Quantifying the Environmental and Economic Benefits of Increased Deployment of Combined Heat and Power Technologies in New York State and the Impacts of Various Regulatory Scenarios

Final Report 09-03
March 2008

New York State
Energy Research and
Development Authority

NYSERDA

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Final Report

Prepared for the

New York State Energy Research and Development Authority

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NYSERDA
Report 09-03

NYSERDA 7617

March 2008

NOTICE

ABSTRACT

Small-scale generation facilities such as distributed generation ("DG") systems operating in combined heat and power ("CHP") applications may provide benefits to all energy customers throughout New York State ("NYS"). However, full realization of these benefits may require changes to environmental regulations that encourage increased CHP development. CHP resources are an efficient use of otherwise wasted energy, and new CHP resources are more efficient (and more likely be fueled by natural gas) than their older counterparts. Benefits include reductions in energy market prices and congestion costs as well as reduced environmental emissions. Specifically, this report explores how CHP facilities may affect the hourly dispatch of energy resources, change the clearing price of the wholesale energy market, and reduce the emissions of nitrogen oxide ("NOx"), sulfur dioxide ("SO_2"), and carbon dioxide ("CO_2") for NYS and other electric markets within the eastern United States. Three specific scenarios, each with different levels of CHP emission regulations, were simulated and analyzed.

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SUMMARY

The deployment of small-scale generation facilities such as distributed generation (“DG”) systems operating in combined heat and power (“CHP”) applications throughout New York State (“NYS”) may provide significant benefits to the energy industry, transmission grid, electric customers, and the public. However, these benefits may not be fully realized without changes to environmental regulations that encourage the development of CHP resources. The purpose of this report is to quantify the benefits of CHP usage over several environmental regulatory scenarios on wholesale energy prices, transmission congestion costs, and environmental emissions.

Three specific scenarios were developed and analyzed, each with different emission reductions regulations that directly affect CHP resources. There is a Base Case and two alternative CHP scenarios - each assumes changes to air emission regulations that encourage the replacement of older, less efficient and less environmentally beneficial resources with new, more efficient resources fueled with natural gas that have desirable emission characteristics. There is also a Reference Case to establish a baseline of the energy market prior to the introduction of CHP resources. These cases are summarized as follows:

- A Reference Case without the addition of CHP;
- A Base Case scenario that incorporates a supportive institutional environment for CHP, and a nitrogen oxide (“NO_X”) emissions limit for CHP systems of 1.6 lb/MWh (Scenario 1);
- A second scenario that maintains the supportive institutional environment and lowers the NOx emissions limit for CHP systems to 1.0 lb/MWh by 2012 and 0.6 lb/MWh by 2020 (Scenario 2); and
- A third scenario that maintains the supportive institutional environment, incorporates the 1.0 lb/MWh by 2012 and 0.6 lb/MWh by 2020 NOx limits, but also includes a CHP thermal credit based on displacing on-site boiler fuel with assumed NOx emissions rates of 0.2 lb/MMBtu (Scenario 3).

The report provides a forecast of the penetration of various technology types of CHP in each of the New York Independent System Operator (“NYISO”) load zones. The forecast was prepared based on a portfolio of resources selected using a market diffusion model. The diffusion model includes delivered electric and natural gas prices, technology capital costs, and other factors related to the geographical area.

For each of the three scenarios, there was a comparison of wholesale energy prices, transmission congestion costs, and air emissions for NO_X, sulfur dioxide (“SO_2”), and carbon dioxide (“CO_2”). New York State was analyzed in detail, considering each of the load zones within the bulk electric market. In addition, the New York State wholesale energy market and other, interconnected wholesale markets contained within the North American Electric Reliability Council (“NERC”) Eastern Interconnection were

reviewed. Results show multiple benefits from additional CHP utilization through regulatory incentives. A significant conclusion resulting from this study is that increased amounts of CHP would both reduce energy prices and have a positive impact on environmental considerations.

1 Introduction

1.1 Purpose of Study

The New York State Research and Development Authority ("NYSERDA") commissioned this comprehensive assessment of the New York wholesale electric market to analyze and quantify how the widespread use of distributed generation ("DG") systems operating in combined heat and power ("CHP") applications throughout New York State ("NYS") would affect emissions of criteria air pollutants and wholesale electricity market prices. The increased development of CHP systems could positively affect the New York energy infrastructure because they make use of heat that is normally a wasted byproduct of power generation to supply the heating and or cooling needs of an industrial process or commercial building. According to the October 2002 NYSERDA report, "Combined Heat and Power Market Potential for New York State," CHP can reach overall efficiencies of 70% to 80%. The total efficiency of separate generation of heat and power is typically only 40 to 50%. There is no question that a CHP system, when measured in terms of total energy use, is more efficient than an equivalent power generating plant plus an onsite boiler or chiller.

New questions now emerge:

- What effects will the widespread use of CHP systems have on the New York electric system?
- Could the widespread deployment of CHP throughout New York introduce enough system-wide efficiencies that other dirtier (but lower cost) forms of generation, such as coal, are displaced?
- If that happens, what are the attendant environmental benefits and economic consequences?
- To what extent could imports of coal-generated electricity from western Pennsylvania and the Midwest also be reduced?
- What are the environmental and economic consequences if more efficient CHP resources merely displace resources that are only marginally less efficient but essentially equivalent in terms of environmental attributes, such as combined cycle natural gas plants?
- What impact would the environmental regulations have on the development of CHP and what market impact would CHP have?

These are some of the issues that NYSERDA sought to have explored through this assessment.

The objective of this analysis was to introduce varying amounts of CHP resources and model the impacts on the environment, electric market prices, and congestion costs in NYS and the individual zones that comprise the New York Independent System Operator ("NYISO"). A Reference Case was established as a baseline prior to the introduction of CHP resources; a Base Case and two additional scenarios were also created. The project team analyzed emissions for three pollutants: nitrogen oxide ("NOx"), sulfur dioxide

("SO_2"), and carbon dioxide ("CO_2"). Economic impacts on the electricity market were gauged by measuring the differences in wholesale market electricity prices.

1.2 Definition of Scenarios

The 2002 NYSERDA study performed by Energy Nexus Group (now Energy and Environmental Analysis, Inc.) and Pace Energy Project reviewed the technical potential for CHP in New York State. The central questions were how much CHP could economically be installed over the next decade, what benefits would the installation of that CHP yield, and what actions could policymakers take to promote CHP growth. The technical market potential, it estimated, was constrained only by technological limits, or the ability of then-existing CHP systems to fit customer applications. Results showed that, in addition to an existing base of approximately 5,000 MW of CHP, there was a technical market potential for nearly 8,500 MW of CHP spread over approximately 26,000 sites. The study evaluated various CHP technologies, classified them according to application (industrial/commercial), and grouped them by size. It then considered the economics of each size range and assessed the impediments to greater market penetration in each size range and application. The study provided three major conclusions: 1) standby charges in utility service areas had a major impact on the competitiveness of CHP; 2) technology improvements increased CHP competitiveness in all size categories; and 3) in the absence of standby charges, CHP would be cost competitive in all size ranges, both upstate and downstate.

Using the 2002 study as a starting point, the current effort developed a new projection of CHP penetration, adding several updates. First, the technical potential was revised, including applications for CHP where the primary thermal output is cooling. Second, the standby rate tariffs were included in the economic analyses, with relevant exemptions that were approved by the New York State Public Service Commission ("NYPSC"). These standby rates essentially removed a penalty for CHP units that were built into utility rates. Third, natural gas prices were updated based on the latest US DOE and EIA short and long-term forecasts. The previous study relied on a 2002 natural gas price forecast; this study was updated to a 2006 natural gas price forecast as used by the Regional Greenhouse Gas Initiative ("RGGI") in its base case modeling. Finally, natural gas utilities have been directed to implement special delivery rates for non-residential customers who own and operate DG/CHP. These rates were also incorporated into this study.

These updates combined formed a positive regulatory environment for CHP. Scenario 1, the Base Case, was built on this supportive economic environment. Assumptions included initial emission rate limits for DG/CHP that remained constant through 2020 (the analysis period), based on early indications of intent by NYSDEC. The NOx limits in this scenario were 1.6 lb/MWh.

Scenario 2 include a more aggressive "environmental forcing" strategy. The favorable economic conditions of the base case scenario were retained, but DG/CHP emission rate limits were reduced every five years in discrete steps. The discrete steps aligned with periodic technology reviews, but did constrain the use of certain CHP technologies, particularly in the near-term time frame of the analysis period. Specific assumptions regarding the technological advancement/improvements that were included in this scenario can be found in Section 2 of this report. NOx limits in this scenario were 1.0 lb/MWh by 2012 and 0.6 lb/MWh by 2020.

Scenario 3 included the phased in approach to more stringent emissions limits from Scenario 2, but has an added CHP thermal credit based on displacing on-site boiler emissions. This scenario also has NOx emission rate limits of 1.0 lb/MWh by 2012 and 0.6 lb/MWh by 2020.

In addition to these three scenarios, a Reference Case was modeled to establish a baseline without the introduction of CHP in order to draw further comparisons and gauge the total magnitude of the CHP impact.

1.3 Analytical Methods Applied

The analysis of CHP impacts in NYS began with the development of cost and performance profiles of CHP technologies. This assessment is explained in detail in Section 2, but the technologies considered included fuel cells, reciprocating engines, microturbines, gas turbines, and back-pressure steam turbines. The cost and performance projections that were developed also included expected technology advancements related to equipment costs and emissions profiles. Emissions performance included carbon monoxide, particulate matter, volatile organic compounds, nitrogen oxides, mercury, sulfur oxides, and carbon dioxide.

Similar to the 2002 CHP study, the second step in the analysis was to develop market penetration rates for each scenario. The assessment of market penetration included factors such as the base level of CHP penetration in each particular application, the maximum achievable growth rate in each application, the economic benefit to customers (considering fuel prices and retail electric rates), and the size of the remaining market. It is not possible to achieve 100% installation due to site restrictions, customer risk preferences, and other factors that inhibit CHP adoption. Accordingly, penetration of CHP in NYS followed an "S" shape curve pattern, where penetration rates slow as the penetration levels reach the technical potential levels for CHP. Finally, as the technology and costs were changed to reflect the assumptions of the different scenarios, the relative economics among the technologies also changed. This yielded different mixes of costs, sizes, and deployed CHP technologies across the different scenarios.

Next, computer simulations of the New York electric system were completed. CHP plants were added to the New York electric system in each scenario, and the economic dispatch of the system was then simulated on an hourly basis (similar to how the system is actually operated by the NYISO). CHP plants were essentially "forced" into the system according to the penetration analysis done in the earlier stages, creating the effect of reduced load, which, in turn, affected the dispatch of the other plants in the system. The CHP were added according to the type of technology, size of plant, and with the environmental and cost characteristics specified by the penetration analysis. When the CHP were modeled together with the other electric supply resources in New York, it was possible to calculate its impact by comparing the scenarios. The impact of the CHP was measured as the difference in the emissions generated by the generating resources as a whole, and the difference in the electric market prices compared to the Reference Case. This deterministic analysis was designed to measure the impact of various levels of CHP penetration on several key energy market attributes, such as changes to prices, congestion costs, and environmental emissions.

The electric system modeling encompassed the entire Eastern Interconnection, which includes a geographic area covering roughly the central and eastern portions of the U.S., and Canada from the foot of the Rockies to the Atlantic Ocean (excluding most of Texas). The simulation was performed in five-year increments, consistent with the timing of technological reassessments. Intermediate years were estimated through interpolation. The simulation of the electric system allowed us to capture the changes in fuel consumed, electric wholesale market prices, pollutant emissions, and generation by various central station and technology types. The results were assessed by season, consistent with the NOx ozone periods, and broken down by each zone in New York.

1.4 Organization of Report

This report is organized into seven sections, beginning with this introduction. Estimates of the technical potential of CHP for New York are developed in Section 2. Section 3 characterizes the amount of CHP that can economically enter the New York market under each of the three scenarios. Section 4 lays out the market modeling approach and describes the simulation model and post processing of the results. Section 5 describes the assumptions used in the modeling that are common to all three scenarios, and Section 6 presents the results of the market modeling. Finally, Section 7 presents the study conclusions. Following the conclusion are the appendices containing major study assumptions.

2 CHP Technical Potential Estimate

2.1 Project objectives

The overall project objectives were to analyze the air emissions and electric market impacts that could result from an increase in CHP units in New York State. This section of the report summarizes the CHP market potential analyses – an assessment of CHP market penetration under a Reference Case and three market/regulatory scenario – and the update of the CHP technical market potential estimate. The market penetration scenarios were defined with input from NYSERDA staff and a stakeholder advisory board as follows:

- A Reference Case without the introduction of CHP;
- A Base Case scenario that incorporated a supportive institutional environment for CHP, and a NOx emissions limit for CHP systems of 1.6 lb/MWh;
- A second scenario that lowered the NOx emissions limit for CHP systems to 1.0 lb/MWh by 2012 and 0.6 lb/MWh by 2020; and
- A third scenario that incorporated the 1.0 lb/MWh by 2012 and 0.6 lb/MWh by 2020 NOx limits, but also included a CHP thermal credit based on displacing onsite boiler fuel with assumed emissions rates of 0.2 lb/MMBtu.

The market penetration results were used as input into an electricity production simulation model to evaluate the air emissions impacts associated with each scenario. This analysis provided insight into the dynamic relationship between emissions regulatory control and CHP penetration. It also provided NYSERDA with a reliable quantification of the potential environmental impacts, as well as system/market benefits, of increased CHP deployment.

The first scenario, aka the Base Case, was designed to examine *the expected market penetration of CHP technologies, and resulting system effects (e.g., air emissions impacts, wholesale market price effects) under a regulatory and market climate that is favorable to clean onsite generation.* This scenario offered an update of the 2002 New York State CHP Market Assessment prepared jointly by Energy Nexus (now Energy and Environmental Analysis, Inc.) and the Pace Energy Project for NYSERDA. Additionally, it incorporated an early DEC proposal for NOx emissions standards for small distributed generation sources.

The second scenario was designed to simulate the impacts of *reducing the DG/CHP emissions rate limit pursuant to a technology review requirement.* Emissions limits were “technology forcing” in nature; i.e., regulatory limits were expressly intended to drive prime mover and after-treatment technology to higher standards of performance. However, more optimistic economic regulatory and market conditions were retained to isolate the market penetration (overall, and technology market share), environmental and electricity system effects of stricter environmental standards.

The third scenario was intended to examine *DG emissions regulatory regimes that included a CHP thermal credit for displaced boiler emissions*. The purpose of this scenario was to determine whether a thermal credit enables DG technologies that would have otherwise been out of compliance to retain market share when operated in a combined heat and power mode, as well as to assess the concomitant environmental and market impacts. In this scenario, we held constant both the optimistic economic regulatory and market conditions from Scenario 1 and the more stringent emissions conditions from Scenario 2.

2.2 Summary of the Market Penetration Analysis

The technical approach used for the market penetration estimates was based on the approach used by EEA and Pace Energy Project in the original 2002 CHP market assessment study.[1] However, the underlying data used in this approach was updated and several enhancements to the approach were incorporated. There are four basic components to the analytical framework used to estimate CHP market penetration:

1. Technical Market Potential – The output of this analysis was an estimate of the technically suitable CHP applications by size and by application. This estimate was derived from the screening of market databases based on application and size characteristics that are used to estimate groups of facilities with appropriate electric and thermal load characteristics.

2. Energy Price Projection – Present and future fuel prices were estimated to provide inputs into the CHP net power cost calculation.

3. Technology Characterization – For each size range, a set of applicable CHP technologies was selected for evaluation. These technologies were characterized in terms of their capital cost, heat rate, non-fuel operating and maintenance costs, emissions and available thermal energy for process use onsite.

4. Market Penetration – Within each market size, the competition among applicable technologies was evaluated. Based on this competition, the economic market potential was estimated and shared among competing CHP technologies. The rate of market penetration by technology was then estimated using a market diffusion model.

[1] *Combined Heat and Power Market Potential for New York State*, Energy Nexus Group (now EEA, Inc.) and Pace Energy Project, NYSERDA, October 2002.

This section of the report summarizes the estimates of technical potential and market penetration for each of the scenarios. Detailed explanations of the methodologies and assumptions are presented in the appendices.

2.2.1 Technical Market Potential

The purpose of the initial market characterization was to identify the number and size of facilities in New York State that provide the physical operating characteristics that are most likely to support an economic CHP system. These target applications, called technical market potential, provided the input to the economic competition and market penetration models that follow. The technical market potential defined for the previous study was used as the starting point for this analysis. The original estimates for technical potential were reviewed and updated to reflect current conditions, and viable CHP targets were increased to include applications incorporating cooling as a thermal output.

To effectively utilize CHP, a commercial building or industrial facility must have at least a portion of its electric and thermal load that coincides with the ratios of thermal to electric energy available from CHP systems. For best economic performance, this coincident thermal and electric load should be fairly steady for as many hours per year as possible. A continuous process industry with a nearly constant steam demand and electric load is an excellent target - a hospital with steady electric and hot water demands is a good example. Facilities with intermittent electric and thermal loads are progressively less attractive as the number of hours of coincident load diminishes.

Two market categories were considered in developing the technical potential:

- High load factor applications – This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons; and

- Low load factor applications – Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

The technical market potential in these categories was calculated for existing commercial and industrial facilities in New York (Table 1) and for new facilities expected from market sector growth during the forecast period (Table 2) based on the sector growth rates contained in Appendix A. As shown, the total technical market potential for CHP in New York equals almost 14,300 MW at existing commercial and industrial facilities, and an additional 5,700 MW from expected new facilities during the forecast period. The tables provide a breakdown of the technical potential in high load (>7000 hours per year) and low load (<5000 hours per year) applications, and a geographical breakdown between upstate and downstate.

Table 1. CHP Technical Potential in Existing Commercial and Industrial Facilities

High Load Applications (>7000 hours/year)

Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
Downstate	470	871	2,082	1,027	1,073	5,523
Upstate	246	589	1,368	1,124	819	4,146
State Total	717	1,460	3,450	2,152	1,891	9,669

Low Load Applications (4000 to 5000 hours/year)

Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
Downstate	739	930	1,208	16	0	2,893
Upstate	484	549	683	9	0	1,726
State Total	1,224	1,479	1,891	25	0	4,618

All Applications

Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
Downstate	1,210	1,802	3,289	1,043	1,073	8,416
Upstate	730	1,137	2,051	1,134	819	5,871
State Total	1,940	2,939	5,340	2,177	1,891	14,287

Table 2. CHP Technical Potential in New Commercial and Industrial Facilities

High Load Applications (>7000 hours/year)

Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
Downstate	68	217	817	310	438	1,849
Upstate	71	230	484	279	200	1,263
State Total	139	447	1,300	588	638	3,112

Low Load Applications (4000 to 5000 hours/year)

Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
Downstate	410	458	723	3	0	1,594
Upstate	253	310	419	0	0	982
State Total	663	768	1,143	3	0	2,576

All Applications

Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
Downstate	478	675	1,540	313	438	3,443
Upstate	323	540	903	279	200	2,245
State Total	801	1,215	2,443	591	638	5,688

It is important to point out that technical potential is not in any sense a market forecast for CHP under current or any reasonable set of assumptions. The technical market potential is intended to represent the universe of potential applications upon which the economic screening and market penetration analysis is conducted. These markets represent the primary sales targets for CHP developers. However, if a developer were to approach one of these target facilities, any number of reasons might stand in the way of a CHP system ever being installed, such as:

- Actual facility electric and thermal loads might vary from the typical industry or application profile;
- The economics might not work out due to site-specific costs or the customer's investment criteria might be highly restrictive;
- There might be site limitations such as lack of fuel availability or environmental restrictions; and
- The customer may be unable or unwilling to consider CHP.

These factors were considered in the economic competition and market penetration model.

3 CHP Market Penetration Results

The economic market potential was determined based on a comparison of the net power costs from the competing CHP technologies with the delivered electric and natural gas prices within that market size and geographical area. Within each market category (size and region), the competition among applicable technologies was evaluated. Based on this competition, the economic market potential was estimated and shared among competing CHP technologies. The rate of market penetration by technology under each scenario was then estimated using a market diffusion model (see Appendix D). Only "within the fence" CHP systems were considered in the analysis. All thermal energy and power generated by the CHP systems was assumed to be used onsite; no power export market was considered for any of the size categories.

Table 3 presents the market penetration results for each state region (upstate and downstate) for each of the three scenarios by year (2010, 2015, and 2020). By 2020, CHP penetration is estimated to range from 10.9% (Scenario 2) to 11.4% (Scenario 3) of the total technical, potential presented in the previous section. The absolute increase is 310 MW, which is 15% greater capacity for Scenario 3 than the total Scenario 2 penetration of 2170 MW.

Table 3. CHP Market Penetration Estimates (MW)

Base Case

	2010	2015	2020
Downstate	255	958	1,342
Upstate	239	775	1,067
Total	494	1,733	2,409

Scenario 2

	2010	2015	2020
Downstate	249	857	1,199
Upstate	232	704	971
Total	481	1,561	2,170

Scenario 3

	2010	2015	2020
Downstate	297	1,000	1,385
Upstate	267	803	1,095
Total	564	1,803	2,480

The more restrictive NOx emissions standards of Scenario 2 (1.0 lb/MWh vs. 1.6 lb/MWh for the Base Case) reduce total CHP penetration by 239 MW (about 10% of the Base Case penetration). Allowing a

CHP thermal credit (Scenario 3) increases CHP penetration slightly compared to the Base Case (71 MW or 3% of the Base Case penetration) even considering the stricter NOx standard of 1.0 lb/MWh.

The impact of the different scenarios is more apparent when individual CHP technology penetration was considered as shown in Table 4.

Table 4. CHP Market Penetration Results by Technology – Year 2020 (MW)

Recip Engine

Size Range	Base	Scenario 2	Scenario 3
50-500 kW	155	155	155
500kW-1,000kW	389	355	392
1-5 MW	912	551	971
5-20 MW	244	114	244
>20 MW	0	0	0
All Sizes	1699	1174	1762

Microturbine

Size Range	Base	Scenario 2	Scenario 3
50-500 kW	17	17	17
500kW-1,000kW	24	32	23
1-5 MW	0	0	0
5-20 MW	0	0	0
>20 MW	0	0	0
All Sizes	40	49	40

Gas Turbine

Size Range	Base	Scenario 2	Scenario 3
50-500 kW	0	0	0
500kW-1,000kW	0	0	0
1-5 MW	186	358	194
5-20 MW	159	257	159
>20 MW	310	310	310
All Sizes	656	926	663

Fuel Cell

Size Range	Base	Scenario 2	Scenario 3
50-500 kW	4	4	4
500kW-1,000kW	3	5	3
1-5 MW	7	13	7
5-20 MW	0	0	0
>20 MW	0	0	0
All Sizes	14	21	14

As shown in Table 4, the stricter NOx standards of Scenario 2 restrict the deployment of reciprocating engine CHP. Much of this is replaced by gas turbine CHP in the larger size categories, but only a small fraction is replaced by other technologies (microturbines and fuel cells) in the smaller size categories. Table 5 presents the market penetration estimates by size, year, and region for each scenario.

Table 5. CHP Market Penetration by Size, Year, and Region

Base Case Cumulative Market Penetration 2010, 2015, and 2020

Year	Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
2010	Downstate	13	42	96	63	41	255
	Upstate	8	27	56	62	86	239
	NY Total	21	69	152	126	127	494
2015	Downstate	57	156	503	159	82	958
	Upstate	37	107	269	174	188	775
	NY Total	94	263	772	334	270	1,733
2025	Downstate	105	243	708	193	93	1,342
	Upstate	69	173	397	210	217	1,067
	NY Total	175	416	1,105	403	310	2,409

Scenario 2 Cumulative Market Penetration 2010, 2015, and 2020

Year	Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
2010	Downstate	13	42	96	58	41	249
	Upstate	8	29	56	53	86	232
	NY Total	21	70	152	111	127	481
2015	Downstate	57	146	424	148	82	857
	Upstate	37	105	218	157	188	704
	NY Total	94	251	642	304	270	1,561
2025	Downstate	105	224	596	181	93	1,199
	Upstate	69	168	326	191	217	971
	NY Total	175	392	922	371	310	2,170

Scenario 3 Cumulative Market Penetration 2010, 2015, and 2020

Year	Region	50-500 kW	0.5-1 MW	1-5 MW	5-20 MW	>20 MW	Total MW
2010	Downstate	13	44	136	63	41	297
	Upstate	8	28	83	62	86	267
	NY Total	21	72	219	126	127	564
2015	Downstate	57	158	544	159	82	1,001
	Upstate	37	108	295	174	188	803
	NY Total	94	266	839	334	270	1,803
2025	Downstate	105	245	749	193	93	1,385
	Upstate	69	174	424	210	217	1,094
	NY Total	175	419	1,172	403	310	2,479

The market penetration results were used in the remaining analysis as follows: Using the MW of CHP capacity estimated to be installed in each county, the hours of operation (low load and high load), and hourly and seasonal load shapes by customer groups, the reduction of electricity purchases from the grid was calculated for each county on a seasonal and daily basis. This reduction in "demand" was factored into the production simulation model that captures the hour-by-hour dynamics of electric power markets and determines the impacts on central station dispatch and the need for new capacity over time. The emissions impacts of CHP at the site (i.e., displacing existing thermal sources with the CHP systems) were compared to the emissions impacts at the power plant level (i.e., comparing net incremental emissions at the sites with displaced emissions from the grid) to determine the overall environmental impact of CHP deployment for each scenario.

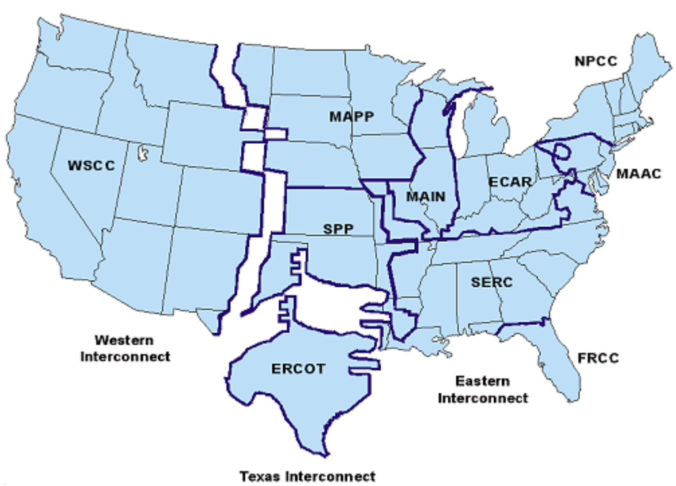
4 Modeling Approach

4.1 Market Simulation

In order to develop reasonable estimations of the environmental and economic impacts of CHP under the three scenarios, it was necessary to simulate operation of these plants in the NYS competitive marketplace. New York operates a competitive wholesale market for power sales where generation plants and demand side resources compete to provide the most cost effective means to meet demand. The CHP plants were introduced into the modeling in such a way to perform as though they were being self-scheduled, their operation being controlled by the steam host. Thus, their electrical output directly offset a portion of system load according to our calculated schedule (peak/off-peak) and caused a reordering of the dispatch of the central station plants compared to the Reference Case. In this way, we were able to simulate the economic dispatch of generators in the market and measure the changes in pollutant levels and wholesale market costs.

NCI used Prosym to develop its wholesale energy market price and plant performance forecast simulation. Prosym is a detailed energy production cost model that simulates hourly operation of generation and transmission resources. Prosym dispatches generating resources to match hourly electricity demand, dispatching the least expensive generation first. The choice of generation is determined by the generator's offer to the market operator, including technical factors such as ramp rates (for fossil resources) or water availability (for hydraulic resources), and transmission constraints. The supply offer of the marginally dispatched unit in each hour sets the hourly market-clearing price. All generators in the same market area whose supply offers are accepted receive the same hourly market-clearing price regardless of actual offer price. The NCI Prosym model specification included the entire Eastern Interconnect, which covers the electrically interconnected areas of the United States and Canada roughly east of the Rocky Mountains, excluding Texas.

Figure 1. Map of Interconnected Electric Systems in U.S.



Within Prosym, production costs were calculated based upon heat rate, fuel, and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outages, start-up, unit ramping, minimum up and down time, and other characteristics were also factored into the simulation. Supply offer prices were developed for each unit within the Prosym construct and correspond to the minimum price the unit owner is willing to accept to operate the unit. For most generation resources, offer prices were composed primarily of incremental production costs. The incremental production cost was calculated as each generating unit's fuel price multiplied by its incremental heat rate, plus unit emissions costs and variable operations and maintenance costs. Unit emissions costs were derived from historic unit specific emission rates and forecasts of allowance prices.

Where relevant (primarily for thermal units), the unit offer price also incorporated the unit's start-up and no-load costs, which are costs that aren't directly incurred with the output of a plant, but do get factored into a generator's offer to sell into the market. The start-up cost component included fuel and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions. The no-load cost reflected the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.

The offer price can also include a markup factor that increases the offer price above the variable production cost. We applied such a factor, where appropriate, to reflect observed market behavior, particularly during times when supply margins are tight or when we observe shadow pricing. We may assign price markups to individual generators depending upon the underlying fuel efficiency, production cost, and technology type. The specific markups were designed to increase offer prices above the cost of production as less efficient resources were called upon for power production and as the intersection of supply and demand occurred at higher points on the supply curve. The level of price markups was determined through a benchmarking of the Prosym market price forecast against recent actual wholesale energy prices and observable energy prices in the forward market. Energy market clearing prices reflect the offer of the last generating resource used to meet the next increment (megawatt) of demand. Station revenues were based on these market-clearing prices within the market area in which the plant is located. The net results were simulations that closely reflect observed market behavior and market outcomes.

CHP plants were entered in the modeling with zero cost and zero emissions. They were divided into two groups of resources, based on the penetration of different technologies under the assumptions in the different scenarios according to the EEA analysis. The technologies were categorized into high load factor CHP resources and low load factor CHP resources. The high load factor CHP resources were assumed to operate around the clock, albeit at varying levels depending on the scenario, time of day (peak/off-peak) and season. The low load factor CHP resources were assumed to operate only during "day-time" (peak) hours, also varying their output based on the scenario and season. These resources were essentially modeled as "energy limited" resources, or resources that would produce energy according to a schedule that was determined by factors outside of the energy market. Run-of-river hydro plants are an example of a resource that falls into this category-- they produce energy when water is available and flowing. In the case of CHP projects, their production schedule is dictated by the host - energy production is a byproduct, and not the primary determinant of when a CHP plant operates. While it was necessary to model the plants in this manner, in reality, the CHP plants would not be dispatched by the system operator and their energy would not be delivered to the grid. The energy they produced would offset their own host's energy needs, thereby reducing system demand and causing a different dispatch order than would occur in their absence.

4.2 Post-Processing of Results

While the Prosym model was able to simulate the competitive dispatch of generators in New York, further analysis and processing of the results was required to quantify the total impacts of the CHP on the New York electric market in terms of both environmental impacts and economic impacts.

As an output from Prosym, we obtained the emissions of SO2, NOx, and CO2 based on calculations of plant fuel consumed from generating power and their emission rates (lbs per MMBtu). Total emissions of these pollutants were then calculated over a given geographical region and time period. Generating plants that use fuels containing high levels of sulfur will have high rates of SO2 emissions unless those plants also employ control technology to capture those emissions. The same is true for NOx and CO2. Because the Prosym model contains actual, historical emissions rates, it captures the impacts of the control technologies already being employed at the generating plants in the database. For modeling purposes, NCI assumed that the cost of emissions rate limits would be captured through the trading of allowances.

NOx emissions results were disaggregated into seasons. Season 1 extends from May through September in the presentation (ozone season), and Season 2 extends from October through April (non-ozone season). This allowed for the differentiation of summer, winter, and annual NOx impacts.

Economic impacts were calculated as the change in the average wholesale market price of electricity in each scenario compared to the base case (in $/MWh) for each scenario for the state of New York as well as for each zone within the state.

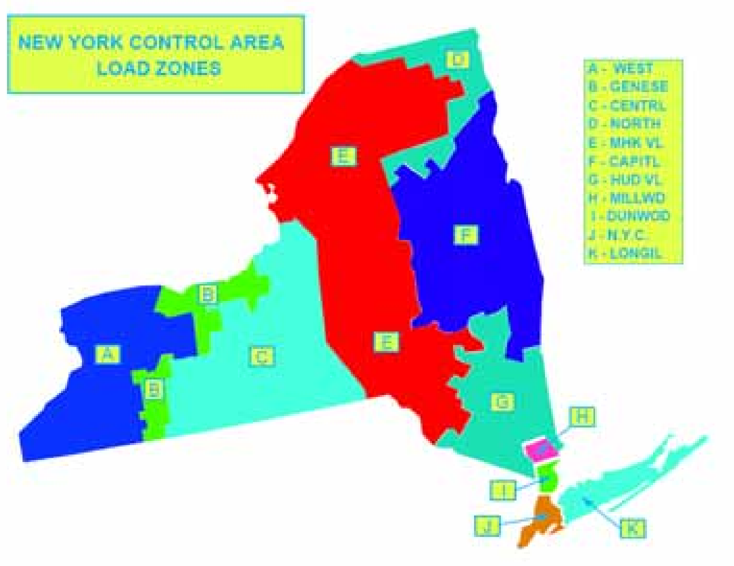
5 Assumptions Used in the Analysis

5.1 Scope of Simulation and Level of Detail for the New York Market

As stated above, we simulated the economic dispatch of the entire Eastern Interconnected electric system, which included the central and eastern portions of the U.S. and Canada, roughly from the foot of the Rocky Mountains to the Atlantic Ocean (excluding most of Texas). Within this area, the transmission topography was represented to take into account major transmission interfaces and bottlenecks where energy pricing differences normally occur. Within New York, the topography was broken down into eight zones. While the NYISO recognizes 11 zones, A through K, we aggregated A through D. This is because there are rarely transmission constraints causing congestion between these zones, and therefore, there is rarely any electric price separation. Zone A is located in the Niagara Falls region of the state; the zones are named roughly west to east, with Zone K corresponding to Long Island.

In the presented results, Upstate New York refers to Zones A-D and E. Downstate New York refers to Zones F through K. See Figure 2 below for a geographical depiction of the zones in New York State.

Figure 2. New York Control Area Zone Reference



5.2 New Capacity Resources

Long-range market price simulations require assumptions regarding future generating plant additions and retirements. We included actual plants in the model that are under active development and have a high probability of successful development. In consultation with NYSERDA and consistent with assumptions used in RGGI policy analysis, NCI introduced capacity into the model that could reasonably be expected to be developed over time due to build economics, reliability requirements, or policy initiatives. These additions included a variety of capacity types, such as conventional gas-fired combined cycle ("CC") and renewable technologies. In New York State, the majority of new capacity additions were combined cycle (see Table 6 below). Of the total capacity additions (5,691 MW by 2020), new renewable capacity accounted for 1,196 MW and were made up of wind as well as landfill gas projects. The combined cycle gas plants that were added were the SCS Astoria plant in NYC and other generic CC units in downstate NY.

In addition, a total of 685 MW of oil and coal capacity were retired over the forecast period. The retired coal plants included Greenidge and Russell, and the retired oil-fired plants included units at East Hampton, East River, Montauk, and Waterside.

Table 6: Assumed Resource Changes in New York State for the Energy Dispatch Model

New York State cumulative capacity changes

	2006	2010	2015	2020
Repower to CC	-	-	-	-
CC	-	995	2,495	4,495
CT	-	-	-	-
Coal	-	-	-	-
Repower to IGCC	-	-	-	-
Oil/Gas	-	-	-	-
Nuclear	-	-	-	-
Nuclear Uprate	-	-	-	-
Total Conventional Capacity	-	*995*	*2,495*	*4,495*
Biomass	-	-	-	-
Fuel Cell	-	-	-	-
Hydro	-	-	-	-
Landfill Gas	48	145	266	378
Solar	-	-	-	-
Wind	102	307	562	818
Total Renewable Capacity	*151*	*452*	*828*	*1,196*
Mothballed Oil/Gas	-	-	-	-
Return to Service Oil/Gas	-	-	-	-
Retire Oil/Gas	-	276	276	286
Retire Coal	-	399	399	399
Net Capacity Added	**151**	**772**	**2,648**	**5,006**

Source: Navigant Consulting Analysis

Additions of CHP resources were included in the model as zero price resources with energy delivery shapes corresponding to whether they were high or low load factor resources. Low load factor resources were set to deliver energy during on peak periods, while high load factor resources were set to deliver energy during all hours. This modeling approach reproduced the effect of having plants on the system that self-schedule their energy production according to their own needs, rather than the system needs. Thus, we were able to control the CHP energy production in a realistic manner.

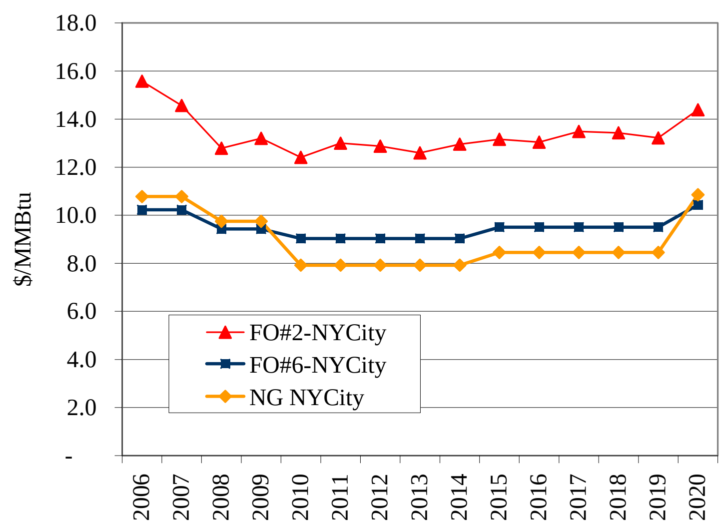
5.3 Time Periods

For the purposes of modeling, the on-peak period was defined as 0700 to 2300 Monday to Friday (excluding holidays) and the off-peak period was defined as all other periods. Two seasonal periods were also defined within the year - summer and winter. The summer period extended from May through October, and the winter period extended from November through April.

5.4 Fuel Prices

The price of natural gas is a major input variable for any power price forecast. As previously illustrated, natural gas-fired generation is the marginal unit for many hours in each of the markets. Consequently, power prices are highly correlated with natural gas prices. Our intention was to coordinate the input assumptions as closely as possible with those used as part of the RGGI policy analysis in order to facilitate the work of policy makers as they attempt to evaluate various future power development objectives. Accordingly, NCI used the fuel forecasts for natural gas, distillate and residual fuel oil ("FO#2" and "FO#6", respectively), coal, and emissions allowances that were used in the RGGI base case. The fuel prices used in the market simulation analyses were also consistent with the fuel prices used in the CHP penetration analysis. Shown in Figure 3 below are the forecasts used for FO#6, FO#2, and Natural gas in New York City[2]. FO#6 and FO#2 track each other fairly closely with FO#2 demonstrating a bit more annual price volatility. FO#6 is not projected to decline in price as much as natural gas beyond 2010. This will put natural gas into a position of relative value compared to FO#6 around 2010. It is not expected to return to price parity with FO#6 until the end of the forecast period in 2020.

Figure 3. Oil and gas price forecasts for New York City



[2] As thermal capacity additions are concentrated in downstate New York, only New York City prices are shown. All fuel prices can be found in the detailed Appendices.

5.5 Allowance Prices

Emission allowance prices were derived in coordination with NYSERDA and the RGGI policy analysis. SO2 and CO2 do not have seasonal differentiation in their markets (or anticipated markets). Therefore, their prices are annual in nature and do not vary within the year. SO2 allowance prices were expected to begin at just over $1,000/ton and rise to over $2,600/ton by 2020. While SO2 are no longer at the levels predicted at the time of the modeling, we do not believe that substituting current, lower SO2 allowance prices would have a material impact on the study outcomes. The CO2 price was expected to start at $3/ton in 2010 (the first modeled year after the start of RGGI), and rise to $6/ton by 2020. While there are annual NOx regulations, NOx prices did vary by season as NOx is a contributor to ground level ozone in the summer and there are stricter summertime environmental restrictions on the NOx emissions. By 2015, it was expected that seasonal prices differences would disappear and the NOx allowance prices would remain consistent throughout the year. The full price forecasts for all three pollutants can be seen in Table 7 below.

Table 7. Emissions Allowance Prices in New York ($/ton)

	New York							
	2006		2010		2015		2020	
	Season 1: May-Oct.	Season 2: Nov-April	Season 1: May-Oct.	Season 2: Nov-April	Season 1: May-Oct.	Season 2: Nov-April	Season 1: May-Oct.	Season 2: Nov-April
SO2 Price ($/ton)	$1,035	$1,035	$1,266	$1,266	$1,513	$1,513	$2,610	$2,610
NOx Price ($/ton)	$3,001	$1,600	$2,244	$2,818	$2,446	$2,446	$3,409	$3,409
CO2 Price ($/ton)	$0	$0	$3	$3	$4	$4	$6	$6

5.6 Emissions Rates

Emission rates for each plant in the Eastern Interconnect were input based on the Continuous Emissions Monitoring System ("CEMS") data as reported to the EPA. This data was entered into Prosym as emission rates for SO2, NOx and CO2, in terms of pounds of each pollutant emitted per unit of fuel consumed (MMBtu). Prosym calculates plant emissions from fuel consumed in start-up and in operation. Presented in Table 8 below are the average emission rates resulting from plant operations over the study period. These emission rates represent the average of the plants' emissions in each technology/ fuel class for each study year, by emission type. Emission changes over time were primarily the result of variations in the individual plants' operations vis-à-vis each other. This is true whether analyzing within or between categories. That is, if the model dispatches lower emission rate plants rather than higher emission rate plants within the same category, then the overall emission rate for that plant category will decline. If the model displaces higher emission rate plants in one category with lower emission rate plants in another category, the higher emission plants will run less and the overall emission rate for their category will, again, decline. The emission rates shown below are for the Reference case - before the introduction of CHP.

Table 8. Average Emission Rates by Technology/ Fuel Class, Year and Emission Type of Existing Plants in New York

	SO2 Rates (lbs/MMBtu)				NOx Rates (lbs/MMBtu)				CO2 Rates (lbs/MMBtu)			
	2006	**2010**	**2015**	**2020**	**2006**	**2010**	**2015**	**2020**	**2006**	**2010**	**2015**	**2020**
New CC		0.001	0.001	0.001		0.013	0.013	0.013		119	119	119
Existing CC	0.294	0.199	0.190	0.191	0.056	0.049	0.046	0.043	97	95	95	95
Gas CT	0.001	0.001	0.001	0.001	0.008	0.010	0.012	0.013	124	124	124	125
Oil CT and IC	0.294	0.199	0.190	0.191	0.056	0.049	0.046	0.043	97	95	95	95
Jet Engine	0.656	0.673	0.670	0.672	0.211	0.217	0.305	0.278	163	165	164	164
Steam Coal	1.193	0.972	0.962	0.955	0.187	0.179	0.179	0.178	203	203	203	203
Steam Gas	0.147	0.084	0.073	0.126	0.119	0.104	0.116	0.139	125	126	125	125
Steam Oil	0.294	0.199	0.190	0.191	0.056	0.049	0.046	0.043	97	95	95	95

6 Modeling Results

6.1 Air Impacts Resulting from DG/CHP

As noted above, each Scenario was designed to introduce specific amounts of CHP into the New York market. Some of these resources were high load factor, or baseload, while others were low load factor, or peaking. Whether baseload or peaking, all of the CHP introduced to the modeling would have the effect of shifting the supply curve to the right and displacing higher cost, less efficient resources. To see the impact of the CHP in full, we modeled a Reference Case that simulated the economic dispatch of the electric system prior to the introduction of CHP. Numerically, the results of the Reference Case are given in Table 9 below. As stated earlier, the Reference Case provides a basis for comparison a “worldview” prior to the introduction of policies that encourage the adoption of CHP resources to the Scenarios with pro-CHP policies. As CHP policies in New York will also have effects on electric market operation and dispatch in other parts of the country, Table 9 shows generation, fuel consumption and cost, emission quantities and costs, and CHP generation for each region of the country. The CHP generation was limited to New York for purposes of this study.

Table 9. Modeling Results for the Reference Case

Reference Case - Real 2006$

		2006			2010			2015			2020		
Market Area	Data	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total
New York	Generation(GWh)	79,586	73,788	153,374	85,669	78,398	164,068	91,917	84,166	176,084	97,354	88,604	185,957
	Fuel Consumption (GBtu)	630,906	559,740	1,190,646	676,423	587,472	1,263,894	722,191	629,667	1,351,858	756,165	658,350	1,414,515
	Fuel Cost ($000)	$3,434,681	$2,960,579	$6,395,259	$2,806,603	$2,358,328	$5,164,931	$2,928,650	$2,500,987	$5,429,637	$3,340,690	$2,859,502	$6,200,193
	SO2 Emissions (000 tons)	93	87	181	67	64	131	66	62	128	68	63	131
	NOx Emissions (000 tons)	20	18	38	19	16	35	18	16	34	18	15	33
	CO2 Emissions (000 tons)	31,454	27,190	58,644	32,830	27,502	60,332	34,407	28,909	63,317	35,407	29,681	65,088
	SO2 Cost ($000)	$96,657	$90,538	$187,195	$84,938	$80,413	$165,351	$99,310	$94,120	$193,430	$127,828	$118,061	$245,890
	NOx Cost ($000)	$56,440	$28,454	$84,894	$39,682	$41,338	$81,019	$36,274	$31,708	$67,981	$43,956	$37,353	$81,309
	CO2 Cost ($000)	$0	$0	$0	$89,568	$75,034	$164,602	$111,179	$93,413	$204,592	$152,425	$127,777	$280,201
	CHP Generation (GWh)												
New England	Generation(GWh)	76,260	77,910	154,170	82,850	84,879	167,729	90,671	92,217	182,888	97,942	99,290	197,232
	Fuel Consumption (GBtu)	649,222	656,528	1,305,750	702,603	703,826	1,406,430	774,825	770,872	1,545,697	835,861	830,968	1,666,829
	Fuel Cost ($000)	$3,171,002	$3,435,071	$6,606,073	$2,583,576	$2,942,013	$5,525,588	$2,898,570	$3,138,203	$6,036,773	$3,517,962	$3,794,177	$7,312,138
	SO2 Emissions (000 tons)	109	112	222	94	100	194	82	83	164	92	93	184
	NOx Emissions (000 tons)	19	20	39	17	18	35	19	18	37	20	20	39
	CO2 Emissions (000 tons)	37,229	37,563	74,792	37,649	39,073	76,722	42,040	42,074	84,113	45,520	45,587	91,107
	SO2 Cost ($000)	$68,047	$71,949	$139,996	$65,147	$72,259	$137,406	$56,167	$58,424	$114,592	$84,092	$87,528	$171,620
	NOx Cost ($000)	$20,588	$625	$21,213	$3,093	$805	$3,897	$859	$871	$1,729	$798	$816	$1,614
	CO2 Cost ($000)	$0	$0	$0	$7,681	$8,688	$16,369	$14,123	$14,408	$28,531	$19,121	$19,878	$39,000
	CHP Generation (GWh)												
PJM	Generation(GWh)	172,729	163,023	335,752	185,850	178,186	364,035	203,116	192,990	396,106	232,565	216,959	449,524
	Fuel Consumption (GBtu)	1,664,623	1,565,904	3,230,527	1,771,805	1,682,297	3,454,101	1,910,445	1,797,157	3,707,602	2,142,347	1,995,113	4,137,460
	Fuel Cost ($000)	$3,946,052	$3,604,258	$7,550,310	$3,826,772	$3,611,129	$7,437,900	$4,717,131	$4,408,281	$9,125,412	$5,998,186	$5,502,811	$11,500,997
	SO2 Emissions (000 tons)	728	691	1,419	538	525	1,062	292	287	578	199	196	395
	NOx Emissions (000 tons)	76	75	151	74	71	145	62	60	122	67	64	131
	CO2 Emissions (000 tons)	106,587	100,120	206,707	112,404	106,869	219,273	120,253	113,145	233,398	138,428	129,141	267,569
	SO2 Cost ($000)	$753,676	$715,116	$1,468,792	$680,645	$664,216	$1,344,861	$441,359	$433,600	$874,960	$372,078	$366,771	$738,850
	NOx Cost ($000)	$194,727	$0	$194,727	$115,012	$88,576	$203,589	$89,981	$87,772	$177,753	$120,130	$115,915	$236,045
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$376,728	$358,302	$735,030	$770,912	$721,700	$1,492,612
	CHP Generation (GWh)												
ECAR	Generation(GWh)	292,161	282,340	574,501	304,693	288,576	593,268	315,411	299,380	614,791	325,479	309,269	634,748
	Fuel Consumption (GBtu)	2,133,092	1,987,358	4,120,451	2,240,909	2,097,115	4,338,024	2,333,491	2,178,714	4,512,205	2,418,022	2,269,802	4,687,825
	Fuel Cost ($000)	$5,025,595	$4,609,301	$9,634,897	$5,162,209	$4,749,011	$9,911,219	$6,264,418	$5,840,275	$12,104,693	$7,007,812	$6,588,585	$13,596,397
	SO2 Emissions (000 tons)	1,692	1,694	3,386	1,305	1,310	2,615	1,034	1,030	2,063	943	939	1,882
	NOx Emissions (000 tons)	288	303	591	279	279	558	246	244	490	238	235	473
	CO2 Emissions (000 tons)	258,618	252,444	511,062	265,109	253,983	519,091	270,594	258,489	529,083	279,470	266,832	546,302
	SO2 Cost ($000)	$1,751,558	$1,753,240	$3,504,798	$1,629,767	$1,635,333	$3,265,100	$1,497,047	$1,487,211	$2,984,257	$1,634,247	$1,622,841	$3,257,088
	NOx Cost ($000)	$720,407	$0	$720,407	$552,214	$460,891	$1,013,105	$478,174	$474,323	$952,497	$563,791	$555,892	$1,119,683
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$1,092,921	$1,044,027	$2,136,948	$2,003,814	$1,913,110	$3,916,924
	CHP Generation (GWh)												
SERC	Generation(GWh)	472,636	424,603	897,239	509,256	459,062	968,318	548,132	491,705	1,039,837	598,993	533,165	1,132,158
	Fuel Consumption (GBtu)	3,385,570	2,988,387	6,373,956	3,630,218	3,236,366	6,866,585	3,886,144	3,457,562	7,343,706	4,223,938	3,709,398	7,933,337
	Fuel Cost ($000)	$10,676,078	$8,757,757	$19,433,836	$10,217,762	$8,699,670	$18,917,432	$12,582,836	$10,738,493	$23,321,329	$16,010,832	$13,633,725	$29,644,557
	SO2 Emissions (000 tons)	1,748	1,610	3,357	1,456	1,355	2,811	1,275	1,178	2,453	1,080	995	2,076
	NOx Emissions (000 tons)	274	259	533	283	258	541	247	218	465	257	229	485
	CO2 Emissions (000 tons)	300,650	269,381	570,031	316,494	284,526	601,020	336,969	300,580	637,549	368,863	327,830	696,692
	SO2 Cost ($000)	$1,808,874	$1,665,864	$3,474,738	$1,830,383	$1,701,909	$3,532,292	$1,901,547	$1,755,117	$3,656,664	$1,977,873	$1,819,240	$3,797,114
	NOx Cost ($000)	$536,935	$0	$536,935	$546,776	$426,458	$973,234	$482,901	$427,945	$910,846	$616,708	$550,462	$1,167,170
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$699,225	$654,006	$1,353,231	$1,347,907	$1,250,731	$2,598,637
	CHP Generation (GWh)												
Midwest	Generation(GWh)	373,709	343,601	717,310	398,191	366,398	764,589	433,874	402,480	836,354	471,984	437,824	909,808
	Fuel Consumption (GBtu)	2,820,938	2,605,984	5,426,922	3,065,127	2,831,262	5,896,389	3,395,790	3,152,379	6,548,169	3,722,907	3,457,592	7,180,499
	Fuel Cost ($000)	$5,626,031	$4,661,324	$10,287,355	$5,609,081	$4,912,250	$10,521,331	$6,962,075	$6,258,614	$13,220,689	$8,541,846	$7,737,112	$16,278,958
	SO2 Emissions (000 tons)	985	936	1,921	991	938	1,929	857	812	1,668	835	787	1,622
	NOx Emissions (000 tons)	324	306	630	313	292	605	266	249	515	261	243	504
	CO2 Emissions (000 tons)	280,199	259,505	539,703	292,924	270,215	563,140	312,557	289,977	602,534	338,007	313,651	651,658
	SO2 Cost ($000)	$1,019,562	$968,295	$1,987,857	$1,243,665	$1,177,455	$2,421,120	$1,262,757	$1,195,908	$2,458,665	$1,504,407	$1,416,309	$2,920,716
	NOx Cost ($000)	$271,884	$0	$271,884	$357,081	$300,513	$657,595	$274,730	$264,128	$538,858	$326,341	$312,035	$638,377
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$377,132	$353,451	$730,583	$692,648	$648,339	$1,340,987
	CHP Generation (GWh)												
Florida	Generation(GWh)	129,863	106,497	236,360	145,982	122,312	268,294	174,146	147,362	321,508	203,400	169,764	373,164
	Fuel Consumption (GBtu)	773,990	622,776	1,396,765	904,877	735,138	1,640,015	1,148,396	963,700	2,112,096	1,367,071	1,157,058	2,524,129
	Fuel Cost ($000)	$7,444,973	$5,775,626	$13,220,599	$5,791,524	$4,773,526	$10,565,050	$6,568,765	$5,519,382	$12,088,147	$8,654,304	$7,147,099	$15,801,403
	SO2 Emissions (000 tons)	167	133	300	157	129	286	162	130	292	159	122	282
	NOx Emissions (000 tons)	54	43	97	51	41	91	37	28	66	41	29	70
	CO2 Emissions (000 tons)	80,899	66,354	147,252	89,212	74,210	163,422	106,726	90,044	196,770	124,182	103,982	228,164
	SO2 Cost ($000)	$172,869	$137,559	$310,429	$198,762	$163,900	$362,662	$245,147	$196,162	$441,310	$297,303	$228,806	$526,109
	NOx Cost ($000)	$0	$0	$0	$100,986	$67,096	$168,082	$73,474	$55,778	$129,252	$97,654	$71,102	$168,756
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)												
Canada	Generation(GWh)	172,424	203,654	376,077	172,511	205,392	377,903	184,863	219,150	404,013	193,990	229,636	423,625
	Fuel Consumption (GBtu)	524,644	583,226	1,107,870	504,100	584,783	1,088,884	515,184	598,332	1,113,516	577,143	666,337	1,243,481
	Fuel Cost ($000)	$1,699,697	$1,993,078	$3,692,776	$1,716,192	$1,957,380	$3,673,572	$1,874,923	$2,112,711	$3,987,634	$2,386,319	$2,692,042	$5,078,360
	SO2 Emissions (000 tons)	68	74	142	70	76	146	73	77	151	75	80	155
	NOx Emissions (000 tons)	11	12	22	11	12	23	11	12	23	12	13	25
	CO2 Emissions (000 tons)	26,714	29,067	55,781	28,777	30,751	59,528	30,406	32,362	62,768	34,386	36,920	71,306
	SO2 Cost ($000)	$15,401	$16,698	$32,100	$15,802	$17,076	$32,878	$16,502	$17,440	$33,942	$16,966	$18,053	$35,020
	NOx Cost ($000)	$15,442	$0	$15,442	$15,650	$0	$15,650	$16,054	$0	$16,054	$17,054	$0	$17,054
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)												
Total For Run	Generation(GWh)	1,769,370	1,675,415	3,444,785	1,885,001	1,783,203	3,668,204	2,042,131	1,929,451	3,971,581	2,221,706	2,084,510	4,306,216
	Fuel Consumption (GBtu)	12,582,984	11,569,902	24,152,887	13,496,062	12,458,258	25,954,321	14,686,467	13,548,381	28,234,848	16,043,453	14,744,620	30,788,073
	Fuel Cost ($000)	$41,024,109	$35,796,996	$76,821,105	$37,713,718	$34,003,306	$71,717,025	$44,797,368	$40,516,946	$85,314,314	$55,457,950	$49,955,053	$105,413,003
	SO2 Emissions (000 tons)	5,591	5,337	10,928	4,677	4,496	9,173	3,840	3,658	7,498	3,452	3,275	6,727
	NOx Emissions (000 tons)	1,067	1,035	2,102	1,047	987	2,034	906	845	1,752	913	849	1,762
	CO2 Emissions (000 tons)	1,122,349	1,041,623	2,163,972	1,175,398	1,087,130	2,262,528	1,253,951	1,155,580	2,409,531	1,364,261	1,253,625	2,617,886
	SO2 Cost ($000)	$5,686,645	$5,419,260	$11,105,905	$5,749,109	$5,512,561	$11,261,670	$5,519,836	$5,237,983	$10,757,820	$6,014,796	$5,677,610	$11,692,405
	NOx Cost ($000)	$1,816,423	$29,078	$1,845,502	$1,730,494	$1,385,677	$3,116,171	$1,452,446	$1,342,525	$2,794,971	$1,786,432	$1,643,575	$3,430,007
	CO2 Cost ($000)	$0	$0	$0	$97,249	$83,722	$180,971	$2,671,307	$2,517,607	$5,188,914	$4,986,827	$4,681,535	$9,668,362
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0

See Table 10, Table 11, and Table 12 below for details of the differences between the three scenarios and the Reference Case. Of particular interest is the difference between the amounts of generation in all of the scenarios compared to the Reference Case in New York. The amount of generation increased in New York when CHP was added to the system. This increase in generation in New York is *not* due to the introduction of CHP resources, since CHP resources displaced other resources and caused them to generate less. Rather, it is a result of changes to the net load shape as a result of adding the CHP to the system. The increase in generation was created by changes in the operation of pumped storage capacity. The pumped storage capacity in New York was being dispatched in the model to reduce peak hours and fill off-peak hours in the hourly load profile. The changes in CHP penetration across the various scenarios have slightly altered the way in which the pumped storage and thermal resources have been dispatched. This, in turn, caused greater fuel consumption in New York. However, the change in dispatch of plants toward a cleaner overall mix led to a reduction of emissions SO2, and CO2 for New York, and the system as a whole. There was also a system-wide reduction in NOx emissions even though there were slight increases in Scenarios 1 and 3 compared to the Reference Case.

Table 10. Comparison of the Reference Case and Scenario 1

Comparison Reference Case & Scenario 1 (2006$)

		2006			2010			2015			2020		
Market Area	Data	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total
New York	Generation(GWh)	0	0	0	546	437	983	1,789	1,413	3,202	1,889	1,259	3,148
	Fuel Consumption (GBtu)	0	0	0	5,108	5,356	10,464	18,879	17,903	36,782	22,912	22,777	45,689
	Fuel Cost ($000)	$0	$0	$0	($85,896)	($82,541)	($168,437)	($261,568)	($271,209)	($532,777)	($407,611)	($422,737)	($830,347)
	SO2 Emissions (000 tons)	0	0	0	(1)	(1)	(1)	(3)	(2)	(4)	(5)	(3)	(8)
	NOx Emissions (000 tons)	0	0	0	0	0	0	0	0	1	(0)	0	0
	CO2 Emissions (000 tons)	0	0	0	(210)	(150)	(360)	(593)	(556)	(1,149)	(969)	(836)	(1,805)
	SO2 Cost ($000)	$0	$0	$0	($1,058)	($807)	($1,866)	($3,985)	($2,705)	($6,690)	($8,733)	($6,155)	($14,888)
	NOx Cost ($000)	$0	$0	$0	$27	$193	$220	$119	$949	$1,068	($305)	$650	$345
	CO2 Cost ($000)	$0	$0	$0	($572)	($410)	($982)	($1,917)	($1,797)	($3,713)	($4,171)	($3,598)	($7,770)
	CHP Generation (GWh)	0	0	0	1,704	1,662	3,367	5,820	5,669	11,489	7,971	7,760	15,731
New England	Generation(GWh)	0	0	0	(143)	(122)	(265)	(431)	(350)	(781)	(455)	(213)	(668)
	Fuel Consumption (GBtu)	0	0	0	(986)	(920)	(1,906)	(3,616)	(2,635)	(6,251)	(3,615)	(1,556)	(5,171)
	Fuel Cost ($000)	$0	$0	$0	($6,749)	($6,367)	($13,116)	($23,176)	($18,297)	($41,473)	($25,407)	($11,055)	($36,462)
	SO2 Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(1)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(51)	(63)	(113)	(240)	(182)	(422)	(247)	(109)	(356)
	SO2 Cost ($000)	$0	$0	$0	$102	($116)	($14)	($425)	($518)	($944)	($568)	($269)	($837)
	NOx Cost ($000)	$0	$0	$0	($2)	$1	($1)	($3)	($3)	($6)	($8)	($2)	($11)
	CO2 Cost ($000)	$0	$0	$0	$5	$7	$12	($66)	($69)	($135)	($179)	($72)	($251)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
PJM	Generation(GWh)	0	0	0	(25)	(118)	(143)	(289)	(193)	(482)	(525)	(382)	(908)
	Fuel Consumption (GBtu)	0	0	0	(99)	(850)	(949)	(2,788)	(1,799)	(4,587)	(4,185)	(2,655)	(6,840)
	Fuel Cost ($000)	$0	$0	$0	$319	($4,586)	($4,266)	($15,584)	($6,173)	($21,757)	($24,357)	($16,935)	($41,292)
	SO2 Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(1)	(1)	(2)	(1)	(0)	(1)
	NOx Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(9)	(65)	(74)	(197)	(168)	(365)	(302)	(189)	(490)
	SO2 Cost ($000)	$0	$0	$0	($64)	($344)	($408)	($797)	($2,169)	($2,966)	($1,940)	($307)	($2,247)
	NOx Cost ($000)	$0	$0	$0	($20)	($43)	($63)	($153)	($315)	($468)	($520)	($50)	($570)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($478)	($491)	($969)	($1,986)	($1,516)	($3,502)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
ECAR	Generation(GWh)	0	0	0	(147)	(119)	(265)	(533)	(156)	(689)	(312)	(564)	(876)
	Fuel Consumption (GBtu)	0	0	0	(429)	529	100	(2,750)	(1,092)	(3,842)	(2,569)	(1,708)	(4,277)
	Fuel Cost ($000)	$0	$0	$0	($6,379)	($8,762)	($15,142)	($26,301)	($4,822)	($31,124)	($12,918)	($26,464)	($39,382)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	0	(1)	(1)	(2)	(1)	(1)	(2)
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	(0)	(0)	(1)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(81)	(44)	(124)	(314)	(143)	(458)	(261)	(324)	(585)
	SO2 Cost ($000)	$0	$0	$0	($78)	$270	$192	($833)	($1,546)	($2,380)	($1,505)	($1,648)	($3,153)
	NOx Cost ($000)	$0	$0	$0	($79)	$174	$95	($257)	($832)	($1,089)	($422)	($555)	($977)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($1,270)	($580)	($1,850)	($1,867)	($2,322)	($4,188)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
SERC	Generation(GWh)	0	0	0	(184)	276	92	38	(302)	(264)	(198)	319	120
	Fuel Consumption (GBtu)	0	0	0	(1,710)	2,025	315	(338)	(4,302)	(4,640)	(4,394)	2,820	(1,575)
	Fuel Cost ($000)	$0	$0	$0	($8,796)	$14,243	$5,447	$689	($2,342)	($1,653)	($3,689)	$23,882	$20,193
	SO2 Emissions (000 tons)	0	0	0	0	0	0	0	0	0	(0)	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	0	0	0	(0)	0	(0)	0	(1)	(0)
	CO2 Emissions (000 tons)	0	0	0	(91)	145	54	(21)	(36)	(58)	(35)	136	101
	SO2 Cost ($000)	$0	$0	$0	$39	$276	$315	$148	$301	$448	($19)	($312)	($331)
	NOx Cost ($000)	$0	$0	$0	$191	$41	$232	($904)	$632	($273)	$667	($1,534)	($867)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($177)	($331)	($508)	$327	$25	$352
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Midwest	Generation(GWh)	0	0	0	(34)	(208)	(242)	(447)	(434)	(881)	(217)	(75)	(292)
	Fuel Consumption (GBtu)	0	0	0	(485)	(1,891)	(2,376)	(4,368)	(1,094)	(5,462)	(1,486)	(1,255)	(2,741)
	Fuel Cost ($000)	$0	$0	$0	($2,842)	($6,908)	($9,749)	($20,525)	($23,535)	($44,061)	($10,475)	$146	($10,329)
	SO2 Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	0	0	0	0	(0)	(0)	(0)	0	(0)
	CO2 Emissions (000 tons)	0	0	0	(13)	(91)	(104)	(263)	(281)	(543)	(116)	(46)	(162)
	SO2 Cost ($000)	$0	$0	$0	$80	($137)	($57)	($365)	($209)	($574)	($255)	($434)	($689)
	NOx Cost ($000)	$0	$0	$0	$23	($20)	$3	$109	($5)	$105	$86	$22	$108
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($1,311)	($348)	($1,659)	($984)	($859)	($1,842)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Florida	Generation(GWh)	0	0	0	17	(96)	(79)	(7)	(42)	(49)	(35)	(185)	(220)
	Fuel Consumption (GBtu)	0	0	0	197	(719)	(522)	(194)	(383)	(577)	(633)	(1,423)	(2,055)
	Fuel Cost ($000)	$0	$0	$0	$1,024	($2,999)	($1,976)	($1,229)	($3,059)	($4,288)	($3,445)	($10,038)	($13,484)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	0	0	0	0	0	0	0
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	0	(0)	0	0	(0)	0
	CO2 Emissions (000 tons)	0	0	0	5	(4)	1	(4)	(16)	(20)	(20)	(84)	(104)
	SO2 Cost ($000)	$0	$0	$0	($72)	$257	$185	$93	$35	$128	$149	$25	$175
	NOx Cost ($000)	$0	$0	$0	($25)	$98	$73	$35	($9)	$26	$28	($12)	$16
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Canada	Generation(GWh)	0	0	0	(73)	(77)	(150)	(184)	(58)	(243)	(250)	(237)	(487)
	Fuel Consumption (GBtu)	0	0	0	(418)	(475)	(893)	(545)	(185)	(729)	(1,291)	(1,386)	(2,678)
	Fuel Cost ($000)	$0	$0	$0	($3,240)	($3,417)	($6,657)	($11,236)	($2,534)	($13,771)	($13,054)	($11,961)	($25,016)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(32)	(31)	(63)	(123)	(29)	(152)	(123)	(98)	(221)
	SO2 Cost ($000)	$0	$0	$0	($10)	$0	($10)	($78)	($18)	($95)	($40)	($10)	($49)
	NOx Cost ($000)	$0	$0	$0	($3)	$0	($3)	($158)	$0	($158)	($47)	$0	($47)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Total For Run	Generation(GWh)	0	0	0	(42)	(27)	(69)	(66)	(122)	(187)	(102)	(79)	(182)
	Fuel Consumption (GBtu)	0	0	0	1,178	3,054	4,232	4,281	6,413	10,694	4,739	15,613	20,351
	Fuel Cost ($000)	$0	$0	$0	($112,558)	($101,337)	($213,895)	($358,932)	($331,972)	($690,904)	($500,957)	($475,163)	($976,120)
	SO2 Emissions (000 tons)	0	0	0	(1)	(0)	(1)	(4)	(5)	(9)	(7)	(5)	(12)
	NOx Emissions (000 tons)	0	0	0	0	0	1	(1)	(0)	(1)	(0)	(1)	(1)
	CO2 Emissions (000 tons)	0	0	0	(482)	(302)	(784)	(1,756)	(1,412)	(3,168)	(2,073)	(1,549)	(3,622)
	SO2 Cost ($000)	$0	$0	$0	($1,062)	($601)	($1,663)	($6,244)	($6,829)	($13,073)	($12,909)	($9,109)	($22,019)
	NOx Cost ($000)	$0	$0	$0	$111	$445	$556	($1,212)	$417	($795)	($521)	($1,482)	($2,003)
	CO2 Cost ($000)	$0	$0	$0	($568)	($402)	($970)	($5,218)	($3,615)	($8,833)	($8,859)	($8,342)	($17,201)
	CHP Generation (GWh)	0	0	0	1,704	1,662	3,367	5,820	5,669	11,489	7,971	7,760	15,731

Table 11. Comparison of the Reference Case and Scenario 2

Comparison Reference Case & Scenario 2 (2006$)

		2006			2010			2015			2020		
Market Area	Data	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total
New York	Generation(GWh)	0	0	0	544	426	970	1,672	1,367	3,039	1,525	1,285	2,810
	Fuel Consumption (GBtu)	0	0	0	5,196	4,868	10,064	17,235	17,194	34,429	18,969	21,758	40,727
	Fuel Cost ($000)	$0	$0	$0	($84,695)	($85,040)	($169,735)	($241,764)	($244,277)	($486,040)	($390,028)	($379,304)	($769,332)
	SO2 Emissions (000 tons)	0	0	0	(1)	(1)	(1)	(2)	(1)	(4)	(4)	(3)	(7)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(3)
	CO2 Emissions (000 tons)	0	0	0	(179)	(165)	(344)	(483)	(380)	(863)	(909)	(621)	(1,530)
	SO2 Cost ($000)	$0	$0	$0	($1,138)	($725)	($1,863)	($3,376)	($2,266)	($5,642)	($7,848)	($6,057)	($13,906)
	NOx Cost ($000)	$0	$0	$0	($206)	($130)	($336)	($1,692)	($1,011)	($2,703)	($3,616)	($2,699)	($6,315)
	CO2 Cost ($000)	$0	$0	$0	($489)	($450)	($939)	($1,561)	($1,227)	($2,788)	($3,915)	($2,673)	($6,588)
	CHP Generation (GWh)	0	0	0	1,686	1,645	3,331	5,347	5,210	10,557	7,314	7,121	14,435
New England	Generation(GWh)	0	0	0	(130)	(137)	(267)	(363)	(279)	(642)	(396)	(206)	(602)
	Fuel Consumption (GBtu)	0	0	0	(962)	(1,069)	(2,031)	(3,047)	(1,961)	(5,008)	(3,335)	(1,496)	(4,831)
	Fuel Cost ($000)	$0	$0	$0	($6,765)	($7,119)	($13,883)	($19,329)	($13,538)	($32,866)	($22,677)	($10,769)	($33,446)
	SO2 Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(1)	(1)	(0)	(1)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(57)	(71)	(128)	(206)	(122)	(328)	(246)	(101)	(348)
	SO2 Cost ($000)	$0	$0	$0	$85	($181)	($96)	($478)	($271)	($749)	($1,047)	($176)	($1,224)
	NOx Cost ($000)	$0	$0	$0	($4)	($2)	($6)	($4)	($5)	($9)	($9)	($1)	($10)
	CO2 Cost ($000)	$0	$0	$0	$27	($44)	($17)	($95)	($65)	($160)	($224)	($33)	($257)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
PJM	Generation(GWh)	0	0	0	(33)	(81)	(114)	(252)	(233)	(485)	(492)	(355)	(846)
	Fuel Consumption (GBtu)	0	0	0	(171)	(497)	(668)	(2,334)	(1,962)	(4,296)	(3,844)	(2,541)	(6,384)
	Fuel Cost ($000)	$0	$0	$0	($106)	($3,588)	($3,694)	($13,352)	($7,808)	($21,160)	($23,161)	($16,567)	($39,728)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	(0)	(0)	(1)	(2)	(1)	(0)	(1)
	NOx Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(14)	(32)	(46)	(166)	(174)	(340)	(272)	(174)	(446)
	SO2 Cost ($000)	$0	$0	$0	($76)	$29	($46)	($581)	($1,949)	($2,530)	($1,650)	($550)	($2,201)
	NOx Cost ($000)	$0	$0	$0	($22)	($23)	($45)	($140)	($272)	($412)	($460)	($98)	($558)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($356)	($561)	($917)	($1,670)	($1,242)	($2,912)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
ECAR	Generation(GWh)	0	0	0	(123)	(40)	(164)	(600)	(228)	(829)	(266)	(470)	(736)
	Fuel Consumption (GBtu)	0	0	0	(272)	(199)	(470)	(3,169)	(1,247)	(4,416)	(2,556)	(1,330)	(3,886)
	Fuel Cost ($000)	$0	$0	$0	($5,312)	($803)	($6,115)	($28,434)	($8,217)	($36,651)	($10,044)	($21,122)	($31,166)
	SO2 Emissions (000 tons)	0	0	0	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(71)	(37)	(108)	(352)	(154)	(506)	(215)	(277)	(492)
	SO2 Cost ($000)	$0	$0	$0	($93)	($642)	($735)	($1,145)	($1,044)	($2,189)	($1,021)	($1,783)	($2,804)
	NOx Cost ($000)	$0	$0	$0	($88)	($49)	($137)	($346)	($817)	($1,163)	($344)	($467)	($811)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($1,422)	($622)	($2,044)	($1,542)	($1,987)	($3,529)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
SERC	Generation(GWh)	0	0	0	(166)	135	(31)	12	(212)	(200)	(166)	281	115
	Fuel Consumption (GBtu)	0	0	0	(1,485)	1,025	(459)	1,278	(3,521)	(2,243)	(4,002)	2,875	(1,128)
	Fuel Cost ($000)	$0	$0	$0	($7,792)	$6,381	($1,411)	($5,066)	$1,074	($3,992)	($361)	$20,735	$20,374
	SO2 Emissions (000 tons)	0	0	0	0	(0)	(0)	0	0	0	(0)	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	0	0	0	(1)	0	(0)	0	(1)	(0)
	CO2 Emissions (000 tons)	0	0	0	(84)	57	(26)	(93)	5	(88)	(16)	109	93
	SO2 Cost ($000)	$0	$0	$0	$33	($54)	($21)	$7	$263	$270	($23)	($406)	($429)
	NOx Cost ($000)	$0	$0	$0	$147	$51	$199	($1,470)	$568	($902)	$670	($1,516)	($846)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($146)	($370)	($517)	$452	($3)	$449
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Midwest	Generation(GWh)	0	0	0	(46)	(258)	(305)	(400)	(377)	(777)	(58)	(136)	(194)
	Fuel Consumption (GBtu)	0	0	0	(531)	(2,258)	(2,789)	(3,954)	(487)	(4,441)	(984)	(1,883)	(2,866)
	Fuel Cost ($000)	$0	$0	$0	($3,309)	($8,656)	($11,965)	($19,711)	($22,121)	($41,832)	($3,010)	($374)	($3,383)
	SO2 Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	0	(0)	(0)	(0)	0	0
	CO2 Emissions (000 tons)	0	0	0	(18)	(134)	(152)	(216)	(238)	(454)	(12)	(108)	(121)
	SO2 Cost ($000)	$0	$0	$0	$78	($361)	($283)	($140)	($49)	($189)	$76	($855)	($779)
	NOx Cost ($000)	$0	$0	$0	$9	($155)	($147)	$96	($19)	$77	$76	$45	$121
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($1,074)	($115)	($1,189)	($596)	($1,226)	($1,821)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Florida	Generation(GWh)	0	0	0	1	(17)	(15)	19	(76)	(57)	(27)	(208)	(235)
	Fuel Consumption (GBtu)	0	0	0	85	(157)	(72)	62	(624)	(562)	(442)	(1,511)	(1,953)
	Fuel Cost ($000)	$0	$0	$0	$100	$1,268	$1,368	$208	($4,210)	($4,002)	($2,155)	($10,698)	($12,854)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	0	0	0	0	0	(0)	0
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	0	(0)	0	0	(0)	0
	CO2 Emissions (000 tons)	0	0	0	(1)	36	35	5	(30)	(25)	(11)	(90)	(101)
	SO2 Cost ($000)	$0	$0	$0	($51)	$241	$190	$22	$14	$36	$142	($6)	$135
	NOx Cost ($000)	$0	$0	$0	($24)	$117	$93	$21	($13)	$8	$21	($15)	$6
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Canada	Generation(GWh)	0	0	0	(84)	(58)	(141)	(146)	(62)	(208)	(194)	(270)	(464)
	Fuel Consumption (GBtu)	0	0	0	(397)	(354)	(751)	(570)	(329)	(899)	(863)	(1,594)	(2,456)
	Fuel Cost ($000)	$0	$0	$0	($4,193)	($2,554)	($6,747)	($8,023)	($2,056)	($10,079)	($9,912)	($13,480)	($23,392)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(41)	(23)	(64)	(85)	(23)	(107)	(95)	(112)	(207)
	SO2 Cost ($000)	$0	$0	$0	($10)	$2	($8)	($39)	($4)	($43)	($40)	($13)	($52)
	NOx Cost ($000)	$0	$0	$0	($3)	$0	($3)	($82)	$0	($82)	($32)	$0	($32)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Total For Run	Generation(GWh)	0	0	0	(38)	(30)	(68)	(57)	(103)	(159)	(73)	(79)	(152)
	Fuel Consumption (GBtu)	0	0	0	1,464	1,359	2,823	5,501	7,063	12,564	2,944	14,278	17,221
	Fuel Cost ($000)	$0	$0	$0	($112,072)	($100,111)	($212,183)	($335,470)	($301,152)	($636,622)	($461,348)	($431,579)	($892,927)
	SO2 Emissions (000 tons)	0	0	0	(1)	(1)	(2)	(4)	(4)	(8)	(6)	(6)	(12)
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	(2)	(1)	(3)	(2)	(2)	(4)
	CO2 Emissions (000 tons)	0	0	0	(465)	(368)	(833)	(1,595)	(1,116)	(2,711)	(1,777)	(1,375)	(3,152)
	SO2 Cost ($000)	$0	$0	$0	($1,170)	($1,691)	($2,861)	($5,730)	($5,305)	($11,036)	($11,412)	($9,846)	($21,258)
	NOx Cost ($000)	$0	$0	$0	($191)	($192)	($382)	($3,617)	($1,569)	($5,186)	($3,693)	($4,752)	($8,445)
	CO2 Cost ($000)	$0	$0	$0	($462)	($494)	($956)	($4,654)	($2,961)	($7,614)	($7,495)	($7,164)	($14,659)
	CHP Generation (GWh)	0	0	0	1,686	1,645	3,331	5,347	5,210	10,557	7,314	7,121	14,435

Table 12. Comparison of the Reference Case and Scenario 3

Comparison Reference Case & Scenario 3 (2006$)

		2006			2010			2015			2020		
Market Area	**Data**	**Season 1: May-Oct.**	**Season 2: Nov-April**	**Annual Total**	**Season 1: May-Oct.**	**Season 2: Nov-April**	**Annual Total**	**Season 1: May-Oct.**	**Season 2: Nov-April**	**Annual Total**	**Season 1: May-Oct.**	**Season 2: Nov-April**	**Annual Total**
New York	Generation(GWh)	0	0	0	622	478	1,100	1,787	1,470	3,258	1,864	1,358	3,222
	Fuel Consumption (GBtu)	0	0	0	6,031	5,515	11,546	19,034	18,246	37,280	23,105	23,915	47,021
	Fuel Cost ($000)	$0	$0	$0	($95,030)	($96,935)	($191,965)	($275,871)	($283,665)	($559,536)	($422,918)	($428,575)	($851,493)
	SO2 Emissions (000 tons)	0	0	0	(1)	(1)	(2)	(2)	(2)	(4)	(5)	(4)	(8)
	NOx Emissions (000 tons)	0	0	0	1	1	1	1	1	2	0	1	1
	CO2 Emissions (000 tons)	0	0	0	(202)	(208)	(410)	(617)	(577)	(1,194)	(993)	(817)	(1,810)
	SO2 Cost ($000)	$0	$0	$0	($1,206)	($1,070)	($2,276)	($3,610)	($2,796)	($6,406)	($8,494)	($6,689)	($15,183)
	NOx Cost ($000)	$0	$0	$0	$1,082	$1,488	$2,570	$1,271	$1,941	$3,212	$886	$1,756	$2,642
	CO2 Cost ($000)	$0	$0	$0	($550)	($567)	($1,117)	($1,993)	($1,864)	($3,857)	($4,275)	($3,518)	($7,793)
	CHP Generation (GWh)	0	0	0	1,929	1,881	3,810	6,041	5,885	11,926	8,191	7,973	16,164
New England	Generation(GWh)	0	0	0	(98)	(157)	(255)	(411)	(368)	(779)	(491)	(238)	(729)
	Fuel Consumption (GBtu)	0	0	0	(684)	(1,250)	(1,933)	(3,573)	(2,688)	(6,261)	(4,003)	(1,826)	(5,829)
	Fuel Cost ($000)	$0	$0	$0	($3,870)	($7,420)	($11,290)	($22,910)	($18,487)	($41,397)	($27,884)	($12,798)	($40,683)
	SO2 Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(1)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(40)	(98)	(138)	(242)	(175)	(418)	(282)	(127)	(409)
	SO2 Cost ($000)	$0	$0	$0	($34)	($500)	($534)	($466)	($368)	($834)	($852)	($525)	($1,377)
	NOx Cost ($000)	$0	$0	$0	$1	($9)	($8)	($2)	($5)	($7)	($10)	($3)	($12)
	CO2 Cost ($000)	$0	$0	$0	$10	($89)	($79)	($39)	($140)	($179)	($210)	($45)	($255)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
PJM	Generation(GWh)	0	0	0	(26)	(106)	(132)	(276)	(266)	(542)	(519)	(389)	(907)
	Fuel Consumption (GBtu)	0	0	0	(146)	(678)	(824)	(2,706)	(2,315)	(5,021)	(4,197)	(2,773)	(6,970)
	Fuel Cost ($000)	$0	$0	$0	$324	($4,032)	($3,708)	($14,983)	($10,101)	($25,084)	($22,934)	($18,421)	($41,355)
	SO2 Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(1)	(2)	(1)	(0)	(2)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(14)	(46)	(60)	(196)	(196)	(391)	(316)	(187)	(503)
	SO2 Cost ($000)	$0	$0	$0	($54)	($167)	($222)	($751)	($2,015)	($2,766)	($2,773)	($607)	($3,381)
	NOx Cost ($000)	$0	$0	$0	($23)	($58)	($81)	($167)	($343)	($510)	($656)	($66)	($722)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($482)	($484)	($966)	($2,235)	($1,297)	($3,532)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
ECAR	Generation(GWh)	0	0	0	(167)	(38)	(205)	(614)	(183)	(797)	(274)	(529)	(803)
	Fuel Consumption (GBtu)	0	0	0	(571)	(125)	(696)	(3,232)	(480)	(3,712)	(2,129)	(1,531)	(3,661)
	Fuel Cost ($000)	$0	$0	$0	($7,980)	($1,477)	($9,457)	($29,978)	($7,501)	($37,479)	($11,444)	($24,645)	($36,089)
	SO2 Emissions (000 tons)	0	0	0	1	(0)	0	(1)	(1)	(2)	(1)	(1)	(2)
	NOx Emissions (000 tons)	0	0	0	0	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(76)	(29)	(105)	(357)	(140)	(497)	(218)	(303)	(522)
	SO2 Cost ($000)	$0	$0	$0	$723	($103)	$620	($918)	($1,560)	($2,477)	($1,266)	($1,724)	($2,990)
	NOx Cost ($000)	$0	$0	$0	$45	($68)	($22)	($296)	($921)	($1,217)	($287)	($484)	($771)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($1,442)	($564)	($2,006)	($1,564)	($2,174)	($3,739)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
SERC	Generation(GWh)	0	0	0	(261)	168	(93)	19	(197)	(177)	(186)	290	104
	Fuel Consumption (GBtu)	0	0	0	(1,581)	1,517	(64)	1,270	(3,664)	(2,393)	(3,498)	2,716	(782)
	Fuel Cost ($000)	$0	$0	$0	($14,946)	$8,676	($6,270)	($5,639)	$1,292	($4,347)	($2,591)	$22,387	$19,797
	SO2 Emissions (000 tons)	0	0	0	(0)	0	0	(0)	0	0	0	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(1)	0	(0)	0	(1)	(0)
	CO2 Emissions (000 tons)	0	0	0	(159)	93	(66)	(109)	8	(101)	(35)	122	87
	SO2 Cost ($000)	$0	$0	$0	($19)	$211	$192	($176)	$254	$78	$10	($366)	($356)
	NOx Cost ($000)	$0	$0	$0	($99)	($29)	($128)	($1,535)	$616	($919)	$472	($1,601)	($1,129)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($269)	($143)	($411)	$223	($132)	$91
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Midwest	Generation(GWh)	0	0	0	(53)	(217)	(270)	(425)	(487)	(911)	(219)	(123)	(342)
	Fuel Consumption (GBtu)	0	0	0	(784)	(1,308)	(2,092)	(4,279)	(1,599)	(5,879)	(2,022)	(1,834)	(3,856)
	Fuel Cost ($000)	$0	$0	$0	($2,971)	($10,217)	($13,188)	($20,822)	($26,183)	($47,005)	($9,508)	$808	($8,700)
	SO2 Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	0	(0)	(0)	(0)	0	0
	CO2 Emissions (000 tons)	0	0	0	(39)	(109)	(148)	(234)	(302)	(536)	(110)	(109)	(219)
	SO2 Cost ($000)	$0	$0	$0	($60)	($93)	($154)	($156)	($179)	($335)	($245)	($948)	($1,193)
	NOx Cost ($000)	$0	$0	$0	($1)	($51)	($53)	$89	$14	$104	$82	$14	$96
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	($1,136)	($337)	($1,473)	($1,011)	($1,293)	($2,304)
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Florida	Generation(GWh)	0	0	0	12	(97)	(86)	(9)	(63)	(72)	(17)	(195)	(213)
	Fuel Consumption (GBtu)	0	0	0	165	(740)	(575)	(233)	(637)	(870)	(376)	(1,493)	(1,868)
	Fuel Cost ($000)	$0	$0	$0	$298	($3,018)	($2,720)	($1,245)	($2,403)	($3,647)	($1,985)	($10,602)	($12,587)
	SO2 Emissions (000 tons)	0	0	0	(0)	0	0	0	0	0	0	0	0
	NOx Emissions (000 tons)	0	0	0	(0)	0	0	0	0	0	0	(0)	0
	CO2 Emissions (000 tons)	0	0	0	1	(7)	(6)	(6)	(6)	(12)	(11)	(88)	(99)
	SO2 Cost ($000)	$0	$0	$0	($74)	$249	$175	$72	$238	$310	$104	$40	$144
	NOx Cost ($000)	$0	$0	$0	($37)	$90	$53	$41	$95	$135	$6	($11)	($5)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Canada	Generation(GWh)	0	0	0	(71)	(70)	(142)	(137)	(34)	(170)	(258)	(268)	(526)
	Fuel Consumption (GBtu)	0	0	0	(317)	(379)	(696)	(237)	(38)	(275)	(1,324)	(1,506)	(2,830)
	Fuel Cost ($000)	$0	$0	$0	($3,663)	($3,129)	($6,792)	($9,074)	($1,181)	($10,255)	($13,107)	($13,603)	($26,711)
	SO2 Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	NOx Emissions (000 tons)	0	0	0	(0)	(0)	(0)	(0)	0	(0)	(0)	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(36)	(30)	(66)	(101)	(16)	(117)	(123)	(114)	(237)
	SO2 Cost ($000)	$0	$0	$0	($11)	($4)	($15)	($73)	($12)	($85)	($40)	($18)	($58)
	NOx Cost ($000)	$0	$0	$0	($3)	$0	($3)	($158)	$0	($158)	($46)	$0	($46)
	CO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
Total For Run	Generation(GWh)	0	0	0	(43)	(40)	(83)	(65)	(127)	(191)	(101)	(93)	(194)
	Fuel Consumption (GBtu)	0	0	0	2,113	2,553	4,666	6,043	6,826	12,870	5,557	15,668	21,225
	Fuel Cost ($000)	$0	$0	$0	($127,840)	($117,550)	($245,390)	($380,521)	($348,230)	($728,751)	($512,371)	($485,450)	($997,821)
	SO2 Emissions (000 tons)	0	0	0	(1)	(1)	(2)	(4)	(4)	(9)	(7)	(6)	(13)
	NOx Emissions (000 tons)	0	0	0	0	1	1	(0)	0	(0)	0	(0)	(0)
	CO2 Emissions (000 tons)	0	0	0	(565)	(433)	(998)	(1,862)	(1,403)	(3,265)	(2,087)	(1,623)	(3,710)
	SO2 Cost ($000)	$0	$0	$0	($735)	($1,478)	($2,213)	($6,077)	($6,437)	($12,515)	($13,556)	($10,837)	($24,393)
	NOx Cost ($000)	$0	$0	$0	$966	$1,363	$2,329	($757)	$1,397	$641	$447	($393)	$54
	CO2 Cost ($000)	$0	$0	$0	($541)	($656)	($1,197)	($5,361)	($3,531)	($8,892)	($9,073)	($8,459)	($17,532)
	CHP Generation (GWh)	0	0	0	1,929	1,881	3,810	6,041	5,885	11,926	8,191	7,973	16,164

As illustrated above, the results of the study were all driven directly by and are correlated to the amount of CHP generation in a given year or scenario. As the quantity of CHP generation increased, the overall market efficiency (Btu/kWh) also tended to increase[3]. In addition, as fuels were substituted , emissions of CO2 and SO2 tended to decline while emissions of NOx tended to increase. Figure 4 below shows the increase in CHP generation over the forecast period and the difference in levels of CHP generation between scenarios. CHP generation was zero in the Reference Case and in 2006, both of which represented cases and periods before the introduction of CHP from the policy programs studied under this analysis.

Figure 4. CHP Generation in New York by Year and Scenario

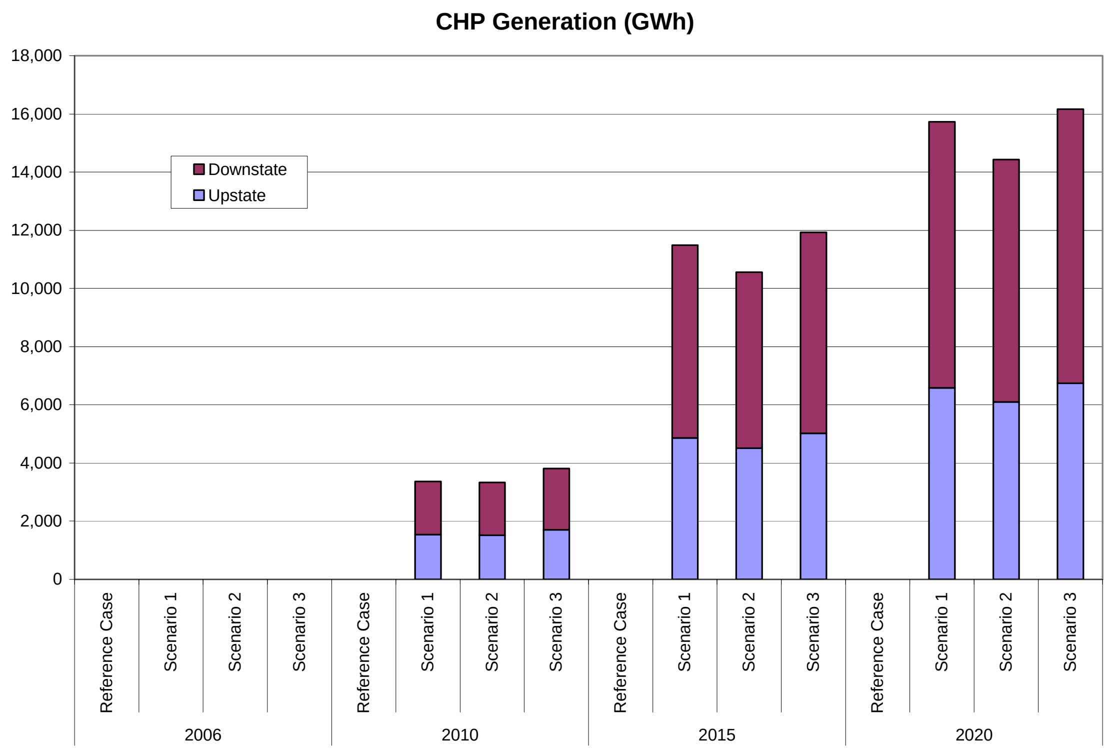
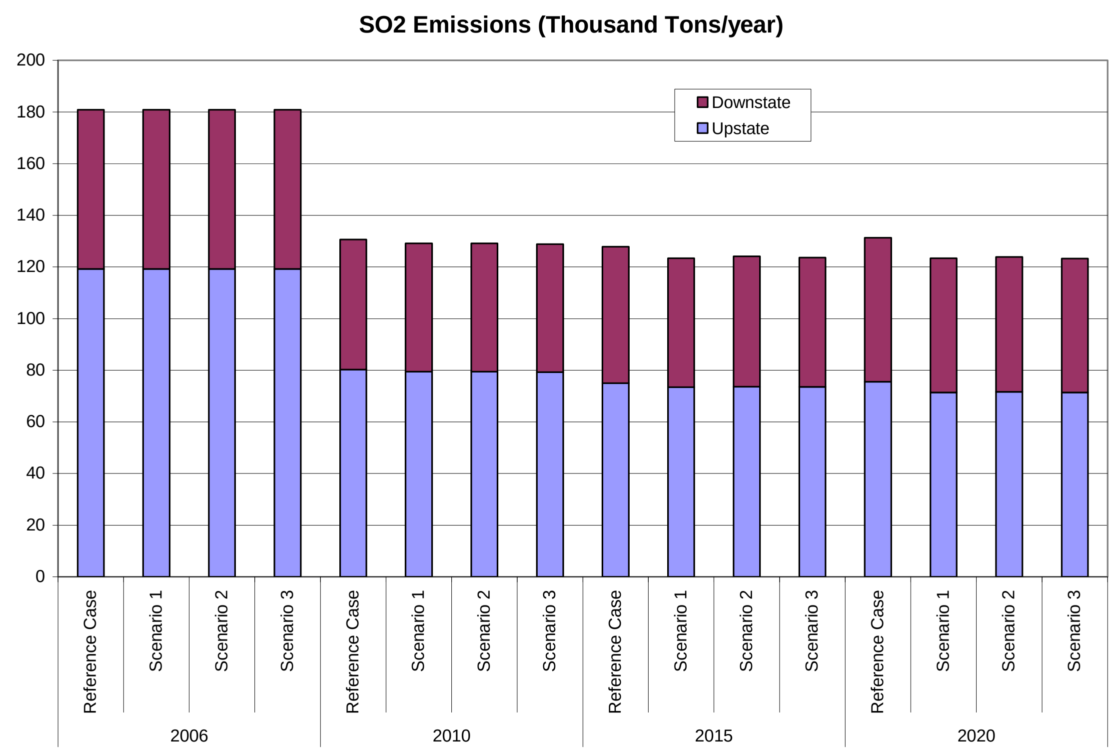


Figure 5 provides a comparison of SO2 emissions for the Reference Case and the three scenarios over the forecast period. As illustrated in the figure, there was dramatic decline in SO2 emissions after 2010. This was due to the planned retirement of coal capacity in upstate New York. CHP resources were projected to provide a significant reduction in SO2 emission levels when compared to the Reference Case during the forecast period. Although the reductions between CHP scenarios were subtle, the reduction between the Reference Case and the CHP scenarios were approximately 1,500 tons in 2010, 4,000 tons in 2015, and

[3] Increased efficiency in this case would indicate that fewer BTUs were consumed for each kWh produced.

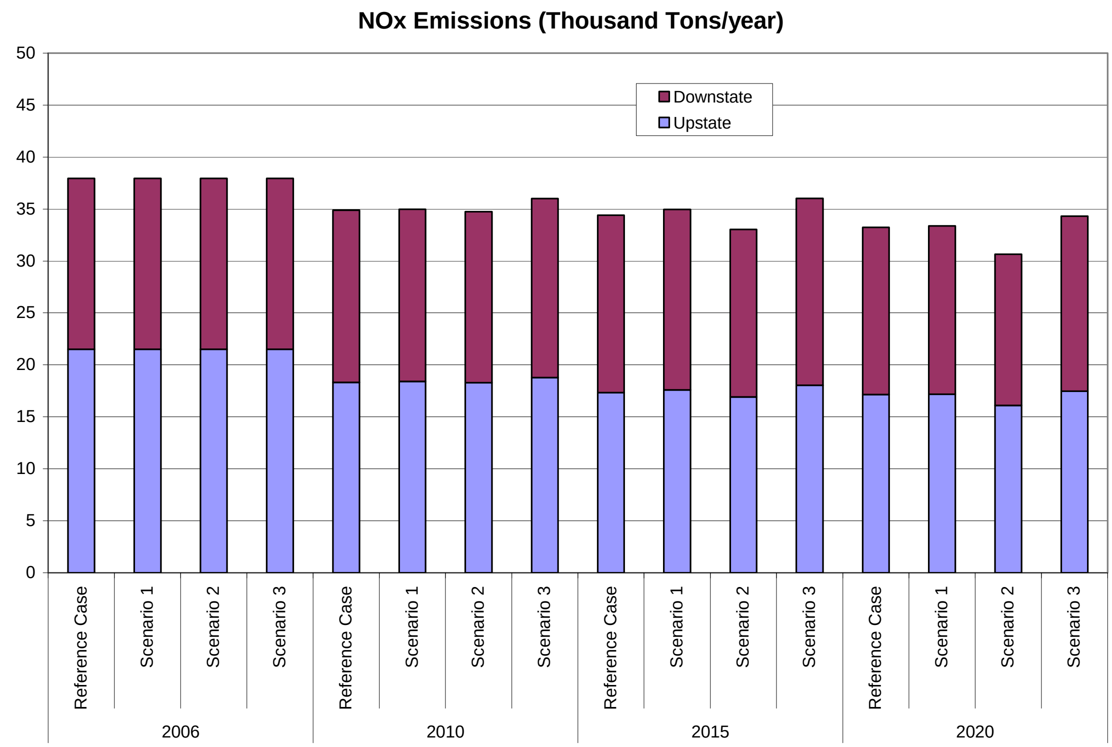
8,000 tons in 2020. As can be seen, the reduction in SO2 emissions was most dramatic in downstate NY, where SO2 was projected to decrease due to of displacement of oil-fired capacity.

Figure 5. SO2 Emissions by Year and Scenario



Similarly to the above, Figure 6 illustrates an overall decline in NOx emissions over the forecast period due to the planned retirement of coal capacity in upstate New York. As also can be seen from this figure, the projected amount of NOx emissions was proportional to the amount of CHP resources being included in the forecast beginning in 2010. In Scenario 1, the projected NOx emissions were similar to those in the Reference Case. In Scenario 2, which includes less CHP generation, the projected NOx emissions were less than Scenario 1. In Scenario 3, which includes more CHP generation than the Scenario 1, the projected NOx emissions were higher than Scenario 1. This indicates that the NOx emissions from CHP generation were, on average, higher than the energy that the CHP resources were displacing from central station plants. In terms of the magnitude of the NOx emissions from the introduction of CHP resources, in 2015 NOx emissions for Scenarios 1, 2, and 3 were approximately 35,000, 33,000, and 36,000 tons, respectively. Similarly, in 2020, NOx emissions for Scenarios 1, 2, and 3 were projected to be 33,400, 30,700, and 34,300 tons, respectively. The changes in NOx emissions between cases were projected to be minimal in 2010.

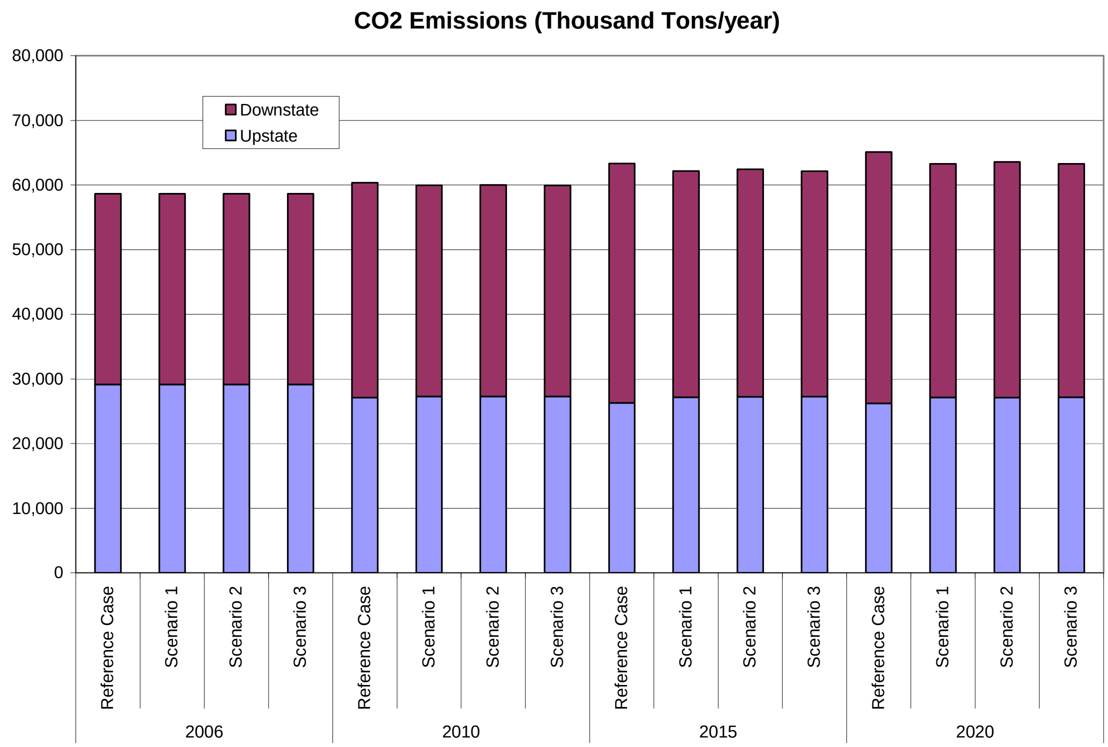
Figure 6. NOx Emissions by Year and Scenario



CO2 emissions were projected to increase over the forecast period in the Reference Case and in each of the three scenarios. However, the rate of increase in CO2 was different for each of the cases. Overall, the projected CO2 emissions for each of the scenarios were less than the Reference Case for each year of the forecast. However, difference between the reductions in CO2 emissions for each of the scenarios was projected to be minimal. In upstate New York, CO2 emissions were projected to decline over the forecast due to the retirement of coal-fired capacity. In downstate New York, CO2 emissions were projected to increase due to an increase in consumption and the increased operation of existing resources that have higher CO2 emission rates than the CHP resources. Figure 7 below shows the CO2 emissions by study year and scenario for New York State. As this chart illustrates, the total CO2 emissions were projected to increase over time with increases in load growth and the increased use of existing generation in downstate New York.

Since the New York electric grid is interconnected with neighboring regions, the impacts of CO2 emissions outside the state should also be considered in order to fully appreciate the potential impacts of CHP penetration. When these impacts are considered, the benefits of CHP installed in New York are significant. Table 10, Table 11, and Table 12 above show that across the entire Eastern Interconnect, the reduction in CO2 emissions resulting from CHP in New York ranges from 3.2 million tons/year to 3.7 million tons/year in 2020 when compared to the Reference Case.

Figure 7. CO2 Emissions by Year and Scenario



Scenario 1 established levels of generation, emissions of SO2, NOx, and CO2, and costs of fuels and emissions based on the emission rates established by NYSDEC and the CHP market penetration levels indicated in the October 2002 CHP study that were updated and revised to include a favorable market environment. These results are presented by region as well as the state as a whole in Table 13 below. Electric generation is shown in GWh by season and for each year studied. In addition, the fuel that was consumed in the production of electric energy is shown as well as the resulting emissions from SO2, NOx, and CO2 and the costs of that fuel and those pollutants. The generation from CHP projects is also given.

As discussed earlier, generation increased over the forecast period as a result of the increased operation of pumped storage hydro plants in New York. This naturally caused increased fuel consumption, which in turn, led to higher emissions of SO2, NOx, and CO2. Comparing across zones, Zone A-D represents greater than 50% of New York generation in 2006, while Zones J and K (New York City and Long Island) account for 20%. Thus, the upstate and downstate distinction was concentrated in these two market areas. Roughly 30% of CHP generation is in Zone A-D while approximately 36% is concentrated in Zone J (New York City).

Table 13. Scenario 1 - Baseline Results by Season and New York Zone (2006$)

		Scenario 1 Results											
		2006			2010			2015			2020		
Market Area	Data	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total
NY-A-D	Generation(GWh)	40,019	40,298	80,317	40,860	41,081	81,941	43,126	43,433	86,559	45,221	45,503	90,723
	Fuel Consumption (GBtu)	270,159	264,275	534,435	276,712	270,055	546,766	299,167	293,355	592,522	320,145	314,144	634,289
	Fuel Cost ($000)	$794,263	$862,244	$1,656,507	$627,408	$654,486	$1,281,894	$648,243	$673,199	$1,321,442	$706,342	$740,314	$1,446,656
	SO2 Emissions (000 tons)	60	58	118	39	39	78	36	36	72	35	35	70
	NOx Emissions (000 tons)	11	10	21	9	9	18	8	9	17	8	8	17
	CO2 Emissions (000 tons)	12,599	12,376	24,975	11,453	11,303	22,755	11,252	11,259	22,510	11,354	11,343	22,697
	SO2 Cost ($000)	$62,395	$59,738	$122,133	$49,731	$49,225	$98,956	$54,061	$55,021	$109,082	$65,192	$65,999	$131,191
	NOx Cost ($000)	$30,200	$16,459	$46,659	$19,238	$22,854	$42,092	$16,500	$17,057	$33,556	$20,237	$20,262	$40,499
	CO2 Cost ($000)	$0	$0	$0	$31,246	$30,837	$62,083	$36,357	$36,379	$72,736	$48,878	$48,833	$97,711
	CHP Generation (GWh)	0	0	0	552	539	1,091	1,741	1,697	3,438	2,354	2,293	4,647
NY-E	Generation(GWh)	2,348	2,700	5,049	2,420	2,788	5,209	2,612	2,973	5,584	2,721	3,066	5,788
	Fuel Consumption (GBtu)	12,820	13,364	26,184	13,545	14,239	27,784	15,451	16,078	31,529	16,541	17,028	33,569
	Fuel Cost ($000)	$91,264	$107,987	$199,251	$68,021	$80,150	$148,171	$65,651	$77,146	$142,797	$72,242	$84,798	$157,040
	SO2 Emissions (000 tons)	1	1	1	1	1	1	1	1	1	1	1	1
	NOx Emissions (000 tons)	0	0	0	0	0	0	0	0	0	0	0	0
	CO2 Emissions (000 tons)	660	692	1,351	679	726	1,405	748	792	1,540	795	827	1,621
	SO2 Cost ($000)	$645	$621	$1,266	$760	$780	$1,541	$950	$963	$1,913	$1,239	$1,209	$2,447
	NOx Cost ($000)	$299	$166	$464	$244	$303	$547	$310	$309	$619	$417	$405	$823
	CO2 Cost ($000)	$0	$0	$0	$1,851	$1,982	$3,833	$2,418	$2,559	$4,978	$3,421	$3,559	$6,980
	CHP Generation (GWh)	0	0	0	82	80	162	261	255	516	355	346	702
NY-F	Generation(GWh)	4,215	3,914	8,129	4,562	4,461	9,023	4,750	4,484	9,234	4,589	4,001	8,590
	Fuel Consumption (GBtu)	25,303	22,388	47,691	27,706	26,306	54,012	29,673	27,143	56,816	28,802	24,070	52,872
	Fuel Cost ($000)	$260,825	$256,231	$517,056	$182,666	$192,564	$375,229	$165,004	$166,702	$331,706	$169,289	$150,970	$320,259
	SO2 Emissions (000 tons)	0	0	0	0	0	0	0	0	0	0	0	0
	NOx Emissions (000 tons)	0	0	0	0	0	0	0	0	0	0	0	0
	CO2 Emissions (000 tons)	1,494	1,324	2,818	1,602	1,523	3,125	1,638	1,489	3,127	1,552	1,267	2,820
	SO2 Cost ($000)	$10	$9	$20	$14	$13	$26	$16	$15	$31	$19	$15	$34
	NOx Cost ($000)	$211	$92	$303	$216	$239	$455	$315	$283	$598	$388	$310	$698
	CO2 Cost ($000)	$0	$0	$0	$4,372	$4,155	$8,527	$5,291	$4,812	$10,104	$6,683	$5,455	$12,137
	CHP Generation (GWh)	0	0	0	145	142	287	461	449	910	624	608	1,232
NY-G	Generation(GWh)	7,078	6,060	13,138	8,833	7,834	16,667	9,083	7,161	16,245	7,642	5,568	13,210
	Fuel Consumption (GBtu)	66,730	55,140	121,870	83,914	72,036	155,949	84,714	63,448	148,163	69,984	48,411	118,395
	Fuel Cost ($000)	$476,472	$388,347	$864,818	$431,208	$380,280	$811,488	$392,924	$280,529	$673,452	$318,688	$177,743	$496,431
	SO2 Emissions (000 tons)	16	16	33	17	17	34	17	17	35	18	17	35
	NOx Emissions (000 tons)	3	3	7	4	4	7	4	4	7	4	3	7
	CO2 Emissions (000 tons)	5,125	4,338	9,464	6,294	5,483	11,777	6,265	4,790	11,055	5,253	3,843	9,095
	SO2 Cost ($000)	$16,979	$16,819	$33,798	$21,506	$21,547	$43,054	$26,465	$25,882	$52,347	$32,950	$32,078	$65,029
	NOx Cost ($000)	$9,470	$5,135	$14,605	$7,918	$9,162	$17,079	$7,639	$6,925	$14,565	$9,053	$8,223	$17,276
	CO2 Cost ($000)	$0	$0	$0	$17,173	$14,960	$32,133	$20,244	$15,476	$35,720	$22,611	$16,542	$39,153
	CHP Generation (GWh)	0	0	0	111	108	219	379	370	749	521	507	1,028
NY-H	Generation(GWh)	7,851	7,564	15,415	7,850	7,561	15,411	7,854	7,571	15,425	7,862	7,574	15,436
	Fuel Consumption (GBtu)	80,145	77,208	157,353	80,137	77,176	157,313	80,171	77,283	157,454	80,253	77,309	157,562
	Fuel Cost ($000)	$47,982	$46,244	$94,226	$45,392	$43,896	$89,288	$42,676	$41,454	$84,130	$40,300	$38,967	$79,267
	SO2 Emissions (000 tons)	0	0	1	0	0	1	0	0	1	0	0	1
	NOx Emissions (000 tons)	0	0	0	0	0	0	0	0	0	0	0	0
	CO2 Emissions (000 tons)	153	148	301	149	149	299	154	158	312	162	160	322
	SO2 Cost ($000)	$336	$325	$660	$400	$401	$801	$493	$506	$999	$641	$635	$1,276
	NOx Cost ($000)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	CO2 Cost ($000)	$0	$0	$0	$407	$408	$815	$497	$510	$1,007	$696	$689	$1,385
	CHP Generation (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
NY-I	Generation(GWh)	7	3	9	108	101	209	370	357	727	505	488	992
	Fuel Consumption (GBtu)	0	0	0	1,011	986	1,997	3,632	3,540	7,172	4,979	4,850	9,829
	Fuel Cost ($000)	$42	$15	$57	$42	$15	$57	$41	$15	$57	$42	$15	$57
	SO2 Emissions (000 tons)	0	0	0	0	0	0	0	0	0	0	0	0
	NOx Emissions (000 tons)	0	0	0	0	0	0	0	0	0	0	0	0
	CO2 Emissions (000 tons)	0	0	0	36	36	72	124	121	246	171	167	338
	SO2 Cost ($000)	$0	$0	$0	$0	$0	$0	$1	$1	$2	$2	$2	$3
	NOx Cost ($000)	$0	$0	$0	$45	$55	$99	$204	$198	$402	$288	$280	$568
	CO2 Cost ($000)	$0	$0	$0	$100	$97	$197	$402	$392	$794	$736	$717	$1,453
	CHP Generation (GWh)	0	0	0	101	99	200	363	354	717	498	485	983
NY-J	Generation(GWh)	11,530	8,103	19,633	16,654	11,549	28,203	19,967	15,190	35,157	23,174	17,970	41,144
	Fuel Consumption (GBtu)	104,559	72,240	176,799	145,080	95,511	240,591	163,840	120,304	284,144	182,972	140,462	323,435
	Fuel Cost ($000)	$1,066,752	$766,802	$1,833,554	$991,766	$677,479	$1,669,245	$946,448	$712,246	$1,658,694	$1,139,072	$901,415	$2,040,487
	SO2 Emissions (000 tons)	5	5	10	4	2	6	3	2	4	3	2	4
	NOx Emissions (000 tons)	3	2	5	3	2	5	3	2	5	3	2	5
	CO2 Emissions (000 tons)	6,475	4,448	10,923	8,850	5,671	14,521	9,446	6,733	16,179	10,295	7,751	18,046
	SO2 Cost ($000)	$5,531	$4,768	$10,299	$5,067	$3,160	$8,228	$3,799	$2,586	$6,385	$5,092	$3,070	$8,162
	NOx Cost ($000)	$7,905	$3,354	$11,259	$6,549	$4,671	$11,220	$5,730	$3,806	$9,536	$6,825	$4,540	$11,365
	CO2 Cost ($000)	$0	$0	$0	$24,143	$15,471	$39,614	$30,523	$21,756	$52,280	$44,320	$33,371	$77,691
	CHP Generation (GWh)	0	0	0	575	560	1,135	2,091	2,036	4,127	2,882	2,806	5,688
NY-K	Generation(GWh)	6,538	5,146	11,685	4,927	3,460	8,387	5,945	4,410	10,355	7,529	5,694	13,222
	Fuel Consumption (GBtu)	71,190	55,125	126,315	53,426	36,520	89,946	64,423	46,419	110,841	75,403	54,850	130,254
	Fuel Cost ($000)	$697,081	$532,708	$1,229,790	$374,205	$246,918	$621,123	$406,095	$278,488	$684,583	$487,104	$342,544	$829,648
	SO2 Emissions (000 tons)	10	8	18	5	4	9	6	4	11	7	5	12
	NOx Emissions (000 tons)	3	2	5	3	2	4	3	2	5	3	2	4
	CO2 Emissions (000 tons)	4,949	3,863	8,812	3,557	2,461	6,017	4,187	3,012	7,199	4,857	3,488	8,345
	SO2 Cost ($000)	$10,762	$8,258	$19,019	$6,401	$4,479	$10,880	$9,540	$6,441	$15,981	$13,961	$8,898	$22,859
	NOx Cost ($000)	$8,355	$3,247	$11,602	$5,499	$4,248	$9,747	$5,695	$4,078	$9,774	$6,443	$3,982	$10,425
	CO2 Cost ($000)	$0	$0	$0	$9,704	$6,714	$16,418	$13,528	$9,732	$23,260	$20,909	$15,013	$35,922
	CHP Generation (GWh)	0	0	0	138	134	273	524	508	1,032	737	715	1,451
Total NY State	Generation(GWh)	79,586	73,788	153,374	86,215	78,836	165,051	93,706	85,579	179,285	99,243	89,863	189,106
	Fuel Consumption (GBtu)	630,906	559,740	1,190,646	681,531	592,827	1,274,358	741,071	647,569	1,388,640	779,077	681,126	1,460,204
	Fuel Cost ($000)	$3,434,681	$2,960,579	$6,395,260	$2,720,708	$2,275,787	$4,996,495	$2,667,082	$2,229,778	$4,896,860	$2,933,079	$2,436,765	$5,369,845
	SO2 Emissions (000 tons)	93	87	181	66	63	129	63	60	123	64	60	123
	NOx Emissions (000 tons)	20	18	38	19	16	35	18	17	35	18	16	33
	CO2 Emissions (000 tons)	31,454	27,190	58,644	32,620	27,352	59,972	33,814	28,353	62,168	34,438	28,845	63,283
	SO2 Cost ($000)	$96,657	$90,538	$187,195	$83,880	$79,606	$163,486	$95,325	$91,415	$186,740	$119,096	$111,906	$231,002
	NOx Cost ($000)	$56,440	$28,454	$84,894	$39,708	$41,531	$81,239	$36,392	$32,657	$69,049	$43,651	$38,003	$81,654
	CO2 Cost ($000)	$0	$0	$0	$88,996	$74,624	$163,620	$109,262	$91,617	$200,878	$148,253	$124,178	$272,432
	CHP Generation (GWh)	0	0	0	1,704	1,662	3,367	5,820	5,669	11,489	7,971	7,760	15,731

With the introduction of CHP resources, the operation of other power plants was changed. Because the CHP plants were able to earn revenue from the production of steam, their power generation was competitively advantaged over many other plants. While they were not dispatched by the system operator, their operation, being exogenously forced upon the system, does alter the dispatch of the central generating stations[4]. Comparing Scenario 1 to Scenario 2, as shown in Table 14, emissions of SO_2 and CO_2 were both lower in Scenario 1. This is because CHP generation in Scenario 1 was greater than in Scenario 2.

4 For modeling purposes, as discussed earlier, the energy production from CHP resources was simply scheduled into the system.

Table 14. Comparison of Scenario 1 Results to Scenario 2 by Season and New York Zone (2006$)

		Scenario 1 less Scenario 2											
		2006			2010			2015			2020		
Market Area	Data	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total
NY-A-D	Generation(GWh)	0.0	0.0	0.0	16.0	12.8	28.7	91.7	89.4	181.1	139.4	137.3	276.7
	Fuel Consumption (GBtu)	0.0	0.0	0.0	155.0	112.7	267.7	853.5	885.9	1,739.4	1,421.5	1,381.6	2,803.1
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$402.1	($233.2)	$168.8	($1,221.3)	($1,443.5)	($2,664.8)	($660.5)	($2,580.2)	($3,240.7)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.14)	(0.14)	(0.28)	(0.25)	0.04	(0.21)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.04	0.04	0.08	0.18	0.26	0.45	0.36	0.40	0.76
	CO2 Emissions (000 tons)	0.00	0.00	0.00	4.05	2.66	6.71	(15.16)	(7.40)	(22.55)	1.82	12.20	14.03
	SO2 Cost ($000)	$0.00	$0.00	$0.00	($1.16)	($4.51)	($5.67)	($211.43)	($218.11)	($429.53)	($461.39)	$68.76	($392.63)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$84.79	$99.02	$183.81	$363.66	$515.45	$879.11	$869.96	$977.62	$1,847.58
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$11.27	$7.25	$18.52	($48.97)	($23.91)	($72.88)	$7.92	$52.40	$60.32
	CHP Generation (GWh)	0.0	0.0	0.0	9.6	9.3	18.8	126.8	123.5	250.3	171.9	167.1	339.0
NY-E	Generation(GWh)	0.0	0.0	0.0	1.4	3.1	4.5	19.5	18.7	38.1	26.4	25.4	51.8
	Fuel Consumption (GBtu)	0.0	0.0	0.0	14.2	31.1	45.2	194.6	186.8	381.4	264.3	254.1	518.4
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$4.1	$51.0	$55.1	$1.9	($1.1)	$0.8	$3.5	$0.0	$3.5
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	0.01	0.01	0.00	(0.00)	0.00	0.00	0.00	0.00
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.01	0.01	0.01	0.05	0.04	0.09	0.06	0.06	0.12
	CO2 Emissions (000 tons)	0.00	0.00	0.00	0.12	1.91	2.03	3.72	3.39	7.11	4.97	4.67	9.64
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$0.45	$6.18	$6.63	$0.65	($0.12)	$0.53	$0.38	$0.05	$0.43
	NOx Cost ($000)	$0.00	$0.00	$0.00	$11.22	$16.34	$27.56	$89.94	$87.29	$177.23	$147.76	$143.89	$291.65
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$0.34	$5.21	$5.55	$12.02	$10.95	$22.96	$21.40	$20.11	$41.50
	CHP Generation (GWh)	0.0	0.0	0.0	1.3	1.2	2.5	19.4	18.7	38.1	26.3	25.4	51.7
NY-F	Generation(GWh)	0.0	0.0	0.0	(5.8)	2.5	(3.3)	2.2	(69.3)	(67.0)	82.6	(46.9)	35.6
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(49.1)	51.4	2.3	186.9	(373.9)	(187.0)	869.0	(133.5)	735.5
	Fuel Cost ($000)	$0.0	$0.0	$0.0	($487.9)	$224.4	($263.5)	($974.4)	($4,713.0)	($5,687.4)	$2,995.6	($5,180.3)	($2,184.6)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.01	0.01	0.02	0.08	0.07	0.15	0.11	0.10	0.21
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(4.63)	1.95	(2.69)	(2.03)	(36.08)	(38.11)	33.50	(27.02)	6.48
	SO2 Cost ($000)	$0.00	$0.00	$0.00	($0.04)	$0.02	($0.02)	($0.03)	($0.37)	($0.40)	$0.40	($0.36)	$0.04
	NOx Cost ($000)	$0.00	$0.00	$0.00	$19.02	$24.79	$43.81	$156.50	$144.97	$301.47	$265.79	$243.26	$509.06
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($12.64)	$5.31	($7.33)	($6.57)	($116.57)	($123.14)	$144.22	($116.31)	$27.91
	CHP Generation (GWh)	0.0	0.0	0.0	2.2	2.2	4.4	33.5	32.6	66.1	46.1	44.8	90.9
NY-G	Generation(GWh)	0.0	0.0	0.0	(13.4)	40.2	26.8	(24.0)	(157.8)	(181.8)	3.5	(46.5)	(42.9)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(163.6)	443.5	279.8	(42.9)	(1,582.6)	(1,625.5)	216.5	(299.9)	(83.4)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	($1,181.4)	$4,285.9	$3,104.5	($2,264.9)	($13,258.5)	($15,523.3)	($1,220.4)	($5,479.2)	($6,699.6)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	(0.03)	(0.02)	0.00	(0.01)	(0.01)	0.00	(0.00)	(0.00)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.00	0.01	0.01	0.08	0.05	0.13	0.10	0.09	0.20
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(17.05)	23.57	6.52	(6.56)	(119.71)	(126.26)	(4.14)	(38.10)	(42.25)
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$2.18	($31.33)	($29.16)	$4.83	($18.41)	($13.58)	$1.05	($1.23)	($0.17)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$6.88	$18.92	$25.81	$161.69	$104.16	$265.85	$255.76	$230.60	$486.36
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($46.52)	$64.31	$17.79	($21.19)	($386.79)	($407.98)	($17.84)	($164.03)	($181.86)
	CHP Generation (GWh)	0.0	0.0	0.0	0.9	0.9	1.8	30.6	30.0	60.6	42.7	41.6	84.3
NY-H	Generation(GWh)	0.0	0.0	0.0	(0.1)	(0.1)	(0.2)	0.0	0.0	0.1	(0.1)	(0.0)	(0.1)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(1.2)	(0.8)	(2.0)	0.5	0.1	0.6	(1.2)	(0.3)	(1.5)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	($3.6)	($2.5)	($6.1)	$1.5	$0.3	$1.8	($3.8)	($0.8)	($4.6)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(0.09)	(0.06)	(0.16)	0.04	0.01	0.05	(0.10)	(0.02)	(0.12)
	SO2 Cost ($000)	$0.00	$0.00	$0.00	($0.25)	($0.17)	($0.42)	$0.12	$0.02	$0.15	($0.39)	($0.08)	($0.47)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($0.26)	($0.17)	($0.43)	$0.12	$0.02	$0.15	($0.42)	($0.09)	($0.51)
	CHP Generation (GWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY-I	Generation(GWh)	0.0	0.0	0.0	0.5	0.5	0.9	31.2	30.2	61.4	43.7	42.5	86.2
	Fuel Consumption (GBtu)	0.0	0.0	0.0	4.4	4.3	8.8	311.9	301.9	613.8	437.0	425.1	862.1
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	SO2 Emissions (000 tons)	0.00	0.00	0.00	(0.00)	(0.00)	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.01	0.01	0.01	0.08	0.07	0.15	0.10	0.10	0.19
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(0.36)	(0.35)	(0.71)	5.15	4.94	10.10	7.82	7.59	15.41
	SO2 Cost ($000)	$0.00	$0.00	$0.00	($0.00)	($0.00)	($0.00)	$0.05	$0.05	$0.10	$0.08	$0.08	$0.16
	NOx Cost ($000)	$0.00	$0.00	$0.00	$11.85	$14.52	$26.37	$149.58	$145.76	$295.34	$240.10	$233.91	$474.00
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($0.98)	($0.95)	($1.93)	$16.66	$15.97	$32.62	$33.66	$32.66	$66.32
	CHP Generation (GWh)	0.0	0.0	0.0	0.5	0.5	0.9	31.2	30.2	61.4	43.7	42.5	86.2
NY-J	Generation(GWh)	0.0	0.0	0.0	5.1	(41.5)	(36.4)	(23.8)	136.8	113.0	51.6	(134.8)	(83.2)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(44.2)	(76.1)	(120.2)	(48.2)	1,357.7	1,309.6	599.8	(561.4)	38.4
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$113.9	($1,302.1)	($1,188.1)	($13,206.1)	($3,820.3)	($17,026.4)	($14,377.6)	($24,607.8)	($38,985.4)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.06	0.04	0.10	(0.25)	(0.08)	(0.33)	(0.16)	(0.04)	(0.21)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.04	0.06	0.10	0.36	0.40	0.76	0.50	0.51	1.01
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(11.70)	(4.58)	(16.28)	(85.46)	7.82	(77.64)	(80.42)	(140.03)	(220.44)
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$72.63	$51.52	$124.15	($376.69)	($121.63)	($498.32)	($303.50)	($80.14)	($383.64)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$85.56	$146.49	$232.04	$711.96	$786.60	$1,498.56	$1,234.37	$1,246.99	$2,481.37
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($31.93)	($12.43)	($44.35)	($276.14)	$25.20	($250.94)	($346.17)	($602.80)	($948.97)
		0.0	0.0	0.0	3.1	2.9	6.1	182.7	177.3	360.0	257.0	249.4	506.4
NY-K	Generation(GWh)	0.0	0.0	0.0	(1.5)	(6.6)	(8.1)	19.6	(1.9)	17.7	17.1	(2.6)	14.5
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(3.4)	(78.8)	(82.2)	187.7	(66.6)	121.1	136.4	(46.9)	89.5
	Fuel Cost ($000)	$0.0	$0.0	$0.0	($48.5)	($524.2)	($572.8)	($2,140.9)	($3,696.4)	($5,837.3)	($4,319.8)	($5,583.8)	($9,903.6)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	(0.08)	(0.08)	(0.02)	(0.05)	(0.07)	(0.06)	(0.05)	(0.11)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.01	0.00	0.01	0.09	0.09	0.18	0.12	0.11	0.23
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(1.11)	(10.39)	(11.50)	(9.77)	(29.34)	(39.11)	(23.04)	(34.21)	(57.24)
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$5.95	($104.44)	($98.49)	($27.22)	($80.05)	($107.27)	($120.89)	($84.99)	($205.88)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$13.09	$3.33	$16.42	$177.22	$176.22	$353.44	$297.23	$272.82	$570.05
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($3.03)	($28.35)	($31.38)	($31.56)	($94.80)	($126.36)	($99.17)	($147.26)	($246.43)
	CHP Generation (GWh)	0.0	0.0	0.0	0.6	0.7	1.3	48.8	47.2	96.1	69.8	67.4	137.2
State	Generation(GWh)	0.0	0.0	0.0	2.1	10.7	12.8	116.5	46.0	162.5	364.2	(25.7)	338.5
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(87.9)	487.3	399.4	1,644.0	709.2	2,353.2	3,943.4	1,018.8	4,962.1
	Fuel Cost ($000)	$0.0	$0.0	$0.0	($1,201.4)	$2,499.3	$1,297.9	($19,804.2)	($26,932.5)	($46,736.7)	($17,583.0)	($43,432.2)	($61,015.1)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.06	(0.06)	(0.00)	(0.40)	(0.29)	(0.69)	(0.47)	(0.05)	(0.53)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.11	0.12	0.24	0.92	0.99	1.91	1.35	1.37	2.72
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(30.77)	14.70	(16.07)	(110.07)	(176.37)	(286.43)	(59.58)	(214.92)	(274.50)
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$79.75	($82.73)	($2.98)	($609.71)	($438.62)	($1,048.33)	($884.25)	($97.91)	($982.16)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$232.42	$323.41	$555.82	$1,810.55	$1,960.45	$3,771.00	$3,310.96	$3,349.10	$6,660.06
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($83.74)	$40.17	($43.57)	($355.63)	($569.94)	($925.57)	($256.40)	($925.32)	($1,181.72)
	CHP Generation (GWh)	0.0	0.0	0.0	18.1	17.6	35.7	473.0	459.5	932.4	657.5	638.2	1,295.7

The greater energy output of the CHP plants in Scenario 1 displaced some generation from coal and oil plants in the state[5], thereby causing fewer emissions of SO2 and CO2 in Scenario 1 than in Scenario 2. The higher level of CHP generation in Scenario 1 compared to Scenario 2 had the opposite impact on NOx emissions. These extra NOx emissions in Scenario 1 were simply due to the extra fuel that was burned by the CHP plants themselves compared to Scenario 2.

[5] In the downstate New York region, particularly New York City and Long Island, there are some oil-fired plants that operate on a "must run" basis in order to provide system support. We did not, however, model these units as "must run" as it was determined inappropriate for this kind of a long-term study. New plants or transmission lines are likely to enter the market and alleviate the need for plants to receive out-of-market payments over time. In addition, the Prosym model is a zonal model and does not capture those local reliability issues. Nonetheless, those plants in New York City and Long Island burning heavy fuel oil operated on average at nearly 40% of capacity in 2006. Adding CHP reduced the capacity factors of those plants to an average of 21% to 26% in Scenario 1 between 2010 and 2020.

Table 15. Comparison of Scenario 1 Results to Scenario 3 by Season and New York Zone (2006$)

		Scenario 1 less Scenario 3											
		2006			2010			2015			2020		
Market Area	Data	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total	Season 1: May-Oct.	Season 2: Nov-April	Annual Total
NY-A-D	Generation(GWh)	0.0	0.0	0.0	(50.4)	(29.8)	(80.2)	(62.4)	(67.3)	(129.8)	(63.6)	(15.6)	(79.1)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(548.8)	(275.7)	(824.6)	(643.5)	(694.6)	(1,338.0)	(629.9)	(153.2)	(783.1)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	($409.7)	$1,303.9	$894.2	$399.9	($1,317.1)	($917.2)	($55.3)	$2,021.3	$1,966.0
	SO2 Emissions (000 tons)	0.00	0.00	0.00	(0.07)	0.15	0.08	(0.13)	(0.02)	(0.14)	(0.20)	0.19	(0.02)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.01	0.02	0.03	(0.06)	(0.00)	(0.06)	(0.00)	0.07	0.07
	CO2 Emissions (000 tons)	0.00	0.00	0.00	(1.79)	27.64	25.85	(10.79)	(9.62)	(20.41)	(7.09)	37.55	30.45
	SO2 Cost ($000)	$0.00	$0.00	$0.00	($90.28)	$209.13	$118.85	($236.64)	($35.38)	($272.02)	($529.67)	$491.00	($38.67)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$16.76	$63.72	$80.48	($145.87)	$1.09	($144.79)	($9.73)	$239.30	$229.57
	CO2 Cost ($000)	$0.00	$0.00	$0.00	($5.28)	$82.94	$77.66	($43.23)	($38.63)	($81.86)	($42.48)	$225.25	$182.77
	CHP Generation (GWh)	0.0	0.0	0.0	(58.7)	(57.0)	(115.7)	(57.5)	(55.9)	(113.3)	(56.9)	(55.5)	(112.5)
NY-E	Generation(GWh)	0.0	0.0	0.0	(8.3)	(8.2)	(16.5)	(8.7)	(8.5)	(17.2)	(8.7)	(8.7)	(17.4)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(83.0)	(81.9)	(164.9)	(86.9)	(84.8)	(171.8)	(87.6)	(86.5)	(174.1)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$20.9	$35.6	$56.5	$3.6	$8.4	$11.9	$1.4	$0.0	$1.4
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO2 Emissions (000 tons)	0.00	0.00	0.00	0.68	0.60	1.27	0.10	0.16	0.26	0.02	0.00	0.02
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$2.33	$1.08	$3.40	$0.44	$0.60	$1.04	$0.12	$0.00	$0.12
	NOx Cost ($000)	$0.00	$0.00	$0.00	$0.72	$0.50	$1.23	$0.09	$0.21	$0.30	($0.02)	$0.00	($0.02)
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$2.03	$1.79	$3.82	$0.39	$0.64	$1.03	$0.14	$0.00	$0.14
	CHP Generation (GWh)	0.0	0.0	0.0	(9.0)	(8.9)	(17.9)	(8.8)	(8.7)	(17.5)	(8.8)	(8.6)	(17.4)
NY-F	Generation(GWh)	0.0	0.0	0.0	(0.6)	12.7	12.1	9.2	(40.6)	(31.4)	11.6	(19.1)	(7.5)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(35.3)	102.1	66.8	28.6	(350.3)	(321.7)	19.6	(190.7)	(171.1)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$894.0	$2,150.6	$3,044.7	$1,473.1	($1,906.3)	($433.2)	$1,717.3	($715.8)	$1,001.6
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	(0.00)	0.00	(0.00)	0.00	(0.00)	(0.00)	(0.00)	(0.00)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	(0.00)	0.00	(0.00)	0.00
	CO2 Emissions (000 tons)	0.00	0.00	0.00	6.97	15.98	22.95	11.03	(14.12)	(3.09)	10.66	(2.14)	8.51
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$0.07	$0.15	$0.22	$0.14	($0.18)	($0.04)	$0.19	($0.04)	$0.15
	NOx Cost ($000)	$0.00	$0.00	$0.00	$1.71	$4.02	$5.73	$2.65	($4.10)	($1.45)	$3.08	($0.97)	$2.11
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$20.91	$47.94	$68.85	$44.11	($56.49)	($12.38)	$63.94	($12.86)	$51.08
	CHP Generation (GWh)	0.0	0.0	0.0	(15.7)	(15.4)	(31.1)	(15.2)	(14.9)	(30.1)	(15.1)	(14.7)	(29.8)
NY-G	Generation(GWh)	0.0	0.0	0.0	23.2	19.4	42.6	110.2	194.7	304.9	87.7	(8.8)	78.9
	Fuel Consumption (GBtu)	0.0	0.0	0.0	77.1	244.7	321.8	1,049.1	2,091.5	3,140.6	781.6	(86.8)	694.8
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$1,810.3	$3,748.5	$5,558.8	$9,711.1	$19,208.6	$28,919.7	$9,527.5	$644.6	$10,172.2
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	(0.01)	(0.01)	0.00	0.00	0.00	0.00	(0.00)	0.00
	NOx Emissions (000 tons)	0.00	0.00	0.00	(0.00)	0.00	0.00	0.02	0.03	0.05	0.01	0.00	0.01
	CO2 Emissions (000 tons)	0.00	0.00	0.00	7.39	24.12	31.51	74.78	138.44	213.22	56.60	3.96	60.56
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$1.44	($11.66)	($10.23)	$3.76	$2.13	$5.89	$5.37	($0.22)	$5.14
	NOx Cost ($000)	$0.00	$0.00	$0.00	($0.45)	$13.82	$13.36	$38.36	$69.52	$107.89	$35.56	$0.48	$36.04
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$22.18	$72.36	$94.54	$299.12	$553.75	$852.87	$339.61	$23.75	$363.36
	CHP Generation (GWh)	0.0	0.0	0.0	(14.8)	(14.5)	(29.3)	(14.6)	(14.1)	(28.7)	(14.3)	(13.8)	(28.1)
NY-H	Generation(GWh)	0.0	0.0	0.0	0.2	(0.1)	0.2	0.0	0.1	0.1	(0.1)	0.0	(0.0)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	2.3	(0.8)	1.6	0.1	0.8	0.9	(0.6)	0.0	(0.6)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$8.0	($2.7)	$5.3	$0.2	$3.1	$3.4	($2.6)	$0.0	($2.6)
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	(0.00)	0.00	(0.00)
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO2 Emissions (000 tons)	0.00	0.00	0.00	0.19	(0.06)	0.12	0.00	0.07	0.07	(0.05)	0.00	(0.05)
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$0.55	($0.19)	$0.37	$0.02	$0.26	$0.28	($0.26)	$0.00	($0.26)
	NOx Cost ($000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$0.56	($0.19)	$0.37	$0.02	$0.26	$0.28	($0.29)	$0.00	($0.29)
	CHP Generation (GWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY-I	Generation(GWh)	0.0	0.0	0.0	(14.9)	(14.7)	(29.7)	(15.0)	(14.6)	(29.6)	(14.7)	(14.3)	(29.1)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(149.6)	(147.2)	(296.7)	(149.7)	(145.7)	(295.5)	(147.3)	(143.2)	(290.5)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	CO2 Emissions (000 tons)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	NOx Cost ($000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	CHP Generation (GWh)	0.0	0.0	0.0	(14.9)	(14.7)	(29.7)	(15.0)	(14.6)	(29.6)	(14.7)	(14.3)	(29.1)
NY-J	Generation(GWh)	0.0	0.0	0.0	(24.2)	(29.8)	(53.9)	(22.8)	(124.9)	(147.7)	(1.2)	(6.8)	(8.0)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(213.2)	(164.5)	(377.7)	(293.5)	(1,233.3)	(1,526.8)	(354.0)	(202.2)	(556.1)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$5,657.6	$5,380.2	$11,037.8	$4,654.1	($3,166.2)	$1,488.0	$5,378.5	$6,861.1	$12,239.6
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.12	(0.00)	0.11	(0.16)	0.03	(0.12)	0.04	0.06	0.10
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.05	0.03	0.08	(0.02)	(0.02)	(0.04)	0.01	0.02	0.03
	CO2 Emissions (000 tons)	0.00	0.00	0.00	40.91	42.12	83.03	32.64	(20.06)	12.58	29.96	37.93	67.89
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$160.92	($1.69)	$159.23	($293.67)	$61.84	($231.84)	$95.81	$167.87	$263.68
	NOx Cost ($000)	$0.00	$0.00	$0.00	$112.49	$84.93	$197.41	($60.77)	($49.28)	($110.05)	$30.73	$63.05	$93.79
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$122.72	$126.33	$249.05	$130.56	($80.23)	$50.32	$179.84	$227.43	$407.27
		0.0	0.0	0.0	(88.3)	(85.9)	(174.2)	(87.0)	(84.8)	(171.9)	(86.9)	(84.3)	(171.2)
NY-K	Generation(GWh)	0.0	0.0	0.0	(1.0)	9.8	8.8	(8.9)	3.5	(5.3)	14.8	(26.0)	(11.2)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	27.7	163.9	191.6	(58.3)	72.8	14.4	224.9	(276.2)	(51.2)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$2,062.4	$3,210.1	$5,272.5	$1,464.2	$2,589.1	$4,053.3	$4,768.0	($673.5)	$4,094.6
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.06	0.07	0.13	0.03	0.04	0.08	0.04	0.03	0.07
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.01	0.03	0.03	(0.02)	0.01
	CO2 Emissions (000 tons)	0.00	0.00	0.00	17.36	24.88	42.24	11.82	19.72	31.54	29.49	(2.94)	26.55
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$87.73	$93.02	$180.75	$61.77	$84.59	$146.35	$97.39	$86.41	$183.79
	NOx Cost ($000)	$0.00	$0.00	$0.00	$25.97	$22.70	$48.68	$40.46	$22.50	$62.95	$98.41	($74.60)	$23.81
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$52.08	$74.64	$126.72	$47.28	$78.89	$126.17	$176.93	($17.62)	$159.31
	CHP Generation (GWh)	0.0	0.0	0.0	(23.2)	(22.4)	(45.6)	(23.0)	(22.5)	(45.5)	(22.8)	(22.2)	(44.9)
State	Generation(GWh)	0.0	0.0	0.0	(76.0)	(40.6)	(116.6)	1.5	(57.6)	(56.1)	25.8	(99.3)	(73.4)
	Fuel Consumption (GBtu)	0.0	0.0	0.0	(922.8)	(159.4)	(1,082.1)	(154.2)	(343.7)	(497.8)	(193.3)	(1,138.8)	(1,332.0)
	Fuel Cost ($000)	$0.0	$0.0	$0.0	$10,043.6	$15,826.2	$25,869.8	$17,706.3	$15,419.6	$33,125.9	$21,334.9	$8,137.8	$29,472.7
	SO2 Emissions (000 tons)	0.00	0.00	0.00	0.12	0.21	0.33	(0.25)	0.06	(0.19)	(0.13)	0.29	0.16
	NOx Emissions (000 tons)	0.00	0.00	0.00	0.07	0.07	0.13	(0.05)	0.02	(0.03)	0.05	0.07	0.11
	CO2 Emissions (000 tons)	0.00	0.00	0.00	71.71	135.28	206.99	119.58	114.58	234.16	119.59	74.35	193.94
	SO2 Cost ($000)	$0.00	$0.00	$0.00	$162.75	$289.84	$452.59	($464.19)	$113.85	($350.34)	($331.07)	$745.02	$413.95
	NOx Cost ($000)	$0.00	$0.00	$0.00	$157.20	$189.69	$346.89	($125.08)	$39.95	($85.14)	$158.05	$227.27	$385.31
	CO2 Cost ($000)	$0.00	$0.00	$0.00	$215.20	$405.82	$621.01	$478.24	$458.20	$936.44	$717.71	$445.94	$1,163.66
	CHP Generation (GWh)	0.0	0.0	0.0	(224.5)	(218.8)	(443.3)	(221.1)	(215.4)	(436.5)	(219.5)	(213.4)	(433.0)

Comparing Scenario 3 to Scenario 1, similar dynamics emerged. Scenario 3 had more CHP capacity, thus energy generation from CHP was greater than in Scenario 1 (See Table 15). This extra generation caused a reduction in the amount of generation from coal and oil units in New York compared to Scenario 1. Consequently, CO2 and SO2 emissions were comparatively lower in Scenario 3. NOx emissions were higher, however, due to the emissions of the CHP plants themselves.

6.2 Impact on wholesale electric prices resulting from DG/CHP by zone

Throughout all scenarios and all years, prices tend to be higher in the downstate zones than in the upstate zones. The upstate Zone A-D is characterized by a great deal of hydro, nuclear and coal capacity. Each of these capacity types has low variable costs of operation, which tends to depress electric prices during low and moderate demand periods. Downstate zones, by contrast, have gas and oil fired generation setting the market clearing price much of the time, leading to comparatively higher average prices.

Table 16. New York LBMP by Year, Zone, Season, and Scenario

		Scenario 1			Scenario 2			Scenario 3		
Market Area	Year	Season 1: May-Oct.	Season 2: Nov-April	Annual Average	Season 1: May-Oct.	Season 2: Nov-April	Annual Average	Season 1: May-Oct.	Season 2: Nov-April	Annual Average
NY-A-D	2006	$63.54	$62.93	$63.24	$63.54	$62.93	$63.24	$63.54	$62.93	$63.24
NY-E	2006	$63.87	$62.57	$63.22	$63.87	$62.57	$63.22	$63.87	$62.57	$63.22
NY-F	2006	$69.60	$73.25	$71.42	$69.60	$73.25	$71.42	$69.60	$73.25	$71.42
NY-G	2006	$71.46	$75.40	$73.43	$71.46	$75.40	$73.43	$71.46	$75.40	$73.43
NY-H	2006	$70.56	$74.63	$72.59	$70.56	$74.63	$72.59	$70.56	$74.63	$72.59
NY-I	2006	$71.15	$75.27	$73.21	$71.15	$75.27	$73.21	$71.15	$75.27	$73.21
NY-J	2006	$92.55	$89.67	$91.11	$92.55	$89.67	$91.11	$92.55	$89.67	$91.11
NY-K	2006	$118.01	$106.75	$112.38	$118.01	$106.75	$112.38	$118.01	$106.75	$112.38
NY-A-D	2010	$61.25	$62.58	$61.91	$61.08	$62.34	$61.71	$61.28	$62.22	$61.75
NY-E	2010	$61.53	$62.39	$61.96	$61.33	$62.09	$61.71	$61.62	$62.05	$61.83
NY-F	2010	$62.96	$65.02	$63.99	$62.78	$64.49	$63.63	$62.88	$64.40	$63.64
NY-G	2010	$64.09	$67.11	$65.60	$63.99	$66.77	$65.38	$63.95	$66.41	$65.18
NY-H	2010	$64.00	$65.80	$64.90	$63.82	$65.44	$64.63	$63.99	$65.37	$64.68
NY-I	2010	$64.60	$66.40	$65.50	$64.41	$66.05	$65.23	$64.58	$65.98	$65.28
NY-J	2010	$85.37	$73.77	$79.57	$85.67	$73.62	$79.65	$85.86	$73.27	$79.56
NY-K	2010	$94.93	$86.83	$90.88	$95.15	$86.60	$90.88	$94.54	$87.21	$90.87
NY-A-D	2015	$71.44	$71.98	$71.71	$71.26	$71.89	$71.57	$71.11	$71.95	$71.53
NY-E	2015	$71.88	$72.12	$72.00	$71.72	$71.98	$71.85	$71.59	$72.04	$71.82
NY-F	2015	$73.38	$73.60	$73.49	$73.29	$73.37	$73.33	$73.04	$73.45	$73.25
NY-G	2015	$74.23	$75.21	$74.72	$74.21	$74.69	$74.45	$73.87	$74.80	$74.34
NY-H	2015	$74.59	$74.54	$74.56	$74.36	$74.31	$74.33	$74.26	$74.44	$74.35
NY-I	2015	$75.29	$75.26	$75.28	$75.07	$75.03	$75.05	$74.96	$75.15	$75.05
NY-J	2015	$88.75	$78.87	$83.81	$88.64	$78.57	$83.61	$88.49	$78.49	$83.49
NY-K	2015	$107.22	$95.84	$101.53	$107.39	$96.04	$101.71	$107.10	$95.71	$101.41
NY-A-D	2020	$90.99	$92.63	$91.81	$91.37	$92.44	$91.90	$91.20	$92.50	$91.85
NY-E	2020	$91.78	$92.34	$92.06	$92.09	$92.08	$92.09	$91.93	$92.09	$92.01
NY-F	2020	$93.68	$94.16	$93.92	$93.93	$94.14	$94.03	$93.92	$94.04	$93.98
NY-G	2020	$95.14	$96.01	$95.57	$95.27	$95.91	$95.59	$95.27	$95.97	$95.62
NY-H	2020	$95.46	$95.72	$95.59	$95.67	$95.51	$95.59	$95.56	$95.57	$95.56
NY-I	2020	$96.41	$96.64	$96.52	$96.61	$96.43	$96.52	$96.49	$96.50	$96.49
NY-J	2020	$103.87	$100.47	$102.17	$104.05	$100.49	$102.27	$104.17	$100.29	$102.23
NY-K	2020	$122.24	$115.27	$118.76	$122.92	$115.54	$119.23	$122.05	$114.91	$118.48

The price impacts as a result of adding CHP when compared to the baseline Scenario 1 are largely driven by the amount of CHP added to the system. Beyond that, differences can be identified between upstate and downstate regions. In the upstate regions, with more low-cost generating capacity, the price effects of adding CHP were muted. In the downstate region, however, where there are more, higher-cost generating resources (fired by oil and gas) that could be displaced by CHP, the price impacts were more pronounced. The differences between the Reference Case and Scenarios 1, 2, and 3 are provided below in Table 17.

Table 17. Summary of LBMP Price Differences between Scenarios[6]

		Comparison Ref Case and Scenario 1			Comparison Ref Case & Scenario 2			Comparison Ref Case & Scenario 3		
Market Area	Year	Season 1: May-Oct.	Season 2: Nov April	Annual Average	Season 1: May-Oct.	Season 2: Nov April	Annual Average	Season 1: May-Oct.	Season 2: Nov April	Annual Average
NY-A-D	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-E	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-F	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-G	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-H	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-I	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-J	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-K	2006	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NY-A-D	2010	($0.46)	($0.19)	($0.32)	($0.62)	($0.43)	($0.53)	($0.42)	($0.55)	($0.49)
NY-E	2010	($0.32)	($0.08)	($0.20)	($0.51)	($0.38)	($0.45)	($0.23)	($0.42)	($0.33)
NY-F	2010	($0.34)	$0.12	($0.11)	($0.52)	($0.42)	($0.47)	($0.42)	($0.50)	($0.46)
NY-G	2010	($0.52)	$0.36	($0.08)	($0.62)	$0.01	($0.30)	($0.65)	($0.35)	($0.50)
NY-H	2010	($0.36)	($0.10)	($0.23)	($0.55)	($0.47)	($0.51)	($0.38)	($0.54)	($0.46)
NY-I	2010	($0.35)	($0.08)	($0.21)	($0.54)	($0.43)	($0.48)	($0.37)	($0.50)	($0.44)
NY-J	2010	($1.84)	($0.38)	($1.11)	($1.54)	($0.52)	($1.03)	($1.36)	($0.87)	($1.11)
NY-K	2010	($1.25)	($0.51)	($0.88)	($1.03)	($0.75)	($0.89)	($1.64)	($0.14)	($0.89)
NY-A-D	2015	($0.98)	($1.18)	($1.08)	($1.16)	($1.28)	($1.22)	($1.31)	($1.22)	($1.26)
NY-E	2015	($1.09)	($1.07)	($1.08)	($1.25)	($1.21)	($1.23)	($1.37)	($1.15)	($1.26)
NY-F	2015	($1.08)	($0.90)	($0.99)	($1.16)	($1.13)	($1.15)	($1.42)	($1.05)	($1.23)
NY-G	2015	($1.20)	($0.44)	($0.82)	($1.22)	($0.95)	($1.09)	($1.56)	($0.84)	($1.20)
NY-H	2015	($0.91)	($0.81)	($0.86)	($1.14)	($1.04)	($1.09)	($1.24)	($0.90)	($1.07)
NY-I	2015	($0.92)	($0.82)	($0.87)	($1.15)	($1.05)	($1.10)	($1.25)	($0.93)	($1.09)
NY-J	2015	($1.01)	($0.80)	($0.90)	($1.11)	($1.09)	($1.10)	($1.27)	($1.17)	($1.22)
NY-K	2015	($1.86)	($1.67)	($1.76)	($1.70)	($1.47)	($1.58)	($1.98)	($1.80)	($1.89)
NY-A-D	2020	($2.29)	($0.94)	($1.61)	($1.91)	($1.13)	($1.52)	($2.08)	($1.07)	($1.57)
NY-E	2020	($2.12)	($0.53)	($1.32)	($1.80)	($0.79)	($1.29)	($1.97)	($0.78)	($1.38)
NY-F	2020	($2.05)	($0.47)	($1.26)	($1.81)	($0.49)	($1.15)	($1.82)	($0.59)	($1.21)
NY-G	2020	($1.91)	($1.51)	($1.71)	($1.79)	($1.62)	($1.70)	($1.79)	($1.56)	($1.67)
NY-H	2020	($1.72)	($0.27)	($1.00)	($1.51)	($0.48)	($1.00)	($1.62)	($0.42)	($1.02)
NY-I	2020	($1.72)	($0.27)	($1.00)	($1.52)	($0.49)	($1.00)	($1.63)	($0.42)	($1.03)
NY-J	2020	($2.33)	($0.80)	($1.57)	($2.15)	($0.77)	($1.46)	($2.03)	($0.98)	($1.51)
NY-K	2020	($5.67)	($1.96)	($3.81)	($4.99)	($1.69)	($3.34)	($5.86)	($2.31)	($4.08)

6 Positive numbers indicate that Reference Case is more.

7 Conclusions

Due to its greater efficiency over traditional forms of generation, CHP has the potential to provide important environmental and economic benefits to New York State. However, many of these benefits may not be fully realized without the establishment of energy policies and environmental regulations that encourage the development of CHP resources. The purpose of this report is to quantify the benefits provided by deployment of CHP in terms of reduced wholesale energy prices, transmission congestion costs, and environmental emissions.

This study builds on a previous CHP market study conducted for NYSERDA in 2002. Using the 2002 study as a starting point, the current effort developed a new projection of CHP penetration, adding several important updates. First, the technical potential for CHP was revised, including applications for CHP where the primary thermal output is cooling. Second, the standby rate tariffs were included in the economic analyses, with relevant exemptions that were approved by the New York State Public Service Commission (NYPSC). These standby rates essentially removed a penalty for CHP units that were built into utility rates. Third, natural gas prices were updated based on the US DOE and EIA short and long-term forecasts. Finally, special delivery rates for natural gas offered by the natural gas utilities for non-residential customers who own and operate DG/CHP systems were incorporated into the study. These updates combined formed a positive regulatory environment for CHP.

Based on this supportive economic environment, CHP penetration was projected for three scenarios built around various approaches to NOx emissions regulations for CHP systems:

- Scenario 1, which was the Base Case scenario of this study, assumed an initial NOx emission rate limit of 1.6 lb/MWh for DG/CHP that remained constant through 2020 (the analysis period).

- Scenario 2 included a more aggressive "environmental forcing" strategy. It retained the favorable economic conditions of the base case scenario, but DG/CHP emission rate limits were reduced after five years to 1.0 lb/MWh and again in 2020 to 0.6 lb/MWh

- Scenario 3 included the phased in approach to more stringent emissions limits from Scenario 2, but also included a CHP thermal credit based on displacing on-site boiler emissions.

In addition to these three Scenarios, a Reference Case was modeled to establish a baseline without the introduction of new CHP in order to draw further comparisons and gauge the total magnitude of the CHP impact.

The economic market potential was determined for each scenario based on a comparison of the net power costs from the competing CHP technologies with the delivered electric and natural gas prices within that market size and geographical area. Within each market category (size and region), the competition among applicable technologies was evaluated, and the rate of market penetration by technology under each scenario was then estimated using a market diffusion model. Only "within the fence" CHP systems were considered in the analysis. All thermal energy and power generated by the CHP systems was assumed to be used on-site; no power export market was considered for any of the size categories.

By 2020, CHP penetration ranged from 11% (Scenario 2 – 2,170 MW of installed CHP) to 12% (Scenario 3 – 2,480 MW) of the technical market potential. The more restrictive NOx emissions standards of Scenario 2 reduced total CHP penetration by about 10% from the Base Case penetration. Allowing a CHP thermal credit (Scenario 3) increased CHP penetration by about 3% over the Base Case, even considering the stricter initial NOx standard of 1.0 lb/MWh. The impact of the different scenarios is more apparent when individual CHP technology penetration is considered. The stricter NOx standards of Scenario 2 restrict the deployment of reciprocating engine CHP compared to both the Base Case and Scenario 3, which included a CHP thermal emissions credit. Much of the reciprocating engine capacity was replaced by gas turbine CHP in the larger size categories, but only a small fraction was replaced by other technologies (microturbines and fuel cells) in the smaller size categories.

The market penetration results were then used as the basis to evaluate the impact of CHP deployment on overall emissions and on electricity prices. The reduction of electricity purchases from the grid was calculated for each county in New York on a seasonal and daily basis using: 1) the amount of estimated CHP capacity installed in each county; 2) the hours of operation (low load and high load); and 3) hourly and seasonal load shapes by customer groups. This reduction in "demand" was then factored into a production simulation model that captured the hour-by-hour dynamics of electric power markets and determined the impacts on central station dispatch and the need for new capacity over time. The emissions impacts of CHP at the site (i.e., displacing existing thermal sources with the CHP systems) were compared to the emissions impacts at the power plant level (i.e., comparing net incremental emissions at the sites with displaced emissions from the grid) to determine the overall environmental impact of CHP deployment for each scenario. To see the impact of CHP deployment in full, a Reference Case was modeled that simulated the economic dispatch of the electric system prior to the introduction of any new CHP capacity.

The load reduction on the electric system resulting from the operation of the CHP plants reduced CO2 emissions in each of the scenarios compared to the Reference Case, and did so across the entire Eastern Interconnect. In New York State alone, CO2 emissions in each of the scenarios were approximately 3% below the CO2 emission rate of the Reference Case in 2020. That reduction represents approximately *1.7 million tons of CO2*, on average, across scenarios when compared to the Reference Case Across the entire Eastern interconnected electric markets, however, the addition of CHP projects in New York was responsible for a reduction of approximately *3.5 million tons of CO2* in 2020 for each of the scenarios compared to the Reference Case. By 2020, there were approximately 3.6 million tons of CO2 emissions reductions in Scenario 1, roughly 3.2 million tons of CO2 emissions reductions in Scenario 2, and approximately 3.7 million tons of CO2 emissions reductions in Scenario 3 resulting from the introduction of CHP. In each of these scenarios, roughly half of the CO2 savings occurred in New York, with the other half distributed throughout the rest of the Eastern Interconnect.

Within New York, as stated in Section 6, the CO2 reductions were not evenly distributed. In the upstate region, coal-fired generation was retired and displaced, which reduced CO2 emissions relative to the Reference Case. In the downstate area, generation levels increased without displacing dirtier (more carbon intensive) forms of generation. This actually caused CO2 emission levels to increase relative to the Reference Case. Nonetheless, on average across scenarios the introduction of CHP was responsible for a reduction of approximately 1.7 million tons of CO2 emissions in NYS, and 3.5 million tons of CO2 emissions in the Eastern Interconnected electric markets in 2020.

The introduction of CHP in all three scenarios reduced prices compared to the Reference Case across the entire New York State. Price reductions occurred throughout the year, but were greatest in the summer season. On average across the state in 2020, Scenario 1 saw a $1.66/MWh (2006$) price decrease due to the introduction of CHP compared to the Reference Case. The price decrease in Scenario 2 in 2020 compared to the Reference case was $1.56/MWh (2006$), and in Scenario 3 it was $1.68/MWh (2006$) on average across the state. These impacts are significant and represent strong potential economic benefits for all electric customers in the state, as all customers would benefit from lower prices and not only those who own CHP plants.

With respect to NOx emissions, there was very little change in Scenario 1 compared to the Reference Case. In fact, NOx emission increased slightly: 140 tons for the full year in 2020, which included a 120-ton decrease during the summer season and a 270-ton increase during the winter season. The NOx emission limits produced emissions reductions throughout the year. In Scenario 1, however, once the NOx emissions from the CHP plants were added to the NOx emissions from all the other plants, the combined emissions increased in the winter months but remained below Reference Case levels in the summer months. In Scenarios 2 and 3, however, where greater restrictions were placed on NOx emissions, greater emission reductions were realized. Scenario 2 saw a 2,583-ton reduction in NOx emissions compared to the Reference Case in 2020 for the full year, and Scenario 3 saw a 1,080 increase in NOx emissions compared to the Reference Case, after accounting for the NOx emissions from the CHP plants themselves. In Scenario 2, NOx emissions were reduced during the summer and winter periods, with greater reductions occurring during the summer.

Considering the impact of the CHP penetration scenarios, it is apparent that reductions in CO2 emissions and electric prices are achievable. Reductions in NOx emissions however, were not realized by the introduction of CHP alone, but rather by the combination with stricter NOx limits. Therefore, while encouraging CHP development may further certain policy objectives, it is not likely to advance improvement in policy goals that seek to reduce NOx emissions in the state unless NOx limits are written into the standards.

Finally, this study demonstrated that the introduction of CHP in New York State will provide benefits to electric consumers in the form of lower electric prices and reduced emissions of CO_2, SO_2, and NOx when combined with policies that limit NOx emissions. Because of the load reducing effects that CHP has on the system, the generation dispatch of central stations is affected. This study showed that, especially in the upstate New York region, dirtier types of generation such as coal were actually retired and displaced, resulting in some of the environmental benefits. The displacement of coal-fired generation was especially apparent, from an environmental perspective, in the reduction of SO_2 emissions. While there were modest SO_2 emission reductions in regions outside of New York, the majority occurred within the state. Given other constraints, such as the available transmission capability between regions and relative prices between regions, emissions reductions outside of New York through the introduction of CHP plants should be viewed as a peripheral benefit -- CHP projects in New York will not likely have a far-reaching impact on the reduction of coal usage in regions outside the state.

It has been demonstrated that CHP is effective at providing economic and environmental benefits within New York and beyond. From a carbon perspective, the benefits were demonstrated in nearly every region modeled. From an economic perspective, the benefits to New York electric customers would be significant: nearly $1.70/MWh (2006$) in 2020 on average across the state. CHP systems can enhance both the economic welfare of New York electric consumers and the environmental conditions within the state and across the modeling region.

8 Appendices

8.1 Appendix A: Technical Potential for CHP

This section provides an estimate of the technical market potential for combined heat and power (CHP) in the industrial, commercial/institutional, and multi-family residential market sectors. The estimation of technical market potential consists of the following elements:

- Identification of applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications were identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.

- Quantification of the number and size distribution of target applications. Several data sources were used to identify the number of applications by sector that meets the thermal and electric load requirements for CHP.

- Estimation of CHP potential in terms of megawatt (MW) capacity. Total CHP potential is then derived for each target application based on the number of target facilities in each size category and sizing criteria appropriate for each sector.

- Subtraction of existing CHP from the identified sites to determine the remaining technical market potential.

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. Identifying technical market potential is a preliminary step in the assessment of market penetration.

The basic approach to developing the technical potential is described below:

- *Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user*. Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

- *Quantify the number and size distribution of target applications*. Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHI were utilized to identify potential CHP sites by SIC code or application, and location (county). The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kWs.
- *Estimate CHP potential in terms of MW capacity.* Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. **Table A-1** presents the specific target market sectors, and the assumed growth factors. Existing CHP capacity was subtracted from the technical potential in each specific size and market sector category.
- *Estimate the growth of new facilities in the target market sectors.* The technical potential included economic projections for growth through 2020 by target market sectors in New York State.

Two different types of CHP markets were included in the evaluation of technical potential:

- Traditional CHP – electric output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have “excess” thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:
    - High load factor applications – This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, and prisons.
    - Low load factor applications – Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

- CHP with thermally activated cooling – All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space-heating load in the winter months, and a portion of the cooling load in during the summer months. Two sub-categories were considered:
  - Low load factor applications – These represent markets that otherwise could not support CHP due to a lack of thermal load.
  - Incremental high load factor applications – These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system.

Table A-1 – Target Market Sectors for CHP and Sector Growth Projections Through 2020

SICs	Application	Adj. Annual Growth	2005-2020 Growth
4581	Airports	5.00%	107.89%
6513	Apartments	0.00%	0.00%
52,53,56,57	Big Box Retail	5.00%	107.89%
7542	Carwashes	0.00%	0.00%
28	Chemicals	5.00%	107.89%
8221, 8222	Colleges/Universities	0.95%	15.27%
34	Fabricated Metals	0.00%	0.00%
20	Food	0.00%	0.00%
5411, 5421, 5451, 5461, 5499	Food Sales	2.00%	34.59%
25	Furniture	0.90%	14.38%
7992, 7997-9904, 7997-9906	Golf/Country Clubs	0.93%	14.91%
7991, 00, 01	Health Clubs	0.93%	14.91%
8062, 8063, 8069	Hospitals	1.86%	31.84%
8062, 8063, 8069	Hospitals- Cooling	1.86%	31.84%
7011, 7041	Hotels	1.24%	20.33%
7011, 7041	Hotels- Cooling	1.24%	20.33%
38	Instruments	2.22%	39.07%
7211, 7213, 7218	Laundries	1.00%	16.10%
24	Lumber and Wood	1.55%	25.87%
35	Machinery/Computer Equip	5.00%	107.89%
39	Misc Manufacturing	0.00%	0.00%
7832	Movie Theaters	0.93%	14.91%
8412	Museums	0.20%	2.98%
8051, 8052, 8059	Nursing Homes	3.81%	75.31%
8051, 8052, 8059	Nursing Homes- Cooling	3.81%	75.31%
6512	Office Buildings	3.00%	55.73%
26	Paper	0.00%	0.00%
29	Petroleum Refining	1.06%	17.17%
43	Post Offices	0.00%	0.00%
33	Primary Metals	4.97%	107.01%
27	Printing/Publishing	0.00%	0.00%
9223, 9211 (Courts), 9224 (firehouses)	Prisons	0.00%	0.00%
5812, 00, 01, 03, 05, 07, 08	Restaurants	3.16%	59.43%
30	Rubber/Misc Plastics	0.78%	12.39%
8211, 8243, 8249, 8299	Schools	0.95%	15.27%
32	Stone/Clay/Glass	0.00%	0.00%
22	Textiles	0.00%	0.00%
37	Trasportation Equip.	1.87%	32.08%
4222, 5142	Warehouses	5.00%	107.89%
4941, 4952	Water Treatment/Sanitary	1.23%	20.18%

8.2 Appendix B: Energy Price Projections

The expected future relationship between purchased natural gas and electricity prices, called the "spark spread" in this context, is one major determinant of the ability of a facility with electric and thermal energy requirements to cost-effectively use CHP. A multilevel analysis of energy costs to customers was conducted for this study. The analysis consisted of the following:

- Detailed analysis of specific utility rate structures including standby and supplementary service to represent downstate and upstate costs
- Customer natural gas prices
- Long-term price trends

Electricity Prices

Niagara Mohawk (NiMo), the largest electric utility in the upstate region of New York was selected as the basis for analysis of customer rates and specific charges related to customers with CHP or other on-site generating systems in the upstate market. Consolidated Edison Company (ConEd) was used as the basis for estimating economic competitiveness in the downstate market.

Under the restructured power markets in the state, utilities bill customers separately for delivery charges and supply charges. The delivery charges cover the utility costs for their local transmission, distribution, and customer service operations. Supply charges represent the costs for electricity generation and transmission; in the current market, the New York Independent System Operator (NYISO) sets these costs on a regional basis. These supply costs are passed through to the customer.

Tariffs Used in the Analysis

For each of the five size categories in the CHP market assessment, the appropriate NiMo electric rate was selected for the upstate region and the ConEd rate selected for the downstate region. These rates are summarized below:

Niagara Mohawk (representing upstate region)

- 100-500 kW – SC3 – Large General Service
- 500-1,000 kW – SC3 – Large General Service
- 1-5 MW – SC3a – Large General Service Time of Use, Secondary
- 5-20 MW – SC3a – Large General Service TOU, Primary
- Greater than 20 MW – SC3a – Large General Service, Transmission voltage
- Standby Rates – SC7

Consolidated Edison (representing downstate region)

- Customers with demand between 10kW and 1,500 kW – SC9, Rate I – General, Large

- All customers with demand greater than 1,500kW – SC9, Rate II – General, Large, Time-of-use
- Supplementary Rate – SC10 – Supplementary Service
- Standby Rates – SC14A – Backup Service (replacing SC3 used in the 2002 New York CHP market study.)

Three usage rates were selected for each customer:

1. Constant usage – 8760 hours – based on the assumption that a nearly continuously operating CHP system would remove this slice from the annual energy bill, less downtime and standby.

2. Low load – 4500 hours – based on consumption patterns for a business that mostly shuts down at night and whose CHP system would be operating only on daytime basis.

3. AC load – 2000-2200 hours – to evaluate the avoided cost of electric chiller load that is taken over by a thermally activated technology using waste heat from the CHP system. Standby costs are not calculated for this usage because the CHP system itself is assumed to operate on one of the two schedules described above. Only the displaced electric chiller load is valued at this level.

Tariffs appropriate to the five customer sizes (50-500kW, 500-1000 kW, 1-5 MW, 5-20 MW, and >20 MW) were evaluated for each of these hourly usage levels and the standby charges were also calculated. The energy delivery costs were assumed to remain constant in real dollars over the forecast period. Half of the electricity supply costs were assumed to vary proportionally as a function of the natural gas price forecast, and the remaining half was assumed to be constant in real dollars.

The standby charges vary as a function of the annual hours of CHP operation with charges increasing as the load factor of the CHP system declines from continuous operation to 4500 hours/year. These charges were assumed to remain constant in real dollars over the forecast period.

The calculated average values were used in the market penetration model with the avoided purchased power cost equal to the average power cost at the appropriate load factor minus the standby costs. Table B-1 shows the average power costs for four sizes (5-20 MW and >20 MW size categories are assumed to use the same rates) and the three annual usage levels.

Table B-1. Calculated Average Electric Rates Input to the Market Penetration Model

Market and Year	Consolidated Edison			Niagara Mohawk		
	High Load	Low Load	Air Cond.	High Load	Low Load	Air Cond.
Commercial 50 kW to 500 kW						
2005	$0.135	$0.163	$0.223	$0.105	$0.141	$0.190
2010	$0.135	$0.162	$0.222	$0.105	$0.141	$0.190
2015	$0.128	$0.155	$0.213	$0.100	$0.136	$0.184
2020	$0.126	$0.153	$0.210	$0.099	$0.134	$0.183
Standby	$0.021	$0.037	n.a.	$0.016	$0.031	n.a.
Industrial -- 500 to 1,000 kW						
2005	$0.131	$0.154	$0.205	$0.102	$0.136	$0.179
2010	$0.130	$0.154	$0.205	$0.102	$0.135	$0.179
2015	$0.124	$0.146	$0.196	$0.098	$0.130	$0.173
2020	$0.122	$0.144	$0.193	$0.097	$0.129	$0.172
Standby	$0.020	$0.035	n.a.	$0.013	$0.029	n.a.
Large Industrial -- 1 to 5 MW						
2005	$0.126	$0.169	$0.306	$0.097	$0.124	$0.159
2010	$0.125	$0.168	$0.305	$0.096	$0.124	$0.159
2015	$0.119	$0.161	$0.291	$0.092	$0.119	$0.154
2020	$0.118	$0.159	$0.288	$0.091	$0.117	$0.152
Standby	$0.022	$0.044	n.a.	$0.011	$0.015	n.a.
Very Large Industrial -- Greater than 5 MW						
2005	$0.124	$0.161	$0.288	$0.088	$0.111	$0.138
2010	$0.124	$0.161	$0.287	$0.087	$0.110	$0.137
2015	$0.118	$0.153	$0.274	$0.083	$0.105	$0.132
2020	$0.116	$0.151	$0.270	$0.082	$0.104	$0.131
Standby	$0.022	$0.043	n.a.	$0.010	$0.013	n.a.

These results are shown graphically for the smallest and largest sizes in Figure B-1 and Figure B-2. Notable aspects of the rate analysis are as follows:

- Downstate rates are higher than upstate rates with the difference becoming more significant as the customer size class increases.
- Electric rates decline slightly over the forecast period as a result of the declining gas price forecast used for the analysis (described in the next section.)
- Standby rates are more severe for low load factor CHP applications. Though the standby costs are high, the high power costs leave enough avoided purchased power costs to provide an economic market for CHP.
- The avoided air conditioning electric costs are the highest, peak period costs reaching as high as $0.28/kWh.

Figure B-1. Calculated Average Purchased Power Costs for Commercial Customers

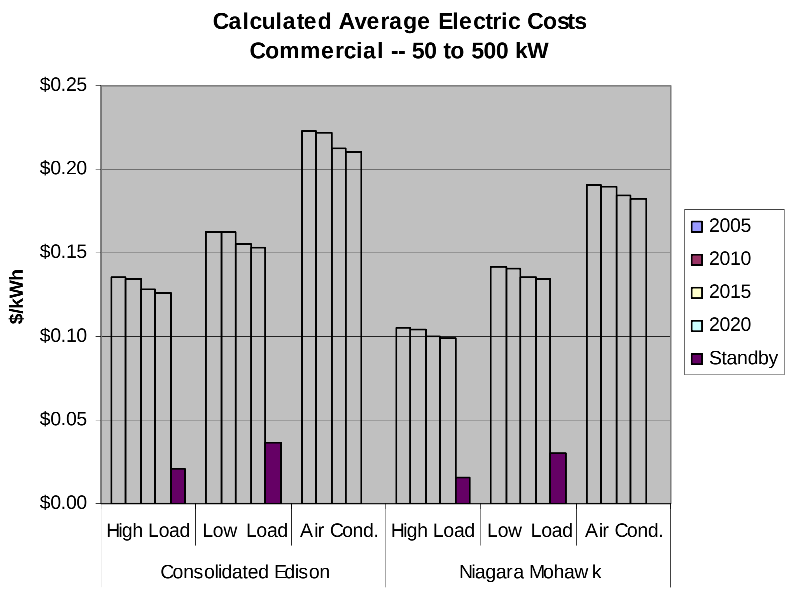
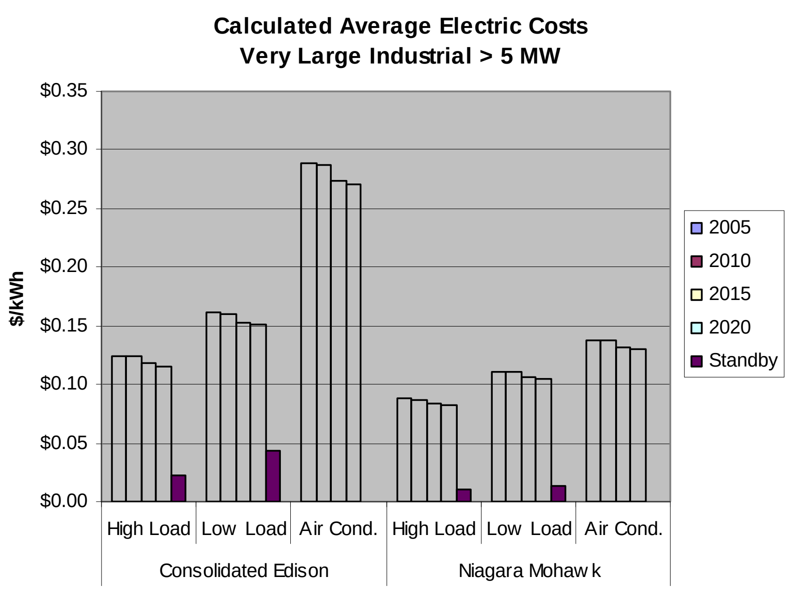


Figure B-2. Calculated Average Purchased Power Costs for Very Large Industrial Customers



Natural Gas Prices

The natural gas wellhead price forecast was specified by NYSERDA staff; the prices used as the basis for the analysis were from the update of the Regional Greenhouse Gas Initiative (RGGI.) The upstate and downstate delivery markups were adapted from the RGGI output as well. The customer markups were based on evaluation of EIA pricing. The complete price forecast is shown in Table B-2. Figure B-3 shows the wellhead price trends in real dollars throughout the forecast period.

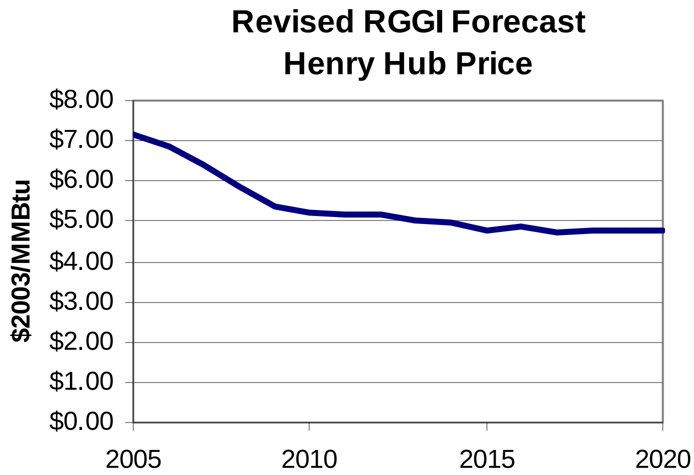
Table B-2. Natural Gas Price Forecast

Year	Henry Hub	Upstate			Downstate		
		EG/CHP	Industrial	Comm.	EG/CHP	Industrial	Comm.
2005	$7.14	$7.39	$7.54	$8.14	$7.96	$8.11	$8.71
2006	$6.86	$7.11	$7.26	$7.86	$7.68	$7.83	$8.43
2007	$6.43	$6.68	$6.83	$7.43	$7.25	$7.40	$8.00
2008	$5.86	$6.11	$6.26	$6.86	$6.68	$6.83	$7.43
2009	$5.39	$5.64	$5.79	$6.39	$6.21	$6.36	$6.96
2010	$5.22	$5.47	$5.62	$6.22	$6.04	$6.19	$6.79
2011	$5.16	$5.41	$5.56	$6.16	$5.98	$6.13	$6.73
2012	$5.19	$5.44	$5.59	$6.19	$6.01	$6.16	$6.76
2013	$5.02	$5.27	$5.42	$6.02	$5.84	$5.99	$6.59
2014	$4.96	$5.21	$5.36	$5.96	$5.78	$5.93	$6.53
2015	$4.79	$5.04	$5.19	$5.79	$5.61	$5.76	$6.36
2016	$4.87	$5.12	$5.27	$5.87	$5.69	$5.84	$6.44
2017	$4.71	$4.96	$5.11	$5.71	$5.53	$5.68	$6.28
2018	$4.76	$5.01	$5.16	$5.76	$5.58	$5.73	$6.33
2019	$4.76	$5.01	$5.16	$5.76	$5.58	$5.73	$6.33
2020	$4.77	$5.02	$5.17	$5.77	$5.59	$5.74	$6.34
Henry Hub Markups		$0.25	$0.40	$1.00	$0.25	$0.40	$1.00
		UpState Delivery		$0.19	Downstate Delivery		$0.57

Note: EG/CHP – Electric Generator/CHP rate

The natural gas prices trend downward more strongly than the electric prices because only a portion of the supply related costs of electricity vary with the gas price, with the remaining supply costs and all of the delivery costs being fixed. This relationship tends to make CHP more competitive during the later years of the forecast period.

Figure B-3 Natural Gas Price Forecast Trends – RGGI



8.3 Appendix C: CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100 – 20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines, and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work previously conducted for NYSERDA, on peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory[7] and on follow-on work conducted by DE Solutions for Oak Ridge National Laboratory.[8] Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work EEA is conducting for EPRI.[9] Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2005 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010 and 2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NOx, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without aftertreatment control (AT). NOx emissions are presented with and without a CHP thermal credit (using a displaced emissions approach and displaced boiler emissions of 0.2 lb/MMBtu for all technologies). Which system is applicable in any size category (e.g., with aftertreatment or without) is a function of the specific emissions requirements assumptions for each scenario. The installed costs in the

[7] "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL, November 2003, http://www.osti.gov/bridge

[8] "Clean Distributed Generation Performance and Cost Analysis", DE Solutions for ORNL. April 2004.

[9] "Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators", EPRI, January 2005.

following technology performance summary tables are based on typical national averages. The installed costs used in the CHP penetration analysis were adjusted for upstate and downstate New York based on industry construction indices.

Table C-1 - Reciprocating Engines

Size and Type	Characterization	2005	2012	2020
100 kW Rich Burn	Capacity, kW	100	100	100
	Installed Costs, $/kW	1,550	1,350	1,100
w/three way catalyst	Heat Rate, Btu/kWh	11,500	10,830	10,500
	Electric Efficiency, %	29.7%	31.5%	32.5%
	Power to Heat Ratio	0.61	0.67	0.7
	Thermal Output, Btu/kWh	5593	5093	4874
	O&M Costs, $/kWh	0.018	0.013	0.012
	NOx Emissions, lbs/MWh (no AT)	40	40	40
	NOx Emissions, lbs/MWh (w/ AT)	0.5	0.25	0.2
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	13.00	10.00	10.00
	CO Emissions w/AT, lb/MWh	1.87	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.47	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	AT Cost, $/kW	N/A	N/A	N/A
300 kW Rich Burn	Capacity, kW	300	300	300
	Installed Costs, $/kW	1,250	1,150	1,050
w/three way catalyst	Heat Rate, Btu/kWh	11,500	10,830	10,500
	Electric Efficiency, %	29.7%	31.5%	32.5%
	Power to Heat Ratio	0.61	0.67	0.7
	Thermal Output, Btu/kWh	5593	5093	4874
	O&M Costs, $/kWh	0.013	0.012	0.01
	NOx Emissions, lbs/MWh (no AT)	40	40	40
	NOx Emissions, lbs/MWh (w/ AT)	0.5	0.25	0.2
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	13.00	10.00	10.00
	CO Emissions, gm/bhp-hr	13	10	10
	CO Emissions w/AT, lb/MWh	1.87	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.47	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.10	0.10
	SO2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	AT Cost, $/kW	50	50	45
800 kW Lean Burn	Capacity, kW	800	800	800
	Installed Costs, $/kW	1,200	1,100	950
	Heat Rate, Btu/kWh	10,650	9,750	9,225
AT is SCR	Electric Efficiency, %	32.0%	35.0%	37.0%
	Power to Heat Ratio	0.8	0.9	1.05
% NOx reduction w/AT	Thermal Output, Btu/kWh	4265	3791	3250
2005 - 40%	O&M Costs, $/kWh	0.012	0.01	0.009
2010 - 30%	NOx Emissions, gm/bhphr	0.8	0.4	0.3
2020 - 40%	NOx Emissions, lbs/MWh (no AT)	2.48	1.24	0.93
	NOx Emissions, lbs/MWh (no AT; w/CHP)	1.41	0.29	0.12
	NOx Emissions, lbs/MWh (w/ AT)	1.49	0.87	0.56
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	3	2.5	2
	CO Emissions w/AT, lb/MWh	0.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.38	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO2 Emissions, lb/MWh	0.0063	0.0057	0.0054
	AT Cost, $/kW	300	190	140
3,000 kW Lean Burn	Capacity, kW	3000	3000	3000
	Installed Costs, $/kW	950	925	875
	Heat Rate, Btu/kWh	9,700	8,750	8,325
AT is SCR	Electric Efficiency, %	35.2%	39.0%	41.0%
	Power to Heat Ratio	1.04	1.07	1.18
% NOx reduction w/AT	Thermal Output, Btu/kWh	3281	3189	2892
2005 - 30%	O&M Costs, $/kWh	0.0085	0.0083	0.008
2010 - 30%	NOx Emissions, gm/bhphr	0.7	0.4	0.25
2020 - 30%	NOx Emissions, lbs/MWh (no AT)	2.17	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	1.35	0.44	0.05
	NOx Emissions, lbs/MWh (w/ AT)	1.52	0.87	0.53
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	2.5	2	2
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	AT Cost, $/kW	200	130	100
5,000 kW Lean Burn	Capacity, kW	5000	5000	5000
	Installed Costs, $/kW	925	900	850
	Heat Rate, Btu/kWh	9,213	8,325	7,935
AT is SCR	Electric Efficiency, %	37.0%	41.0%	43.0%
	Power to Heat Ratio	1.02	1.22	1.31
% NOx reduction w/AT	Thermal Output, Btu/kWh	3345	2797	2605
2005 - 20%	O&M Costs, $/kWh	0.008	0.008	0.008
2010 - 30%	NOx Emissions, gm/bhphr	0.5	0.4	0.25
2020 - 30%	NOx Emissions, lbs/MWh (no AT)	1.55	1.24	0.775
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.71	0.54	0.12
	NOx Emissions, lbs/MWh (w/ AT)	1.24	0.87	0.54
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, gm/bhp-hr	2.5	2	2
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.1	0.1
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	AT Cost, $/kW	150	115	80

CHP thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu

AT = Aftertreament

Additional O&M Costs for SCR

	2005	2012	2020	
800 kW Lean Burn	0.005	0.003	0.002	SCR Adder, $/kWh
	0.017	0.013	0.011	New total O&M w/SCR, $/kWh
3,000 kW Lean Burn	0.003	0.002	0.002	SCR Adder, $/kWh
	0.011	0.011	0.010	New total O&M w/SCR, $/kWh
5,000 kW Lean Burn	0.002	0.002	0.001	SCR Adder, $/kWh
	0.010	0.010	0.009	New total O&M w/SCR, $/kWh

Table C-2 Gas Turbines

Size and Type	Characterization	2005	2012	2020
1 MW Gas Turbine	Capacity, MW	1	1	1
	Installed Costs, $/kW	1,900	1,500	1,300
	Heat Rate, Btu/kWh	15,580	14,500	13,500
AT is SCR	Electric Efficiency, %	21.9%	23.5%	25.3%
	Power to Heat Ratio	0.51	0.61	0.7
	Thermal Output, Btu/kWh	6690	5593	4874
	O&M Costs, $/kWh	0.01	0.013	0.012
	NOx Emissions, ppm	42.0	15.0	9.0
	NOx Emissions, lbs/MWh (no AT)	2.2	0.7	0.4
	NOx Emissions, lbs/MWh (no AT; w/CHP)	0.53	-0.70	-0.82
	NOx Emissions, lbs/MWh (w/ AT)	0.22	0.07	0.04
	CO Emissions, ppm	6	20	20
	CO Emissions, lb/MWh	0.027	0.6	0.56
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.32	0.30	0.28
	SO2 Emissions, lb/MWh	0.0092	0.0085	0.0079
	AT Cost, $/kW	300	250	150
3 MW Gas Turbine	Capacity, MW	3	3	3
	Installed Costs, $/kW	1,300	1,200	1,000
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
AT is SCR	Power to Heat Ratio	0.68	0.76	0.84
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.68	0.38	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.57	-0.74	-0.82
	NOx Emissions, lbs/MWh (w/ AT)	0.068	0.038	0.02
	CO Emissions, ppm	20	20	20
	CO Emissions, lb/MWh	0.55	0.53	0.47
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO2 Emissions, lb/MWh	0.007	0.0069	0.0069
	AT Cost, $/kW	210	175	150
5 MW Gas Turbine	Capacity, MW	5	5	5
	Installed Costs, $/kW	1,100	1,000	950
	Heat Rate, Btu/kWh	12,590	11,375	10,500
	Electric Efficiency, %	27.1%	30.0%	32.5%
AT is SCR	Power to Heat Ratio	0.68	0.76	0.84
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.68	0.38	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.57	-0.74	-0.82
	NOx Emissions, lbs/MWh (w/ AT)	0.068	0.038	0.02
	AT Cost, $/kW	210	175	150
10 MW Gas Turbine	Capacity, MW	10	10	10
	Installed Costs, $/kW	965	950	850
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
AT is SCR	Power to Heat Ratio	0.73	0.84	0.94
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.006	0.005	0.005
	NOx Emissions, ppm	15.0	9.0	5.0
	NOx Emissions, lbs/MWh (no AT)	0.67	0.37	0.2
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.50	-0.65	-0.71
	NOx Emissions, lbs/MWh (w/ AT)	0.067	0.037	0.02
	CO Emissions, ppm	20	20	20
	CO Emissions, lb/MWh	0.5	0.46	0.42
	VOC Emissions, lb/MWh	0.022	0.021	0.02
	PMT 10 Emissions, lb/MWh	0.2	0.18	0.17
	SO2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	AT Cost, $/kW	140	125	100
25 MW Gas Turbine	Capacity, MW	25	25	25
	Installed Costs, $/kW	800	755	725
	Heat Rate, Btu/kWh	9,945	9,225	8,865
	Electric Efficiency, %	34.3%	37.0%	38.5%
AT is SCR	Power to Heat Ratio	0.95	1.04	1.1
	Thermal Output, Btu/kWh	3592	3281	3102
	O&M Costs, $/kWh	0.005	0.005	0.004
	NOx Emissions, ppm	15.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.6	0.2	0.1
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.30	-0.62	-0.68
	NOx Emissions, lbs/MWh (w/ AT)	0.06	0.02	0.01
	CO Emissions, ppm	20	20	20
	CO Emissions w/AT, lb/MWh	0.05	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.17	0.16	0.15
	SO2 Emissions, lb/MWh	0.0058	0.0054	0.0052
	AT Cost, $/kW	100	80	50
40 MW Gas Turbine	Capacity, MW	40	40	40
	Installed Costs, $/kW	700	680	660
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
AT is SCR	Power to Heat Ratio	1.07	1.13	1.18
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NOx Emissions, ppm	15.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.55	0.2	0.1
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.25	-0.55	-0.62
	NOx Emissions, lbs/MWh (w/ AT)	0.055	0.02	0.01
	CO Emissions, ppm	20	20	20
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.157	0.15	0.15
	SO2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	AT Cost, $/kW	90	75	40

CHP Thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu

AT = Aftertreatment

Table C-3 Microturbines

Size and Type	Characterization	2005	2012	2020
70-100 kW	Capacity, kW	70	70	70
	Installed Costs, $/kW	2,200	1,800	1,400
	Heat Rate, Btu/kWh	13,500	12,500	11,375
	Electric Efficiency, %	25.3%	27.3%	30.0%
	Power to Heat Ratio	0.7	0.9	1.1
	Thermal Output, Btu/kWh	4874	3791	3102
	O&M Costs, $/kWh	0.017	0.016	0.012
	NOx Emissions, ppm	3.0	3.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.15	0.14	0.13
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-1.07	-0.81	-0.65
	NOx Emissions, lbs/MWh (w/ AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, ppm	8	8	8
	CO Emissions, lb/MWh	0.24	0.22	0.20
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	AT Cost, $/kW	N/A	N/A	N/A
250 kW	Capacity, kW	250	250	250
	Installed Costs, $/kW	2,000	1,600	1,200
	Heat Rate, Btu/kWh	11,850	11,750	10,825
	Electric Efficiency, %	28.8%	29.0%	31.5%
	Power to Heat Ratio	0.94	1	1.3
	Thermal Output, Btu/kWh	3630	3412	2625
	O&M Costs, $/kWh	0.016	0.015	0.012
	NOx Emissions, ppm	9.0	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	0.43	0.24	0.13
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.48	-0.62	-0.53
	NOx Emissions, lbs/MWh (w/ AT)	N/A	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	N/A	N/A	N/A
	CO Emissions, ppm	9	9	9
	CO Emissions, lb/MWh	0.26	0.26	0.24
	VOC Emissions, lb/MWh	0.027	0.025	0.023
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	AT Cost, $/kW	500	200	90
500 kW	Capacity, kW	-	500	500
	Installed Costs, $/kW	-	1,150	900
	Heat Rate, Btu/kWh	-	10,350	9,750
	Electric Efficiency, %	-	33.0%	35.0%
	Power to Heat Ratio	-	1.3	1.38
	Thermal Output, Btu/kWh	-	2625	2472
	O&M Costs, $/kWh	-	0.015	0.012
	NOx Emissions, ppm	-	5.0	3.0
	NOx Emissions, lbs/MWh (no AT)	-	0.2	0.11
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-	-0.46	-0.51
	NOx Emissions, lbs/MWh (w/ AT)	-	N/A	N/A
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)	-	N/A	N/A
	CO Emissions, ppm	-	9	9
	CO Emissions, lb/MWh	-	0.24	0.23
	VOC Emissions, lb/MWh	-	0.025	0.023
	PMT 10 Emissions, lb/MWh		0.0061	0.0057
	SO2 Emissions, lb/MWh	-	0.0056	0.0053
	AT Cost, $/kW	-	200	90

CHP thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu
AT = Aftertreament

Table C-4 Fuel Cells

Size and Type	Characterization	2005	2012	2020
150 kW PEMFC	Capacity, kW	150	150	150
	Installed Costs, $/kW	3,800	3,600	2,700
	Heat Rate, Btu/kWh	9,750	9,480	8,980
	Electric Efficiency, %	35.0%	36.0%	38.0%
	Power to Heat Ratio	0.95	0.98	1.04
	Thermal Output, Btu/kWh	3592	3482	3281
	O&M Costs, $/kWh	0.023	0.017	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.10	0.07	0.05
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.80	-0.80	-0.77
	CO Emissions, ppm	-	-	-
	CO Emissions, lb/MWh	0.07	0.07	0.07
	VOC Emissions, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.001	0.001	0.001
	SO2 Emissions, lb/MWh	0.0057	0.0056	0.0053
250 kW MCFC/SOFC	Capacity, kW	250	250	250
	Installed Costs, $/kW	5,000	3,200	2,500
	Heat Rate, Btu/kWh	7,930	7,125	6,920
	Electric Efficiency, %	43.0%	47.9%	49.3%
	Power to Heat Ratio	1.95	1.98	2.13
	Thermal Output, Btu/kWh	1750	1723	1602
	O&M Costs, $/kWh	0.032	0.02	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.06	0.05	0.04
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.38	-0.38	-0.36
	NOx Emissions, lbs/MWh (w/ AT)			
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)			
	CO Emissions, ppm	-	-	-
	CO Emissions, lb/MWh	0.06	0.05	0.04
	VOC Emissions, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.001	0.001	0.001
	SO2 Emissions, lb/MWh	0.0047	0.0042	0.0041
2 MW MCFC	Capacity, kW	2,000	2000	2000
	Installed Costs, $/kW	3,250	2,800	2,200
	Heat Rate, Btu/kWh	7,420	7,110	6,820
	Electric Efficiency, %	46.0%	48.0%	50.0%
	Power to Heat Ratio	1.92	2	2.27
	Thermal Output, Btu/kWh	1777	1706	1503
	O&M Costs, $/kWh	0.033	0.019	0.015
	NOx Emissions, ppm			
	NOx Emissions, lbs/MWh (no AT)	0.05	0.05	0.04
	NOx Emissions, lbs/MWh (no AT; w/CHP)	-0.39	-0.38	-0.34
	NOx Emissions, lbs/MWh (w/ AT)			
	NOx Emissions, lbs/MWh (W/ AT; w/CHP)			
	CO Emissions, ppm	-	-	-
	CO Emissions, lb/MWh	0.04	0.04	0.03
	VOC Emissions, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.001	0.001	0.001
	SO2 Emissions, lb/MWh	0.0044	0.0042	0.0040

CHP thermal credit based on Displaced Boiler Emissions = 0.2 lbs/MMBtu

AT = Aftertreament

8.4 Appendix D: Market Penetration Analysis

The economic market potential was determined based on a comparison of the net power costs from the competing CHP technologies with the delivered electric and natural gas prices within that market size and geographical area. Within each market category (size and region), the competition among applicable technologies was evaluated. Based on this competition, the economic market potential was estimated and shared among competing CHP technologies. The rate of market penetration by technology under each scenario was then estimated using a market diffusion model.

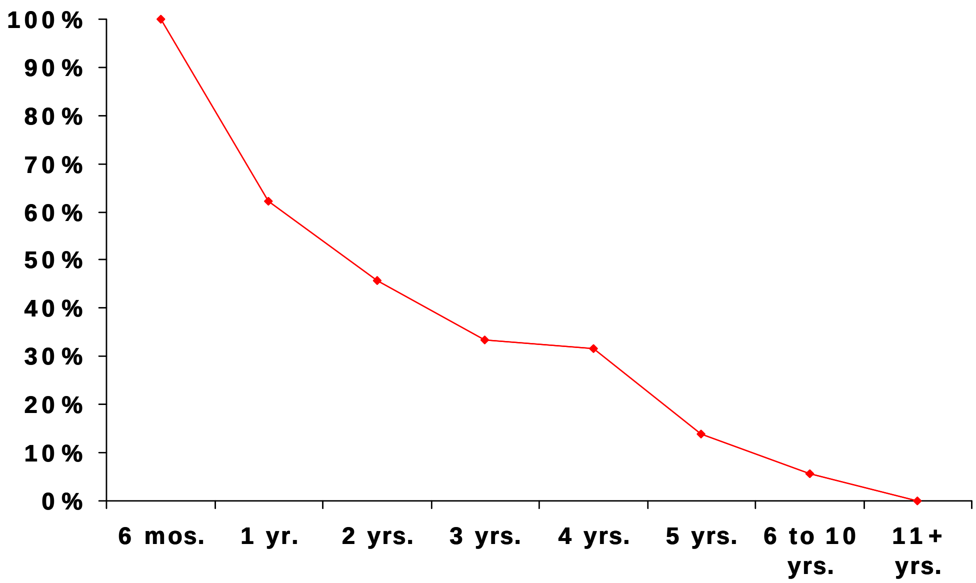
The roughly 20,000 MW of technical market potential was identified by screening only with respect to the fact that the particular applications were likely to have the operating conditions necessary to support a high load factor CHP system. An additional screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the technical potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW.) These factors were intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the iMarket database.

Among the customers that will consider CHP, the expected future fuel and electricity prices and the cost and performance of CHP technologies determined the economic competitiveness of CHP in each market. The economic figure-of-merit chosen to reflect this competition in the market penetration model was simple payback.[10] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers. In addition, all of the CHP projects have similar operating lives and cost structures making it likely that payback is very highly correlated with more detailed financial measures based on discounted cash flow analysis (net present value, return on investment, and return on equity).

[10] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.

Figure D-1 shows the response of a cross section of commercial and small industrial customers to a market survey concerning the payback that would be required for a distributed energy project to be accepted for investment[11]. As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investments in just one year. A little more than half would reject a project with a payback of two years. This type of payback translates into a project with an ROI of between 49-100%. Potential explanations for rejecting a project with such high returns are that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted; or that the facility is very capital limited and is rationing its capital-raising capability for higher-priority projects (market expansion, product improvement, etc.).

Figure D-1 Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

An approximation of this payback acceptance curve was used as the basis of determining the share of the market that would install CHP based on the calculated paybacks within each region/size market bin.

The technical potential was grouped into four separate categories (high load and low load factor traditional CHP, high and low load factor CHP with cooling,) based on their operating characteristics. Each category

[11] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July 2005.

and each size bin within the category have specific assumptions about the annual hours of CHP operation, the share of recoverable thermal energy that is utilized, and the share of useful thermal energy that is used for cooling compared to traditional heating.

CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (Table D-1). Within each of these size categories, the payback for each technology was estimated using appropriate gas and electric rates for the region, size, and load. The technology with the lowest payback was assumed to set the market acceptance share, which is a function of the percent of the market that will accept paybacks of different levels. The market acceptance share was based on this payback, using the payback acceptance curve that determines what share of the market will accept a given payback.

The market acceptance share was applied to the technical market potential constrained by a maximum market penetration (MMP) factor (from 32% to 64% depending on the size and scenario.) The resultant product equals the economic market for that region/size. The smaller the size bin, the greater the constraints on facilities considering CHP, so the smallest size bins are multiplied by the smallest MMP factors and the largest sizes have corresponding fewer constraints so a larger share of the market is considered receptive to CHP.

Table D-1 Technology Competition Assumed within Each Size Category

Market Size Bins	*Competing Technologies*
50 - 500 kW	100 kW Reciprocal Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Reciprocal Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 - 5 MW	3 MW Reciprocal Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Reciprocal Engine
	5 MW Gas Turbine
20 - 100 MW	40 MW Gas Turbine

The rate of market penetration was based on a *Bass diffusion curve* with allowance for growth in the maximum market. This determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curves shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The market penetration was allocated by competing CHP technology with a size/utility bin based on a *logit function* calculated on the comparison of the system paybacks. The greatest market share went to the lowest cost technology, but more expensive technologies received some market share depending on how close they were to the technology with the lowest payback.

Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity were assumed to have an economic life of 10 years. Larger systems were assumed to have an economic life of 15 years. Capital-related amortization costs were based on a 10% discount rate. All applications less than 5 MW were assumed to have an electric load factor of 80% and an 80% utilization of recoverable thermal energy. In the larger projects of 5 MW and larger, 90% electric load factor and 90% utilization of recoverable thermal energy were assumed.

For each scenario, the economic and dollar benefits for deployment of the mix of CHP technologies were calculated, and the environmental residuals were tracked for use in the comparison with the MAPS modeling system

8.5 Appendix E. Detailed Modeling Assumptions

Table E 1. Peak Demand and Energy by Model Region

	Peak Demand (MW)														
Model Region Group	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Upstate New York (A-E)	10,162	10,331	10,465	10,508	10,560	10,587	10,586	10,558	10,587	10,619	10,625	10,667	10,709	10,752	10,794
NY Capital (F)	2,298	2,334	2,360	2,362	2,365	2,360	2,348	2,331	2,327	2,328	2,323	2,325	2,328	2,330	2,333
Downstate New York (G-I)	4,641	4,737	4,822	4,879	4,933	4,977	5,007	5,025	5,063	5,103	5,133	5,182	5,231	5,281	5,332
New York City (J)	11,630	11,800	11,970	12,140	12,290	12,440	12,570	12,705	12,815	12,925	13,003	13,159	13,316	13,476	13,637
Long Island (K)	5,469	5,549	5,628	5,738	5,840	5,936	6,037	6,141	6,249	6,372	6,511	6,584	6,658	6,733	6,809

Note: these are zonal peaks. They are not coincident

	Energy Demand (GWh)														
Model Region Group	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Upstate New York (A-E)	60,103	61,426	62,311	62,478	62,486	62,253	61,880	61,641	61,507	62,073	62,446	62,693	62,941	63,190	63,440
NY Capital (F)	12,069	12,287	12,415	12,399	12,352	12,257	12,136	12,041	11,967	12,029	12,053	12,066	12,079	12,092	12,104
Downstate New York (G-I)	19,936	20,400	20,799	21,040	21,263	21,440	21,569	21,727	21,887	22,185	22,449	22,663	22,880	23,098	23,319
New York City (J)	52,276	53,230	54,275	55,179	56,158	57,136	57,993	58,863	59,628	60,403	61,188	61,921	62,662	63,412	64,171
Long Island (K)	22,515	22,796	23,122	23,544	23,892	24,261	24,710	25,036	25,439	25,904	26,500	26,798	27,099	27,403	27,711

Table E 2. Emission Allowance Costs ($/ton)

EMISSION ALLOWANCE COSTS ($/ton)				
Date	SO2	CO2	NOx Ozone	NOx Non-Ozone
1/1/2005	1,500	-	2,250	1,500
1/1/2006	1,035	-	3,001	1,600
1/1/2007	1,035	-	3,001	1,700
1/1/2008	1,143	-	3,051	1,750
1/1/2009	1,143	-	3,051	1,500
1/1/2010	1,392	3	2,244	2,818
1/1/2011	1,392	3	1,818	2,318
1/1/2012	1,392	3	1,818	2,018
1/1/2013	1,392	3	1,818	1,818
1/1/2014	1,392	3	1,818	1,818
1/1/2015	1,873	4	2,446	2,446
1/1/2016	1,873	4	2,446	2,446
1/1/2017	1,873	4	2,446	2,446
1/1/2018	1,873	4	2,446	2,446
1/1/2019	1,873	4	2,446	2,446
1/1/2020	2,610	6	3,409	3,409
1/1/2021	2,610	6	3,409	3,409
1/1/2022	2,610	6	3,409	3,409
1/1/2023	2,610	6	3,409	3,409
1/1/2024	2,610	6	3,409	3,409
1/1/2025	2,610	6	3,409	3,409

Table E 3. Gas Price Forecast for Upstate and Downstate ($/MMBtu)

ANNUAL NATURAL GAS PRICES ($/MMBtu)		
Year	NG NYCity	NG NYPP
2006	10.780	10.791
2007	10.780	10.791
2008	9.750	9.773
2009	9.750	9.773
2010	7.922	7.957
2011	7.922	7.957
2012	7.922	7.957
2013	7.922	7.957
2014	7.922	7.957
2015	8.454	8.467
2016	8.454	8.467
2017	8.454	8.467
2018	8.454	8.467
2019	8.454	8.467
2020	10.850	10.880

Table E 4. Oil Price Forecast for Upstate and Downstate ($/MMBtu)

ANNUAL FUEL OIL PRICES ($/MMBtu)				
Year	FO#2-NYUpstate	FO#2-NYCity	FO#6-NYUpstate	FO#6-NYCity
2006	15.573	15.573	10.232	10.232
2007	14.563	14.563	10.232	10.232
2008	12.786	12.786	9.431	9.431
2009	13.203	13.203	9.431	9.431
2010	12.411	12.411	9.033	9.033
2011	12.999	12.999	9.033	9.033
2012	12.874	12.874	9.033	9.033
2013	12.599	12.599	9.033	9.033
2014	12.961	12.961	9.033	9.033
2015	13.156	13.156	9.505	9.505
2016	13.039	13.039	9.505	9.505
2017	13.484	13.484	9.505	9.505
2018	13.432	13.432	9.505	9.505
2019	13.220	13.220	9.505	9.505
2020	14.389	14.389	10.427	10.427

Table E 5. Coal Price Forecast Delivered to Plants ($/MMBtu)

COAL PRICES ($/MMBtu)												
Date	Huntley	Russell-Bit	Greenidge-Bit	Dunkirk-Bit	Goudey-Bit	Hickling-Bit	Milliken-Bit	Kintigh, AE-Bit	Coal-NPCC	Niagara	Danskammer	Lovett-Bit
1/1/2006	1.011	2.600	1.011	1.011	1.011	1.700	1.011	1.011	2.800	1.493	1.114	1.150
1/1/2007	1.067	2.652	1.067	1.067	1.067	1.734	1.067	1.067	2.856	1.480	1.171	1.207
1/1/2008	1.176	2.705	1.176	1.176	1.176	1.769	1.176	1.176	2.913	1.596	1.281	1.317
1/1/2009	1.116	2.759	1.116	1.116	1.116	1.804	1.116	1.116	2.971	1.542	1.222	1.259
1/1/2010	1.038	2.814	1.038	1.038	1.038	1.840	1.038	1.038	3.031	1.471	1.145	1.182
1/1/2011	1.085	2.871	1.085	1.085	1.085	1.877	1.085	1.085	3.091	1.525	1.193	1.230
1/1/2012	1.135	2.928	1.135	1.135	1.135	1.914	1.135	1.135	3.153	1.582	1.244	1.283
1/1/2013	1.133	2.987	1.133	1.133	1.133	1.953	1.133	1.133	3.216	1.587	1.243	1.282
1/1/2014	1.267	3.046	1.267	1.267	1.267	1.992	1.267	1.267	3.281	1.728	1.378	1.417
1/1/2015	1.300	3.107	1.300	1.300	1.300	2.032	1.300	1.300	3.346	1.768	1.412	1.451
1/1/2016	1.243	3.169	1.243	1.243	1.243	2.072	1.243	1.243	3.413	1.718	1.356	1.396
1/1/2017	1.291	3.233	1.291	1.291	1.291	2.114	1.291	1.291	3.481	1.773	1.406	1.446
1/1/2018	1.411	3.297	1.411	1.411	1.411	2.156	1.411	1.411	3.551	1.900	1.526	1.567
1/1/2019	1.467	3.363	1.467	1.467	1.467	2.199	1.467	1.467	3.622	1.964	1.584	1.625
1/1/2020	1.516	3.431	1.516	1.516	1.516	2.243	1.516	1.516	3.695	2.021	1.634	1.675

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