46m in 2024 Variant 2 = $201m in 2019; $196m in 2024	**Resource Cost Svgs = $469m** Variant 1 = $499m Variant 2 = $720m	-$157m if 2,000 MW retires in UPNY to +$438m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $1.8/MWh in 2019, $2/MWh in 2024 Saves: $4.2m in 2019; $10.7m in 2024	**$125m**	-$78m to just meet 2024 RPS to +$103m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$25m in 2019; $27m in 2024	**$309m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = -$11m** **B/C Ratio = 1**	

Annual Emissions Impacts	Total System CO_2: 0 % in 2019; 0 % in 2024 Total System NO_x: 0.02% in 2019; -0.09 % in 2024 Total System SO_2: 0.03% in 2019; -0.14 % in 2024	NYCA CO_2: -0.72 % in 2019; -1.03 % in 2024 NYCA NO_x: -0.03% in 2019; -1.35 % in 2024 NYCA SO_2: 3.66% in 2019; -5.07 % in 2024
Employment During Construction	7500 FTE (60% direct; 40% indirect and induced)	
Retirement Preparedness	Able to accommodate 1030 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*	

A2. Benefit-Cost Analysis Results: Benefits by Project

P9 NYTO (Group B)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $484m	**PVRR = -$681m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $4m in 2019; $10m in 2024 Multiplier for Other Factors = 1.6x	**$128m**	-$39m with lower 1.2x multiplier to +$16m with 1% real escalation
Early Refurbishment Credits	See later slides	**$260m**	-$45m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1025 MW in G-J, 293 MW in J, 172 MW in K Resource Cost Svgs = $27m in 2019; $42m in 2024 Variant 1 = $35m in 2019; $50m in 2024 Variant 2 = $220m in 2019; $223m in 2024	**Resource Cost Svgs = $494m** Variant 1 = $539m Variant 2 = $897m	-$157m if 2,000 MW retires in UPNY to +$384m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.1/MWh in 2019, $0.5/MWh in 2024 Saves: $0.3m in 2019; $2.5m in 2024	**$28m**	-$18m to just meet 2024 RPS to +$23m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$11m in 2019; $11m in 2024	**$86m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$316m** **B/C Ratio = 1.5**	
Annual Emissions Impacts	Total System CO_2: -0.02 % in 2019; -0.01 % in 2024 Total System NOx: -0.01% in 2019; -0.04 % in 2024 Total System SO_2: -0.09% in 2019; 0.1 % in 2024	NYCA CO_2: -0.35 % in 2019; -0.47 % in 2024 NYCA NOx: -0.22% in 2019; -1.09 % in 2024 NYCA SO_2: 0.94% in 2019; -0.45 % in 2024	
Employment During Construction	3200 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1200 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

A2. Benefit-Cost Analysis Results: Benefits by Project

P12 NYTO (Group C)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $943m	**PVRR = -$1326m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $27m in 2019; $32m in 2024 Multiplier for Other Factors = 1.6x	**$460m**	-$140m with lower 1.2x multiplier to +$53m with 1% real escalation
Early Refurbishment Credits	See later slides	**$873m**	-$286m if Refurbishment Required 10 Years Later in the Base CaseN/A
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 872 MW in G-J, 279 MW in J, 164 MW in K Resource Cost Svgs = $25m in 2019; $40m in 2024 Variant 1 = $31m in 2019; $46m in 2024 Variant 2 = $201m in 2019; $200m in 2024	**Resource Cost Svgs = $470m** Variant 1 = $501m Variant 2 = $754m	-$157m if 2,000 MW retires in UPNY to +$394m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $1.3/MWh in 2019, $1.7/MWh in 2024 Saves: $3.1m in 2019; $8.9m in 2024	**$103m**	-$64m to just meet 2024 RPS to +$85m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$21m in 2019; $22m in 2024	**$93m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$672m** **B/C Ratio = 1.5**	

Annual Emissions Impacts	Total System CO_2: 0.04 % in 2019; 0 % in 2024 Total System NO_x: 0.06% in 2019; 0 % in 2024 Total System SO_2: -0.02% in 2019; -0.14 % in 2024	NYCA CO_2: -0.3 % in 2019; -0.67 % in 2024 NYCA NO_x: 0.44% in 2019; -0.81 % in 2024 NYCA SO_2: 6.59% in 2019; -2.21 % in 2024
Employment During Construction	6200 FTE (60% direct; 40% indirect and induced)	
Retirement Preparedness	Able to accommodate 1040 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*	

A2. Benefit-Cost Analysis Results: Benefits by Project

P17 NextEra (Group D)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $1076m	**PVRR = -$1513m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $28m in 2019; $34m in 2024 Multiplier for Other Factors = 1.6x	**$485m**	-$148m with lower 1.2x multiplier to +$56m with 1% real escalation
Early Refurbishment Credits	See later slides	**$1041m**	-$372m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1116 MW in G-J, 305 MW in J, 179 MW in K Resource Cost Svgs = $28m in 2019; $44m in 2024 Variant 1 = $38m in 2019; $53m in 2024 Variant 2 = $233m in 2019; $241m in 2024	**Resource Cost Svgs = $513m** Variant 1 = $566m Variant 2 = $1014m	-$159m if 2,000 MW retires in UPNY to +$469m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $1.6/MWh in 2019, $1.7/MWh in 2024 Saves: $3.6m in 2019; $9.1m in 2024	**$107m**	-$66m to just meet 2024 RPS to +$88m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$23m in 2019; $25m in 2024	**$96m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$729m** **B/C Ratio = 1.5**	
Annual Emissions Impacts	Total System CO_2: -0.02 % in 2019; -0.04 % in 2024 Total System NO_x: 0.03% in 2019; -0.05 % in 2024 Total System SO_2: 0.06% in 2019; -0.08 % in 2024	NYCA CO_2: -0.53 % in 2019; -0.81 % in 2024 NYCA NO_x: 0.09% in 2019; -0.83 % in 2024 NYCA SO_2: 5.78% in 2019; 0.21 % in 2024	
Employment During Construction	7100 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1300 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

A2. Benefit-Cost Analysis Results: Benefits by Project

P19a NextEra (Group B)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $314m	**PVRR = -$441m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $6m in 2019; $14m in 2024 Multiplier for Other Factors = 1.6x	**$178m**	-$54m with lower 1.2x multiplier to +$22m with 1% real escalation
Early Refurbishment Credits	See later slides	**$264m**	-$86m if Refurbishment Required 10 Years Later in the Base Case +$91m if Project Avoids 20% of Future Refurbishment Cost
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 1002 MW in G-J, 292 MW in J, 171 MW in K Resource Cost Svgs = $27m in 2019; $42m in 2024 Variant 1 = $35m in 2019; $50m in 2024 Variant 2 = $219m in 2019; $221m in 2024	**Resource Cost Svgs = $493m** Variant 1 = $536m Variant 2 = $887m	-$158m if 2,000 MW retires in UPNY to +$465m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $0.1/MWh in 2019, $0.5/MWh in 2024 Saves: $0.2m in 2019; $2.5m in 2024	**$27m**	-$17m to just meet 2024 RPS to +$23m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$7m in 2019; $7m in 2024	**$36m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$557m** **B/C Ratio = 2.3**	
Annual Emissions Impacts	Total System CO_2: 0 % in 2019; -0.04 % in 2024 Total System NO_x: 0.01% in 2019; -0.16 % in 2024 Total System SO_2: -0.11% in 2019; -0.36 % in 2024	NYCA CO_2: -0.42 % in 2019; -0.67 % in 2024 NYCA NO_x: -0.31% in 2019; -1.32 % in 2024 NYCA SO_2: -0.58% in 2019; -2.7 % in 2024	
Employment During Construction	2100 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 1170 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

A2. Benefit-Cost Analysis Results: Benefits by Project

P20 Boundless (Group A)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $879m	**PVRR = -$1236m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $-3m in 2019; $3m in 2024 Multiplier for Other Factors = 1.6x	**$28m**	-$8m with lower 1.2x multiplier to +$5m with 1% real escalation
Early Refurbishment Credits	See later slides	**$157m**	N/A
Capacity Resource Cost Savings from reduced LCR enabling exit of existing capacity, and delay and shift of new construction	LCR Reduction: 398 MW in G-J, 178 MW in J, 104 MW in K Resource Cost Svgs = $14m in 2019; $29m in 2024 Variant 1 = $16m in 2019; $30m in 2024 Variant 2 = $116m in 2019; $94m in 2024	**Resource Cost Svgs = $300m** Variant 1 = $305m Variant 2 = $282m	-$159m if 2,000 MW retires in UPNY to +$478m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	Assuming 3,600 MW new wind by 2030 REC Cost Reduction: $-0.1/MWh in 2019, $0.3/MWh in 2024 Saves: $-0.2m in 2019; $1.5m in 2024	**$15m**	-$10m to just meet 2024 RPS to +$13m for 15% RPS in 2040
Tax Receipts from property tax and state income tax in RevReq	$19m in 2019; $21m in 2024	**$221m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = -$515m** **B/C Ratio = 0.6**	
Annual Emissions Impacts	Total System CO_2: -0.03 % in 2019; -0.05 % in 2024 Total System NOx: -0.03% in 2019; -0.06 % in 2024 Total System SO_2: -0.06% in 2019; 0.08 % in 2024	NYCA CO_2: -0.23 % in 2019; -0.34 % in 2024 NYCA NOx: -0.27% in 2019; -0.94 % in 2024 NYCA SO_2: 1.4% in 2019; -1.54 % in 2024	
Employment During Construction	5800 FTE (60% direct; 40% indirect and induced)		
Retirement Preparedness	Able to accommodate 500 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Insurance Against Extremes, Market Benefits, Storm Hardening and Resiliency, Maximizing Future Capacity Options on Existing ROW, Synergies w/Other Future Tx Projects, Relieving Gas Transport Constraints, Help Meet EPA Clean Power Goals *(see following slides)*		

1,320 MW CC in G Benefit-Cost Analysis (25-year)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $2077m	**PVRR = -$3332m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $15m in 2019; $39m in 2024 Multiplier for Other Factors = 1.2x	**$337m**	-$56m with lower 1.09x multiplier to +$25m with 1% real escalation
Early Refurbishment Credits	None	N/A	N/A
Capacity Resource Cost Savings from avoided new construction	Capacity clears auction starting in 2033 due to MOPR Resource Cost Svgs = $119m in 2033 Variant 1 = $135m in 2033 Variant 2 = $262m in 2033	**Resource Cost Svgs = $602m** Variant 1 = $681m Variant 2 = $1240m	$13m if 2,000 MW retires in UPNY to +$70m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	None	N/A	N/A
Tax Receipts from property tax and state income tax in RevReq	$17m in 2019; $19m in 2024	**$273m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = -$2121m** **B/C Ratio = 0.4**	

Annual Emissions Impacts	NYCA CO_2: 0.77 % in 2019; 2.04 % in 2024 NYCA NO_x: -3.04% in 2019; -3.3 % in 2024 NYCA SO_2: -3.96% in 2019; -0.13 % in 2024	Total System CO_2: -0.07 % in 2019; -0.09 % in 2024 Total System NO_x: -0.33% in 2019; -0.5 % in 2024 Total System SO_2: -0.36% in 2019; -0.51 % in 2024
Employment During Construction	5600 FTE (66% direct; 34% indirect and induced)	
Retirement Preparedness	Able to accommodate 1320 MW of additional SENY retirements without falling below LCR in 2019	
Other Benefits not Quantified	May provide Market Benefits and Storm Resiliency *(see following slides)*	

1,320 MW CC in G Benefit-Cost Analysis (45-year)

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $2077m	**PVRR = -$3473m**	N/A
Production Cost Savings, including change in losses and factors not captured in MAPS	MAPS: $15m in 2019; $39m in 2024 Multiplier for Other Factors = 1.2x	**$401m**	-$67m with lower 1.09x multiplier to +$51m with 1% real escalation
Early Refurbishment Credits	None	N/A	N/A
Capacity Resource Cost Savings from avoided new construction	Capacity clears auction starting in 2033 due to MOPR Resource Cost Svgs = $119m in 2033 Variant 1 = $135m in 2033 Variant 2 = $262m in 2033	**Resource Cost Svgs = $880m** Variant 1 = $967m Variant 2 = $1273m	$13m if 2,000 MW retires in UPNY to +$70m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	None	N/A	N/A
Tax Receipts from property tax and state income tax in RevReq	$17m in 2019; $19m in 2024	**$307m**	N/A
Monetarily Quantified Benefit-Cost		**NPV = -$1885m** **B/C Ratio = 0.5**	
Annual Emissions Impacts	NYCA CO_2: 0.77 % in 2019; 2.04 % in 2024 NYCA NO_x: -3.04% in 2019; -3.3 % in 2024 NYCA SO_2: -3.96% in 2019; -0.13 % in 2024	Total System CO_2: -0.07 % in 2019; -0.09 % in 2024 Total System NO_x: -0.33% in 2019; -0.5 % in 2024 Total System SO_2: -0.36% in 2019; -0.51 % in 2024	
Employment During Construction	5600 FTE (66% direct; 34% indirect and induced)		
Retirement Preparedness	Able to accommodate 1320 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	May provide Market Benefits and Storm Resiliency *(see following slides)*		

Note: Although very low fixed O&M costs assumed for final 20 years, additional production cost and capacity resource cost savings increased NPV by just $235m and B:C ratio from 0.4 to 0.5

A2. Benefit-Cost Analysis Results: Benefits by Project

REV Resources Benefit-Cost Analysis

Components	Base Benefit Summary	Base Present Value	PV Sensitivity Analysis
Costs	Capital Costs = $2629m	**PVRR = -$2156m**	N/A
Production Cost Savings, including multiplier (model vs. futures LBMPs)	MAPS: $210m in 2019; $336m in 2024 Multiplier for Other Factors = 1.03x in Zones GHI, 1.06x in Zone J	**$1965m**	-$262m if EE capacity factor is reduced to 65% to + $89m if based on load-weighted average LMP
Early Refurbishment Credits	None	N/A	N/A
Capacity Resource Cost Savings from avoided new construction	Resource Cost Svgs = $62m in 2019; $101m in 2024 Variant 1 = $72MM in 2019; $116MM in 2024 Variant 2 = $476MM in 2019; $648MM in 2024	**Resource Cost Svgs = $696m** Variant 1 = $773m Variant 2 = $3420m	$136m if 2,000 MW added in SENY to +$393m if 2,000 MW retires in SENY (resource cost savings are less sensitive to capacity additions and supply slopes)
Reduced Net Cost of Meeting RPS Goals from lower REC prices	None	N/A	N/A
Tax Receipts from property tax and state income tax in RevReq	None	N/A	N/A
Monetarily Quantified Benefit-Cost		**NPV = +$504m** **B/C Ratio = 1.2**	
Annual Emissions Impacts	NYCA CO2: -1,231 thousand tons in 2019; -1,538 thousand tons in 2024 NYCA NOx: -1,438 tons in 2019; - 1,797 tons in 2024 NYCA SO2: -1,725 tons in 2019; -2,157 tons in 2024		
Employment During Construction	2000 to 16000 FTE (4% to 80% direct, depending on type of measure)		
Retirement Preparedness	Able to accommodate 1200 MW of additional SENY retirements without falling below LCR in 2019		
Other Benefits not Quantified	Market Benefits, Storm Resiliency, Relieving Gas Transport Constraints *(see following slides)*		

Note: Emissions reductions based on REV GEIS.

Appendix A: Analysis Without CPV Valley

A1. Solutions Analyzed

A2. Benefit-Cost Analysis Results

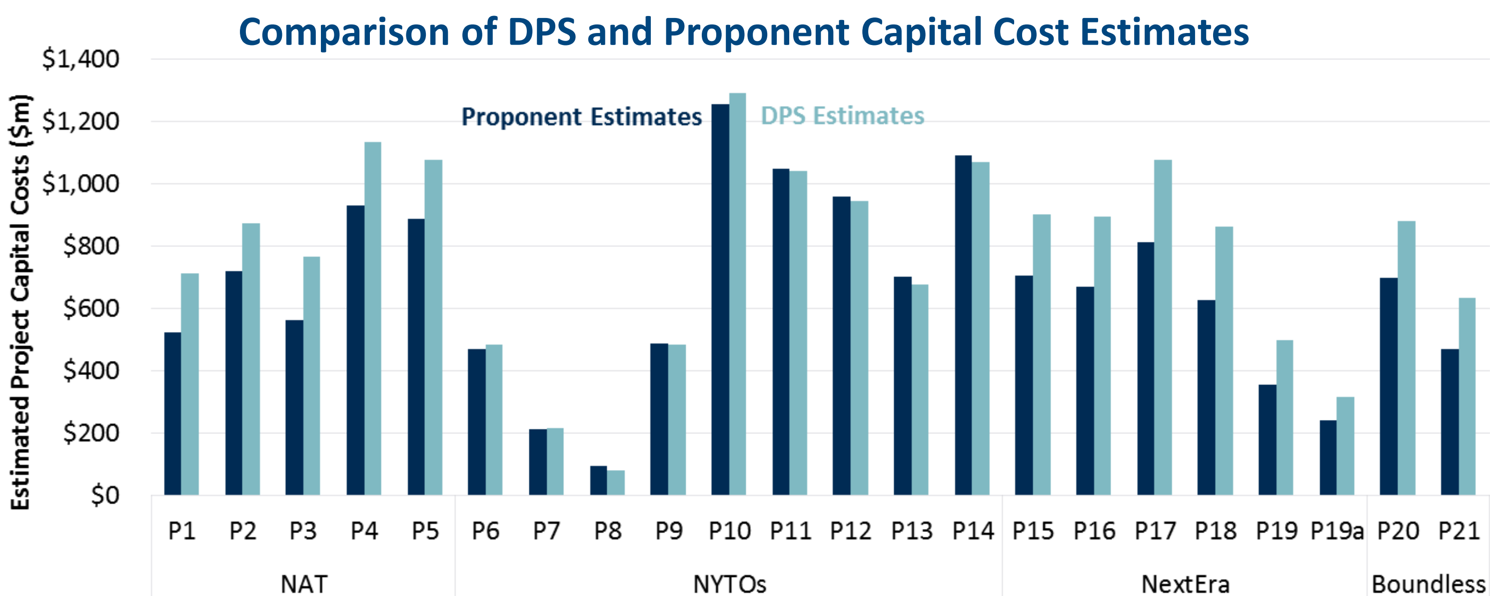
A3. Detailed Cost Information

A4. Detailed Benefit Analysis

Estimated Overnight Capital Costs

DPS staff developed capital cost estimates for each Tx portfolio based on their own analysis

- We calculated NPV and B:C ratio using both cost estimates on slides 144 and 145
- All other analyses in this report use DPS's estimates



DPS Cost Estimates and PVRR for All Portfolios

Calculated the present value of the revenue requirements (PVRR) based on approach described on slides 46-47

Group A	DPS Estimated Capital Cost (2015 $m)	PVRR (2015 $m)
P7 - NYTO	$214	$301
P8 - NYTO	$79	$112
P13 - NYTO	$676	$950
P20 - Boundless	**$879**	**$1,236**
P21 - Boundless	$632	$889
Group B		
P6 - NYTO	$484	$681
P9 - NYTO	**$484**	**$681**
P19 - NextEra	$498	$701
P19a - NextEra	**$314**	**$441**
Group C		
P12 - NYTO	**$943**	**$1,326**
Group D		
P10 - NYTO	$1,292	$1,817
P11 - NYTO	$1,042	$1,465
P14 - NYTO	$1,071	$1,506
P15 - NextEra	$902	$1,269
P16 - NextEra	$894	$1,257
P17 - NextEra	**$1,076**	**$1,513**
P18 - NextEra	$861	$1,211
Group E		
P1 - NAT	$711	$999
P2 - NAT	$874	$1,229
P3 - NAT	$765	$1,075
P4 - NAT	**$1,134**	**$1,595**
P5 - NAT	$1,077	$1,515

Projects in bold are the 6 selected transmission portfolios that benefits were analyzed in detail as representative of the groups

A3. Detailed Cost Analysis: Generation and REV

Non-Transmission Alternatives

For a description of the cost analysis for the Generation solution and REV resources, see the following slides:

- Generation: Slide 49
- REV Resources: Slide 50

Appendix A: Analysis Without CPV Valley

MAPS Analysis without CPV Valley

The following MAPS results do not include CPV Valley. These results were analyzed in May 2015.=

- At that time, we evaluated P4 NAT, P9 NYTO, P12 NYTO, P17 NextEra, P19a NextEra, P20 Boundless, and 1,320 MW Generation (Note: Cases highlighted red were only analyzed for the without CPV Valley analysis)
- All other analyses provided above in this slide deck are including CPV Valley. These results are included for reference

For a summary of the assumptions and Base Case results of the MAPS analysis, see **slides 54– 60**

A4. Detailed Benefit Analysis: MAPS Analysis

P4 NAT (Group E)

Input Changes:

- Topology: new line from Edic to Fraser, NS-PV, FR-G SC, Fraser tie M-CC, M/ED-NS SC
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Ratings increases on other lines binding in Base Case: nothing else significant
- Central East limits: increase by 300 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
FRASR345 345.00-GILB 345 345.00	E	F	0	16,058	0	7,614
DUNWOODIE SHORE ROAD	I	K	25,050	1,659	29,549	3,056
COOPC345 345.00-MARCCSC2 345.00	E	G	N/A	1,609	N/A	7,843
COOPC345 345.00-FRASR345 345.00	E	E	1,228	991	432	3,518
CLAY 345.00-CLAY 115.00	C	C	71	(71)	3,149	(2,999)
HUNTLEY PACKARD	A	A	49,083	(1,016)	75,491	(10,340)
GARDV230 230.00-STOLE230 230.00	A	A	5,614	(1,829)	30,592	(5,182)
VOLNEY SCRIBA	C	C	29,874	(20,003)	46,059	(32,699)
LEEDS PLEASANT VALLEY	F	G	23,587	(23,587)	59,538	(59,493)
CENTRAL EAST	D/E/F	NE/F	306,077	(76,008)	295,372	(64,114)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**(147,902)**	**1,968,251**	**(206,608)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.97	1.26	52.03	1.17
GENESSEE (B)	35.82	1.61	47.59	1.96
CENTRAL (C)	36.78	1.46	48.85	1.60
NORTH (D)	34.34	2.19	46.15	2.44
MOHAWKVA (E)	36.49	1.72	48.50	1.95
CAPITAL (F)	47.00	(1.16)	58.37	(0.51)
HUDSONVA (G)	44.60	(0.38)	57.12	(0.48)
MILLWOOD (H)	45.00	(0.53)	57.70	(0.81)
DUNWOODI (I)	44.93	(0.49)	57.67	(0.78)
NYCITY (J)	45.45	(0.39)	58.13	(0.69)
LONGISLA (K)	48.81	(0.21)	62.27	(0.31)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,561	(34)	4,339	(42)
Total System	29,763	(34)	41,091	(41)

Source: The Brattle Group analysis using MAPS

A4. Detailed Benefit Analysis: MAPS Analysis

P9 NYTO (Group B)

Input Changes:

- Topology: add a third path from Leeds to PV, NS-Leeds reconductor
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Ratings increases on other lines binding in Base Case: LEEDS3_N.SCOT99_345 increases 616 MW
- Central East limits: increase by 25 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	306,077	9,107	295,372	5,689
COOPC345 345.00-FRASR345 345.00	E	E	1,228	1,490	432	7,385
DUNWOODIE SHORE ROAD	I	K	25,050	848	29,549	2,123
HUNTLEY PACKARD	A	A	49,083	27	75,491	(9,055)
COOPC345 345.00-MARCCSC2 345.00	E	G	N/A	5	N/A	1,542
CLAY 345.00-CLAY 115.00	C	C	71	(26)	3,149	(2,622)
GARDV230 230.00-STOLE230 230.00	A	A	5,614	(256)	30,592	(1,107)
NEW SCOTLAND LEEDS	F	F	2,185	(2,185)	7,633	(7,633)
VOLNEY SCRIBA	C	C	29,874	(5,343)	46,059	(15,013)
LEEDS PLEASANT VALLEY	F	G	23,587	(23,587)	59,538	(59,538)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**(24,258)**	**1,968,251**	**(92,895)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.97	0.13	52.03	0.27
GENESSEE (B)	35.82	0.15	47.59	0.62
CENTRAL (C)	36.78	0.13	48.85	0.41
NORTH (D)	34.34	0.13	46.15	0.57
MOHAWKVA (E)	36.49	0.14	48.50	0.51
CAPITAL (F)	47.00	0.38	58.37	0.79
HUDSONVA (G)	44.60	(0.02)	57.12	(0.09)
MILLWOOD (H)	45.00	(0.10)	57.70	(0.34)
DUNWOODI (I)	44.93	(0.08)	57.67	(0.32)
NYCITY (J)	45.45	(0.04)	58.13	(0.27)
LONGISLA (K)	48.81	0.04	62.27	(0.03)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,561	(4)	4,339	(10)
Total System	29,763	2	41,091	(7)

Source: The Brattle Group analysis using MAPS

A4. Detailed Benefit Analysis: MAPS Analysis

P12 NYTO (Group C)

Input Changes

- Topology: new line from Edic to New Scotland; reconductor NS-Leeds-PV
- Leeds-PV limit on existing line : pre-2024 limit increased by 523 MW with Leeds-PV reconductor
- Rating increases on other lines binding in Base Case: LEEDS3_N.SCOT99_345 increases 616 MW
- Central East limits: increase by 350 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
COOPC345 345.00-FRASR345 345.00	E	E	1,228	5,488	432	9,988
DUNWOODIE SHORE ROAD	I	K	25,050	1,988	29,549	2,590
COOPC345 345.00-MARCCSC2 345.00	E	G	N/A	15	N/A	1,656
CLAY 345.00-CLAY 115.00	C	C	71	(71)	3,149	(3,146)
HUNTLEY PACKARD	A	A	49,083	(314)	75,491	(9,059)
GARDV230 230.00-STOLE230 230.00	A	A	5,614	(1,794)	30,592	(5,756)
NEW SCOTLAND LEEDS	F	F	2,185	(2,185)	7,633	(7,633)
VOLNEY SCRIBA	C	C	29,874	(16,106)	46,059	(25,037)
LEEDS PLEASANT VALLEY	F	G	23,587	(23,587)	59,538	(59,538)
CENTRAL EAST	D/E/F	NE/F	306,077	(53,169)	295,372	(55,477)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**(116,286)**	**1,968,251**	**(174,815)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.97	1.08	52.03	1.18
GENESSEE (B)	35.82	1.28	47.59	1.83
CENTRAL (C)	36.78	1.22	48.85	1.55
NORTH (D)	34.34	1.65	46.15	2.13
MOHAWKVA (E)	36.49	1.41	48.50	1.83
CAPITAL (F)	47.00	(1.40)	58.37	(0.84)
HUDSONVA (G)	44.60	(0.33)	57.12	(0.27)
MILLWOOD (H)	45.00	(0.43)	57.70	(0.53)
DUNWOODI (I)	44.93	(0.41)	57.67	(0.52)
NYCITY (J)	45.45	(0.36)	58.13	(0.46)
LONGISLA (K)	48.81	(0.12)	62.27	(0.15)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,561	(27)	4,339	(32)
Total System	29,763	(16)	41,091	(29)

Source: The Brattle Group analysis using MAPS

P17 NextEra (Group D)

Input Changes

- Topology: new line from Oakdale to Fraser, Marcy-Princetown-NS-KN-PV
- Leeds-PV limit on existing line : pre-2024 limit tightened by 93 MW with early SPS retirement
- Rating increases on other lines binding in Base Case: nothing else significant
- Central East limits: increase by 350 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
VOLNEY SCRIBA	C	C	29,874	25,657	46,059	20,630
COOPC345 345.00-FRASR345 345.00	E	E	N/A	6,146	N/A	12,547
KNICKERB 345.00-N.SCOT77 345.00	F	F	N/A	3,323	N/A	4,177
DUNWOODIE SHORE ROAD	I	K	25,050	2,077	29,549	3,619
HUNTLEY PACKARD	A	A	49,083	1,049	75,491	(6,224)
CLAY 345.00-CLAY 115.00	C	C	71	(71)	3,149	(2,922)
GARDV230 230.00-STOLE230 230.00	A	A	5,614	(1,723)	30,592	(6,057)
NEW SCOTLAND LEEDS	F	F	2,185	(2,185)	7,633	(7,633)
LEEDS PLEASANT VALLEY	F	G	23,587	(23,543)	59,538	(59,432)
CENTRAL EAST	D/E/F	NE/F	306,077	(58,729)	295,372	(55,606)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**(94,299)**	**1,968,251**	**(127,999)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.97	1.31	52.03	1.18
GENESSEE (B)	35.82	1.47	47.59	1.79
CENTRAL (C)	36.78	1.64	48.85	1.78
NORTH (D)	34.34	1.76	46.15	2.08
MOHAWKVA (E)	36.49	1.62	48.50	1.88
CAPITAL (F)	47.00	(1.42)	58.37	(0.81)
HUDSONVA (G)	44.60	(0.52)	57.12	(0.58)
MILLWOOD (H)	45.00	(0.63)	57.70	(0.88)
DUNWOODI (I)	44.93	(0.59)	57.67	(0.84)
NYCITY (J)	45.45	(0.48)	58.13	(0.72)
LONGISLA (K)	48.81	(0.26)	62.27	(0.30)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,561	(28)	4,339	(34)
Total System	29,763	(29)	41,091	(35)

Source: The Brattle Group analysis using MAPS

P19a NextEra (Group B)

Input Changes

- Topology: add new lines from Knickerbocker to Pleasant Valley
- Leeds-PV limit on existing line: pre-2024 limit tightened by 93 MW with early SPS retirement
- Ratings increases on other lines binding in Base Case: nothing else significant
- Central East limits: increase by 50 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	306,077	15,829	295,372	9,003
KNICKERB 345.00-N.SCOT77 345.00	F	F	N/A	1,147	N/A	2,042
HUNTLEY PACKARD	A	A	49,083	569	75,491	(7,041)
DUNWOODIE SHORE ROAD	I	K	25,050	161	29,549	1,610
CLAY 345.00-CLAY 115.00	C	C	71	(32)	3,149	(2,747)
GARDV230 230.00-STOLE230 230.00	A	A	5,614	(189)	30,592	(1,418)
COOPC345 345.00-FRASR345 345.00	E	E	1,228	(566)	432	3,024
NEW SCOTLAND LEEDS	F	F	2,185	(2,185)	7,633	(7,633)
VOLNEY SCRIBA	C	C	29,874	(6,827)	46,059	(15,901)
LEEDS PLEASANT VALLEY	F	G	23,587	(23,165)	59,538	(57,459)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**(14,734)**	**1,968,251**	**(96,499)**

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.97	0.10	52.03	0.28
GENESSEE (B)	35.82	0.09	47.59	0.60
CENTRAL (C)	36.78	0.09	48.85	0.42
NORTH (D)	34.34	0.08	46.15	0.59
MOHAWKVA (E)	36.49	0.10	48.50	0.52
CAPITAL (F)	47.00	0.42	58.37	0.83
HUDSONVA (G)	44.60	0.05	57.12	(0.08)
MILLWOOD (H)	45.00	(0.02)	57.70	(0.34)
DUNWOODI (I)	44.93	(0.00)	57.67	(0.33)
NYCITY (J)	45.45	0.02	58.13	(0.27)
LONGISLA (K)	48.81	0.02	62.27	(0.09)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,561	(6)	4,339	(14)
Total System	29,763	(12)	41,091	(16)

Source: The Brattle Group analysis using MAPS

P20 Boundless (Group A)

Input Changes

- Topology: NS-LD SR, (LD-PV, LD-HA, CPV-RT reconductor), LD-HA-R SC, RS-EF two cables
- Leeds-PV limit on existing line: pre-2024 limit increased by 551 MW with Leeds-PV reconductor
- Ratings increases on other lines binding in Base Case: nothing else significant
- Central East limits: *decrease* by 50 MW

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
CENTRAL EAST	D/E/F	NE/F	306,077	14,211	295,372	6,698
HURLEYSC 345.00-ROSETON 345.00	G	G	N/A	12,143	N/A	23,832
VOLNEY SCRIBA	C	C	29,874	1,056	46,059	(7,790)
DUNWOODIE SHORE ROAD	I	K	25,050	553	29,549	1,614
Ramapo PAR	G	G	18,322	540	9,733	338
CLAY 345.00-CLAY 115.00	C	C	71	(29)	3,149	(2,737)
GOWANUS 345 GOETHSLN 345 1	J	J	1,056	(470)	927	(807)
HUNTLEY PACKARD	A	A	49,083	(602)	75,491	(4,908)
COOPC345 345.00-FRASR345 345.00	E	E	1,228	(1,025)	432	417
LEEDS PLEASANT VALLEY	F	G	23,587	(23,587)	59,538	(59,538)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**(3,670)**	**1,968,251**	**(58,927)**

Impacts on Zonal LBMPs ($/MWh)

Area	2019 Base	2019 Impact	2024 Base	2024 Impact
WEST (A)	37.97	(0.07)	52.03	0.21
GENESSEE (B)	35.82	(0.06)	47.59	0.36
CENTRAL (C)	36.78	(0.05)	48.85	0.22
NORTH (D)	34.34	(0.13)	46.15	0.32
MOHAWKVA (E)	36.49	(0.06)	48.50	0.30
CAPITAL (F)	47.00	0.62	58.37	0.83
HUDSONVA (G)	44.60	0.12	57.12	(0.02)
MILLWOOD (H)	45.00	0.03	57.70	(0.24)
DUNWOODI (I)	44.93	0.03	57.67	(0.23)
NYCITY (J)	45.45	0.04	58.13	(0.20)
LONGISLA (K)	48.81	0.10	62.27	(0.01)

Impacts on Production Costs ($m)

	2019 Base	2019 Impact	2024 Base	2024 Impact
NYCA+Imports-Exports	3,561	3	4,339	(3)
Total System	29,763	8	41,091	(5)

Source: The Brattle Group analysis using MAPS

P20 Boundless and Central East

Impact on Central East Limits

- In 2019, production costs increase since it is the only Tx portfolio with Central-East limits decreasing (by 50 MW)
  - Traps upstate generation and therefore leads to lower upstate LBMPs
  - Benefits of UPNY-SENY limit increase cannot be fully utilized; Leeds – PV average flow drops from 1,050 MW in the Base Case to 890 MW in the P20 Change Case
- In 2024, production costs decrease as load growth reduces surplus of lower cost generation available in UPNY
  - Therefore flow on Central East is reduced and binds less (compared to 2019)
  - The benefits of UPNY-SENY limit increase appear (indicated by lower downstate LBMP and higher upstate LBMP)

Impacts on Production Costs ($m)

	2019		2024	
	Base	Impact	Base	Impact
NYCA+Imports-Exports	3,561	3	4,339	(3)
Total System	29,763	8	41,091	(5)

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	Base	Impact	Base	Impact
WEST (A)	37.97	(0.07)	52.03	0.21
GENESSEE (B)	35.82	(0.06)	47.59	0.36
CENTRAL (C)	36.78	(0.05)	48.85	0.22
NORTH (D)	34.34	(0.13)	46.15	0.32
MOHAWKVA (E)	36.49	(0.06)	48.50	0.30
CAPITAL (F)	47.00	0.62	58.37	0.83
HUDSONVA (G)	44.60	0.12	57.12	(0.02)
MILLWOOD (H)	45.00	0.03	57.70	(0.24)
DUNWOODI (I)	44.93	0.03	57.67	(0.23)
NYCITY (J)	45.45	0.04	58.13	(0.20)
LONGISLA (K)	48.81	0.10	62.27	(0.01)

Source: The Brattle Group analysis using MAPS

A4. Detailed Benefit Analysis: MAPS Analysis

1,320 MW CC in Zone G

Input Changes

- Addition of four 330 MW CC units in Zone G for a total of 1,320 MW of added capacity
- All new units are distributed among high load buses in Zone G
- New CCs have 7,000 Btu/kWh full load heat rate and $7.01/MWh VOM (2019$), comparable to other new CCs modeled in MAPS

Impacts on Congestion Rents (10 Largest Deltas in NYISO , in $k)

Constraints	From	To	2019 Base	2019 Impact	2024 Base	2024 Impact
VOLNEY SCRIBA	C	C	29,874	15,486	46,059	26,322
DUNWOODIE SHORE ROAD	I	K	25,050	2,464	29,549	3,620
MOTTHAVEN RAINEY	J	J	1,555	1,392	171	457
GARDV230 230.00-STOLE230 230.00	A	A	5,614	296	30,592	2,267
Ramapo PAR	G	G	18,322	85	9,733	3,094
HUNTLEY PACKARD	A	A	49,083	(145)	75,491	(3,861)
NEW SCOTLAND LEEDS	F	F	2,185	(327)	7,633	(2,428)
COOPC345 345.00-FRASR345 345.00	E	E	1,228	(1,148)	432	(316)
CENTRAL EAST	D/E/F	NE/F	306,077	(1,538)	295,372	1,427
LEEDS PLEASANT VALLEY	F	G	23,587	(7,669)	59,538	(15,287)
Total Congestion Rents (NYISO, PJM, ISO-NE, Ont)			**1,371,739**	**13,767**	**1,968,251**	**13,891**

Impacts on Zonal LBMPs ($/MWh)

Area	2019 Base	2019 Impact	2024 Base	2024 Impact
WEST (A)	37.97	(0.16)	52.03	(0.32)
GENESSEE (B)	35.82	(0.19)	47.59	(0.32)
CENTRAL (C)	36.78	(0.16)	48.85	(0.32)
NORTH (D)	34.34	(0.18)	46.15	(0.32)
MOHAWKVA (E)	36.49	(0.21)	48.50	(0.36)
CAPITAL (F)	47.00	(0.28)	58.37	(0.31)
HUDSONVA (G)	44.60	(0.48)	57.12	(0.75)
MILLWOOD (H)	45.00	(0.46)	57.70	(0.74)
DUNWOODI (I)	44.93	(0.46)	57.67	(0.74)
NYCITY (J)	45.45	(0.33)	58.13	(0.66)
LONGISLA (K)	48.81	(0.10)	62.27	(0.21)

New Unit Capacity Factors

Unit	2019 Capacity	2024 Capacity
Generic CARIS Add CC1 Zone G	39%	42%
Generic CARIS Add CC2 Zone G	36%	39%
Generic CARIS Add CC3 Zone G	33%	36%
Generic CARIS Add CC4 Zone G	29%	34%

Impacts on Production Costs ($m)

	2019 Base	2019 Impact	2024 Base	2024 Impact
NYCA+Imports-Exports	3,561	(15)	4,339	(39)
Total System	29,763	(19)	41,091	(35)

Source: The Brattle Group analysis using MAPS

Production Cost Savings for REV Resources

The REV alternative reduces the NPV of production costs by ~$2 billion

- PCS are calculated in 2019 and 2024 using zonal average LBMPs from MAPS
- REV resources are assumed to be phased in from 2016-2020 (20% of total each year); GWh savings shown below apply to years in which full 1,200 MW peak reduction is achieved
- Savings are likely optimistic due to assumption that avoided production costs are equal to LBMP*Energy Savings and high capacity factor of EE (offset by assuming average LBMPs)

Estimated Production Cost Savings of the REV Alternative

	Annual GWh Energy Savings by Zone					Nominal 2019 Savings ($m)	Nominal 2024 Savings ($m)	Measure Life	NPV
Resource Type	G	H	I	J	Total	G-J	G-J	(years)	**(2015 $m)**
Energy Efficiency	598	154	328	4,417	**5,497**	$199	$319	12	**$1,830**
Customer-sited Renewables	31	8	7	53	**98**	$4	$6	25	**$49**
Combined Heat & Power	4	0	0	190	**195**	$7	$11	20	**$89**
Demand Response	0	0	0	0	**0**	$0	$0	10	**$0**
Fossil Fuel Distributed Generation	0	0	0	0	**0**	$0	$0	--	**$0**
Grid Integrated Vehicles	(0)	(0)	(0)	(1)	**(2)**	($0.1)	($0.1)	10	**($0)**
Storage (flywheel and battery)	(1)	(0)	(0)	(3)	**(5)**	($0.2)	($0.3)	15	**($2)**
Rate Structures	0	0	0	0	**0**	$0	$0	15	
Total	**632**	**161**	**335**	**4,656**	**5,783**	**$210**	**$336**		**$1,965**

Sources: REV GEIS. See slide 51 for sources supporting resource distribution and economic life estimates

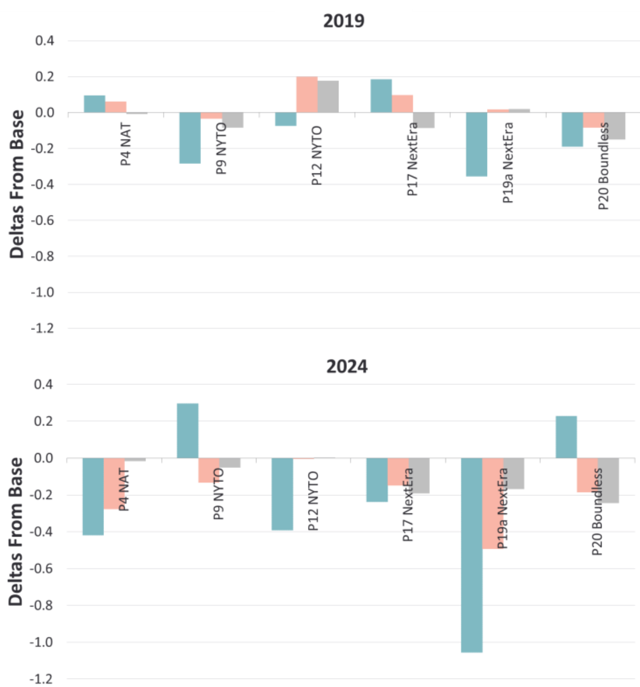
* REV case was not modeled in MAPS, although PCS are calculated using LBMPs from MAPS

A4. Detailed Benefit Analysis: MAPS Analysis
Emissions Impacts from MAPS

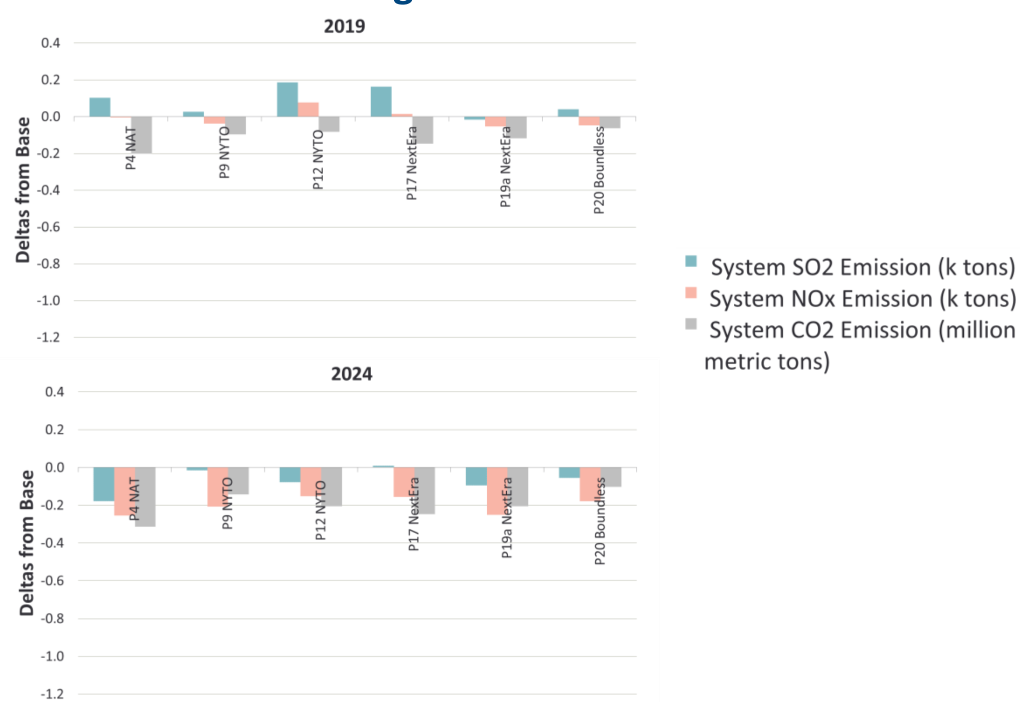
No clear patterns among various portfolios

- Emission allowance prices have small impact on the marginal cost of generation
- CO_2 emission reduction for NYCA across all Change Cases indicates a more efficient dispatch (less fossil fuel usage) with transmission upgrades
- Change in coal unit dispatch (Huntley and Somerset) largely explains the NYCA-wide emissions changes, as described in the following slides

System-wide Change in Emissions



NYCA-wide Change in Emissions

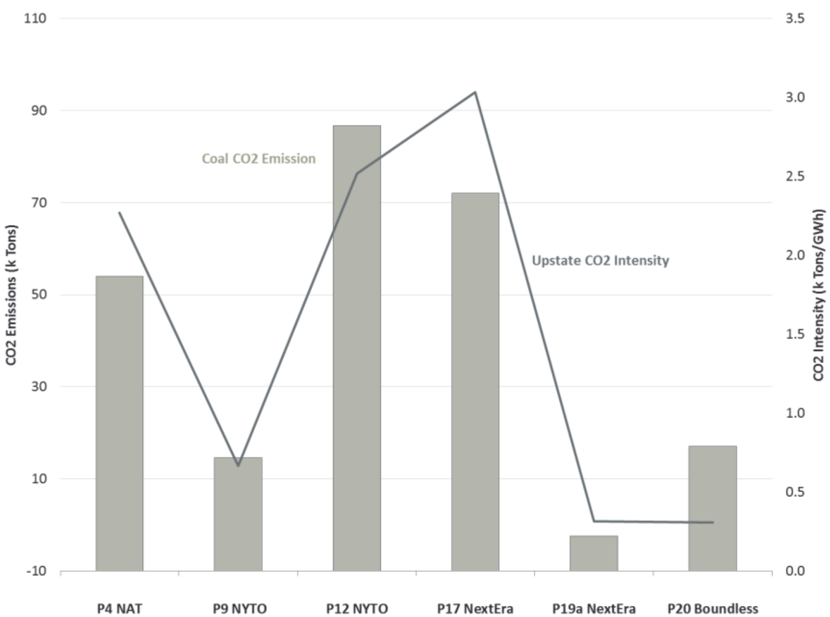


CO_2 Emissions Impacts

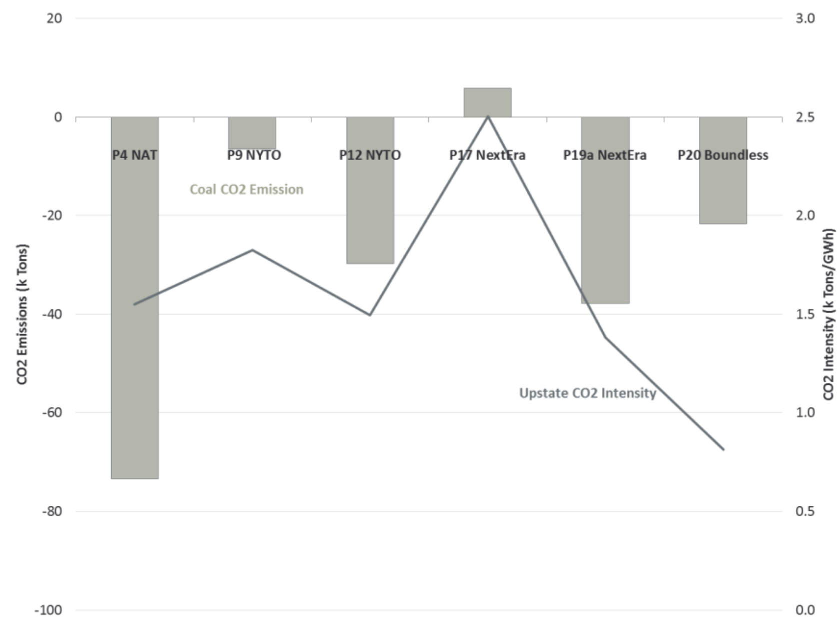
Trends in emissions can be explained largely by changes in generation from coal plants

- Upstate CO_2 Intensity mostly follows changes in Coal Emissions from two representative upstate coal plants (Huntley and AES Somerset).
- Downstate CO_2 Intensity is less than the Base Case in all Change Cases (not shown here)

2019 Coal CO_2 Emissions and Upstate CO_2 Intensity (Deltas from Base Case)



2024 Coal CO_2 Emissions and Upstate CO_2 Intensity (Deltas from Base Case)

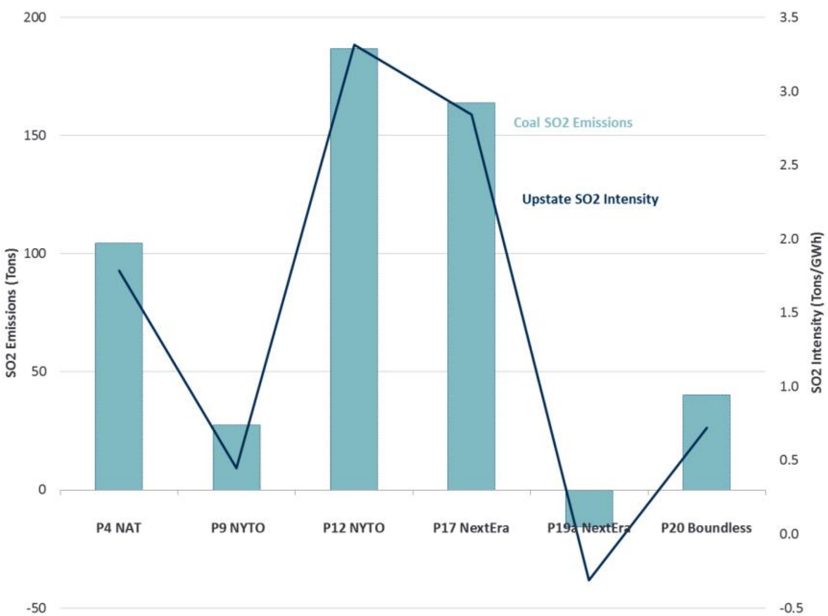


SO_2 Emissions Impacts

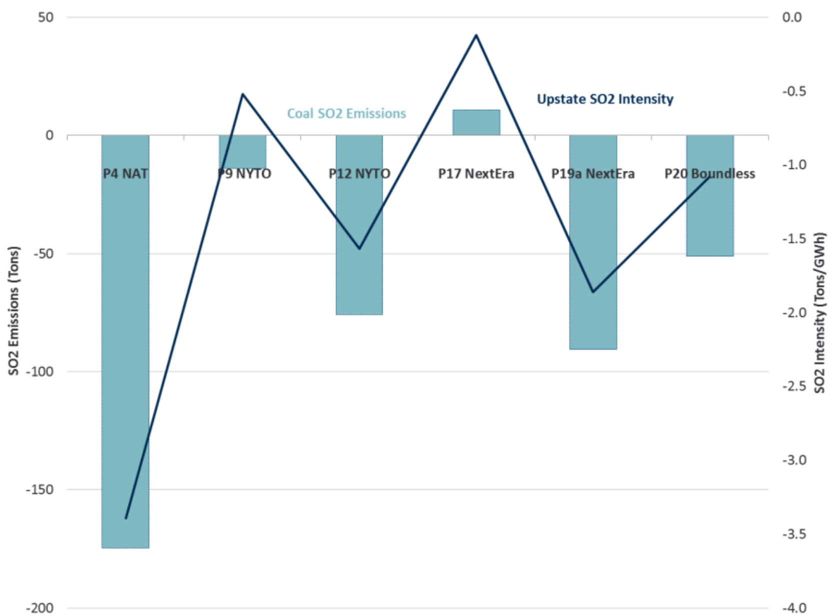
Trends in emissions can largely be explained by changes in generation from coal plants

- Upstate SO_2 Intensity closely follows changes in Coal Emissions from two upstate coal plants (Huntley and AES Somerset)
- Downstate SO_2 Intensity is generally the same as the Base Case (not shown here)

2019 Coal SO_2 Emissions and Upstate SO_2 Intensity (Deltas from Base Case)



2024 Coal SO_2 Emissions and Upstate SO_2 Intensity (Deltas from Base Case)



NOx Emissions Impacts

Trends in emissions can be explained largely by changes in generation from coal plants

- Upstate NOx Intensity mostly follows changes in Coal Emissions from two upstate coal plants (Huntley and AES Somerset)
- Downstate NOx Intensity is less than the Base Case in all Change Cases (not shown here)

2019 Coal NOx Emissions and Upstate NOx Intensity (Deltas from Base Case)

2024 Coal NOx Emissions and Upstate NOx Intensity (Deltas from Base Case)

A4. Detailed Benefit Analysis: MAPS Analysis

Summary of CARIS Metrics

	units	Base Case 2019	Base Case 2024	NAT 4 2019	NAT 4 2024	NYTO 9 2019	NYTO 9 2024	NYTO 12 2019	NYTO 12 2024	NEET 17 2019	NEET 17 2024	NEET 19 2019	NEET 19 2024	Boundless 20 2019	Boundless 20 2024	Generation 2019	Generation 2024	REV 2019	REV 2024
		Absolute		delta		delta		delta		delta		delta		delta		delta		delta	
Production Costs																			
NYCA Adjusted Production	$m	3,561	4,339	-34	-42	-4	-10	-27	-32	-28	-34	-6	-14	3	-3	-15	-39	-210	-336
Total System Production	$m	29,763	41,091	-34	-41	2	-7	-16	-29	-29	-35	-12	-16	8	-5	-19	-35		
Payments																			
NYCA Generator Payments	$m	5,493	7,477	85	118	16	57	62	115	22	48	18	52	4	39	-21	-5		
NYCA Load Payments	$m	6,906	9,007	47	36	9	8	21	34	34	26	17	12	11	7	-50	-86		
Congestion Rents																			
NYCA Congestion Rents	$m	815	1,059	-95	-150	-16	-71	-83	-138	-40	-83	-8	-65	3	-47	14	23		
Emissions																			
NYCA CO2	1000 tons	27,840	30,586	-201	-314	-96	-143	-82	-206	-147	-247	-117	-206	-63	-103	214	624	-1,231	-1,538
	%			-0.7%	-1.0%	-0.3%	-0.5%	-0.3%	-0.7%	-0.5%	-0.8%	-0.4%	-0.7%	-0.2%	-0.3%	0.8%	2.0%		
NYCA SOX	tons	2,826	3,517	103	-178	26	-16	186	-78	163	7	-17	-95	40	-54	-112	-5	-1,725	-2,157
	%			3.7%	-5.1%	0.9%	-0.4%	6.6%	-2.2%	5.8%	0.2%	-0.6%	-2.7%	1.4%	-1.5%	-4.0%	-0.1%		
NYCA NOX	tons	17,484	18,946	-5	-255	-39	-207	78	-153	16	-157	-54	-251	-47	-179	-532	-625	-1,438	-1,797
	%			0.0%	-1.3%	-0.2%	-1.1%	0.4%	-0.8%	0.1%	-0.8%	-0.3%	-1.3%	-0.3%	-0.9%	-3.0%	-3.3%		
Total System CO2	1000 tons	483,295	446,524	-8	-17	-84	-51	178	3	-87	-193	19	-168	-149	-245	-342	-398		
	%			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.1%	-0.1%	-0.1%		
Total System SOX	tons	317,031	289,186	96	-418	-284	295	-74	-392	186	-237	-356	-1,054	-190	228	-1,128	-1,471		
	%			0.0%	-0.1%	-0.1%	0.1%	0.0%	-0.1%	0.1%	-0.1%	-0.1%	-0.4%	-0.1%	0.1%	-0.4%	-0.5%		
Total System NOX	tons	330,038	308,250	61	-278	-34	-134	200	-5	97	-148	18	-494	-85	-185	-1,101	-1,529		
	%			0.0%	-0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	-0.2%	0.0%	-0.1%	-0.3%	-0.5%		

Notes:

Red values indicate adverse impacts (such as increasing costs or greater emissions)

NYCA Adjusted Production Cost Savings is defined as Total NYCA+Imports-Exports, with Imports and Exports valued at border LBMPs

ICAP Savings not shown here; see next section of this presentation

REV metrics calculated using MAPS base case LBMPs; emissions from EIS report

A4. Detailed Benefit Analysis: MAPS Analysis

IP Retirement: Assumptions

What would be the production cost savings of new transmission if Indian Point retired in 2019 without forewarning? Compare two scenarios:

- **IP-Out Base Case with Compensating Generation** but takes 3 years to build
  - *Reliability standards not met for the first 3 years* (affects production costs but cost of lower reliability not quantified)
  - 810 MW CCs online by 2022 and 1,020 MW by 2024 to meet reliability standards (7,000 Btu/kWh full load heat rate and $7/MWh VOM, distributed among high voltage buses in Zone G)

	Compensating MW Needed with Indian Point Retirement						
	2016	2019	2020	2021	2022	2023	2024
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
2014 CRP Compensatory MW	500						
2014 Gold Book G-J Non-Coincident Summer Peak Load	16,749						
2015 Gold Book G-J Non-Coincident Summer Peak Load	16,441	16,800	16,867	16,957	17,053	17,158	17,263
Change in Load (relative to 2016 in 2014 Gold Book)	-308	51	118	208	304	409	514
Compensatory MW Needs (Rounded up to the nearest 10 MW)	200	560	620	710	810	910	1,020

Sources: 2014 CRP (p. 23); 2014 Gold Book (p. 14); 2015 Long Term Forecast from NYISO .

- **IP-Out with Tx Solution** (modeling in MAPS one representative Tx portfolio)
  - Tx in service prior to IP surprise retirement
  - No compensating generation needed for reliability since Tx provides adequate imports to SENY

While these scenarios relate to the retirement of Indian Point, similar (though less extreme) conclusions could be drawn about other large potential retirements

A4. Detailed Benefit Analysis: MAPS Analysis

IP Retirement: Production Cost and LBMP Impacts

- NYCA-wide production cost savings from the **IP-Out with Tx Solution** scenario as compared to the **IP-Out Base Case with Compensating Generation** scenario are $177m in NPV terms
- 61% of the PV of production cost savings occur in the 3 years w/o compensating generation

Production Cost Savings from Transmission

Production Cost Savings	NPV ($m)	Percent of Total
No Compenating Generation (2019 - 2021)	108	61%
With Compenating Generation (2022 - 2063)	69	39%
Total (2019 - 2063)	177	100%

- Zone G LBMP impact of the **IP-Out with Tx Solution** (compared to the IP-Out Base Case with Compensating Generation starting in 2022) is **-$0.15** in in 2019 but **+$0.60** in 2024
  - LBMPs are lower in 2019 compared to no Tx and no compensating generation (not online yet in alternative case)
  - LBMPs are higher LBMPs in 2024 since Tx avoids adding 1,020 MW of efficient new CCs in G
- Similar effects in surrounding areas

Impacts on Zonal LBMPs ($/MWh)

	2019		2024	
Area	IP-Out Base Case with Compensating Generation	Impact of Tx with IP Out (and no compensating Gen)	IP-Out Base Case with Compensating Generation	Impact of Tx with IP Out (and no compensating Gen)
WEST (A)	39.03	1.30	52.55	1.45
GENESSEE (B)	36.95	1.51	48.30	2.25
CENTRAL (C)	37.99	1.42	49.73	1.87
NORTH (D)	35.31	1.98	46.82	2.56
MOHAWKVA (E)	37.76	1.72	49.38	2.28
CAPITAL (F)	49.13	(0.95)	59.48	0.26
HUDSONVA (G)	47.37	(0.15)	59.01	0.60
MILLWOOD (H)	48.03	(0.48)	59.98	(0.02)
DUNWOODI (I)	47.95	(0.46)	59.95	(0.01)
NYCITY (J)	48.17	(0.43)	60.26	(0.03)
LONGISLA (K)	50.26	(0.31)	63.28	(0.03)

A4. Detailed Benefit Analysis: MAPS Analysis

Present Value of Production Cost Savings

Solution	MAPS 2019 PCS ($m)	MAPS 2024 PCS ($m)	PCS Multiplier	Total 2019 PCS ($m)	Total 2024 PCS ($m)	Production Cost Savings (2015 $m)
P4 NAT (Group E)	$34	$42	x 1.6	$53	$65	$594
P9 NYTO (Group B)	$4	$10	x 1.6	$5	$16	$128
P12 NYTO (Group C)	$27	$32	x 1.6	$42	$50	$460
P17 NextEra (Group D)	$28	$34	x 1.6	$44	$53	$485
P19a NextEra (Group B)	$6	$14	x 1.6	$9	$21	$178
P20 Boundless (Group A)	-$3	$3	x 1.6	-$5	$5	$28
Generation (25 Years)	$15	$39	x 1.24	$19	$48	$401
Generation (45 Years)	$15	$39	X 1.24	$19	$48	$337
REV Resource Solution	$210	$336	GHI: x 1.03 J: x 1.06	$220	$353	$1,965

Note: MAPS PCS listed here are NYCA-wide Adjusted Production Costs savings

ICAP Analysis without CPV Valley

For background on our approach to calculating the capacity resource cost savings for each solution, see slides 91– 96

We include the adjustment for Net Purchases described on slide 92, but not CPV Valley or supply responses to CPV Valley

ICAP MW Impact of Tx Portfolios

We developed with NYISO an approach for estimating the MW impact of the Tx portfolios on LCRs in the Change Case

- For a summary of the approach, see slide 97

Proposed Solution	UPNY/SENY Emergency N-1 Impact (MW)	NYCA IRM Impact (MW)	Zone G-J LCR Impact (MW)	Zone J LCR Impact (MW)	Zone K LCR Impact (MW)
P4 NAT	+1,203	0	-867	-278	-163
P9 NYTO	+1,598	0	-1,025	-293	-172
P12 NYTO	+1,200	0	-872	-279	-164
P17 NextEra	+1,653	0	-1,116	-305	-179
P19a NextEra	+1,528	0	-1,002	-292	-171
P20 Boundless	+588	0	-398	-178	-104

A4. Detailed Benefit Analysis: ICAP Analysis

Summary of Capacity Value

Solution	Capacity Resource Cost Savings (2015 $m)	CARIS Variant 1 (2015 $m)	CARIS Variant 2 (2015 $m)
P4 NAT	$469	$499	$720
P9 NYTO	$494	$539	$897
P12 NYTO	$470	$501	$754
P17 NextEra	$513	$566	$1,014
P19a NextEra	$493	$536	$887
P20 Boundless	$300	$305	$282
Generation (25 yr)*	$602	$681	$1,240
REV Resource Solution	$696	$773	$3,420

Note: Generation capacity value is reduced due to the MOPR

Approach for Estimating Capacity Value of All Tx Portfolios

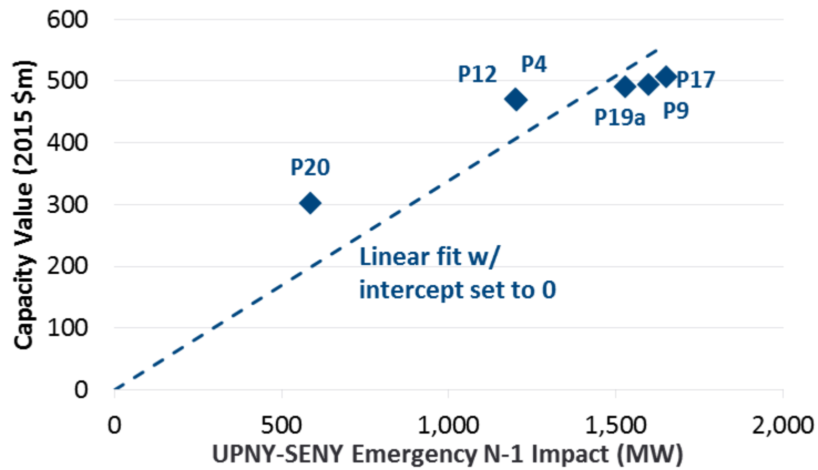
Based on the results for the 6 Tx portfolios we analyzed in the ICAP model:

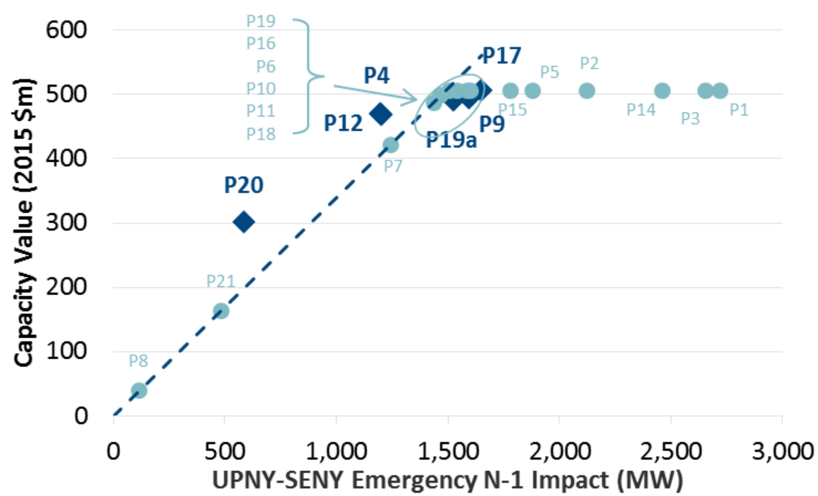
- Found a linear relationship between G-J LCR MW Impacts and the UPNY-SENY Emergency N-1 transfer limit impact
- Fit a linear trend line between the Emergency N-1 transfer limit impact and capacity value

For the other 16 proposed Tx portfolios:

- Estimated their capacity value based on the linear trend line generated in previous step
- Analysis by NYISO found that incremental impacts to the Emergency N-1 transfer limit beyond the 1,653 MW impact of P17 has limited to no effect on the SENY LCRs and its capacity value
- For this reason, the capacity value for projects with Emergency N-1 impacts beyond P17's was set at the P17 capacity value ($506m)

Analysis of Relationship between UPNY-SENY STE Impact and Capacity Value





A4. Detailed Benefit Analysis: ICAP Analysis

Capacity Value of All Tx Portfolios

Group A	UPNY-SENY STE Impact (MW)	Capacity Resource Savings (2015 $m)
P7 - NYTO	1,243	$423
P8 - NYTO	116	$39
P13 - NYTO	-108	$0
P20 - Boundless	**588**	**$300**
P21 - Boundless	482	$164
Group B		
P6 - NYTO	1,544	$513
P9 - NYTO	**1,598**	**$494**
P19 - NextEra	1,601	$513
P19a - NextEra	**1,528**	**$493**
Group C		
P12 - NYTO	**1,200**	**$470**
Group D		
P10 - NYTO	1,507	$513
P11 - NYTO	1,469	$500
P14 - NYTO	2,460	$513
P15 - NextEra	1,780	$513
P16 - NextEra	1,587	$513
P17 - NextEra	**1,653**	**$513**
P18 - NextEra	1,436	$489
Group E		
P1 - NAT	2,722	$513
P2 - NAT	2,122	$513
P3 - NAT	2,657	$513
P4 - NAT	**1,203**	**$469**
P5 - NAT	1,880	$513

Source: UPNY-SENY STE impacts provided by NYISO.

Sensitivity of Capacity Value

Sensitivity Results: The capacity value of the proposed solutions depends on assumptions about the supply curves and the discount rate used to calculate NPV

- **Supply Curve Slope**: Adjusting the estimated slopes of the supply curves by +/- 25% impacts the results for Tx portfolios by **-$8m to +$10m** (-2% to + 2%) on average
- **Discount Rate:** Applying a discount rate of 5.58% increases the value by **$389m**(+85%) on average for the Tx portfolios

Uncertain Capacity Additions and Retirements: The capacity value of the transmission solutions depends on excess UPNY capacity being available as well as the difference in the cost of new entry between UPNY and SENY; for this reason, we analyzed the change in capacity value across the following conditions

Scenario	Average Impact on Transmission Capacity Value ($m)
2,000 MW Retires in SENY	+$280
500 MW Retires in SENY	+$160
500 MW Retires in UPNY	-$80
2,000 MW Retires in UPNY	-$210

Maintaining Reliability with Major Retirements

In addition to reduced capacity costs, the additional transfer capability into SENY provided by the Tx solutions will increase the flexibility to accommodate generation retirements without falling below LCRs

Additional Capacity Retirement Flexibility of Proposed Solutions (MW)

Portfolio	G-J	J	K	Total
P4 NAT	867	278	163	**1,030 MW**
P9 NYTO	1,025	293	172	**1,197 MW**
P12 NYTO	872	279	164	**1,036 MW**
P17 NextEra	1,116	305	179	**1,295 MW**
P19a NextEra	1,002	292	171	**1,173 MW**
P20 Boundless	398	178	104	**502 MW**

Note: Total is calculated based on sum of G-J and K since J is nested in G-J.

A4. Detailed Benefit Analysis: Avoided Tx Costs

Summary of Avoided Refurbishment Costs

Type of Project Elements	Avoided "Base Case" Cost	Approach to Quantifying	P4 NAT ($m)	P9 NYTO ($m)	P12 NYTO ($m)	P17 NextEra ($m)	P19a NextEra ($m)	P20 Boundless ($m)
Project Elements Upgrade Existing Lines	Ongoing taxes and O&M costs	Credit equals the present value of the avoided revenue requirements of existing lines upgraded (*Note: Cost only avoided until date line planned to be refurbished in Base Case, if refurbished at all.*)	**$87** Replace KB-PV	**$112** Reconductor NS-LD and replaces LD-PV	**$135** Retire PR-RM; reconductor NS-LD and LD-PV	**$80** Retire PR-RM, rebuild NS-ALPS, and replace GRB-PV	**$41** Replace GRB-PV	**$157** Reconductor LD-PV, HA-LD, and CPV-RT
Project Elements Replace Aging Lines that will have to be replaced anyway	Future Refurbishment costs	Credit equals the present value of future revenue requirements for refurbishments	–	**$148** Retires Leeds-PV 115 kV Lines	**$739** Retires 2 P-R Lines	**$961** Retires 2 P-R Lines & Retires 2 G-PV 115 kV Lines	**$223** Retires 2 G-PV 115 kV Lines	–
Project Elements Provide Parallel Paths to Aging Lines that will have to be replaced in the future	Congestion during Construction	Aging lines are predominantly 115 kV rated, and were expected to have very low production cost/congestion impact	–	–	–	–	–	–
	Construction Costs due to Extended Construction Schedule	**Base Analysis** conservatively assume no costs avoided	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
		Sensitivity Analysis avoid 20% of costs due to normal construction schedule; credit equals the present value of future revenue requirements for refurbishments	**$112** Avoids costly constr. of 6 115kV Lines in NS-L-PV Corridor	**$91** Avoids costly constr. of 6 115kV Lines in L-PV Corridor	–	**$91** Avoids costly constr. of 6 115kV Lines in L-PV Corridor	**$91** Avoids costly constr. of 6 115kV Lines in L-PV Corridor	–

Existing Lines

Tx Portfolio	Facility Upgraded	Type of Upgrade	Assumed Refurbishment Year	Replacement Costs (2015$)	PVRR of Avoided Costs (2015$)
P4 NYTO	KN - PV 115 kV	Replaced	2030	$482m	**$87**
P9 NYTO	NS - LD 115 kV	Reconductor	N/A	$171m	**$112**
	LD - PV 115 kV	Replaced	2030	$312m	
P12 NYTO	PT - RM 230 kV	Retired	2020	$396m	**$135**
	NS - LD 115 kV	Reconductor	N/A	$171m	
	LD - PV 115 kV	Reconductor	N/A	$214m	
P17 NYTO	PT - RM 230 kV	Retired	2020	$396m	**$80**
	NS - ALPS 115 kV	Reconductor	N/A	$91m	
	GB - PV 115 kV	Replaced	2030	$230m	
P19a NextEra	GB - PV 115 kV	Replaced	2030	$230m	**$41**
P20 Boundless	LD - PV 115 kV	Reconductor	N/A	$246m	**$157**
	HA - LD 115 kV	Reconductor	N/A	$128m	
	CPV - RT 115 kV	Reconductor	N/A	$107m	

Notes:

Assume RevReq for existing lines would be required through 2063 unless the line is aging and projected to be refurbished in year shown (see next section for more details).

PVRR of avoided costs calculated by reducing O&M costs in RevReq workbook proportional to 1 minus the ratio of Replacement Costs over Portfolio Capital Costs and calculating the change in the RevReq.

A4. Detailed Benefit Analysis: Avoided Tx Costs

Avoided Costs of Refurbishing Aging Lines

Project	Aging Transmission Facility (identifed in STARS 2012 Report)	Estimated Year of Refurbishment	Proposed Refurbishment	Refurbishment Mileage	Avoided Capital Costs (mid-2015 $m)	Avoided Investment Cost (Mid-Year before Investment $m)	Avoided PVRR (Mid-Year before Investment $m)	Avoided PVRR (mid-2015 $m)
P4 – NAT	None		None		-	-	-	-
P9 - NYTO	Leeds - Pleasant Valley 115 kV (2 Lines)	2030	Replacement	82	**$212**	**$305**	**$502**	**$148**
P12 – NYTO	Porter - Rotterdam 230 kV (2 Lines)	2020	Retirement	140	**$560**	**$636**	**$1,048**	**$739**
P17 – NextEra	Porter - Rotterdam 230 kV (2 Lines)	2020	Retirement	140	**$560**	**$636**	**$1,048**	**$739**
	Greenbush - N. Churchtown - Pleasant Valley 115 kV (2 lines)	2030	Retirement	124	**$319**	**$459**	**$757**	**$223**
	Total				**$879**		**$1,804**	**$961**
P19a – NextEra	Greenbush - N. Churchtown - Pleasant Valley 115 kV (2 lines)	2030	Retirement	124	**$319**	**$459**	**$757**	**$223**
P20 – Boundless	None		None		-	-	-	-

Notes:

Assumed lines to be replaced in STARS report in 0 – 10 years occur in 2020 and 11 – 20 years occur in 2030.

Assumed all identified aging facilities will require a full rebuild to calculate the avoided capital cost; used generic equipment cost of $2.6m for a 115 kV Tx rebuild to calculate avoided capital cost for 115 kV Lines.

See slides 46 – 47 for an explanation of how we convert 2015 overnight costs to PVRR in 2015$.

A4. Detailed Benefit Analysis: Avoided Tx Costs

Avoided Construction Costs by Adding Parallel Line

Portfolio	Facilities Proposed	Aging Lines whose Refurbishment is Enabled by Proposed Facility	Proposed Refurbishment	Estimated Year of Refurbishment	Refurbishment Mileage	Estimated Cost of Refurbishment (mid-2015 $m)	20% of Estimated Refurbishment Costs (mid-2015 $m)	Avoided Investment Costs (Mid-Year before Investment $m)	Avoided PVRR (Mid-Year before Investment $m)	Avoided PVRR (mid-2015 $m)
P4 – NAT	**New Scotland to Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		GB-NC-PV 115 kV (2 lines)	Rebuild	2030	124	$319	$64	$92	$151	$44
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		Total				**$801**				**$112**
P9 – NYTO	**Leeds - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P12 – NYTO	**None**	-	-	-	-	-	-	-	-	-
P17 – NextEra	**Knickerbocker to Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P19a – NextEra	**Greenbush - Pleasant Valley 345 kV**	LD-PV 115 kV (2 lines)	Rebuild	2030	80	$205	$41	$59	$97	$29
		KN-PV 115 kV (2 lines)	Rebuild	2030	108	$278	$56	$80	$132	$39
		NC-PV 115 kV (2 lines)	Rebuild	2030	65	$166	$33	$48	$79	$23
		Total				**$648**	**$130**			**$91**
P20 – Boundless	**None**	-	-	-	-	-	-	-	-	-

Notes:

Assumed lines to be replaced in 11 – 20 years in STARS report occur in 2030.

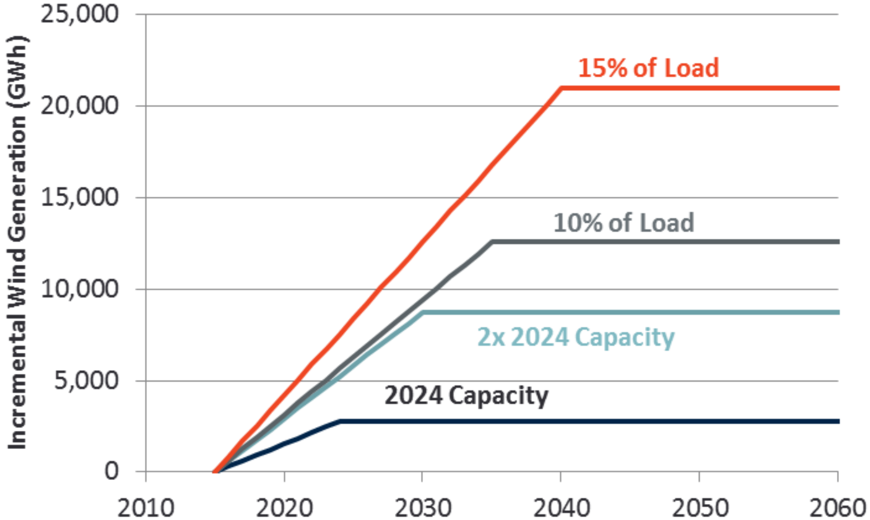
Assumed all identified aging facilities will require a full rebuild to calculate the avoided capital cost; used generic equipment cost of $2.6m for a 115 kV Tx rebuild to calculate avoided capital cost for 115 kV Lines.

See slides 46 – 47 for an explanation of how we convert 2015 overnight costs to PVRR in 2015$.

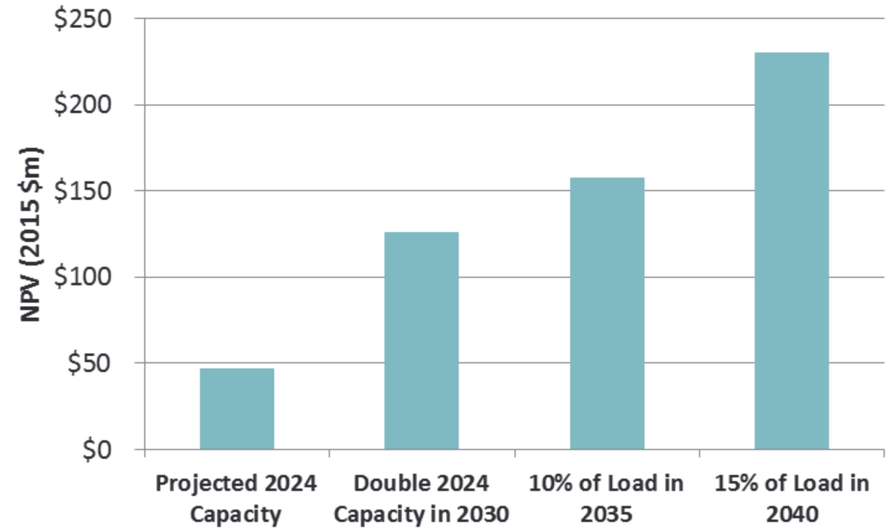
Summary of RPS/CO_2 Benefits

Depending on the assumed goals, the savings for P12 in 2024 could be $5m to $13m with an NPV of $39m to $188m in benefits with an average of $115m

Future RPS Scenarios



NPV for P12 of Future RPS Scenarios



RPS/CO2 Benefits of Transmission Portfolios ($m)

RPS	P4	P9	P12	P17	P19a	P20
Low	$47	$10	$39	$40	$10	$5
2x 2024	**$125**	**$28**	**$103**	**$107**	**$27**	**$15**
High	$228	$51	$188	$194	$51	$29

A4. Detailed Benefit Analysis: Employment and Economic Activity

Increased Employment During Construction

Investment in new transmission facilities will have employment impacts in the regions in which the facilities are built

- Based on previous analysis using NREL's JEDI model, every $1m in transmission investment results in 6.6 full-time equivalent ("FTE") jobs during construction
- 60% of jobs are directly associated with the project and the remaining 40% indirect or induced
- The capital costs of the proposed solutions range from $300 to $1,100m, which would be expected to result in 2,100 to 7,500 FTEs

This does not account for the effects of rate impacts on customer spending and associated economic activity

Also, does not include employment benefits from ongoing transmission maintenance and improved viability of upstate generators

- Near term, we project upstate generator revenues to increase by $1 – 2/kW-mo
- Long term, we project 800 – 1,000 MW of additional UPNY capacity

Increased Revenues to Upstate Generators ($/kW-mo)

Unit Type	Capacity Factor	LBMP Impact $1/MWh	LBMP Impact $2/MWh	Capacity Revenues	Total
Nuclear	95%	$0.7	$1.4	$0.5 - 1.0	$1.2 - 2.4
CC	60%	$0.4	$0.9	$0.5 - 1.0	$0.9 - 1.9
Oil/Gas Steam	40%	$0.3	$0.6	$0.5 - 1.0	$0.8 - 1.6

Appendix B
Acronyms

Project Related Acronyms and Associated Descriptions

Acronym	Description
CPV-RT	*CPV Tap - Rock Tavern 345 kV Line*
ED-FR	*Edic - Fraser 345 kV Line*
ED-NS	*Edic - New Scotland 345 kV Line*
FR-G	*Fraser - Gilboa 345 kV Line*
FR-G SC	*Series Compensation of Fraser - Gilboa 345 kV Line*
Fraser tie M-CC	*Looping Marcy - Coopers Corner 345 kV Line into Fraser 345 kV Substation*
KN-PV	*Knickerbocker - Pleasant Valley 345 kV Line*
LD-HA	*Leeds - Hurley 345 kV Line*
LD-PV	*Leeds - Pleasant Valley 345 kV Line*
M-NS	*Marcy - New Scotland 345 kV Line*
M/ED-NS SC	*Series Compensation of Marcy/Edic - New Scotland 345 kV Line*
NC-PV	*North Churchtown - Pleasant Valley 115 kV Line*
NS-PV	*New Scotland - Pleasant Valley 345 kV Line*
NS-LD	*New Scotland - Leeds 345 kV Line*
NS-LD-PV(R)	*Reconductoring New Scotland - Leeds - Pleasant Valley 345 kV Line*
NS-LD SR	*Series Reactor on New Scotland - Leeds 345 kV Line*
PT-RM	*Porter - Rotterdam 230 kV Line*