Electricity Assessment: Modeling New York State Energy Plan 2009

December 2009

1 Overview

Extensive electricity sector modeling was performed for the purpose of analyzing the potential impacts of alternative energy policy directions and system changes on future capacity needs, generation mix, fuel diversity, net imports of electricity, wholesale electricity prices, emissions, loss of load expectations, and emission allowance prices. This Section first explains how two "reference" cases are created, then summarizes the results of multiple "policy scenario" analyses as compared to the reference cases. Modeling results are also combined with additional data to obtain a better understanding about how retail prices might be impacted under various policy scenarios.

The modeling analysis and review process was coordinated by New York State Energy Research and Development Authority (NYSERDA) staff, working closely with the Energy Planning Working Group and the New York Independent System Operator (NYISO). The analysis was performed using the Integrated Planning Model (IPM), developed by ICF International. IPM is a nationally recognized modeling tool that is widely used by the U.S. Environmental Protection Agency (EPA), state energy and environmental agencies, and private sector firms, such as utilities and generation companies.

IPM is a 20-year linear programming model, which incorporates the New York electricity system, the systems managed by the New England Independent System Operator (ISO) and Pennsylvania, Jersey, Maryland (PJM), as well as the systems extending throughout the rest of the United States and Canada. The objective function is to solve for the optimal system dispatch (including imports and exports), new capacity, retirements, and repowering, given the specified demand, system characteristics, reserve margins, and environmental constraints. Key input data include existing and firmly planned generation units, annual electricity demand by zone, load shapes, transmission system capacities and transfer limits, generation unit level operation and maintenance costs and performance characteristics, fuel prices, new capacity and emission control technology costs and performance characteristics, zonal reliability requirements, Renewable Portfolio Standard (RPS) requirements, national and state environmental regulations, and financial market assumptions.

The electricity modeling scope was developed to explore the impacts of the following policy and system areas:

- Achieving the ‘15 by 15’ policy goal
- Expanding RPS to 30 percent of resources in 2015 compared to 25 percent of resources by 2013
- Retiring the Indian Point nuclear plants
- Adding a new nuclear plant in Oswego
- Adding additional transmission capability from Canada into upstate New York, from upstate to downstate, and adding both simultaneously.
- Federal Greenhouse Gas (GHG) policy resulting in Carbon Dioxide (CO_2) allowance prices in the \$23 to \$36 range (2015 to 2024)
- Substantial penetration of plug-in hybrid electric vehicles (PHEV)

1.1 "Reference" Cases

The first task in the State Energy Plan (SEP) modeling analysis was to develop "Reference" cases to be used as points of reference for comparing the impacts of potential policy directions and/or system changes. To estimate the impact of any potential policy direction, it is first necessary to estimate what is likely to occur in the absence of that policy direction. The increment between a "Reference" case and a "Policy" scenario represents the expected impact of the policy or system change. Values from the IPM model are not intended to be precise predictions. Rather, output from different scenarios can be examined to determine how they vary in terms of directionality and order of magnitude.

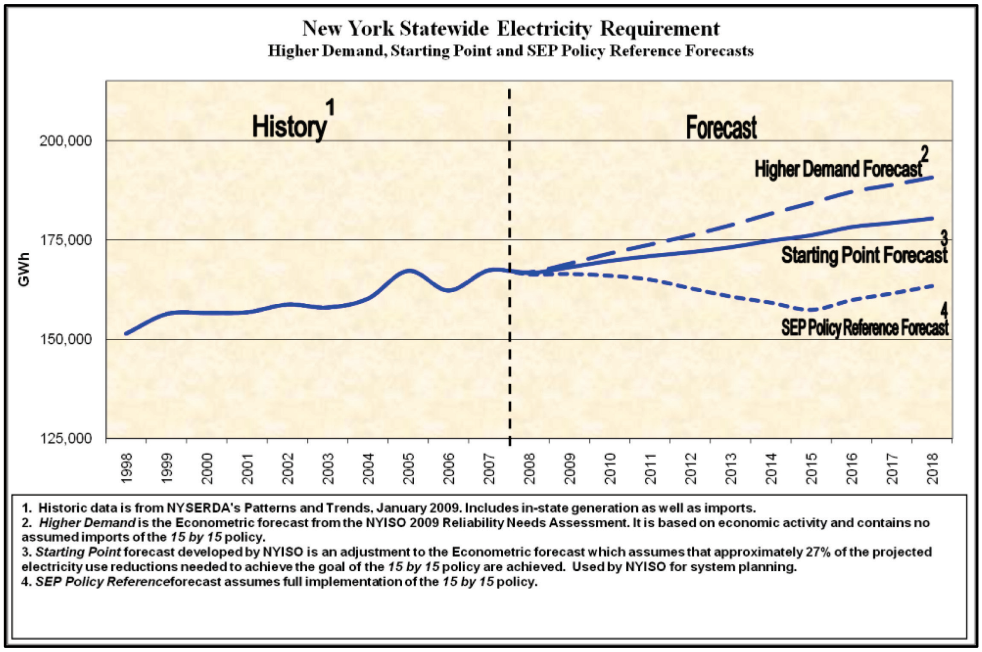
For the 2009 Plan, two "Reference" cases were developed, which differ only in the electricity demand forecasts used as model input, for use as points of comparison for alternative policy directions. The alternative electricity demand forecasts, both developed by the NYISO, are shown in Figure 1. Policy scenarios were generally run separately using each of the two reference cases for background assumptions.

The ***"Starting Point Case"*** is based on the electricity demand forecast used by the NYISO in its 2009 Reliability Needs Assessment (RNA) for purposes of electricity system planning. From 2009 to 2018, electricity demand is assumed to increase at an average rate of 0.8 percent per year, or a total increase of 7.3 percent over this period. The NYISO used moderately risk adverse assumptions which were widely vetted among market participants and considered to be appropriate for their baseline analysis of system reliability. The RNA forecast assumed only currently authorized funding levels for energy efficiency programs, which translates into the assumption that approximately 27 percent of the '15 by 15' policy goal associated with the Energy Efficiency Portfolio Standard (EEPS) is achieved.

The ***"SEP Policy Reference Case"*** is based on the electricity demand forecast (also developed by the NYISO) that assumes full implementation of the '15 by 15' policy goal, which requires that electricity demand be reduced by 2015 to a level that is 15 percent lower than the forecasted level without the policy goal. From 2009 to 2018, electricity demand is assumed to decrease by a total of 1.8 percent.

The econometric load forecast from the NYISO 2009 Reliability Needs assessment is also shown in Figure 1 as additional baseline information. It is labeled as the "Higher Demand Forecast." More information about this forecast can be found in Energy Demand and Price Forecasts.

Figure 1. New York Statewide Electricity Requirement



The critical input assumptions common to both Starting Point and SEP Policy Reference Cases are:

- Near-term expected infrastructure changes, including new generation units, capacity uprates, retirements, and transmission additions are consistent with the 2009 NYISO RNA. Capacity changes in other regions are consistent with the assumptions of the applicable ISOs wherever possible.

- New coal-fired and nuclear plants are precluded as an economic choice to meet projected capacity shortfalls in New York and other states that are participating in the Regional Greenhouse Gas Initiative (RGGI).

- The electricity system is assumed to maintain a 16.5 percent statewide reserve margin, an 80 percent in-City (NYC) reserve margin, and a 94 percent reserve margin on Long Island.

- Transmission capacities and limits were made consistent with NYISO RNA assumptions for New York State to the extent possible. Regional capacities and limits were provided by regional ISOs.

- All existing Renewable Portfolio Standard (RPS) objectives are assumed to be met in the northeast and mid-Atlantic regions.

- The requirements of the CO_2 emission cap imposed by the Regional Greenhouse Gas Initiative (RGGI) are achieved in each year.

- A national 3-pollutant (sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury) policy that approximates expectations of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) is assumed.

- All nuclear units in the State will continue to operate and will receive extensions of their operating licenses from the Nuclear Regulatory Commission.

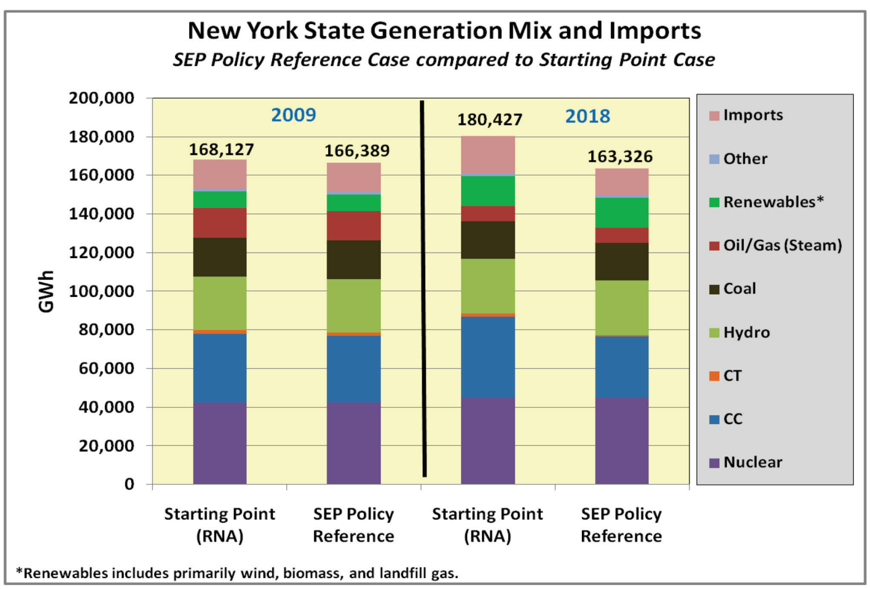
2 *Key Results from "Starting Point" and "SEP Policy Reference" Cases*

2.1 Generation Mix and Net Imports

As shown in Figure 2, in the Starting Point case, from 2009 to 2018, system load grows by 12,300 gigawatt hours (GWh) or seven percent. Base load hydro, nuclear, and coal generation remain relatively unchanged from current levels, while oil/gas steam generation decreases by 7,328 GWh. The growth in load from 2009 to 2018 is largely met by increasing natural gas combined cycle (CC) generation by 6,552 GWh, increasing renewable resources (primarily wind) by 6,837 GWh, and increasing imports of electricity by 4,393 GWh.

As also shown in Figure 2, in the SEP Policy Reference case, system load decreases by 3,100 GWh or two percent over the 2009 to 2018 period. Similar to the Starting Point case, base load hydro, nuclear, and coal generation remain relatively unchanged over the 2009 to 2018 period. In contrast to the Starting Point case, natural gas combined cycle generation *decreases* by 2,638 GWh from the 2009 level and imports *decrease* by 1,454 GWh from the 2009 level.

Figure 2. New York State Generation Mix and Imports

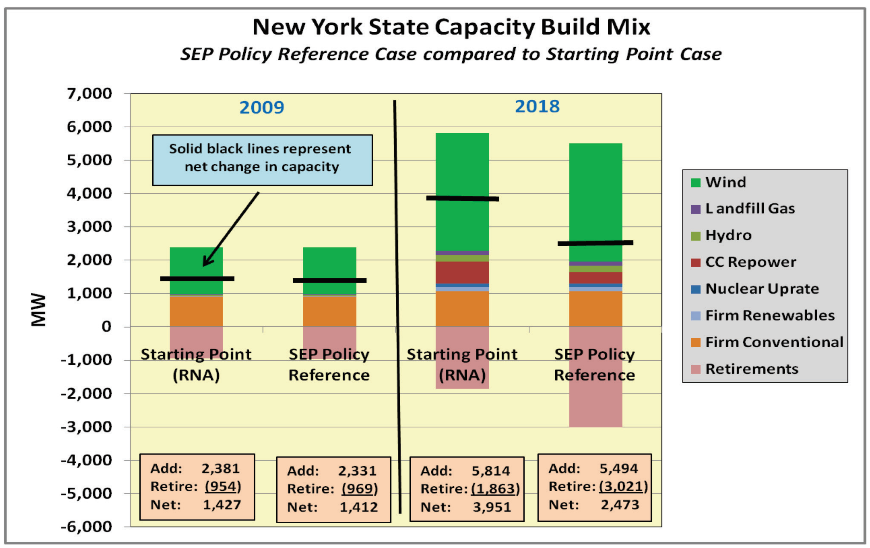


2.2 Capacity Build Mix

As shown in Figure 3, in the Starting Point case, it is estimated that by 2018 New York would install 3,951 MW (nameplate) of *net* capacity additions to meet forecasted load growth. This includes "firm" additions and retirements that are "hard-wired" as model inputs based on the NYISO RNA, as well as the additional capacity changes based on IPM's internal economic comparison of the long-term present value of unit costs and revenues. Note that the 3,543 MW of new wind capacity by 2018 is primarily due to compliance with the RPS, and not the need to meet forecasted capacity shortfalls on an economic (unsubsidized) basis. The largest block of capacity builds by 2018 based on economics is 670 MW of repowering of existing oil/gas steam units to combined cycle units.[1] Of the 1,863 MW of retirements shown by 2018, 1,028 MW are "firm" retirements identified in the NYISO RNA process. The vast majority (780 MW) of the remaining potential plant retirements projected by the model for this case are related to oil/gas steam units.

Figure 3 also shows that, in the SEP Policy Reference case, by 2018, it is estimated that 2,473 MW (nameplate) of net capacity additions would be installed, which is about 1,500 MW less than in the Starting Point case. Compared to the Starting Point case, by 2018, the SEP Policy Reference case has 1,158 MW of increased retirements and 320 MW decreased repowering. Essentially all of these additional potential retirements are related to oil/gas units.

Figure 3. New York State Capacity Build



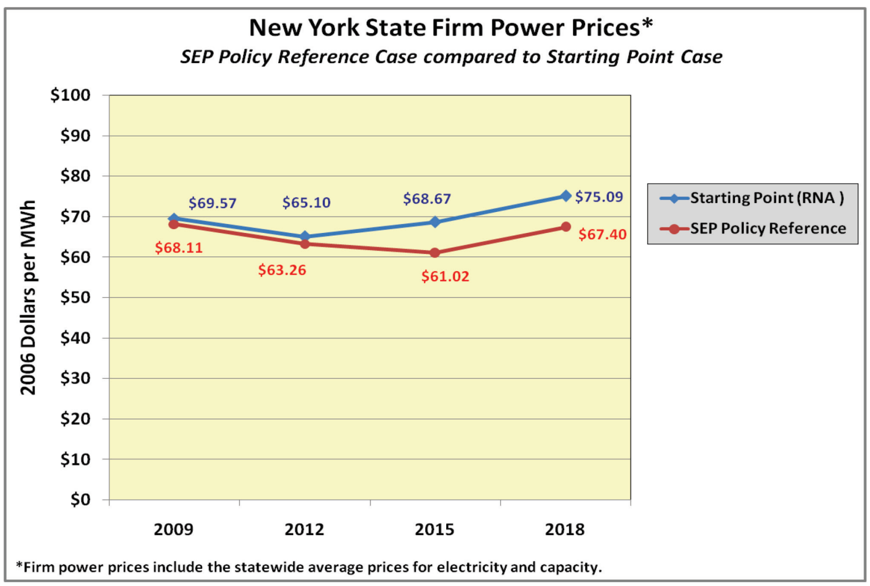
[1] Because IPM is an economic planning model based on a 20-year optimization algorithm, existing power plants may be modified (e.g., repowered, uprated, emissions control technologies added, etc.) or retired over the planning period. Similarly, new power plants can be built based on long-term economic comparison with continued operation of existing plants. This methodology differs conceptually from the NYSIO Reliability Needs Assessment (RNA) analysis, which assumes a predefined portfolio and configuration of generators that is assumed to be held constant over the planning period, whereby the need for additional capacity is determined based on successive calculations of loss-of-load probabilities. The SEP modeling work using IPM was closely coordinated with NYISO staff to ensure that the results, while based on different objectives, are based on the same system data and are relatively consistent in their conclusions.

2.3 Wholesale Electricity Prices

As shown in Figure 4, in the Starting Point case, it is estimated that, from 2009 to 2018, New York's average wholesale price of electricity (including both energy and capacity prices) would increase by $5.51/MWh or about eight percent in constant 2006 dollars. The estimated price change over this period is largely correlated to the forecasted change in the commodity cost of natural gas, as natural gas-fired units are most frequently the marginal units that set the market clearing price of electricity.

Figure 4 also shows that, in the SEP Policy Reference case, the average wholesale price of electricity would be about the same in 2018 as in 2009. Compared to the Starting Point case, the price of electricity in 2018 in the SEP Policy Reference" case is projected to be about $7.69 per MWh or 10 percent lower in constant 2006 dollars. This is due to the substantial load reduction resulting from the '15 by 15' program. The load reduction causes lower capacity costs, more efficient generation units to be on the margin more often, and also results in lower costs of environmental compliance.

Figure 4. New York State Firm Power Prices

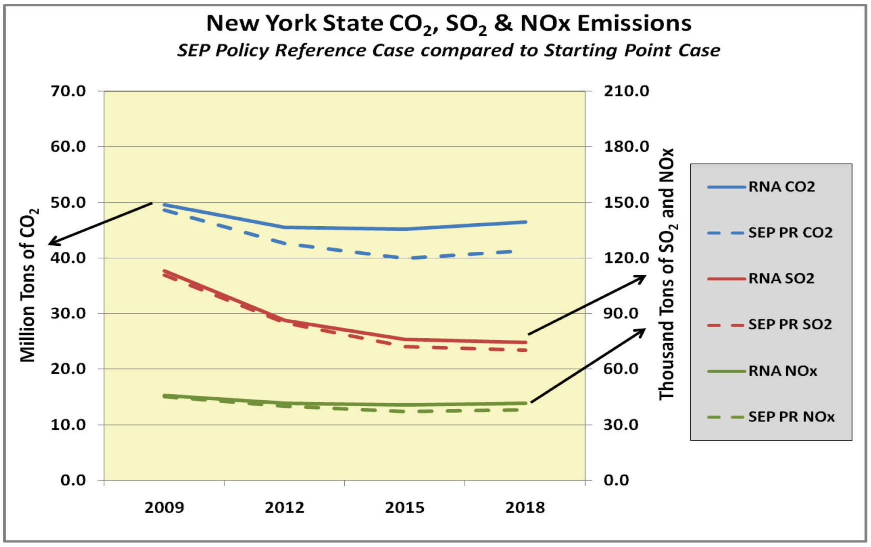


2.4 CO_2, SO_2, and NO_X Emissions

As shown in Figure 5, in the Starting Point case, from 2009 to 2018, New York's annual emissions of CO_2, SO_2, and NO_X are estimated to decrease by six percent, 34 percent, and nine percent, respectively. Emissions of CO_2 decrease due to the Regional Greenhouse Gas Initiative (RGGI). Emissions of SO_2 and NO_X decrease due to the expected requirements of the Clean Air Interstate Rule (CAIR).

Figure 5 also shows that the lower electricity demand assumed in the SEP Policy Reference case results in lower emissions of CO_2, SO_2, and NO_X in New York. Because these emissions are regulated by regional caps that allow interstate trading, the apparent emission reductions in New York due to reduced electricity load may be offset by emission increases in other states. It should be noted that, regardless of the assumptions for electricity load in New York, total emissions of CO_2, SO_2, and NO_X across all states are expected to be reduced as a direct result of both RGGI and CAIR.

Figure 5. New York State CO_2, SO_2 & NO_x Emissions

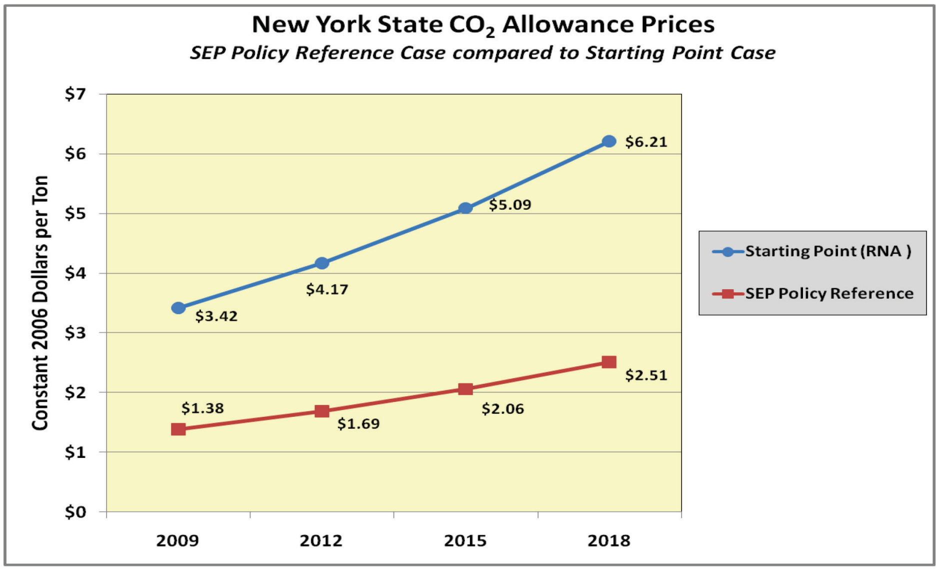


2.5 CO_2 Allowance Prices

As shown in Figure 6, in the Starting Point case, from 2009 to 2018, the price of CO_2 allowances is projected to increase from $3.42 per ton in 2009 to $6.21 per ton in 2018. The lower electricity demand due to the '15 by 15' policy assumed in the SEP Policy Reference case causes a substantial decrease in the projected allowance prices. By 2018, allowance prices in the SEP Policy Reference are projected to be $2.51 per ton, which is $3.70 per ton or 60 percent lower than in the Starting Point case. All prices are in constant 2006 dollars.

The allowance prices do not start at the same level in 2009 under the SEP Policy Reference case because the model has "perfect foresight" of future electric load, fuel prices, and system constraints such as environmental regulations on which to base decisions in each year. This theoretical construct eliminates market and regulatory uncertainty, and therefore results in present prices that reflect knowledge of future outcomes that are actually yet to be determined.

Figure 6. New York State CO_2 Allowance Prices



3 SEP Policy Reference Case Compared to the Starting Point Case

Comparing results of the SEP Policy Reference case to the Starting Point case, in 2018, indicate the expected impacts of full implementation of the '15 by 15' policy. For instance, the lower electricity load growth associated with the SEP Policy Reference case results in the need for 1,478 MW fewer new net capacity additions in New York and a reduction of 5,892 GWh of net electricity imports (a 30 percent reduction) compared with the Starting Point case. Natural gas generation is also projected to decrease by 11,059 GWh (25 percent) in the SEP Policy Reference case relative to the Starting Point case. As a result of the lower generation levels in New York under the SEP Policy Reference case, the CO_2 allowance price is projected to be \$3.70/ton (or 60 percent) lower than under the Starting Point case. Relative to the Starting Point case, the average New York wholesale electricity price decreases by \$7.69 per MWh (10 percent). Information on the potential net retail impacts of the SEP Policy Reference case can be found in the section of this report entitled "Analysis of Net Retail Price Impacts."

4 Reliability Analysis of Reference Cases

Reliability analyses of the two SEP reference cases (Starting Point and SEP Policy Reference) were performed by the NYISO to determine the loss-of-load probabilities over the 2009 to 2018 planning period. The New York State requirement for a loss-of-load event is no more than one day in 10 years, or 0.1 days per year. If the system loss-of-load expectation (LOLE) is determined to be less than 0.1 days per year, it is deemed to be in compliance with reliability requirements, meaning that no further system infrastructure is needed for reliability purposes.

The reliability analyses were performed using the Multi-Area Reliability Simulation (MARS) model, a proprietary model developed by General Electric (GE). The MARS model enables the NYISO to assess the ability of the interconnected bulk power system, given unit capacities and transmission transfer limits, to adequately meet customer load requirements on an hour by hour basis. The MARS model determines when, where, and to what extent the loss-of-load criteria are violated, and if so, assigns the level and location of "compensatory megawatts" necessary to bring the system back into compliance with the reliability criteria. Compensatory MW could be comprised of either additional generation capacity or strategic system modifications such as capacitor banks.

Table 1 and Table 2 show the results of the LOLE analyses by zone and for the entire State for both the Starting Point and the SEP Policy Reference cases. The LOLE for both cases were determined to be well below the 0.1 days per year threshold, and hence both meet New York State reliability criteria. The Statewide LOLE reached its highest level of 0.032 days per year in 2018 in the Starting Point case. Analysis of the SEP Policy Reference case shows that by meeting the ‘15 x 15’ policy goal, system reliability is substantially enhanced, as the highest statewide LOLE was 0.007 days per year in 2012, or less than one day in 100 years.

Table 1. Starting Point Case: Loss of Load Expectation (LOLE) (days per year)

	Starting Point Case			
Zone	**2009**	**2012**	**2015**	**2018**
A	0.0	0.0	0.0	0.0
B	0.0	0.0	0.0	0.004
C	0.0	0.0	0.0	0.0
D	0.0	0.0	0.0	0.0
E	0.0	0.0	0.0	0.002
F	0.0	0.0	0.0	0.0
G	0.0	0.0	0.0	0.001
H	0.0	0.0	0.0	0.0
I	0.0	0.002	0.007	0.028
J	0.0	0.003	0.007	0.03
K	0.001	0.0	0.0	0.0
NYS	0.001	0.003	0.008	0.032

Table 2. SEP Policy Reference Case: Loss of Load Expectation (LOLE) (days per year)

	SEP Policy Reference Case			
Zone	2009	2012	2015	2018
A	0.0	0.0	0.0	0.0
B	0.0	0.0	0.0	0.0
C	0.0	0.0	0.0	0.0
D	0.0	0.0	0.0	0.0
E	0.0	0.0	0.0	0.0
F	0.0	0.0	0.0	0.0
G	0.0	0.001	0.0	0.0
H	0.0	0.0	0.0	0.0
I	0.0	0.006	0.0	0.001
J	0.0	0.005	0.0	0.001
K	0.0	0.0	0.0	0.0
NYS	0.001	0.007	0.0	0.001

To illustrate the critical nature of ensuring that new capacity is built in a timely fashion to meet expected load growth, the NYISO performed a supplemental MARS analysis which used the *higher load forecast* from the Starting Point case with the *lower capacity build schedule* from the SEP Policy Reference case. As shown in Table 3, the LOLE using these assumptions results in violation of reliability criteria as early as 2012 at 0.102 days per year, and the violation grows to 0.627 days per year by 2018. These results indicate that if the system infrastructure were designed to function at the load level targeted by the '15 by 15' load forecast, but the actual load in future years was the higher amount assumed in the Starting Point case, the system would not be in compliance with established reliability criteria, and system modifications would be needed.

Table 3. Starting Point Case Load Forecast with SEP Policy Reference Net Capacity Additions: Loss of Load Expectation (LOLE) (days per year)

	Starting Point Case Load Forecast & SEP Policy Reference Case Net Capacity Additions			
Zone	2009	2012	2015	2018
A	0	0	0	0
B	0	0.006	0.01	0.026
C	0	0	0	0
D	0	0	0	0
E	0	0.001	0.003	0.009
F	0	0	0	0
G	0	0.033	0.07	0.203
H	0	0.001	0.001	0.001
I	0	0.096	0.213	0.589
J	0	0.081	0.181	0.523
K	0.001	0.001	0.001	0.003
NYS	0.001	0.102	0.23	0.627

In the following sections, a number of scenarios are described and are compared with these reference cases. Some of the key modeling results for the year 2018 are summarized in Table 4. Selected actual results for the two reference cases are displayed, and the incremental difference, in both absolute terms and on a percentage basis, between the reference case and each scenario is shown.

Table 4. Key New York State SEP Modeling Results in 2018

Key New York State SEP Modeling Results in 2018 *Sensitivities compared to both the Starting Point Case and SEP Policy Reference Case*										
	Starting Point	**Policy Reference**	**Indian Point Retirement**	**Nuclear Add in Oswego**	**National Carbon Policy**	**30% RPS**	**HQ-Upstate Transmission**	**Upstate to Downstate Transmission**	**Combined Transmission**	**Plug-In Hybrid**
Fuel Use (TBtu)										
Natural Gas	361	283								
Compared to Starting Point	N/A	-78 (-22%)	88 (24%)	-34 (-9%)	-6 (-2%)	-29 (-8%)	3 (1%)	-30 (-8%)	-16 (-4%)	13 (4%)
Compared to Policy Reference	78 (28%)	N/A	71 (25%)	-19 (-7%)	4 (1%)	0 (0%)	23 (8%)	11 (4%)	7 (2%)	15 (5%)
Generation Mix (GWh)										
Natural Gas (CC & CT only)	43,676	32,617								
Compared to Starting Point	N/A	-11,059 (-25%)	13,903 (32%)	-4,431 (-10%)	-75 (0%)	-3,903 (-9%)	363 (1%)	-3,245 (-7%)	-1,408 (-3%)	1,684 (4%)
Compared to Policy Reference	11,059 (34%)	N/A	12,384 (38%)	-2,567 (-8%)	1,289 (4%)	-7 (0%)	4,513 (14%)	3,276 (10%)	2,640 (8%)	2,006 (6%)
Oil & NG Steam	8,162	7,914								
Compared to Starting Point	N/A	-248 (-3%)	-1,988 (-24%)	-306 (-4%)	-1,373 (-17%)	-178 (-2%)	123 (2%)	-1,137 (-14%)	-984 (-12%)	135 (2%)
Compared to Policy Reference	248 (3%)	N/A	-2,410 (-30%)	-47 (-1%)	-1,188 (-15%)	-9 (0%)	-873 (-11%)	-1,117 (-14%)	-1,045 (-13%)	113 (1%)

	Starting Point	Policy Reference	Indian Point Retirement	Nuclear Add in Oswego	National Carbon Policy	30% RPS	HQ-Upstate Transmission	Upstate to Downstate Transmission	Combined Transmission	Plug-In Hybrid
Coal	19,351	19,490								
Compared to Starting Point	N/A	139 (1%)	-552 (-3%)	-421 (-2%)	-909 (-5%)	-132 (-1%)	22 (0%)	479 (2%)	435 (2%)	44 (0%)
Compared to Policy Reference	-139 (-1%)	N/A	-146 (-1%)	-363 (-2%)	-1,947 (-10%)	16 (0%)	80 (0%)	124 (1%)	326 (2%)	79 (0%)
Nuclear	44,689	44,689								
Compared to Starting Point	N/A	0 (0%)	-16,604 (-37%)	13,525 (30%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Compared to Policy Reference	0 (0%)	N/A	-16,604 (-37%)	13,525 (30%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Renewables	41,428	41,387								
Compared to Starting Point	N/A	-41 (0%)	2,588 (6%)	-4 (0%)	38 (0%)	8,996 (22%)	-3 (0%)	1,951 (5%)	-20 (0%)	24 (0%)
Compared to Policy Reference	41 (0.1%)	N/A	29 (0%)	-7 (0%)	56 (0%)	1 (0%)	1 (0%)	-14 (0%)	-22 (0%)	28 (0%)
Net Imports	19,414	13,522								
Compared to Starting Point	N/A	-5,892 (-30%)	2,652 (14%)	-8,365 (-43%)	2,319 (12%)	-4,784 (-24%)	-506 (-3%)	1,952 (10%)	1,978 (10%)	1,033 (5%)
Compared to Policy Reference	5,892 (44%)	N/A	6,747 (50%)	-10,542 (-78%)	1,790 (13%)	0 (0%)	-3,720 (-28%)	-2,269 (-17%)	-1,899 (-14%)	694 (5%)

	Starting Point	Policy Reference	Indian Point Retirement	Nuclear Add in Oswego	National Carbon Policy	30% RPS	HQ-Upstate Transmission	Upstate to Downstate Transmission	Combined Transmission	Plug-In Hybrid
Capacity Mix (MW)										
Net Capacity Added	3,951	2,473								
Compared to Starting Point	N/A	-1,478 (-37%)	347 (9%)	372 (9%)	209 (5%)	2,834 (72%)	0 (0%)	927 (23%)	1,071 (27%)	27 (0%)
Compared to Policy Reference	1,478 (60%)	N/A	-908 (-37%)	1,216 (49%)	56 (2%)	2 (0%)	14 (1%)	-37 (-2%)	18 (1%)	2 (0%)
Retirements[2]	1,863	3,021								
Compared to Starting Point			1,890 (101%)	1,228 (66%)	27 (1%)	709 (38%)	0 (0%)	-691 (-37%)	-835 (-45%)	0 (0%)
Compared to Policy Reference			1,721 (56%)	384 (13%)	178 (6%)	-2 (0%)	254 (8%)	357 (12%)	302 (10%)	-2 (0%)
Emissions (Million Tons)										
Carbon Dioxide	46.4	41.3								
Compared to Starting Point	N/A	-5.1 (-11%)	3.6 (8%)	-2.5 (-5%)	-2.3 (-5%)	-1.9 (-4%)	0.3 (0%)	-1.9 (-4%)	-1.1 (-2%)	0.9 (2%)

[2] For all model runs, retirements include 1,028 MW of "firm" retirements. Indian Point is also a "firm" retirement in the Indian Point Retirement scenario. All other retirements are "economic" retirements. A "retirement" has been given a positive value within this category.

	Starting Point	Policy Reference	Indian Point Retirement	Nuclear Add in Oswego	National Carbon Policy	30% RPS	HQ-Upstate Transmission	Upstate to Downstate Transmission	Combined Transmission	Plug-In Hybrid
Compared to Policy Reference	5.1 (12%)	N/A	3.6 (9%)	-1.5 (-4%)	-2.5 (-6%)	0 (0%)	1.5 (4%)	0.7 (2%)	0.7 (2%)	1.0 (2%)
Allowance Price (2006 Dollars per Ton)										
Regional Carbon Dioxide	6.21	2.51								
Compared to Starting Point	N/A	-3.70 (-60%)	3.21 (52%)	-1.43 (-23%)	N/A	-2.09 (-34%)	0.00 (0%)	-1.88 (-30%)	-1.56 (-25%)	0.56 (9%)
Compared to Policy Reference	3.70 (147%)	N/A	2.50 (100%)	-0.39 (-16%)	N/A	0.03 (1%)	0.24 (10%)	-0.24 (-10%)	-0.12 (-5%)	0.26 (10%)
Electricity Price (2006 Dollars per MWh)										
Firm Price	75.09	67.40								
Compared to Starting Point	N/A	-7.69 (-10%)	3.64 (5%)	-4.62 (-6%)	15.19 (20%)	-3.56 (-5%)	-0.16 (0%)	-2.05 (-3%)	-2.54 (-3%)	1.15 (2%)
Compared to Policy Reference	7.69 (11%)	N/A	5.46 (8%)	-1.84 (-3%)	18.41 (27%)	0.00 (0%)	-0.78 (-1%)	-3.44 (-5%)	-2.15 (-3%)	0.44 (1%)

5 Indian Point Retirement Scenario

The Starting Point and SEP Policy Reference cases assume that all nuclear units in the State will continue to operate and will receive extensions of their operating licenses from the Nuclear Regulatory Commission. This alternative scenario assumes that Indian Point (IP) generating units #2 and #3 (summer capacity value of 2,065 MW) cease operations in 2015.

Indian Point Retirement Scenario Compared to Starting Point Case in 2018. Compared to the Starting Point case, nuclear generation decreases by 16,604 GWh (or 37 percent) under the Indian Point Retirement scenario. This decrease in nuclear generation is balanced by a 14,058 GWh (33 percent) increase in combined cycle generation and a 2,652 GWh (14 percent) increase in net imports compared with the Starting Point case. The changes in generation and net imports are shown in Figure 7. In order to make up for the retired nuclear generation, approximately 1,800 MW of additional combined cycle units are built under the IP Retirement scenario relative to the Starting Point case. The shift toward a more carbon intensive generation mix under the IP Retirement scenario causes New York CO_2 emissions to increase by about 3.6 million tons and to create a corresponding increase in CO_2 allowance prices of $3.21/ton compared with the Starting Point case. As shown in Figure 8, average wholesale electricity prices are projected to be about $3.64/MWh (five percent) higher in the IP Retirement scenario relative to the Starting Point case.

Figure 7. New York State Generation Mix and Imports

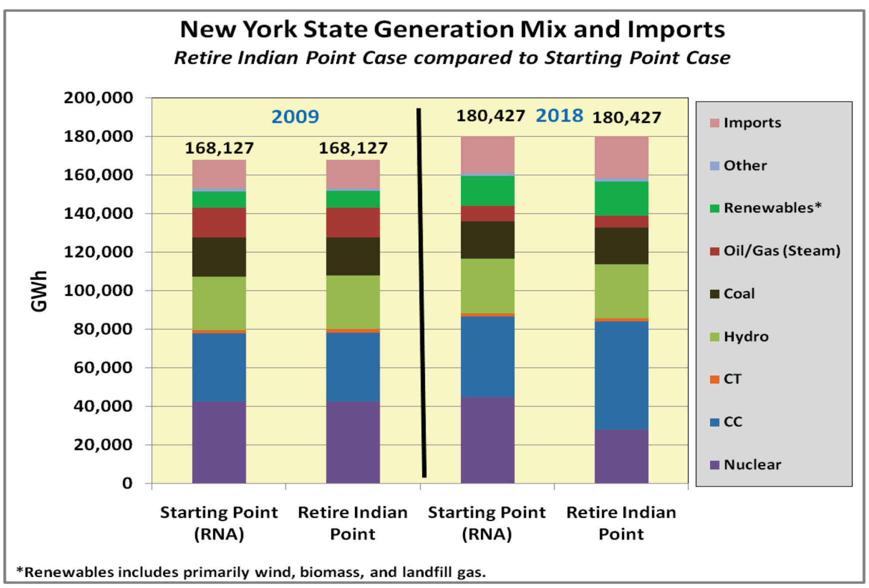
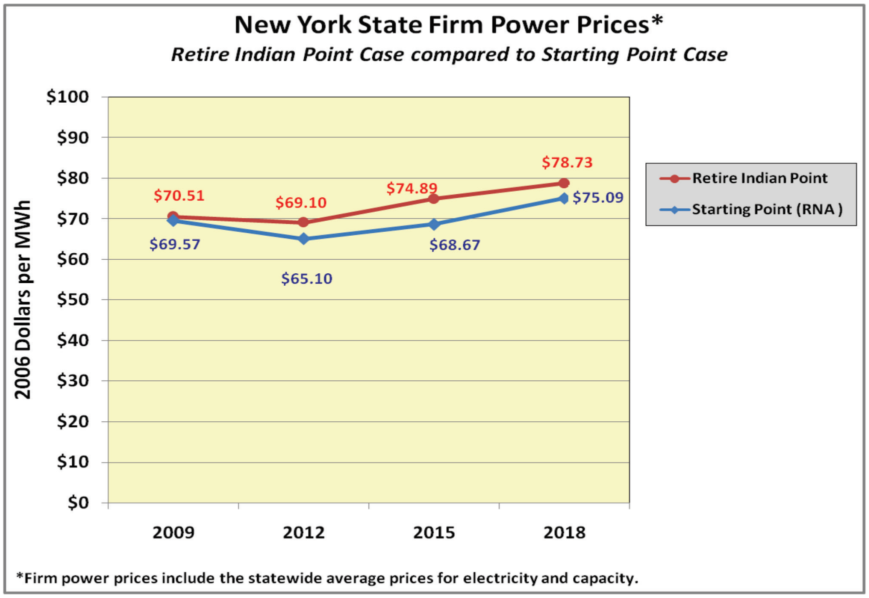


Figure 8. New York State Firm Power Prices



Indian Point Retirement Compared to SEP Policy Reference Case in 2018. The same general trends are observed when comparing the IP Retirement scenario against the SEP Policy Reference case. However, the projected changes are of a smaller order of magnitude because less electricity generation and capacity are needed under the SEP Policy Reference case.

Compared to the SEP Policy Reference case, nuclear generation decreases by 16,604 GWh (or 37 percent) under the Indian Point Retirement scenario. This decrease in nuclear generation is balanced by a 11,836 GWh (37 percent) increase in combined cycle generation and a 6,747 GWh (50 percent) increase in net imports relative to the SEP Policy Reference case. The changes in generation and net imports are shown in Figure 9. In order to make up for the retired nuclear generation, approximately 700 MW of additional combined cycle units are built under the IP Retirement scenario relative to the SEP Policy Reference case. The shift toward a more carbon intensive generation mix under the IP Retirement Scenario causes CO_2 emissions to increase by 3.6 million tons and regional CO_2 allowance prices to increase by $2.50 per ton relative to the SEP Policy Reference case. As shown in Figure 10, average wholesale electricity prices are projected to be about $5.47 per MWh (eight percent) higher in the IP Retirement Scenario relative to the SEP Policy Reference case. However, statewide wholesale electricity prices are projected to be $5.87per MWh (seven percent) lower in 2018 under an IP Retirement Scenario with the SEP Policy Reference load forecast when compared with an IP Retirement Scenario with the Starting Point load forecast.

Figure 9. New York State Generation Mix and Imports

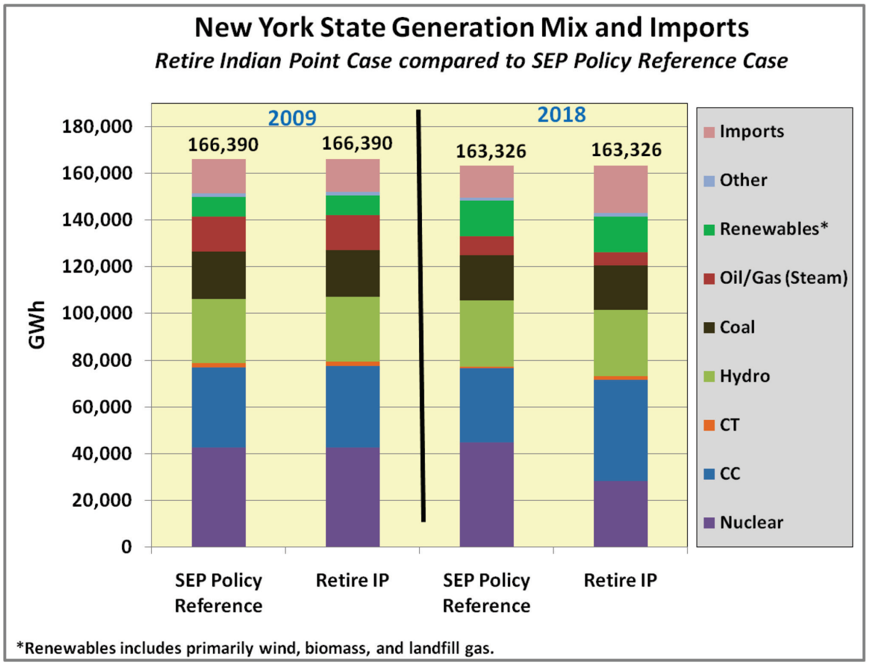
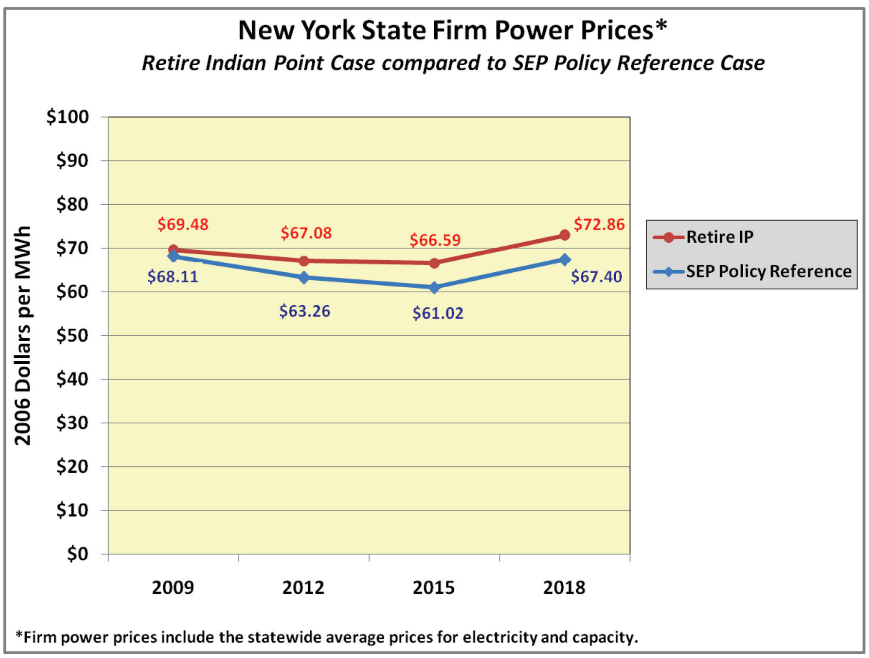


Figure 10. New York State Firm Power Prices



Information on the potential net retail impacts of the IP Retirement Scenario can be found in the section entitled "Analysis of Net Retail Price Impacts."

6 Additional Nuclear Unit Scenario

This scenario evaluates the potential impact of adding a new 1,600 MW nuclear unit at the upstate Oswego site in 2018. This scenario is compared against both the Starting Point and SEP Policy Reference cases.

Additional Nuclear Unit Scenario Compared to Starting Point Case in 2018. Relative to the Starting Point case, nuclear generation increases by 13,525 GWh (30 percent) under the Additional Nuclear Unit scenario. As a result, gas-fired combined cycle generation decreases by 4,365 GWh (10 percent) and net electricity imports decrease by 8,365 GWh (43 percent) relative to the Starting Point case. The changes in generation and net imports are shown in Figure 11. Compared with the Starting Point case, CO_2 emissions decrease by 2.5 million tons and the CO_2 allowance price decreases by $1.43 per ton under the Additional Nuclear Unit scenario. In addition, the average New York wholesale electricity price decreases by $4.62 per MWh (six percent) under the Additional Nuclear Unit Scenario relative to the Starting Point case, as shown in Figure 12.

Figure 11. New York State Generation Mix and Imports

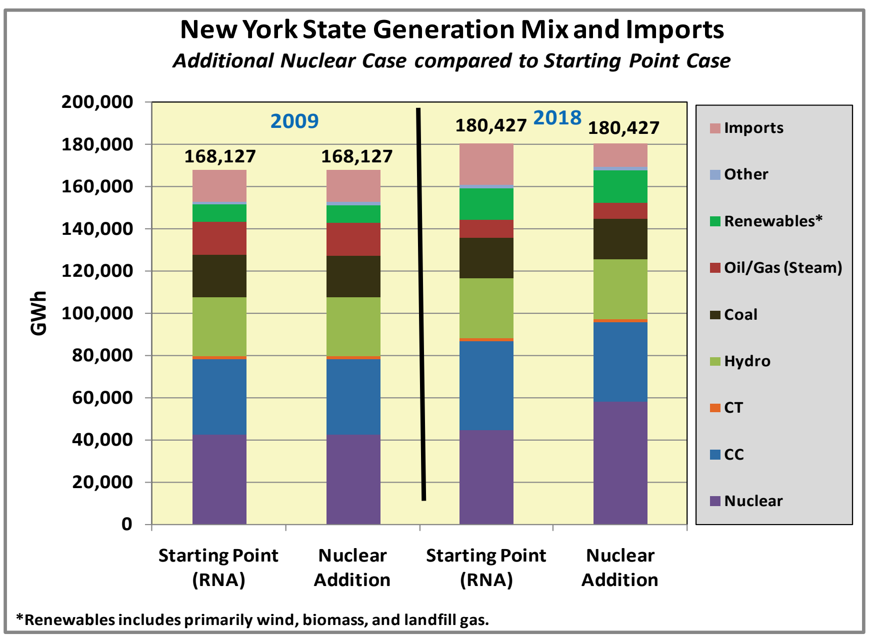
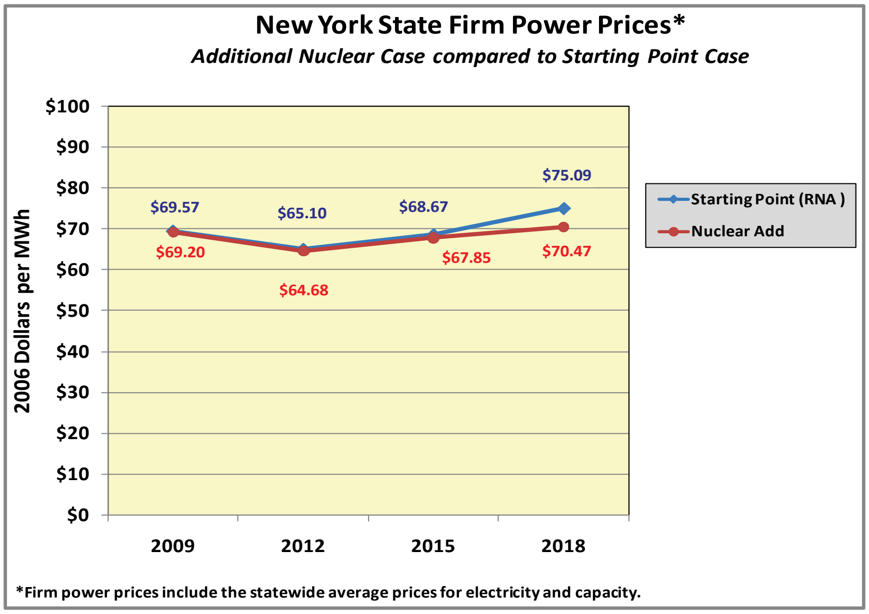


Figure 12. New York State Firm Power Prices



Additional Nuclear Unit Scenario Compared to SEP Policy Reference Case in 2018. Compared to the SEP Policy Reference Case, nuclear generation increases by 13,525 GWh (30 percent) under the Additional Nuclear Unit scenario. Gas-fired combined-cycle generation decreases by 2,487 GWh (eight percent) and net imports decrease by 10,542 GWh (78 percent) in the Additional Nuclear Unit scenario. The changes in generation and net imports are shown in Figure 13. Relative to the SEP Policy Reference case, CO_2 emissions decrease by 1.5 million tons and the CO_2 allowance price decreases by $0.39 per ton under the Additional Nuclear Unit scenario. Furthermore, the average New York wholesale electricity price decreases by $1.84 per MWh (three percent) under the Additional Nuclear Unit Scenario relative to the SEP Policy Reference case, as shown in Figure 14.

Figure 13. New York State Generation Mix and Imports

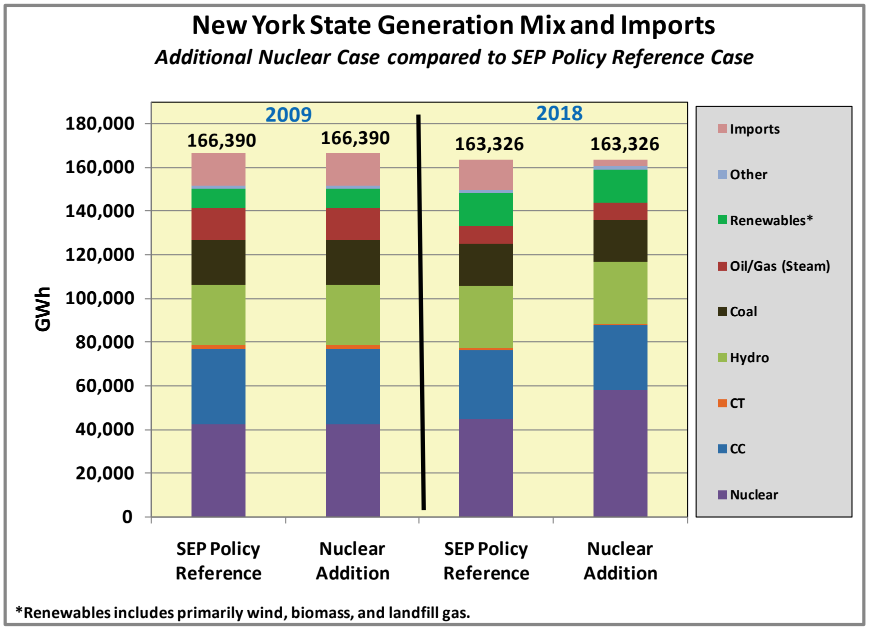
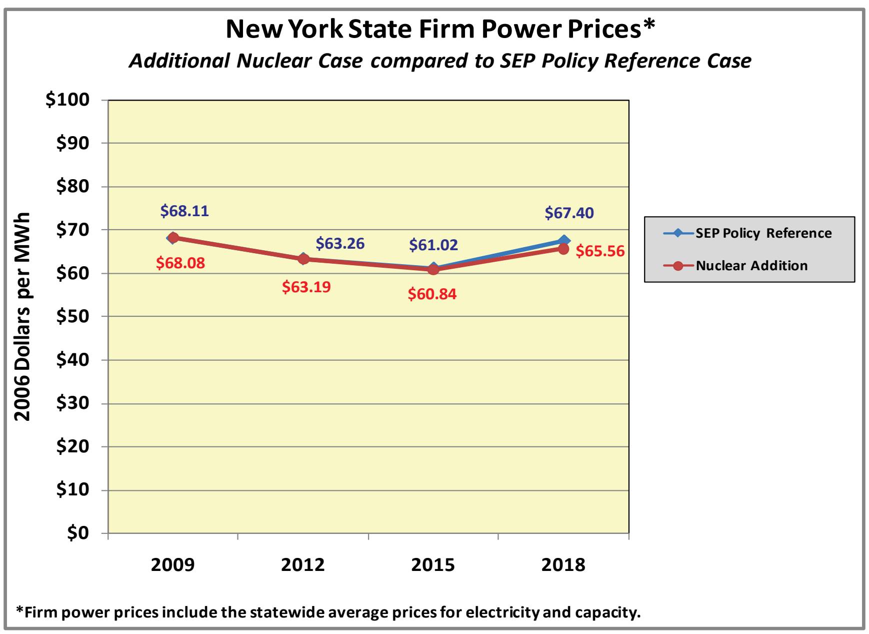


Figure 14. New York State Firm Power Prices



Information on the potential net retail impacts of the Additional Nuclear Scenario can be found in the section entitled "Analysis of Net Retail Price Impacts."

6.1 Reliability Analysis of Additional Nuclear Scenario

Reliability analysis of the Additional Nuclear runs was performed by the NYISO to determine the loss-of-load probabilities over the 2009 to 2018 planning period. As described earlier, the NYISO used the GE MARS model for this analysis. Table 5 and Table 6 show the results of the LOLE analyses by zone and for the entire New York Control Area (NYCA) for the Additional Nuclear scenario under the Starting Point and the SEP Policy Reference case load forecasts, respectively.

Table 5. Starting Point – Additional Nuclear Case: Loss of Load Expectation (LOLE) (days per year)

	Starting Point - Additional Nuclear Case			
Zone	2009	2012	2015	2018
A	0.0	0.000	0.000	0.0
B	0.0	0.000	0.000	0.002
C	0.0	0.000	0.000	0.0
D	0.0	0.000	0.000	0.0
E	0.0	0.000	0.000	0.001
F	0.0	0.000	0.000	0.0
G	0.0	0.000	0.000	0.084
H	0.0	0.000	0.000	0.0
I	0.0	0.002	0.007	0.255
J	0.0	0.003	0.007	0.223
K	0.001	0.000	0.000	0.0
NYCA	0.001	0.003	0.008	0.276

Table 6. SEP Policy Reference – Additional Nuclear Case: Loss of Load Expectation (LOLE) (days per year)

	SEP Policy Reference - Additional Nuclear Case			
Zone	2009	2012	2015	2018
A	0.0	0.000	0.000	0.0
B	0.0	0.000	0.000	0
C	0.0	0.000	0.000	0.0
D	0.0	0.000	0.000	0.0
E	0.0	0.000	0.000	0
F	0.0	0.000	0.000	0.0
G	0.0	0.001	0.000	0.001
H	0.0	0.000	0.000	0.0
I	0.0	0.006	0.000	0.003
J	0.0	0.005	0.000	0.003
K	0.001	0.000	0.000	0.0
NYCA	0.001	0.007	0	0.004

The LOLE for the SEP Policy Reference – Additional Nuclear scenario was determined to be well below the 0.1 days per year threshold, and hence met New York State reliability criteria. However, the projected LOLE values exceeded the threshold in 2018 under the Starting Point – Additional Nuclear scenario in Zones I and J and for NYCA. The NYISO conducted another MARS run to determine the location and number of compensatory megawatts needed to avoid violating the LOLE criteria. Under this additional run, approximately 570 MW of generation was added back into zones G, H, and I (zones consolidated for modeling purposes). As seen in Table 7, the projected LOLE values for this scenario met the New York State reliability criteria.

Table 7. Starting Point – Additional Nuclear Scenario: Loss of Load Expectation (LOLE) (days per year)

	Starting Point - Additional Nuclear Case (Retain 570 MW generation in Zone GHI)			
Zone	2009	2012	2015	2018
A	0.0	0.000	0.000	0.0
B	0.0	0.000	0.001	0.001
C	0.0	0.000	0.000	0.0
D	0.0	0.000	0.000	0.0
E	0.0	0.000	0.000	0
F	0.0	0.000	0.000	0.0
G	0.0	0.000	0.000	0.004
H	0.0	0.000	0.000	0.0
I	0.0	0.002	0.007	0.063
J	0.0	0.003	0.007	0.064
K	0.001	0.000	0.000	0.0
NYCA	0.001	0.003	0.008	0.071

7 Transmission Expansion Scenarios

7.1 Hydro-Quebec (HQ) Transmission Expansion

This scenario examines the impact of adding 1,000 MW of new transmission capability between Hydro-Quebec (HQ) and upstate New York (modeled zones A-E) in 2015. This scenario was compared against both the Starting Point and SEP Policy Reference cases. As shown in Figure 15 and Figure 16, adding transmission capability from HQ had negligible impact on New York's annual average wholesale electricity prices. The HQ Transmission Expansion scenario also had minimal impact on New York's annual CO_2 emissions and had little impact on regional CO_2 prices.

Figure 15. New York State Firm Power Prices

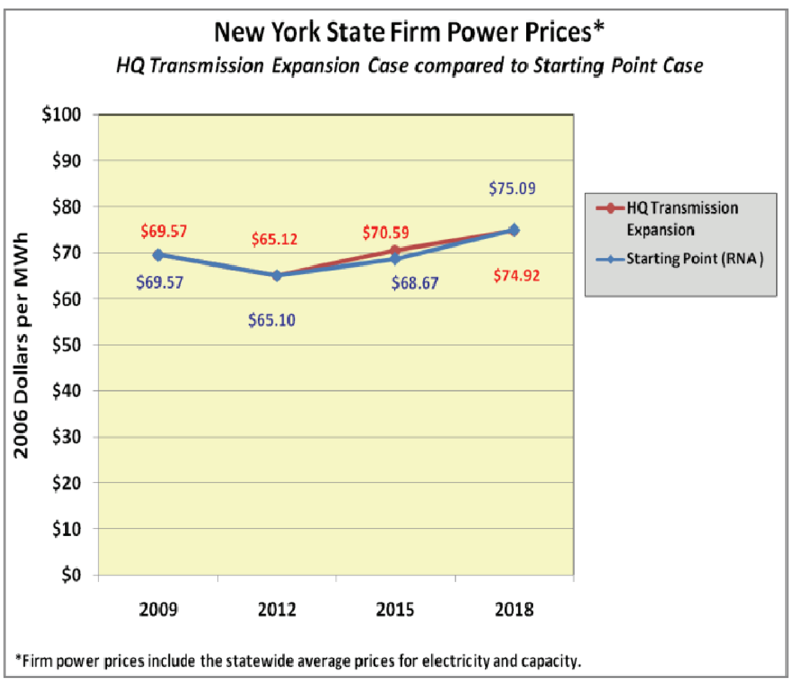
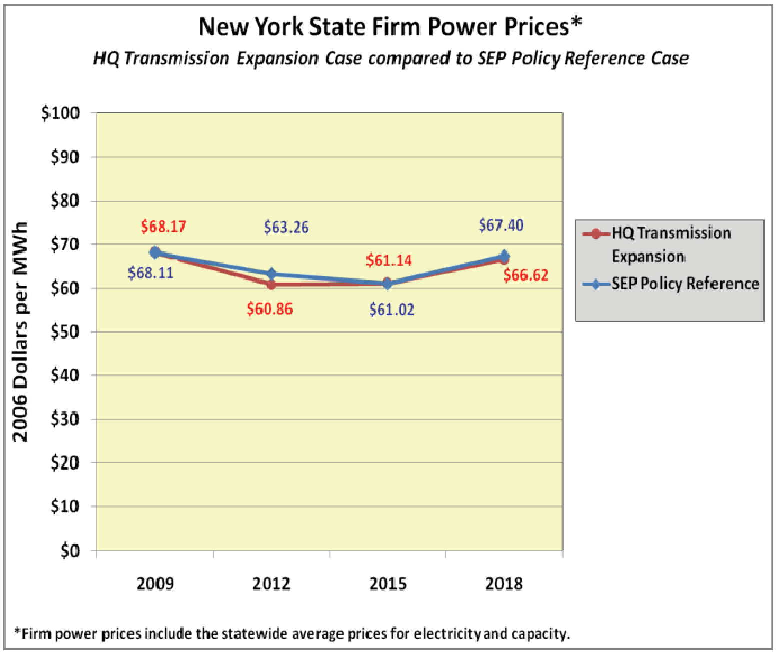


Figure 16. New York State Firm Power Prices



Relative to both the Starting Point and SEP Policy Reference cases, more electricity flows into New York from Quebec in the summer under the HQ Transmission Expansion scenario. However, Quebec is a winter peaking region and the model projects an even larger increase in exports of power from New York to Quebec during the winter heating season. On balance, New York's annual net imports are projected to decrease under the HQ Transmission Expansion scenario.

Information on the potential net retail impacts of the HQ Transmission Expansion scenario can be found in the section entitled "Analysis of Net Retail Price Impacts."

7.2 Upstate to Downstate Transmission Expansion

This scenario evaluates the potential effect of adding 1,200 MW of new transmission capability from upstate New York (modeled Zone A-E) directly to New York City (Zone J) in 2015. This scenario is compared against both the Starting Point and SEP Policy Reference cases.

Upstate to Downstate Transmission Expansion Scenario Compared to the Starting Point Case in 2018. As shown in Figure 17, the average New York wholesale electricity price is $2.05 per MWh (three percent) lower under the Upstate to Downstate Transmission Expansion scenario, indicating that there could be a net economic benefit to the State, with respect to wholesale electricity prices, if such a project were to be implemented. The net economic benefit is due to the increased ability to transfer lower priced electricity from upstate to downstate. A breakdown of estimated changes in wholesale prices in 2018 for upstate (modeled Zone A-E) and downstate (modeled Zone J) is shown in Table 8. Prices in Zone J are projected to go down by approximately $8.90 per MWh (10 percent) and increase by an estimated $3.74 per MWh (six percent) in modeled Zone A-E.

Figure 17. New York State Firm Power Prices

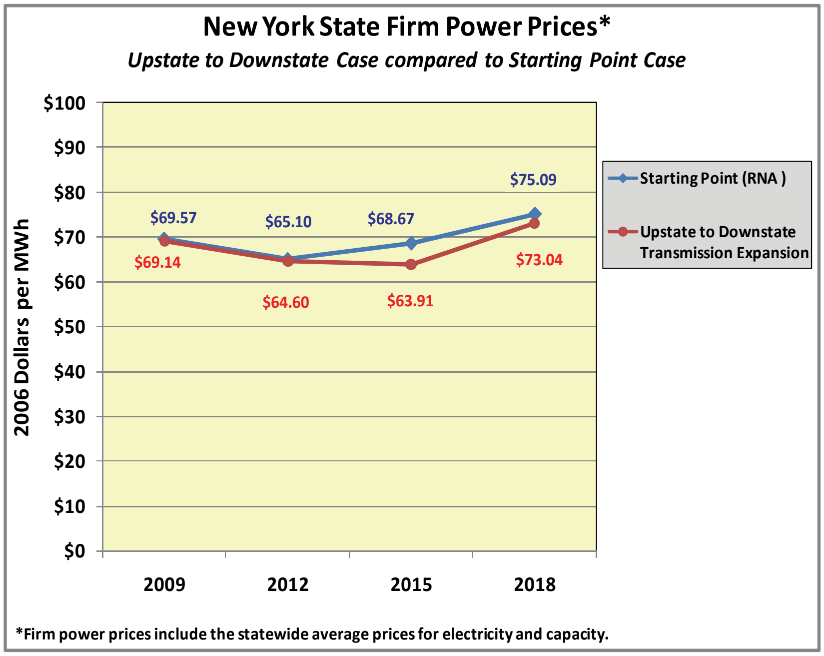


Table 8. Comparison of Zonal Firm Power Prices ($/MWh)

Modeled NY Zone	Starting Point	Upstate to Downstate Expansion	Upstate to Downstate - Starting Point	% Change
Upstate (A-E)	$63.25	$66.99	$3.74	5.9%
Downstate (J)	$85.42	$76.52	-$8.90	-10.4%
Average	$75.09	$73.04	-$2.05	-2.7%

Relative to the Starting Point case, gas generation decreases by 3,245 GWh (seven percent) and oil/gas steam generation decreases by 1,137 GWh (14 percent). At the same time, renewable generation increases by 1,951 GWh (five percent) and net imports increase by 1,952 GWh (10 percent). Also, relative to the Starting Point case, the level of plant retirements decreases under the Upstate to Downstate Transmission Expansion scenario because more upstate generation can now be transported to the downstate market. These shifts in the power supply portfolio relative to the Starting Point case promote a 1.9 million ton reduction in New York CO_2 emissions and contribute to a $1.88 per ton reduction in the regional CO_2 allowance price.

Upstate to Downstate Transmission Expansion Scenario Compared to the SEP Policy Reference Case in 2018. Similar to the previous comparison, the average New York wholesale electricity price is $3.44 per MWh (five percent) lower under the Upstate to Downstate Transmission Expansion scenario compared to the SEP Policy Reference Case. The average statewide wholesale prices are shown in Figure 18 and a comparison of the estimated changes in wholesale prices in 2018 for upstate (modeled Zone A-E) and downstate (modeled Zone J) is shown in Table 9. Prices in Zone J are projected to go down by approximately $12.36 per MWh (16 percent) and increase by an estimated $3.19 per MWh (six percent) in modeled Zone A-E.

Figure 18. New York State Firm Power Prices

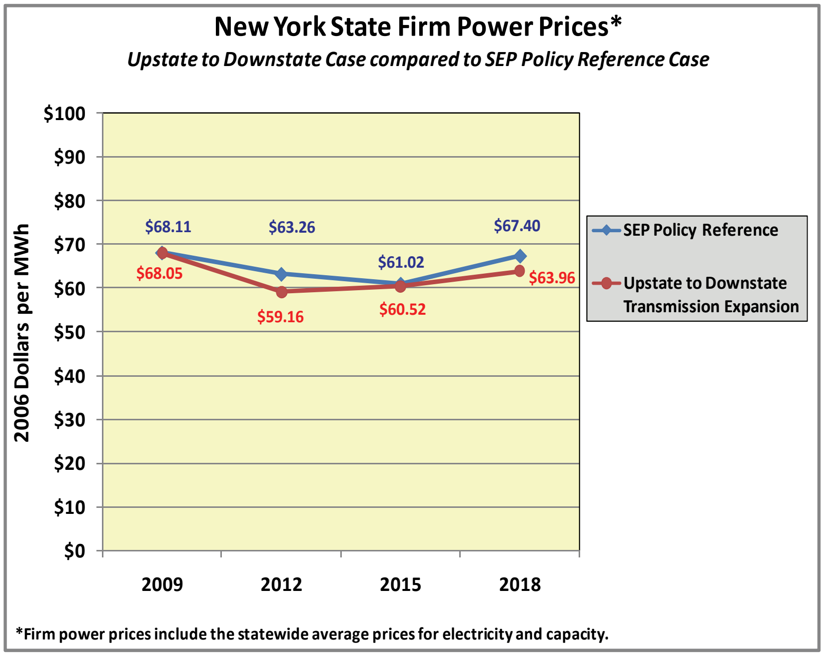


Table 9. Comparison of Zone Firm Power Prices ($/MWh)

Modeled NY Zone	SEP Policy Case	Upstate to Downstate Expansion	Upstate to Downstate - SEP Policy Case	% Change
Upstate (A-E)	$56.36	$59.55	$3.19	5.7%
Downstate (J)	$76.82	$64.46	-$12.36	-16.1%
Average	$67.40	$63.96	-$3.44	-5.1%

Plant retirements are projected to be higher under the Upstate to Downstate Transmission Expansion scenario when compared with the SEP Policy Reference case. These potential retirements could occur because overall electricity demand and transmission congestion is lower. Therefore, an even higher volume of less expensive upstate power can reach downstate markets and displace more downstate generation. Accordingly, the energy supply mix is projected to change and gas generation increases by 3,276 GWh (10 percent) and oil/gas steam generation decreases by 1,117 GWh (14 percent) under the Upstate to Downstate Transmission Expansion scenario. At the same time, net imports decrease by 2,269 GWh (17 percent) relative to the SEP Policy Reference case. New York CO_2 emissions and regional CO_2 allowance prices do not change appreciably under the Upstate to Downstate Transmission Expansion scenario relative to the SEP Policy Reference case.

Information on the potential net retail impacts of the Upstate to Downstate Transmission Expansion scenario can be found in the subsection entitled “Analysis of Net Retail Price Impacts.”

7.3 Combined Transmission Expansion

This scenario examines the potential impacts associated with implementing both a 1,200 MW upstate to downstate transmission project and a 1,000 MW Hydro-Quebec to upstate New York transmission expansion at the same time in 2015. This Combined Transmission Expansion scenario is compared against both the Starting Point and the SEP Policy Reference cases.

Combined Transmission Expansion Scenario Compared to the Starting Point Case in 2018. Relative to the Starting Point case, gas generation decreases by 1,408 GWh (three percent) and oil/gas steam generation decreases by 984 GWh (12 percent) under the Combined Transmission Expansion scenario. Compared with the Starting Point case, net imports increase by 1,978 GWh (10 percent). Also, relative to the Starting Point case, the level of plant retirements decreases under the Combined Transmission Expansion scenario because more upstate generation (and imports) can now be transported to the downstate market. Relative to the Starting Point case, New York CO_2 emissions decrease by 1.1 million tons and regional CO_2 allowance prices decrease by $1.56 per ton in the Combined Transmission Expansion Scenario.

As shown in Figure 19, the average New York wholesale electricity price is $2.54 per MWh (three percent) lower under the Combined Transmission Expansion scenario. A comparison of the estimated changes in wholesale prices in 2018 for upstate (modeled Zone A-E) and downstate (modeled Zone J) is shown in Table 10. Prices in Zone J are projected to go down by approximately $8.42 per MWh (10 percent) and increase by an estimated $2.80 per MWh (four percent) in modeled Zone A-E. The fact that this scenario resulted in a reduction in average statewide electricity prices indicates that there may be a net economic benefit to the State associated with this combination of transmission projects. However, as indicated by the results of the Upstate to Downstate Transmission Expansion scenario above, the net benefit is only marginally increased by the simultaneous inclusion of the HQ project; i.e. most of the net benefit is due to the Upstate to Downstate Transmission Expansion project.

Figure 19. New York State Firm Power Prices

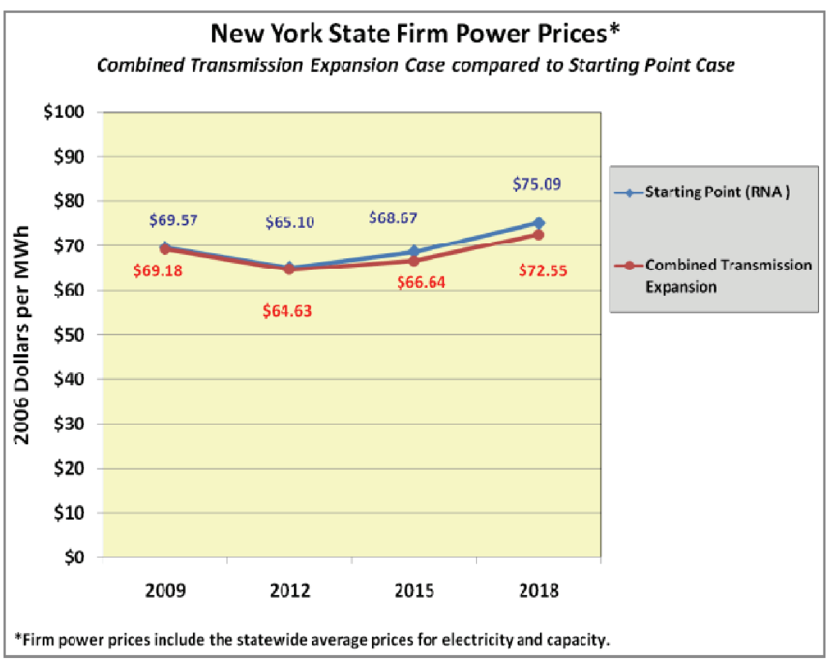


Table 10. Comparison of Zonal Firm Power Prices ($/MWh)

Comparison of Zonal Firm Power Prices				
Modeled NY Zone	Starting Point	Combined Transmission Expansion	Combined Tranmission Expansion - Starting Point	% Change
Upstate (A-E)	$63.25	$66.04	$2.80	4.4%
Downstate (J)	$85.42	$77.00	-$8.42	-9.9%
Average	$75.09	$72.55	-$2.54	-3.4%

Combined Transmission Expansion Scenario Compared to the SEP Policy Reference Case in 2018. Plant retirements are projected to be higher under the Combined Transmission Expansion scenario when compared with the SEP Policy Reference case. These potential retirements could occur because overall electricity demand and transmission congestion is lower. Therefore, an even higher volume of less expensive upstate power can reach downstate markets and displace more downstate generation. Accordingly, the energy supply mix is projected to change and gas generation increases by 2,640 GWh (eight percent) and oil/gas steam generation decreases by 1,045 GWh (13 percent) under the Combined Transmission Expansion scenario. At the same time, net imports decrease by 1,899 GWh (14 percent) relative to the SEP Policy Reference case.

New York CO_2 emissions and regional CO_2 allowance prices do not change appreciably under the Combined Transmission Expansion scenario relative to the SEP Policy Reference case. However, the average New York wholesale electricity price is $2.15 per MWh (three percent) lower under the Combined Transmission Expansion scenario. The statewide annual average price reduction is not as large when compared with the Upstate to Downstate Transmission Expansion scenario because some of the increase in gas generation is attributed to an increase in winter exports of power to Quebec. The average statewide wholesale prices are shown in Figure 20 and a comparison of the estimated changes in wholesale prices in 2018 for upstate (modeled Zone A-E) and downstate (modeled Zone J) is shown in Table 11. Prices in Zone J are projected to go down by approximately $10.98 per MWh (14 percent) and increase by an estimated $4.32 per MWh (eight percent) in modeled Zone A-E.

Figure 20. New York State Firm Power Prices

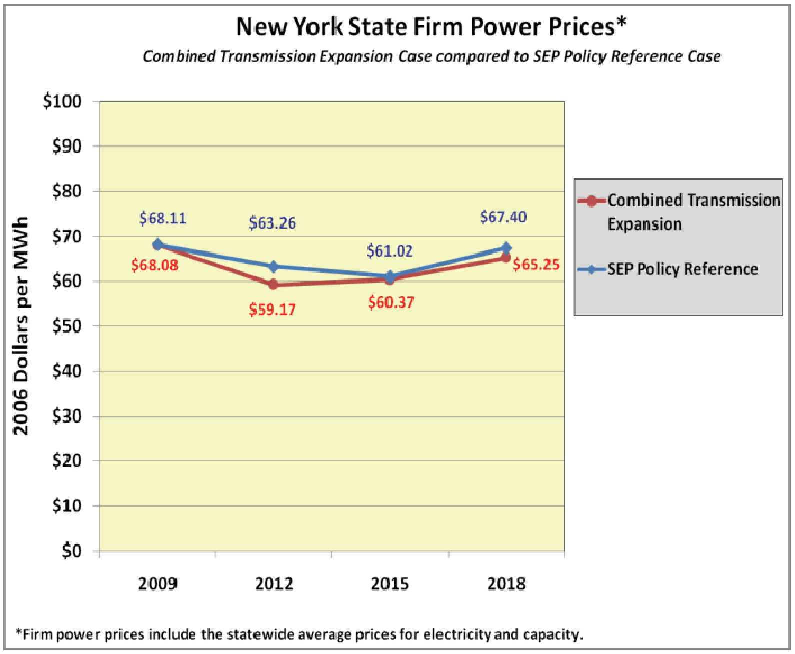


Table 11. Comparison of Zonal Firm Power Prices ($/MWh)

Comparison of Zonal Firm Power Prices				
Modeled NY Zone	SEP Policy Case	Combined Transmission Expansion	Combined Tranmission Expansion - SEP Policy Case	% Change
Upstate (A-E)	$56.36	$60.68	$4.32	7.7%
Downstate (J)	$76.82	$65.84	-$10.98	-14.3%
Average	$67.40	$65.25	-$2.15	-3.2%

Information on the potential net retail impacts of the Combined Transmission Expansion scenario can be found in the section entitled “Analysis of Net Retail Price Impacts.”

8 Expanded Renewable Portfolio Standard (RPS)

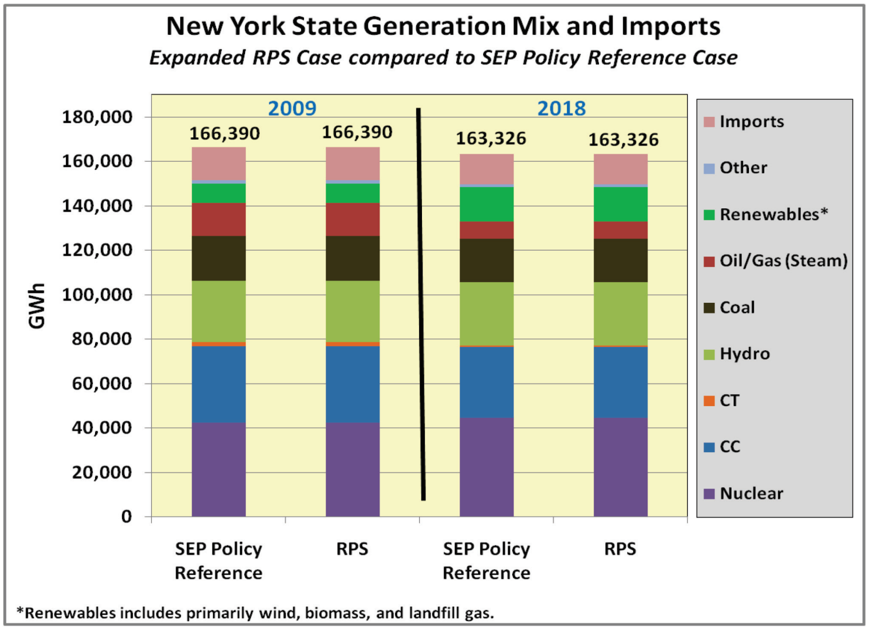
The original Public Service Commission (PSC) RPS order set a goal of increasing the proportion of renewable electricity used by New York consumers from the 2004 level of 19.3 percent to at least 25 percent by 2013. To help achieve this objective, the PSC order established a Main Tier[3] goal of 9,854,038 MWh new renewable generation by 2013, based on the forecast of future load applicable at that time. Subsequently, the State established a '15 by 15' policy goal to promote substantial decreases in electricity use through the implementation of various energy efficiency measures by 2015. The Expanded RPS scenario assumes that sustained and aggressive renewable energy expansion targets in New York are achieved in parallel with the pursuit of lower electricity load growth consistent with the '15 by 15' policy goal.

Therefore, this scenario evaluates the potential impacts of expanding the current RPS goal to increase the proportion of renewable electricity used in New York to 30 percent by 2015, as proposed by Governor Paterson in his 2009 State of the State address. The 30 percent RPS scenario analyzed is defined based on an updated load forecast that assumes that the '15 by 15' policy goal is simultaneously achieved. As a result, the 30 percent RPS goal calls for 10,123,157 MWh of Main Tier renewable generation by 2015, a MWh target that exceeds the original 25 percent RPS target by 269,119 MWh (with two additional years to ramp up to it).

Because the absolute MWh target is not significantly increased by the 30 percent RPS proposal, modeling results indicate virtually no discernable changes in the generation mix, net imports, CO_2 emissions, CO_2 allowance prices, and wholesale electricity prices due to layering on the 30 percent RPS target values to the SEP Policy Reference case. Figure 21 shows the generation mix for both the Expanded RPS and SEP Policy Reference cases, which are not significantly different. These results exemplify the potential benefits available by simultaneously pursuing aggressive energy efficiency and renewable goals, thereby enabling renewable energy resources to provide a larger proportion of New York's electricity requirements without incurring additional costs to energy users.

[3] Large-scale generators that sell power to the wholesale grid such as large wind farms.

Figure 21. New York State Generation Mix and Imports



Information on the potential net retail impacts of the Expanded RPS scenario can be found in the section entitled "Analysis of Net Retail Price Impacts."

9 Plug-In Hybrid Vehicles

This scenario examines the potential impact of expanded use of plug-in hybrid electric vehicles (PHEV) in New York. The analysis assumed 100,000 PHEV sales per year, resulting in 1,000,000 PHEV in the State by 2018. The vehicle locations were distributed within the NYISO electric zones proportional to vehicle registration. Furthermore, it was assumed that each vehicle would be equipped with smart charge technology and charge at the rate of one kilowatt per hour between 10 pm to 7 am on weekdays and throughout the day on weekends. Each vehicle was assumed to have an electric demand of approximately 2,880 kWh per year[4] or eight kWh per day. This PHEV scenario is compared against both the Starting Point and the SEP Policy Reference cases.

PHEV Scenario Compared to the Starting Point Case in 2018. Relative to the Starting Point case, gas-fired generation increases by 1,684 GWh (four percent) and oil/gas steam generation increases by 135 GWh (two percent) under the PHEV scenario. Net imports also increase by 1,033 GWh (five percent). Net capacity additions are predicted to be virtually the same under both cases since the vehicles are assumed to be charged during off-peak hours when this load can be met by increasing the capacity factors of New York generators and with some additional imports. Relative to the Starting Point case, CO_2 emissions increase by 0.9 million tons and CO_2 allowance prices increase by $0.56 per ton in the PHEV scenario. As shown in Figure 22, the average New York wholesale electricity price is $1.15 per MWh (two percent) higher under the PHEV scenario.

PHEV Scenario Compared to the SEP Policy Reference Case in 2018. Compared to the SEP Policy Reference case, gas-fired generation increases by 2,006 GWh (six percent) and oil/gas steam generation increases by 113 GWh (one percent) under the PHEV scenario. Net imports also increase by 694 GWh (five percent). Again, net capacity additions are predicted to be virtually the same under both cases since the vehicles are assumed to be charged during off-peak hours when this load can be met by increasing the capacity factors of New York generators and with some additional imports during off-peak hours. Relative to the SEP Policy Reference case, CO_2 emissions increase by 1.0 million tons and CO_2 allowance prices increase by $0.26 per ton in the PHEV scenario. As shown in Figure 23, the average New York wholesale electricity price is $0.44 per MWh (one percent) higher under the PHEV scenario. The implementation of additional energy efficiency measures helps to counter the load growth associated with PHEVs and to mitigate the potential increase in wholesale electricity prices.

[4] Each vehicle is assumed to be driven 12,000 miles per year, of which 80 percent would be in the electric vehicle mode with vehicle efficiency (kwh/mi) of 30 percent. Each vehicle would recharge 100 percent daily.

Figure 22. New York State Firm Power Prices Related to Starting Point Case

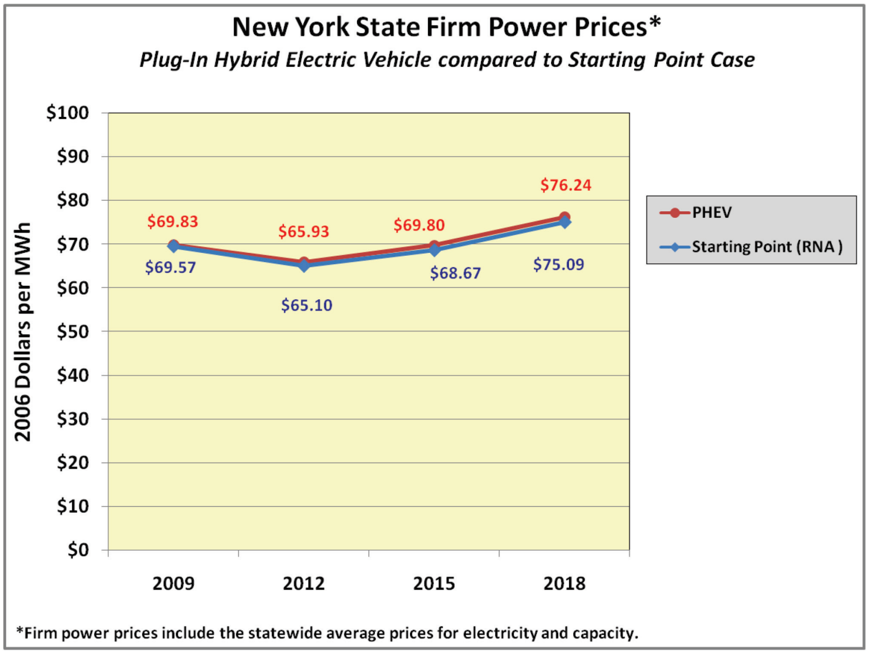
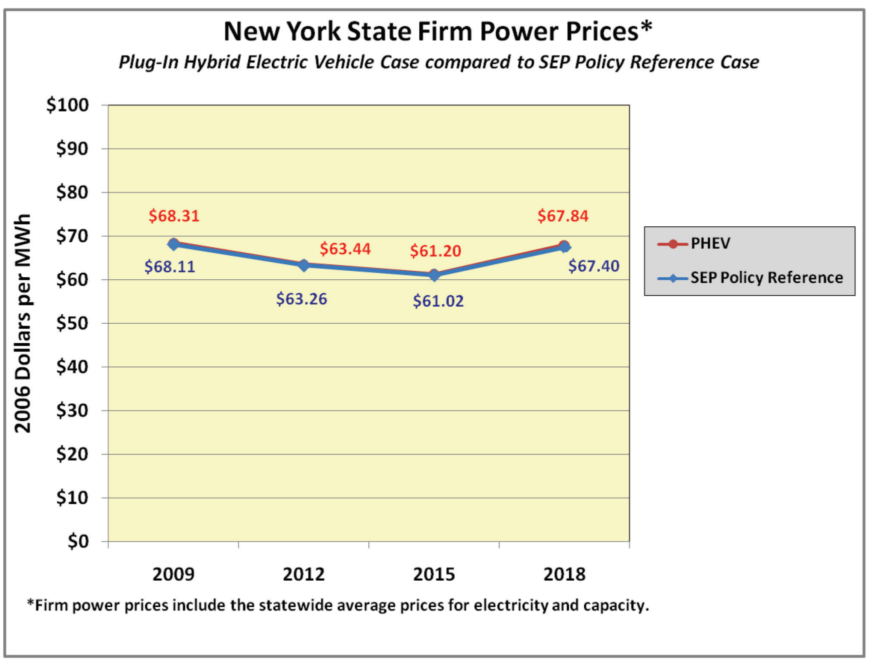


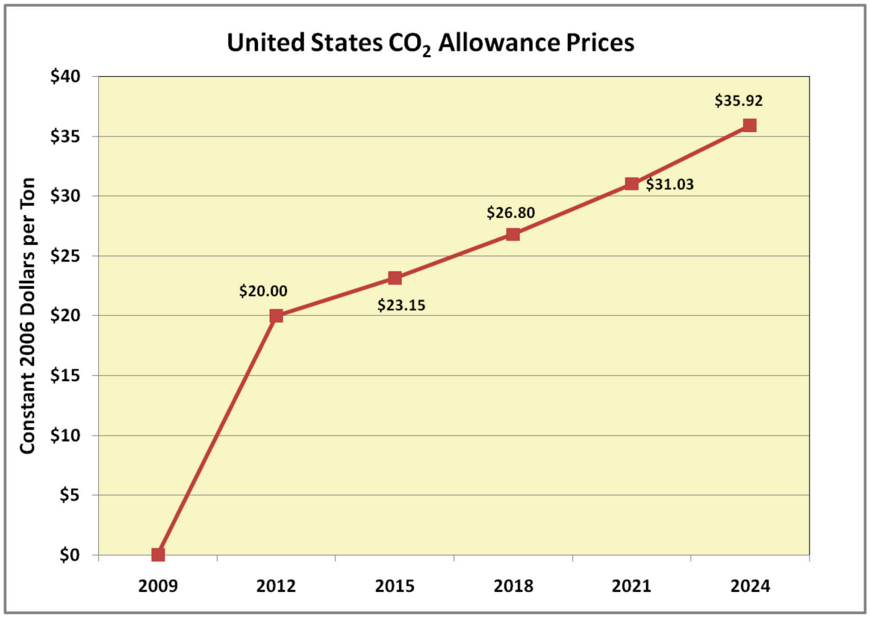
Figure 23. New York State Firm Power Prices Related to SEP Policy Reference Case



10 *Federal Carbon Policy*

The potential impact of a relatively strong federal carbon policy, effective beginning in 2015, was estimated by assuming that all CO_2 emissions from the electricity sector (nationwide) must be offset by the purchase of emission allowances valued at $23 per ton in 2015, increasing to $36 per ton by 2024. The series of CO_2 allowance prices assumed is shown in Figure 24. Although the hypothetical federal carbon policy is assumed to be implemented in 2015, values for CO_2 allowances are shown beginning in 2012 due to the fact that expectations of future prices would begin to change behavior before the program is implemented. The federal carbon policy modeled was not reflective of any specific proposal, but was intended to evaluate the impact of allowance prices from approximately the middle of the range of values that could result under various proposals that have been discussed. In this analysis, the price of CO_2 allowances in a national market is a data input to the IPM model, analogous to a higher cost of fuel. This approach differs from the methodology used in all other Reference case and policy scenario runs, in which aggregate CO_2 emissions are constrained to the level specified by the RGGI regional emission cap, and the resultant price of CO_2 allowances is a model output, not a data input. This methodology implicitly assumes that the federal carbon policy would subsume the regional impacts of RGGI due to the fact that the input allowance prices are substantially higher than those expected under the existing regional emission cap established by RGGI. The following discussion of the impacts of a federal carbon policy focus on 2024 is significantly beyond the 10-year planning period normally addressed in the Plan, because focus on 2018 does not provide sufficient time for the effects of a hypothetical policy implemented in 2015 to become substantially evident. However, for consistency and completeness, the graphics presented below show results for both 2018 and 2024.

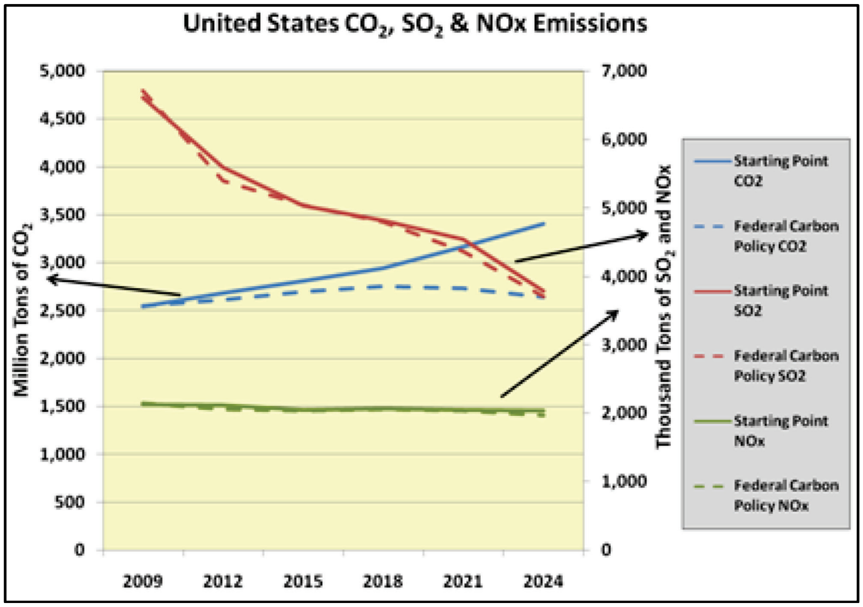
Figure 24. United States CO_2 Allowance Prices



10.1 **Impacts of a Federal Carbon Policy on the United States**

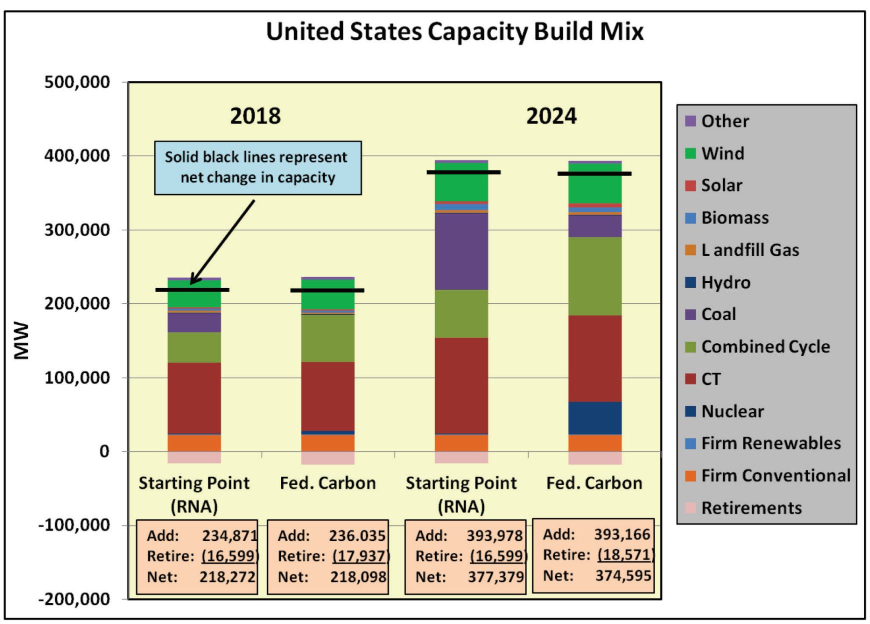
To evaluate the impacts of a federal carbon policy on New York, it is first necessary to evaluate the impacts on the United States as a whole. The projected impact of a federal carbon policy on U.S. CO_2 emissions, based on the allowance price assumptions from Figure 24, is shown in Figure 25. In the Starting Point Case without the federal carbon policy, from 2009 to 2024, U.S. CO_2 emissions increase by about 764 million tons, or 37 percent. The federal carbon policy modeled has the effect of approximately stabilizing U.S. CO_2 emissions at the 2009 level, equivalent to establishing a carbon cap at current levels of emissions.

Figure 25. United States CO_2, SO_2 & NO_x Emissions



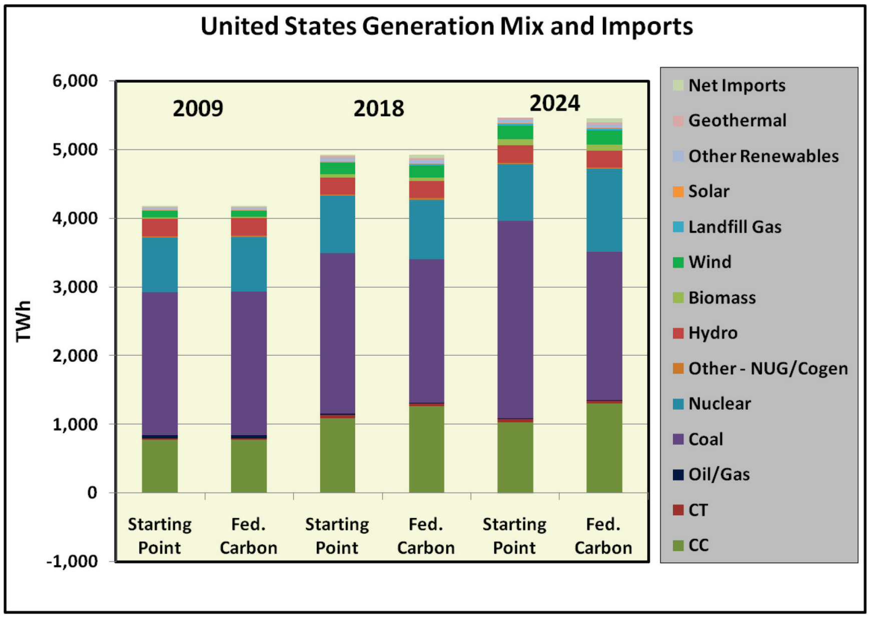
The federal carbon policy causes substantial changes in the types and quantities of new capacity projected to be added in the United States over the next two decades. As shown in Figure 26, in 2024, cumulative new coal capacity is 74,000 MW or 72 percent lower with the federal carbon policy compared to without it. The federal carbon policy causes cumulative new natural gas capacity to be 28,000 MW greater or 14 percent more than the amount without it. The federal carbon policy also results in about 40,000 MW of additional new nuclear capacity being built.

Figure 26. United States Capacity Build Mix



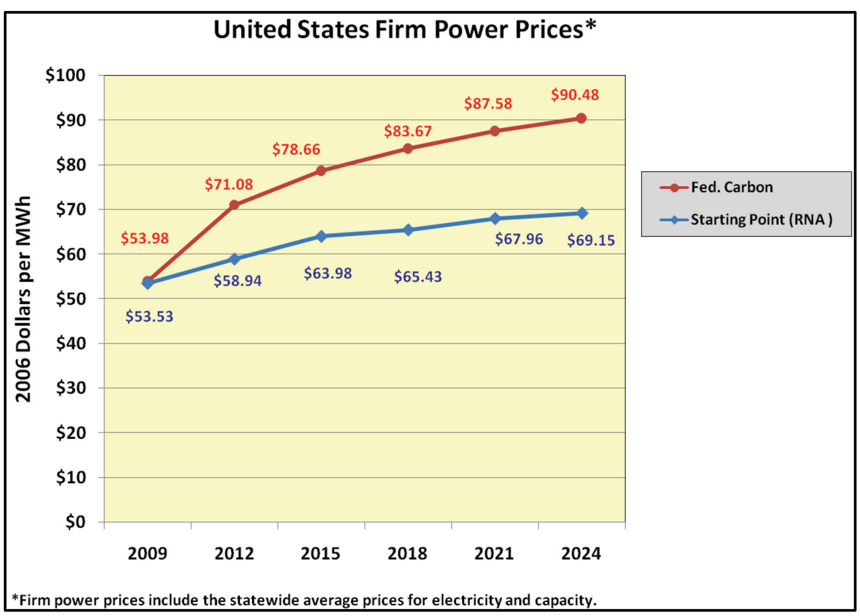
The federal carbon policy causes substantial changes in the U.S. generation mix, as shown in Figure 27. In 2024, the carbon policy causes coal generation to be reduced by 24 percent, while natural gas combined cycle and nuclear generation are increased by 27 and 44 percent, respectively, compared to what would be expected to occur without the policy.

Figure 27. United States Generation Mix and Imports



The federal carbon policy causes a substantial increase in the average U.S. wholesale price of electricity, as shown in Figure 28 . In 2024, the U.S. wholesale price of electricity is $21.33 per MWh or 31 percent higher as a result of the carbon policy.

Figure 28. United States Firm Power Prices



10.2 Impacts of a Federal Carbon Policy on New York

The modeling results discussed below indicate that a federal carbon policy would be likely to have substantial impacts on New York's capacity build mix, generation mix, CO_2 emissions, and wholesale electricity prices. For the analysis of a federal carbon policy, the construction of new nuclear plants in New York was allowed as an economic choice for meeting projected capacity needs. Results are shown based on both the Starting Point and SEP Policy Reference cases, demonstrating clearly that the federal carbon policy has substantially lower impacts on New York if the goals of the '15 by 15' policy are fully achieved.

In general, the federal carbon policy causes:

- Additional plant retirements, repowering of oil/gas steam units, and construction of new nuclear units
- Reduced generation from coal, oil and natural gas-fired units and more generation from nuclear units
- Lower CO_2 emissions
- Higher electricity prices; however, because U.S. prices increase more than New York prices, the price differential between New York and the U.S. is reduced

Federal Carbon Policy Compared to Starting Point Case—New York (Figure 29, Figure 30, *Figure* 31 *and Figure* 32 *).* By 2024, cumulative plant retirements increase by about 600 MW, repowering of oil/gas steam units increases by 236 MW, and new nuclear units increase by 1,100 MW. Coal, natural gas combined cycle, and oil/gas steam unit generation decrease by 3,167, 4,183, and 1,586 GWh, respectively, while nuclear generation increases by 9,299 GWh. In 2024, New York's CO_2 emissions are reduced by 7.0 million tons, while the wholesale price of electricity is increased by $16.40 per MWh or 20 percent.

Figure 29. New York State Capacity Build Mix

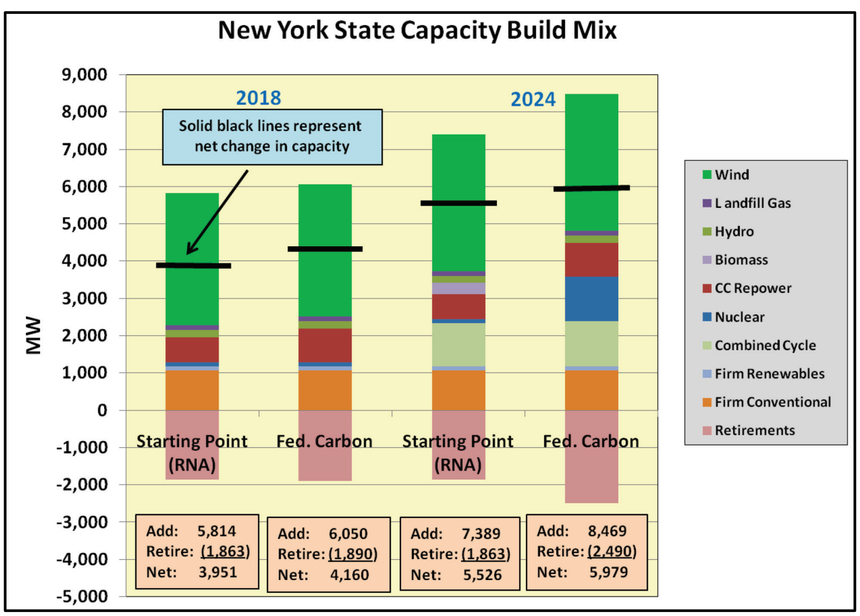


Figure 30. New York State Generation Mix and Imports

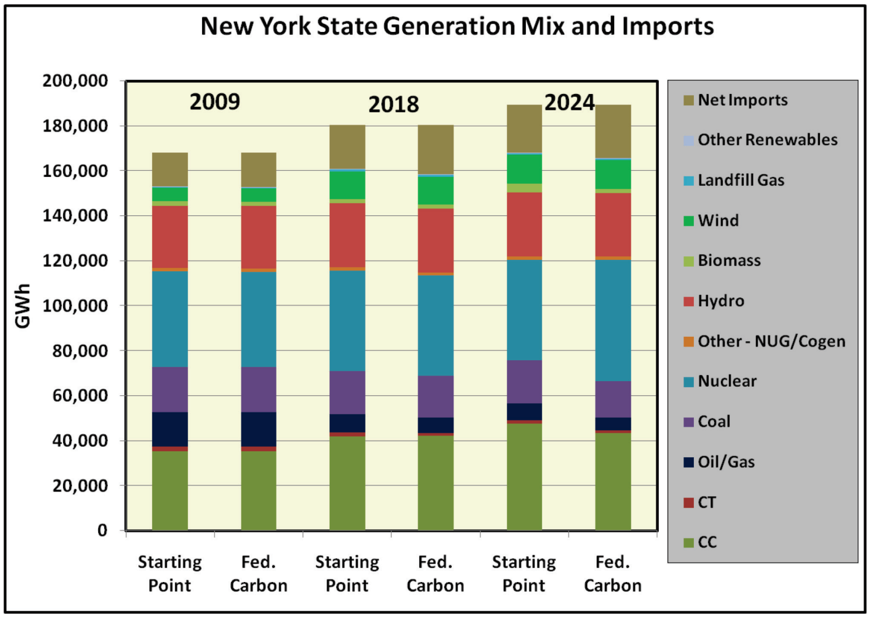


Figure 31. New York State CO_2, SO_2 & NO_x Emissions

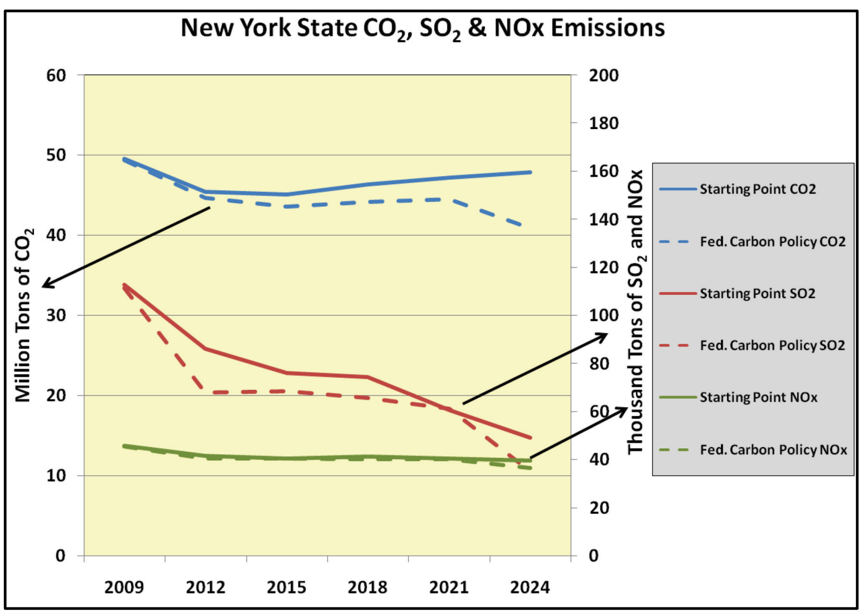
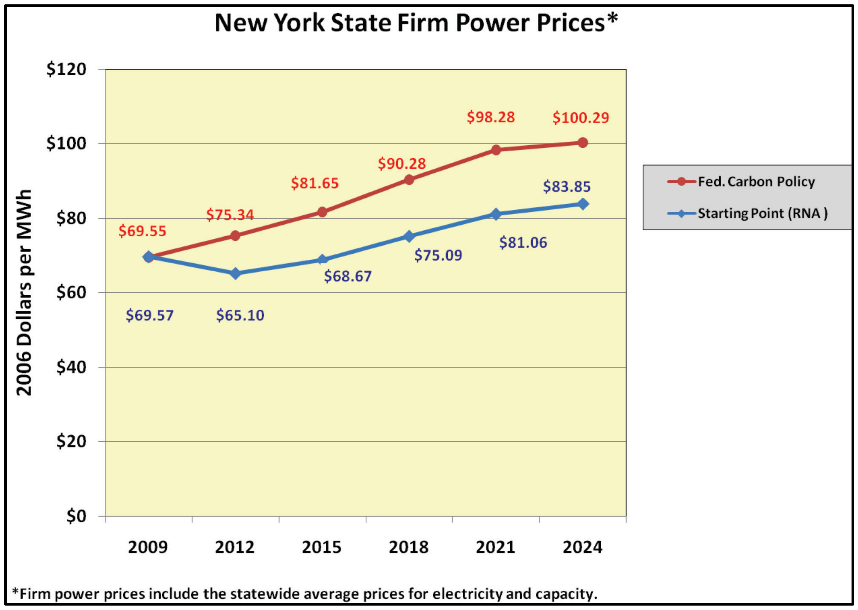


Figure 32. New York State Firm Power Prices



Federal Carbon Policy Compared to SEP Policy Reference Case—New York (Figure 33, Figure 34, *Figure* 35 *and Figure* 36*).* By 2024, cumulative plant retirements increase by about 178 MW, repowering of oil/gas steam units increases by 236 MW, and new nuclear units increase by 530 MW. Coal, natural gas combined cycle, and oil/gas steam unit generation decrease by 3,966, 3,374, and 1,416 GWh, respectively, while nuclear generation increases by 4,481 GWh. In 2024, New York's CO_2 emissions are reduced by 7.2 million tons, while the price of electricity is increased by $20.30 per MWh or 26 percent.

Figure 33. New York State Capacity Build Mix

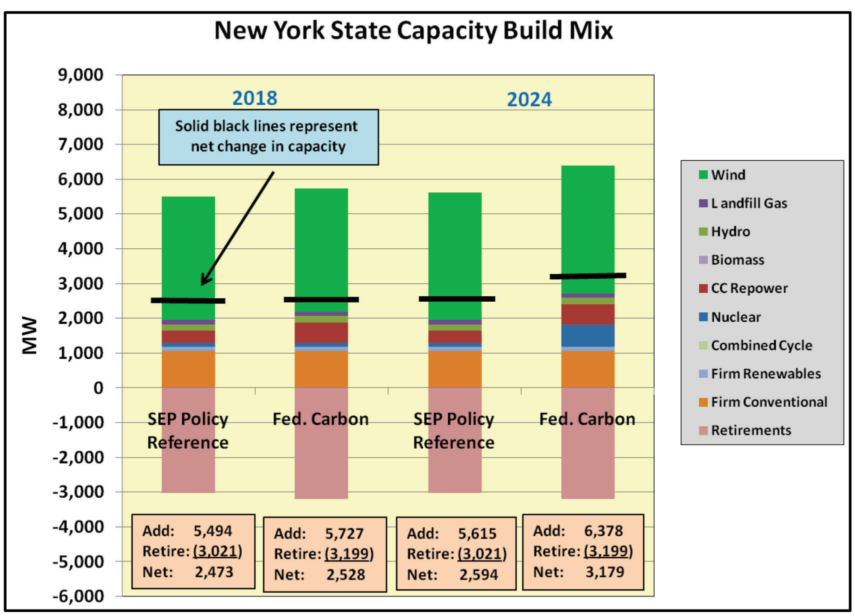


Figure 34. New York State Generation Mix and Imports

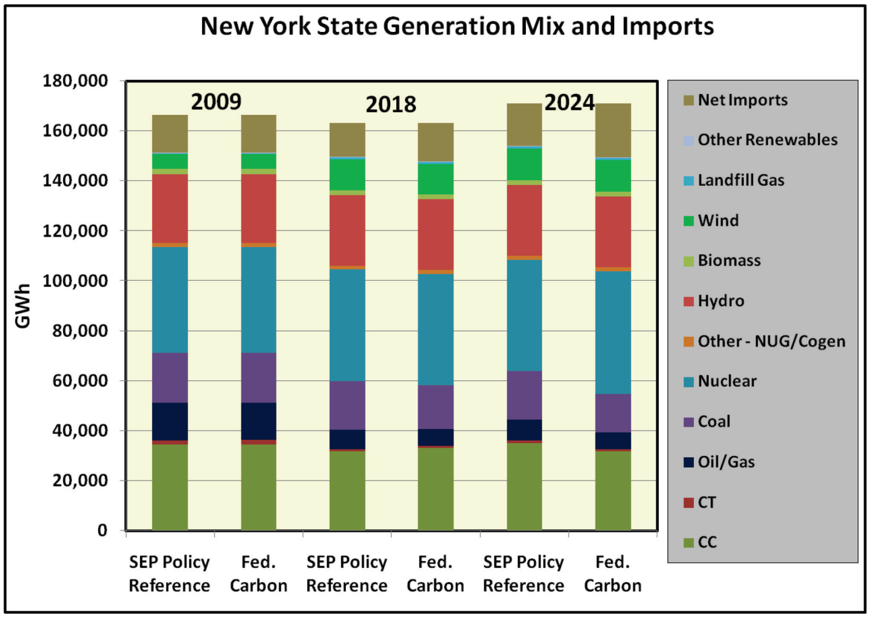


Figure 35. New York State CO_2, SO_2 & NO_x Emissions

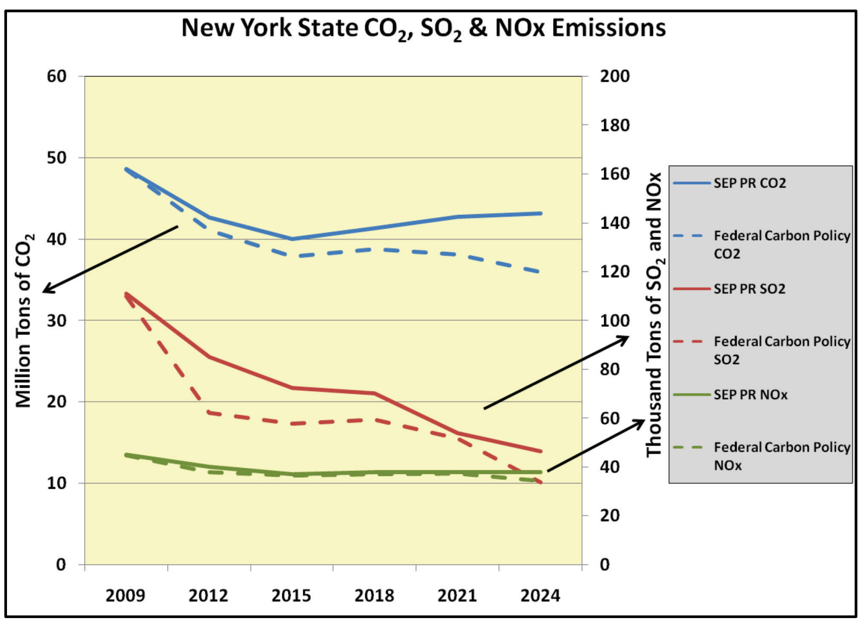
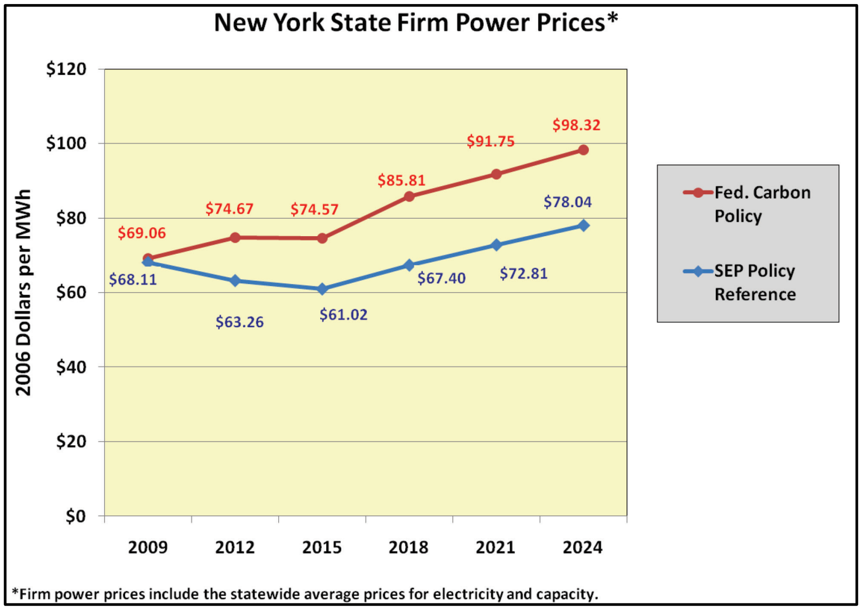


Figure 36. New York State Firm Power Prices



The overarching impact of the federal carbon policy on New York is that it reduces the price differential between New York and the United States, as illustrated in Figure 37 and Figure 38. The federal carbon policy increases electricity prices both in the United States and New York, but the price increases in other states (thereby increasing the U.S. average price) are larger than the increases in New York due to higher proportions of more carbon-intensive coal generation. Figure 37 shows that, in 2024, in the Starting Point case, New York's wholesale electricity price is $14.69 per MWh or 21 percent higher than the United States. This differential is reduced to $9.81 per MWh or 11 percent higher than the United States when the federal carbon policy is implemented.

The potential impact of the federal carbon policy on New York is most emphatically illustrated in Figure 41, which shows New York with the SEP Policy Reference case that includes full achievement of the '15 by 15' energy efficiency goal. By 2015, the combined impacts of the '15 by 15' policy and the federal carbon policy result in New York's average electricity price reaching a point that is lower than the average U.S. price. While Figure 38 shows New York's average electricity price again exceeding the U.S. price in 2018 through 2024, this result is largely due to the electricity use forecast assumptions that do not assume '15 by 15' efficiency program expenditures beyond 2015, whereby electricity load is assumed to grow at pre-'15 by 15' annual growth rates. The implication is that if the types of programs implemented to achieve the '15 by 15' policy goal are continued and possibly intensified in the years following achievement of the initial policy goal in 2015, the federal carbon policy could have the effect of causing New York's electricity prices to remain lower than average U.S. prices through 2024. This could be a strong positive force in encouraging future economic development and growth in New York.

Figure 37. US and New York State Firm Power Prices

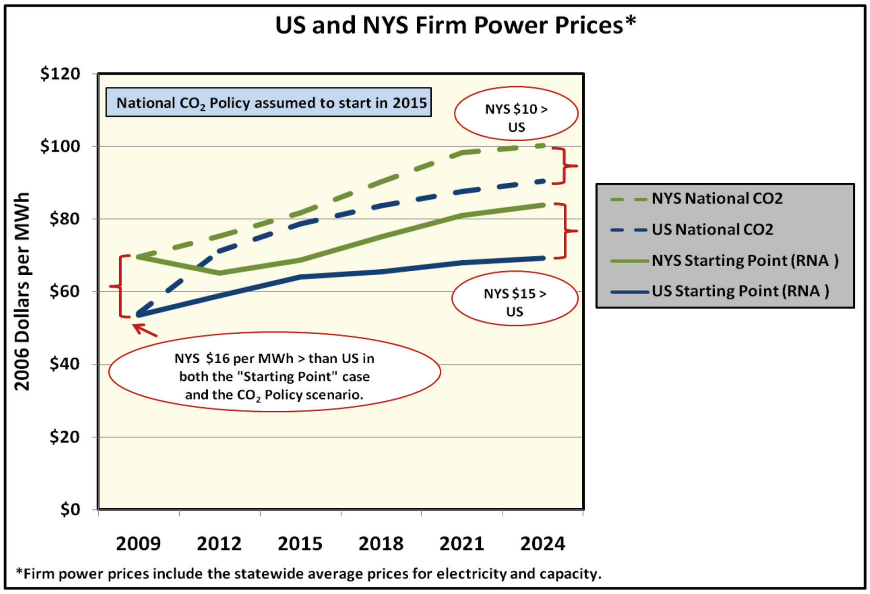
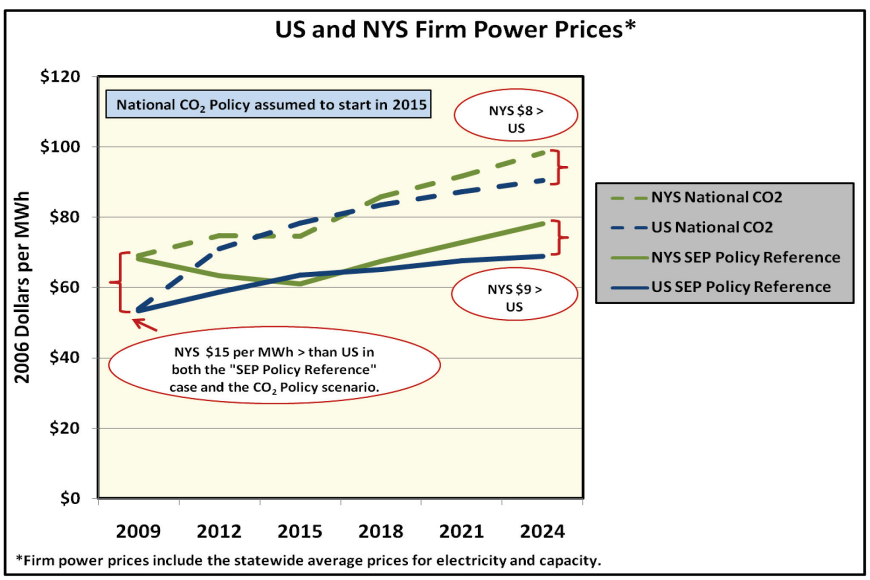


Figure 38. US and New York State Firm Power Prices



11 Analysis of Net Retail Price Impacts

The IPM provides projections of the potential impacts that a scenario may have on *wholesale* electricity prices. To better understand the possible *retail* price impacts of policies like the RPS or the EEPS, other information must be considered. This section combines modeling results with additional data to obtain a better understanding of retail price impacts for the following cases and scenarios:

- SEP Policy Reference Case (EEPS case)
- Expanded RPS Scenario
- IP Retirement Scenario
- Additional Nuclear Unit Scenario
- HQ Transmission Expansion Scenario
- Upstate to Downstate New York Transmission Expansion Scenario
- Combined Transmission Expansion Scenario

11.1 Net Rate Impact of the SEP Policy Reference Case (EEPS Case)

Achieving the '15 by 15' policy goal by full implementation of the EEPS is expected to reduce the net retail price of electricity paid by all ratepayers by 2015. Figure 39 and Figure 40 show the results of an analysis of the net impacts of the '15 by 15' policy on statewide average retail electricity prices in selected years. As shown in Figure 39, in 2015, the statewide average retail price of electricity is projected to be 0.4 to 0.9 cents per kWh lower, on a net basis, than if the '15 by 15' policy were not implemented. Figure 40 indicates that this estimated reduction in net price per kWh is equivalent to aggregate annual bill savings to ratepayers of $600 million to $1.4 billion in 2015.

Figure 39. Estimated Statewide Average Retail Price Impact of Achieving the EEPS

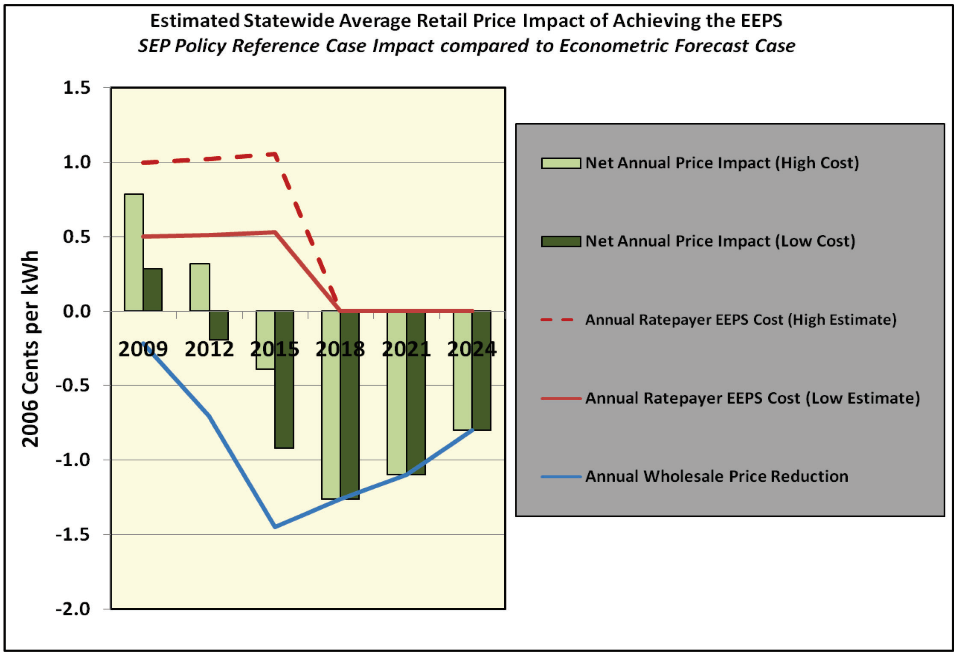
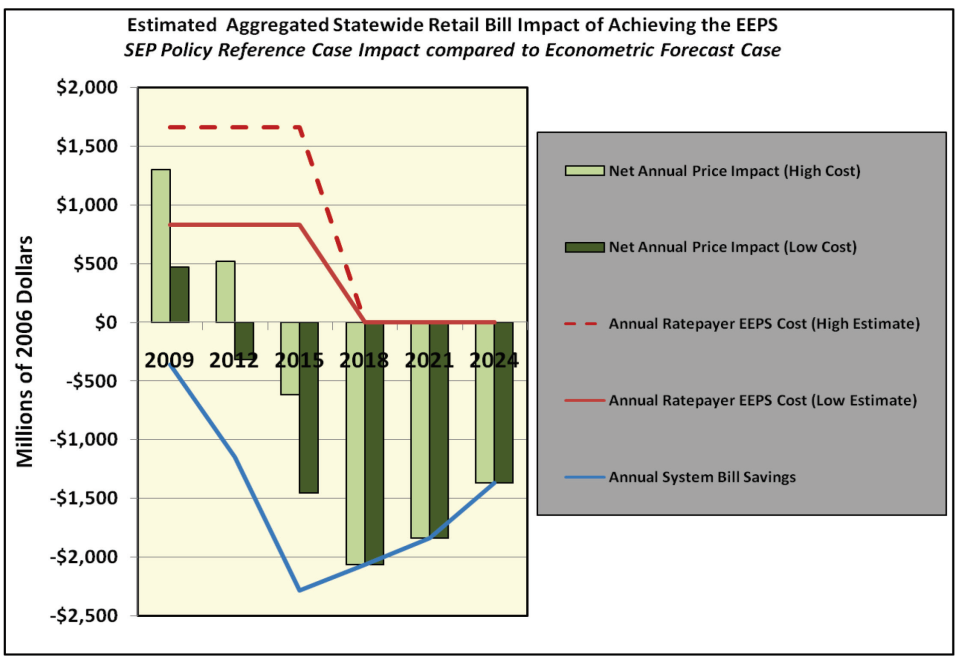


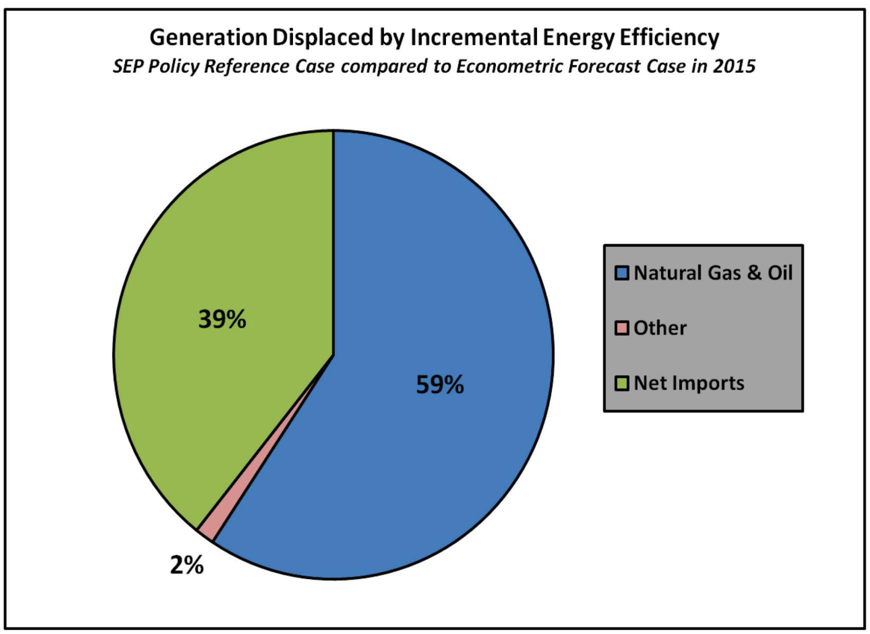
Figure 40. Estimated Aggregated Statewide Retail Bill Impact of Achieving the EEPS



Pursuing the '15 by 15' policy goal impacts average retail electricity prices in two opposing ways. First, the average retail price is expected to increase because the annual cost of implementing and administering energy efficiency programs is added to customer bills. Second, the commodity portion of the electricity price is expected to decrease as a result of the price reduction effect of lower overall demand for electricity. Both types of price impacts affect ALL ratepayers (assuming that energy efficiency program costs are averaged across all customer classes and locations). This analysis does not include the additional bill savings that accrue to program participants who install energy-saving equipment and thereby benefit as a result of reduced volume of electricity purchased over time.

The price reduction impact of achieving the '15 by 15' policy goal is extracted directly from IPM modeling results by comparing the statewide average electricity prices in the SEP Policy Reference Case (which assumes full achievement of the '15 by 15' policy goal) to the Higher Demand Scenario (based on the NYISO's Econometric Forecast, which includes no downward adjustments for implementation of the '15 by 15' policy goal). The lower average electricity prices in the SEP Policy Reference Case are directly attributable to achievement of the '15 by 15' policy goal, due to the reduction in the need for electricity generated by the most inefficient and expensive fossil fuel-fired units, as well as by reducing imports of electricity from outside New York. As shown in Figure 41, the avoided electricity due to implementation of the '15 by 15' policy in 2015 is projected to be comprised of 59 percent oil and gas, 39 percent imports, and two percent various other sources.

Figure 41. Generation Displaced by Incremental Energy Efficiency



Because the annual costs to ratepayers of the programs needed to achieve the '15 by 15' policy goal are not yet known with any certainty, "low" and "high" estimates are used to bound the analysis. The low estimate is based on a three- year historical average (2006 through 2008) of NYSERDA's energy efficiency programs funded through the System Benefits Charge (SBC). The high estimate assumes that the future cost of energy efficiency programs on a cents per kWh basis is double the cost of programs implemented to-date. The expected system load reduction due to improved Codes and Standards is assumed to be achievable with no incremental cost to ratepayers.

11.2 Net Rate Impact of the Expanded Renewable Portfolio Standard (RPS) Scenario

Similar to the EEPS, the RPS impacts electricity rates in two ways. First, the delivery rate increases because money will be collected from ratepayers through a fixed charge on utility bills to fund the program through 2024. NYSERDA will use these funds to pay production-based incentives to renewable generators that provide environmental attributes ("RPS Attributes") created by the generation of electricity by eligible renewable resources under long-term contracts. In exchange for receiving the production incentives, the renewable generator provides NYSERDA all rights and/or claims to the RPS Attributes associated with each MWh of renewable electricity generated and delivered to New York State. Second, the commodity portion of the rate decreases as a result of the price reduction effect of adding renewable generation to the New York State electricity mix. In both cases, these rate changes impact ALL ratepayers.

As shown in Figure 42 and Figure 43, building renewable resources to achieve the goals of the RPS is expected to *reduce the net retail price of electricity paid by all ratepayers*. Figure 45 indicates that, in 2018, the average statewide retail price of electricity is projected to be 0.06 to 0.16 cents per kWh lower than it would otherwise be if the RPS did not exist. Figure 46 indicates that this estimated reduction in net price per kWh is equivalent to aggregate annual bill savings to ratepayers of $93-262 million. The estimated net retail price impact includes a *reduction in the wholesale commodity price* of electricity of 0.26 cents per kWh, netted against the estimated *retail price increase* of 0.10 to 0.20 cents per kWh, due to the collection of ratepayer funds to pay the price premium for the purchase of renewable energy under the RPS.

Figure 42. Estimated Statewide Average Retail Price Impact of Achieving the 30 Percent RPS

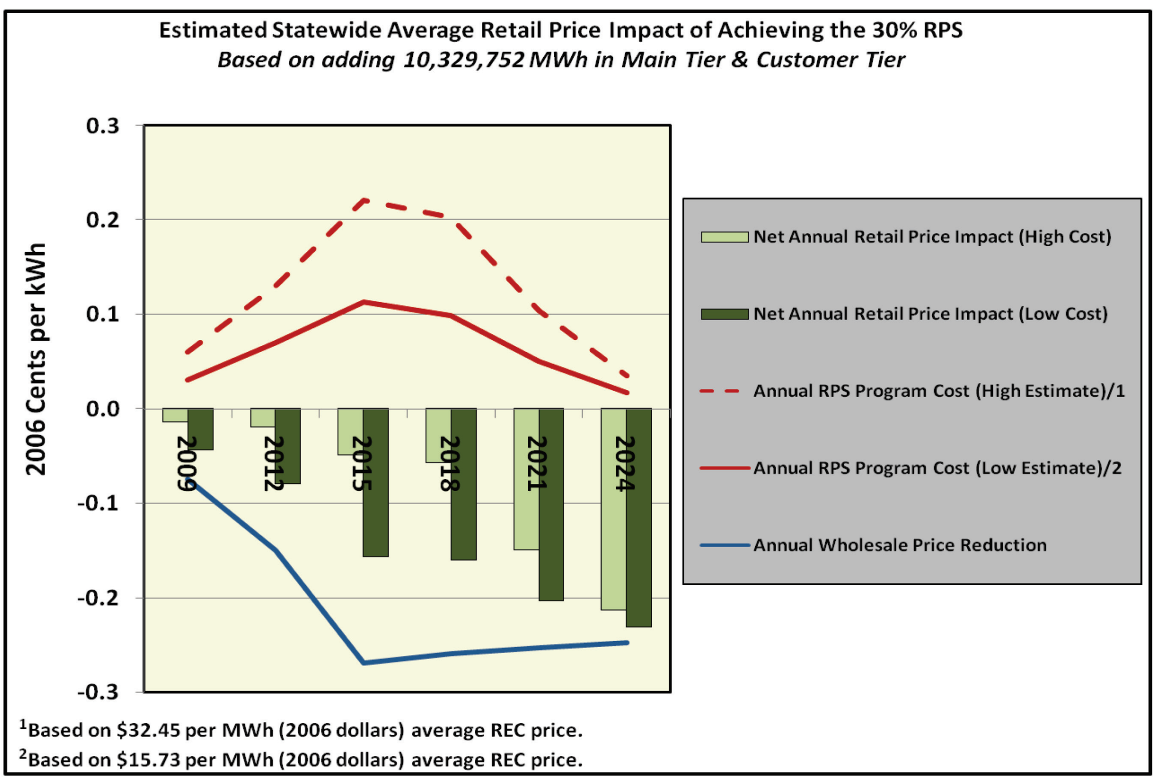
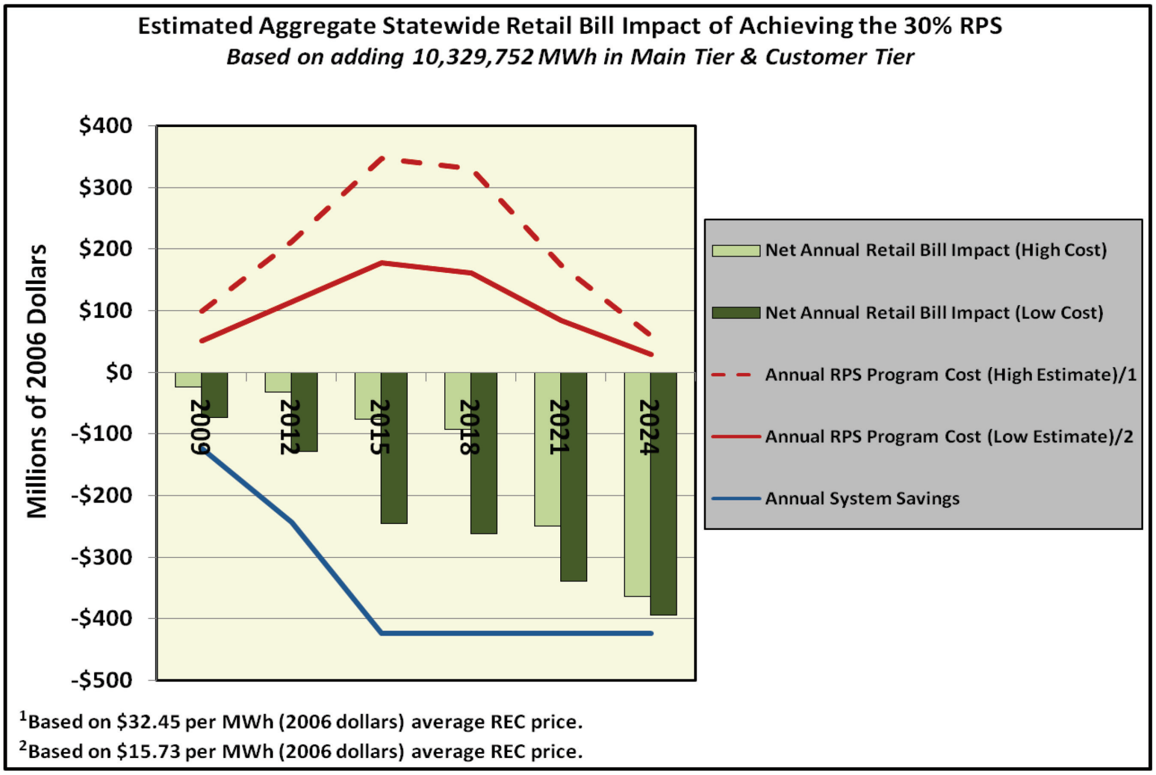


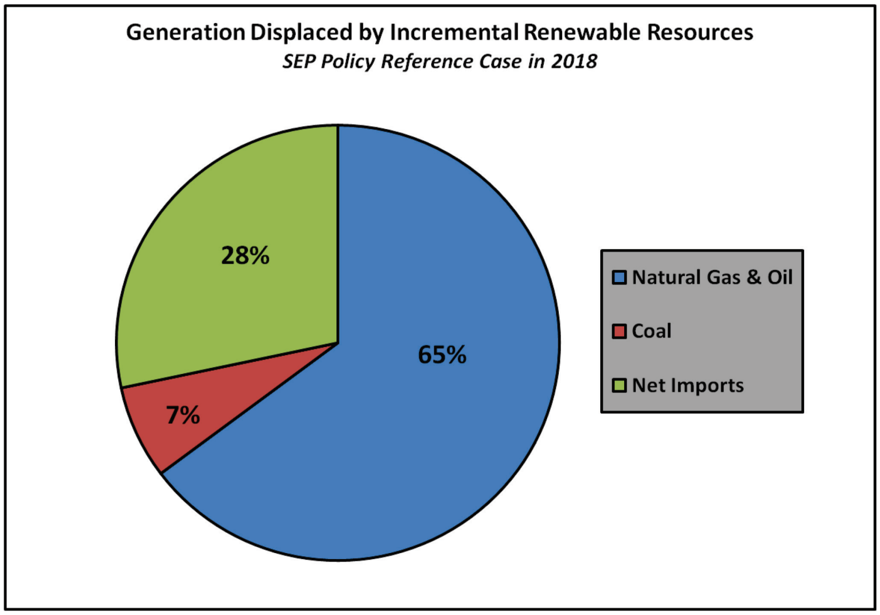
Figure 43. Estimated Aggregate Statewide Retail Bill Impact of Achieving the 30 Percent RPS



The reduction in statewide wholesale electricity prices or *price reduction* due to implementation of renewable resources is extracted directly from electricity sector modeling runs performed as part of the Electricity Assessment using the IPM, a proprietary linear programming model developed by ICF Resources International. The reduction in wholesale prices is based on achieving the 30 percent RPS goal by adding 10,329,752 MWh of "Main Tier" and "Customer Tier" renewable resources by 2015, assuming that the '15 by 15' energy efficiency goal is also met by 2015. Implementation of renewable resources reduces the average wholesale price of electricity by reducing the need for electricity generated by the most inefficient and expensive fossil fuel-fired units, as well as by reducing imports of electricity from outside New York.

As shown in Figure 44, it is estimated that about 65 percent of the electricity displaced by the renewable resources implemented to meet the RPS are natural gas and oil-fired (includes both steam and combined cycle units), about seven percent is coal-fired, and about 28 percent is imports.

Figure 44. Generation Displaced by Incremental Renewable Resources



Because the precise amount of money needed to meet the RPS goal is uncertain, both "low" and "high" cost estimates are calculated as analytical boundaries. Both low and high estimates are based on NYSERDA's preliminary analysis to update the RPS cost estimates ("2009 Update"). The 2009 Update builds a theoretical "bid stack" of participant bids for each year through 2015. Each bidder is assumed to bid their minimum bid price necessary to ensure the individual project's viability and produce a reasonable rate of return to investors. The lowest priced bids are accepted first, and so on, until the annual targets are achieved. The highest priced bid accepted in a given year is deemed the “clearing” price. The low cost estimate assumes all accepted bidders receive their “as bid” bid price only. The high cost estimate assumes the clearing price is paid to all bidders. The actual program cost is likely to settle somewhere between the two estimates presented, because some bidders are likely to bid higher than their minimum monetary requirements, but all bidders are unlikely to be paid as high as the clearing prices calculated. Also included in both the "low" and “high" cost estimates are projected "Customer Tier" program costs and estimated program administrative expenses, which were also extracted from the "2009 Update".

11.3 Combined Rate and Bill Impacts of the EEPS and RPS

Figure 45 and Figure 46 show the combined rate and bill impacts of meeting both the EEPS and RPS program goals. Two bars for each year are presented to reflect both the "low" and "high" program cost estimates (described above), respectively.

Figure 45. Net Rate Impact of EEPS and RPS

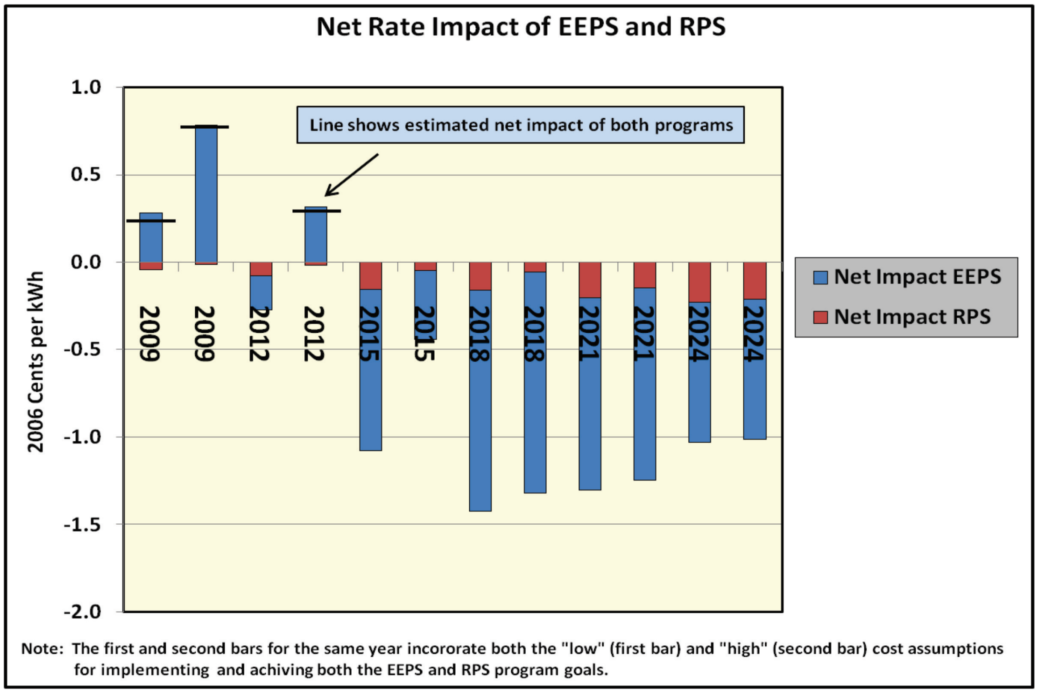
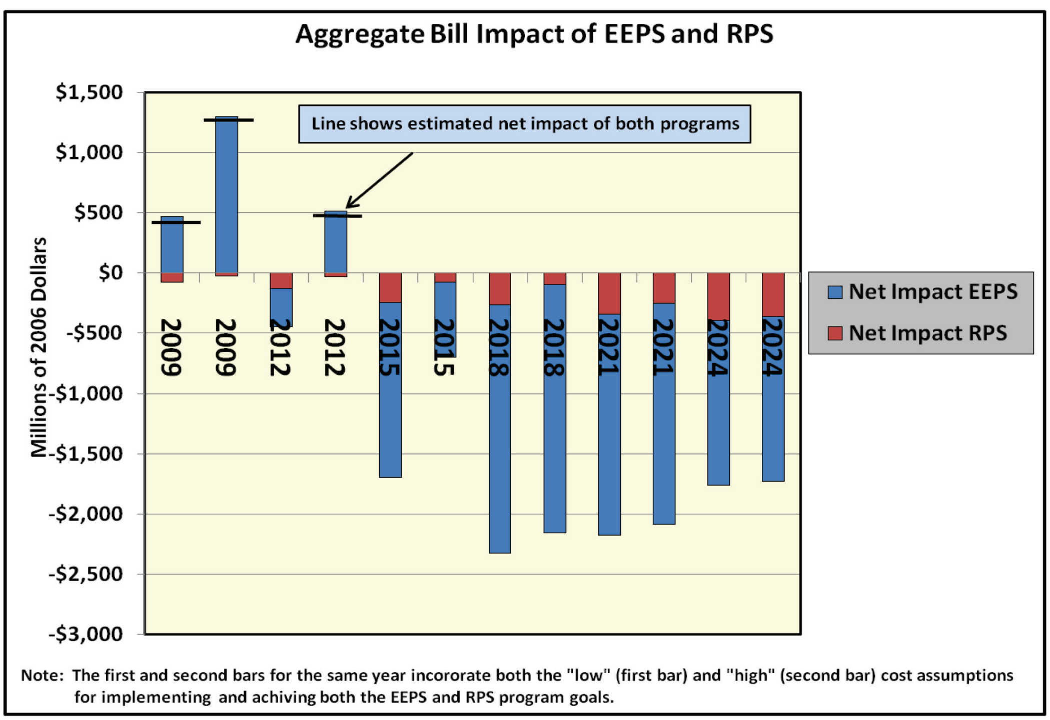


Figure 46. Aggregate Bill Impact of EEPS and RPS



11.4 Net Rate Impact of the Indian Point Retirement Scenario

Under both the Starting Point and SEP Policy Reference Case load scenarios, the IPM model built a new gas combined cycle plant in response to a potential Indian Point retirement scenario (an 1,800 MW unit was added under the former scenario and a 700 MW unit was added under the latter). The modeling results described earlier in this Electricity Assessment projected the changes in wholesale firm power prices, however, the model does not capture the necessary infrastructure required to connect the new plant to the gas pipeline. Additional research, beyond this assessment, is required to determine the actual infrastructure requirements. However, for the purpose of this analysis, it was assumed that the new combined cycle plant would be located at or near the existing Indian Point site and that the plant would be connected to the Algonquin pipeline. The cost of the primary infrastructure component, the gas compressor station, was estimated to be in the range of $25 to $55 million (for a 10,000 horsepower compressor station). This additional cost, when amortized across twenty years, results in a minimal incremental retail $/kWh cost impact.

11.5 Net Rate Impact of the Additional Nuclear Unit Scenario

The operating reserve requirements for the NYISO are based upon the value of the largest single contingency for the control area. Currently, the largest single contingency is 1,200 MW. Under this modeling scenario, a 1,600 MW nuclear plant was added at the Oswego site. Such an addition would increase the largest single contingency for the NYISO control area and increase the operating reserve requirements. A number of factors would need to be considered to determine what the new operating reserve requirement would be and to estimate the cost for acquiring them. Such analysis is beyond the scope of the IPM model and the analysis for this report.

11.6 Net Rate Impact of the Transmission Expansion Scenarios

Three transmission expansion scenarios were evaluated using IPM. The costs associated with the construction of the transmission lines in these scenarios are not reflected in the wholesale electricity price output by the IPM model. To assess these additional impacts on retail rates, high level construction cost estimates were established for each scenario. Information from the New York City Economic Development Corporation's report entitled "A Master Electrical Transmission Plan for New York City" and from the New York State Department of Public Service was used to create high and low cost estimates for each transmission expansion scenario. Table 12 contains a summary of the construction cost estimates for the Hydro-Quebec (HQ), Upstate to Downstate NY, and Combined Transmission Expansion scenarios described earlier in this section:

Table 12. Transmission Expansion Scenarios: Construction Cost Estimates

Expansion Scenario	Basic Project Assumptions	Low Estimate (2006 dollars)[5]	High Estimate (2006 dollars)[5]
HQ to NY	• 1,000 MW capacity • HVDC • 60 mile distance from HQ to Massena	$565 million	$820 million
Upstate to Downstate	• 1,200 MW capacity • HVDC • 300 mile distance Massena to NYC	$1.6 billion	$2.0 billion
Combined	• Combination of the previous two projects	$2.2 billion	$2.8 billion

Table 13 and Table 14 show the average retail price impacts of the three transmission scenarios during the 2015 to 2024 time horizon. Table 10 reflects the retail impacts of each transmission expansion scenario under the Starting Point (RNA) load forecast while Table 11 shows the impacts under the SEP Policy Reference Case (EEPS) load forecast.

In both figures, row A represents the estimated range of costs associated with the levelized capital costs of each respective transmission project. The values are different in each figure because the load forecasts are different (i.e, the costs are spread over fewer kWh in the SEP Policy Reference case). Row B reflects the average impact on wholesale electricity prices caused by the addition of that project. These values are derived using the output from the IPM model that was described in earlier sections of the Electricity Assessment. Row C shows the net retail impacts (essentially the summation of the impacts in Rows A and B).

[5] Both high and low cost estimates include direct costs, indirect costs, contractor risks and fees and contingency costs.

Table 13. Average Retail Price Impact: Starting Point Case

Average Retail Price Impact in 2015, 2018, 2021, & 2024 Run Years: Starting Point Case *(2006 Cents per kWh)*			
	HQ - Upstate (1,000 MW)	**Upstate - Downstate (1,200 MW)**	**Combined Transmission**
A) Price Impact of Project Cost (Low & High Estimate)[6]	**0.044 to 0.064**	**0.123 to 0.151**	**0.167 to 0.215**
B) Average Impact of Project on Wholesale Prices	**0.0506**	**(0.319)**	**(0.260)**
C) Net Price Impact of Project (Low & High Cost Estimates)	**0.094 to 0.114**	**(0.196) to (0.168)**	**(0.093) to (0.045)**

Table 14. Average Retail Price Impact: SEP Policy Reference Case

Average Retail Price Impact in 2015, 2018, 2021, & 2024 Run Years: SEP Policy Reference Case *(2006 Cents per kWh)*			
	HQ - Upstate (1,000 MW)	**Upstate - Downstate (1,200 MW)**	**Combined Transmission**
A) Price Impact of Project Cost (Low & High Estimate)[6]	**0.049 to 0.070**	**0.137 to 0.168**	**0.185 to 0.238**
B) Average Impact of Project on Wholesale Prices	**0.065**	**(0.171)**	**(0.058)**
C) Net Price Impact of Project (Low & High Cost Estimates)	**0.114 to 0.135**	**(0.035) to (0.003)**	**0.127 to 0.180**

In summary, the Upstate to Downstate Transmission Expansion project shows net benefits under both the Starting Point and SEP Policy Reference load forecast scenarios, i.e., the net rate impacts are negative. The retail benefits are less substantial on a $/kWh basis under the SEP Policy Reference Case primarily because the project provides less wholesale commodity price reduction under a scenario where statewide load has been dramatically decreased through the implementation of the EEPS. The HQ Transmission Expansion project does not show net benefits for New York under either load forecast scenario. The analysis shows a net benefit from the Combined Transmission Expansion scenario under the Starting Point (RNA) load forecast. The project does not appear to provide net benefits to New York under the SEP Policy Reference Case because the reduction of wholesale commodity prices is much lower under this scenario because statewide load has been dramatically decreased through the implementation of the EEPS.

This analysis of projected retail price impacts of transmission projects is based on future infrastructure developments that are known with some degree of certainty (per coordination with NYISO system

[6] Assumes a carrying charge rate of 12.95 percent over a 20-year time horizon.

planning) and generic transmission project costs that could be significantly different in the event of specific projects that may be proposed over the planning period. Costs of transmission projects could vary widely depending on precise locations, distances, sizing, engineering design, and integration with existing infrastructure and equipment. The net costs and/or benefits to ratepayers of actual projects could be highly dependent on negotiated long-term contractual agreements among specific parties, other generation, transmission, and natural gas infrastructure that is built or retired (both in New York and in neighboring regions), and significant additions to energy supply (such as potential large-scale hydro projects in Canada).