FINAL REPORT

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New York City Economic Development Corporation

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A Master Electrical Transmission Plan for New York City

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1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

CRA International (formerly Charles River Associates) was retained by the New York City Economic Development Corporation (NYCEDC) to develop a master electrical transmission plan for New York City. Our plan analyzes the economic and environmental impacts of various proposed and conceptual transmission and generation projects that could improve power supply to NYC, and provides recommendations for further action to meet NYC's energy needs in an efficient and clean manner.

This study is intended as a tool for decision making by City and State policymakers and the utilities which serve our region, and not as the terminal analysis for any of the projects studied. We conducted our study with both the input and participation of multiple stakeholders, including ConEdison, NYISO, PJM, NYPA, NYS DPS, and National Grid.

The study is primarily an economic evaluation of transmission options to serve NYC's energy needs, although we did include three generation options as points of comparison. We analyzed specific commercial projects that have been proposed as well as upgrades and projects that are only conceptual today. The inclusion of conceptual projects is intended to help NYC decisionmakers identify and evaluate options that have not previously been analyzed, and to provide guidance as to potentially valuable initiatives which might warrant further consideration.

We worked with stakeholders to develop appropriate methodologies and assumptions so that our analysis was as accurate, comprehensive, and unbiased as possible. Every project, however, has unique attributes and benefits that would influence the choice of methodology and assumptions used to analyze it; our methodology attempts to provide a balanced framework within which different projects can be compared against each other.

The development of electrical generation and transmission projects is a complex process incorporating many factors, including system stability, dynamic effects, and other technical factors. We did not explicitly evaluate all of those impacts; however, we worked closely with technical staff from our stakeholder group to ensure that our analyses were as accurate and comprehensive as possible.

1.2. Options Evaluated

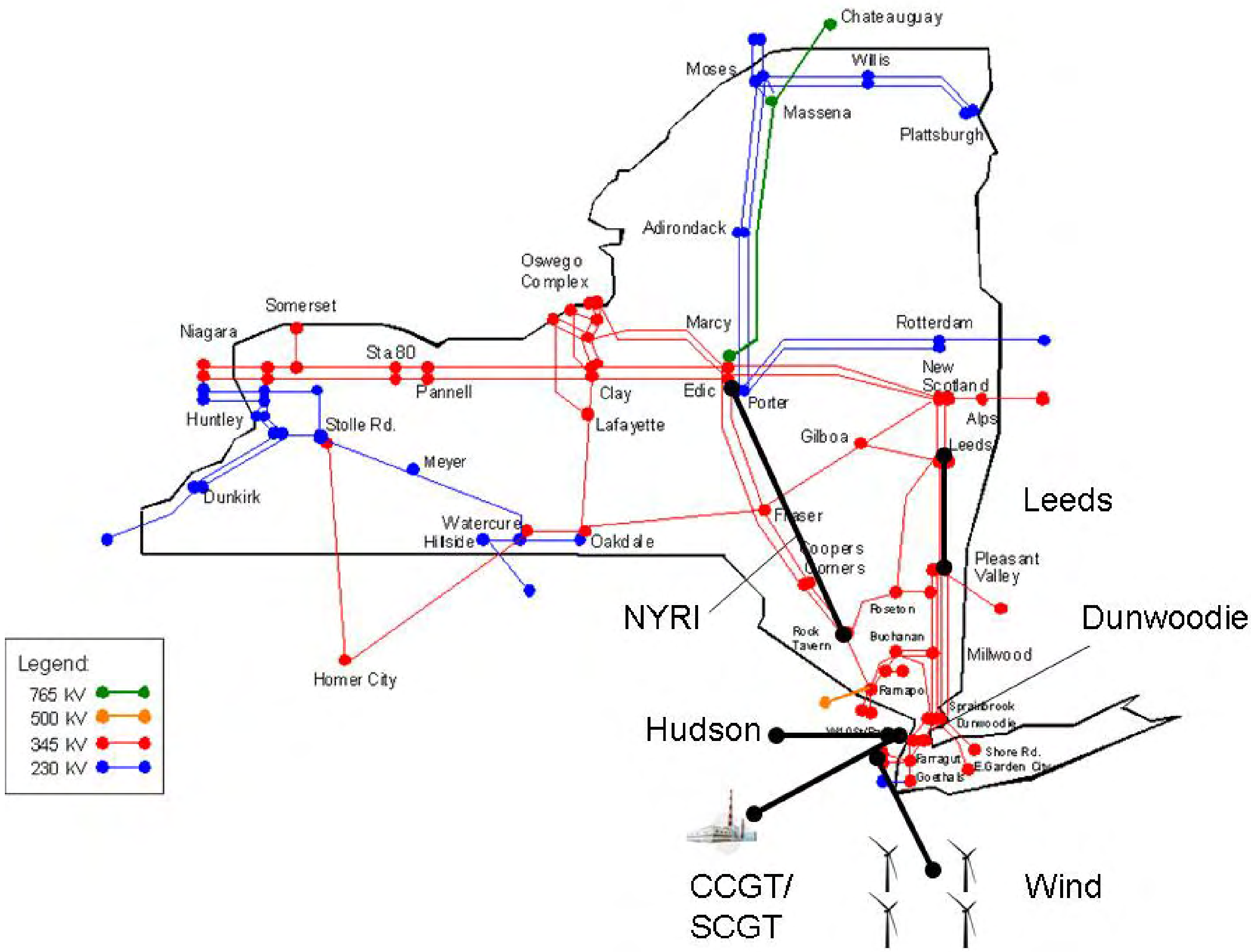
We collaboratively identified a number of projects that have the potential to meet NYC's energy needs, including:

- A 500 MW combined cycle gas-turbine (CCGT) plant on Staten Island connected via underwater cable to the Gowanus substation in Brooklyn
- An increased export capacity from New York City to Long Island (CE-LIPA)
- A 1,200 MW high-voltage direct current (HVDC) connection between the Edic (near Utica) and Rock Tavern (in Orange County) substations in upstate New York (NYRI)
- A 660 MW HVDC cable between Bergen (New Jersey) and West 49th St. substation in Manhattan (Hudson)[1]
- A 500 MW simple cycle gas turbine (SCGT) plant connected to the Gowanus substation
- A 500 MW offshore wind farm with a connection to the Gowanus substation (Wind)
- A third circuit between the Leeds and Pleasant Valley substations in upstate New York (Leeds)
- The NYRI project plus a 350 MW increase in the transfer capacity on the Dunwoodie South (near Yonkers) interface (NYRI/DW)
- The Leeds project plus a 350 MW increase in the transfer capacity on the Dunwoodie South interface (Leeds/DW)

Figure 1 provides a map showing the locations of the projects and their grid interconnection points.

[1] We evaluated the Hudson cable project under both our base assumption set and an updated PJM load forecast that became available shortly before completion of this study.

Figure 1: Geographic map of projects evaluated



1.3. SUMMARY OF RESULTS

1.3.1. Economic Benefits and Costs

We analyzed each project's costs and benefits on a twenty-year net-present value basis, evaluating all projects as "rate-base" projects, for which capital and operating costs would be recovered through consumer rates. While some projects might be developed as merchant (i.e., privately funded) projects, evaluating all projects under a rate-base approach provides consistent comparisons. Burns & Roe, Inc. (BRE) developed independent engineering, procurement, and construction (EPC) estimates for each project. We analyzed project benefits from three perspectives, and they are described below in Table 1.

Table 1: Summary of benefit metrics

Benefit Metric	Description
NYC Consumer	The change in the price that NYC consumers pay for energy and capacity in NYC, factoring in long-term contracts and hedges owned by load-serving entities in NYC, plus the profits from a ratepayer-owned plant or transmission line that are passed back to consumers
NYS Production Cost	The change in the cost of producing energy from all of the powerplants in NYS plus the change in the cost of imported energy. It is sometimes referred to as "system benefit."
NYS Consumer	The change in the price that statewide consumers (including NYC consumers) pay for energy within NYS, plus the profits from a ratepayer-owned plant or transmission line that are passed back to consumers. Long-term hedges and contracts held by NYC load-serving entities are not subtracted from this calculation.

NYC consumer benefits consist of two distinct elements. The first is the benefit that accrues to consumers from market-clearing prices being lowered by new market entry, sometimes referred to as "indirect" or "market-price" benefits. The second is the benefit that consumers accrue from their nominal ownership of the resource; they receive their energy or capacity at the resource's cost, not the market clearing price. These latter benefits are sometimes referred to as "direct" or "arbitrage" benefits. Our benefit calculations for NYC assume that load-serving entities (e.g., ConEdison or NYPA) will continue to hold bilateral agreements with generators and transmission hedges throughout the study timeframe similar to those they hold today, and that net profits from each City-owned project would be returned to City ratepayers.

There is debate about the persistence of market-price benefits for in-City generation projects. Calculation of long-term market-price benefits for generation projects is difficult and depends to a great extent on assumptions about future regulatory policies, new technologies, and market participant behavior.

Our analysis indicates that, in 2019, NYC will require new capacity to meet reliability requirements, and a gas turbine combined-cycle will be the economically optimal technology to add that that point. We assume that an efficiently scaled 500 MW combined-cycle powerplant would be constructed. This is a reasonable, if somewhat conservative, assumption; if reliability requirements were met by a smaller powerplant or by alternative technologies (such as distributed generation, demand response, or small renewable plants), then long-term market-price benefits could be higher than those presented here.[2]

We have summarized single-year and twenty-year net present values in this section. Year-by-year benefits for each project are included in its respective section.

Table 2 presents the estimated benefits and costs of each project, including a proposed allocation of project costs to NYC.[3] The benefits described in this table are those defined in Table 2.

Table 2: Economic costs and benefits, 20 year NPV, million 2008$

	NYS Consumer	NYC Consumer	NYS Production Cost	NYS Costs	NYC Cost Allocation	NYC Costs
CCGT	$1,647	$1,266	$309	$795	74%	$592
Hudson	$892	$412	$67	$836	49%	$411
Hudson/ revised	$1,768	$756	$401	$836	51%	$427
Leeds	$1,047	$1,149	$582	$505	50%	$250
Leeds/DW	$1,324	$1,063	$665	$1,035	63%	$653
NYRI	$1,046	$962	$208	$2,002	53%	$1,053
NYRI/DW	$1,745	$907	$244	$2,532	65%	$1,646
Wind	$2,537	$2,208	$709	$1,683	70%	$1,179

Table 3 displays our estimates of project development costs. Our EPC cost estimates were supplemented with other public data available for each project. The EPC cost estimates are accurate to within ±30%, and included a simplified analysis of financing charges. In cases in which

[2] See section 3.1.1 for a fuller discussion of this assumption and its implication

[3] The costs of the project differ depending on whether the assumption in the future is added by the same party who might add capacity today, and whether one considers only market-price or also direct benefits. This is discussed in greater detail in section 3.1.1

there were publicly available cost estimates from developers, or in which there were likely to be significant costs other than EPC costs, we incorporated that information to arrive at a final estimated project cost.

At the request of project stakeholders, we assumed that the offshore wind project would benefit from pending legislation that would extend an investment tax credit scheme for wind generation that would effect a 30% reduction in capital costs.

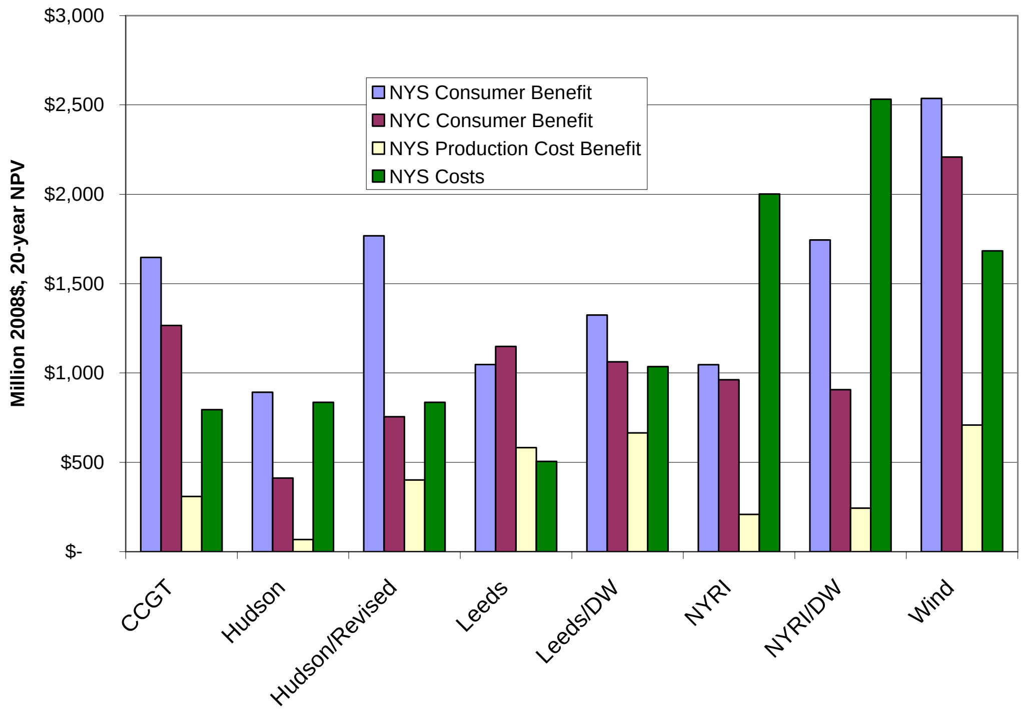
Table 3: Cost estimates for projects ($million 2008)

	EPC Cost	Land Cost (Est.)	Adjustments	Interest During Const.	Public Cost Estimates	Estimated Total Cost
CCGT	$696	$50		$49		$794
Hudson	$501		$300	$35	$660	$836
Leeds	$192	$105	$200	$8		$504
NYRI	$1,202			$109	$2,002	$2,002
Dunwoodie upgrades	$486			$44		$530
Wind	$2,097		-$629	$215		$1,683

From the NYS production cost perspective, no project evaluated shows substantial net benefits, although the Leeds project does show small positive net benefits. With a less restrictive assumption about market-price benefits persistence, new in-City generation would show net benefits as well.

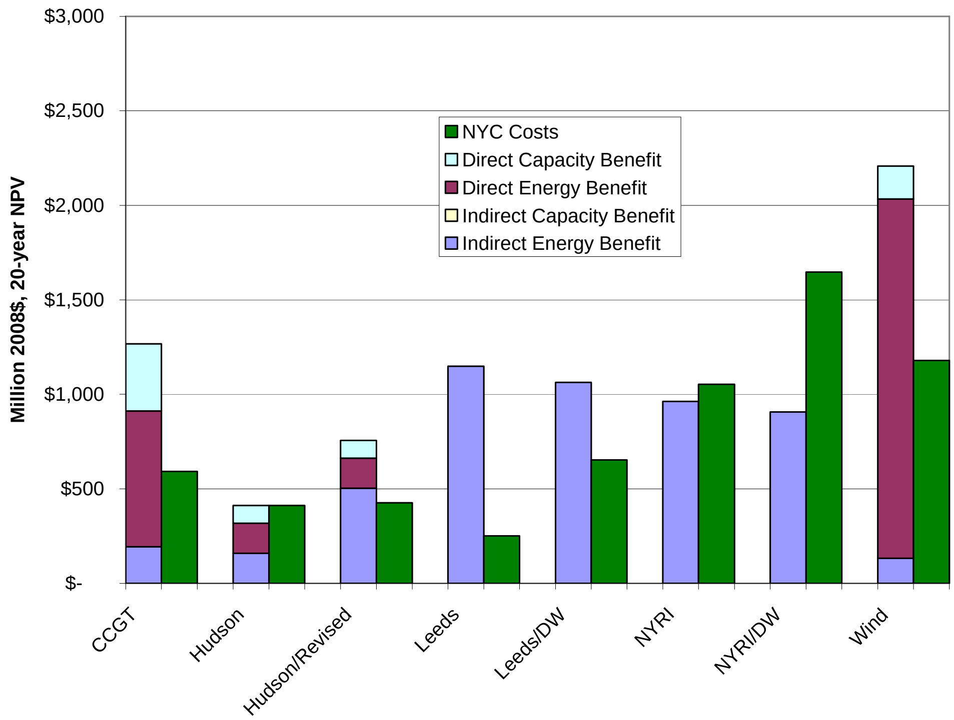
From the NYS consumer cost perspective in which profits from the project are returned to ratepayers, the Leeds project, revised Hudson case, and in-City generation projects show net benefits. Figure 2 graphically displays costs and benefits from the three different perspectives discussed earlier.

Figure 2: Statewide costs and benefits, 20 year NPV, million 2008$



A final statewide cost allocation approach has not yet been developed for rate-base projects, but in this study, we have adopted a simplified approach in which project costs are allocated to NYC in proportion to its share of statewide benefits. Figure 3 displays a more detailed summary of economic benefits by type and costs for NYC consumers using this allocation approach, in which all of the profits from the project are returned to consumers.

Figure 3: Costs and benefits from NYC consumer perspective, using proposed NYC cost allocation, 20 year NPV, million 2008$



From the NYC consumer cost perspective, the in-City combined cycle generator, the Leeds and revised Hudson projects show substantial net benefits. The offshore wind project evaluated shows very high overall benefits and compelling net benefits under the assumption that investment tax credits would reduce capital cost.

Consumer benefits from NYC's installed capacity market are muted because NYC is forecast to have an excess of installed capacity until approximately 2019. Because there will be an offer floor for new capacity added by net buyers in the installed capacity market, potential reductions in market prices would be curtailed.

1.3.2. Air Emissions Impact

We analyzed the impact of each project on NYC and NYS air emissions, shown below in Table 4. The in-City generation project we evaluated shows a net increase in NYC's CO_2 output, as its efficiency causes it to run frequently, increasing the City's CO_2 emissions, but leaving NYS' emissions almost unchanged. All of the other projects evaluated, with the exception of the SCGT and the increased export capacity from NYC to Long Island, show net in-City emissions reductions.

Table 4: Impact on NYC emissions, percentage change from reference case for 2013

	NO_x	SO_x	Hg	CO_2
CCGT	-5.5%	-18.0%	0.0%	4.8%
SCGT	1.8%	1.2%	0.0%	0.8%
LIPA	1.3%	0.8%	0.0%	0.8%
Hudson	-1.7%	-16.4%	0.0%	-1.4%
Leeds	-5.5%	-18.0%	0.0%	-6.7%
NYRI	-8.9%	-22.0%	0.0%	-5.2%
Wind	-5.2%	-10.0%	0.0%	-3.4%
Hudson revised	-4.1%	-45.8%	0.0%	-2.0%
Leeds/DW	-13.5%	-36.9%	0.0%	-8.5%
NYRI/DW	-10.9%	-13.1%	0.0%	-6.7%

The table below shows the impact of each project on NYCA emissions. The Leeds and NYRI projects, which increase generation from higher-emitting plants upstate to serve load downstate, show increased NO_x emissions, but smaller change for other pollutants. We also analyzed the impact on air emissions in PJM; they are summarized in section 3.2.3.

Table 5: Impact on NYS emissions, percentage change from reference case for 2013

	NO_x	SO_x	Hg	CO_2
CCGT	-0.4%	-0.1%	-0.1%	0.0%
SCGT	0.1%	0.1%	0.1%	-0.1%
LIPA	0.3%	-0.1%	-0.1%	0.1%
Hudson	-0.4%	-0.3%	0.0%	-0.5%
Leeds	3.3%	-0.1%	-0.1%	-0.6%
NYRI	4.7%	0.5%	0.4%	0.1%
Wind	-0.9%	-0.5%	-0.4%	-1.5%

Hudson revised	-0.7%	-0.5%	-0.3%	-0.8%
Leeds/DW	3.9%	0.2%	0.1%	-0.5%
NYRI/DW	5.1%	0.9%	0.6%	0.2%

1.4. Key Findings

The transmission projects we evaluated did not show significant net benefits across all metrics

The transmission projects we evaluated did not show significant statewide net benefits by either production cost or consumer benefit standards. There is no "low-hanging fruit" from a transmission perspective. There are several factors that explain this:

- Statewide and Citywide, energy demand growth is slowing because of the current economic climate and ongoing demand reduction programs.
- Developing transmission projects in NYS and NYC can be extremely expensive relative to other regions.
- Fuel prices continue to fall and are forecast to do so for some time.
- There is sufficient generation capacity in NYC and NYS, and sufficient imports available, to avoid scarcity prices for some time.
- In the long term, the economy-wide impact of mandatory carbon pricing may temper demand growth.

One transmission project we evaluated, the Leeds project, had production-cost benefits that exceeded its costs, but no projects had a significant "margin of safety" to account for uncertainties. In addition, benefits for NYC consumers and NYS consumers are generally not additive; transmission projects that lower prices downstate generally increase prices for upstate (or New Jersey) consumers.

The most economically attractive options for NYC consumers are new in-City generation and the Leeds project

From a NYC perspective, the most attractive options under the reference case assumptions are in-City generation and the Leeds project. These projects reduce the cost to consumers in NYC by reducing local power prices. Two other projects, the offshore wind farm, and the revised analysis of the Hudson case, also show promise.

The combined cycle option is attractive from a consumer perspective because it is highly efficient generation in NYC that lowers prices by displacing older, less-efficient generation and imports.

The Leeds project lowers prices in the lower Hudson Valley and NYC by allowing more lower-priced energy from upstate to reach southeast New York. The Statewide benefits for the Leeds project increase by reinforcing the Dunwoodie import interface into NYC, but the costs of such a project would include extensive and costly construction in NYC and are similar to the consumer benefits to NYS consumers. Because of financial contracts and hedges held by ConEdison and NYPA, there would be no benefit to NYC customers by upgrading the Dunwoodie interface.[4]

The Hudson cable lowers consumer prices in NYC, and to a lesser extent upstate, by importing lower-priced energy and capacity from PJM. Shortly before this study was completed, PJM released a new load forecast which showed markedly lower growth rates than the current forecast; a revised analysis of the Hudson project using this forecast substantially increased the project’s benefits. We will be conducting additional analysis of this option in a supplement to this report.

The offshore wind project that we analyzed showed the greatest overall benefits, but its high capital costs would reduce its overall net benefits if solely evaluated on economic bases. We have included in our analysis the effect on capital cost of pending legislation which, if approved, would provide economic incentives to reduce the wind project’s capital costs to a point where it could potentially be economically viable.

We analyzed examined a range of external sensitivities for the Leeds and Hudson project, including scenarios with lower mandatory carbon allowance prices, higher load growth, and higher gas prices. Each sensitivity showed modest changes from the base project or sensitivity case. Neither project showed a significant change in relative benefits from either the base sensitivity case or the base project case.[5]

[4] This effect is discussed more extensively in section 3.3.3

[5] These results are discussed in sections 3.2.6, 3.3.3, and 3.3.2.

There is not a critical reliability need for new transmission or generation in NYC in the near future

In our study timeframe, New York City is forecast to have an excess of capacity, gas prices are expected to be substantially lower than recent history, and demand growth is forecast to slow; we are at a point where there is neither a compelling system-wide economic nor a reliability-based argument for development of new transmission or generation. Based solely on reliability criteria, NYC would not need new generating capacity before approximately 2019 under current forecasts.

The development of a transmission or generation project before the point at which such a project would be needed to satisfy reliability criteria would result in increased benefits for City consumers; it represents a policy decision to reduce costs and emissions for NYC energy consumers at the expense of some producers.

1.4.1. Recommendations

Because of its potential economic and environmental benefits, seek ways to encourage clean, efficient in-City generation capability, especially through re-powering of older, less-efficient resources

We found that clean, efficient in-City generation can provide substantial economic benefits to NYC and NYS consumers. Developing generation (and transmission) projects in NYC has historically been very difficult. The expense of building transmission or generation in NYC increases development costs and risks. Many private developers are unwilling to bear these risks; development by a regulated or governmental entity, or energy and capacity contracted for by such agencies, may be an effective way to create new capacity.

Decision-makers should examine expanding the ability of the City, utilities, the New York Power Authority and others to drive regional power market improvements by buying or building the resources that best meet public policy objectives, or by providing financing for strategic projects that benefit the region or the State. A key element of this would be exploring regulatory or legislative mechanisms that could facilitate such an expanded role for these entities.

New generation need not mean development on a new, or “green-field” site. As powerplants age and are no longer economic to operate, their sites and infrastructure can be re-used by “re-powering” the plant with clean and efficient technology. There are suitable sites on western Staten Island or in New Jersey that could potentially support new generation.

Development on these sites does not necessarily mean that new overland transmission lines would have to be built; underwater cables, or “generator leads,” could be used to connect these generating plants to critical locations on the City’s power grid.

The development of such new or re-powered resources may not always be justified by purely economic criteria. There are public policy objectives, such as meeting environmental goals, stimulating economic activity, and promoting new technologies which may not (or can not) be fully captured when projects are evaluated only by economic metrics. Achieving some of these objectives may require solutions that can provide energy at an above-market rate, and that the costs of such projects be socialized among beneficiaries. The precise mechanisms of how to do so have not yet been designed, nor has a framework been developed in which to explicitly make these tradeoffs, but important policy goals should be considered alongside, not be trumped by, economic orthodoxy.

While we did not explicitly evaluate the effects of our projects on the regional economy, the development of in-City projects would create economic activity through construction and its associated job creation, and could provide increased tax revenue to the City.

Conduct additional analysis on the Hudson cable project

We analyzed a scenario for the Hudson cable in which load growth in PJM slows; it is based on an updated PJM load forecast released shortly before the completion of this study. While not directly comparable to the base-case analyses of other projects, this one-off analysis showed that the potential benefits of the Hudson cable are very sensitive to changing conditions in PJM. In addition, PJM has recently authorized the development of new transmission upgrades in New Jersey that could relieve congestion and improve the economic benefits of the Hudson project.

Because these changes occurred just prior to the release of this study, it was not possible to include them in this analysis, but the sensitivity of the Hudson project’s benefits to these changed conditions warrants future study. We are conducting additional analysis on this option that will be released as a supplement to this report.

Develop strategies to capture wind resources

The offshore wind project we evaluated shows large potential benefits for NYC. The availability of nearly-free power injected directly into NYC with few direct emissions is an attractive prospect. However, a large amount of work remains to be done; the technical challenges associated with offshore wind power, including deep-water construction, integration of large amounts of intermittent wind resources into the grid, and environmental impact analysis, are significant. In addition, offshore wind's construction costs are high relative to competing technologies, and are still regarded with a great degree of uncertainty.

The potential benefits of offshore wind, however, are compelling enough to warrant further analysis, especially research coordinated with other NYC and regional stakeholders. In addition, pending legislation may substantially reduce the development cost of new wind power, making it more economically attractive. The time required to address the technical and economic challenges posed by offshore wind power is substantial – work should continue towards these goals.

Pursue policies that reduce energy consumption

Our analysis confirms the strong impact of demand and energy reduction on system economics. We did not explicitly evaluate policies such as demand-responsive or real-time pricing, conservation incentives, or "smart grid" technologies, but the expected benefits of such programs indicate that they should continue to be strongly encouraged. Demand reduction need not mean only energy conservation efforts; regulatory action to promote market-based solutions could be very effective.

These are not new ideas. Demand reduction programs are already integral parts of planning processes at State and City levels. Both the City and State have set ambitious goals (e.g., "15 by 2015") for energy conservation, and our analysis confirms the strong impact that they can have on the electric system. The State and City should continue to focus on executing their plans and meeting their targets.

Pursue joint planning studies within NYS and with neighboring regions

The analysis of new transmission and generation projects is a complex process involving technical, economic, and environmental reviews that must be coordinated. These analyses must be coordinated and consistent to provide the greatest benefit. Several efforts are underway at the state level to create joint economic and technical planning processes that address these multiple factors, and we strongly urge the State to continue these activities.

Our analysis also reveals that changes in the condition of neighboring regions, especially PJM, can have dramatic economic and environmental impacts on NYC, especially in the case of the Hudson cable. Necessary coordination with PJM and New Jersey goes beyond the technical aspects; inter-regional projects create economic and regulatory issues for each region and state. Joint planning can help ensure that analyses factor in each party's objectives and impacts.

This is especially true in the case of wind resources. Neighboring states and regions may have aligned objectives to encourage new renewable resources; the complex technical and economic questions that accompany wind generation, and its interregional effects, would benefit from coordinated planning efforts.

Continue to evaluate options as circumstances change

There is an exceptionally high degree of uncertainty about future energy market conditions right now; load forecasts are changing rapidly, fuel prices are volatile, regulatory policy is uncertain, and capital costs are in flux.

Compared against these uncertainties, the risk of postponing a decision is low. Capacity is not forecast to be needed for reliability reasons, even under high load forecasts, for some time, and consumer economic benefits are low in the near-term because of NYC's excess of supply.

The opportunity cost of not acting now is the value of the potential savings to consumers. Given current market forecasts, many of the projects continue to show significant long-term impacts, meaning that NYC would not be "missing the boat" on potential project benefits by not acting now. Many of the benefits that would accrue to NYC and NYS consumers from projects developed by governmental or non-profit entities persist throughout the projects life; not all the gains from these projects occur in the first few years.

That must be weighed against the risks of project development. If project development costs increase unexpectedly, and the current economic climate persists, the City and its consumers could be worse off by acting now to develop projects than if a decision were deferred. On balance, the risks of not acting now are low.

We recommend that the City continue to evaluate its options with respect to new transmission as circumstances change, and revisit this analysis in no more than two years, when there may be less uncertainty about the future and greater information about the ultimate effects of the current economic crisis.

1.4.2. Implications for policymakers

The projects that we evaluated can be broadly grouped into two categories, upstate transmission projects (Leeds & NYRI) and NYC projects (Hudson, CCGT, Wind).

In general, the upstate projects provide consumer benefits to NYC while raising prices upstate, and reduce production cost by allowing lower-priced generation to reach load centers.

The NYC projects concentrate consumer benefits in NYC, but also provide benefits for upstate consumers. How costs for these projects would be allocated among consumers in different parts of NYS has not yet been resolved by regulators.

Comparing in-City options

For the NYC consumer, all three in-City options are generally beneficial, albeit to varying degrees. All provide significant NYC consumer benefits, although the capacity benefits in the early years are muted by the fact that NYC will have an excess of generation for approximately the next decade. Because adding capacity to a region before it might be warranted for reliability reasons tends to depress consumer prices and reduce revenues to producers, the decision to develop new in-City generating capacity (or a controllable cable like Hudson) represents a policy decision to concentrate project benefits and costs locally with little adverse impact on upstate consumers. It also means that some electricity generators will see their profits reduced.

In choosing between projects, a critical distinguishing factor between the projects might be their level of uncertainty as well as their ancillary effects such as economic activity and job creation.

For the combined cycle unit, construction costs are relatively predictable; the development of a modern combined cycle plant is a routine project. The acquisition of land and the development of an underwater cable are complex, but not unprecedented, endeavors. Overall, the development risk is low and the potential net benefits high for new in-City generation relative to the other resources evaluated.

In-City generation also benefits neighboring regions economically, especially New Jersey. More energy produced in NYC means that less energy must be produced and exported from New Jersey, lowering prices for consumers there. The development of new in-City generation capacity would also create economic activity and jobs in the City and region, both during construction and on an ongoing basis.

For an offshore wind farm, the production cost is almost completely predictable: wind is free (not accounting for maintenance costs). What is uncertain, however, is the construction cost. Offshore wind of this scale is a new technology in the United States, and such large and complex projects rarely come in under budget or ahead of schedule.

Because of its high capital cost (and without subsidies or incentives), an offshore wind farm is not likely to be more attractive in an economic sense than conventional generation technologies. Nevertheless, there may be ancillary benefits in the form of reduced cost uncertainty, diversity of supply, achievement of renewable generation targets, and fulfillment of NYC's and NYS's environmental stewardship goals. Similarly to the in-City generation option, an offshore wind farm would also create substantial economic activity and jobs in NYC and the region.

The Hudson cable can be compared with the in-City generation option; both provide energy and capacity benefits concentrated in NYC. In terms of environmental benefits, the transmission of power by wire into NYC has the net effect of reducing emissions in NYS and increasing them elsewhere.[6]

The picture is not that simple though: emissions increases elsewhere are not dramatic, and NYS emissions do not always decrease. Power flows from upstate into PJM to meet its export needs (including the Hudson cable) which can in some cases raise emissions in NYS.

With respect to economic benefits, if we compare the Hudson cable to new in-City generation, the deciding factor would be the availability of low-cost power in PJM. It's not always clear that such power can be obtained—the mix of powerplants in New Jersey is not that different from NYC, and import prices might not often be well below the NYC market price. The Hudson cable would, however, have the effect of increasing energy market competition in NYC by reducing producer market power.[7]

[6] These changes in PJM are not dramatic, however, and are on the order of 1% changes in total emissions. They are summarized in section 3.2.3.

[7] The short-run marginal production cost for the Hudson cable would be set by the PJM market, not an individual generator, reducing supplier market power as measured by the Herfindahl-Hirschman Index or related metrics.

The principal factors that would make a PJM cable the more attractive option would be changes that would allow lower-cost power to be obtained at the bus in PJM. These changes could be caused by lower fuel prices in PJM, or perhaps more importantly, by changes in transmission and demand patterns in PJM that would result in lower-cost power in New Jersey.

These uncertainties are important enough to warrant careful consideration; we analyzed the Hudson cable project with a lower load forecast for PJM, and the increase in economic benefits was significant. This was a special, one-off, analysis, but its results imply that this option should be evaluated in greater detail.

The choice among in-City options is not, ultimately, clear-cut. Adding combined-cycle generation or controllable transmission in the City is an economically attractive option, and would have ancillary benefits in terms of job creation and economic activity. In addition, adding clean, efficient generation to NYC will displace older, less-efficient sources of energy, reducing emissions. Offshore wind power, if evaluated on purely economic bases, would not appear to be the optimal choice, but if alternative criteria that recognize the additional value of renewable generation are included, and governmental policies providing financial support materialize, it may become a very attractive option.

Comparing NYC, NYS, and New Jersey benefits

The effect of building transmission between areas of high-priced power and low-priced power is to level the difference; prices in the high-priced region go down, while prices in the lower-priced region go up. In some cases, however, the overall benefit to the system may remain positive—customers that benefit outnumber those who are penalized.

The question when building transmission should be, according to most regulatory entities, whether “the system” as a whole benefits, but policymakers have different views on what “the system” comprises.

The bulk transmission projects we evaluated, NYRI and Leeds, provide overall system benefits, but consumers upstate would pay more for power and downstate consumers less. For the Hudson cable, New Jersey consumers would pay more, and NYC consumers less.

In-City generation, on the other hand, can potentially benefit both Upstate and NYC consumers. In the case of merchant generation, consumers generally benefit, while less-efficient generators are penalized in the market. In the case of rate-base generation, the allocation of net benefits is more complex, but if one hews to the principle of "beneficiary pays," then those who benefit the most (NYC ratepayers, in our specific example) pay while upstate consumers are not penalized.

The ideal solution would be an option that provides net benefits for both NYC and NYS as a whole and did not increase any consumers' rates. The projects that come closest to meeting these goals in our current study are clean, efficient in-City generation options, including the combined cycle project and the offshore wind project. The Hudson cable meets these criteria for NYC and NYS, but does increase consumer prices and emissions for consumers in New Jersey and surrounding regions.

Comparing upstate transmission options

The two transmission projects located upstate that we studied, the Leeds and NYRI projects, are broadly similar. Both attempt to relieve historic and well-known transmission constraints, and generally have the effect of increasing generation and power prices upstate while decreasing power prices downstate by allowing more power to reach the load centers of southeastern New York. Both have been proposed (either formally or conceptually) as rate-base projects.

Our analysis shows that the economic benefits and environmental impacts of these two projects are similar. Both provide benefits to NYC consumers as well as NYS consumers as a whole, and both increase the overall efficiency of the power system by allowing less-expensive power from upstate to reach NYC. Looked at from a cost-benefit perspective, the costs for the Leeds project appear to be considerably lower than the NYRI project while benefits appear similar.

One result from our analysis is that projects that alleviate upstate bottlenecks expose the fact that power is still constrained from getting into the City through the Dunwoodie interface; either of these projects combined with an upgrade to this interface would show higher benefits to NYS as a whole, but the costs of upgrading the Dunwoodie interface are roughly equal to the increase in statewide benefits. The transmission hedges that ConEdison and NYPA own limit the impact of these upgrades on NYC ratepayers, and NYC consumers would see little, if any, benefit.

Transmission to alleviate constraints between Upstate and NYC can also potentially provide greater penetration of renewable wind energy by allowing power to reach load centers. Bulk transmission alone, however, does not have significant effects on future upstate wind development in our analysis. Encouraging greater wind development still requires addressing its relatively high capital cost, technical solutions that allow wind to overcome local, lower-voltage transmission constraints, and operational solutions that allow substantially increased amounts of wind to be integrated reliably into the grid.

Planning under rapidly changing forecasts and uncertainties

The economic conditions of the past year, during which we have seen multiple, rapid shifts in load forecasts, fuel prices, capital costs, and financing costs, present unique challenges to policymakers.

The ultimate long-term impact of the current financial crisis on the economy and its need for energy is not yet known; current decreases in energy consumption may turn out to be a prolonged drop in demand, or a brief interruption in historic growth. The only thing that is clear is that there is considerable uncertainly today.

We utilized assumptions which represented industry consensuses for our analysis, but in an environment where outlooks change rapidly and dramatically, the possibility remains that the future may turn out different from what we anticipate. While forecasts always have some inherent uncertainty, it may be prudent, given the lack of urgent need for new capacity, to wait until a time when there is less uncertainty to make a major decision in new transmission or generation capacity.

This is not, however, a blanket recommendation to do nothing. There may be compelling reasons to proceed with projects that are not purely economic. The development of new transmission or generation projects can have far reaching effects, including meeting environmental goals, stimulating economic activity, increasing competition and fostering the development of new technology that may all be as important as pure economic impacts.

Further information & acknowledgements

Project stakeholders have access to additional project data at https://nycedc.crai.com.

We would like to thank our stakeholders, especially ConEdison, the NYISO, NYPA, PJM and National Grid and the NYS DPS for their generous assistance during this long and complex endeavor. Their assistance and cooperation was essential to this study’s success.

2. PROJECT OVERVIEW

2.1. Methodology & Assumptions

We developed the methodology and assumptions for the study in concert with a group representing numerous energy stakeholders in NYC and NYS. Our stakeholder group included:

- New York City Economic Development Corporation (NYCEDC)
- Consolidated Edison (ConEdison)
- New York ISO (NYISO)
- National Grid
- New York Power Authority (NYPA)
- PJM Interconnection (PJM)
- NYC Office of Long-Term Planning and Sustainability
- CRA International (formerly Charles River Associates)
- New York State Department of Public Service (NYSDPS)

We held workshops periodically to present and discuss results and solicit stakeholder feedback. The project was conducted in an open manner, in which all project data were shared with stakeholders throughout the process.

2.1.1. Initial Phase – Assumptions and methodology development

The initial phase of the project focused on the development of key assumptions and methodology with the input of stakeholders. In any analysis as complex as this, there is a large number of assumptions that go into the analysis. In a multi-stakeholder study such as this, the objective is to develop consensus assumptions that allow us to compare options on an equal footing. We modified some of our standard CRA assumptions at the request of project stakeholders. The appendix includes a description of the assumptions employed, but we highlight some of the key ones here:

- The load forecast used was the 2009 RNA load forecast from the NYISO. This load forecast is used by the NYISO for resource adequacy purposes, and along with the NYISO Gold Book, it is generally viewed as one of the two reference load forecasts.[8]

- We have assumed that a national mandatory carbon policy is imposed starting in 2015 with prices starting at approximately $30 at that time. This largely mirrors industry consensus forecasts.

- In contrast to the NYISO RNA forecast, we assume that the Astoria Energy Phase 2 unit comes online before 2013. While not included in the RNA forecasts because of its strict inclusion requirements, the stakeholder group consensus opinion was that it would be in place and operational by 2013.

- We utilized the 2008-series Eastern Interconnection Reliability Assessment Group (NERC ERAG) power flow case for our production cost simulations. This load flow case shows differences from prior cases in transmission flows and load profiles, especially in the NYC area.[9] It includes a subset of the approved RTEP transmission upgrades for PJM. The NERC ERAG selected which upgrades to include in its development of the 2008 case.

- We did not model an interface limit for UPNY-SENY, but did model individual constraints on the lines that make up this interface. NYISO confirmed that they do not model the interface limit itself in their commitment and dispatch, although it is modeled for planning purposes.

- 2013 was selected as the base year for comparisons. The choice of a single base year for comparisons involves some compromises: there are some projects evaluated that could potentially be in operation before 2013, and some projects that could become operational some time after. Nevertheless, the selection of a single base year in which to run analyses provides a

[8] The 2009 RNA forecast does include some energy-efficiency portfolio standard (EEPS) penetration, and is slightly lower than the 2008 Gold Book forecast. Both forecasts show marked reductions in growth rates for energy and peak load in coming years.

[9] These changes generally tend to reduce economic congestion in NYC and allow greater flow into NYC from Upstate. In our discussions with ConEd, they indicated that some of the changes that we observed were the results of moving load between substations, and buses, leading to reduced economic congestion.

useful basis for making “apples to apples” comparisons between projects.

- We did not model strategic bidding behavior (i.e. “bid adders”) or transmission outages. We also modeled the system using unit commitment by pool and dispatch by the entire system.

- We assumed that when new capacity were necessary in NYC to meet installed reserve margins, the need would be satisfied by 500 MW combined cycle. This assumption is discussed in greater detail in section 3.1.1.

The initial phase also focused on the development of study methodology. There are tradeoffs between the number of strategies evaluated, the timeframe for evaluation, and the number of uncertainties that can be analyzed. Based on group consensus, we designed a methodology that focused on narrowing down the list of effective strategies through a multi-stage process, described in the following sections.

2.1.2. Phase One – Single-year production cost analyses

Phase One concentrated on single-year security-constrained production cost analyses using the GE MAPS simulation model. The New York and Eastern Interconnection grids are highly complex systems: the GE MAPS model, with its transmission-constrained representation of the grid and generating units, provides the best simulation of the system while taking into account its complex nature. The raw data from these runs were made available to project stakeholders.

We analyzed a base-case simulation of the grid in 2013 using the project assumptions. We presented the results of this base-case simulation in November of 2008 and January 2009. Our findings from this phase of the analysis are described in section 3. These model results were used to calibrate the long-term NEEM model to calculate benefits persistence.

Following presentation of the results to the stakeholder group, we chose the following projects for analysis in the first round:

- 500 MW combined cycle with a generator lead to the Gowanus substation

- 500 MW simple cycle with a generator lead to the Gowanus substation

- 550 MW offshore wind farm with a generator lead to the Gowanus substation
- 660 MW HVDC cross-Hudson cable from the PSEG Bergen substation to the ConEdison W. 49th St. substation
- 1,200 MW HVDC NYRI interconnection
- Leeds-Pleasant Valley AC connection
- 1,200 MW HVDC NYRI interconnection plus Dunwoodie South upgrade
- Leeds-Pleasant Valley AC connection plus Dunwoodie South upgrade
- Increase of the ConEdison-LIPA transfer limit to 900 MW

2.1.3. Phase Two – Long term reference case analyses

Following Phase One, we selected seven projects from the first round and conducted long-term analyses using the phase one results. Long-term analyses were conducted using CRA's NEEM model, described in greater detail in sections D.5.10 and C.2.

The NEEM model takes into account multiple factors, including demand growth, reserve margins, and emissions prices, and optimally expands the system over a long time period to minimize cost while meeting operational constraints. It is not a security-constrained dispatch model, but rather a constrained general equilibrium optimization model that utilizes a zonal model of the NYCA (and surrounding areas) to perform its analysis.

The long-term results from NEEM were merged with the short-term results from GE MAPS to develop long-term projections of project benefits. After evaluating results from both models, CRA determined that the most accurate way to develop long-term projections was by using NEEM to calculate how benefits decline over time.[10] We assumed that our

[10] A project that enters the market as an inframarginal resource may see its consumer and production cost benefits decline over time as a portion of its capacity is replaced by other inframarginal resources. As long as some portion of the project's capacity remains inframarginal, however, there will be at least some consumer and production cost benefit.

reference case for system expansion included the installation of a 500 MW combined cycle unit in NYC in 2019. This assumption is described in greater detail in section 3.1.1.

The NEEM and GE MAPS models were calibrated against each other to produce proportional benefits for each project in the base year. The change in production cost and consumer benefits from the long-term model was used to scale the benefits from the detailed production-cost simulation. If, for example, NEEM showed that consumer benefits for a specific project were 90% of the benefits in the base year in NEEM, then the consumer benefits for that project were calculated to be 90% of the production-cost simulation benefits in the base year.

2.1.4. Phase Three – Sensitivity analyses

Following Phase Two, we selected two projects, the Hudson project and the combination of the Leeds line with Dunwoodie South upgrades for evaluation against multiple sensitivities.

These projects were selected by the NYCEDC in consultation with CRA and project stakeholders. The criteria for selection were not purely economic. The Hudson project shows potentially promising economic benefits, and was selected for further analysis on the basis of two main factors. First, the project is further along in the development cycle than other alternatives, resulting in desire for more extensive analysis. Second, the results from the single-year analysis with a revised PJM load forecast show the great deal of uncertainty that still remains about the project's benefits.

The analysis used a modified subset of sensitivities from the NYISO 2009 RNA. Most significant among those added were scenarios analyzing the impact of a mandatory national carbon policy. The sensitivities utilized in this phase are described in greater detail in section 3.2.6.

Because the sensitivities and scenarios we analyzed address long-term factors such as mandatory carbon policies, fuel prices, and loads, we elected to use our long-term regional methodology exclusively for these scenarios. The imposition of a mandatory national carbon policy was the principal driver for this decision; our assumptions assume such a policy goes into effect in 2015, after our 2013 production-cost analysis timeframe.[11]

The absolute effects and benefits of each scenario or each project are not directly comparable to the results obtained through scaled production-cost simulation results. They are intended to show the relative impact of each sensitivity or project on the overall supply mix. Because the regional model does not provide nodal results, we did not utilize the same methodology for the calculation of NYC benefits as we did with our security-constrained production cost simulations.

2.1.5. Project development & financing strategies

In parallel with this quantitative analysis, we conducted a review of regulatory and financial options that NYC has at its disposal to help support beneficial energy infrastructure. While related, this analysis is not specifically a part of this study, and results are reported under separate cover.

2.2. Analysis Tools & Methodology

2.2.1. Security-constrained production cost analysis

We used the GE MAPS model to simulate the interconnected power system in Phase One. GE MAPS is a detailed economic security-constrained dispatch and production-costing model for electricity networks. It was originally developed by General Electric and is currently used by over twenty major utilities in the U.S. GE MAPS determines the least-cost secured dispatch of generating units to satisfy a given demand, on the assumption that the units are dispatched according to their variable costs. The major advantage of GE MAPS is its ability to simulate the hourly operation of generating units and transmission systems (e.g., transformers, lines, phase shifters, buses) in significant detail. For example, it accurately represents generator capacity constraints and minimum up and down time limitations, thermal constraints on the transfer capability of transmission lines, line and unit contingencies, and scheduling limitations of hydro-plants. GE MAPS provides a highly accurate, detailed simulation of the hourly operation of the individual

[11] The methodology used for this phase of the analysis was the very similar to that used for the 2008 NYPA IRP study

generating units and transmission system that constitute the wholesale market.[12]

Among the key outputs of the GE MAPS model is a set of Locational Marginal Prices (LMPs, referred to in New York as Location-Based Marginal Prices, or LBMPs), computed for each bus in each hour, as well as the hourly production cost. Such a detailed representation of the physical part of power markets makes GE MAPS an ideal tool for conducting a precise analysis of them. GE MAPS is described in more detail in the appendix.

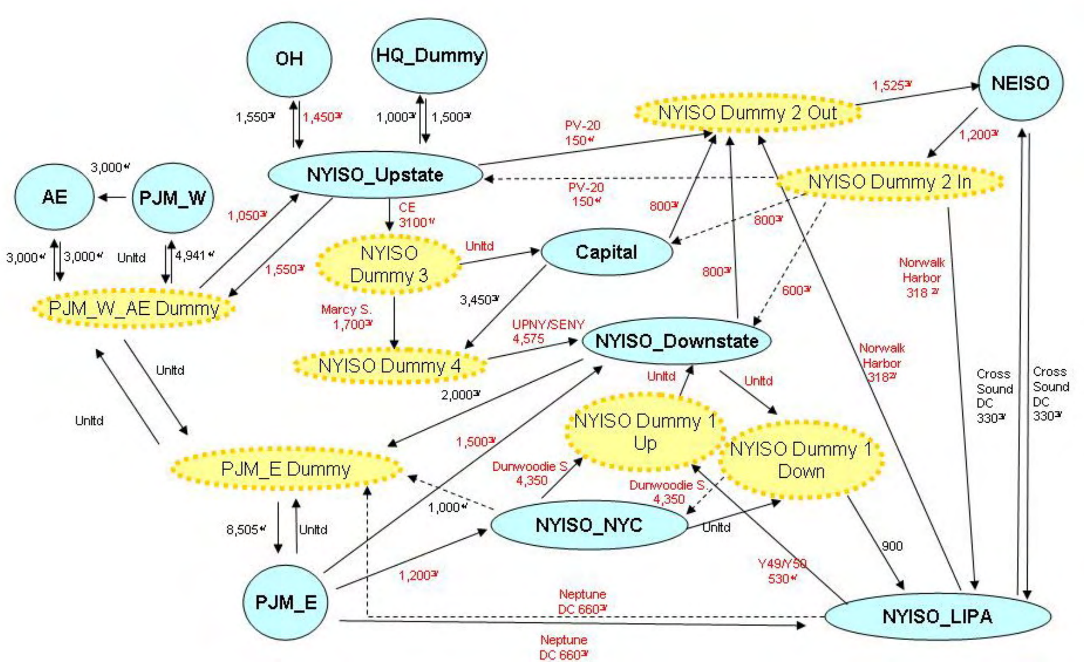
2.2.2. Long-term regional analysis

We used CRA's NEEM model to develop long-term projections of how benefits change over time for each project. Planned entry and retirements affect the fuel mix of installed capacity and composition of plants on the margin.

NEEM simultaneously models system expansion and environmental compliance (including retrofits) over a long-term planning horizon. The model employs detailed information on generating units in the United States and large portions of Canada. NEEM models the evolution of the North American power system over time, taking into account demand growth, available generation and environmental technologies and environmental regulations both present and future. The North American interconnected power system is modeled as a set of regions (roughly similar to NERC regions and NERC sub-regions, but refined by known transmission constraints separating regions, and specified in the level of detail required for analysis) that are connected by a network of inter-regional transmission paths. For our NEEM analysis, we subdivided New York into five subregions: Upstate (NYISO load zones A-E), Capital (zone F), Lower Hudson Valley (zones G-I), New York City (zone J), and Long Island (zone K).

[12] For this analysis, we configured the GE MAPS model to commit resources by pool, and dispatch resources system-wide.

Figure 4: Long-term regional model of NYCA topology



Environmental regulations and significant changes to the transmission system, such as the those brought about by the project, affect decisions about: (1) the mix and timing of new capacity, (2) retirement of existing units, (3) the mix and timing of environmental retrofits at existing facilities, (4) fuel choice, (5) dispatch of all units, (6) maintenance scheduling for all units, and (7) the flow of power among regions. NEEM captures all of these impacts in the process of optimizing responses of the electric sector to environmental policies, and in our analysis, to the project.

NEEM minimizes, subject to the various constraints described above, the present value of total costs, including (1) fixed and variable non-fuel operating costs for all units, (2) fuel costs, (3) opportunity costs associated with the use of emission allowances, (4) the capital investments in new plants and retrofits at existing facilities, and (5) the cost of moving power between regions (wheeling charges). Appendix C.2 provides further detail on the NEEM model.

3. PROJECT ANALYSES

3.1. ANALYSIS FRAMEWORK

3.1.1. Benefits types and persistence

Benefits were calculated as twenty-year net present value. The benefits over this time were calculated as the difference between the system's production cost or consumer cost in a given year versus what it would have been had the project not been developed in 2013 and a 500 MW unit were developed in 2019 in NYC.

There are two distinct types of economic benefits for the projects we evaluated: "market-price benefits" or "indirect benefits" and "direct benefits" or "arbitrage benefits."[13]

Market-price benefits are conceptually simple. Introducing additional inframarginal supply into a system will reduce the market-clearing price paid by all consumers for either energy or capacity, even those consumers not directly served by that resource.

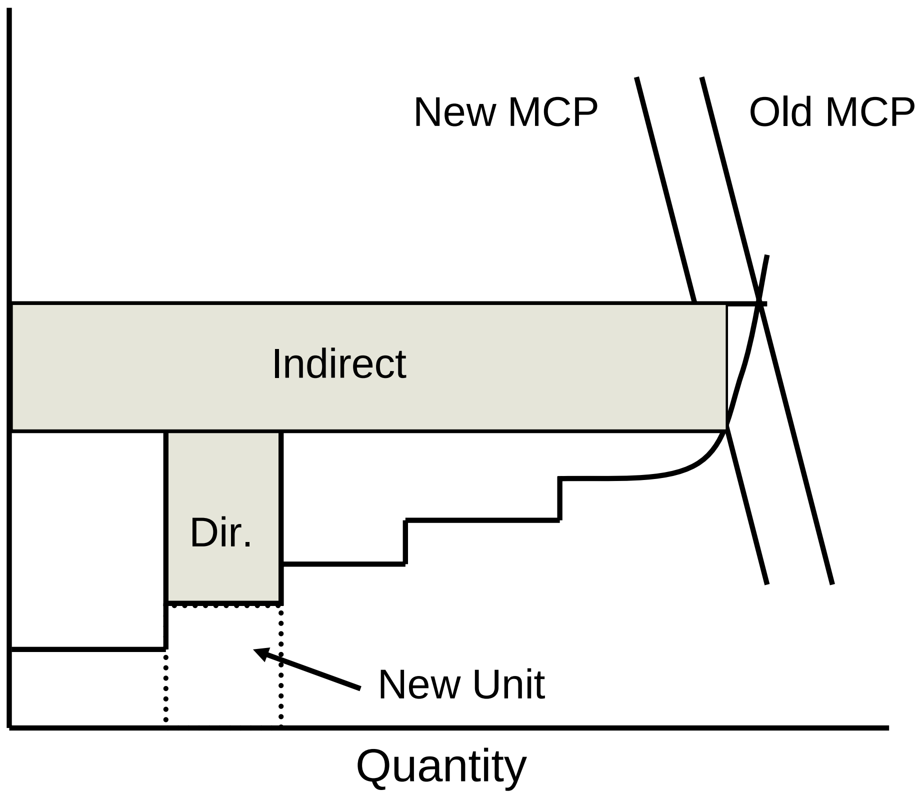
In the case of the in-City generation (or controllable transmission) projects, however, there is an additional factor to consider. When analyzing each generation project, we assume that it would be operated by a non-profit entity for the benefit of NYC customers, and that NYC consumers would benefit from the difference from the difference between the marginal cost of the resource and the market clearing price. In practice, we calculate that the margin earned by the generator or cable is returned to ratepayers. This methodology is applicable to both energy and capacity markets, and both in-City generation projects and the Hudson project.

Figure 5 graphically displays the difference between market-price ("indirect") benefits and direct benefits. The figure demonstrates the effect of inserting a new inframarginal unit into the supply stack that shifts the supply curve to the right. For ease of illustration, the market clearing price (MCP) is shown as moving from right to left, equivalent to the supply curve moving from left to right.

[13] The term "arbitrage benefits" may be misleading, as it would seem only to apply to the Hudson cable and the difference between NYC and PJM prices. In reality, it applies to all in-City projects. In the case of the in-City combined cycle, for instance, the difference between the generators short-run marginal cost and the market-clearing price would be returned to the consumer, as would the difference between its cost and the market-clearing capacity price

The indirect benefits accrue because the market-clearing price is lowered for all consumers, and the direct benefits accrue as the new unit's profit (or inframarginal rent) is returned to its owners, the customers.

Figure 5: Illustration of economic benefit types

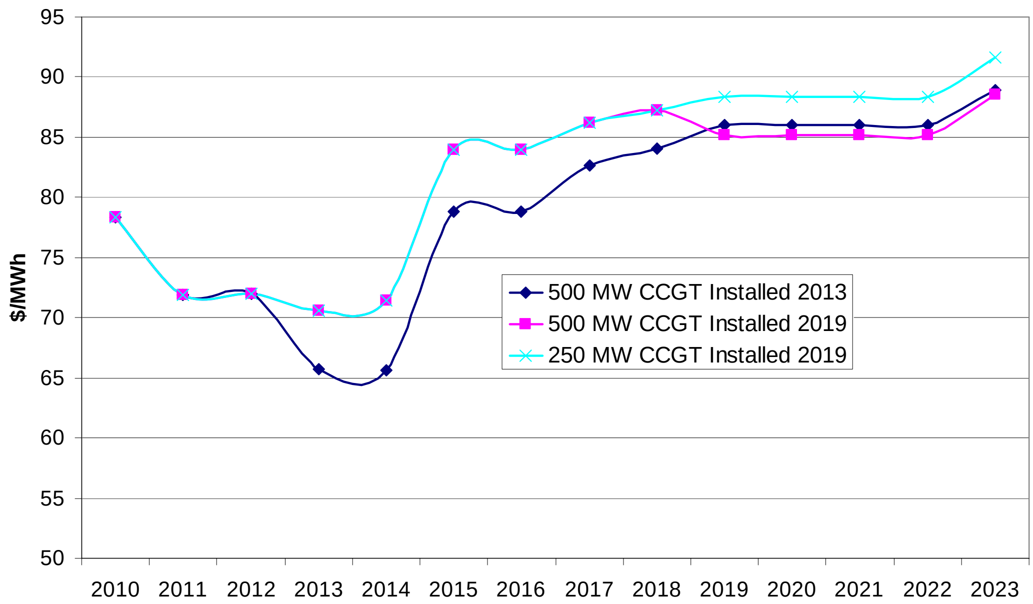


Comparing benefits from generation and transmission is inherently difficult. Transmission and generation are driven by fundamentally different factors.

New generation, especially in NYC, is often driven by reliability criteria, and it has been asserted that new capacity added before need only replaces the plant that would have been added later.

Figure 6 shows an illustrative example of how prices in NYC might change upon introduction of new generation. One trend shows how market prices in a region would change with a 500 MW CCGT installed in 2013, and the other shows how prices would change if an identical unit were installed at an identical location in 2019. Prices converge to an identical level after the CCGT is installed in 2019. The third trend shows how prices would change if no CCGT were installed in 2013 and then a smaller CCGT (approximately 250 MW) were installed to meet the required reserve margin in 2019.

Figure 6: Example of benefits persistence



Comparing the case where the CCGT is installed in 2013 versus the case where a 250 MW CCGT is added in 2019 shows that the 2013 CCGT case does indeed show persistently lower market-price benefits over time.

The view that market-price benefits expire upon installation of new capacity (and that adding capacity ahead of need only "moves up" future capacity additions) contains the critical assumptions that technology remains static and all capacity is fungible. In reality, the future capacity that is displaced by a CCGT installed today might not be the same CCGT. It could be new demand response capacity, special case resources, distributed generation, or some other form of generation. Any persistent price impact would be the result of a change in the fuel or technology mix relative to what would result with a pure merchant additions.

In this study, we have chosen to model the introduction of a 500 MW CCGT in NYC in 2019 to meet required reserve margins even though it is more capacity than would be necessary to meet NYC's capacity requirement. This approach is a conservative one; long-term market price benefits would persist longer if a smaller plant, or a different technology (e.g., a peaker), were added instead.

It has been asserted that the true cost of a generation project is not the capital cost of the project, but rather the difference in cost between the project constructed in 2013 versus the cost of the project constructed in 2019 when it would be needed for reliability reasons. This is true but only under a limited set of assumptions and conditions. If one is looking at the overall societal impact of the project, and is indifferent to whether project profits accrue to a merchant developer or consumers, then the true cost is indeed the difference between constructing a plant now and constructing one later. As an example, consider a scenario in which a non-profit entity (e.g., NYPA) constructs new generation in NYC in 2013, and a merchant developer constructs a new plant to meet reserve margins in 2019. The overall societal impact would be the same, but in the latter case, the generator profits (i.e. “direct benefits”) would accrue to the developer rather than consumers.

None of the transmission projects that we evaluated are likely to be proposed as “backstop” projects to meet reliability criteria; they are purely economic transmission projects. The generation projects we evaluated, conversely, could conceivably meet mandated reliability criteria, and one can argue that “something would have been built anyway.” This is not the case with the bulk transmission projects under consideration, and so it is unlikely that their market-price benefits are displacing those that would likely be conferred on the system by a different project.

3.1.2. Definition of evaluation metrics

The appropriate way to calculate benefits from the projects we evaluated was a topic of significant discussion among the stakeholder group. There are numerous methods to do so: production cost impact, consumer cost impact, NYC cost impact, and overall interconnected-system impact. Our analysis focuses on the impact of transmission projects on NYC, and so the impact on NYC ratepayers is the foremost economic metric used for project evaluation, but multiple benefit metrics have been reported.

An important point is that the introduction of generating or transmission capacity into a market before it would otherwise be needed for reliability reasons has the effect of lowering consumers’ prices, representing an implicit policy decision to concentrate project benefits to consumers.

Three distinct ways of measuring economic benefits have been employed in this analysis:

- Production cost benefit: the change in total cost of producing power to serve the NYCA load, including both in-State generation as well as imports. This method of measuring benefits is the

NYISO's preferred benefits metric, as decreases in production cost have the effect of maximizing total economic surplus. In the case of imports, the total amount imported is counted at the import's locational marginal price of energy. Exports are treated in the same manner.

- Consumer cost benefit: the change in the total cost to consumers for electrical energy, consisting of the LBMP for each zone multiplied by the load for that zone. This is the most direct indication (with capacity market impacts) of consumer impact. This metric is sometimes favored by regulators, as it is the most direct impact on that state's consumers. Individual zones' consumer benefits are not additive; statewide savings might be positive despite some zones seeing increased prices. For the purposes of this analysis, we have also included the profits earned by the ratepayer-owned resource as attributable to the entire state. Hedges and contracts held by NYC LSEs are not counted in this calculation.

- NYC consumer benefit: the change in the total cost of electrical energy and capacity to NYC consumers, factoring in load-serving entities' contracts for generation and transmission congestion contracts (TCCs). This is the most direct metric of the projects' benefits on the NYC ratepayer. For the purposes of this analysis, we have also included the profits earned by the ratepayer-owned resource as attributable to the City.

In the specific case of NYC, we calculated the impact to NYC consumers by analyzing the impact of ConEdison's and NYPA's contracted generation, its TCCs, and other power purchase agreements (PPAs) along with the impact of changing LMBPs on the portion of load that purchases its energy at the market price. We used a simplified analysis method that we developed with stakeholders in which NYC LSEs essentially own a share of output from a particular generating unit. Our analysis assumes that ConEdison and NYPA will continue to hold bilateral contracts with generators and TCCs in similar proportions as they do today.

Note that the NYC consumer benefits and the NYS consumer benefits are not additive; the full amount of the direct benefits from each project was added to both NYC and NYS benefit calculations. Subtracting this direct benefit from the NYS calculation would yield the more traditional calculation of statewide consumer impact. In addition, we have displayed our results for statewide and NYC consumer benefits without attempting to allocate benefits to NYC.

We did not include statewide benefits to consumers from TCCs that might be allocated to project developers for bulk transmission projects because we analyzed only physical transactions.[14]

We also calculated the air emissions impact of each project. We report these numbers in terms of percentage change from the reference case rather than absolute amounts for ease of comparison. The cost of air emissions permits for CO_2, NO_x, and SO_x have been factored into the dispatch and analyses of the system. If one believes that the cost of these tradable permits accurately reflects the true externality cost of emissions, as they are intended to, then these externality costs are accounted for, as generators pay a higher cost to emit air pollutants

3.1.3. Cost allocation approach

Projects were analyzed as if they were all rate-base projects for which costs were recovered from NYS ratepayers to provide a consistent method of comparing costs and benefits. Though some of the projects proposed would likely be rate-base projects, others, such as a combined cycle in NYC might well be built as merchant projects.[15]

Cost allocation for regulated transmission projects is a complex issue. The FERC has mandated in its Order 890 that RTOs adopt several

[14] The NYISO tariff permits project developers to choose to receive either TCCs along their project path, or from among a series of proposed alternate TCC packages; it is thus impossible to know precisely which package of TCCs that a project developer might elect to receive. In addition, if we were to have evaluated the benefits that result from TCCs granted to project developers, we would also have to evaluate the value of diluted TCCs held by other market participants. Further, the dilution of TCCs held by NYISO market participants would have affected future TCC auction revenues, which feed into the NYISO TSC as an offset to transmission charges. CRA did not include these TCC effects in its analysis of the NYRI project for its Article VII application, and the PSC commented in that proceeding that there was no generally accepted way of allocating these TCC effects among consumers. Finally, the flow across the Hudson cable analyzed, while conceptually similar, represents a physical interchange rather than the change in the value of a financial instrument and so is not directly equivalent.

[15] The method of examining costs and benefits are different for each option. For merchant generation projects, the cost of the project is less relevant to the policymaker. The project developer develops the project, and recovers their costs through transfers in producer surplus between generators. One generator might win, another might lose, but the costs of the project are irrelevant if one assumes that the number of interest is the cost to consumers or the production cost impact. For rate-base generation projects, the calculation is relatively straightforward – the cost of the plant is weighed against both the market-price and direct benefits of the project.

different "planning principles," including the requirement for specific cost allocation procedures for reliability and economic projects. The Commission also indicated its general preference that transmission costs be allocated according to the principle of "beneficiary pays." FERC declined to describe a specific implementation formula, leaving development of such methodologies to the regional RTOs and their stakeholders. The NYISO's Order 890 compliance filings have presented specific cost allocation methodologies which have been accepted by the FERC.

In New York State, utility transmission revenue requirements are recovered through the NYISO's Wholesale Transmission Service Charge (TSC) as well as through bundled retail rates under NYS tariffs. The TSC is a "license plate" rate, meaning that there is only one charge to load, which differs based upon its geographic location, to provide for transmission service throughout the state.[16]

For the purpose of this analysis, we have developed a simplified cost allocation methodology based on the "beneficiary pays" principle. It is presented here as our proposed cost-allocation method.

For each project, load cost benefits were calculated for those zones which saw a benefit. The load benefits are listed below in Table 6. Zones for which no benefit is listed saw an increased cost to serve load.

Table 6: Load benefits by zone, million 2008$

	CCGT	NYRI	Hudson	Wind	Leeds	Leeds/DW	NYRI/DW	Hudson revised
A				$2				$3
B				$1				$2
C				$2				$4
D			$1					$3
E				$1				$3
F			$1	$1				$6
G	$10	$26	$5	$7	$32	$24	$21	$15

[16] In contrast, a "postage stamp" approach is a single average rate throughout the region—regardless of the location of the load. A "megawatt-mile" approach would allocate costs based on a calculation of the capacity of the transmission system utilized by the market participant.

H	$3	$10	$1	$2	$14	$12	$8	$4
I	$8	$23	$3	$5	$33	$28	$19	$10
J	$119	$94	$32	$75	$99	$150	$148	$95
K	$19	$26	$20	$12	$22	$24	$31	$41
Sum	**$159**	**$179**	**$65**	**$107**	**$199**	**$238**	**$227**	**$186**

We did not allocate costs within each zone to its load-serving entities. We then allocated costs to each zone according to their percentage of total benefits, as shown in Table 7.

Table 7: Proposed cost allocation by zone

	CCGT	NYRI	Hudson	Wind	Leeds	Leeds/DW	NYRI/DW	Hudson revised
A				1%				2%
B				1%				1%
C				2%				2%
D			1%					1%
E			1%	1%				2%
F			2%	1%				3%
G	6%	15%	8%	7%	16%	10%	9%	8%
H	2%	5%	2%	2%	7%	5%	3%	2%
I	5%	13%	5%	4%	16%	12%	8%	5%
J	74%	53%	49%	70%	50%	63%	65%	51%
K	12%	14%	31%	11%	11%	10%	14%	22%

The proposed cost allocation methodology shows, not surprisingly, that downstate zones bear the most of the costs of projects that relieve constraints from upstate to downstate. The two projects that relieve constraints into the lower Hudson Valley, NYRI, and Leeds allocate a larger share of cost to lower Hudson Valley zones as those zones accrue a large share of the benefits.

3.2. Summary of Findings

3.2.1. Reference Case Energy Market Summary

The power grid of 2013 looks different than today's market. Changes in load, generation patterns, transmission system upgrades, and changing fuel prices lead to market patterns that differ from current conditions. Prices overall tend to be lower than today's for several key reasons:

- There is a reduction in in-City congestion. Load pocket congestion has traditionally driven the zonal price for NYC—high prices from peaking units have had a significant effect on the overall zonal price. In the new power flow configuration used for this project, we have observed changes in some base flows, and some load shifts between substations that reduce the effect of this transmission congestion. In our discussions with ConEdison, they have indicated that these changes are the result of physical changes to the system and the corresponding updated analyses, and not capital projects, with the exception of the M-29 project.

- Prices in northern New Jersey PJM are not significantly and consistently lower than in NYC with the base set of assumptions. The gap between PSEG and NYC prices has narrowed.

- The flow across Dunwoodie South increases because of transmission system upgrades. Both ConEdison's M-29 project and increased reactive support provided by the Millwood capacitor banks increase the limit significantly. We compared the flow limits from the 2005-series MMWG power flow case and the 2008-series power flow case and found differences of approximately 400 MW between the two cases. As a result, there is less price separation between the lower Hudson valley (LHV) and NYC.

- Older generation has been replaced by more efficient in-City resources. In particular, the Poletti unit will have been retired by 2013, and its capacity has largely been replaced by the new and more efficient Astoria Energy Phase 2 unit and the Linden VFT project.[17]

[17] The new Astoria unit, for example, largely replaces the Poletti unit, trading a 11,000 heat rate and higher emissions for a 7,100 heat rate with lower emissions.

- Load forecasts show growth slowing. The NYISO's RNA forecast for load, largely viewed as the reference forecast, shows load growing at lower rates than in the past. The historic compound annual growth rate (CAGR) between 1999 and 2007 was 2.8% for NYC's coincident peak; the RNA forecast shows a forecast CAGR of 0.8% from 2008 through 2018.[18]

- Imports into NYC increase. This is partly due to increased transmission capacity into the City that allows increased flows into zone J, but also by reduced economic congestion, especially between the 345 kV and 138 kV systems, that allows more of this imported power to be utilized at lower voltages.

- Long Island will continue to see high prices as many of its marginal units are oil-fired. Current price forecasts indicate that oil prices are likely to remain high, leading to higher marginal prices on Long Island.

Figure 7 displays a contour map of all-hour LBMPs for New York State for our reference case analysis.

18 The RNA forecast is slightly lower than other contemporaneous forecasts of load growth, in particular the 2008 NYISO Gold Book. This load forecast is based principally on econometric factors, and so its trajectory is driven as much by economic activity as by EEPS impact.

Figure 7: Reference case price contours[19]

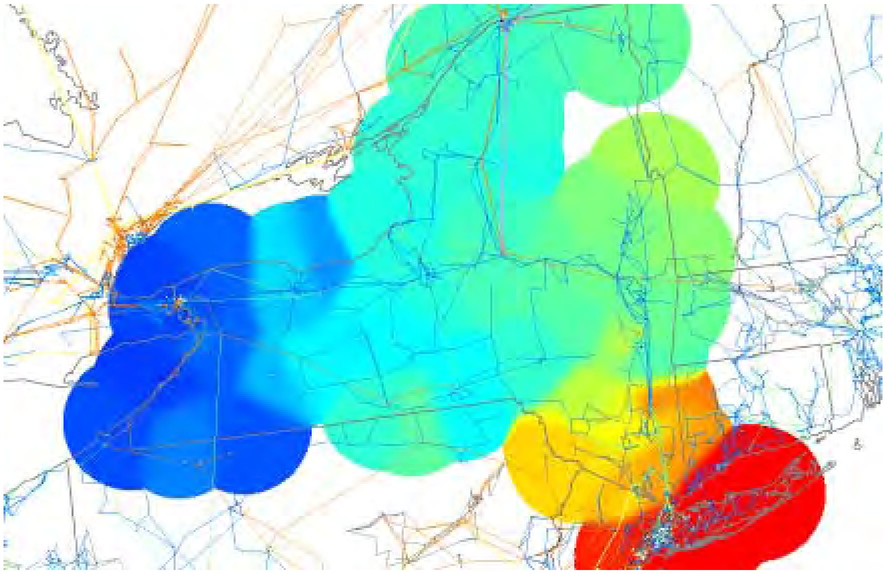


Table 8 shows the all-hours load-weighted LBMPs by each zone for the reference case analysis in 2008 dollars. Prices in 2013 show broadly similar patterns to today's prices, with somewhat less congestion between the LHV and NYC that is party attributable to increases in the Dunwoodie South interface.[20]

Table 8: Reference all-hours LBMPs by zone for 2013, 2008$/MWh

	A	B	C	D	E	F	G	H	I	J	K
Base	54.72	58.22	61.44	64.24	64.16	66.63	77.56	80.19	80.70	84.92	86.78
CCGT	54.94	58.35	61.53	64.25	64.21	66.69	76.66	79.02	79.45	82.89	85.95
CE-LIPA	54.88	58.32	61.52	64.26	64.21	66.65	77.70	80.34	80.80	85.09	86.42
NYRI	55.44	59.67	63.21	66.04	66.27	68.91	75.23	76.79	77.21	83.31	85.66

19 Legends for the colored contour plots are included in the Appendix

20 Reports for the revised Hudson case are not included in all tables. The revised Hudson analysis utilized new load forecasts for both its base case (i.e.., without the cable), and the sensitivity case, and those results are thus not directly comparable to the results reported in some of these tables. Results for the revised Hudson analysis are reported in its individual section

HTP	54.70	58.21	61.46	64.10	64.10	66.51	77.13	79.69	80.17	84.38	85.90
SCGT	54.70	58.22	61.46	64.27	64.19	66.68	77.47	80.06	80.56	84.60	86.77
Wind	54.62	58.13	61.34	64.21	64.06	66.53	76.94	79.43	79.97	83.64	86.26
Leeds	55.36	59.65	63.17	66.17	66.25	69.78	74.78	75.42	75.75	83.23	85.80
Leeds/ DW	55.50	59.88	63.61	66.43	66.67	70.13	75.57	76.40	76.59	81.52	85.52
NYRI/ DW	55.53	59.77	63.47	66.11	66.44	68.83	76.00	77.87	78.19	81.84	85.36

Table 9 shows the change in each zone's load-weighted LBMP from the introduction of each project.

Table 9: Change in all-hours load-weighted LBMPs by zone for 2013, 2008$/MWh

	A	B	C	D	E	F	G	H	I	J	K
CCGT	0.23	0.13	0.10	0.01	0.06	0.06	(0.89)	(1.17)	(1.25)	(2.03)	(0.83)
CE-LIPA	0.17	0.11	0.09	0.02	0.06	0.02	0.14	0.15	0.10	0.16	(0.36)
NYRI	0.72	1.46	1.77	1.80	2.12	2.28	(2.33)	(3.39)	(3.48)	(1.62)	(1.12)
Hudson	(0.01)	(0.01)	0.02	(0.13)	(0.05)	(0.12)	(0.43)	(0.50)	(0.52)	(0.55)	(0.88)
SCGT	(0.01)	0.00	0.02	0.04	0.04	0.05	(0.08)	(0.13)	(0.13)	(0.33)	(0.01)
Wind	(0.09)	(0.09)	(0.10)	(0.02)	(0.09)	(0.10)	(0.62)	(0.76)	(0.72)	(1.29)	(0.52)
Leeds	0.65	1.43	1.73	1.93	2.10	3.15	(2.77)	(4.77)	(4.95)	(1.69)	(0.98)
Leeds/DW	0.79	1.66	2.17	2.19	2.51	3.50	(1.98)	(3.79)	(4.10)	(3.40)	(1.26)
NYRI/DW	0.82	1.56	2.04	1.88	2.28	2.21	(1.55)	(2.32)	(2.51)	(3.08)	(1.42)

Table 10 shows the market heat rates for NYC by month, calculated on the non-weighted average LBMP over the year.

Table 10: Implied heat rates for NYC, 2013, BTU/kWh

	Implied Heat Rate for NYC
Jan	7,182
Feb	7,509

Mar	8,382
Apr	8,688
May	8,692
Jun	9,663
Jul	10,934
Aug	10,854
Sep	9,354
Oct	8,436
Nov	8,125
Dec	8,410
Average	**8,852**

Table 11 shows generation by each zone for the reference case.

Table 11: Generation by zone (GWh) for reference 2013 case[21]

	A	B	C	D	E	F	G	H	I	J	K
Gas	978	189	6,346	751	403	17,616	48		6	21,433	6,014
Coal	12,164		4,676		300		2,795				-
Nuclear		5,316	20,768					17,298			-
Hydro	16,219	227	276	7,136	1,970	3,061	378		1		-
Gas/Oil			14				1,531			5,006	873
Refuse	245		198	116	125	74	111	329			737
Wind	247	105	496	452	710	280					-
HQ Imports				1,822							-
Imports	4,178		-1,057	1,694		-3,352	3,395			2,015	8,243
Total	29,852	5,837	32,774	8,455	3,508	21,031	4,863	17,627	7	26,439	7,623

21 Negative values indicate an export from a zone

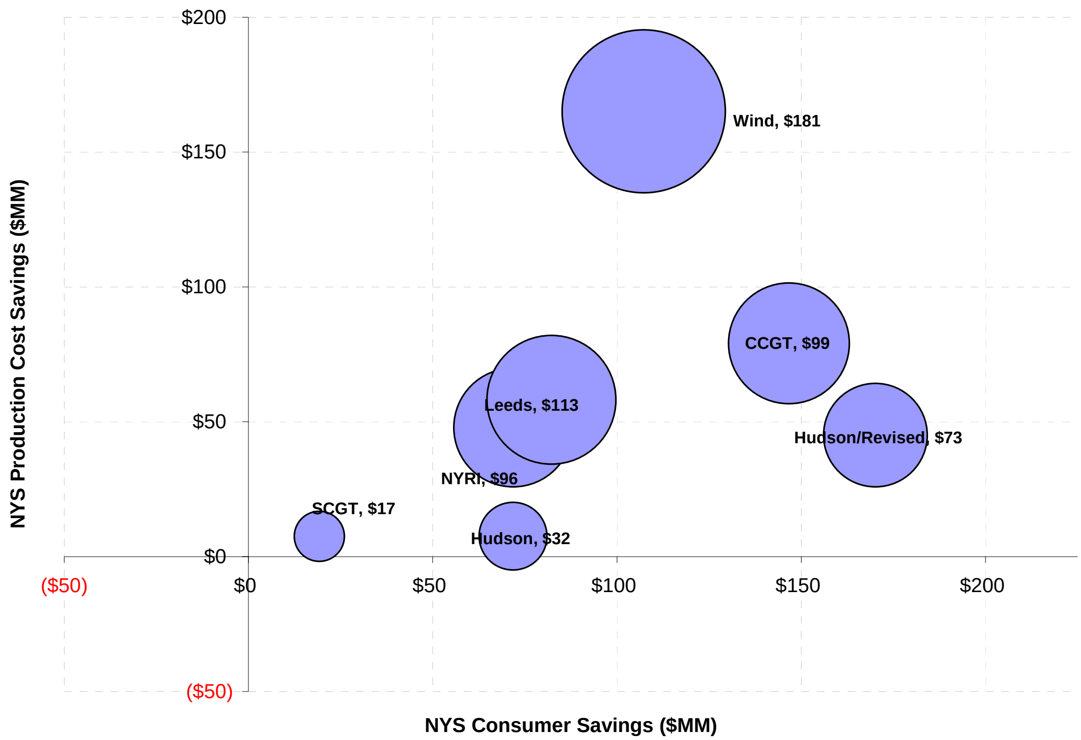
Table 12 shows the capacity factors of each project in the production cost simulation.

Table 12: Capacity factors of projects evaluated, 2013

	Capacity factor (towards NYC)
CCGT	77%
SCGT	14%
Hudson	56%
NYRI	46%
Leeds	50%
CE-LIPA	73%
Hudson revised	59%

Figure 8 displays the production cost benefits, the consumer savings, and the NYC impact of each project in the analysis year 2013. The chart shows only energy benefits—there are no capacity benefits in the base year. The size of each circle (and its label) indicates the magnitude of NYC consumer benefit.

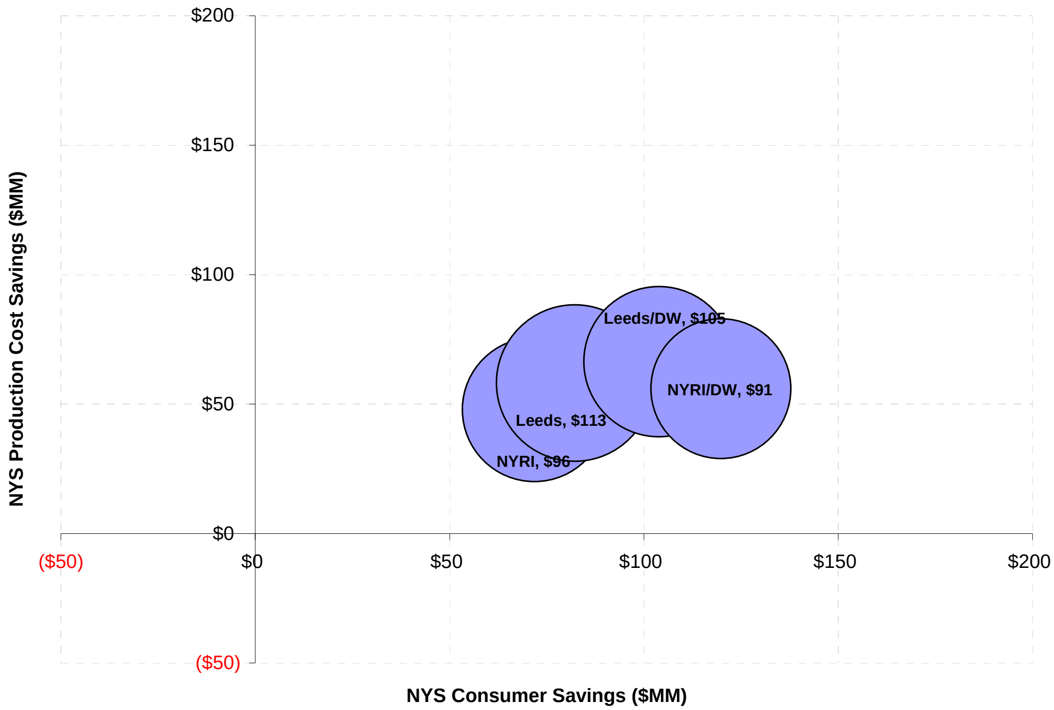
Figure 8: 2013 Benefit Results (million 2008$)



After examining the results from the first round options, we examined the impact of combining the two upstate projects, Leeds and NYRI, with an increased in the Dunwoodie South interface limit. Examination of the results indicated that while these two projects relieved Upstate constraints across Central East and the cables that make up UPNY-SENY, power was still bottle-necked into the City. After examination of the production cost simulation data, we determined that the principal constraint into the City was the Dunwoodie South interface.

Figure 9 displays the change in producer, consumer, and NYC benefits for the two projects (Leeds and NYRI) that were combined with upgrades to the Dunwoodie South interface.

Figure 9: 2013 Benefits—Leeds/DW and NYRI/DW Options



The results indicate that upgrades in the interface affect each project in a similar manner: NYS consumer benefits increase, but NYC consumer benefits are almost unchanged because of ConEdison's and NYPA's transmission congestion contracts. These results are described in greater detail in sections 3.3.5.

Price Impact on Neighboring Areas

In general, constructing transmission capacity from an area with low prices to an area with higher prices will tend to equalize prices, raising prices in the lower-priced region and decreasing them in the higher-priced region. This is of particular relevance to the Hudson cable, as its purpose is to allow lower-priced PJM power to be imported into NYC.

We analyzed the impact on area LMPs in two regions in our GE MAPS model, the PSE&G area in northern New Jersey, and the Jersey City (JCPL) area. The Hudson cable connects the PSEG area and the NYC area in our topology. Table 13 displays annual load-weighted area LMPs for each region.

Table 13: Impact on LMP in New Jersey, 2008$/MWh

	PSEG	JCPL
NYRI	-0.25	-0.20
Hudson	0.76	0.69
Hudson revised	0.65	0.75
Leeds	-0.37	-0.36
CE-LIPA	-0.02	-0.01
CCGT	-0.18	-0.18
SCGT	0.01	0.01
Wind	-0.39	-0.38
Leeds/DW	-0.27	-0.27
NYRI/DW	-0.19	-0.16

Connecting PJM and NYC with the Hudson project causes PSEG LMPs to rise by $0.76 in the base case and $0.65 in the revised case. What is less obvious is that projects that increase supply in NYC, either through generation or transmission (with the exception of the Hudson project, which imports power from New Jersey) generally have a beneficial effect on New Jersey prices as well, allowing less import into the NYCA and thus lower prices for New Jersey residents.

3.2.2. Reference Case Capacity Market Summary

Transmission and generation additions can affect the costs of installed capacity for New York City in one of two ways. Projects that provide firm installed capacity counted by the NYISO in meeting the Locational Capacity Requirement (LCR) for Zone J add supply to the market, directly factoring into the market clearing price and total quantity cleared in the market. Firm capacity can be provided by either generators or controllable transmission lines backed by a firm transmission resource.

Pure transmission projects with no firm capacity behind them can also potentially affect the capacity market. Transmission projects that increase the capability to move power into New York City may allow the same level of system reliability to be achieved with a lower quantity of locally installed capacity.[22] As a result, the presence of these projects may allow LCR to be set lower, reducing demand.

In this study we have calculated ICAP benefits only for projects that count as firm capacity supply resources, which include the generation projects and the Hudson transmission cable. While pure transmission projects that interconnect directly into New York City would clearly provide additional access to external capacity and, all else equal, lead to a reduction in LCR, the impact on the LCR of transmission projects that terminate outside Zone J is much less obvious and these projects are assumed to not affect LCR in this study.[23] Note, however, that a lowering of the LCR may not necessarily lead to a reduction in capacity costs for consumers, an effect discussed in section 3.3.5.

We modeled capacity benefits in this study using our proprietary model of the NYISO Installed capacity market. The model estimates results of the NYISO spot auctions using the demand curves for each NYISO location along with the available supply of ICAP resources. The parameters for demand curves have already been set through April 30, 2011. After April 2011, CRA has assumed that the annual revenue requirement used to set the demand curve will increase at the rate of general inflation.

In addition to the demand curve, estimating market clearing prices requires a supply curve. CRA obtained unit ratings for all existing capacity resources from the 2008 NYISO Gold Book. Assumptions regarding new capacity resources are detailed elsewhere in this report. The offer curves modeled for New York City reflect the NYISO rules for mitigation of buyer and seller market power; existing resources are offered on a price-taking basis, and new resources sponsored by a net buyer (such as the projects

[22] In practice, this means that pure transmission projects would have to change the Loss of Load Expectation (LOLE) for a zone sufficiently to warrant a change in the LCR.

[23] It has been suggested that the Hudson cable might also lead to changes in the LCR. However, because the developer of the cable has proposed to treat the cable as capacity into NYC, it is expected that it be treated as a capacity resource, or equivalent to a powerplant, and not as transmission. If HVDC lines are counted as controllable capacity, they are not assumed to also increase the import capacity to NYC, as doing so would essentially double count the lines capacity by claiming it both as a source of ICAP and a source of potential imports. Any effect that the Hudson project would have on LCR would occur indirectly, through, e.g., an impact on the market-wide average EFORd. Neither the direction nor magnitude of such an impact is quantified in this study.

evaluated in this study) are subject to an offer floor at 75 percent of the NYISO estimated cost of new entry (CONE).

Figure 10 shows the projected market clearing for Zone J for 2013. The flat segment at the top, far right of the offer curve reflects new capacity provided by the second Astoria Energy combined-cycle plant, expected in the market in 2011, which will be subject to the offer floor. The offer for this unit, at 75 percent of CONE, is expected to set the market clearing price. Figure 11 shows the 2013 reference case clearing prices on a monthly basis and Figure 12 shows the longer-term project clearing prices in the reference case.

Figure 10: Capacity market analysis for reference case

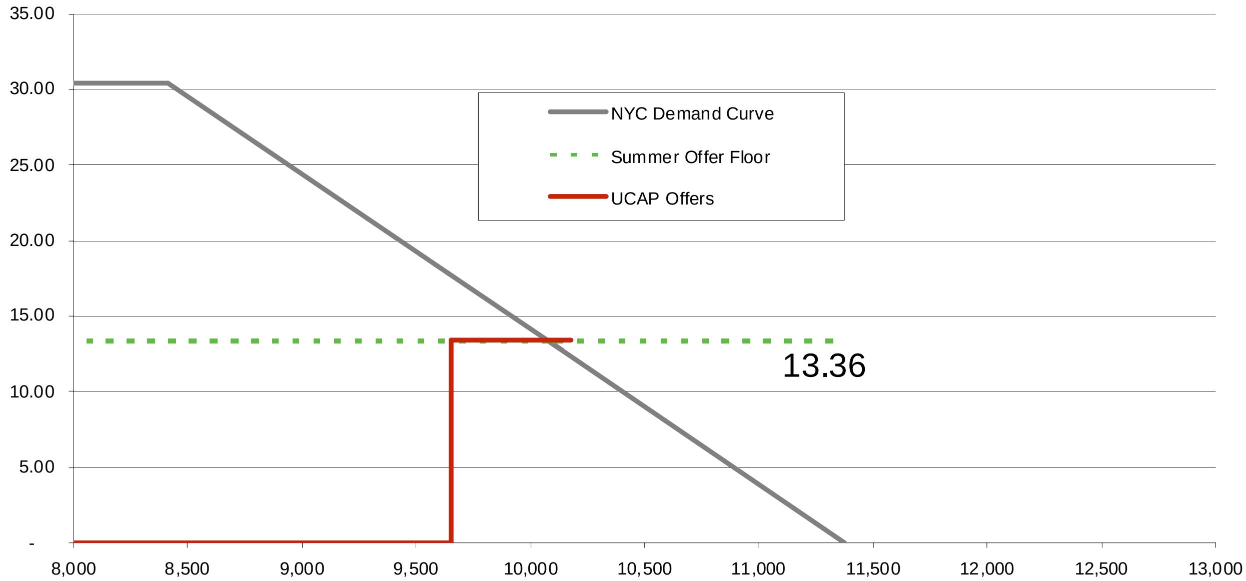


Figure 11: 2013 Base Case UCAP Price Forecast for Zone J

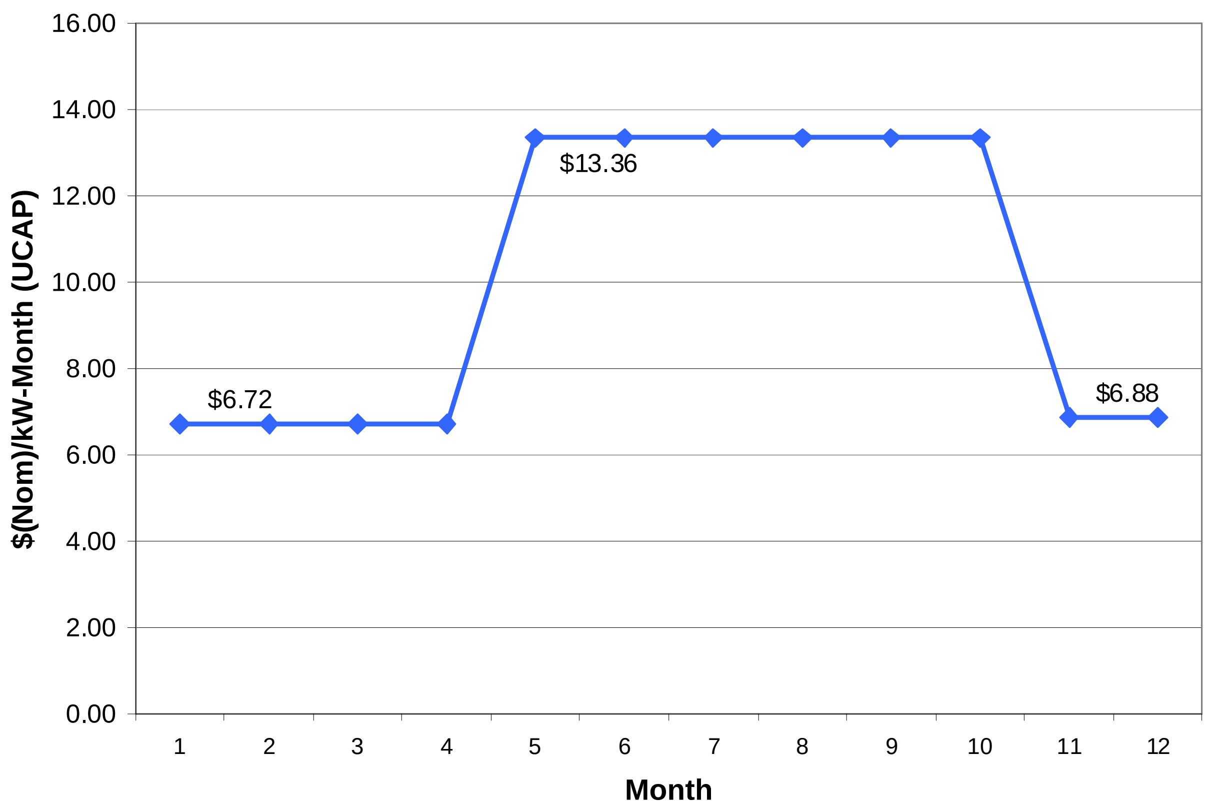
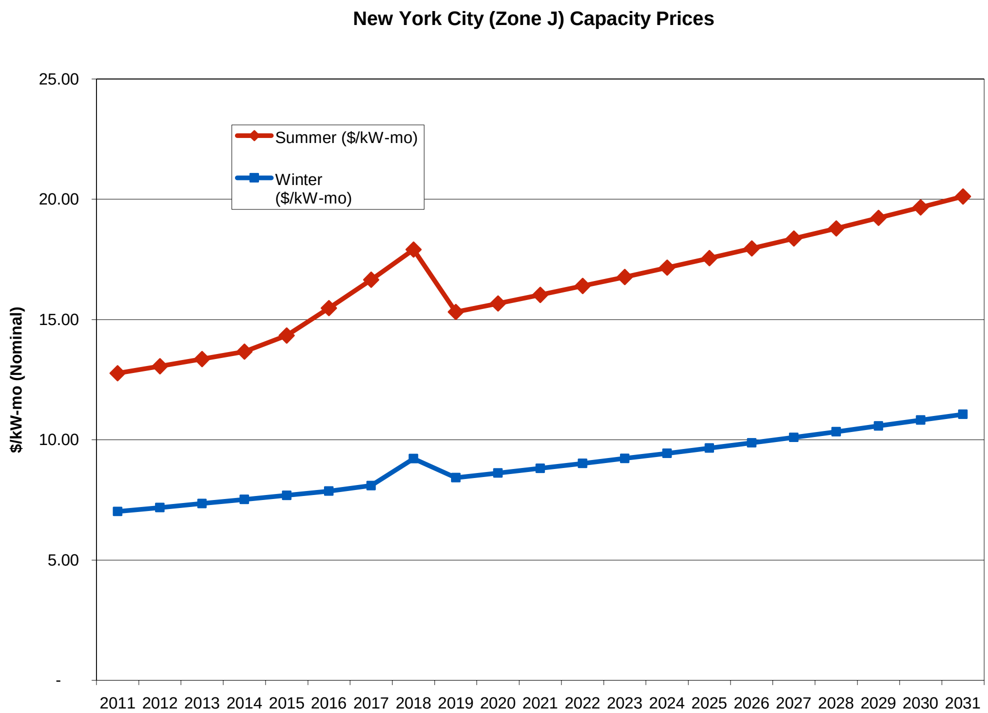


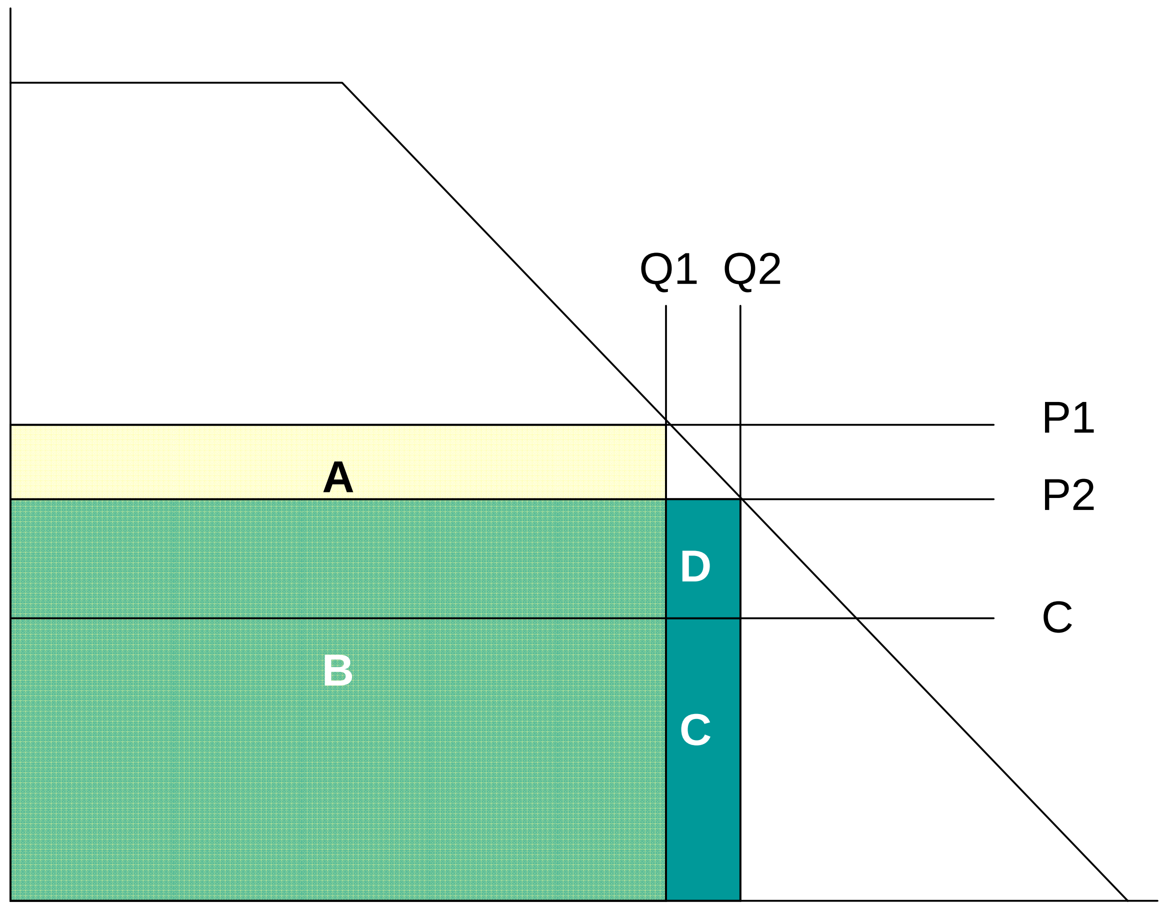
Figure 12: Reference Case UCAP Price Forecast for Zone J



New capacity resources added or sponsored by LSEs in NYC generate potential benefits for ratepayers in two ways. First, the projects have direct benefits, in that they provide capacity that partially offsets the LSEs' purchase requirements, reducing financial exposure to market prices. Second, the projects affect the overall procurement costs for LSEs by changing the market clearing point, potentially shift prices lower, but also increasing the total quantity cleared in the market and the each LSE's procurement requirement. The indirect, market-price benefits apply to LSEs' total capacity procurement requirement, which includes both in-City capacity to meet LCR and statewide capacity to meet the LSEs' shares of the statewide Installed Reserve Margin requirement.

Figure 13 illustrates the impact of capacity additions on the ICAP market and the resulting benefits to ratepayers. The value of direct benefits is equal to the quantity of capacity from the project that clears in the market, net of any variable costs of providing firm capacity. In the case of generation projects, there is no cost of securing firm capacity (the project itself provides it directly), so the direct benefit is simply the market clearing price with the capacity in the market (P2 in the graph) multiplied by the quantity of capacity from the project that clears in the market (Q2-Q1 in the graph), which is represent by Area C plus Area D in the figure. In the case of the Hudson Cable, in order for the project to provide capacity, resources must be secured at the point of origination in PJM. Hence, the direct benefit is equal to the market clearing price, less the cost of PJM capacity (labeled C in the graph). As a result, the net direct benefit is equal to the incremental quantity cleared in the market, times the NYC market price less the PJM market price: (Q2-Q1)*((P2-C), or Area D in the graph.

Figure 13: Market Impact of New Capacity Additions



The market price impact to ratepayers of new capacity additions is determined by the difference in total market payment for capacity, before netting off of revenues from self-supplied ICAP. Because the capacity price is reduced from P1 to P2, ratepayers save (P2-P1)*Q1, or Area A. However, because the market clears with a higher quantity, Q2, ratepayers total procurement obligation also increases, partially offsetting benefits. The offsetting increase in procurement costs is represented by the sum of Areas C and D in the graph, so that the net market price benefit is Q1*(P1-P2) – (Q2-Q1)*P2, or Area A – Areas B+C.

To summarize, CRA calculated the ratepayer impacts on ICAP procurement costs of these projects as:

Market clearing price with project added * incremental capacity cleared in the market

+ price reduction in Zone J * NYC quantity procured in reference case

- increased quantity procured in Zone J * market price after addition

+ price reduction for upstate capacity * quantity of upstate capacity procured by Zone J LSEs in reference case

- increased quantity of upstate capacity procured by Zone J LSEs * upstate market price after addition.

3.2.3. Reference Case Air Emissions Summary

We analyzed the impact of each project on NYC's and NYS' emissions. Results are reported here in percentage change from the base case.

Change in Emissions for NYC and NYS

Table 14 shows the changes in NYS emissions for each project evaluated in the production cost analyses. Most projects show relatively small changes, with the exceptions of the offshore wind farm and the Leeds and NYRI projects. The wind farm shows consistent decreases in all air pollutants. The Leeds and NYRI projects show increased NO_x emissions, primarily driven by increases in upstate gas-fired generation output.

Table 14: Change in NYS emissions from base case[24]

	NO_x	SO_x	Hg	CO_2
Hudson	-0.4%	-0.3%	0.0%	-0.5%
NYRI	4.7%	0.5%	0.4%	0.1%
Leeds	3.3%	-0.1%	-0.1%	-0.6%

24 The Hudson revised case has been compared to a base case developed with the revised PJM load forecast.

CCGT	-0.4%	-0.1%	-0.1%	0.0%
SCGT	0.1%	0.1%	0.1%	-0.1%
Wind	-0.9%	-0.5%	-0.4%	-1.5%
CE-LIPA	0.3%	-0.1%	-0.1%	0.1%
Hudson revised	-0.7%	-0.5%	-0.4%	-0.8%
NYRI/DW	5.1%	0.9%	0.6%	0.2%

Table 15 shows the impact of each project on NYC air emissions. The in-City CCGT option we evaluated shows a net increase in NYC's CO2 output, as its efficiency causes it to run frequently, displacing imported energy. While this increases NYC's carbon emissions, the statewide impact is negligible. All of the other projects evaluated with the exception of the SCGT and the line from NYC to Long Island, show net in-City emissions reductions.

Table 15: Change in air emissions from reference case for NYC from base case[25]

	NO_x	SO_x	CO_2
Hudson	-1.7%	-16.4%	-1.4%
NYRI	-8.9%	-22.0%	-5.2%
Leeds	-11.7%	-42.7%	-6.7%
CCGT	-5.5%	-18.0%	4.8%
SCGT	1.8%	1.2%	0.8%
Wind	-5.2%	-10.0%	-3.4%
CE-LIPA	1.3%	0.8%	0.8%
Hudson revised	-4.1%	-45.8%	-2.0%
NYRI/DW	-10.9%	-13.1%	-6.7%
Leeds/DW	-13.5%	-36.9%	-8.5%

[25] Ibid [25] Ibid 24

Change in emissions for other regions

In addition to the analyzing the air emissions impact for New York, we also analyzed the emissions impact for PJM. This is most relevant to the Hudson cable project, as it affects generation patterns in PJM more than the other projects. We calculated the change in emissions for the PJM regions of PSEG, PP&L, PECO, GPU, Delmarva, and Atlantic Electric.

Table 16: Change in air emissions changes from reference case for eastern PJM for 2013[26]

	NO_x	SO_x	Hg	CO_2
CCGT	-0.5%	-0.3%	-0.1%	-0.7%
SCGT	-0.1%	0.0%	0.0%	-0.1%
LIPA	-0.1%	-0.2%	-0.1%	0.0%
Hudson	0.9%	1.4%	0.8%	0.7%
Hudson revised	0.7%	1.0%	0.2%	0.5%
NYRI	-0.5%	-0.3%	-0.1%	-0.8%
Leeds	-0.4%	-0.7%	-0.3%	-0.6%
Wind	-0.1%	-0.1%	-0.1%	-0.1%
NYRI/DW	-0.8%	-0.7%	-0.2%	-0.9%
Leeds/DW	-0.3%	-0.3%	-0.1%	-0.6%

Because it draws power from the PJM system, it has been asserted that the Hudson project will drive up emissions in New Jersey and Pennsylvania, creating a “coal by wire” situation. Our analysis found that he changes are in PJM are relatively small; adding the Hudson cable with the base assumptions increases air emissions by approximately 1% for all pollutants.

Transmission projects such as NYRI and Leeds actually result in an emissions decrease in PJM, as less generation is necessary to be able to feed the NYC area. It is important to remember that PJM exports power to NYC even in the absence of the Hudson cable; it is just that the Hudson cable provides a much more direct connection between the two regions.

[26] Ibid [26] Ibid 24

3.2.4. Project Cost Estimate Methodology

We developed EPC cost estimates in order to compare projects by their net benefits. Our cost estimates are planning-level estimates with an error range of +/- 30% for most cases. We assumed for the purposes of this calculation that costs were incurred in 2008 dollars. Table 17 presents a summary of our project cost estimates. All estimates assume the project beginning commercial operation in 2013.

Table 17: Summary of Project Cost Estimates

Project Name	Project Value	Amount Financed	Interest Rate	Construction Time	IDC Cost	Total Project Value
CCGT	$696,111,217	$348,056,000	8%	30 Months	$48,727,840	$744,839,057
Hudson	$501,385,347	$250,693,000	8%	30 Months	$35,097,020	$536,482,367
Wind	$2,097,092,118	$1,048,546,000	8%	44 Months	$215,301,446	$2,312,393,564
NYRI[27]	$1,201,763,857	$600,882,000	8%	39 Months	$109,360,524	$1,311,124,381
Leeds-PV	$191,605,920	$95,803,000	8%	18 Months	$8,047,452	$199,653,372
Dunwoodie Upgrades	$486,112,945	$243,056,000	8%	39 Months	$44,236,192	$530,349,137

These cost estimates were developed independently of developer cost estimates, although with the input of project stakeholders in some cases. We developed bottom-up cost estimates for each project and identified areas in which there were insufficient or incomplete data available.[28]

The estimation of financing charges for such projects can be exceptionally difficult. We adopted a simplified approach to calculate interest during construction estimates where we assumed a 50/50 debt to equity ratio, an 8% interest rate, and construction schedules based on our engineering estimates.

In many cases, there were cost estimates for projects that were available through public sources (e.g., Article VII filings) or through other sources, and we have incorporated those data from those estimates into our

[27] Note that the developers' cost estimates were used for the NYRI project in place of our calculations

[28] For example, we found that in some cases, "conventional wisdom" cost estimates did not include the cost of land purchases, a major part of the overall project costs.

analysis.[29] These cost estimates should generally be considered as a floor for the ultimate cost of the project; "soft costs" for projects will add to the development cost of all projects surveyed.

Soft costs have also been excluded from the cost estimates due to the potential wide range in costs that could occur for legal fees, land acquisition, rights of way, permits, and any other associated project development cost that is not part of the normal EPC construction cost. In general, our cost estimates may be conservative, in that they do not capture all of the non-construction and interest potential costs associated with each project.

Composite field craft labor rates were calculated for thirty-five individual crafts based on rates of the labor unions having jurisdiction for those areas where the work would be performed. In addition to the base labor rate paid to the worker, the calculation includes the associated fringe benefits paid, insurance, taxes, worker's compensation costs and a percentage mark-up to include a working foreman. All non-working construction support including general foremen, superintendents and managers have their costs included separately from the calculated composite rates in the indirect cost section of each of the six cost estimates.

Major equipment costs were developed from the BRE in-house cost database that contains cost information from previously completed projects. These costs are updated to present market conditions on a regular basis. Costs for five MW wind turbines, including blades and masts, were also solicited and a verbal quotation was received and included in the wind power cost estimate.

Material costs were also developed from the BRE in-house cost database. These costs were also updated to present market conditions as required. We solicited verbal proposals for supply of underwater cable for the project and utilized these costs in the various cost estimates.

Two of the six cost estimates required converter stations. We calculated these costs based on recent experience on a completed project in the New York metropolitan area, and later obtained quotations for the

[29] For instance, the NYRI project developers have publicly stated that their development costs will be approximately $2 billion. In developing the EPC cost for this project, we were unable to identify more than $1.2b2 billion in "hard" costs, but it is not unreasonable to expect that there could be up to $800m800 million in "soft" costs such as land acquisition, legal fees, and development costs.

converter stations and found our cost estimates to be in line with the costs received from the vendors.

In regard to field labor unit hours for performing the work, BRE utilized their in-house database and adjusted the unit rates to suit the expected labor productivity for the area where the work would be performed. Burns and Roe has prior experience in jet plowing labor and other incidental costs associated with the installation of underwater cable in the New York metropolitan area. We applied this experience in estimating the costs for cable installation in three of the six cost estimates where underwater cable installation is required.

3.2.5. Reference Case Long-term Analysis Summary

Capacity Additions

Table 18 shows necessary capacity additions for the reference long-term analysis. Capacity additions overall are relatively modest, reflecting slowing load growth rates. The NEEM model adds capacity in a zone when market conditions make it economic for new generation to site there, or when mandated by reserve margins.

Table 18: Capacity additions for Reference Case (MW)

Year	Type	Capital	Downstate	LIPA	NYC	Upstate
2017	Wind					780
2018	CCGT					605
2018	Wind					33
2019	CCGT				500	
2023	Nuclear	49				
2023	Wind					89
2027	Nuclear	2,303				
2027	Wind					117
2031	IGCC	1,597	451			
2031	Nuclear	826				
2031	Wind					75

The results show the new combined cycle capacity we assume will be added in 2019 in NYC. We conducted analysis using NEEM in which we allowed it to build new capacity in NYC without assuming that a new CC would site in NYC in 2019, and we found that in such a case where capacity was not “forced” in, combined-cycle capacity was the most economic type of capacity to add (as opposed to a peaking unit, for example). New nuclear and IGCC capacity are added later, near the end of the study timeframe, as emissions prices and market conditions make it economic to add capacity at that point.[30]

After capacity additions in 2019, our analysis indicates that new capacity would not be necessary to meet reserve margins in NYC through the end of the study timeframe. This is a long interval between capacity additions; the principal reason behind this is the slow load growth forecast in the later years of the RNA forecast and the impact of mandatory carbon pricing on the energy demand in NYS.

The later years of the RNA (post 2015) show very slow load growth rates, on the order of eight-tenths of one percent. We extrapolated this growth rate into the future as per our assumption set. The impact of our base carbon price trajectory (which begins at approximately $30 in 2015) reduces demand growth slightly, and results in long-term load growth being very small, approximately one-half of one percent.

Benefits change methodology

Our long-term analysis methodology shows how benefits change over time in response to changes in capacity additions and retirements, load growth, and response of load to market conditions. We define the benefits in this case as the state of the system in a given year after addition of a project versus the state of the system had the project not been added.

The change in production cost and consumer benefits from the long-term model was used to scale the benefits from the detailed production-cost simulation. If, for example, NEEM showed that consumer benefits for a specific project were 90% of the benefits in the base year in NEEM, then the consumer benefits for that project were calculated to be 90% of the production-cost simulation benefits in the base year.

For the special case of NYC impact, we assume that load-serving entities in NYC continue to hold similar portfolios of contracted generation and transmission hedges as they do today until the end of the study period.

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[30] Note that NEEM adds capacity in small block sizes in later years. This is characteristic of long-term capacity-addition optimization models.

As a result, the impacts on NYC are less than they would be if all load in NYC purchased its energy and capacity at market prices. An alternative assumption would be to assume that market prices in NYC trend towards NYC LBMPs in the long run. Many transmission congestion contracts, however, persist for long periods of time, and not all contracts for generation with in-City LSEs have been struck at market prices in the past.

In this study, we have assumed that 500 MW of capacity is added in NYC in 2019. This is approximately 350 MW more than would be needed to meet reliability requirements. Because of this assumption, market-price benefits for in-City generation decay more rapidly than they would had only enough capacity to meet installed capacity requirements been added. Consequently, our long-term market price benefits are conservative, and may understate long-term indirect benefits of in-City generation (or controllable transmission) projects under alternate assumptions for future capacity additions.

Our analysis showed that in some cases, generation projects showed a very small “disbenefit” in later years (generally on the order of 5% of the original benefits). For simplicity of presentation, we have assumed that when generation project benefits expire, they stay at zero, and do not turn negative.

Table 19 shows the benefit ratios for each case for the reference analysis for the production cost impact.

Table 19: Benefits change over time for NYS production cost

	CCGT	Hudson	Hudson revised	Leeds	Leeds/ DW	NYRI	NYRI/ DW	Wind
2013	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2014	1.20	1.45	1.45	0.93	0.93	0.86	0.86	0.96
2015	0.88	1.86	1.86	1.09	1.09	0.66	0.66	1.48
2016	0.64	1.25	1.25	0.98	0.98	0.64	0.64	0.82
2017	0.64	1.25	1.25	0.98	0.98	0.64	0.64	0.82
2018	0.55	1.07	1.07	0.99	0.99	0.38	0.38	0.33
2019	0.00	0.38	0.38	0.89	0.89	0.20	0.20	0.00
2020	0.00	0.50	0.50	0.94	0.94	0.18	0.18	0.00
2021	0.00	0.50	0.50	0.94	0.94	0.18	0.18	0.00

2022	0.00	0.50	0.50	0.94	0.94	0.18	0.18	0.00
2023	0.00	0.50	0.50	0.94	0.94	0.18	0.18	0.00
2024	0.00	0.54	0.54	0.80	0.80	0.00	0.00	0.00
2025	0.00	0.54	0.54	0.80	0.80	0.00	0.00	0.00
2026	0.00	0.54	0.54	0.80	0.80	0.00	0.00	0.00
2027	0.00	0.54	0.54	0.80	0.80	0.00	0.00	0.00
2028	0.00	0.52	0.52	1.20	1.20	0.34	0.34	0.00
2029	0.00	0.52	0.52	1.20	1.20	0.34	0.34	0.00
2030	0.00	0.52	0.52	1.20	1.20	0.34	0.34	0.00
2031	0.00	0.52	0.52	1.20	1.20	0.34	0.34	0.00
2032	0.00	0.76	0.76	1.69	1.69	0.47	0.47	0.00
2033	0.00	0.76	0.76	1.69	1.69	0.47	0.47	0.00

Table 20 shows the same ratios for consumer cost benefit for each project.

Table 20: Benefits change over time for NYS consumer cost

	CCGT	Hudson	Hudson revised	Leeds	Leeds/ DW	NYRI	NYRI/ DW	Wind
2013	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2014	1.18	1.48	1.48	1.36	1.36	1.34	1.34	0.96
2015	0.88	1.82	1.82	1.67	1.67	1.64	1.64	1.53
2016	0.60	1.22	1.22	1.09	1.09	1.08	1.08	0.85
2017	0.60	1.22	1.22	1.09	1.09	1.08	1.08	0.85
2018	0.52	1.05	1.05	1.02	1.02	1.00	1.00	0.33
2019	0.00	0.39	0.39	0.62	0.62	0.61	0.61	0.00
2020	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2021	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2022	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2023	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2024	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00

2025	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2026	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2027	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2028	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2029	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2030	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2031	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2032	0.00	0.58	0.58	1.67	1.67	1.61	1.61	0.00
2033	0.00	0.58	0.58	1.67	1.67	1.61	1.61	0.00

Under our long-term capacity addition assumption, the net benefits for the in-City CCGT decay rapidly upon addition of new in-City capacity. The Hudson project, as a hybrid of generation and transmission, decays somewhat less rapidly. Benefits from upstate transmission project change over time as the generation patterns in NYS change.

The wind project has perhaps the most interesting long-term pattern, showing attenuated production cost and consumer benefits after the introduction of new in-City capacity. This potentially counterintuitive result is discussed in greater detail in section 3.3.6.

Table 21 shows how benefits change over time for NYC consumers.

Table 21: Benefits change for NYC consumer cost for indirect energy

	CCGT	Hudson	Hudson revised	Leeds	Leeds/ DW	NYRI	NYRI/ DW	Wind
2013	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2014	1.18	1.48	1.48	1.36	1.36	1.34	1.34	0.96
2015	0.88	1.82	1.82	1.67	1.67	1.64	1.64	1.53
2016	0.60	1.22	1.22	1.09	1.09	1.08	1.08	0.85
2017	0.60	1.22	1.22	1.09	1.09	1.08	1.08	0.85
2018	0.52	1.05	1.05	1.02	1.02	1.00	1.00	0.33
2019	0.00	0.39	0.39	0.62	0.62	0.61	0.61	0.00
2020	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00

2021	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2022	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2023	0.00	0.49	0.49	0.74	0.74	0.72	0.72	0.00
2024	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2025	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2026	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2027	0.00	0.45	0.45	0.72	0.72	0.71	0.71	0.00
2028	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2029	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2030	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2031	0.00	0.45	0.45	1.00	1.00	1.02	1.02	0.00
2032	0.00	0.58	0.58	1.67	1.67	1.61	1.61	0.00
2033	0.00	0.58	0.58	1.67	1.67	1.61	1.61	0.00

The pattern of changes for NYC prices is similar as for NYS prices, with in-City generation benefits declining upon addition of new in-City capacity in 2019.

3.2.6. Sensitivity Analysis Summary

We analyzed the impact of three scenarios from the on the results of two projects, the Leeds project combined with the Dunwoodie South upgrade and the Hudson cable. We present in this section a comparison of each scenario on each project.[31]

We selected two sensitivities from the 2009 NYISO RNA and added a third after consultation with stakeholders. The three scenarios selected were:

- The 2009 RNA econometric high load scenario
- The 2009 RNA high fuel price scenario

[31] The terms “scenario” and “sensitivity” are used interchangeably throughout this report.

- A mandatory national carbon policy with a price starting at $15/ton in 2015

The values and assumptions used for these scenarios are described in greater detail in the Appendix.[32]

We utilized our long-term regional model to develop our long-term sensitivity results. The methodology and basis for this are described in greater detail in section 2.1.4. The results of the long-term scenario effects are not directly comparable to the results derived from our security-constrained production cost simulation results, and are intended to illustrate the relative benefit of each project or scenario on the overall project metrics. In particular, our NYC consumer benefits assume that all energy is purchased at the NYC LBMP, potentially slightly overstating consumer benefits in NYC in absolute terms.

Results are reported here in terms of absolute numbers rather than relative benefits to assist in easier comparisons across both projects and scenarios. Table 22 through Table 26 illustrate the impact of the different sensitivities

Table 22: 20-year NPV of low-carbon scenarios, million 2008$

	Base	Low Carbon	HTP Low Carbon	Leeds Low Carbon
Production Cost	$80,356	$75,616	$72,207	$73,465
NYS Consumer Cost	$328,651	$282,456	$279,473	$278,044
NYC Consumer Cost	$56,508	$49,181	$45,879	$44,063

Table 23: Change in 20-year NPV of low-carbon scenarios

	Low Carbon	HTP Low Carbon	Leeds Low Carbon
Production Cost	$(4,740)	$(8,150)	$(6,892)
NYS Consumer Cost	$(46,195)	$(49,178)	$(50,606)
NYC Consumer Cost	$(7,327)	$(10,629)	$(12,445)

32 These scenarios are the same as those used in the preparation of NYPA's 2008 IRP study.

A lower carbon price effects approximately a 9% reduction in overall production cost compared to the base case (with a carbon price that starts at $30 in 2015). In the low-carbon scenario, the Hudson cable is slightly more effective than the Leeds project in reducing production cost.

A lower carbon price has a similar effect on NYS consumer costs, reducing overall costs by approximately 10%. The Hudson cable and Leeds project both effect small reductions in consumer cost, but there is no significant difference between the two projects in a low-carbon scenario in our analysis.

For NYC, the overall gross consumer reduces by approximately 10%, and both the Hudson cable and Leeds project reduce costs to similar levels, effecting approximately an additional 10% decrease in gross consumer costs. In a low-carbon scenario, both projects have relatively small impacts on overall NYS benefits, but stronger impacts on NYC consumers.

Table 24 shows the impact of high gas prices on NYS and NYC.

Table 24: 20-year NPV of high gas price scenarios, million 2008$

	Base	High Gas	HTP High Gas	Leeds High Gas
Production Cost	$80,356	$80,057	$75,674	$77,936
NYS Consumer Cost	$328,651	$361,666	$355,974	$356,619
NYC Consumer Cost	$56,508	$63,660	$58,044	$57,407

Table 25: Change in 20-year NPV of high gas price scenarios, million 2008$

	High Gas	HTP High Gas	Leeds High Gas
Production Cost	$(299)	$(4,682)	$(2,420)
NYS Consumer Cost	$33,015	$27,324	$27,969
NYC Consumer Cost	$7,152	$1,536	$898

High gas prices result in approximately 3% increase in overall NYS production cost. Under this high-gas scenario, both the Hudson cable and the Leeds project reduce production cost, but the Hudson cable is slightly more effective in reducing production cost because it allows greater import of power from PJM, where less of the power is produced by gas-fired units.

High gas prices increase overall NYS consumer costs by approximately 12%. Unger higher gas prices, both the Hudson cable and Leeds project have similar effects on NYS consumers, reducing the impact to approximately a 9% increase in consumer rates.

High gas prices have their strongest effect on NYC consumers, as much of the power in NYC is produced by gas-fired units. NYC consumer prices increase by approximately 17%, and both the Hudson cable and Leeds project are similarly effective in mitigating the impact of higher gas prices in NYC.

Table 26 displays the results of the high-load scenarios.

Table 26: 20-year NPV of high-load scenarios, million 2008$

	Base	High Load	HTP High Load	Leeds High Load
Production Cost	$80,356	$92,526	$89,461	$88,115
NYS Consumer Cost	$328,651	$331,558	$329,176	$327,979
NYC Consumer Cost	$56,508	$56,912	$54,131	$51,727

Table 27: Change in 20-year NPV of high-load scenarios - million 2008$

	High Load	HTP High Load	Leeds High Load
Production Cost	$12,170	$9,104	$7,759
NYS Consumer Cost	$2,908	$525	$(672)
NYC Consumer Cost	$404	$(2,377)	$(4,781)

High load growth increases overall production cost by approximately 11% statewide. The Hudson and Leeds projects show similar effects under this scenario, limiting the increase to approximately 7% overall.

Consumer costs are not greatly affected, showing only approximately a 1% increase. This is in part because the high-load growth scenario in the NYISO RNA does not an exceptionally high historic growth level, and partly because NYS is not short on installed capacity, resulting in inframarginal units with increased capacity factors.

The same factors affect NYC similarly. The increase in consumer cost is relatively small, as NYC's excess of installed capacity limit the impact of high load growth. Both the Hudson and Leeds project are effective in reducing NYC consumer costs in this scenario, although the Leeds project is somewhat more effective, allowing greater generation from upstate to reach NYC.

Table 28 shows the capacity additions under the base high load scenario. Because we conducted a purely long-term optimal analysis, we allowed our NEEM model to insert capacity in economically optimal increments rather than the fixed insertion of 500 MW of combined-cycle capacity in NYC in 2019 that we assumed in our reference cases.

Table 28: Capacity additions for high-load base scenario (MW)

Year	Unit Type	Capital	Downstate	LIPA	NYC	Upstate
2014	CC				38	
2014	CT				14	
2015	CC				182	
2017	CC				219	
2017	Wind			46		734
2018	CC	238			112	1,349
2018	Wind			33		
2019	CC				82	
2023	Wind			75		39
2023	Nuclear	50				
2027	Wind			117		
2027	Nuclear	2,302				
2031	IGCC	1,983	540			
2031	CC				200	
2031	Wind			75		
2031	Nuclear	826				

The results show that NYC would require the addition of approximately 450 MW of new capacity by 2018. This new capacity would be necessary to not only meet reserve margin requirements, but would also be given incentive to enter the market by economic conditions. Note that the introduction of this much capacity earlier than our reference insertion year of 2019 would cause indirect project benefits to expire even sooner than in the reference case

3.3. Individual Project Analyses

Table 29 shows which analyses were performed for which projects.

Table 29: List of Analyses

	Production Cost	ICAP	Long-term base	Long-term sensitivities	EPC Cost Estimates
Base	x	x	x		
CCGT	x	x	x		X
LIPA	x				
NYRI	x	x	x		X
Hudson	x	x	x	x	X
Hudson revised	x	x	x		X
SCGT	x				
Wind	x	X	x		x
Leeds	x	X	x		x
Leeds/DW	x	x	x	x	X
NYRI/DW	x	x	x		X

The following sections present summaries of each project's quantitative analysis results.

3.3.1. CCGT

Project Description

One potential solution to NYC's energy needs is the development of a powerplant in the City itself. There have been various options proposed to develop plants in various locations, and one plant currently in development (Astoria Energy Phase 2) will become an important part of the City's energy supply mix in the future. For this study, we analyzed the impact of a 500 MW combined cycle plant based in Staten Island, with a generator lead to the 345 kV Gowanus substation in Brooklyn.

Western Staten Island has often been proposed as an ideal site for siting new generation, with the caveat that there is insufficient transmission to the site. Transmission from Staten Island to other locations in the City is indeed limited, but the proposed solution of building new transmission to stimulate generation development may not the only one.

Building new transmission capacity across Staten Island is extremely expensive and may not bypass all of the transmission constraints that are important. Building an underwater cable to transmit the power where it's needed (in this case Gowanus) may be a more cost-effective solution.

The unit was modeled with a summer capacity of 500 MW, and a heat rate of 7,100 BTU/kWh, reflecting the state-of-the-art technology expected to be available in 2013. Table 30 summarizes our economic analysis results.

Table 30: Summary of CCGT Economic Results, million 2008$

	2013	**20-year NPV**
NYS Consumer Benefits	$147	$1,647
NYS Production Cost Benefits	$79	$309
NYC Indirect Benefits	$51	$193
NYC Direct Benefits	$49	$1,073
Project Cost	$794, $592 allocated to NYC	

Energy Benefits

Figure 14: CCGT LBMP delta contour

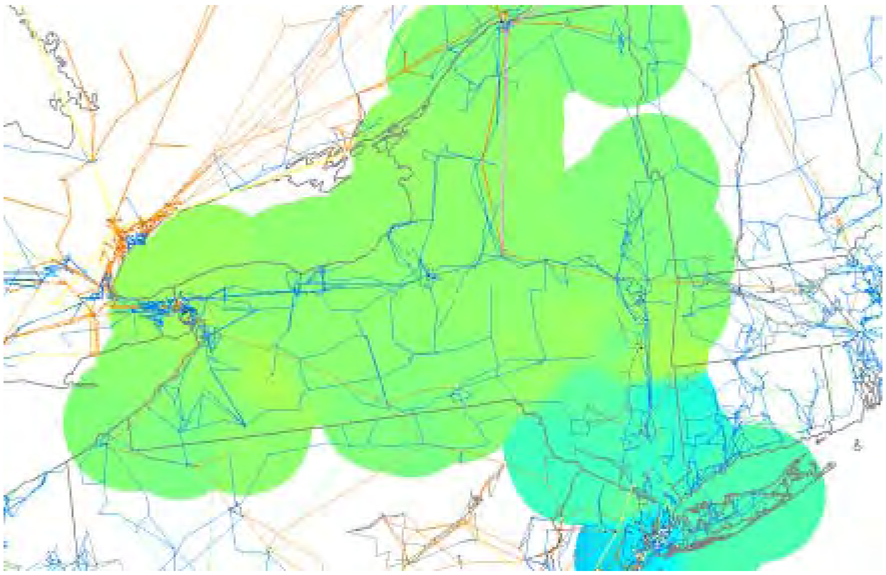
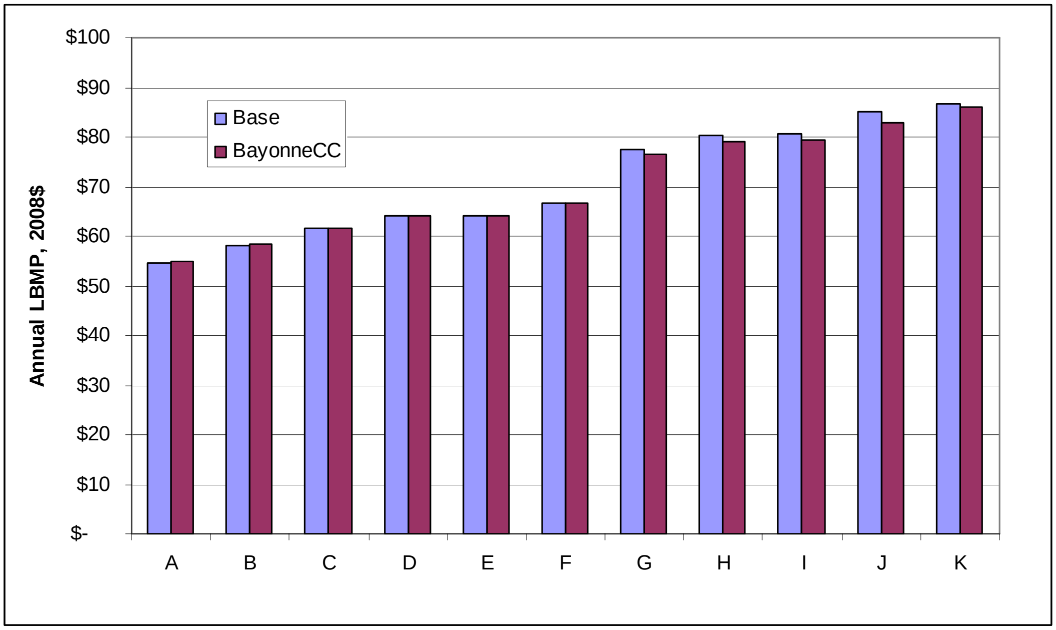


Table 31: Change in Generation Patterns—CCGT (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	(121)	(1)	-	(32)	-	0	-	116	-	(38)
B	(48)	-	(0)	0	-	-	(0)	-	-	(48)
C	(251)	(13)	1	-	(14)	0	-	(21)	-	(297)
D	(12)	-	-	(0)	-	0	-	(24)	126	90
E	(53)	10	-	(0)	-	(0)	-	-	-	(44)
F	(132)	-	-	(150)	-	(0)	-	(93)	-	(375)
G	(1)	(5)	-	-	(231)	(0)	-	(34)	-	(271)
H	-	-	0	-	-	(1)	-	-	-	(1)
I	0	-	-	-	-	-	-	-	-	0
J	2,748	-	-	-	(835)	-	-	(723)	-	1,190
K	(151)	-	-	-	(108)	2	-	(256)	-	(513)
Sum	1,979	(10)	1	(182)	(1,187)	1	(0)	(1,034)	126	(306)

Figure 15: Change in LBMPs for CCGT, 2008$/MWh



The CC unit has a high capacity factor in our analyses—approximately 77% in our reference case simulation. This accounts for its substantial impact on NYC prices. The unit operates as inframarginal capacity in most hours, lowering overall prices and production cost. The unit displaces primarily gas/oil plants and imports from NYC, while displacing marginal gas units Upstate.

The unit's relatively new performance and low heat rate are the primary drivers for its performance. To some extent it displaces capacity from the new Astoria unit (its capacity factor drops from 67% to 62%), but its principal impact is in displacing other inframarginal generation in the City—capacity factors from other units generally fall across the board, and imports into the City decrease from upstate. The market-price benefits of the combined cycle unit generally accrue to all consumers, but mostly to NYC consumers.

Capacity Benefits

Calculation of the capacity benefits of the combined cycle unit is relatively straightforward. The CC unit is able to bid its full capacity into the ICAP market, reducing overall market clearing prices for all participants. However, because a new CC, sponsored by an LSE, would be subject to an offer floor at 75% of CONE, the full quantity of the project is not guaranteed to clear. In fact, in the initial years after 2013, the price is already expected to be at the floor due to surplus capacity from Astoria

Energy unit 2. Hence, none of the capacity from the CC unit would clear in the market and it would have no direct or market price benefits until sufficient load growth occurs to absorb the other surplus capacity in the market. Thus, the benefits are muted by the fact that the capacity market is expected to clear the floor through 2014.

Project Costs

We prepared an estimate for a 2 x 1 gas turbine project to be located in Staten Island delivering 500 MW to the Gowanus Substation in Brooklyn. We assumed two 7FA gas turbines, two heat recovery steam generators and one steam turbine generator. Power would be delivered at 345 kV underwater to Gowanus, assuming an 8-mile run. Based on our experience designing projects of this technology, size and configuration, we consider this estimate to be ± 20%. We estimate $696 million, including the generator lead, which translates to $1,392 per kW. This is higher than the average EPC plant cost throughout the country, but we are considering New York labor and we included the cost of the submarine cable and certain substation improvements at Gowanus.

There have been claims the cost of installing a generator lead cable through the Kill Van Kull would cost on the order several hundred million dollars; our estimate is approximately $50 million. Part of the difference can be attributed to changed geological conditions. The vintage of some of these cost estimates suggest that they were conducted prior to the US Army Corps of Engineers' dredging of the Kill Van Kull. This dredging, scheduled for completion this year, increases the depth of the channel to approximately fifty feet, sufficient for jet-plowing of a cable trench, avoiding underwater blasting and excavation costs that could have accounted for part of this high cost estimate. Based on our engineering analysis, we estimate that construction would take approximately thirty months, and would incur $48 million in interest during construction charges.

Long-term effects

The table below shows how the generator's energy margin changes over time in our simulation:

Table 32: Change in energy margin for CCGT compared to base year

Year	Margin compared to base year
2013	1.00
2014	1.04

2015	1.31
2016	1.31
2017	1.45
2018	1.50
2019	1.57
2020	1.57
2021	1.57
2022	1.57
2023	1.61
2024	1.61
2025	1.61
2026	1.61
2027	1.71
2028	1.71
2029	1.71
2030	1.71
2031	2.01
2032	2.01
2033	2.01

The CCGT shows energy margins increasing over time. This is principally due to the increase in carbon prices in the future. Over time, the marginal unit in NYC is likely to become a less-efficient, higher-carbon-emitting unit. The CCGT's efficiency, both in terms of heat rate and in terms of carbon emissions, increases its margin over time. Table 33 displays year-by-year benefits for the CCGT project.

Table 33: Yearly benefits for CCGT—million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy	NYC Direct Energy	NYC Indirect Capacity	NYC Direct Capacity
2013	$146.65	$79.08	$50.55	$48.79		
2014	$176.55	$95.16	$59.72	$50.92		

2015	$129.11	$69.59	$44.53	$63.80	$0.01	$2.41
2016	$93.75	$50.53	$30.42	$63.80	$0.04	$7.98
2017	$93.75	$50.53	$30.42	$70.81	$0.06	$13.62
2018	$81.34	$43.84	$26.21	$73.29	$0.10	$20.78
2019				$76.64	$0.02	$48.57
2020				$76.64		$60.92
2021				$76.64		$61.06
2022				$76.64		$61.20
2023				$78.40		$61.34
2024				$78.40		$61.49
2025				$78.40		$61.63
2026				$78.40		$61.77
2027				$83.64		$61.92
2028				$83.64		$62.06
2029				$83.64		$62.21
2030				$83.64		$62.35
2031				$97.99		$60.40
2032				$97.99		$62.05
2033				$97.99		$63.93

The long-term capacity additions indicate that the addition of the CCGT in NYC removes the need to add new in-City capacity for the duration of the study timeframe. Patterns in the rest of the state are little-changed from the base case.

Table 34: Capacity additions for CCGT case (MW)

Year	**Type**	**Capital**	**Downstate**	**LIPA**	**NYC**	**Upstate**
2017	Wind					780
2018	CCGT					839
2018	Wind					33
2023	Nuclear	49				

2023	Wind				89
2027	Nuclear	2,303			
2027	Wind				117
2031	IGCC	1,606	457		
2031	Nuclear	826			
2031	Wind				75

3.3.2. Hudson

Project Description

The Hudson cable was modeled as a 660 MW HVDC transmission project, connecting the 230 kV PSEG Bergen substation in Ridgefield, New Jersey, with the 345 kV bus at the ConEdison West 49^{th} St. substation in Manhattan. We have assumed that the full transmission capacity is available for this project, and that the power is deliverable at the NYC side. Based on the input of stakeholders, we did not model wheeling charges on this line, nor did we model a dedicated energy or capacity resource associated with this cable.

The option we evaluated uses back-to-back high-voltage DC converters to connect New York to PJM. HVDC lines often connect long-distance asynchronous AC networks, but in this case, the project developers chose DC technology in order to take advantage of NYISO market rules that permit such lines to qualify as installed capacity, similar to an in-City powerplant. In order to participate in the NYC capacity market, the project developers require PJM Firm Transmission Withdrawal Rights (FTWRs), requiring upgrades on the PJM side.

There are system reinforcements necessary to support the FTWRs on the PJM side. The ultimate amount of these system upgrades continues to be the subject of discussions between the Hudson developers and regulatory authorities. Hudson developers have informed us that the most recent projected total for these system upgrades is approximately $300 million, and we have used that estimate for this study.

The PJM board, however, recently approved the extension of the 500 kV network from Branchburg to Hudson. The Hudson developers assert that approximately $140 million of the upgrades that are necessary to support the Hudson cable are in fact included in the Branchburg-Hudson extension, and they are currently in discussions regarding this issue with

PJM. Regardless of the ultimate resolution of this issue, these upgrade costs must be accounted for when assessing the true costs of the project.

The subject of future potential PJM transmission upgrades identified in its Regional Transmission Expansion Plan (RTEP) was the subject of much discussion among our stakeholder group. Based on the advice of our stakeholder audience, which included PJM and NYISO, we elected to use the base 2008-series ERAG power flow case. This power flow case contains the following backbone transmission additions:

- TrAIL (502 Jct-Loudon 500 kV)
- Susquehanna-Roseland 500 kV

The following upgrades were not in the ERAG power flow case for 2013:

- PATH (Amos - Kemptown 765 kV)
- MAPP (Possum Pt. to Calvert Cliffs 500 kV, HVDC to Vienna, HVDC to Indian River)
- Branchburg-Roseland-Hudson 500 kV

The timing of these projects is still uncertain, and may be influenced by load growth in PJM; slowing load growth would cause them to be put into service later. These projects, especially the Branchburg-Hudson 500 kV extension, would relieve constraints on the PSEG system, and would likely improve the economic benefits of the Hudson project. We will be conducting a full analysis of these upgrade impacts in a supplement to this report.

Alternate cross-Hudson projects have been proposed in the past, including at least one proposal using Phase Angle Regulators (PARs). PARs permit a degree of control over AC flows between two terminals, but do not, under NYISO market rules, qualify as installed capacity. This alternate proposal might avoid some upgrade costs on the PJM side, but would not provide capacity market economic benefits. Energy market benefits for a project the same size as the Hudson cable could be similar to those calculated in this analysis.

Table 35 and Table 36 summarize our economic analysis results.

Table 35: Summary of Hudson Economic Results, million 2008$

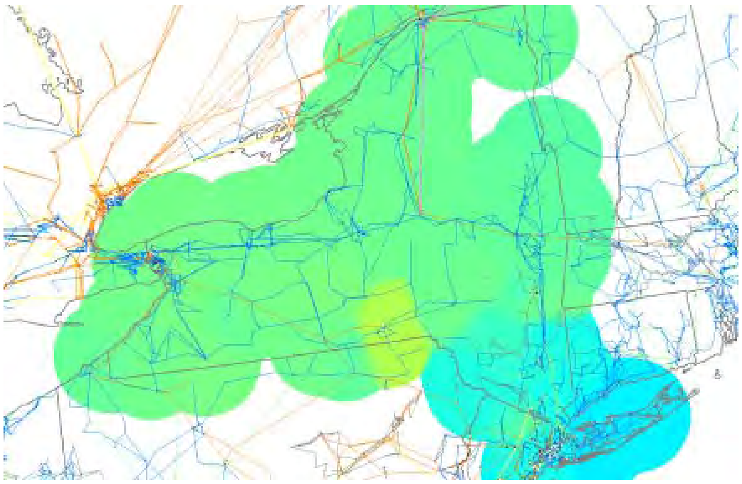
	2013	20-year NPV
NYS Consumer Benefits	$72	$892
NYS Production Cost Benefits	$8	$67
NYC Indirect Benefits	$19	$159
NYC Direct Benefits	$13	$253
Cost	$836, $411 allocated to NYC	

Table 36: Summary of Hudson revised economic results, million 2008$

	2013	20-year NPV
NYS Consumer Benefits	$170	$1,768
NYS Production Cost Benefits	$45	$401
NYC Indirect Benefits	$59	$503
NYC Direct Benefits	$14	$253
Cost	$836, $426 allocated to NYC	

Energy Benefits

Figure 16: Hudson LBMP delta contour[33]



[33] This contour map plots only prices from buses in New York. The blue color in Northern New Jersey represents "color bleeding" from New York bus prices, and not a decrease in New Jersey prices.

Table 37: Change in Generation Patterns—Hudson (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	15	25	-	(3)	-	(3)	-	(149)	-	(116)
B	18	-	-	(0)	-	-	-	-	-	18
C	(37)	(35)	-	-	0	-	-	(70)	-	(142)
D	75	-	-	(0)	-	-	-	(47)	(21)	8
E	8	(4)	-	(0)	-	0	-	-	-	5
F	(79)	-	-	(32)	-	(2)	-	12	-	(101)
G	(0)	(7)	-	0	(18)	(0)	-	(288)	-	(313)
H	-	-	(1)	-	-	9	-	-	-	8
I	0	-	-	-	-	-	-	-	-	0
J	(166)	-	-	-	(168)	-	-	1,654	-	1,321
K	(116)	-	-	-	(12)	11	-	(674)	-	(791)
Sum	(281)	(21)	(1)	(35)	(197)	15	-	438	(21)	(104)

Figure 17: Change in LBMPs for Hudson cases, 2008$/MWh

Overall indirect benefits for the Hudson cable in our reference case are relatively modest. With the original load forecast, it displaces primarily gas-fired generation on Long Island and in NYC, showing similar, but stronger effects with the revised lower PJM forecast.

As the only inter-regional project modeled in the study, we modeled the cable with the following parameters:

- No dedicated resource on the PJM side. There have been several cross-Hudson projects proposed that contract with a PJM generator for dedicated energy and capacity, but based on the advice of stakeholders, we did not model such a dedicated resource for this analysis. A dedicated resource could improve the economic benefits of the project.

- Based on stakeholder advice, we did not model wheeling or transfer charges across the line.

- We calculated the direct benefits as the difference between zonal prices in PJM (i.e., PSEG to zone J) rather than node-to-node (i.e., Bergen to W. 49th St.)[34]

- We assumed that the full energy capacity of the line is deliverable into the West 49th St. substation.

Because there are no wheeling charges modeled across the Hudson cable, there is little "friction" across it, and so flows can change significantly according to system dispatch. Because other connections between PJM and NYCA do have wheeling charges, flow overall on those lines vary less than across Hudson. The capacity factor of the line was 56% into NYC.

The production cost benefits for the Hudson cable were calculated by multiplying the flow across the line by the LMP on the source end, in this case, the bus price in PJM. For consumer costs, the benefits were divided into two tranches—one relating to direct benefits and another relating to price-suppression benefits relating to lowering LBMPs for all consumers. These different benefit types are described in greater detail in section 3.1.1.

The principal factor limiting the impact of the Hudson cable in our reference case simulation is the availability of less-expensive power on the PJM side of the line—the marginal-price-setting unit in PJM is often an older combined cycle, and that price competes with efficient combined cycle generation in NYC.

We found that one additional reason bus prices in PJM were high because of the spinning reserve requirements in PJM. In our analysis, we model dispatch constraints on the interconnected system, including system dispatch constraints. The spinning reserve requirements in PJM and northern New Jersey are such that, combined with transmission constraints, they change the dispatch pattern enough to increase marginal prices at the bus in PJM.

The implied heat rate for the PSEG zone is slightly above historical levels, and the implied heat rate for NYC is slightly below historical levels. The NYC effect is discussed in section 3.2.1. The increase in heat rates in

[34] In the past, the Bergen node has often cleared at a price slightly above that of the PSEG zone, and the W. 49th St. node has often cleared a price slightly below the zone J price. Utilizing the zone to zone difference assumes that the line's operator would strike a contract with similar terms.

PSEG is caused by a number of factors, including increased load growth (the base PJM load forecast shows approximately 960 MW of load growth for the PSEG area alone between 2008 and 2013), the impact of the Neptune cable that was installed in 2007 on the nearby 230 kV Sayreville bus, and the effects of increased transmission congestion.

Table 38: Implied heat rate for PJM and NYC areas, BTU/KWh, 2013

	PSEG	AEP	NYC
Jan	8,209	5,894	7,182
Feb	8,951	6,065	7,509
Mar	8,283	6,433	8,382
Apr	8,673	6,847	8,688
May	8,483	7,031	8,692
Jun	9,794	7,388	9,663
Jul	11,233	8,286	10,934
Aug	11,125	8,001	10,854
Sep	9,270	6,994	9,354
Oct	8,662	6,847	8,436
Nov	8,282	6,753	8,125
Dec	9,043	6,544	8,410
Average	**9,167**	**6,924**	**8,852**

In addition, we found that the addition of the line caused the price difference to decrease between PJM and NYC—sometimes known as "collapsing the arbitrage." This is a common effect of adding a transmission line—if the line is too large, or if (as in this case), there is too little energy left at a lower price, the line can cause the prices to increase on the withdrawal side to the point where transfers become uneconomic. We found that in many hours, adding the line to the simulation caused this effect.

In some ways, a useful comparison is to compare the Hudson cable to a combined cycle in NYC. If one makes the assumption that the marginal price of energy in northern NJ is set by a gas-fired combined cycle unit, and that fuel prices and heat rates are similar, then the impact on NYC prices should be similar. The Hudson cable would benefit from changes on the PJM side that would allow lower-cost resources from other areas in PJM to set the marginal price at the node it withdraws energy from.

Because the performance of the Hudson cable is so dependent on the market conditions in PJM, we analyzed the economic performance of the project using a revised load forecast that PJM released shortly before this study was completed, shown in Figure 18 and Figure 19.

Figure 18: Comparison of revised PJM peak load and energy forecasts for Hudson case

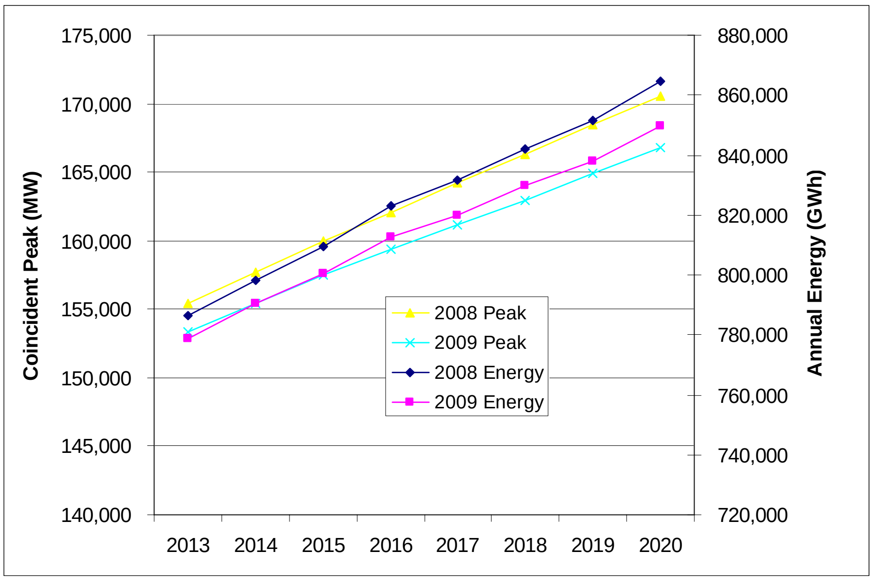
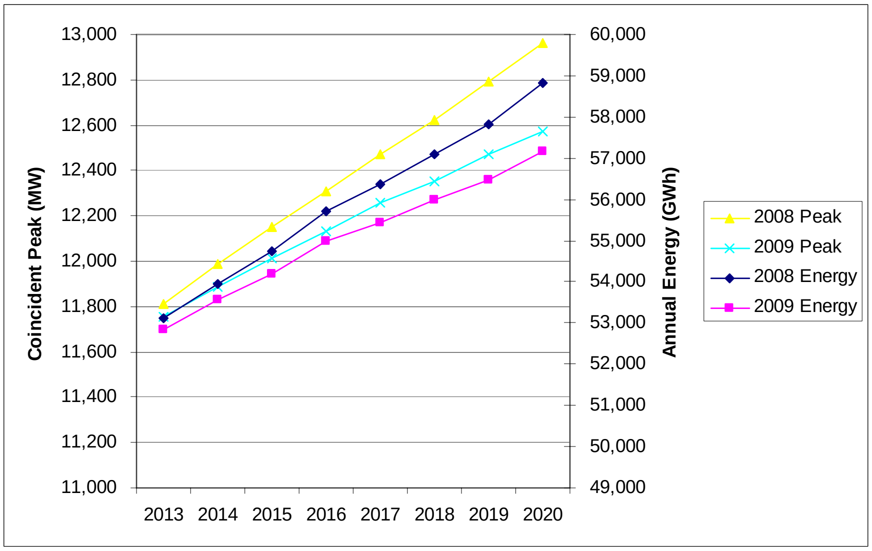


Figure 19: Comparison of PSEG peak load and energy forecasts for Hudson case



The analysis with the new load forecast indicates that the economic benefits of the Hudson cable are increased by lower loads on the PJM side. PJM, similarly to NYC, has substantially lowered its load growth rate in its most recent forecasts to reflect the slowing economy. This reduced load forecast improves the consumer benefit of the line by approximately $100 million in our single year. With the revised load forecast, the capacity factor increased only modestly, to 59%, but the lowered prices in PJM had a substantial effect on the consumer benefits of the project.

Capacity Benefits

We have assumed that the Hudson cable would be supported by firm capacity and therefore counted as a capacity resource in New York City. We have also assumed that it would be contracted to NYPA and operated in the interest of the operator's NYC customers. Hence, in addition to market price benefits, the project would generate direct benefits to ratepayers in the form of the market value of the capacity from project cleared in the New York City capacity market, net of the cost of procuring firm capacity in PJM.

The market price benefit is temporary, persisting until the point when new capacity would be added in the City in the reference case. The direct benefits persist for the life of the project. Moreover, we assumed that the capacity offered into the New York City market would be subject to the offer floor at 75% of CONE for net buyers. If the operator's contractual costs for the line, plus the cost of procuring firm capacity in PJM can be demonstrated to be lower than 75% of the NYC CONE, the offer floor would be reduced and net benefits could be greater. Finally, we assumed that the PJM capacity could be purchased at the value of PJM's most recent estimates of CONE for PSEG North ($235/MW-day), and that the line's operator would be required to purchase an annual contract for capacity.

The direct benefit is not large, as the amount of capacity that would clear the market is initially small, due to excess capacity available at the offer floor. Additionally, because the floor will prevent the Hudson capacity from clearing in the market in the winter for longer than the summer, the cost of purchasing PJM capacity would need to be recovered in the summer months only, but the costs would be driven by the value of the annual PJM capacity product. As a result, it would not be cost effective to procure PJM capacity in the initial years. Additionally, unlike the direct capacity benefit for a CCGT, which can provide capacity at virtually no incremental cost once the unit is already on-line, the capacity to support sales across the Hudson cable must be purchased from resources located in PJM, limiting the value to the difference in prices between PJM and NYC.

Table 39 shows our estimates of how much of Hudson's summer capacity would clear the market each year if offered at the price floor of 75% of CONE. Because the market has a larger surplus in the winter, a smaller quantity would clear in those months. The original NYPA agreement specified 500 MW of UDRs into NYC, and we assumed the project would provide that quantity of capacity in our analysis. As noted above, the fact that the PJM capacity market is based on a year-round product could make it uneconomic to procure capacity for only the summer period, meaning it may not be economic to procure PJM capacity to support these volumes. In fact, our analysis shows that in the early years of operation of the cable, the CONE price for northern New Jersey is actually higher than the annual average revenue from selling ICAP at the floor in NYC during the summer season only. This means that it capacity purchased in New Jersey would actually be sold at a loss in NYC. We assume that the line's operator would not purchase this capacity to sell at a loss in NYC.

Table 39: Hudson cable's cleared capacity (MW)

	Amount cleared
2013	0
2014	0
2015	34

2016	114
2017	193
2018	277
2019	500
2020	500
2021	500
2022	500
2023 - 2033	500

We did not examine a scenario in which the actual PJM clearing prices were lower than the CONE estimate applied as a proxy for the cost of PJM capacity, which we believe to be a reasonable estimate of the long-term PJM clearing price.

Table 40 shows how capacity market benefits change benefits change over time for the Hudson cable.

Table 40: Hudson cable capacity benefits summary, million 2008$

	Indirect Capacity	Direct Capacity
2013		
2014		
2015	$0.01	
2016	$0.04	
2017	$0.06	
2018	$0.10	
2019	$0.02	$5.73
2020		$18.09
2021		$18.25
2022		$18.41
2023		$18.57
2024		$18.73
2025		$18.89

2026	$19.05
2027	$19.21
2028	$19.38
2029	$19.54
2030	$19.70
2031	$17.77
2032	$19.44
2033	$21.33

Project Costs

The transmission route starts at the Bergen Station in New Jersey. A 230 kV underground transmission circuit will connect to a Back-to-Back High Voltage DC Converter Station (HVDC) in Ridgefield, NJ, where power is stepped up to 345 kV. A new 345 kV transmission line will be installed underground for approximately 3.5 miles to reach the Hudson River in Edgewater, NJ. The cable in New Jersey will follow existing railroad rights-of-way for portions of the route. Portions of the cable will also be installed in an existing (but not used) railroad tunnel. There will be road crossings and elevation changes. The route will then include approximately 3.0 miles of submarine cable under the Hudson River. There will be approximately 1,500 feet of directional drilling and a cofferdam at each end. Once in New York, the cable will be installed beneath the streets to reach the ConEdison 49th Street Substation.

We made certain assumption to develop the EPC construction cost. Installation on the New York side will utilize hand digging. The submarine cable will be installed using jet-plowing technology to a depth of 12 to 15 feet beneath the river bed. There are at least two places in the Hudson River where existing electric and gas lines will be crossed. The GIS switchgear in the ConEdison Substation will be expanded to accommodate a new breaker. On the New Jersey side we assumed that the portion of the cable in the existing railroad tunnel will be excavated and buried. There is a “breaker-and-a-half” bus arrangement at the Bergen Substation that will require an extension of an existing bay with breakers and disconnects. We obtained quotes for the HVDC Converter Station and for the various cables.

Out total EPC cost estimate is $500 million. There are significant owner’s costs that would be added to this figure. The 3.5 miles of cable underground in the New Jersey crosses under highways, rights-of-way, rail lines, and private property. There could be significant unknown cost for working in the tunnel to meet regulations, OSHA, etc. Land acquisition, leases and easement costs are also not in the $500 million EPC cost. Adding to that are significant legal, permitting and other Owners soft costs that will likely place the total project cost in the $630 to $670 million range.

Our EPC cost estimate does not include additional system reinforcements on the PJM side that would be necessary to secure firm transmission withdrawal rights. These cost estimates range from $160 to $300 million, and, discussed at greater length above and included in our overall cost estimate. We estimated that construction would take approximately thirty months, and incur interest charges of $35 million during construction.

Long-term effects

Table 41 indicates how the benefits for the direct energy from the Hudson project change over time compared to the base year. We calculated the “margin” on the Hudson project by comparing how the ratio of prices in PJM and NYC change relative to each other over the study timeframe.

Table 41: Ratio of direct energy benefits to base year for Hudson projects

Year	Hudson	Hudson revised
2013	1.00	1.00
2014	0.85	0.91
2015	0.76	0.70
2016	0.76	0.70
2017	1.06	0.97
2018	1.29	1.12
2019	1.37	1.22
2020	1.37	1.22
2021	1.37	1.22
2022	1.37	1.22
2023	1.42	1.27
2024	1.42	1.27

2025	1.42	1.27
2026	1.42	1.27
2027	1.55	1.37
2028	1.55	1.37
2029	1.55	1.37
2030	1.55	1.37
2031	1.85	1.53
2032	1.85	1.53

Table 42 and Table 43 show the yearly benefits for the Hudson project over time.

Table 42: Yearly benefits for Hudson project, million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy	NYC Direct Energy	NYC Indirect Capacity	NYC Direct Capacity
2013	$71.77	$7.56	$18.63	$12.87		
2014	$104.09	$10.97	$27.51	$10.88		
2015	$133.90	$14.11	$33.98	$9.82	$0.01	
2016	$89.72	$9.45	$22.77	$9.82	$0.04	
2017	$89.72	$9.45	$22.77	$13.60	$0.06	
2018	$77.11	$8.12	$19.52	$16.58	$0.10	
2019	$27.40	$2.89	$7.28	$17.65	$0.02	$5.73
2020	$35.61	$3.75	$9.05	$17.65		$18.09
2021	$35.61	$3.75	$9.05	$17.65		$18.25
2022	$35.61	$3.75	$9.05	$17.65		$18.41
2023	$35.61	$3.75	$9.05	$18.33		$18.57
2024	$38.82	$4.09	$8.45	$18.33		$18.73
2025	$38.82	$4.09	$8.45	$18.33		$18.89
2026	$38.82	$4.09	$8.45	$18.33		$19.05
2027	$38.82	$4.09	$8.45	$19.93		$19.21

2028	$37.58	$3.96	$8.32	$19.93		$19.38
2029	$37.58	$3.96	$8.32	$19.93		$19.54
2030	$37.58	$3.96	$8.32	$19.93		$19.70
2031	$37.58	$3.96	$8.32	$23.80		$17.77
2032	$54.27	$5.72	$10.84	$23.80		$19.44
2033	$54.27	$5.72	$10.84	$23.80		$21.33

Table 43: Yearly benefits for revised Hudson project, million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy	NYC Direct Energy	NYC Indirect Capacity	NYC Direct Capacity
2013	$189.47	$24.32	$58.78	$14.25		
2014	$274.80	$35.26	$86.79	$13.03		
2015	$353.48	$45.35	$107.20	$10.01	$0.01	
2016	$236.87	$30.39	$71.85	$10.01	$0.04	
2017	$236.87	$30.39	$71.85	$13.89	$0.06	
2018	$203.58	$26.12	$61.59	$15.90	$0.10	
2019	$72.34	$9.28	$22.98	$17.34	$0.02	$5.73
2020	$94.00	$12.06	$28.55	$17.34		$18.09
2021	$94.00	$12.06	$28.55	$17.34		$18.25
2022	$94.00	$12.06	$28.55	$17.34		$18.41
2023	$94.00	$12.06	$28.55	$18.05		$18.57
2024	$102.48	$13.15	$26.65	$18.05		$18.73
2025	$102.48	$13.15	$26.65	$18.05		$18.89
2026	$102.48	$13.15	$26.65	$18.05		$19.05
2027	$102.48	$13.15	$26.65	$19.53		$19.21
2028	$99.21	$12.73	$26.26	$19.53		$19.38
2029	$99.21	$12.73	$26.26	$19.53		$19.54
2030	$99.21	$12.73	$26.26	$19.53		$19.70
2031	$99.21	$12.73	$26.26	$21.87		$17.77

2032	$143.27	$18.38	$34.21	$21.87		$19.44
2033	$143.27	$18.38	$34.21	$21.87		$21.33

The change in benefits over time for the Hudson project reflects the changing generation mix in NYC, NYS and PJM. Table 44 shows the capacity additions in NYS for the Hudson case.

Table 44: Capacity additions for Hudson case (MW)

Year	Type	Capital	Downstate	LIPA	NYC	Upstate
2017	Wind					780
2018	CCGT					828
2018	Wind					33
2023	Nuclear	49				
2023	Wind					89
2027	Nuclear	2,303				
2027	Wind					117
2031	IGCC	1,597	434			
2031	Nuclear	826				
2031	Wind					75

The installation of the Hudson cable obviates the need for new capacity in NYC until the end of the study timeframe—capacity addition patterns in the rest of the state show little change. The capacity additions in the Hudson revised case were unchanged.

Sensitivities

Table 45 shows the results of our analysis of the Hudson cable across our multiple scenarios. The comparison of the base case across multiple scenarios is included in section 3.2.6.

Table 45: 20 year NPV of Hudson long-term scenario analyses, million 2008$

	HTP Base	HTP Low Carbon	HTP High Gas	HTP High Load
Production Cost	$75,943	$72,207	$75,674	$89,461
NYS Consumer	$325,009	$279,473	$355,974	$329,176

Cost				
NYC Consumer Cost	$52,451	$45,879	$58,044	$54,131

Table 46: Change in 20-year NPV of Hudson long-term scenario analyses, million 2008$

	HTP Low Carbon	HTP High Gas	HTP High Load
Production Cost	$(3,736)	$(269)	$13,518
NYS Consumer Cost	$(45,537)	$30,965	$4,167
NYC Consumer Cost	$(6,571)	$5,594	$1,681

Under a low-carbon scenario, the Hudson project delivers reductions of approximately 10% by each metric to NYC and NYS ratepayers. High gas prices have a strong effect on the prices for NYC consumers with the Hudson cable in, although proportionally, it is a similar increase to the base case under the high gas price scenario.

3.3.3. Leeds

Project Description

The Leeds project was modeled as a third AC 345 kV circuit between the Leeds and Pleasant valley substations in Upstate NY. The summer nominal capacity was 1,671 MW, although transmission contingencies and constraints usually limit the amount of flow on the line to less than that amount.

The existing two conductors form part of the UPNY-SENY interface in NYS. For this analysis, the UPNY-SENY interface itself was not monitored as a constraint, while the lines that make up the interface were.

There will likely be system upgrades necessary to support voltage stability issues in the lower Hudson Valley after the construction of this project. We have not estimated a cost for these upgrades in this study, as doing so accurately would require a full SRIS, but they must be accounted for as part of the total system cost. We have estimated, in the absence of SRIS results, a total of $200 million for these upgrades.

Table 47 and Table 48 summarize our economic analysis results.

Table 47: Summary of Leeds Economic Results, million 2008$

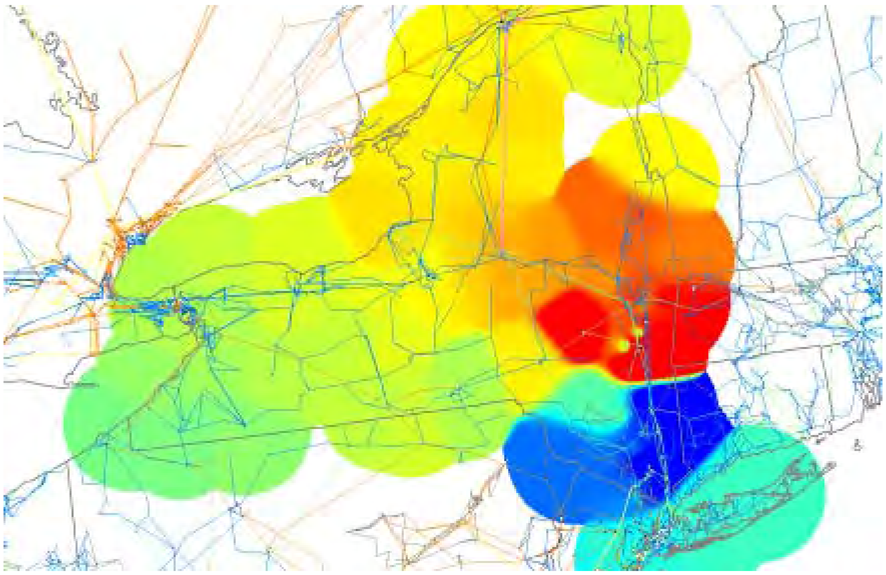
	2013	20-year NPV
NYS Consumer Benefits	$82	$1,047
NYS Production Cost Benefits	$58	$582
NYC Indirect Benefits	$113	$1.149
NYC Direct Benefits		
Cost	$504, $250 allocated to NYC	

Table 48: Summary of Leeds/DW economic results, million 2008$

	2013	20-year NPV
NYS Consumer Benefits	$104	$1,324
NYS Production Cost Benefits	$66	$665
NYC Indirect Benefits	$105	$1,063
NYC Direct Benefits		
Cost	$1,035, $652 allocated to NYC	

Energy Benefits

Figure 20: Leeds LBMP delta contour



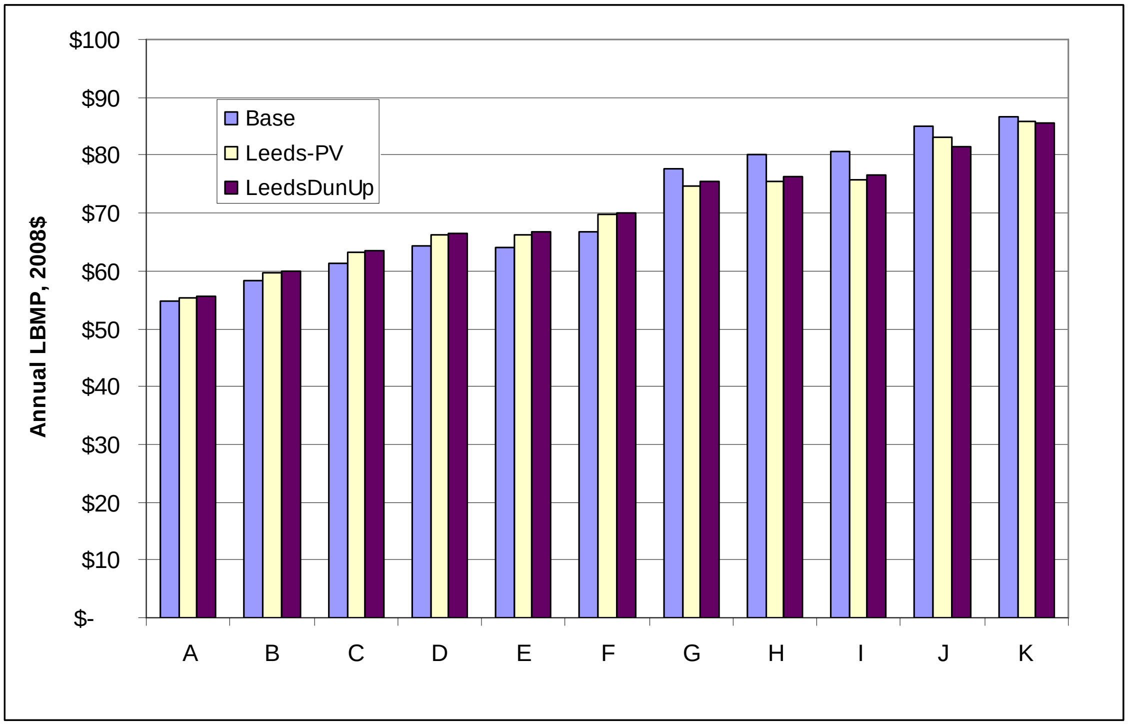
Leeds' capacity factor was 50% in the downstate direction, with no significant flow in the Upstate direction. This capacity factor does not necessarily mean that the line is underutilized—the full thermal capacity of the line (approximately 1,600 MW) cannot always be fully utilized because of other system constraints.

Table 49: Change in Generation Patterns—Leeds (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	32	(3)		(30)				95		93
B	35									35
C	230	(27)		0	3			(44)		162
D	235			0				358	926	1,519
E	97	8		0						104
F	1,107			(155)		0		75		1,028
G	(1)	(1)		0	(716)	(0)		(1,624)		(2,342)
H										
I										
J	(471)				(957)			1,082		(345)

K	(167)				(97)	(0)		28		(236)
Sum	1,096	(23)		(185)	(1,766)	0		(30)	926	18

Figure 21: Change in LBMPs for Leeds case, 2008$/MWh



The Leeds project has its strongest effect on the Capital and NYC regions. It substantially increases marginal gas-fired generation in the Capital region, displacing gas-fired generation in the Millwood and NYC zones. It allows substantially higher imports into NYC as more power can now move from F to the lower Hudson Valley zones.

Figure 22: Leeds-Dunwoodie LBMP delta contour

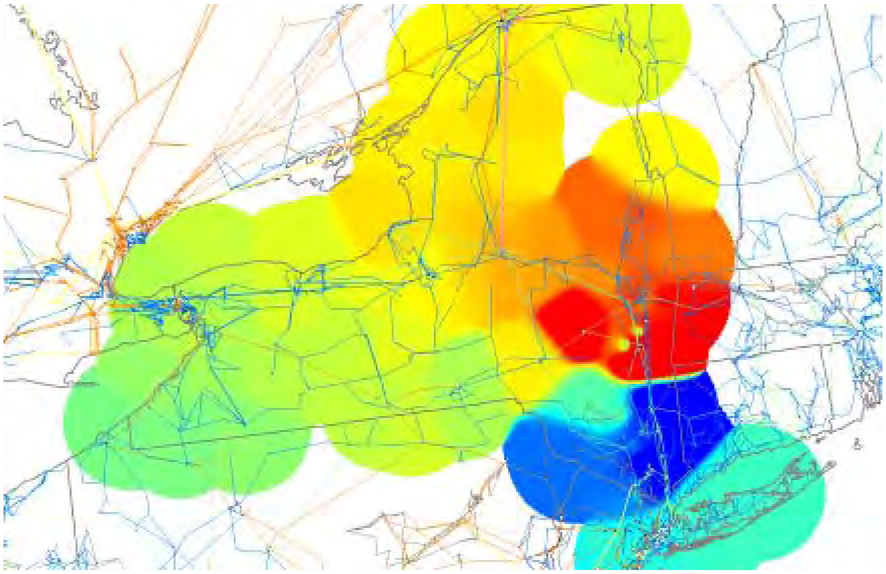


Table 50: Change in Generation Patterns—Leeds/DW (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	45	(0)		(32)				159		173
B	43			0			(0)			43
C	288	6			6			(3)		298
D	260							378	986	1,625
E	115	10		(0)						125
F	1,271			(148)		0		138		1,262
G	(1)	(1)			(591)	0		(262)		(855)
H										
I										
J	(820)				(1,059)			(89)		(1,969)
K	(184)				(93)	(0)		(307)		(584)
Sum	1,019	15		(180)	(1,737)	0	(0)	14	986	118

After analysis of the base Leeds scenario, we discovered that the Dunwoodie South interface was still constrained. We analyzed the impact of the upgrade of the Dunwoodie South interface to 4,700 MW on the dispatch of the system.

While the upgrade of this interface has a beneficial effect on the state as a whole, its impact on NYC consumers is actually slightly negative. Because the TCCs that ConEdison and NYPA hold would be diluted, and their generation contracts reduced in value, NYC consumers would see a slight increase in energy cost from this upgrade, even as the State as a whole benefits. Table 51 and Table 52 show the calculation of NYC impact for each case.

Table 51: Leeds NYC impact calculation

	Quantity (GWh)	Average Cost ($/MWh)	Total Cost ($ million)
Gross Wholesale Cost to Zone J Load	58,358	$83	$4,847
Market Value of LSE Generation	19,929	$(77)	$(1,529)
Cost of LSE Generation	19,929	$62	$1,243
Offset to Wholesale Cost			$(286)
Value of TCCs held by LSEs	39,867		$(389)
Total Ratepayer Cost	58,358	$71	$4,172

Table 52: Leeds/DW impact calculation

	Quantity (GWh)	Average Cost ($/MWh)	Total Cost ($ million)
Gross Wholesale Cost to Zone J Load	58,358	$82	$4,796
Market Value of LSE Generation	19,777	$(76)	$(1,508)
Cost of LSE Generation	19,777	$62	$1,230
Offset to Wholesale Cost			$(278)

Value of TCCs held by LSEs	39,867		$(338)
Total Ratepayer Cost	58,358	$72	$4,180

The largest change to the value of NYC ratepayers is the impact on the LSE-held TCCs. Table 53 shows how TCC values change in each case. The value of TCCs held to zone G show the largest change, reducing the NYC ratepayer benefit.

Table 53: Change in value of LSE-held TCCs for Leeds and Leeds/DW cases

		Leeds		**Leeds/DW**	
TCC Zone	Quantity	Price Difference	TCC Value	Price Difference	TCC Value
G	228	$(7.47)	$(13)	$(6.16)	$(11)
G	6	$(7.47)	$(0)	$(6.16)	$(0)
A	4	$(25.40)	$(1)	$(24.37)	$(1)
C	20	$(17.84)	$(3)	$(16.76)	$(3)
G	800	$(7.47)	$(47)	$(6.16)	$(39)
F	250	$(11.70)	$(23)	$(10.63)	$(21)
I	10	$(6.57)	$(1)	$(5.25)	$(0)
I	114	$(6.57)	$(6)	$(5.25)	$(5)
A	600	$(25.40)	$(120)	$(24.37)	$(116)
G	2220	$(7.47)	$(131)	$(6.16)	$(108)
H	797	$(6.88)	$(43)	$(5.52)	$(35)
Sum			$(389)		$(338)

Capacity Benefits,

There are expected to be no changes in the LCR for NYC as a result of either of the Leeds projects, as the project does not connect directly into zone J, and would likely not change the LOLE in NYC sufficiently to warrant a change in the LCR.

Project Costs

This project is the proposed 40-mile 345 kV transmission line from Leeds, NY to Pleasant Valley, NY. It is proposed as a new line along an existing right-of-way. The new right-of-way will be a 100-foot expansion for the full 40 miles utilizing new tubular steel towers. The new transmission line will consist of two (2) conductors per phase of 1192 kcmil ACSR cable. The significant issue here is that the property for the 100-foot expansion needs to be acquired.

The total EPC construction cost ± 30% is $191 million dollars. This includes costs for the substation improvements on both ends of the transmission line. Additionally, there will be the cost of acquiring the land along the 40-mile route widening the present right-of-way by 100 feet. A very rough guideline that might be used for land acquisition in the absence of better data might be $200,000 per acre, leading to a potential land acquisition cost of approximately $105 million, assuming that 525 acres must be purchased to complete the developer's right of way acquisition.

Our EPC cost estimate does not include reinforcement of the NYISO system to address voltage stability issues in the Lower Hudson Valley, nor does it address additional equipment that might be required at other substations to meet changing load conditions. The necessary system reinforcements and additions would results from a full system impact study. In the absence of full information on what these reinforcements might entail, we have assumed a total cost of $200 million for these upgrades. There is, however, a great deal of uncertainty in this cost estimate.[35]

Our construction estimate includes eighteen months of construction, and interest charges of $8 million during construction.

Long-term effects

Table 54 and Table 55 display the yearly benefits by category for the Leeds project.

Table 54: Yearly benefits for Leeds project, million 2008$

	NYS Consumer	NYS Production	NYC Indirect

35 National Grid submitted written comments on the draft report that indicated that they believe the ultimate costs of both land acquisition and system upgrades will be lower than those quoted here.

		Cost	Energy
2013	$82.17	$58.15	$113.10
2014	$120.18	$53.86	$154.26
2015	$166.97	$63.27	$188.36
2016	$110.37	$56.99	$123.25
2017	$110.37	$56.99	$123.25
2018	$107.69	$57.49	$115.62
2019	$61.35	$51.86	$70.40
2020	$77.66	$54.72	$83.66
2021	$77.66	$54.72	$83.66
2022	$77.66	$54.72	$83.66
2023	$77.66	$54.72	$83.66
2024	$83.65	$46.48	$81.75
2025	$83.65	$46.48	$81.75
2026	$83.65	$46.48	$81.75
2027	$83.65	$46.48	$81.75
2028	$118.57	$69.53	$113.33
2029	$118.57	$69.53	$113.33
2030	$118.57	$69.53	$113.33
2031	$118.57	$69.53	$113.33
2032	$200.94	$98.23	$189.04
2033	$200.94	$98.23	$189.04

Table 55: Yearly benefits for Leeds/DW project, million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy
2013	$103.85	$66.38	$104.62
2014	$151.89	$61.48	$142.69
2015	$211.03	$72.22	$174.24
2016	$139.49	$65.05	$114.01

2017	$139.49	$65.05	$114.01
2018	$136.10	$65.62	$106.95
2019	$77.54	$59.20	$65.12
2020	$98.15	$62.45	$77.39
2021	$98.15	$62.45	$77.39
2022	$98.15	$62.45	$77.39
2023	$98.15	$62.45	$77.39
2024	$105.73	$53.05	$75.62
2025	$105.73	$53.05	$75.62
2026	$105.73	$53.05	$75.62
2027	$105.73	$53.05	$75.62
2028	$149.85	$79.37	$104.84
2029	$149.85	$79.37	$104.84
2030	$149.85	$79.37	$104.84
2031	$149.85	$79.37	$104.84
2032	$253.96	$112.13	$174.87
2033	$253.96	$112.13	$174.87

Over time, as the generation mix in NYS changes, the benefit of the line will change.

Table 56 shows capacity additions for the Leeds and Leeds/DW cases.

Table 56: Capacity additions for Leeds case (MW)

Year	**Type**	**Capital**	**Downstate**	**LIPA**	**NYC**	**Upstate**
2017	Wind					780
2018	CCGT	12			36	809
2018	Wind					33
2019	CCGT				500	
2023	Nuclear	49				
2023	Wind					89

2027	Nuclear	2303				
2027	Wind					117
2031	IGCC	2551	76			
2031	Nuclear	826				
2031	Wind					75

The Leeds cable, with its relief of upstate to Downstate constraints, provides incentives for more capacity to site Upstate, starting as soon as 2018. In-City generation additions are still necessary to meet reserve margin requirements in the near-term and around 2031. Capacity additions for the Leeds/DW case were unchanged from the base Leeds case.

Sensitivities

Table 57 displays the results of our long-term analysis of the Leeds project under our different scenarios. Comparisons of each scenario across multiple projects are included in section 3.2.6.

Table 57: 20-year NPV for Leeds scenario analyses, million 2008$

	Leeds Base	Leeds Low Carbon	Leeds High Gas	Leeds High Load
Production Cost	$78,520	$73,465	$77,936	$88,115
NYS Consumer Cost	$324,771	$278,044	$356,619	$327,979
NYC Consumer Cost	$51,413	$44,063	$57,407	$51,727

Table 58: Change in 20-year NPV for Leeds scenario analyses, million 2008$

	Leeds Low Carbon	Leeds High Gas	Leeds High Load
Production Cost	$(5,056)	$(584)	$9,595
NYS Consumer Cost	$(46,726)	$31,849	$3,208
NYC Consumer Cost	$(7,350)	$5,993	$314

Similarly to the Hudson case, the Leeds project shows approximately a 10% decrease in production cost under a low-carbon scenario. Its proportional increases under the high-gas and high-load scenarios are similar to those of the Hudson cable and reference cases.

The Leeds project is particularly effective at mitigating the impact of high loads on gross NYC consumer prices, showing only a 1% increase in NYC costs.

3.3.4. NYRI

Project Description

We modeled a bipolar, bi-directional, high voltage direct current transmission line, two converter stations, and 345kV interconnections to the existing bulk power system in New York State, with the DC line extending approximately 190 miles from the NYRI Substation in the Town of Marcy, Oneida County, to the Rock Tavern Substation in the Town of New Windsor, Orange County. The transmission had a rated capacity of 1,200 MW and will operate at a nominal voltage of ± 400kV DC.

The NYRI project is principally intended to relieve constraints across Central-East and enable power to be more easily transmitted from Upstate to Downstate. The NYRI project is currently undergoing its Article VII hearing before the NYS PSC, supported by the analysis of another team of CRA consultants. The physical parameters used to model this line were the same used in CRA's prior analysis of the NYRI project in the NYRI developers' Article VII application.[36]

The difference in benefits from the prior analysis of the NYRI project is a consequence of different assumptions. The differences in results are principally attributable to:

- Changes in installed capacity. The NYRI analysis did not include the Astoria Energy Phase 2 plant, but did include the then-proposed HTP cable. The NYRI analysis did not include the Linden VFT.

- Changes in load forecasts. The NYRI analysis used the then-current 2007 Gold Book forecasts for load, which are higher than the more recent 2009 RNA forecasts used for this study.

- Changes in transmission system configuration. The NYRI study used the 2005-series MMWG power flow case. We used the 2008-series ERAG case.

[36] Just prior to the final publication of this report, the NYRI developers withdrew their application from the New York regulatory process, effectively bringing development to a halt.

- At the request of the ConEdison and the NYISO, we did not model an interface limit for the UPNY-SENY interface (but did monitor constraints on the individual lines that make up that interface). The NYRI analysis modeled a limit for the interface itself.

- Changes in fuel price forecasts. The fuel price forecasts used for this study are lower than the fuel price forecasts used in the NYRI study.

- Changes in carbon prices. The NYRI study did not model carbon prices. We modeled RGGI prices for 2013, and a mandatory national carbon policy that begins in 2015.

Table 59 and Table 60 summarize our economic analysis results.

Table 59: Summary of NYRI Economic Results, million 2008$

	2013	20-year NPV
NYS Consumer Benefits	$72	$1,046
NYS Production Cost Benefits	$48	$208
NYC Indirect Benefits	$96	$962
NYC Direct Benefits		
Cost	$2,002, $1,053 allocated to NYC	

Table 60: Summary of NYRI/DW economic results, million 2008$

	2013	10-year NPV
NYS Consumer Benefits	$120	$1,745
NYS Production Cost Benefits	$56	$244
NYC Indirect Benefits	$91	$907
NYC Direct Benefits		
Cost	$2,532, $1,646 allocated to NYC	

Energy Benefits

Figure 23: NYRI LBMP delta contour

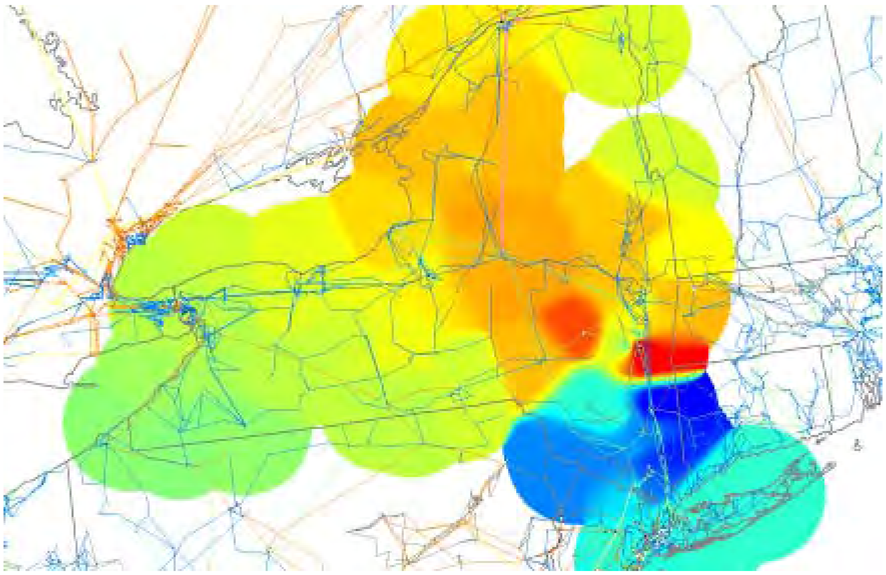
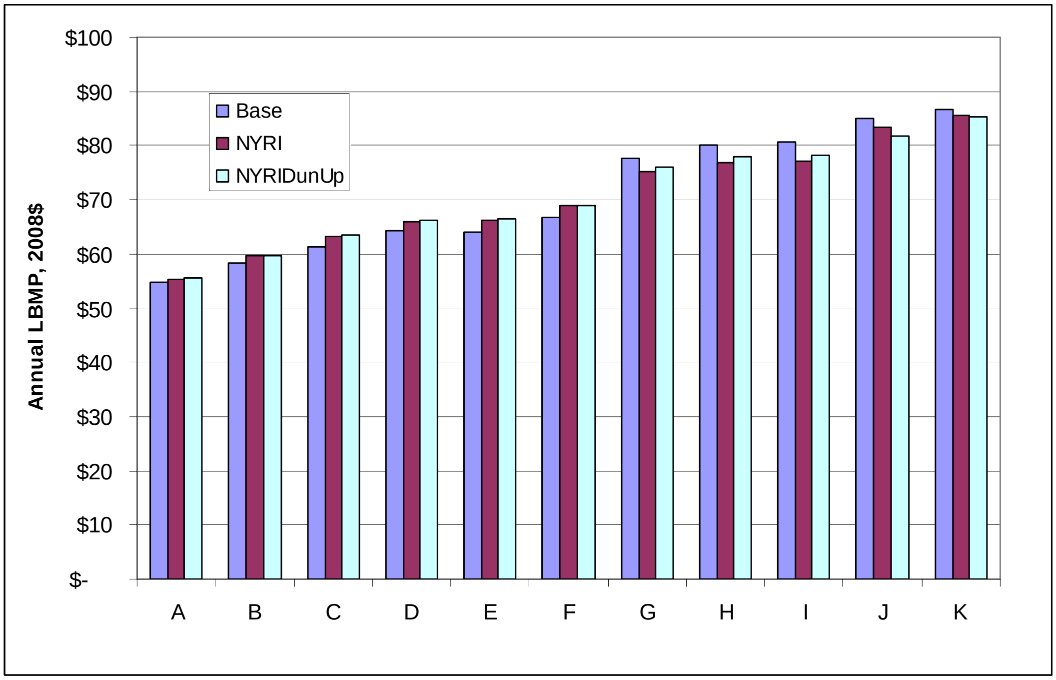


Table 61: Change in Generation Patterns—NYRI (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	34	20		(19)				196		231
B	32			0						32
C	357	29			13			(21)		378
D	271							222	1,073	1,566
E	107	17		(0)						123
F	757			(83)		0		42		717
G	(1)	(2)		(0)	(571)	0		(1,566)		(2,140)
H										
I										
J	(544)				(614)			713		(445)
K	(168)				(87)	(0)		46		(209)
Sum	844	63		(103)	(1,259)	0		(367)	1,073	252

Figure 24: Change in LBMPs for NYRI cases, 2008$/MWh



The overall impact of the project is to allow power to flow more freely from upstate to downstate, and the results match intuition. Generation increases in all of the Upstate zones, displacing gas-fired generation, and gas/oil generation downstate and in NYC. Prices generally rise upstate and decrease downstate, as detailed in Table 8.

Figure 25: NYRI/DW LBMP delta contour

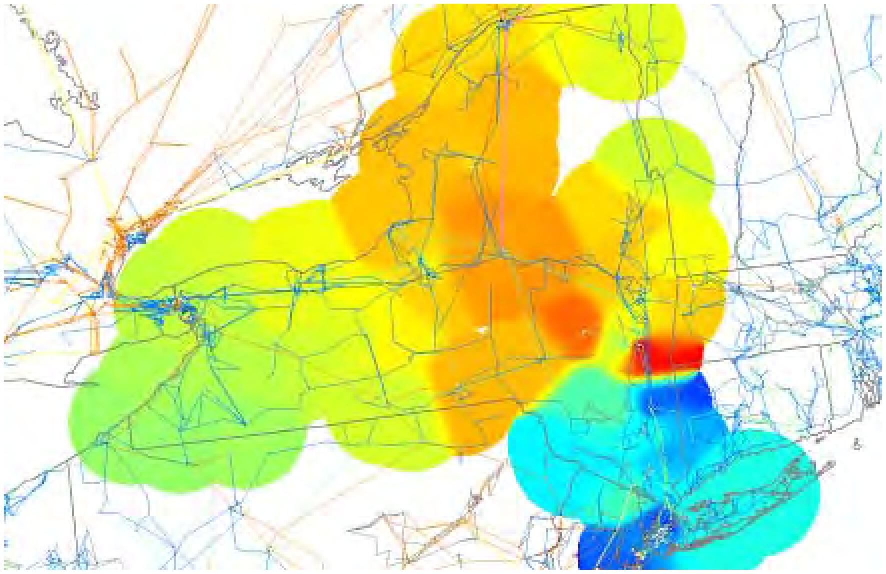


Table 62: Change in Generation Patterns—NYRI/DW (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	77	27		(22)				238		320
B	44			0						44
C	411	56			13			28		507
D	263			(0)				241	1,090	1,593
E	118	24		(0)						142
F	858			(76)		0		90		872
G	(1)	(2)			(433)	(0)		(191)		(627)
H										
I										
J	(803)				(751)			(432)		(1,986)
K	(188)				(62)	(0)		(301)		(552)
Sum	779	104		(97)	(1,234)	(0)		(328)	1,090	314

The combination of an increased Dunwoodie South interface limit shows a similar result to the combination of the Dunwoodie upgrade with the Leeds project. Overall statewide costs decrease, but dilution of ConEdison's and NYPA's TCCs and generation contracts results in a slight increase in energy costs for NYC consumers.

The combination of an increased Dunwoodie South interface limit shows a similar result to the combination of the Dunwoodie upgrade with the Leeds project. Overall statewide costs decrease, but dilution of ConEdison's and NYPA's TCCs and generation contracts results in a slight increase in energy costs for NYC consumers. This may be somewhat counterintuitive, but Table 63 and Table 64 display the impact of each project on NYC.

Table 63: NYRI NYC impact calculation

	Quantity (GWh)	Average Cost ($/MWh)	Total Cost ($ million)
Gross cost to serve NYC load	58,358	$83	$4,851
Market Value of LSE-contracted generation	19,890	$(77)	$(1,525)
Cost of LSE-contracted generation	19,890	$62	$1,239
Offset to gross cost			$(286)
Offset from LSE-owned TCCs	39,867		$(377)
Total NYC impact	58,358	$72	$4,189

Table 64: NYRI/DW impact calculation

	Quantity (GWh)	Average Cost ($/MWh)	Total Cost ($ million)
Gross cost to serve NYC load	58,358	$82	$4,799
Market Value of LSE-contracted generation	19,803	$(76)	$(1,507)
Cost of LSE-contracted	19,803	$62	$1,232

generation			
Offset to gross cost			$(275)
Offset from LSE-owned TCCs	39,867		$(330)
Total NYC impact	58,358	$72	$4,194

The difference in the cost to serve NYC load in each case ($4,194 - $4,189) is the change in NYC benefits by the addition of the Dunwoodie upgrade. The difference in the value of TCCs held by NYC LSEs is the principal driver of this result. Table 65 displays the changes in each set of LSE-held TCCs that lead to this result. Changes in the value of TCCs held to zone G are particularly significant contributors to this result.

Table 65: Change in value of LSE-held TCCs for NYRI and NYRI/DW cases

		NYRI		**NYRI/DW**	
TCC Zone	Quantity	Price Difference	TCC Value	Price Difference	TCC Value
G	228	$(7.22)	$(13)	$(6.00)	$(11)
G	6	$(7.22)	$(0)	$(6.00)	$(0)
A	4	$(25.36)	$(1)	$(24.50)	$(1)
C	20	$(17.80)	$(3)	$(16.88)	$(3)
G	800	$(7.22)	$(46)	$(6.00)	$(38)
F	250	$(12.43)	$(25)	$(11.68)	$(23)
I	10	$(5.52)	$(0)	$(4.20)	$(0)
I	114	$(5.52)	$(5)	$(4.20)	$(4)
A	600	$(25.36)	$(120)	$(24.50)	$(116)
G	2220	$(7.22)	$(127)	$(6.00)	$(105)
H	797	$(5.91)	$(37)	$(4.54)	$(29)
Sum			$(377)		$(330)

Capacity Benefits

As for the Leeds project, NYRI is a pure transmission project outside of New York City and therefore has no expected capacity benefits.

Project Costs

The NYRI project has significant soft (e.g., development, legal etc.) costs making ± 30% the best possible accuracy for current cost estimates. There will be significant land acquisition time and cost, which is difficult to quantify in a pre-feasibility estimate. We prepared the EPC cost for the procurement of towers and cable as well as the construction costs for clearing rights-of-way, foundations, site work, erection, cable installation and HVDC converter stations. This portion of the estimate is $1.2 billion dollars ± 30%. The soft costs add an additional $800 million dollars, but are not as well-defined. The total cost estimate used for this analysis is $2 billion, and is based on the NYRI developers' public statements of their project costs. Our engineering estimate includes 39 months of construction, with interest charges of $109 million incurred.

Long-term effects

Table 66 and Table 67 show the yearly benefits for the NYRI and NYRI/DW case.

Table 66: Yearly benefits for NYRI case, million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy
2013	$71.82	$47.89	$96.04
2014	$105.97	$41.18	$128.28
2015	$160.48	$31.65	$157.14
2016	$112.65	$30.63	$103.43
2017	$112.65	$30.63	$103.43
2018	$119.71	$18.22	$96.17
2019	$65.95	$9.74	$58.53
2020	$84.57	$8.71	$69.37
2021	$84.57	$8.71	$69.37
2022	$84.57	$8.71	$69.37

2023	$84.57	$8.71	$69.37
2024	$88.25	$0.00	$67.78
2025	$88.25	$0.00	$67.78
2026	$88.25	$0.00	$67.78
2027	$88.25	$0.00	$67.78
2028	$120.58	$16.18	$98.42
2029	$120.58	$16.18	$98.42
2030	$120.58	$16.18	$98.42
2031	$120.58	$16.18	$98.42
2032	$177.32	$22.59	$154.33
2033	$177.32	$22.59	$154.33

Table 67: Yearly benefits for NYRI/DW case, million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy
2013	$119.77	$56.00	$90.53
2014	$176.73	$48.16	$120.92
2015	$267.62	$37.01	$148.12
2016	$187.86	$35.82	$97.49
2017	$187.86	$35.82	$97.49
2018	$199.64	$21.31	$90.65
2019	$109.99	$11.40	$55.17
2020	$141.04	$10.18	$65.39
2021	$141.04	$10.18	$65.39
2022	$141.04	$10.18	$65.39
2023	$141.04	$10.18	$65.39
2024	$147.18	$0.00	$63.89
2025	$147.18	$0.00	$63.89
2026	$147.18	$0.00	$63.89

2027	$147.18	$0.00	$63.89
2028	$201.08	$18.93	$92.77
2029	$201.08	$18.93	$92.77
2030	$201.08	$18.93	$92.77
2031	$201.08	$18.93	$92.77
2032	$295.70	$26.41	$145.47
2033	$295.70	$26.41	$145.47

Table 68 displays capacity additions for the NYRI and NYRI/DW cases.

Table 68: Capacity additions for NYRI case (MW)

Year	Type	Capital	Downstate	LIPA	NYC	Upstate
2017	Wind					780
2018	CCGT				36	1,244
2018	Wind					33
2019	CCGT				500	
2023	Wind					89
2027	Nuclear	2,352				
2027	Wind					117
2031	IGCC	1,711				321
2031	Nuclear	826				
2031	Wind					75

The NYRI project, similarly to the Leeds project, provides incentives for generators to site Upstate to take advantage of higher power prices. Its effect is concentrated in the Upstate zones of A-E, showing approximately 500 MW more of new capacity being added in those zones compared to the base case. Capacity additions are still necessary in NYC to meet reserve margin requirements. The addition of the Dunwoodie enhancements does not change the pattern of statewide additions.

3.3.5. Dunwoodie Interface Upgrades

Project Description

After examination of the initial results, we determined that there were still constraints on the Dunwoodie South interface that inhibited economic flow into the City. The Dunwoodie interface, made up of a grouping of lines, has its own interface limit as well as a limit on the individual lines themselves. With ConEd's input and assistance, we modeled an increase in the limit of 350 MW to 4,700 MW. This 350 MW increase is roughly equivalent to the increase that would be effected by the addition of forced cooling to the current M-29 project and the development of a new AC connection between the Academy and W. 49th St. substations.

Economic Benefits

For both the NYRI and Leeds projects, the principal effect of the expansion of the Dunwoodie interface is to help decrease peak prices in NYC. In off-peak, non-constrained hours, the marginal unit in NYC and the marginal unit Upstate are often both combined cycle units. When the system is constrained on-peak, however, the greater import capacity of the Dunwoodie interface allows more power to reach NYC, avoiding the dispatch of peaking units in NYC. Peaking units have little effect on production cost, but a large impact on consumer cost, as they set the marginal price.

Both projects show that while there is a substantial impact on prices Downstate, there is still a constraint moving power into NYC. The generation patterns show similar trends to the original (i.e without the Dunwoodie upgrade) projects. Both substantially increase generation Upstate, and displace gas-fired and gas/oil-fired generation in NYC.

Overall, the enhancements to the Dunwoodie interface have a measurable effect on statewide consumer prices and production cost, but a minimal (slightly negative, in fact) impact on NYC consumer prices. This is because the NYC LSEs' portfolio of TCCs is degraded, and their generation portfolio negatively impacted. This effect is discussed in greater detail in sections 3.3.4 and 3.3.3 for the NYRI and Leeds projects, respectively.

Capacity Benefits

We have assumed for the purposes of this analysis that an increase in the Dunwoodie South interface to 4,700 MW would result in a two percent decrease in the in-City LCR, reducing it from 80% to 78%. A full reliability analysis of required IRMs was not part of our analysis, but informal conversations with NY stakeholders and experts were used to confirm that a reduction of this magnitude was a reasonable approach.

This two percent reduction in LCR does not, by itself, necessarily result in an overall material reduction in customer cost. While savings may be generated by a reduction in the amount of capacity that NYC LSEs must purchase within Zone J, the offer floor that is assumed to apply to the Astoria Energy Phase 2 project precludes any resulting impact on market prices in the initial years. However, with a lower LCR, the amount of capacity that clears the market to meet the Zone J requirement is also lower, meaning more capacity needs to be purchased upstate, raising the NYCA capacity price. Because NYC LSEs also must purchase NYCA capacity to meet their share of the statewide reserve margin requirement in excess of Zone J purchases, the higher upstate prices result in higher capacity cost for the in-City LSEs.

Project Costs

The estimate for routing a new 345kv cable from the Academy Street Substation in upper Manhattan to the 49th Street ConEdison Substation assumed the following:

- The Dunwoodie South improvement is associated with the ConEdison Sherman Creek Station. While the Sherman Creek Station is on the Harlem River in the Inwood Section of Manhattan, the Academy Street Substation is west of there and we are assuming a run of 1-mile to get to the west side of Manhattan.

- The run along the west side down to 49th Street will be another 9 miles.

- There are no existing ConEdison tunnels, vaults, or rights-of way we can use.

- We cannot assume use of any existing train or subway tunnels as there is no system precedent for sharing space with the transit companies.

- This installation will be new, using oil-filled cable in pipe, direct buried in the street using conventional digging and trenching. The estimate includes road repairs and disposal of pavement and debris.

- ConEdison believes that either oil-filled or solid dielectric cable could be utilized. Solid dielectric would require duct bank of a much larger cross-section than cable in pipe with an oil return line. The use of forced cooling for the entire run length adds capacity.

- There will be a need for some series reactors for short circuit and shunt reactors for voltage compensation if not handled by the load tap changers. The existing Academy Substation will require some upgrades.

- We assume that the spare breaker position at 49th Street is available. We are taking these projects as stand-alone, not in combination with other projects. We will use the same costs for the few blocks into the 49th St. substation as we used in the cross Hudson estimate for that portion after the core drill on the Manhattan side.

We estimated a construction schedule of 39 months, with interest charges of $44 million during construction.

Long-term effects

Long-term effects for the Dunwoodie enhancements to NYRI and Leeds are reported in sections 3.3.4 and 3.3.3, respectively.

3.3.6. Wind

Project Description

There have been several proposals in recent years for offshore wind power near NYC. We modeled a 550 MW wind farm connected via generator lead to the 345 kV Gowanus substation.

The wind farm was modeled with a capacity factor of 40%. While this is high for an on-shore wind farm, our research confirmed that wind farms in offshore waters often operate at such a capacity factor. This capacity factor is also used by the NYISO for capacity market purposes for offshore wind resources.

Table 69 summarizes our economic analysis results for the wind project.

Table 69: Summary of Wind Economic Results, million 2008$

	2013	20-year NPV

NYS Consumer Benefits	$107	$2,537
NYS Production Cost Benefits	$165	$709
NYC Indirect Benefits	$30	$132
NYC Direct Benefits	$150	$2,076
Cost	$2,312, $1,683 with ITC credit assumption, $1,178 allocated to NYC	

Energy Benefits

Figure 26: Wind LBMP delta contour

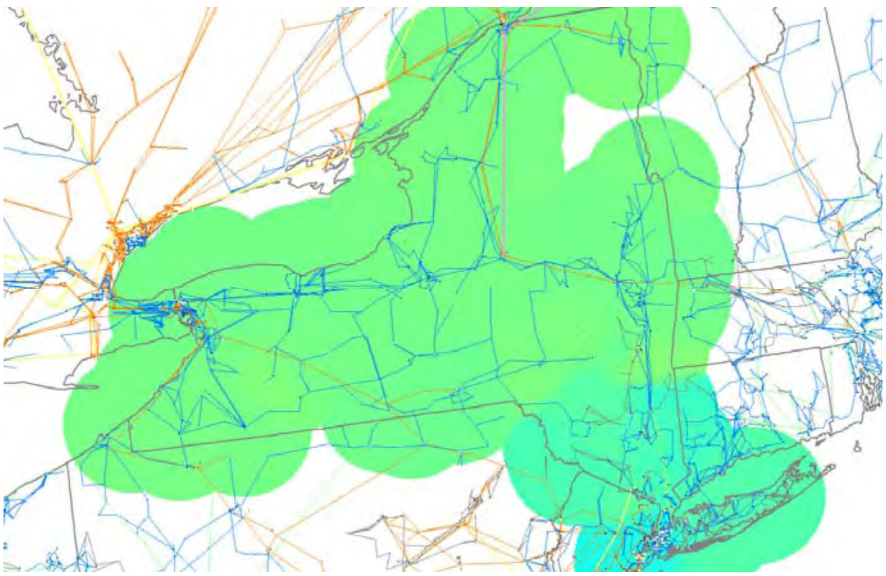
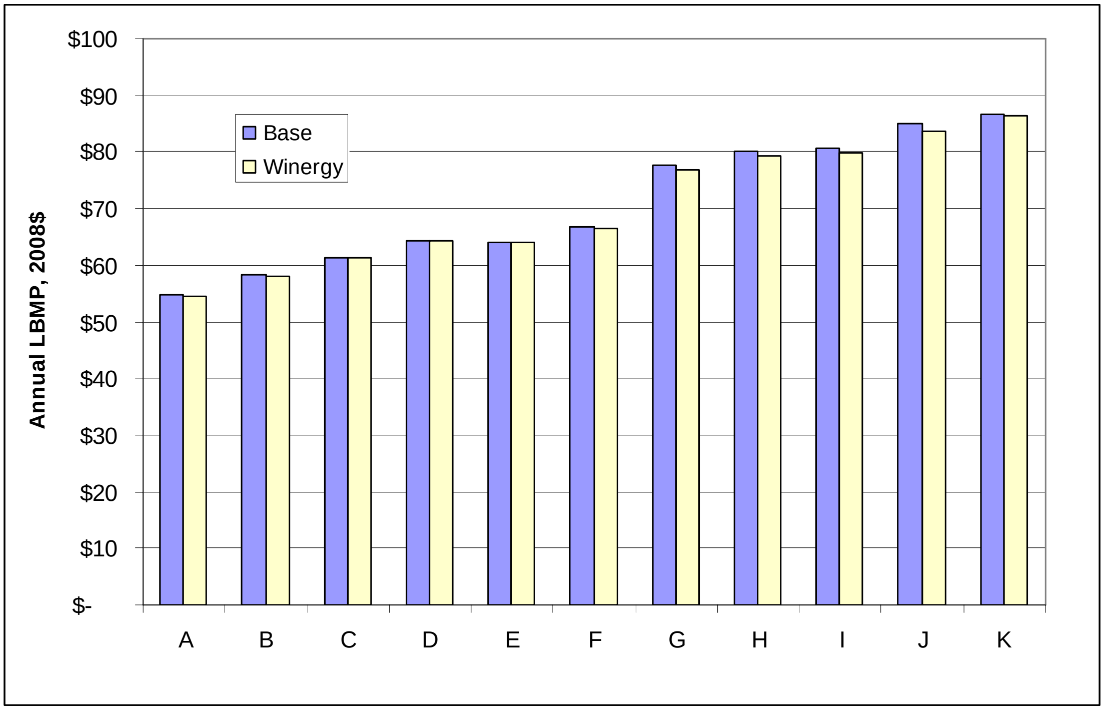


Table 70: Change in Generation Patterns—Wind (MW)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	(32)	(32)		(10)				36		(38)
B	(16)			0						(16)
C	(170)	(18)		(0)	(14)			8		(193)
D	(43)			0				33	(40)	(50)
E	(10)	(8)		(0)						(18)
F	(121)			(78)		0		(16)		(215)
G	(0)	(2)		0	(78)	(0)		(22)		(103)
H						(0)				(0)

I										
J	(419)				(378)		1,927	(349)		781
K	(72)				(53)	(1)		(174)		(299)
Sum	(884)	(60)		(88)	(523)	(1)	1,927	(484)	(40)	(152)

Figure 27: Change in LBMPs for Wind case, 2008$/MWh



The effect of the wind farm on LBMPs is not surprising; power generated and bid at near-zero marginal cost into NYC would be expected to have strong benefits. (We have assumed that the wind plant is essentially a price-taker in the market.) The power from the project displaces power statewide, but primarily displaces gas-fired and gas/oil generation in NYC. The injection of power into the City network has a beneficial effect on prices that lowers them overall. Its net effect, with its constant capacity factor as modeled, is as if load were reduced by 220 MW at all hours.

Capacity Benefits

The offshore wind project was assumed to have an effective ICAP rating equal to forty percent of its nameplate capacity, which yields a total capacity value of 220 MW. The capacity market impacts and resulting benefits for the wind project were calculated similarly to the benefits for the CCGT. While the direct benefits of the wind project are lower due to its lower ICAP rating, the market price benefits are identical due to the impact of the offer floor, which we assumed would apply to this project if sponsored by an LSE. If the project cost, less tax incentives, is low enough, the offer floor may not apply and the benefits could be higher.

Project Costs

We approached the cost for this project in two ways. One was to research costs of recent wind projects in the US and Europe. The second was a bottom up cost estimate based on reasonable assumptions for the number of towers, platforms, switchgear, submarine cable, on-shore switchyard cable, equipment, and controls. We also made certain assumptions as to the technology a developer would select for a 500 MW wind farm for commercial operation in 2013:

- The project would be constructed in phases. Perhaps 120 MW, 180 MW and 200 MW and brought on line over time.
- Each phase would have its own submarine cable to the on-shore switchyard, which also provides diversity.
- We assumed the wind farm to be located 20 miles off-shore with the on-shore switchyard in Queens, NY.
- We assumed 5 MW nacelles which are state-of-the-art now, but will have many years of experience in Europe by 2013.
- We assumed 100 wind towers on platforms anchored to the sea floor. We also assumed platforms for switchgear and step-up transformers.
- The wind towers would be spaced 500 meters apart, each row of 6 being electrically connected at 26 kV to step-up transformers. The transformers would step up the voltage to 138 kV and connect to an on-shore 138 kV substation. There, the voltage would be stepped up to meet the on-shore grid voltage requirements. We did not include reinforcement of the grid in our estimate.
- We included some spare transformers for redundancy, but no spare installed submarine cables. No spare wind turbines were included.
- We included controls at sea and a Control Building on-shore.

Our bottom up estimate for total EPC cost is $2.1 billion or $4,200 per kW. Our research of existing and planned off-shore wind projects at 300-500 MW capacity indicates a range of $3,600 to $5,200 per kW. These reference plants utilize from 3.0 MW to 5.0 MW wind turbines. Our bottom up estimate falls within the $3,600-5,200/kW range. We would not expect a project developed for New York City to be at the low range, so we consider our $4,200/kW estimate to be a + 30 / - 10% estimate. Our estimate includes 44 months of construction time with interest charges of $215 million incurred during that time.

At our stakeholders' request, we included the impact of pending legislation that would allow the conversion of a three-year investment tax credit on depreciable property to be converted to an upfront credit to capital cost. We estimated this credit to be equivalent to a 30% reduction in EPC cost for the wind project.

Long-term effects

Table 71 displays a table of the wind project's long-term margins for the wind project.

Table 71: Margins of wind project to base year

Year	Benefit compared to base year
2013	1.00
2014	1.01
2015	1.16
2016	1.16
2017	1.22
2018	1.27
2019	1.30
2020	1.30
2021	1.30
2022	1.30
2023	1.34
2024	1.34
2025	1.34

2026	1.34
2027	1.45
2028	1.45
2029	1.45
2030	1.45
2031	1.61
2032	1.61
2033	1.61

The wind's projects margins in later years are lower than the comparable margins for the CCGT project. This is the result of the wind project having a constant diurnal and seasonal capacity factor. In later years, the combined cycle is able to take advantage of higher on-peak prices to increase its margin, while the wind project has a constant output, reducing its profitability.

Table 72: Yearly benefits for wind project, million 2008$

	NYS Consumer	NYS Production Cost	NYC Indirect Energy	NYC Direct Energy	NYC Indirect Capacity	NYC Direct Capacity
2013	$107.22	$165.09	$30.14	$150.40		
2014	$102.51	$157.72	$28.80	$152.06		
2015	$159.28	$245.07	$46.14	$174.88	$0.01	$2.41
2016	$87.88	$135.22	$25.60	$174.88	$0.04	$7.98
2017	$87.88	$135.22	$25.60	$184.18	$0.06	$13.62
2018	$35.78	$55.05	$10.00	$190.60	$0.08	$17.40
2019				$194.77		$41.52
2020				$194.77		$32.98
2021				$194.77		$24.04
2022				$194.77		$24.10
2023				$201.95		$24.15
2024				$201.95		$24.21
2025				$201.95		$24.26

2026	$201.95	$24.32
2027	$218.49	$24.38
2028	$218.49	$24.43
2029	$218.49	$24.49
2030	$218.49	$24.55
2031	$242.78	$24.61
2032	$242.78	$25.45
2033	$242.78	$26.35

The wind project's benefits have a potentially surprising pattern. Compared to a case in which combined-cycle capacity is added to the City in 2019, it actually shows no benefit in consumer prices. The lack of benefit to consumer prices is because of its lower capacity factor and its inability to vary its output on-peak and off-peak—it can't increase its output in on-peak hours to displace more expensive generation.

Its lack of production cost benefits after the introduction of the combined cycle also may seem counterintuitive, but there is an explanation. The key is that we are looking at changes in production cost, and so the critical factor is not the cost of the capacity, but rather what it is displacing.

Consider the following example in which a wind plant is added in 2013, pre-mandatory carbon, when the marginal unit is a combined cycle with a marginal production cost of $60/MWh. The wind plant, with its effective capacity of 200 MW, displaces 200 MW of $60 energy, for a production cost savings of $12,000 per hour.

In 2019, prices have risen as capacity margins have tightened, and in addition, mandatory carbon pricing has been introduced, widening the gap between the production cost for a combined cycle and a peaking unit because of the latter's higher marginal carbon output. The introduction of 500 MW of $65 energy in 2019 might displace 500 MW of $100 peaker-generated energy, for a production cost savings of $12,500 per hour, meaning that there would be almost no production cost difference at that point between the two cases.

The introduction of 500 MW of new capacity in 2019 is more than would be necessary to meet reserve margin requirements; the introduction of only enough capacity to meet reserve margins at that point would prolong production cost benefits for the wind project similarly to the other in-City generation projects evaluated.

Table 73 displays the long-term capacity additions for the wind case.

Table 73: Capacity additions for Wind case (MW)

Year	Type	Capital	Downstate	LIPA	NYC	Upstate
2017	Wind					46
2018	CCGT					1,022
2018	Wind					33
2023	Nuclear	49				
2023	Wind					89
2027	Nuclear	2,303				
2027	Wind					117
2031	CCGT				96	
2031	IGCC	1,597	457			
2031	Nuclear	826				
2031	Wind					75

The wind farm postpones the need to add new capacity in the NYC area until nearly the end of the study timeframe. Capacity addition patterns in other zones do not change substantially, with the exception that less wind generation is built elsewhere in NYS to satisfy renewable requirements.

3.3.7. SCGT

Project Description

We analyzed the effect of a simple-cycle gas turbine plant of 512 MW located in NYC, and connected via a generator lead to the Gowanus substation. The plant was modeled as eight GT units, with a net heat rate of 10,000 BTU/kWh. Table 74 summarizes our economic results for this project.

Table 74: Summary of SCGT Economic Results, million 2008$

	2013	20-year NPV
NYS Consumer Benefits	$19	Not evaluated
NYS Production Cost Benefits	$8	Not evaluated

NYC Indirect Benefits	$8	Not evaluated
NYC Direct Benefits	$9	Not evaluated
EPC costs	Not evaluated	

Economic Benefits

Figure 28: SCCT LBMP Delta Contour

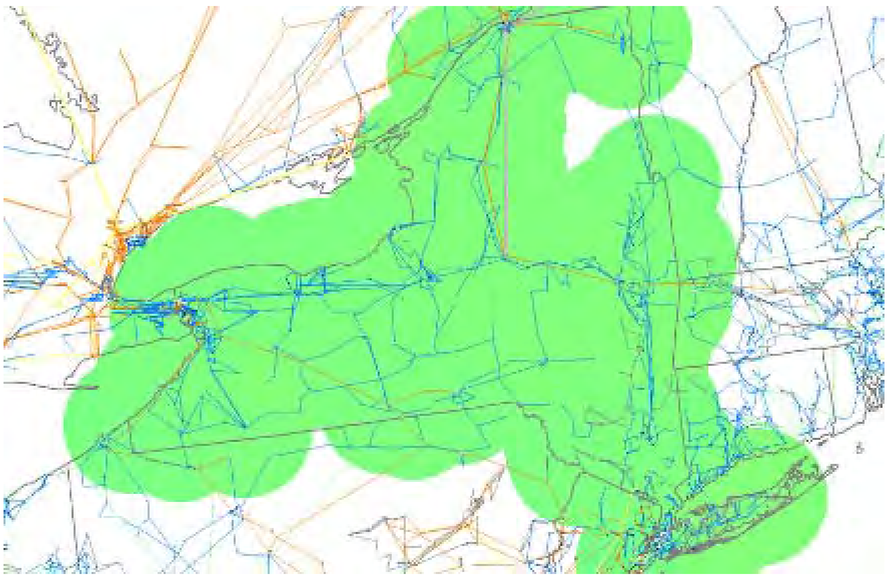
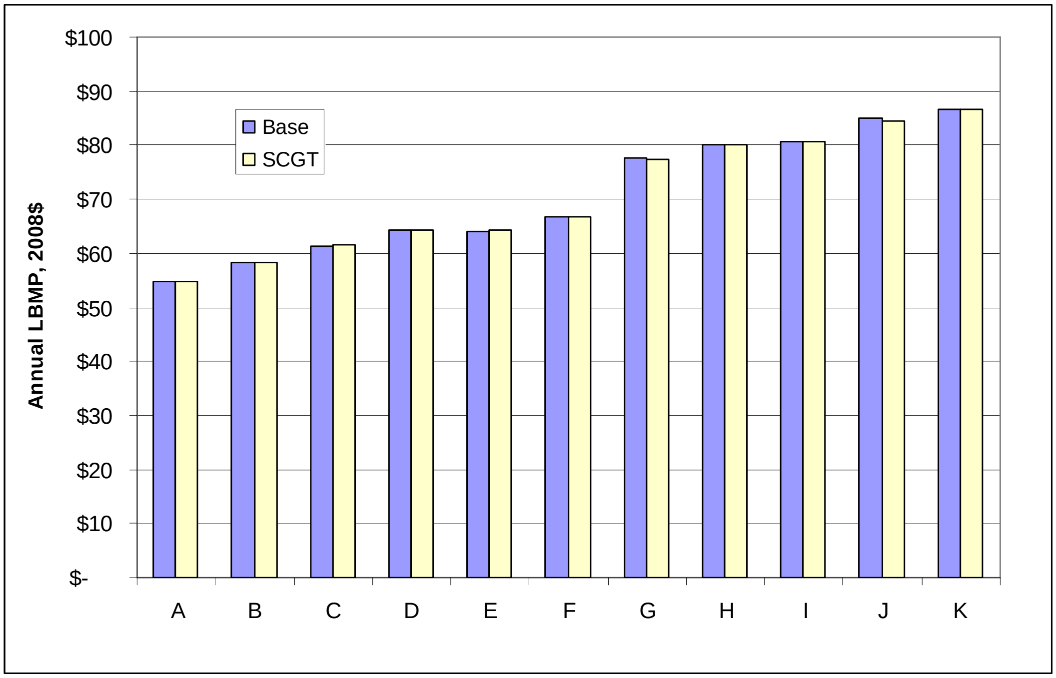


Table 75: Change in Generation Patterns—SCGT (GWh)

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	(9)	(1)		(4)		0		18		4
B	(10)									(10)
C	(19)	12		(0)	(14)			(5)		(26)
D	(25)					0		17	64	56
E	(6)	1		(0)						(5)
F	(38)			(14)		0		28		(24)
G	(1)	(1)		(0)	(132)	0		25		(108)
H	-					(0)				(0)
I	0									0
J	581				(383)			(39)		160

K	13				(78)	(1)		(9)		(75)
Sum	486	11		(18)	(606)	(1)		35	64	(29)

Figure 29 : Change in LBMPs for SCGT, 2008$/MWh



The SCGT has limited effect on the prices in NYC or NYS. Its capacity factor is only 14%, as its high price keeps it out of the market in most hours. Because of its low capacity factor, it displaces primarily gas-generation in NYC, but its effect is small.

Long-term and capacity market effects were not evaluated for this option, but capacity market impacts would be similar to those for the CCGT.

3.3.8. ConEdison-LIPA

Project Description

We analyzed the impact of an increase in the interface limit between ConEdison and LIPA by 15%. While not a project currently being proposed, nor a project likely to benefit NYC ratepayers, it was thought valuable by stakeholders to analyze its impact on the system. The interface gross limit was increased to 1,035 MW from 900 MW. Table 76 summarizes our economic results.

Table 76: Summary of ConEdison-LIPA Economic Results, million 2008$

	2013	20-year NPV
NYS Consumer Benefits	-$9	Not evaluated
NYS Production Cost Benefits	-$0.1	Not evaluated
NYC Indirect Benefits	-$6	Not evaluated
NYC Direct Benefits		Not evaluated
Cost	Not evaluated	

Economic Analysis

Figure 30: LIPA LBMP delta contour

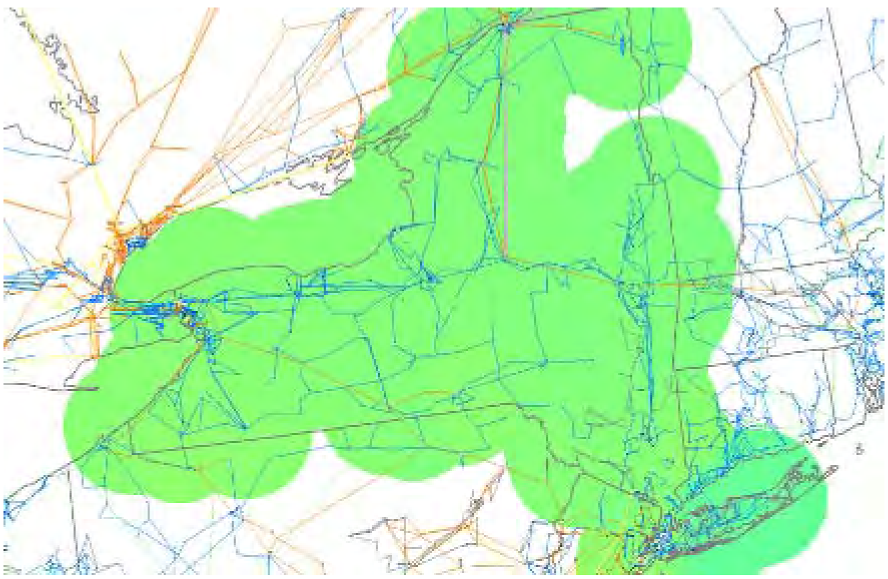
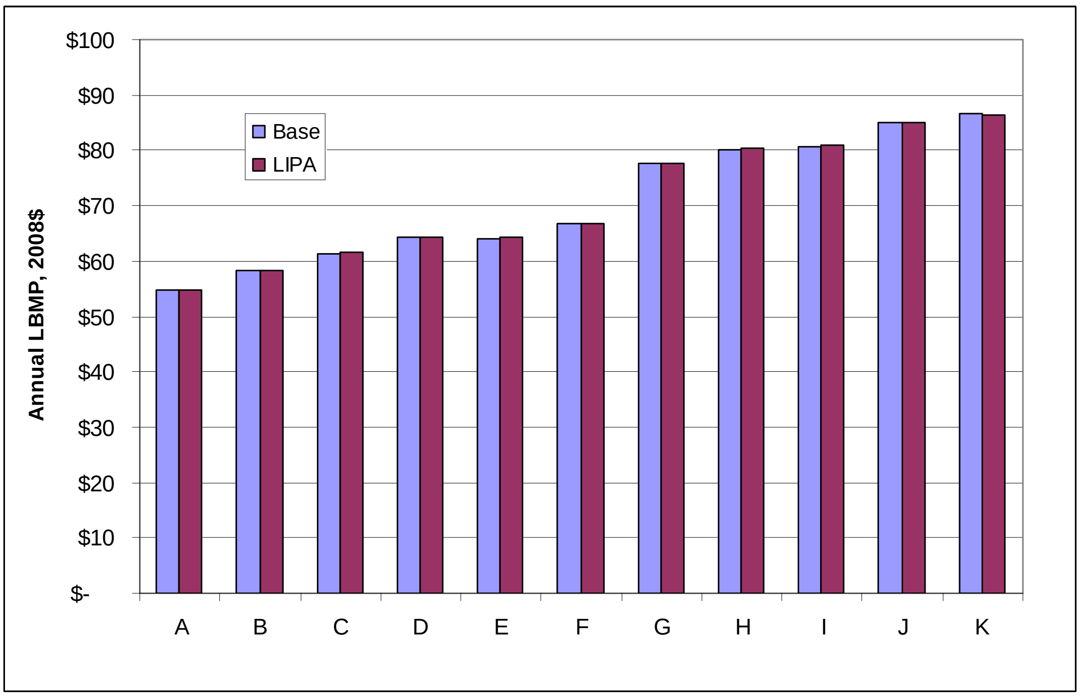


Table 77: Change in Generation Patterns—LIPA

	Gas	Coal	Nuclear	Hydro	Gas/Oil	Refuse	Wind	Imports	HQ	Total
A	(8)	(14)		(1)		(3)		(34)		(60)
B	4			0						4
C	(9)	3		0	(0)			3		(3)
D	14			0				(17)	62	59
E	(4)	0		0						(4)
F	11			(1)		(0)		53		64

G	(0)	(0)		(0)	7	0		45		51
H						1				1
I										
J	95				95			136		325
K	(69)				(44)	0		(315)		(428)
Sum	33	(11)		(1)	57	(2)		(128)	62	10

Figure 31: Change in LBMPs for LIPA case



The increase in the limit from NYC to Long Island has the intended effect—gas-fired generation (mostly CCs) can displace gas-fired and gas/oil-fired generation on NYC. The impact on the rest of the state is negligible.

4. CONCLUSION & ACKNOWLEDGEMENTS

There is no one single answer to which options are best to serve NYC's future energy needs. The decision involves tradeoffs between policy aims, economic benefits, and the weighing of significant uncertainties. Our hope is that policymakers can use this analysis to guide their

development of an economic and sustainable future power system that can serve New York’s and the region’s customers.

This project would not have been possible without the close cooperation and participation of NYC and NYS energy stakeholders, especially ConEdison, the NYISO, NYPA, PJM, and the NYS DPS. We are grateful to them for their assistance.

CRA’s project team for this project included Scott Niemann, John Goldis, Bill Foote, Max Palmer, Pablo Ruiz, and Bruce Tsuchida. Their input and assistance were essential to this effort. Robert Stoddard served as the project Officer-in-Chief, and Christopher Russo was the Project Manager and principal author of this report.

APPENDIX A: DETAILED COST ESTIMATE DATA

A.1 INTEREST DURING CONSTRUCTION WORKSHEET

PROJECT NAME	PROJECT VALUE	AMOUNT FINANCED	INTEREST RATE	CONSTRUCTION START	COMMERCIAL OPERATION DATE	IDC COST	TOTAL PROJECT VALUE
500MW COMBINED CYCLE POWER PLANT - STATEN ISLAND TO GOWANUS 345kV SUBSTATION	696,111,217	348,056,000	8%	6/30/2011	12/31/2013 30 Months	48,727,840	744,839,057
600MW HVDC CABLE AND CONVERTER STATION - BERGEN STATION TO W.49TH STREET CON ED SUBSTATION	501,385,347	250,693,000	8%	6/30/2011	12/31/2013 30 Months	35,097,020	536,482,367

500MW WIND TURBINE PROJECT - QUEENS, N.Y.	2,097,092,118	1,048,546,000	8%	4/30/2010	12/31/2013 44 Months	215,301,446	2,312,393,564
1,200 MW HVDC TRANSMISSION LINE & CONVERTER STATIONS - UTICA TOROCK TAVERN	1,201,763,857	600,882,000	8%	9/30/2010	12/31/2013 39 Months	109,360,524	1,311,124,381
345kV TRANSMISSION LINE - 40 MILES LONG - LEEDS TO PLEASANT VALLEY	191,605,920	95,803,000	8%	6/30/2012	12/31/2013 18 Months	8,047,452	199,653,372
DUNWOODIE SOUTH 345 Kv CABLE ACADEMY STREET SUBSTATION TO vW.49TH STREET CON ED SUBSTATION	486,112,945	243,056,000	8%	9/30/2010	12/31/2013 39 Months	44,236,192	530,349,137

A.2 DUNWOODIE UPGRADE

BURNS and ROE - CRA PROJECT FOR NYCEDC

DUNWOODIE SOUTH 345kV CABLE ACADEMY STREET SUB TO 49th STREET CON ED SUB

Description	Quant	Unit Hrs	Hours	Labor $	Unit Matl	Material	Major Equip	Const Equip	Subcontr.	Lump Sum	Total Cost
ACADEMY ST. UPGRADES											
345 kV Circuit Breakers incld. associated DS and Bus	2	3,200	6,400	524,800	0	0	3,300,000	0	0	0	3,824,800
Tie-in to existing and install extension of 345kV Open Air Bus	2	2,150	4,300	352,600	0	0	2,050,000	0	0	0	2,402,600
Relay System Additions and Modifications	1	800	800	65,600	0	0	575,000	0	0	0	640,600
Revenue Metering/Control	1	1,325	1,325	108,650	0	0	880,000	0	0	0	988,650
System Modifications											
SCADA/NYISO Modifications	1	1,100	1,100	90,200	0	0	775,000	0	0	0	865,200
Fiber Optic Cables	2	2,400	4,800	393,600	135,000	270,000	0	0	0	0	663,600

Concrete Work	1	2,600	2,600	169,000	105,000	105,000	0	35,000	0	0	309,000
Contractor Indirects/OH&P	1	2,950	2,950	278,775	0	0	0	0	0	1,890,000	2,168,775
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	485,000	485,000
TOTAL ACADEMY STREET UPGRADES			24,275	1,983,225		375,000	7,580,000	35,000	0	2,375,000	12,348,225
345kV UG CABLE - ACADEMY STREET SUBSTATION TO CON EDISON 49TH STREET											
Cable Shakeout along route	1	44,000	44,000	4,158,000	0	0	0	1,600,000	0	0	5,758,000
345kV Cable - 10 mile length Academy Street Substation to Con Edison 49th Street Sub	1	105,600	105,600	9,979,200	23,760,000	23,760,000	0	0	0	0	33,739,200
345kV Cable Splices	1	28,000	28,000	2,646,000	4,500,000	4,500,000	0	0	0	0	7,146,000
Conduit for Cable including Fittings/Supports/Survey	1	422,400	422,400	39,916,800	13,015,000	13,015,000	0	1,920,000	0	0	54,851,800
Hand Excavation in NYC	1	240,000	240,000	18,000,000	6,900,000	6,900,000	0	4,300,000	0	0	29,200,000

Forced Oil Cooling of 345kV Cable Including Pumps, Cooling Equipment and Pipe	1	115,000	115,000	10,867,500	10,560,000	10,560,000	1,325,000	0	0	0	22,752,500
Series and Shunt Reactors for Voltage Compensation	1	18,500	18,500	1,748,250	375,000	375,000	1,750,000	0	0	0	3,873,250
Hi-Pot Testing	1	3,400	3,400	321,300	125,000	125,000	0	60,000	0	0	506,300
Traffic Control	1	25,000	25,000	3,125,000	750,000	750,000	0	225,000	0	0	4,100,000
Haul Waste to Landfill	1	160,000	160,000	14,080,000	0	0	0	7,900,000	8,000,000	0	29,980,000
Restoration of Roads/Walks	1	220,000	220,000	18,040,000	11,000,000	11,000,000	0	5,500,000	0	0	34,540,000
Concrete Work	1	135,000	135,000	11,475,000	6,000,000	6,000,000	0	1,700,000	0	0	19,175,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	5,500,000	5,500,000
TOTAL 345kV UG CABLE - ACADEMY STREET SUBSTATION TO CON EDISON 49TH STREET SUBSTATION			1,516,900	134,357,050		76,985,000	3,075,000	23,205,000	8,000,000	5,500,000	251,122,050

49th STREET UPGRADES											
Ring Bus/Brkrs/Con Ed/Sub	1	32,000	32,000	3,024,000	650,000	650,000	12,500,000	480,000	0	0	16,654,000
Concrete Work	1	8,000	8,000	680,000	300,000	300,000	0	85,000	0	0	1,065,000
Relay System Additions and Modifications	1	800	800	65,600	0	0	575,000	0	0	0	640,600
Revenue Metering/Control System Modifications	1	1,325	1,325	108,650	0	0	880,000	0	0	0	988,650
SCADA/NYISO Modifications	1	1,100	1,100	90,200	0	0	775,000	0	0	0	865,200
Fiber Optic Cables	2	2,400	4,800	393,600	135,000	270,000	0	0	0	0	663,600
Contractor Indirects/OH&P	1	7,200	7,200	680,400	0	0	0	0	0	3,575,000	4,255,400
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	950,000	950,000
TOTAL 49th STREET UPGRADES			55,225	5,042,450		1,220,000	14,730,000	565,000	0	4,525,000	26,082,450

TOTAL DIRECT COSTS			1,596,400	141,382,725		78,580,000	25,385,000	23,805,000	8,000,000	12,400,000	289,552,725
INDIRECT COSTS											
Construction Management	1	15,200	15,200	1,368,000	0	0	0	0	0	14,750,000	16,118,000
Temporary Facilities/Utilities	1	6,800	6,800	612,000	0	0	0	0	0	1,975,000	2,587,000
Construction Equipment and Operators	1	84,000	84,000	7,560,000	0	0	0	8,250,000	0	0	15,810,000
Indirect Construction Services and Support	1	68,000	68,000	6,120,000	0	0	0	0	0	2,145,000	8,265,000
Insurance/Taxes/Permits/ Other	1	8,450	8,450	760,500	0	0	0	0	0	13,978,000	14,738,500

A/E Engineering	1	0	0	0	0	0	0	0	0	16,750,000	16,750,000
Start-Up and Testing	1	0	0	0	0	0	0	0	0	3,750,000	3,750,000
TOTAL INDIRECT COSTS			182,450	16,420,500	0	0	0	8,250,000	0	53,348,000	78,018,500
TOTAL DIRECT/INDIRECT			1,778,850	157,803,225		78,580,000	25,385,000	32,055,000	8,000,000	65,748,000	367,571,225
CONTRACTOR RISK & FEE										55,135,684	55,135,684
SUBTOTAL CONTR VALUE											422,706,909
CONTINGENCY										63,406,036	63,406,036

TOTAL EPC CONSTRUCTION	1,778,850	157,803,225		78,580,000	25,385,000	32,055,000	8,000,000	184,289,720	486,112,945

A.3 NYRI

BURNS and ROE - CRA PROJECT FOR NYCEDC

1,200 MW HVDC TRANSMISSION LINE & CONVERTER STATIONS - UTICA TO ROCK TAVERN

Description	Quant	Unit Hrs	Hours	Labor $	Unit Matl	Material	Major Equip	Const Equip	Subcontr.	Lump Sum	Total Cost
EDIC INTERCONNECTION											
345 kV Circuit Breaker incld. associated DS and Bus	1	3,200	3,200	262,400	0	0	1,650,000	0	0	0	1,912,400
Tie-in to existing and install extension of 345kV Open Air Bus	1	2,200	2,200	180,400	0	0	1,050,000	0	0	0	1,230,400
345kV UG Cable - EDIC to Converter Station - 5,000 lf	1	21,000	21,000	1,722,000	1,325,000	1,325,000	0	110,000	0	0	3,157,000

Relay System Additions and Modifications	1	660	660	54,120	0	0	450,000	0	0	0	504,120
Revenue Metering/Control System Modifications	1	1,100	1,100	90,200	0	0	775,000	0	0	0	865,200
SCADA/NYISO Modifications	1	900	900	73,800	0	0	625,000	0	0	0	698,800
345kV UG Cable	1	6,400	6,400	524,800	1,185,000	1,185,000	0	0	0	0	1,709,800
Fiber Optic Cables	2	5,200	10,400	852,800	312,000	624,000	0	0	0	0	1,476,800
Concrete Work	1	4,200	4,200	273,000	190,000	190,000	0	54,000	0	0	517,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	975,000	975,000
TOTAL EDIC INTERCONNECT			50,060	4,033,520		3,324,000	4,550,000	164,000	0	975,000	13,046,520
CONVERTER STATIONS											

SITE WORK											
Site Preparation	1	12,000	12,000	780,000	370,000	370,000	0	245,000	0	0	1,395,000
Site Clearing/Demolition	1	14,000	14,000	910,000	43,000	43,000	0	238,000	0	0	1,191,000
Mass Earthwork	1	6,000	6,000	390,000	0	0	0	120,000	0	0	510,000
Mass Cut and Fill	1	4,300	4,300	279,500	125,000	125,000	0	194,000	0	0	598,500
Detention Pond/Drainage	1	1,900	1,900	123,500	0	0	0	150,000	0	0	273,500
Site Utilities	1	15,500	15,500	1,007,500	385,000	385,000	0	210,000	0	0	1,602,500
Erosion Control	1	2,300	2,300	149,500	156,000	156,000	0	33,500	0	0	339,000
Dewatering	1	1,850	1,850	120,250	0	0	0	32,900	0	0	153,150
Foundation Excav. & Backfill	1	5,400	5,400	351,000	115,000	115,000	0	186,000	0	0	652,000
Piling	1	0	0	0	0	0	0	0	4,750,000	0	4,750,000
Site Improvements	1	2,400	2,400	156,000	970,000	970,000	0	54,000	0	0	1,180,000

Paving and Surfacing	1	4,900	4,900	318,500	521,000	521,000	0	84,600	47,800	0	971,900
Landscaping	1	2,100	2,100	136,500	495,000	495,000	0	12,700	0	0	644,200
SUBTOTAL SITE WORK			72,650	4,722,250		3,180,000	0	1,560,700	4,797,800	0	14,260,750
FOUNDATIONS											
Converter Bldg Foundation	1	54,500	54,500	3,542,500	2,835,000	2,835,000	0	118,000	0	0	6,495,500
Misc Equipment Foundations	1	4,800	4,800	312,000	249,000	249,000	0	15,000	0	0	576,000
Transformer Foundations	8	1,800	14,400	936,000	78,000	624,000	0	16,000	0	0	1,576,000
Transformer Fire Walls	8	6,400	51,200	3,328,000	240,000	1,920,000	0	110,000	0	0	5,358,000
Reactive Compen Filter Fnds	16	800	12,800	832,000	35,000	560,000	0	32,000	0	0	1,424,000
Harmonic Filter Foundations	16	800	12,800	832,000	35,000	560,000	0	32,000	0	0	1,424,000

Spare Transformer Fnds.	2	800	1,600	104,000	60,000	120,000	0	5,000	0	0	229,000
Misc Site Building Foundation	1	3,100	3,100	201,500	149,500	149,500	0	17,000	0	0	368,000
SUBTOTAL FOUNDATIONS			155,200	10,088,000		7,017,500	0	345,000	0	0	17,450,500
MASONRY											
Building Masonry	1	14,500	14,500	870,000	410,000	410,000	0	48,000	0	0	1,328,000
SUBTOTAL MASONRY			14,500	870,000		410,000	0	48,000	0	0	1,328,000
METALS											
Converter Building	1	36,700	36,700	2,899,300	3,986,000	3,986,000	0	277,000	0	0	7,162,300

Administration/Control/	1	14,200	14,200	1,121,800	1,570,000	1,570,000	0	162,000	0	0	2,853,800
Maintenance Building											
Miscellaneous Buildings	1	9,800	9,800	774,200	1,086,000	1,086,000	0	116,000	0	0	1,976,200
Yard Steel Structures	2	44,000	88,000	6,952,000	3,760,000	7,520,000	0	234,000	0	0	14,706,000
SUBTOTAL METALS			148,700	11,747,300		14,162,000	0	789,000	0	0	26,698,300
MISCELLANEOUS CIVIL											
Wood and Plastics	1	1,200	1,200	82,800	24,000	24,000	0	0	0	0	106,800
Thermal/Moisture Protection	1	62,500	62,500	4,312,500	3,785,000	3,785,000	0	135,000	1,050,000	0	9,282,500
Doors and Windows	1	2,600	2,600	179,400	387,000	387,000	0	0	0	0	566,400
Finishes	1	32,600	32,600	2,249,400	545,000	545,000	0	0	343,000	0	3,137,400
Specialties	1	3,500	3,500	241,500	188,000	188,000	0	0	0	0	429,500

SUBTOTAL MISC. CIVIL			102,400	7,065,600		4,929,000	0	135,000	1,393,000	0	13,522,600
TOTAL CIVIL/STRUCTURAL			493,450	34,493,150		29,698,500	0	2,877,700	6,190,800	0	73,260,150
MECHANICAL											
Piping - Spec 600	1	8,800	8,800	660,000	888,000	888,000	0	0	0	0	1,548,000
Piping - Spec 300	1	5,400	5,400	405,000	131,000	131,000	0	0	0	0	536,000
Piping - Spec 150	1	47,900	47,900	3,592,500	1,134,000	1,134,000	0	0	0	0	4,726,500
Pipe Hangers and Supports	1	8,320	8,320	624,000	1,075,000	1,075,000	0	0	0	0	1,699,000
Valves - Spec 600	1	5,700	5,700	427,500	114,000	114,000	0	0	0	0	541,500
Valves - Spec 300	1	875	875	65,625	108,000	108,000	0	0	0	0	173,625
Valves - Spec 150	1	2,410	2,410	180,750	490,000	490,000	0	0	0	0	670,750

Flow Elements	1	165	165	12,375	84,600	84,600	0	0	0	0	96,975
Control Valves	1	1,620	1,620	121,500	592,000	592,000	0	0	0	0	713,500
Insulation	1	0	0	0	0	0	0	0	1,235,000	0	1,235,000
Fire Protection	1	0	0	0	0	0	0	0	3,645,000	0	3,645,000
Plumbing	1	0	0	0	0	0	0	0	345,700	0	345,700
HVAC	1	0	0	0	0	0	0	0	11,000,000	0	11,000,000
Miscellaneous Mechanical	1	2,230	2,230	167,250	0	0	0	0	320,000	0	487,250
SUBTOTAL MECHANICAL			83,420	6,256,500		4,616,600	0	0	16,545,700	0	27,418,800
TOTAL MECHANICAL			83,420	6,256,500		4,616,600	0	0	16,545,700	0	27,418,800
ELECTRICAL											

ELECTRICAL EQUIPMENT												
Main Transformers	8	1,600	12,800	1,049,600	0	0	29,800,000	0	0	0	30,849,600
Spare Transformers	2	400	800	65,600	0	0	7,450,000	0	0	0	7,515,600
Misc Transformers	1	800	800	65,600	0	0	4,200,000	0	0	0	4,265,600
Reactive Compensation Filter	1	6,400	6,400	524,800	0	0	9,600,000	0	0	0	10,124,800
Tuned Harmonic Filters	1	6,400	6,400	524,800	0	0	7,200,000	0	0	0	7,724,800
HF Noise Filters	1	3,200	3,200	262,400	0	0	3,750,000	0	0	0	4,012,400
Thyristor Valves	1	7,000	7,000	574,000	0	0	4,275,000	0	0	0	4,849,000
230kV Bus	1	8,200	8,200	672,400	0	0	2,653,000	0	0	0	3,325,400
345kV Bus	1	9,760	9,760	800,320	0	0	2,145,000	0	0	0	2,945,320
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	8,800,000	8,800,000

TOTAL ELECTRICAL EQUIP.			55,360	4,539,520		0	71,073,000	0	0	8,800,000	84,412,520
ELECTRICAL BULKS											
Raceways	1	48,500	48,500	3,977,000	1,635,000	1,635,000	0	0	0	0	5,612,000
Building Services	1	24,300	24,300	1,992,600	1,094,000	1,094,000	0	0	0	0	3,086,600
Conductors	1	34,600	34,600	2,837,200	2,632,800	2,632,800	0	0	0	0	5,470,000
Fire Detection	1	2,200	2,200	180,400	134,800	134,800	0	0	0	0	315,200
Site Lighting	1	10,800	10,800	885,600	660,000	660,000	0	0	0	0	1,545,600
Grounding	1	21,500	21,500	1,763,000	987,000	987,000	0	0	0	0	2,750,000
Electrical Heat Tracing	1	4,800	4,800	393,600	510,000	510,000	0	0	0	0	903,600
Electrical Indirect Costs	1	14,400	14,400	1,180,800	0	0	0	0	0	4,900,000	6,080,800
TOTAL ELECTRICAL BULKS			161,100	13,210,200		7,653,600	0	0	0	4,900,000	25,763,800

TOTAL ELECTRICAL			216,460	17,749,720	0	7,653,600	71,073,000	0	0	13,700,000	110,176,320
TOTAL CONVERTER STATION			793,330	58,499,370		41,968,700	71,073,000	2,877,700	22,736,500	13,700,000	210,855,270
345kV AG/UG CABLE - NORTH CONVERTER STATION TO SOUTH CONVERTER STATION											
Cable Shakeout along route	1	65,000	65,000	5,330,000	0	0	0	2,100,000	0	0	7,430,000
345kV Cable - North Converter	1	1,003,200	1,003,200	82,262,400	175,560,000	175,560,000	0	0	0	0	257,822,400
Station to South Converter											
Station											
Conduit	1	32,500	32,500	2,665,000	975,000	975,000	0	234,000	0	0	3,874,000
HDD Operations - 8 locations	8	6,400	51,200	4,198,400	125,000	1,000,000	0	1,240,000	0	0	6,438,400

Tubular Towers Complete	1,600	360	576,000	47,232,000	75,000	120,000,000	0	5,675,000	0	0	172,907,000
Clear Greenfield	1	42,000	42,000	3,444,000	400,000	400,000	0	3,200,000	0	0	7,044,000
Construct Transition Vault	8	22,000	176,000	11,440,000	446,000	3,568,000	0	1,175,000	0	0	16,183,000
Concrete Work/Towers/Other	1	280,000	280,000	18,200,000	12,000,000	12,000,000	0	650,000	0	0	30,850,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	6,500,000	6,500,000
TOTAL 345kV AG/UG CABLE - NORTH CONVERTER STATION TO SOUTH CONVERTER STATION			2,225,900	174,771,800		313,503,000	0	14,274,000	0	6,500,000	509,048,800
ROCK TAVERN INTERCONNECT											

345 kV Circuit Breaker incld. associated DS and Bus	2	3,200	6,400	524,800	0	0	3,300,000	0	0	0	3,824,800
Tie-in to existing and install extension of 345kV Open Air Bus	2	2,200	4,400	360,800	0	0	2,100,000	0	0	0	2,460,800
345kV UG Cable - Rock Tav to Converter Station - 5,000 lf	2	21,000	42,000	3,444,000	1,325,000	2,650,000	0	198,000	0	0	6,292,000
Relay System Additions and Modifications	2	660	1,320	108,240	0	0	900,000	0	0	0	1,008,240
Revenue Metering/Control System Modifications	2	1,100	2,200	180,400	0	0	1,550,000	0	0	0	1,730,400
SCADA/NYISO Modifications	2	900	1,800	147,600	0	0	1,250,000	0	0	0	1,397,600
345kV UG Cable	2	6,400	12,800	1,049,600	1,185,000	2,370,000	0	0	0	0	3,419,600
Fiber Optic Cables	4	5,200	20,800	1,705,600	312,000	1,248,000	0	0	0	0	2,953,600
Concrete Work	1	6,500	6,500	422,500	287,000	287,000	0	116,000	0	0	825,500
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	1,250,000	1,250,000

TOTAL ROCK TAVERN INTERCONNECT			98,220	7,943,540		6,555,000	9,100,000	314,000	0	1,250,000	25,162,540
TOTAL DIRECT COSTS			3,167,510	245,248,230		365,350,700	84,723,000	17,629,700	22,736,500	22,425,000	758,113,130
INDIRECT COSTS											
Construction Management	1	35,600	35,600	3,204,000	0	0	0	0	0	26,700,000	29,904,000
Temporary Facilities/Utilities	1	12,300	12,300	1,107,000	0	0	0	0	0	4,340,000	5,447,000
Construction Equipment and Operators	1	27,600	27,600	2,484,000	0	0	0	9,876,000	0	0	12,360,000

Indirect Construction Services and Support	1	86,500	86,500	7,785,000	0	0	0	0	0	4,213,000	11,998,000
Insurance/Taxes/Permits/ Other	1	17,600	17,600	1,584,000	0	0	0	0	0	47,300,000	48,884,000
A/E Engineering	1	0	0	0	0	0	0	0	0	33,400,000	33,400,000
Start-Up and Testing	1	0	0	0	0	0	0	0	0	8,600,000	8,600,000
TOTAL INDIRECT COSTS			179,600	16,164,000	0	0	0	9,876,000	0	124,553,000	150,593,000
TOTAL DIRECT/INDIRECT			3,347,110	261,412,230		365,350,700	84,723,000	27,505,700	22,736,500	146,978,000	908,706,130
CONTRACTOR RISK & FEE										136,305,920	136,305,920

SUBTOTAL CONTR VALUE										1,045,012,050
CONTINGENCY									156,751,807	156,751,807
TOTAL EPC CONSTRUCTION		3,347,110	261,412,230		365,350,700	84,723,000	27,505,700	22,736,500	440,035,727	1,201,763,857

A.4 Wind

BURNS and ROE - CRA PROJECT FOR NYCEDC

500 MW DEEPWATER WIND TURBINE PROJECT - QUEENS, N.Y.

Description	Quan	Unit Hrs	Hours	Labor $	Unit Matl	Material	Major Equip	Const Equip	Subcontr.	Lump Sum	Total Cost
LAND BASED FABRICATION											
Lease Land for Shore Based Fabrication Plant	1	0	0	0	0	0	0	0	0	5,000,000	5,000,000
Construct Fabrication Plant	1	60,000	60,000	4,920,000	2,000,000	2,000,000	0	8,000,000	0	0	14,920,000
Fabricate Gravity Base Tower/ Foundations	102	10,500	1,071,000	87,822,000	875,000	89,250,000	0	0	0	0	177,072,000
Prepare Ocean Floor for	102	3,600	367,200	30,110,400	125,000	12,750,000	0	8,500,000	0	0	51,360,400
Gravity Base Towers											
Haul and Install Gravity Base Towers	102	2,800	285,600	23,419,200	0	0	0	7,500,000	0	0	30,919,200

Return Leased Land to Original State	1	25,000	25,000	2,050,000	0	0	0	250,000	0	300,000	2,600,000
TOTAL LAND BASED FAB'R.			1,808,800	148,321,600		104,000,000	0	24,250,000	0	5,300,000	281,871,600
WIND TURBINE GENERATOR											
Freight, Insurance, Taxes on Wind Turbines from Europe	102	0	0	0	0	0	0	0	0	12,750,000	12,750,000
Receive and Unpack Wind Turbine Generators	102	800	81,600	7,711,200	0	0	637,500,000	0	0	0	645,211,200
Preassemble Wind Turbine Generators at Plant	102	1,400	142,800	13,494,600	0	0	0	0	0	0	13,494,600
Level and Grout Counter Plates of Wind Turbines	102	600	61,200	5,783,400	0	0	0	0	0	0	5,783,400
Haul and Install Wind Turbine	102	3,900	397,800	37,592,100	0	0	0	9,000,000	0	0	46,592,100

Generators, Blades and Towers											
TOTAL WIND TURBINE GEN.			683,400	64,581,300		0	637,500,000	9,000,000	0	12,750,000	723,831,300
OCEAN PLATFORM											
Construct Foundation	1	12,000	12,000	1,020,000	900,000	900,000	0	0	0	0	1,920,000
Construct Concrete Columns	1	28,000	28,000	2,380,000	2,250,000	2,250,000	0	0	0	0	4,630,000
Construct Steel Frame	1	48,000	48,000	4,632,000	7,600,000	7,600,000	0	0	0	0	12,232,000
Install Metal Decking/Shielding	1	14,000	14,000	1,351,000	3,600,000	3,600,000	0	0	0	0	4,951,000
Main Transformers	3	2,400	7,200	680,400	0	0	9,525,000	0	0	0	10,205,400
Spare Transformers	1	600	600	56,700	0	0	3,175,000	0	0	0	3,231,700
Misc Transformers	1	1,200	1,200	113,400	0	0	1,500,000	0	0	0	1,613,400

Other Misc. Equipment	1	2,000	2,000	189,000	0	0	1,750,000	0	0	0	1,939,000
TOTAL OCEAN PLATFORM			113,000	10,422,500	0	14,350,000	15,950,000	0	0	0	40,722,500
LAND BASED ELECTRICAL											
Switchyard Civil Work	1	6,800	6,800	578,000	245,000	245,000	0	0	0	0	823,000
Control Room Civil Work	1	5,400	5,400	459,000	452,000	452,000	0	0	0	0	911,000
Construct Switchyard	1	24,000	24,000	2,268,000	350,000	350,000	8,500,000	0	0	0	11,118,000
Construct Control Room	1	6,000	6,000	567,000	0	0	3,750,000	0	0	0	4,317,000
Fiber Optic Cable & Conduit	1	8,000	8,000	756,000	125,000	125,000	0	0	0	0	881,000
Purchase Land for Control Room and Switchyard	1	0	0	0	0	0	0	0	0	3,000,000	3,000,000

TOTAL LAND BASED ELECT.			50,200	4,628,000		1,172,000	12,250,000	0	0	3,000,000	21,050,000
SUBMARINE CABLE											
Transfer Cable to Barge	1	8,000	8,000	756,000	0	0	0	0	0	0	756,000
26kV Marine Cable - 52.3 Mile	1	0	0	0	41,421,600	41,421,600	0	0	0	0	41,421,600
138kV Marine Cable - 75 Mile	1	0	0	0	99,000,000	99,000,000	0	0	0	0	99,000,000
Subsurface Route Survey	1	12,000	12,000	1,134,000	0	0	0	0	0	0	1,134,000
QA/QC Cable	1	8,400	8,400	793,800	225,000	225,000	0	0	0	0	1,018,800
Construct Wet Cofferdam	1	21,500	21,500	2,031,750	790,000	790,000	0	220,000	0	0	3,041,750
HDD Operations	3	6,400	19,200	1,814,400	125,000	375,000	0	475,000	0	0	2,664,400
Lay Marine Cable - 26kV	1	552,300	552,300	52,192,350	760,000	760,000	0	9,000,000	0	0	61,952,350
Lay Marine Cable - 138kV	1	792,000	792,000	74,844,000	940,000	940,000	0	11,500,000	0	0	87,284,000

All other Underwater Work	1	0	0	0	0	0	0	0	0	8,000,000	8,000,000
Pull Marine Cable Ashore	3	2,400	7,200	680,400	65,000	195,000	0	210,000	0	0	1,085,400
Manholes/Anchor Cable	2	12,400	24,800	2,343,600	345,000	690,000	0	110,000	0	0	3,143,600
Construct Tansition Vault	1	18,000	18,000	1,701,000	126,000	126,000	0	48,000	0	0	1,875,000
Run Cores to Transition Stand	3	2,400	7,200	680,400	425,000	1,275,000	0	105,000	0	0	2,060,400
Grounding	1	8,000	8,000	756,000	360,000	360,000	0	115,000	0	0	1,231,000
Mandrill Ductbank	1	6,800	6,800	642,600	170,000	170,000	0	112,000	0	0	924,600
Pull Land-Based Cable	1	4,200	4,200	396,900	550,000	550,000	0	75,000	0	0	1,021,900
Hand Excavation	3	2,400	7,200	680,400	425,000	1,275,000	0	105,000	0	0	2,060,400
Cable Splicing at Shoreline	1	8,000	8,000	756,000	360,000	360,000	0	115,000	0	0	1,231,000
Haul Wast to Landfill	1	6,800	6,800	642,600	170,000	170,000	0	112,000	0	0	924,600
Retoration of Roads/Walks	1	4,200	4,200	396,900	550,000	550,000	0	75,000	0	0	1,021,900
Land Based Cable - 138kV	1	7,600	7,600	718,200	3,225,000	3,225,000	0	0	0	0	3,943,200
Land Based Cable - 138kV	1	15,800	15,800	1,493,100	590,000	590,000	0	0	0	0	2,083,100

Concrete Work	1	9,000	9,000	765,000	315,000	315,000	0	75,000	0	0	1,155,000
Terminate Land-Based Cable	1	2,400	2,400	226,800	145,000	145,000	0	50,000	0	0	421,800
Hi-Pot Testing	1	2,700	2,700	255,150	125,000	125,000	0	60,000	0	0	440,150
Contractor Indirects/OH&P	1	79,200	79,200	7,484,400	0	0	0	0	0	35,368,000	42,852,400
TOTAL SUBMARINE CABLE			1,632,500	154,185,750		153,632,600	0	22,562,000	0	43,368,000	373,748,350
TOTAL DIRECT COSTS			4,287,900	405,206,550		273,154,600	665,700,000	55,812,000	0	64,418,000	1,441,223,750
INDIRECT COSTS											
Construction Management	1	48,000	48,000	4,536,000	0	0	0	0	0	23,700,000	28,236,000
Temporary	1	11,250	11,250	1,063,125	0	0	0	0	0	2,775,000	3,838,125

Facilities/Utilities											
Construction Equipment and Operators	1	32,500	32,500	3,071,250	0	0	0	6,855,000	0	0	9,926,250
Indirect Construction Services and Support	1	74,000	74,000	6,993,000	0	0	0	0	0	3,135,000	10,128,000
Insurance/Taxes/Permits/ Other	1	14,400	14,400	1,360,800	0	0	0	0	0	43,490,000	44,850,800
A/E Engineering	1	0	0	0	0	0	0	0	0	32,500,000	32,500,000
Start-Up and Testing	1	0	0	0	0	0	0	0	0	15,000,000	15,000,000
TOTAL INDIRECT COSTS			180,150	17,024,175		0	0	6,855,000	0	120,600,000	144,479,175

TOTAL DIRECT/INDIRECT	4,468,050	422,230,725		273,154,600	665,700,000	62,667,000	0	185,018,000	1,585,702,925
CONTRACTOR RISK & FEE								237,855,439	237,855,439
SUBTOTAL CONTR VALUE									1,823,558,364
CONTINGENCY								273,533,755	273,533,755
TOTAL EPC CONSTRUCTION									2,097,092,118

A.5 Hudson

BURNS and ROE - CRA PROJECT FOR NYCEDC

660 MW HVDC CABLE AND CONVERTER STATION - BERGEN STATION TO W.49TH STREET REV. 1

Description	Quant	Unit Hrs	Hours	Labor $	Unit Matl	Material	Major Equip	Const Equip	Subcontr.	Lump Sum	Total Cost
PSEG INTERCONNECTION											
230 kV Circuit Breakers incld. associated DS and Bus	2	2,400	4,800	393,600	0	0	2,880,000	0	0	0	3,273,600
Tie-in to existing and install extension of 230kV Open Air Bus	2	1,800	3,600	295,200	0	0	1,800,000	0	0	0	2,095,200
230kV UG Cable - PSEG to Converter Station - 2,000 lf	1	8,000	8,000	656,000	600,000	600,000	0	0	0	0	1,256,000
Relay System Additions and Modifications	1	660	660	54,120	0	0	450,000	0	0	0	504,120
Revenue Metering/Control System Modifications	1	1,100	1,100	90,200	0	0	775,000	0	0	0	865,200

SCADA/NYISO Modifications	1	900	900	73,800	0	0	625,000	0	0	0	698,800
230kV UG Cable	1	3,200	3,200	262,400	792,000	792,000	0	0	0	0	1,054,400
Fiber Optic Cables	2	2,400	4,800	393,600	135,000	270,000	0	0	0	0	663,600
Concrete Work	1	2,600	2,600	169,000	105,000	105,000	0	35,000	0	0	309,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	900,000	900,000
TOTAL PSEG INTERCONNECT			29,660	2,387,920		1,767,000	6,530,000	35,000	0	900,000	11,619,920
CONVERTER STATION											
SITE WORK											
Site Preparation	1	8,000	8,000	520,000	225,000	225,000	0	190,000	0	0	935,000
Site Clearing/Demolition	1	12,000	12,000	780,000	25,000	25,000	0	210,000	0	0	1,015,000

Mass Earthwork	1	4,000	4,000	260,000	0	0	0	120,000	0	0	380,000
Mass Cut and Fill	1	2,800	2,800	182,000	50,000	50,000	0	165,000	0	0	397,000
Detention Pond/Drainage	1	950	950	61,750	0	0	0	75,000	0	0	136,750
Site Utilities	1	9,500	9,500	617,500	230,000	230,000	0	140,000	0	0	987,500
Erosion Control	1	1,150	1,150	74,750	78,000	78,000	0	22,000	0	0	174,750
Dewatering	1	1,200	1,200	78,000	0	0	0	24,500	0	0	102,500
Foundation Excav. & Backfill	1	4,800	4,800	312,000	85,000	85,000	0	165,000	0	0	562,000
Piling	1	0	0	0	0	0	0	0	4,250,000	0	4,250,000
Site Improvements	1	1,700	1,700	110,500	810,000	810,000	0	37,000	0	0	957,500
Paving and Surfacing	1	2,760	2,760	179,400	374,000	374,000	0	56,000	32,000	0	641,400
Landscaping	1	975	975	63,375	275,000	275,000	0	6,500	0	0	344,875
SUBTOTAL SITE WORK			49,835	3,239,275		2,152,000	0	1,211,000	4,282,000	0	10,884,275
FOUNDATIONS											

Converter Bldg Foundation	1	47,500	47,500	3,087,500	2,375,000	2,375,000	0	75,000	0	0	5,537,500
Misc Equipment Foundations	1	4,800	4,800	312,000	249,000	249,000	0	15,000	0	0	576,000
Transformer Foundations	8	1,800	14,400	936,000	78,000	624,000	0	16,000	0	0	1,576,000
Transformer Fire Walls	8	6,400	51,200	3,328,000	240,000	1,920,000	0	110,000	0	0	5,358,000
Reactive Compen Filter Fnds	16	800	12,800	832,000	35,000	560,000	0	32,000	0	0	1,424,000
Harmonic Filter Foundations	16	800	12,800	832,000	35,000	560,000	0	32,000	0	0	1,424,000
Spare Transformer Fnds.	2	800	1,600	104,000	60,000	120,000	0	5,000	0	0	229,000
Misc Site Building Foundation	1	1,600	1,600	104,000	110,000	110,000	0	12,000	0	0	226,000
SUBTOTAL FOUNDATIONS			146,700	9,535,500		6,518,000	0	297,000	0	0	16,350,500
MASONRY											
Building Masonry	1	8,500	8,500	510,000	265,000	265,000	0	32,000	0	0	807,000

SUBTOTAL MASONRY			8,500	510,000		265,000	0	32,000	0	0	807,000
METALS											
Converter Building	1	24,500	24,500	1,935,500	2,635,000	2,635,000	0	198,000	0	0	4,768,500
Administration/Control/	1	7,200	7,200	568,800	822,000	822,000	0	84,000	0	0	1,474,800
Maintenance Building											
Miscellaneous Buildings	1	4,900	4,900	387,100	543,000	543,000	0	58,000	0	0	988,100
Yard Steel Structures	2	34,500	69,000	5,451,000	3,120,000	6,240,000	0	165,000	0	0	11,856,000
SUBTOTAL METALS			105,600	8,342,400		10,240,000	0	505,000	0	0	19,087,400
MISCELLANEOUS CIVIL											

Wood and Plastics	1	1,200	1,200	82,800	24,000	24,000	0	0	0	0	106,800
Thermal/Moisture Protection	1	44,000	44,000	3,036,000	3,175,000	3,175,000	0	90,000	725,000	0	7,026,000
Doors and Windows	1	1,400	1,400	96,600	220,000	220,000	0	0	0	0	316,600
Finishes	1	27,500	27,500	1,897,500	385,000	385,000	0	0	293,000	0	2,575,500
Specialties	1	1,750	1,750	120,750	94,000	94,000	0	0	0	0	214,750
SUBTOTAL MISC. CIVIL			75,850	5,233,650		3,898,000	0	90,000	1,018,000	0	10,239,650
TOTAL CIVIL/STRUCTURAL			386,485	26,860,825		23,073,000	0	2,135,000	5,300,000	0	57,368,825
MECHANICAL											
Piping - Spec 600	1	8,040	8,040	603,000	802,500	802,500	0	0	0	0	1,405,500
Piping - Spec 300	1	4,950	4,950	371,250	112,500	112,500	0	0	0	0	483,750
Piping - Spec 150	1	43,500	43,500	3,262,500	1,005,000	1,005,000	0	0	0	0	4,267,500

Pipe Hangers and Supports	1	7,350	7,350	551,250	982,500	982,500	0	0	0	0	1,533,750
Valves - Spec 600	1	5,100	5,100	382,500	91,500	91,500	0	0	0	0	474,000
Valves - Spec 300	1	720	720	54,000	96,000	96,000	0	0	0	0	150,000
Valves - Spec 150	1	1,932	1,932	144,900	438,000	438,000	0	0	0	0	582,900
Flow Elements	1	150	150	11,250	73,500	73,500	0	0	0	0	84,750
Control Valves	1	1,350	1,350	101,250	525,000	525,000	0	0	0	0	626,250
Insulation	1	0	0	0	0	0	0	0	1,065,000	0	1,065,000
Fire Protection	1	0	0	0	0	0	0	0	2,035,000	0	2,035,000
Plumbing	1	0	0	0	0	0	0	0	245,000	0	245,000
HVAC	1	0	0	0	0	0	0	0	7,500,000	0	7,500,000
Miscellaneous Mechanical	1	1,560	1,560	117,000	0	0	0	0	240,000	0	357,000
SUBTOTAL MECHANICAL			74,652	5,598,900		4,126,500	0	0	11,085,000	0	20,810,400
TOTAL MECHANICAL			74,652	5,598,900		4,126,500	0	0	11,085,000	0	20,810,400

ELECTRICAL											
ELECTRICAL EQUIPMENT											
Main Transformers	8	1,600	12,800	1,049,600	0	0	29,800,000	0	0	0	30,849,600
Spare Transformers	2	400	800	65,600	0	0	7,450,000	0	0	0	7,515,600
Misc Transformers	1	800	800	65,600	0	0	4,200,000	0	0	0	4,265,600
Reactive Compensation Filter	1	6,400	6,400	524,800	0	0	9,600,000	0	0	0	10,124,800
Tuned Harmonic Filters	1	6,400	6,400	524,800	0	0	7,200,000	0	0	0	7,724,800
HF Noise Filters	1	3,200	3,200	262,400	0	0	3,750,000	0	0	0	4,012,400
Thyristor Valves	1	7,000	7,000	574,000	0	0	4,275,000	0	0	0	4,849,000
230kV Bus	1	4,800	4,800	393,600	0	0	2,135,000	0	0	0	2,528,600
345kV Bus	1	5,600	5,600	459,200	0	0	2,690,000	0	0	0	3,149,200
Vendor Engineering/Design	1	0	0	0	0	0	0	0	0	8,500,000	8,500,000

and Supervision											
TOTAL ELECTRICAL EQUIP.			47,800	3,919,600		0	71,100,000	0	0	8,500,000	83,519,600
ELECTRICAL BULKS											
Raceways	1	32,000	32,000	2,624,000	1,135,000	1,135,000	0	0	0	0	3,759,000
Building Services	1	15,800	15,800	1,295,600	650,000	650,000	0	0	0	0	1,945,600
Conductors	1	21,700	21,700	1,779,400	1,815,000	1,815,000	0	0	0	0	3,594,400
Fire Detection	1	1,200	1,200	98,400	74,000	74,000	0	0	0	0	172,400
Site Lighting	1	5,400	5,400	442,800	350,000	350,000	0	0	0	0	792,800
Grounding	1	11,500	11,500	943,000	575,000	575,000	0	0	0	0	1,518,000
Electrical Heat Tracing	1	2,600	2,600	213,200	342,000	342,000	0	0	0	0	555,200
Electrical Indirect Costs	1	8,450	8,450	692,900	0	0	0	0	0	3,600,000	4,292,900

TOTAL ELECTRICAL BULKS			98,650	8,089,300		4,941,000	0	0	0	3,600,000	16,630,300
TOTAL ELECTRICAL			146,450	12,008,900	0	4,941,000	71,100,000	0	0	12,100,000	100,149,900
TOTAL CONVERTER STATION			607,587	44,468,625		32,140,500	71,100,000	2,135,000	16,385,000	12,100,000	178,329,125
345kV UG CABLE - CONVERTER STATION TO EDGEWATER, NJ SUB- MARINE CABLE TIE-IN											
Cable Shakeout along route	1	12,000	12,000	984,000	0	0	0	375,000	0	0	1,359,000
345kV Cable - Converter Station to Edgewater, NJ Shoreline	1	18,480	18,480	1,515,360	8,316,000	8,316,000	0	0	0	0	9,831,360
Conduit	1	36,960	36,960	3,030,720	741,000	741,000	0	315,000	0	0	4,086,720
HDD Operations - 4 locations	4	6,400	25,600	2,099,200	125,000	500,000	0	615,000	0	0	3,214,200
Work in Tunnel	1	31,000	31,000	2,542,000	260,000	260,000	0	420,000	0	0	3,222,000

Cable Splicing at Shoreline	1	4,800	4,800	393,600	160,000	160,000	0	45,000	0	0	598,600
Construct Transition Vault	1	22,000	22,000	1,430,000	446,000	446,000	0	148,000	0	0	2,024,000
Concrete Work	1	8,000	8,000	520,000	300,000	300,000	0	85,000	0	0	905,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	2,200,000	2,200,000
TOTAL EDGEWATER, NJ UG CABLE FROM CONVERTER STATION			158,840	12,514,880		10,723,000	0	2,003,000	0	2,200,000	27,440,880
SUBMARINE CABLE											
Transfer Cable to Barge	1	1,600	1,600	151,200	0	0	0	0	0	0	151,200
Marine Cable Cost Allowance	1	0	0	0	14,784,000	14,784,000	0	0	0	0	14,784,000

Subsurface Route Survey	1	2,400	2,400	226,800	0	0	0	0	0	0	226,800
QA/QC Cable	1	1,800	1,800	170,100	50,000	50,000	0	0	0	0	220,100
Construct 2 Wet Cofferdams	2	21,500	43,000	4,063,500	790,000	1,580,000	0	440,000	0	0	6,083,500
HDD Operations - 2 locations	2	6,400	12,800	1,209,600	125,000	250,000	0	325,000	0	0	1,784,600
Lay Marine Cable	1	23,500	23,500	2,220,750	190,000	190,000	0	4,500,000	0	0	6,910,750
All other Underwater Work	1	9,500	9,500	897,750	510,000	510,000	0	290,000	0	0	1,697,750
Marine Transfer Insurance	1	0	0	0	0	0	0	0	0	1,700,000	1,700,000
Pull Marine Cable Ashore	2	2,400	4,800	453,600	65,000	130,000	0	165,000	0	0	748,600
Manholes/Anchor Cable	2	12,400	24,800	2,343,600	345,000	690,000	0	110,000	0	0	3,143,600
Run Cores to Transition Stand	2	2,400	4,800	453,600	425,000	850,000	0	70,000	0	0	1,373,600
Grounding	1	8,000	8,000	756,000	360,000	360,000	0	115,000	0	0	1,231,000
Mandrill Ductbank	1	6,800	6,800	642,600	170,000	170,000	0	112,000	0	0	924,600
Pull Land-Based Cable	1	4,200	4,200	396,900	550,000	550,000	0	75,000	0	0	1,021,900
Terminate Land-Based at Edgewater, NJ	1	2,400	2,400	226,800	145,000	145,000	0	50,000	0	0	421,800

Hi-Pot Testing	1	2,700	2,700	255,150	125,000	125,000	0	60,000	0	0	440,150
Contractor Indirects/OH&P	1	19,800	19,800	1,871,100	0	0	0	0	0	8,842,000	10,713,100
TOTAL SUBMARINE CABLE			172,900	16,339,050		20,384,000	0	6,312,000	0	10,542,000	53,577,050
345kV UG CABLE - NYC PIER 92 - 94 ENTRY FROM HUDSON RIVER TO CON EDISON 49TH STREET SUBSTATION											
Cable Shakeout along route	1	2,200	2,200	207,900	0	0	0	80,000	0	0	287,900
345kV Cable - Pier 92 - 94 to Con Edison 49th Street Substation	1	5,280	5,280	498,960	1,188,000	1,188,000	0	0	0	0	1,686,960
Conduit	1	10,560	10,560	997,920	126,000	126,000	0	48,000	0	0	1,171,920
HDD Operations - 4 locations	4	6,400	25,600	2,419,200	125,000	500,000	0	615,000	0	0	3,534,200
Hand Excavation in NYC	1	12,000	12,000	900,000	345,000	345,000	0	215,000	0	0	1,460,000
Cable Splicing at Shoreline	1	4,800	4,800	453,600	160,000	160,000	0	45,000	0	0	658,600
Haul Waste to Landfill	1	8,000	8,000	704,000	0	0	0	395,000	400,000	0	1,499,000

Restoration of Roads/Walks	1	11,000	11,000	902,000	550,000	550,000	0	275,000	0	0	1,727,000
Construct Transition Vault	1	22,000	22,000	1,870,000	446,000	446,000	0	148,000	0	0	2,464,000
Ring Bus/Brkrs/Con Ed/Sub	1	32,000	32,000	3,024,000	650,000	650,000	12,500,000	480,000	0	0	16,654,000
Hi-Pot Testing	1	3,400	3,400	321,300	125,000	125,000	0	60,000	0	0	506,300
Concrete Work	1	8,000	8,000	680,000	300,000	300,000	0	85,000	0	0	1,065,000
Contractor Indirects/OH&P	1	7,600	7,600	718,200	0	0	0	0	0	3,825,000	4,543,200
345kV UG CABLE - NYC PIER 92 - 94 ENTRY FROM HUDSON RIVER TO CON EDISON 49TH STREET			152,440	13,697,080		4,390,000	12,500,000	2,446,000	400,000	3,825,000	37,258,080
SUBSTATION											
TOTAL DIRECT COSTS			1,121,427	89,407,555		69,404,500	90,130,000	12,931,000	16,785,000	29,567,000	308,225,055

INDIRECT COSTS											
Construction Management	1	16,500	16,500	1,485,000	0	0	0	0	0	14,750,000	16,235,000
Temporary Facilities/Utilities	1	7,470	7,470	672,300	0	0	0	0	0	1,975,000	2,647,300
Construction Equipment and Operators	1	12,600	12,600	1,134,000	0	0	0	3,475,000	0	0	4,609,000
Indirect Construction Services and Support	1	47,400	47,400	4,266,000	0	0	0	0	0	1,775,000	6,041,000
Insurance/Taxes/Permits/ Other	1	6,600	6,600	594,000	0	0	0	0	0	14,093,000	14,687,000
A/E Engineering	1	0	0	0	0	0	0	0	0	22,400,000	22,400,000

Start-Up and Testing	1	0	0	0	0	0	0	0	0	4,275,000	4,275,000
TOTAL INDIRECT COSTS			90,570	8,151,300	0	0	0	3,475,000	0	59,268,000	70,894,300
TOTAL DIRECT/INDIRECT			1,211,997	97,558,855		69,404,500	90,130,000	16,406,000	16,785,000	88,835,000	379,119,355
CONTRACTOR RISK & FEE										56,867,903	56,867,903
SUBTOTAL CONTR VALUE											435,987,258
CONTINGENCY										65,398,089	65,398,089
TOTAL EPC CONSTRUCTION			1,211,997	97,558,855		69,404,500	90,130,000	16,406,000	16,785,000	211,100,992	501,385,347

A.6 Combined Cycle

BURNS and ROE - CRA PROJECT FOR NYCEDC

500 MW COMBINED CYCLE POWER PLANT - STATEN ISLAND TO GOWANUS 345kV SUBSTATION - R 1

Description	Quant	Unit Hrs	Hours	Labor $	Unit Matl	Material	Major Equip	Const Equip	Subcontr.	Lump Sum	Total Cost
MECHANICAL EQUIPMENT											
Gas Turbine Gens. 165 MW	2	26,500	53,000	4,902,500	0	0	96,000,000	0	0	0	100,902,500
Steam Turbine Gen. 165 MW	1	28,700	28,700	2,654,750	0	0	49,500,000	0	0	0	52,154,750
HRSGs w/Stack	2	48,500	97,000	8,972,500	0	0	55,000,000	0	0	0	63,972,500
Condenser w/Stn. Stl. Tubes	1	3,200	3,200	296,000	0	0	4,300,000	0	0	0	4,596,000
Cooling Tower F&I - 10 Cell	1	0	0	0	0	0	0	0	5,600,000	0	5,600,000
Compressors - Gas	2	720	1,440	133,200	0	0	2,750,000	0	0	0	2,883,200
Compressors - Air	2	220	440	40,700	0	0	370,000	0	0	0	410,700

Fuel Gas Equipment	1	1,200	1,200	111,000	0	0	2,150,000	0	0	0	2,261,000
Exchangers/Separators	1	420	420	38,850	0	0	1,560,000	0	0	0	1,598,850
Water Treatment Equipment	1	2,100	2,100	194,250	0	0	1,650,000	0	0	0	1,844,250
BFD Pumps - 3,500 HP	4	400	1,600	148,000	0	0	4,780,000	0	0	0	4,928,000
Circulating Water Pumps	2	280	560	51,800	0	0	1,200,000	0	0	0	1,251,800
Condensate Pumps	3	160	480	44,400	0	0	375,000	0	0	0	419,400
Misc. Pumps	1	800	800	74,000	0	0	400,000	0	0	0	474,000
Misc. Equipment	1	1,200	1,200	111,000	0	0	1,750,000	0	0	0	1,861,000
Field Erected Tanks	1	0	0	0	0	0	0	0	2,500,000	0	2,500,000
Shop Fabricated Tanks	1	800	800	74,000	0	0	800,000	0	0	0	874,000
Ammonia System	1	400	400	37,000	0	0	450,000	0	0	0	487,000
Fire Pump House	1	280	280	25,900	0	0	390,000	0	0	0	415,900
Turbine Room OH Crane	1	360	360	33,300	0	0	425,000	0	0	0	458,300
Misc. Hoists	4	80	320	29,600	0	0	140,000	0	0	0	169,600

SUBTOTAL MECH. EQUIP.			194,300	17,972,750		0	223,990,000	0	8,100,000	0	250,062,750
ELECTRICAL EQUIPMENT											
Step-Up Transformers GTGs	2	900	1,800	166,500	0	0	7,300,000	0	0	0	7,466,500
Step-Up Transformer STG	1	900	900	83,250	0	0	3,650,000	0	0	0	3,733,250
Auxiliary Transformers	3	600	1,800	166,500	0	0	7,425,000	0	0	0	7,591,500
Misc. Transformers	1	400	400	37,000	0	0	900,000	0	0	0	937,000
4160V Switchgear	2	480	960	88,800	0	0	2,600,000	0	0	0	2,688,800
Iso Phase Bus	1	4,400	4,400	407,000	0	0	1,700,000	0	0	0	2,107,000
DCS	1	600	600	55,500	0	0	1,675,000	0	0	0	1,730,500
CEMS	2	480	960	88,800	0	0	700,000	0	0	0	788,800
UPS	1	240	240	22,200	0	0	165,000	0	0	0	187,200
Unit Substations	2	480	960	88,800	0	0	820,000	0	0	0	908,800

Motor Control Centers	1	1,200	1,200	111,000	0	0	950,000	0	0	0	1,061,000
480V Switchgear	1	280	280	25,900	0	0	600,000	0	0	0	625,900
345kV Breaker	1	600	600	55,500	0	0	575,000	0	0	0	630,500
Electrical Buildings	2	400	800	74,000	0	0	1,100,000	0	0	0	1,174,000
Misc. Electrical Equipment	1	1,200	1,200	111,000	0	0	750,000	0	0	0	861,000
Instrumentation and Controls	1	1,100	1,100	101,750	0	0	1,275,000	0	0	0	1,376,750
SUBTOTAL ELECT. EQUIP.			18,200	1,683,500		0	32,185,000	0	0	0	33,868,500
TOTAL MAJOR EQUIPMENT			212,500	19,656,250		0	256,175,000	0	8,100,000	0	283,931,250
CIVIL/STRUCTURAL											
SITE WORK											

Site Preparation	1	17,500	17,500	1,417,500	825,000	825,000	0	780,000	75,000	0	3,097,500
Site Clearing	1	11,500	11,500	931,500	0	0	0	455,000	110,000	0	1,496,500
Mass Earthwork	1	9,200	9,200	745,200	0	0	0	685,000	0	0	1,430,200
Mass Cut and Fill	1	16,500	16,500	1,336,500	1,250,000	1,250,000	0	1,425,000	0	0	4,011,500
Detention Pond/Drainage	1	950	950	76,950	0	0	0	75,000	0	0	151,950
Site Utilities	1	18,900	18,900	1,530,900	625,000	625,000	0	310,000	0	0	2,465,900
Erosion Control	1	4,800	4,800	388,800	105,000	105,000	0	35,000	0	0	528,800
Dewatering	1	4,320	4,320	349,920	0	0	0	31,000	0	0	380,920
Foundation Excav. & Backfill	1	7,500	7,500	607,500	280,000	280,000	0	315,000	0	0	1,202,500
Piling	1	0	0	0	0	0	0	0	7,350,000	0	7,350,000
Site Improvements	1	5,500	5,500	445,500	1,325,000	1,325,000	0	80,000	25,000	300,000	2,175,500
Paving and Surfacing	1	2,200	2,200	178,200	345,000	345,000	0	45,000	32,000	0	600,200
Landscaping	1	975	975	78,975	275,000	275,000	0	6,500	0	0	360,475

SUBTOTAL SITE WORK			99,845	8,087,445		5,030,000	0	4,242,500	7,592,000	300,000	25,251,945
FOUNDATIONS											
Steam Turbine Gen. Building	1	21,750	21,750	1,848,750	700,000	700,000	0	45,000	0	0	2,593,750
Equipment Foundations	1	93,500	93,500	7,947,500	3,475,000	3,475,000	0	155,000	0	0	11,577,500
Tank Foundations	1	9,400	9,400	799,000	145,000	145,000	0	4,000	0	0	948,000
Building Foundations	1	19,600	19,600	1,666,000	810,000	810,000	0	110,000	0	0	2,586,000
Elev 345kV Transformer Fnd.	1	7,500	7,500	637,500	335,000	335,000	0	35,000	0	0	1,007,500
345kV Breaker Foundation	1	2,200	2,200	187,000	80,000	80,000	0	1,500	0	0	268,500
Submarine Cable Speading	1	9,800	9,800	833,000	490,000	490,000	0	47,000	0	0	1,370,000
Area Vault											
SUBTOTAL			163,750	13,918,750		6,035,000	0	397,500	0	0	20,351,250

FOUNDATIONS											
MASONRY											
Building Masonry	1	12,000	12,000	984,000	310,000	310,000	0	38,000	0	0	1,332,000
SUBTOTAL MASONRY			12,000	984,000		310,000	0	38,000	0	0	1,332,000
METALS											
Steam Turbine Gen. Building	1	39,500	39,500	4,147,500	3,585,000	3,585,000	0	230,000	0	0	7,962,500
Administration/Control/	1	13,700	13,700	1,438,500	1,150,000	1,150,000	0	105,000	0	0	2,693,500
Maintenance Building											
Water Treatment/Misc Bldgs.	1	15,800	15,800	1,659,000	1,035,000	1,035,000	0	90,000	0	0	2,784,000

Equipment Support	1	14,800	14,800	1,554,000	1,875,000	1,875,000	0	110,000	0	0	3,539,000
SUBTOTAL METALS			83,800	8,799,000		7,645,000	0	535,000	0	0	16,979,000
MISCELLANEOUS CIVIL											
Wood and Plastics	1	950	950	82,650	18,500	18,500	0	0	0	0	101,150
Thermal/Moisture Protection	1	34,500	34,500	3,139,500	1,575,000	1,575,000	0	62,000	650,000	0	5,426,500
Doors and Windows	1	875	875	76,125	139,000	139,000	0	0	0	0	215,125
Finishes	1	33,300	33,300	2,264,400	465,000	465,000	0	0	345,000	0	3,074,400
Specialties	1	250	250	17,000	35,000	35,000	0	0	0	0	52,000
SUBTOTAL MISC. CIVIL			69,875	5,579,675		2,232,500	0	62,000	995,000	0	8,869,175
TOTAL			429,270	37,368,870		21,252,500	0	5,275,000	8,587,000	300,000	72,783,370

CIVIL/STRUCTURAL											
MECHANICAL											
Piping - Spec 2500	1	25,720	25,720	2,379,100	2,350,000	2,350,000	0	0	65,000	0	4,794,100
Piping - Spec 900	1	19,500	19,500	1,803,750	435,000	435,000	0	0	80,000	0	2,318,750
Piping - Spec 600	1	26,800	26,800	2,479,000	2,675,000	2,675,000	0	0	0	0	5,154,000
Piping - Spec 300	1	16,500	16,500	1,526,250	375,000	375,000	0	0	0	0	1,901,250
Piping - Spec 150	1	145,000	145,000	13,412,500	3,350,000	3,350,000	0	0	0	0	16,762,500
Piping - Spec 125	1	19,500	19,500	1,803,750	1,485,000	1,485,000	0	0	0	0	3,288,750
Pipe Hangers and Supports	1	24,500	24,500	2,266,250	3,275,000	3,275,000	0	0	0	0	5,541,250
Valves - Spec 2500	1	2,000	2,000	185,000	275,000	275,000	0	0	0	0	460,000
Valves - Spec 900	1	1,200	1,200	111,000	285,000	285,000	0	0	0	0	396,000
Valves - Spec 600	1	1,700	1,700	157,250	305,000	305,000	0	0	0	0	462,250
Valves - Spec 300	1	2,400	2,400	222,000	320,000	320,000	0	0	0	0	542,000

Valves - Spec 150	1	6,440	6,440	595,700	1,460,000	1,460,000	0	0	0	0	2,055,700
Valves - Spec 125	1	3,200	3,200	296,000	420,000	420,000	0	0	0	0	716,000
Flow Elements	1	500	500	46,250	245,000	245,000	0	0	0	0	291,250
Control Valves	1	4,500	4,500	416,250	1,375,000	1,375,000	0	0	0	0	1,791,250
Insulation	1	0	0	0	0	0	0	0	3,550,000	0	3,550,000
Fire Protection	1	0	0	0	0	0	0	0	1,775,000	0	1,775,000
Plumbing	1	0	0	0	0	0	0	0	285,000	0	285,000
HVAC	1	0	0	0	0	0	0	0	720,000	0	720,000
Miscellaneous Mechanical	1	5,200	5,200	481,000	0	0	0	0	240,000	0	721,000
SUBTOTAL MECHANICAL			304,660	28,181,050		18,630,000	0	0	6,715,000	0	53,526,050
TOTAL MECHANICAL			304,660	28,181,050		18,630,000	0	0	6,715,000	0	53,526,050
ELECTRICAL											

Raceways	1	48,000	48,000	4,536,000	1,450,000	1,450,000	0	0	0	0	5,986,000
Building Services	1	4,200	4,200	396,900	265,000	265,000	0	0	0	0	661,900
Conductors	1	46,800	46,800	4,422,600	2,620,000	2,620,000	0	0	0	0	7,042,600
Fire Detection	1	700	700	66,150	48,000	48,000	0	0	0	0	114,150
Site Lighting	1	3,200	3,200	302,400	170,000	170,000	0	0	0	0	472,400
Grounding	1	2,850	2,850	269,325	190,000	190,000	0	0	0	0	459,325
Electrical Heat Tracing	1	3,650	3,650	344,925	385,000	385,000	0	0	0	0	729,925
Electrical Indirect Costs	1	5,500	5,500	519,750	0	0	0	0	0	2,900,000	3,419,750
TOTAL ELECTRICAL			114,900	10,858,050		5,128,000	0	0	0	2,900,000	18,886,050
ELECTRICAL TRANSMISSION											
Transfer Cable to Barge	1	2,200	2,200	207,900	0	0	0	0	0	0	207,900

Marine Cable Cost Allowance	1	0	0	0	27,456,000	27,456,000	0	0	0	0	27,456,000
Subsurface Route Survey	1	3,200	3,200	302,400	0	0	0	0	0	0	302,400
QA/QC Cable	1	2,400	2,400	226,800	50,000	50,000	0	0	0	0	276,800
Construct 2 Wet Cofferdams	2	14,000	28,000	2,646,000	465,000	930,000	0	275,000	0	0	3,851,000
HDD Operations - 2 locations	2	5,400	10,800	1,020,600	80,000	160,000	0	240,000	0	0	1,420,600
Lay Marine Cable	1	28,800	28,800	2,721,600	304,000	304,000	0	4,600,000	0	0	7,625,600
All other Underwater Work	1	6,000	6,000	567,000	385,000	385,000	0	250,000	0	0	1,202,000
Marine Transfer Insurance	1	0	0	0	0	0	0	0	0	1,700,000	1,700,000
Pull Marine Cable Ashore	2	1,500	3,000	283,500	40,000	80,000	0	125,000	0	0	488,500
Manholes/Anchor Cable	2	6,500	13,000	1,228,500	310,000	620,000	0	90,000	0	0	1,938,500
Run Cores to Transition Stand	2	2,400	4,800	453,600	425,000	850,000	0	70,000	0	0	1,373,600
Grounding	1	2,900	2,900	274,050	165,000	165,000	0	55,000	0	0	494,050
Mandrill Ductbank	1	2,600	2,600	245,700	95,000	95,000	0	80,000	0	0	420,700

Pull Land-Based Cable	1	4,200	4,200	396,900	550,000	550,000	0	75,000	0	0	1,021,900
Terminate Land-Based	1	3,200	3,200	302,400	270,000	270,000	0	50,000	0	0	622,400
Cable at Gowanus Substa.											
Ring Bus/Breakers at	1	26,000	26,000	2,457,000	600,000	600,000	11,250,000	440,000	0	0	14,747,000
Gowanus Substation											
Hi-Pot Testing	1	2,700	2,700	255,150	125,000	125,000	0	60,000	0	0	440,150
Contractor Indirects/OH&P	1	33,600	33,600	3,175,200	0	0	0	0	5,946,000	0	9,121,200
TOTAL ELEC TRANSMISSION			177,400	16,764,300		32,640,000	11,250,000	6,410,000	5,946,000	1,700,000	74,710,300
INSTRUMENTS/CONTROLS											
Instrumentation Construction	1	18,000	18,000	1,701,000	150,000	150,000	0	0	0	0	1,851,000
Instrument Indirect Costs	1	2,000	2,000	189,000	0	0	0	0	0	425,000	614,000

TOTAL INSTRUMENTATION			20,000	1,890,000		150,000	0	0	0	425,000	2,465,000
TOTAL DIRECT COSTS			1,258,730	114,718,520		77,800,500	267,425,000	11,685,000	29,348,000	5,325,000	506,302,020
INDIRECT COSTS											
Construction Management	1	11,700	11,700	1,053,000	0	0	0	0	0	10,500,000	11,553,000
Temporary Facilities/Utilities	1	5,300	5,300	477,000	0	0	0	0	0	1,150,000	1,627,000
Construction Equipment and Operators	1	10,400	10,400	936,000	0	0	0	3,200,000	0	0	4,136,000

Indirect Construction Services and Support	1	36,400	36,400	3,276,000	0	0	0	0	0	1,200,000	4,476,000
Insurance/Taxes/Permits/ Other	1	4,800	4,800	432,000	0	0	0	0	0	12,250,000	12,682,000
A/E Engineering	1	0	0	0	0	0	0	0	0	16,500,000	16,500,000
Start-Up and Testing	1	0	0	0	0	0	0	0	0	3,200,000	3,200,000
TOTAL INDIRECT COSTS			68,600	6,174,000	0	0	0	3,200,000	0	44,800,000	54,174,000
TOTAL DIRECT/INDIRECT			1,327,330	120,892,520		77,800,500	267,425,000	14,885,000	29,348,000	50,125,000	560,476,020
CONTRACTOR RISK & FEE										84,071,403	84,071,403

SUBTOTAL CONTR VALUE											644,547,423
CONTINGENCY										51,563,794	51,563,794
TOTAL EPC CONSTRUCTION			1,327,330	120,892,520		77,800,500	267,425,000	14,885,000	29,348,000	185,760,197	696,111,217

A.7 LEEDS

BURNS and ROE - CRA PROJECT FOR NYCEDC

345kV TRANSMISSION LINE - 40 MILES LONG - LEEDS TO PLEASANT VALLEY

Description	Quant	Unit Hrs	Hours	Labor $	Unit Matl	Material	Major Equip	Const Equip	Subcontr.	Lump Sum	Total Cost
LEEDS INTERCONNECTION											
345 kV Circuit Breaker incld. associated DS and Bus	1	3,200	3,200	262,400	0	0	1,650,000	0	0	0	1,912,400
Tie-in to existing and install extension of 345kV Open Air Bus	1	2,200	2,200	180,400	0	0	1,050,000	0	0	0	1,230,400
Relay System Additions and Modifications	1	660	660	54,120	0	0	450,000	0	0	0	504,120
Revenue Metering/Control	1	1,100	1,100	90,200	0	0	775,000	0	0	0	865,200
System Modifications											
SCADA/NYISO Modifications	1	900	900	73,800	0	0	625,000	0	0	0	698,800

Fiber Optic Cables	2	800	1,600	131,200	65,000	130,000	0	0	0	0	261,200
Concrete Work	1	2,400	2,400	156,000	112,000	112,000	0	18,000	0	0	286,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	275,000	275,000
TOTAL LEEDS INTERCONNECTION			12,060	948,120		242,000	4,550,000	18,000	0	275,000	6,033,120
345kV AG/UG CABLE - LEEDS SUBSTATION TO PLEASANT VALLEY SUBSTATION											
Cable Shakeout along route	1	12,500	12,500	1,025,000	0	0	0	575,000	0	0	1,600,000
345kV Cable - Leeds Sub-Station to Pleasant Valley Substation	1	168,960	168,960	13,854,720	32,960,000	32,960,000	0	0	0	0	46,814,720
Conduit	1	4,000	4,000	328,000	68,000	68,000	0	21,000	0	0	417,000
HDD Operations - 3 locations	3	6,400	19,200	1,574,400	125,000	375,000	0	465,000	0	0	2,414,400
Tubular Towers Complete	365	360	131,400	10,774,800	75,000	27,375,000	0	1,702,500	0	0	39,852,300
Clear Greenfield	1	6,500	6,500	533,000	157,000	157,000	0	1,125,000	0	0	1,815,000

Construct Transition Vault	2	22,000	44,000	2,860,000	446,000	892,000	0	325,000	0	0	4,077,000
Concrete Work/Towers/Other	1	54,000	54,000	3,510,000	2,600,000	2,600,000	0	217,000	0	0	6,327,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	1,890,000	1,890,000
TOTAL 345kV AG/UG CABLE LEEDS SUBSTATION TO PLEASANT VALLEY SUBSTATION			440,560	34,459,920		64,427,000	0	4,430,500	0	1,890,000	105,207,420
PLEASANT VALLEY INTERCONNECTION											
345 kV Circuit Breaker incld. associated DS and Bus	1	3,200	3,200	262,400	0	0	1,650,000	0	0	0	1,912,400
Tie-in to existing and install extension of 345kV Open Air Bus	1	2,200	2,200	180,400	0	0	1,050,000	0	0	0	1,230,400
Relay System Additions and Modifications	1	660	660	54,120	0	0	450,000	0	0	0	504,120

Revenue Metering/Control System Modifications	1	1,100	1,100	90,200	0	0	775,000	0	0	0	865,200
SCADA/NYISO Modifications	1	900	900	73,800	0	0	625,000	0	0	0	698,800
Fiber Optic Cables	2	800	1,600	131,200	65,000	130,000	0	0	0	0	261,200
Concrete Work	1	2,400	2,400	156,000	112,000	112,000	0	18,000	0	0	286,000
Vendor Engineering/Design and Supervision	1	0	0	0	0	0	0	0	0	275,000	275,000
TOTAL PLEASANT VALLEY INTERCONNECT			12,060	948,120		242,000	4,550,000	18,000	0	275,000	6,033,120
TOTAL DIRECT COSTS			464,680	36,356,160		64,911,000	9,100,000	4,466,500	0	2,440,000	117,273,660
INDIRECT COSTS											
Construction Management	1	10,500	10,500	945,000	0	0	0	0	0	5,435,000	6,380,000

Temporary Facilities/Utilities	1	4,100	4,100	369,000	0	0	0	0	0	1,760,000	2,129,000
Construction Equipment and Operators	1	6,400	6,400	576,000	0	0	0	2,124,000	0	0	2,700,000
Indirect Construction Services and Support	1	24,950	24,950	2,245,500	0	0	0	0	0	1,894,000	4,139,500
Insurance/Taxes/Permits/ Other	1	4,780	4,780	430,200	0	0	0	0	0	6,675,000	7,105,200
A/E Engineering	1	0	0	0	0	0	0	0	0	6,800,000	6,800,000
Start-Up and Testing	1	0	0	0	0	0	0	0	0	2,235,000	2,235,000
TOTAL INDIRECT COSTS			50,730	4,565,700	0	0	0	2,124,000	0	24,799,000	31,488,700

TOTAL DIRECT/INDIRECT		515,410	40,921,860		64,911,000	9,100,000	6,590,500	0	27,239,000	148,762,360
CONTRACTOR RISK & FEE									22,314,354	22,314,354
SUBTOTAL CONTR VALUE										171,076,714
CONTINGENCY									20,529,206	20,529,206
TOTAL EPC CONSTRUCTION		515,410	40,921,860		64,911,000	9,100,000	6,590,500	0	70,082,560	191,605,920

APPENDIX B: THE NEW YORK STATE TRANSMISSION SYSTEM

The New York transmission system is divided into eleven load zones. Zones A through E occupy the western portion of the system, with a total projected 2008 summer peak demand of 9.9 GW and installed capacity of 14.3 GW. In general, these zones currently have a generation surplus. The eastern portion of the system north of New York City, zones F through I, has a projected summer peak demand of approximately 6.9 GW and installed capacity of 9.1 GW. Under peak load conditions, these zones must rely on imports from neighboring control areas. Zone J, New York City, accounts for 12.0 GW of summer peak demand and has 10.1 GW of installed capacity. Zone K, Long Island, has summer peak of 5.4 GW and its summer installed capacity amounts to 5.3 GW.

The generation capacity mix in zones A through E is 18% coal-fired, 11% oil-fired, 20% natural gas-fired, 21% nuclear, and 27% hydroelectric. Other technologies such as wind or refuse account for 3%.

The capacity mix in zones F through I is quite different. Coal accounts for 7% of capacity, oil for 14%, natural gas for 40%, nuclear for 22%, hydro for 16%, and other technologies for 1%.

Finally, the generation mix in New York City and Long Island is 49% oil-fired, 50% natural gas-fired, and 1% other technologies.

On a statewide level, approximately 63% of New York's internal capacity is gas-only, oil-only, or dual-fueled oil and gas as of 1 March 2008. Only 39% of the actual generation throughout 2007, however, came from those three sources. By contrast, nuclear and hydro resources—most of them located upstate, and all of them located outside New York City—supplied 45% of the energy generated in 2007, despite comprising only 27% of New York's capacity. Coal and other resources made up 10% of the capacity mix, but 16% of the generation mix.[37]

The imbalance in generation and loads among different subregions of the system and difference in the technological mixes of generation results, in general, in a predominant flow of power from West and North to East and South. Load zones are separated by major transmission interfaces:

[37] *Id.*, pp. 48-49.

Dysinger East separates zones A and B, West Central separates zones B and C, Volney East separates zones C and E, Moses South separates zones D and E, Central East separates zones E from zones F and G, UPNY/SENY separates zones C through F from zone G, UPNY-ConEdison separates zones G and H, Millwood South separates zones H and I, Dunwoodie South separates zone I from J and K. The NYISO system is interconnected with ISO New England in the East, PJM Interconnection in the West and South, and Hydro Quebec and Ontario in the North and Northwest.

APPENDIX C: MODEL DESCRIPTIONS

C.1 GE MAPS Model Description

GE-MAPS is a detailed economic dispatch and production-costing model for electricity networks. It was originally developed by General Electric and is currently used by over twenty major utilities and RTOs in the U.S. CRA has worked closely with General Electric to ensure that the model's data structures and functionality accurately reflect the competitive market.

GE-MAPS determines the least-cost secured dispatch of generating units to satisfy a given demand, on the assumption that the units are dispatched according to their variable costs. The major advantage of GE-MAPS is its ability to simulate the hourly operation of generating units and transmission systems (e.g., transformers, lines, phase shifters, busses) in significant detail. For example, it accurately represents capacity constraints, minimum up time limitations, and thermal constraints on the transfer capability of transmission lines, line and unit contingencies, and scheduling limitations of hydro-plants. Thus, GE-MAPS provides a highly accurate, detailed simulation of the hourly operation of the individual generating units and transmission system that constitute the wholesale market.

Among the key outputs of the GE-MAPS model is a set of Locational Marginal Prices (LMPs), computed for each bus in each hour, and a set of capacity prices for each relevant geographical market. Such a detailed representation of the physical part of power markets makes GE-MAPS an ideal tool for conducting a precise analysis of them.

C.1.1 Outputs

The outputs from GE-MAPS include key technical and economic parameters such as hourly generation levels, costs, revenues, profit margins, spot and average prices, and profitability indices. These characteristics are generated at the market-wide, transmission owner, and generating unit levels and on an hourly, daily, weekly, monthly, and annual basis.

C.1.2 System Representation in GE-MAPS

One of the major advantages of GE-MAPS is its ability to represent and simulate the operation of, the transmission system and individual generating units. Following is a list of the major inputs used to represent the market structure and physical system being modeled. The list is followed by a discussion of these components.

Market Assumptions

- Structure and Rules
- Boundaries
- Operating Reserves
- Bidding Behavior

Demand

- Load Inputs
- Dispatchable Demand (Non-Program Interruptible Load)

Supply

- Nuclear Units
- Conventional Hydro & Pumped Storage Units
- Thermal Units
- Planned Additions and Retirements
- NUG Contracts
- Imports and Exports
- Environmental Regulations
- Fuel Price Forecasts
- Transmission System

C.1.3 Market Assumptions

ISO/RTO Boundaries: The unit commitment, dispatch, and reserve requirements are maintained on a geographic basis using the existing and/or assumed ISO boundaries. The imports/exports among ISOs and between ISOs and neighboring systems reflect economy energy purchase/sales and incur wheeling charges. Transactions within the ISO boundary do not incur any transmission charge (we assumed selling/buying from the pool, and the load pays the transmission charge irrespective where it buys its energy from within the pool).

Operating Reserves (spinning and standby): The operating reserves are based on the specific requirements instituted by each ISO in the region. These requirements typically involve the loss of the largest single generator or the largest single generator and half the second largest generator. The spinning reserves market affects the energy market prices since the units that spin cannot produce electricity under normal conditions. The energy prices are typically higher when reserves markets are modeled.

Bidding Behavior: GE MAPS has a relatively simple bidding logic. Bids can be based either on variable generation costs or user-defined inputs. The latter is being used when bids are generated by COMPEL-21 to assess the impact of strategic bidding on the system.

C.1.4 Demand Assumptions

Load Inputs: GE MAPS takes load inputs on an hourly basis (8760 per year) for every load serving entity. Loads for future years are scaled based on a forecast of annual peak demand and energy. The models adjust the load profile in every year to account for the change in the day of the week at the start of every new year.

Dispatchable Demand (Interruptible Load): Representations of (existing) interruptible load to capture its impact on electricity prices are included. In the energy market, the value of energy to interruptible load caps the prices and the capacity of interruptible load works as installed reserves and lowers the capacity value.

C.1.5 Supply Assumptions

Nuclear Unit Analysis: A combination of market knowledge, the Nuclear Regulatory Commission’s (NRC) watch list, and economic performance as reflected in model runs is used to determine whether any nuclear units should retire prior to their license expiration. A four-year (94-97) average of O&M costs and revenue projections from model runs are used to assess units’ economic performance. Maintenance schedules and current outages posted on the NRC website and other public domain are also modeled.

Conventional Hydro and Pumped Storage Units: GE MAPS has special provisions for modeling hydro units based on seasonal patterns of water flow.

Thermal Unit Characteristics: GE MAPS model generation units in detail, in order to accurately simulate their operational characteristics and therefore project realistic hourly prices. These characteristics include:

- Unit type (steam, combined-cycle, combustion turbine, cogeneration, etc.)
- Heat rate values and curve
- Summer and winter capacity
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick start and spinning reserves capabilities
- Startup costs

Heat rate curves for different units were developed based on technology type and capacity.

Imports and Exports: To the extent important neighboring market regions are not fully modeled, they can be represented as the "outside world." The outside world is modeled as a series of representative loads or generating units. The thermal capacities of these representational units determine either the maximum export capability across tie lines, or the maximum generation capacity available for export from the outside area. Historic exports, combined with the expectation of future conditions in the areas of this outside world, are used to project export levels and prices for each of the forecast years.

NUG Contracts: Usually, Non-Utility Generation (NUG) units with long term contracts with the utilities are modeled as must-run units in the short term by assigning them a low fuel cost. The development of competitive markets, however, is assumed to result in the restructuring of these NUG contracts. Thus on a going forward basis, NUGs will be modeled as becoming fully dispatchable based on economics, just as any other unit.

Planned Additions and Retirements: Planned entry and retirements impact the fuel mix of installed capacity and composition of plants on the margin. New capacity addition in the near term future (the next two years or so) will be based only on existing projects in development or in advanced stages of permitting, as indicated by environmental permit applications and internal knowledge. In addition to known projects, new capacity will be added based on reliability criteria. That is, new capacity is entered as needed to satisfy the reliability requirements of each pool.

Planned and announced retirements are tracked from power pool load and capacity reports as well as trade press announcements.

Environmental Regulations: The impact of compliance with the NO_x budget and cap-and-trade program and SO_x emission adders is included in the modeling.

Fuel Price Forecasts: GE MAPS takes monthly fuel prices for all plants. Fuel-switching capability and the seasonality of fuel prices are modeled in order to accurately model dispatch behavior. The fundamental assumption of bidding behavior in competitive energy markets is that generators' variable cost are driven by the opportunity cost of fuel purchased (in addition to variable O&M and environmental adders), or the spot price of fuels at the closest location to the plant. Therefore, natural gas prices are first forecasted for the spot prices at regional hubs, and further refined based on historical differentials between pricing points around each hub. For oil estimates of the price delivered to generators on a regional basis is used. For coal generating unit specific forecasts is used.

Transmission System Representation: CRA is capable of modeling any transmission system in the US and Canada, including transformers, lines, phase shifters, and buses. Most data are provided in the form of a solved load flow case (PTI file). Potentially binding lines and interfaces are identified and monitored for the purpose of defining congestion zones.

Transmission Losses and Regional Wheeling Charges: The GE MAPS simulation accounts for transmission losses. GE MAPS offers the user a choice between accounting for losses on average basis or on the marginal basis. The wheeling charges for inter-ISO transactions are based on the ISOs' tariffs filed with FERC. Hourly point-to-point transmission service charges are used for modeling imports and exports.

C.1.6 Databases

The market simulations are based on up-to-date data from public and commercial sources. CRA maintains databases on:

Load: Historical electricity load data for all local service territories of the United States and Canada and load forecast scenarios developed by major forecasting institutions.

Fuel: Forecasts of fuel prices for specific generating units based on energy price forecasts from major forecasting institutions.

Generating Units: Physical, geographical, environmental, administrative, regulatory, and economic data for all existing generating units in the U.S. and Canada as well as for all generating units under development and proposed for development.

Transmission Systems: Physical, geographical, regulatory, and economic data for all existing transmission lines in the U.S. and Canada; constraints, contingencies, and significant interfaces within and across all regions of the Eastern Interconnect, Western Electricity Coordinating Council (WECC), and Electric Reliability Council Of Texas (ERCOT).

C.2 NEEM & MRN Model Description

CRA developed the North American Electricity and Environment Model (NEEM) to fill the need for a flexible model of the North American electric sector that simultaneously models system expansion and environmental compliance over a long-term planning horizon.

The model employs detailed unit-level information on all of the generating units in the United States and large portions of Canada. NEEM models the evolution of the North American power system over time, taking into account demand growth, available generation, and environmental technologies and environmental regulations both present and future. The North American interconnected power system is modeled as a set of regions (roughly similar to NERC regions and NERC sub-regions, but refined by known transmission constraints separating regions, and specified in the level of detail required for analysis) that are connected by a network of inter-regional transmission paths.

Environmental regulations and significant changes to the transmission system affect decisions about: (1) the mix and timing of new capacity, (2) retirement of existing units, (3) the mix and timing of environmental retrofits at existing facilities, (4) fuel choice, (5) dispatch of all units, (6) maintenance scheduling for all units, and (7) the flow of power among regions. NEEM captures all of these impacts in the process of optimizing responses of the electric sector to environmental policies.

NEEM minimizes—subject to the various constraints described above—the present value of total costs, including (1) fixed and variable non-fuel operating costs for all units, (2) fuel costs, (3) opportunity costs associated with the use of emission allowances, (4) the capital investments in new plants and retrofits at existing facilities, and (5) the cost of moving power between regions (wheeling charges).

NEEM has been designed to be a flexible model which can easily adapt to client requests such as different cost assumptions, regional breakouts, new generation technologies, and additional emissions constraints.

C.2.1 Model Outputs

The outputs from the model include detailed system-level and unit-level information. Key outputs include:

- Wholesale prices by region by load period (different load periods in each season)
- Allowance prices on each emission constraint
- Renewable energy certificate (REC) prices by state or region
- New capacity additions (by region, by model year, by generation technology)
- Retrofit additions and re-powering decisions (by unit and summarized by year)
- Fuel consumption (by unit and summarized by year)
- Annual emissions (by unit and summarized by year)
- Present value of system costs

C.2.2 Emission Constraints

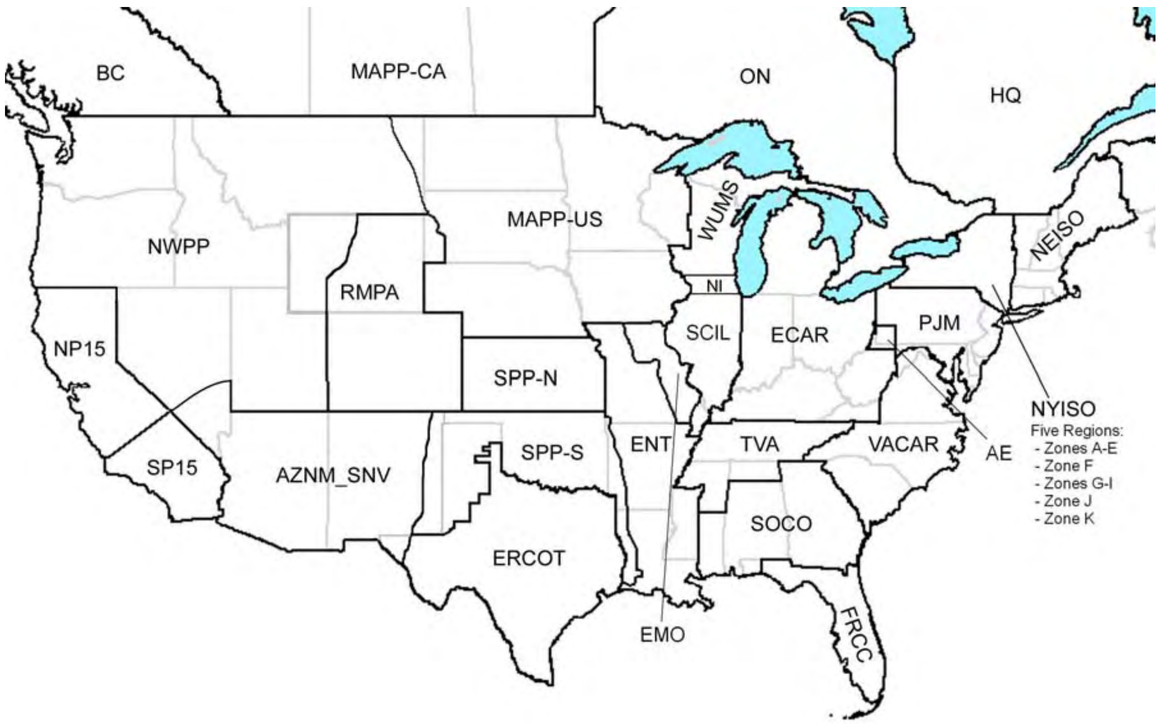
CRA's Base NEEM Model includes emission constraints (tonnage limits or rate limits), from existing US federal legislation and rules, including Title IV, NO_x SIP Call, CAIR, CAMR, and CAVR (Western Best Available Retrofit Technology). State caps are applied as relevant. Additional emissions constraints can be easily incorporated into the model. The model has been used to evaluate proposed legislation affecting the electric sector including further tightening of existing regulations and limitations on carbon emissions. In addition to being able to apply caps on emissions, the model also can apply allowance prices (sometimes referred to as taxes).

These inputs are completely flexible. Any set of units (including individual stations—"command and control") can be put under a tonnage or rate cap.

C.2.3 NEEM Geographical Structure

The NEEM model includes 28 US regions as shown in the graphical depiction of NEEM below as well as three Canadian regions (Ontario, Alberta and British Columbia).[38]

NEEM Regions



38 MAPP Canada is included in the current NEEM database, as is Hydro Quebec, but they are not modeled as interconnected regions. They are only modeled as supply sources for the US.

C.2.4 Generation Technologies

NEEM includes existing generation technologies including coal, combined cycle, gas/oil peakers and steam turbines, nuclear, hydroelectric, wind, and other renewable generating options. New plant technologies include many of the existing generation technologies as well as newer technologies such as IGCC and IGCC with carbon capture. The costs and characteristics of new generation technologies play a large role in determining which new units are built. The details of these assumptions can be modified easily, and new unit options can be added. NEEM allows restrictions to be imposed on the location, timing, and quantity of new generation that can be added.

Planned additions that have been previously announced and are likely to be built can be forced into the model. All other new capacity decisions are based on the economics of creating the lowest cost solution given the constraints.

Each unit that is greater than 200 MW is individually represented. Other types of units are aggregated together based on their region, fuel requirements, and existing control equipment. This reduces the problem size, which allows more years to be included in the analysis.

C.2.5 Fuel Costs and Options

A key input for each generation unit is the type of fuel burned, its efficiency (heat rate) and the cost of the fuel. Natural gas prices are determined for each unit, at a regional level by season and change each year. Other fuel cost inputs include distillate oil and residual oil.

Coal prices for each unit are determined from CRA's coal price model, described later in this section. The coal price for each unit reflects both mine cost and transportation cost. NEEM allows units to switch coals, based on economic criteria, and this is taken into account when NEEM considers retrofits.

C.2.6 Energy and Peak Demand

NEEM contains a forecast of energy demand by load segment for each of the 28 US regions. The base NEEM model includes ten load periods for the summer and five each for winter and shoulder periods. Additional load segments can be added. Peak demand is also forecast and is used in combination with reserve margins to determine the level of new capacity additions.

C.2.7 Emission Control Technologies

The model data include existing equipment for each unit, which determines the starting emission rates for each pollutant for each unit. Existing equipment that is tracked includes scrubbers, fabric filters, SCRs, SNCRs, and ESPs. This existing equipment is particularly relevant as it determines the level of mercury co-benefits that a unit will achieve. For each NO_x-emitting unit, the input data includes a NO_x emission rate, which is automatically adjusted if retrofits that reduce NO_x are added to the unit. The input data do not include explicit SO2 or mercury emission rates for each coal plant, as these are a function of the type of coal burned, as well as the existing equipment. Consequently, these emissions are calculated taking into account the fuel and existing equipment for a unit.

To comply with existing and new environmental rules there are a number of retrofit options available to coal units. These options include scrubbers, SCRs, SNCRs, and activated carbon injection. Additional retrofit technologies can be added as well. Planned retrofit decisions can be forced into the model. All other retrofit decisions are based on economics.

C.2.8 CRA's Coal Model

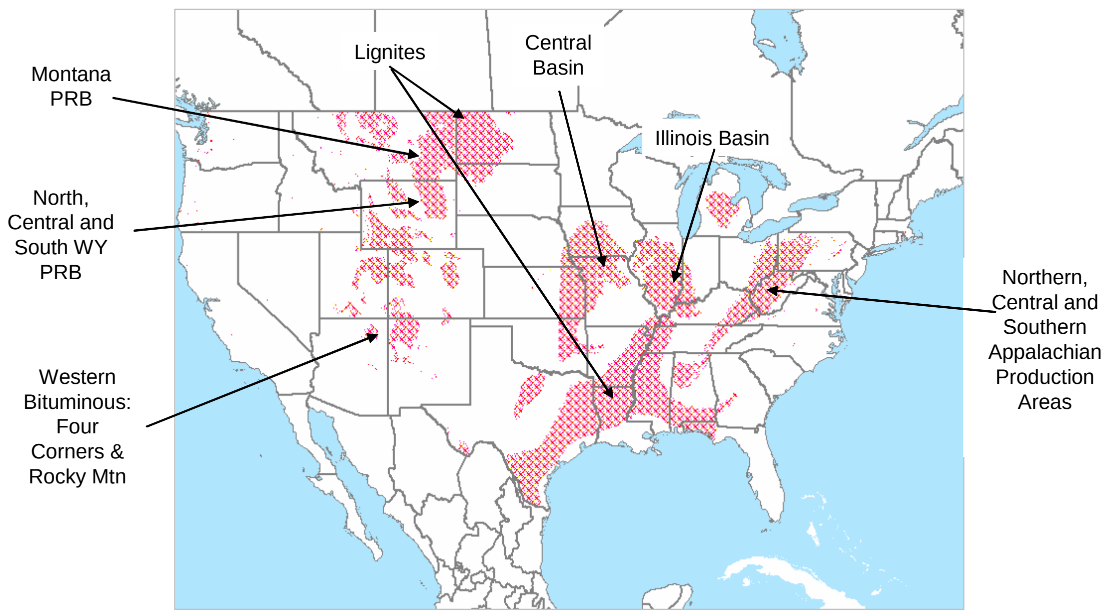
NEEM contains a detailed treatment of coal supply, with a representation of the supply curves for nineteen distinct coal types. These coal types represent permutations on the coal producing region, the coal's rank, BTU content, and sulphur content.

Units in the model choose between the coal options based on the coal's specification and the plant specific delivered price for each. Each of the supply curves is divided into tranches of tonnages, typically three to six; as demand rises, exhausting the annual supplies available at a given tranche, the market price for that coal rises accordingly.

The individual coal supply curves have been constructed using mine level cost and available tonnage information from some 1000 mines. Over time, the curves shift both with respect to tonnage available, and the cost of production. Tonnages are impacted by a combination of resource depletion and reserve and mine expansion; mine costs rise or fall over time due to region-specific changes in key input parameters such as productivity, labour costs, permitting, and other factors.

Coal transport cost assumptions to over 500 individual plants were derived from a detailed analysis of Platt's data on coal transactions. Transaction data were classified by mode, coal origin and plant. The mode-specific transport matrices—rail, tuck, barge, mixed—match plants to coals. The matrix values were derived from plant and mode specific data on transportation costs associated with past coal purchases. In cases where individual plant and units have no transaction history for a given coal, the matrix is populated with a mode/regional average transport cost assumption for that coal type. This matrix sets the menu of coal options from which each plant is allowed to choose and translates the FOB mine costs implicit in the supply curves into a delivered fuel cost.

NEEM Coal Supply



APPENDIX D: ANALYSIS ASSUMPTIONS

D.1 CONTOUR PLOT LEGENDS

Figure 32: Contour plot color key

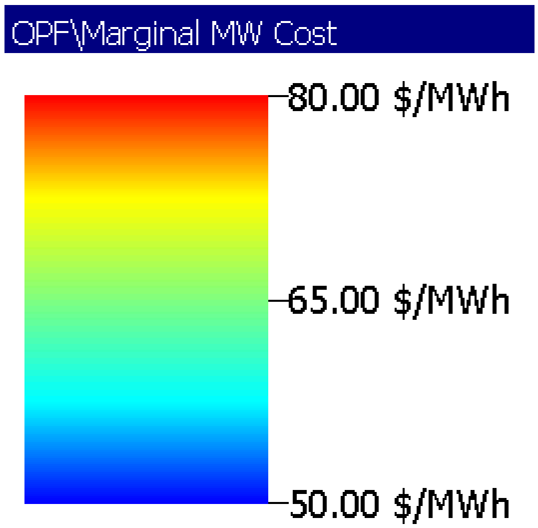
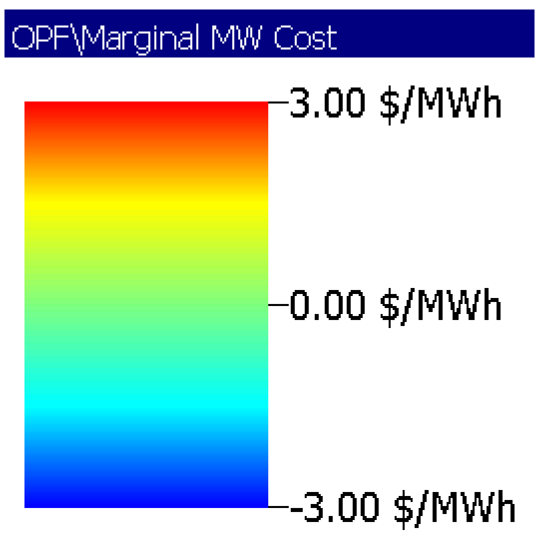


Figure 33: Contour plot color delta key



D.2 MISCELLANEOUS

D.2.1 Discount Rate & Inflation

Projects benefits were evaluated using a twenty-year timeframe, and a real discount rate of eight percent. Inflation was assumed to be 2.02 percent.

Projects were evaluated over a lifespan of twenty years. Because of the discounting effect of future-year benefits, the benefits later than twenty years are so discounted that they have a negligible effect on the overall answer. Evaluating projects over their projected lifespan (as opposed to a fixed timeframe) would make little difference in the overall benefits calculation.

D.2.2 Study Timeframe

The base year was 2013 for base LMP comparisons. The long-term study horizon will be 2013-2033.

D.2.3 Economic Market Model Assumptions

All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable permits). It is reasonable to assume that the real markets are not perfectly competitive and so the model tends to underestimate the prices in the real markets.

Installed capacity reserve requirements are set at a percentage of forecast peak load for each NERC region or sub-region, as shown in the table below. CRA adds capacity to ensure that each region meets the installed capacity target indicated by these requirements.

Pool	Fraction
NEPOOL	115%
NYPP	116.5%
Long Island	94%
New York City	80%
MAAC	117%
ECAR	117%
MAIN	117%
MAPP	115%
SPP	115%
Entergy	115%
Southern	115%
TVA	115%
VACAR	115%
FRCC	115%
Ontario	118%

CRA uses hurdle rates for all flows (transactions) between various ISOs. These hurdle rates simulate both existing wheeling rates and market inefficiencies associated with inter-ISO transactions. All hurdle rates are set at $2/MWh in each direction in dispatch, except as documented in the table below.

From	To	Dispatch
ISO-NE	NYISO	$4
NYISO	ISO-NE	$6
PJM	NYISO	$1
NYISO	PJM	$6
ONTARIO	NYISO	$1
NYISO	ONTARIO	$3
PJM	MISO	$0
MISO	PJM	$0
ONTARIO	MISO	$1

Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled. The table below shows a list of operating reserves by reliability region, and the fraction met by spinning reserves. The remainder is assumed to be met by quick start reserves.

ISO/Region	Operating Reserve	% Met by Spin
ISO-NE	1,320 MW	40%
NYISO	1,200 MW	50%
Eastern NY	1,200 MW	25%
Long Island	120 MW	50%
Midwest ISO (Reserve Sharing group)	2250MW	65%
SPP	1,746 MW	50%
Entergy	4% of load	65%

Southern	4% of load	65%
TVA	4% of load	65%
VACAR	4% of load	65%
FRCC	853 MW	65%
Ontario	880 MW	55%
PJM (MAAC)	1700 MW and 1% of load	75%
PJM (West)	4% of load	63%
PJM (Virginia)	431 MW and 1% of load	35%
PJM (ComEd)	647 MW	62%

D.2.4 Environmental Regulations

D.2.5 Relations

CRA models NO_x and SO_2 emission rates for all units where such data are available. In addition, CRA models compliance with various allowance trading programs and attempts to capture the effect of future environmental regulations. All plant emission rates are drawn from the Emissions Scorecard published by the U.S. Environmental Protection Agency. Allowance price forecasts were derived from NEEM[39].

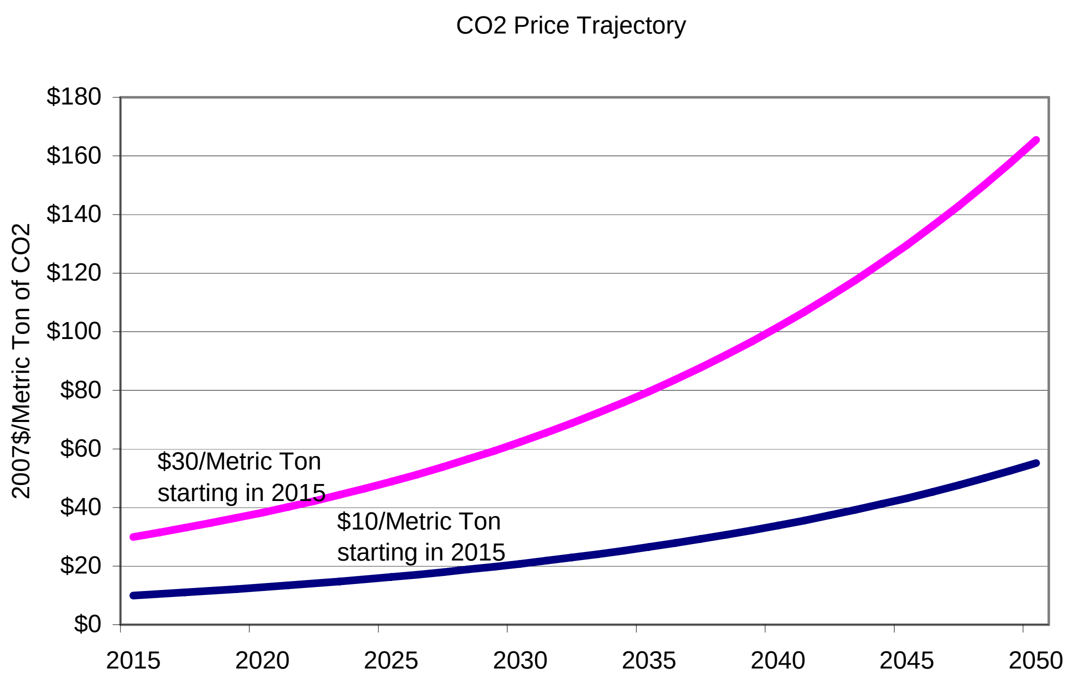
We assume that RGGI will go into effect in 2009 for affected states and be superseded by a national, mandatory cap-and-trade system. We assume that RGGI permit prices start at a value of $2.94 per short ton and grow at 5% per annum in real terms until a mandatory national regime starts in 2015. For 2013 the value used was $3.34.

CRA will model two different price trajectories for potential carbon costs imposed by potential trading regimes. These trajectories are *roughly* equivalent to what prices might be for a McCain-Lieberman-Obama or Bingaman bill. We assume that all credits are purchased by generators, with no free initial allocations.

[39] Emission rates (allowance prices) for the near future for NOx and SO_2 are obtained from industry futures, in particular those published by the Evolution Markets Brokerage.

The base case for our analysis will be the higher of the two trajectories listed below. The starting price of approximately $30 per metric ton starting in 2015 largely mirrors current consensus estimates used in the industry today.

Figure 34: Carbon Credit Price Forecast



D.2.6 Installed Capacity Market

We have employed the following assumptions for the capacity market analysis

- Local Sourcing Requirement for Zone J remains at 80% of peak load
- Load forecast per Draft 2009 RNA
- 2010/11 Price at demand curve reference level ($15.99) escalated at assumed inflation rate of 2.3 percent.
    - 2012/13: $16.73/kW-month
    - 2013/14: $17.12/kW-month

- Summer Special Case Resources assumed to total 622 MW summer, 435 MW winter (ICAP)
- Average EFORd of 3.88 percent

We have assumed that capacity purchased in PJM is purchased at the PJM CONE of $235/MW-day and escalates at the level of inflation.

D.2.7 NYC non-LBMP supply

Table 78 shows our assumptions for the TCCs held by NYC LSEs. We verified this list with our project stakeholders. We assumed that the TCCs were 90% feasible.

Table 78: TCCs assumed for NYC benefit calculation

TCC Value	(MW)
G	228
G	6
A	4
C	20
G	800
F	250
I	10
I	114
A	600
G	2220
H	797
Total	4,551

Table 79 shows our assumptions for the portion of generation owned by NYC LSEs. We did not have access to the terms of every contract held by ConEdison or NYPA, and so adopted a simplified approach in which a fixed portion of each unit's output was owned by the LSEs.

Table 79: LSE resources assumed for NYC benefit calculation

Unit Name	Zone	LSE Share
59St.GT1	J	1.00
74St.GT1	J	1.00
74St.GT2	J	1.00
Brooklyn Navy Yard	J	1.00
East River1	J	1.00
East River2	J	1.00
East River6	J	1.00
East River7	J	1.00
Gowanus 5 (23rdSt/Seymour	J	1.00
Gowanus 6 (23rdSt/Seymour	J	1.00
Harlem River 1	J	1.00
Harlem River 2	J	1.00
Hellgate 1	J	1.00
Hellgate 2	J	1.00
Hudson Ave 3	J	1.00
Hudson Ave 4	J	1.00
Hudson Ave 5	J	1.00
Indeck-Corinth	F	1.00
Independence CC1	C	0.75
Independence CC2	C	0.75
IndianPt3	C	0.20
Kent (North 1st)	J	1.00
Linden Cogen	J	1.00
Poletti (NYPA Astoria)	J	1.00
Poletti 1	J	1.00
Pouch	J	1.00

Selkirk-2	F	1.00
Vernon Blvd 2	J	1.00
Vernon Blvd 3	J	1.00
Ashokan 1&2	G	1.00
Crescent 1-4	F	1.00
Vischer Ferry 1-4	F	1.00
Zone G Small Hydro	H	1.00
Blenheim 1-4	F	0.25

D.3 TRANSMISSION SYSTEM CONFIGURATION

We used ERAG power flow cases from 2009 to 2013 provided by the NYISO, which incorporate the most recent information regarding adjoining regions, in particular PJM.

In addition to constraints provided by the NYISO, CRA updated New York constraints from the following sources.[40]

- 2005 Intermediate Area Transmission Review of the New York State Bulk Power Transmission System (Study Year 2010)
- NYISO Operating Study Summer 2006
- New York actual and historical flow data from NYISO website.
- All lines listed in the NYISO Operating Study Summer 2007 above 100kV were included in the model. For non-NY constraints monitored for their thermal limit violations, their limits are updated with respect to the MMWG 2010 loadflow to reflect the transmission upgrades. For constraints enforced for the stability purposes, their limits remain the same as the current values.

We filtered out non-significant constraints that are outside of the focus area of study. For this study, all non-duplicate constraints from the

[40] Occasionally these sources would contain contradicting information, such as variation in interface limits.. CRA discussed these issues with stakeholder personnel to verify the most appropriate limits.

abovementioned sources within the NYCA were included. For other study areas, constraints were included if

- The constraint was binding in the 2006 DOE study conducted by CRA
- The constraint's monitored-facility nominal voltage level is at 500kV or above

Some major New York transmission projects (note that this is not a complete list) that will be included in CRA's base case include:

- ConEdison M-29 (2011)
- Linden VFT (2009)
- Millwood capacitor banks (2008)

Note that the Athens SPS protection scheme will be phased out in 2011 as per the current agreement with National Grid and the assumptions employed by the NYISO in its modeling.

We do not model transmission line de-ratings or outages in this analysis. While these do occur in practice, we have determined through consultation with stakeholders that they do not warrant inclusion.

D.3.1 New York Transmission Interface Limits

While we monitor individual constraints in its market simulation using GE MAPS, we also monitor interface limits in parallel. Interface limits may represent voltage stability constraints not fully addressed by monitoring constraints in the power flow cases. The following table represents our list of New York interface limits and their sources

Interface	Limit (MW)
Dysinger East	2,850
West Central	2,250
Volney East	None
Moses South	2,900
Central East	2700.
Total East	6,500
UPNY-SENY	None

UPNY-ConEdison	5,100
Millwood South	None
Dunwoodie South	4,350
ConEdison - LIPA	900
LIPA - ConEdison Wheel	280˙300

These limits were developed in consultation with stakeholders (especially the NYISO and ConEdison) with their input and approval.

D.4 LOAD AND ENERGY FORECASTS

Load and energy forecasts for the NYCA were taken from the 2009 RNA. Load and Energy Forecasts for PJM were taken from PJM's 2008 Load Forecast Report.

Table 80: Forecast of Coincident Summer Peak Demand by Zone—MW

Year	2013	2014	2015	2016	2017	2018
A	16,287	16,375	16,436	16,532	16,615	16,689
B	10,210	10,323	10,410	10,519	10,615	10,703
C	17,102	17,219	17,311	17,418	17,464	17,507
D	7,178	7,192	7,176	7,185	7,171	7,187
E	8,127	8,171	8,202	8,228	8,238	8,244
F	12,160	12,257	12,355	12,487	12,621	12,757
G	11,382	11,496	11,566	11,656	11,757	11,827
H	2,871	2,884	2,903	2,928	2,954	2,985
I	6,593	6,586	6,595	6,607	6,638	6,680
J	58,358	59,430	60,353	61,628	62,083	62,569
K	22,888	22,866	22,870	23,062	23,127	23,278
NYCA	173,158	174,799	176,176	178,250	179,283	180,427

Table 81: Forecast of Coincident Winter Peak Demand by Zone—MW

Year	2013	2014	2015	2016	2017	2018
A	2,690	2,705	2,715	2,731	2,744	2,757
B	1,958	1,979	1,996	2,017	2,035	2,052
C	2,894	2,914	2,930	2,948	2,956	2,963
D	856	858	856	857	855	857
E	1,404	1,412	1,417	1,421	1,423	1,424
F	2,347	2,366	2,385	2,410	2,436	2,462
G	2,425	2,450	2,465	2,484	2,505	2,520
H	669	668	671	675	681	688
I	1,567	1,557	1,554	1,554	1,562	1,571
J	12,537	12,627	12,683	12,787	12,879	12,980
K	5,377	5,370	5,358	5,374	5,354	5,383
NYCA	34,725	34,905	35,029	35,258	35,430	35,658

Table 82: Forecast of Coincident Winter Peak Demand by Zone—MW

Year	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
A	2,357	2,368	2,381	2,390	2,404	2,416	2,427
B	1,546	1,554	1,571	1,584	1,601	1,616	1,629
C	2,646	2,656	2,674	2,689	2,705	2,712	2,719
D	996	999	1,001	999	1,000	998	1,001
E	1,363	1,364	1,372	1,377	1,381	1,383	1,384
F	1,901	1,915	1,930	1,945	1,966	1,987	2,009
G	1,772	1,785	1,803	1,814	1,828	1,844	1,855
H	548	556	558	562	566	572	578
I	943	947	946	947	949	953	959
J	8,257	8,380	8,534	8,666	8,849	8,915	8,985
K	3,735	3,718	3,702	3,688	3,685	3,687	3,687

NYCA	26,064	26,243	26,472	26,661	26,935	27,083	27,231

Table 83: Forecast of Non-Coincident Summer Peak Demand by Zone

Year	2013	2014	2015	2016	2017	2018
A	2,770	2,785	2,796	2,812	2,826	2,839
B	2,022	2,045	2,062	2,084	2,103	2,120
C	2,957	2,977	2,993	3,012	3,020	3,027
D	931	933	931	932	930	933
E	1,459	1,467	1,472	1,477	1,479	1,480
F	2,403	2,422	2,441	2,467	2,494	2,521
G	2,452	2,476	2,491	2,511	2,532	2,548
H	697	697	700	704	710	718
I	1,583	1,572	1,570	1,570	1,577	1,587
J	12,537	12,627	12,683	12,787	12,879	12,980
K	5,444	5,438	5,427	5,443	5,424	5,454

Table 84: Forecast of Non-Coincident Winter Peak Demand by Zone

Year	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
A	2,371	2,382	2,395	2,404	2,418	2,430	2,441
B	1,553	1,562	1,579	1,592	1,609	1,624	1,637
C	2,698	2,708	2,727	2,742	2,759	2,766	2,773
D	1,026	1,029	1,031	1,029	1,030	1,028	1,031
E	1,373	1,374	1,382	1,387	1,392	1,393	1,394
F	1,976	1,990	2,006	2,022	2,043	2,065	2,087
G	1,779	1,791	1,809	1,820	1,835	1,850	1,861
H	599	607	610	615	619	625	633
I	990	995	993	995	996	1,001	1,007

J	8,335	8,459	8,614	8,748	8,932	8,998	9,069
K	3,779	3,761	3,745	3,730	3,728	3,729	3,730

For other regions, CRA uses the latest load forecast data available for each company within the study region, typically taken from the FERC Form 714, EIA 411, or equivalent publications.

Figure 35: Comparison of 2009 RNA and 2008 Gold Book forecasts for NYC

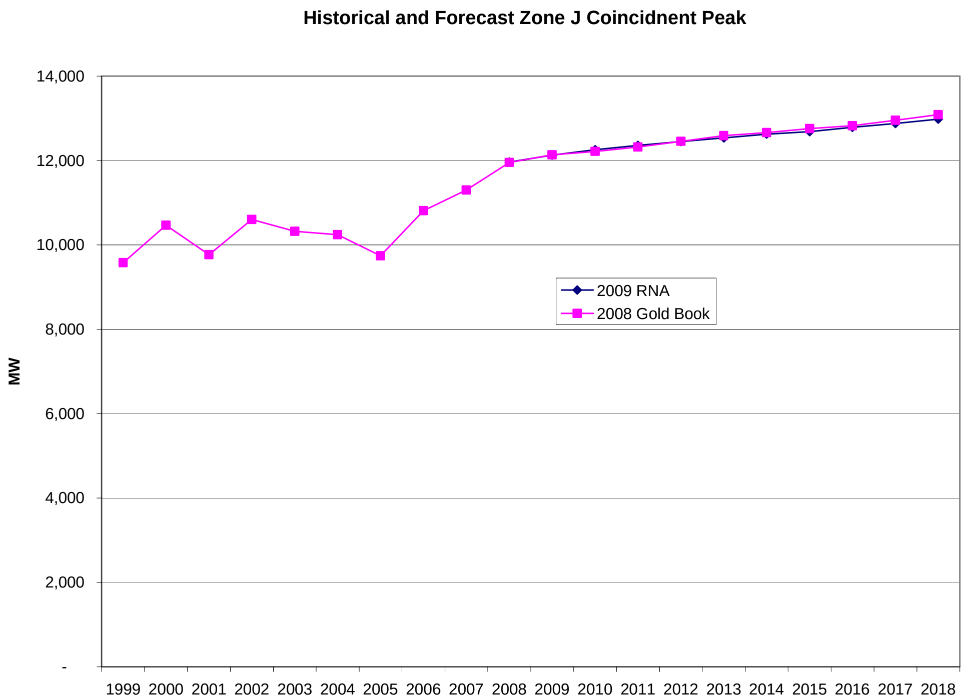
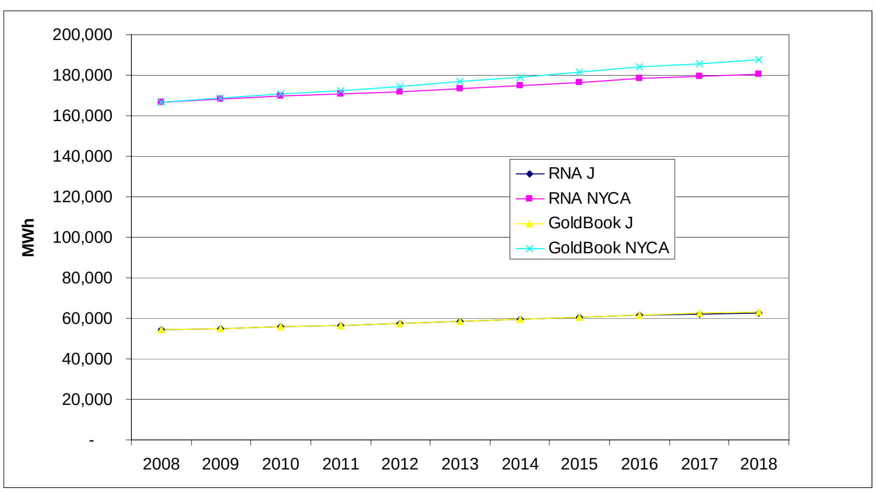


Figure 36: Comparison of energy forecasts for NYCA and NYC



For years beyond which each load forecast specifies values (2018 and 2023 for NYISO and PJM respectively), CRA will extrapolate a growth rate from the final three years of each forecast.

Load shapes are drawn from hourly actual demand for 2002[41], as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions. These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used to develop a complete load shape by area for each forecast year.

Shortly before this study was completed, PJM published their most recent 2009 load forecast that showed significant decreases in demand growth rate. Because of the Hudson project's sensitivity to demand in PJM, a special one-off scenario using this load forecast was analyzed using GE MAPS.

D.5 RESOURCE CONFIGURATION

D.5.1 Thermal Unit Configuration

CRA uses GE MAPS to run a detailed model of thermal generation, in order to accurately simulate operational characteristics, and project realistic hourly dispatch and prices. Characteristics include unit type, unit fuel type, heat rate values and shape (based on unit technology), summer and winter capacities, fixed and variable non-fuel operation and maintenance costs, startup fuel usage, forced and planned outage rates, minimum up and down times, and quick start and spinning reserve capabilities.

The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) database, which contains unit type, fuel type (primary and secondary), and capacity data for existing units. Heat rate data is drawn from prior ES&D databases where available. For newer plants, heat rates are based on industry averages for the technology of the unit.

The NERC Generation Availability Data System (GADS) 2003 database, released January 2005, is the source for forced and planned outage rates, based on plant type, size, and vintage. Fixed and variable operation and maintenance costs are estimates based on plant size, technology, and age. These estimates are supplemented by FERC Form 1 submissions

[41] 2002 was the most recent year with data considered to be relatively normal.. 2003 data included the August black out, 2004 was an atypical year with a mild summer and severe winter resulting with low summer load and record winter load, and 2005 data included the numerous hurricanes, including Katrina.

where available. The FOM values include an estimate of $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

In certain cases, CRA has additional information regarding the operation of certain generating assets, obtained from various public and industry sources. Where appropriate, CRA updates its database with this information.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

D.5.2 Nuclear Unit Configuration

CRA assumes that nuclear plants run when available, and that they have minimum up and down times of one week. Forced outage rates for each unit are drawn from the Energy Central database of unit outages. Nuclear plants do not contribute to quick-start or spinning reserves. The model includes refueling and maintenance outages for each nuclear plant. In the near future, outages posted on the NRC website or announced in the trade press are included. For later years, refueling outages are projected on the basis of the refueling cycle, typical outage length, and last known outage dates of each plant. Since these facilities are treated as must run units, CRA does not specifically model their cost structure. Within the timeframe of this study, no nuclear retirements are applied.

Note that the 95MW upgrade of Ginna are included in our base case. Indian Point is assumed to stay online in our base case past its 2013 and 2015 license renewals.

D.5.3 Hydro Unit Configuration

GE MAPS has special provisions for modeling hydro units. For conventional or pondage units, a monthly pattern of water flow (i.e., the minimum and maximum generating capability and the total energy for each plant in each month) is specified. For pumped storage units, the maximum generating and pumping capability of the plant is specified. For both types of hydro resource, CRA assumes that the plant is able to provide spinning reserves of up to 50% of plant capacity. Plant capacity data is drawn from the NERC ES&D database and the General Electric generating unit database. Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992 to 1998.

Hydro-Quebec imports into New York will be modeled as a price-sensitive supply as per individual discussions with stakeholders. The precise configuration of this supply curve is still under discussion and will be released to the stakeholder group as soon as it is finalized.

D.5.4 Renewable Resources

It is difficult to predict exact operational patterns of wind and solar generators, since these are dependent on weather and ambient conditions. Wind resources are with a 30% annual capacity factor and $1/MWh dispatch cost. Solar generators are run at 24% annual capacity factor and restricted to daytime hours. Our base-case assumptions regarding the additions of renewable resources are contained in the appendix.

D.5.5 Interruptible Load

The presence of demand response is important to energy and installed capacity prices. The value of energy to interruptible loads caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. CRA uses values for interruptible load and demand side management reduction in peak, as reported by the various Independent System Operators and reliability regions in the EIA-411 and other equivalent annual forecasts. This dispatchable demand is spread among load areas based on their load share of the total system load (unless there is more detailed data available). Following discussions with stakeholders, the dispatchable demand has been implemented as generators with a dispatch price of $600/MWh for the first block (50% of area dispatchable demand) and $800/MWh for the second block. These units rarely run, as the high prices they require indicate a supply shortfall and prompt economic new entry; dispatchable demand plays an insignificant direct role in the energy market.

D.5.6 Capacity Additions and Retirements

The governing document for the units online in 2013 is the 2008 ERAG Powerflow case for 2013 as provided by the NYISO and commented upon by other stakeholders.

Where information from the power flow case is not available, the initial set for new entry is based on existing projects in development and on projects with signed interconnection agreements as of June 2008. For the study, CRA will add capacity based on economic and/or reliability criteria with the use of the CRA's NEEM model. Capacity additions are made such that each capacity region complies with its specified reserve margin. The table below indicates capacity additions within the NYCA and PJM that will be modeled in our study.

Details of renewable capacity additions to meet New York State's RPS are included in the Appendix.

D.5.7 Capacity Additions

Table 85: Major NYCA Capacity Additions

Year	Unit Additions	Type	Zone	MW (Summer ICAP)
2007	Wind	Wind	A-E	23
2007	Maple Ridge Wind 1&2	Wind	F	32
2008	Wind	Wind	A-E	116
2009	Wind	Wind	A-E	75
2010	Besicorp	CC	F	563
2010	Jericho Rise Wind Farm	Wind	E	8
2009	Caithness	CC	K	350
2011	SCS Astoria CC2	CC	J	550

D.5.8 Capacity Retirements

Table 86: Major NYCA Capacity Retirements

Year	Unit Retirements	Type	Zone	MW
2010	Poletti 1	ST	J	891
2013	Astoria GT (05, 07, 08, 10, 11, 12, 13)	GT	J	124
2007	Ogdensburg	CC	E	77
2007	Russell 1 – 4	ST	B	237

2008	Onondaga County	ST	C	32
2008	Lovett 3	ST	G	57
2008	Lovett 5	ST	G	188

D.5.9 External Region Supply

CRA explicitly models the US portion of the Eastern Interconnect and the Canadian provinces of Ontario and New Brunswick. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas, to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from Hydro Quebec to Ontario are modeled as scheduled flows, based on 12 months of historical data. Hydro Quebec ties to New York and New England are currently modeled as price sensitive supply curves.

The DC ties with the WECC and ERCOT interconnections are modeled as price sensitive supply curves. CRA uses historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. These heat rates are multiplied by the appropriate forecast gas price in each scenario to arrive at a price points for each DC tie. The tie is then modeled as follows:

- When the locational price at the DC tie is within ± $2.50/MWh of the corresponding price point, zero flow is assumed on the tie.
- At locational prices that are between $2.50/MWh and $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at full capacity.
- At locational prices that are between $2.50/MWh and $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at full capacity.

D.5.10 New Unit Assumptions for NEEM

CRA's NEEM model adds new capacity to each region when mandated by the capacity margin and warranted by economic forces, subject to certain constraints. The table below indicates the capital costs for new capacity added by CRA's capacity expansion model.

Table 87: New Fossil and Nuclear Unit Assumptions for NEEM

	SCPC	IGCC	IGCC w/ CCS	Nuclear	CT F-frame	CC F-frame	CC H-frame
2015 Capex ($/kW)	2,982	3,583	N/A	N/A	852	906	N/A
2020 Capex ($/kW)	2,625	3,215	4,716	4,042	794	N/A	892
2025 Capex ($/kW)	2,269	2,908	4,265	3,662	735	N/A	892
2030 Capex ($/kW)	1,912	2,201	3,229	3,282	677	N/A	892
Heat Rate (Btu/kWh)	8,844	8,662	9,713	10,400	10,842	7,000	6,650
FOM ($/kW-y)	41.31	51.86	61.20	110.41	16.07	17.92	17.17
VOM ($/MWh)	4.35	2.76	4.20	0.47	3.01	1.96	1.89

Table 88: New Unit Assumptions: Natural Gas CCs and CTs in NY

	NYC		LIPA		Rest of NY	
	CC (2008$/kW)	CT ($2008/kW)	CC (2008$/kW)	CT ($2008/kW)	CC (2008$/kW)	CT ($2008/kW)
2010	2,241	1,576	2,123	1,492	1,073	684
2015	1,979	1,392	1,875	1,318	948	604

2018	1,947	1,369	1,845	1,297	933	594
2020	1,947	1,369	1,845	1,297	933	594
2025	1,947	1,369	1,845	1,297	933	594
2030	1,947	1,369	1,845	1,297	933	594

Table 89: New Unit Assumptions: Generic Costs and Performance of Renewables

	Biomass	Landfill Gas	Wind – Land	Wind – Complex Terrain	Wind Offshore	Geothermal	PV	Solar Thermal
2015 Capex ($/kW)	4,816	2,770	2,102	3,364	4,051	5,454	6,188	4,816
2020 Capex ($/kW)	5,015	2,688	2,046	3,274	3,943	4,759	5,249	4,816
2025 Capex ($/kW)	4,536	2,606	2,046	3,274	3,943	4,064	4,309	4,816
2030 Capex ($/kW)	3,435	2,524	2,046	3,274	3,943	3,369	3,369	4,816
FOM ($/kW-y)	80.47	108.25	28.71	28.71	28.71	78.04	11.07	53.80
VOM ($/MWh)	6.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A

In addition, NEEM assumes different construction costs for each region based on historical data. These regional cost multipliers are listed below:

Table 90: New Unit Regional Multipliers for NEEM

NEEM Region	EMM Region	Multiplier
AE	MAAC	1.06
AZ_NM_SNV_Coal	RA	1.04
AZ_NM_SNV_Gas	RA	1.04
AZ_NM_SNV_NucRenew	RA	1.04
ECAR	MAPP, ECAR, MAIN	1.06
EMO	MAPP, ECAR, MAIN	1.06
ENT	STV	1.01
ERCOT	ERCOT	1.01
FRCC	FL	1.00
MAPP_US	MAPP, ECAR, MAIN	1.07
NEISO	NE, NY	1.07
NI	MAPP, ECAR, MAIN	1.06
NP15	CNV	1.10
NWPP_Coal	NWP	1.10
NWPP_Gas	NWP	1.10
NWPP_NucRenew	NWP	1.10
NYISO_Upstate	NE, NY	See Above
NYISO_Downstate	NE, NY	See Above
NYISO_Capital	NE, NY	See Above
NYISO_NYC	NE, NY	See Above
NYISO_LIPA	NE, NY	See Above
PJM	MAAC	1.13
PJM_E	MAAC	1.13
PJM_SW	MAAC	1.00
PJM_W	MAAC	1.13
RMPA	RA	1.04

SCIL	MAPP, ECAR, MAIN	1.06
SOCO	STV	1.00
SP15	CNV	1.10
SPP_N	SPP	1.07
SPP_S	SPP	1.01
TVA	STV	1.00
VACAR	STV	1.00
WUMS	MAPP, ECAR, MAIN	1.06
ALB		1.04
BC		1.10
HQ		1.07
MAPP_CA		1.07
OH		1.10

Renewable Addition Assumptions

Section D.5.6 lists additions and retirements in New York necessary to comply with RPS regulations; we have assumed that there is full compliance with Main Tier MWh targets.

D.6 FUEL PRICE FORECASTS

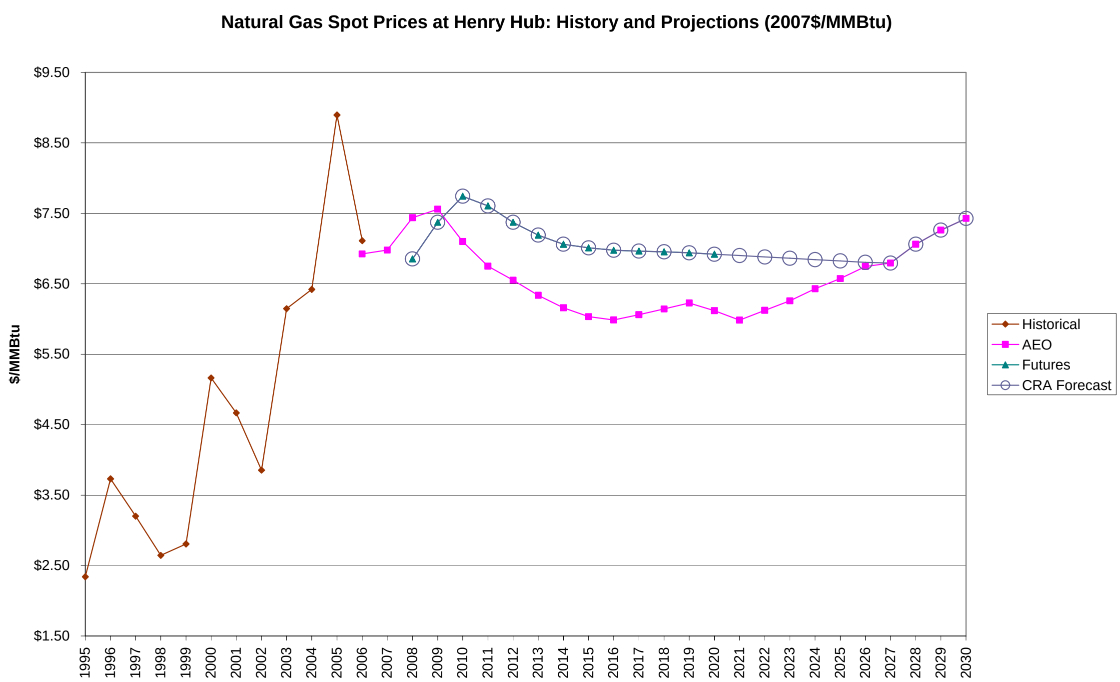
We model a monthly fuel price for each thermal unit. The fundamental assumption of behavior in competitive markets is that generators bid their marginal cost into the energy market. The marginal cost for a gas plant is the opportunity cost of fuel purchased (in addition to non-fuel variable O&M and environmental adders), or the spot price of gas at the location closest to the plant. CRA therefore uses forecasts of spot prices at regional hubs, and refines these on the basis of historical differentials between price points and their associated hubs. For fuel oil CRA uses estimates of the price delivered to generators on a regional basis.

Coal prices are drawn CRA's NEEM model.

We believe these prices are reasonable and reliable, and largely mirror long-term EIA forecasts, although they are somewhat higher than the most recent AEO forecasts.

D.6.1 Natural Gas Forecast

Figure 37: Henry Hub Gas Price Forecast



Principal Drivers: The principal drivers are the projected prices for natural gas at Henry Hub.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub. For later years, the forecast is an interpolation between the futures and the AEO2008. The CRA Base Case forecast for natural gas prices at Henry Hub is shown above, and it is identical to the gas prices forecast used for the 2008 NYPA IRP.

Regional Prices: CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region and local delivery charge by state, to the Henry Hub gas price.

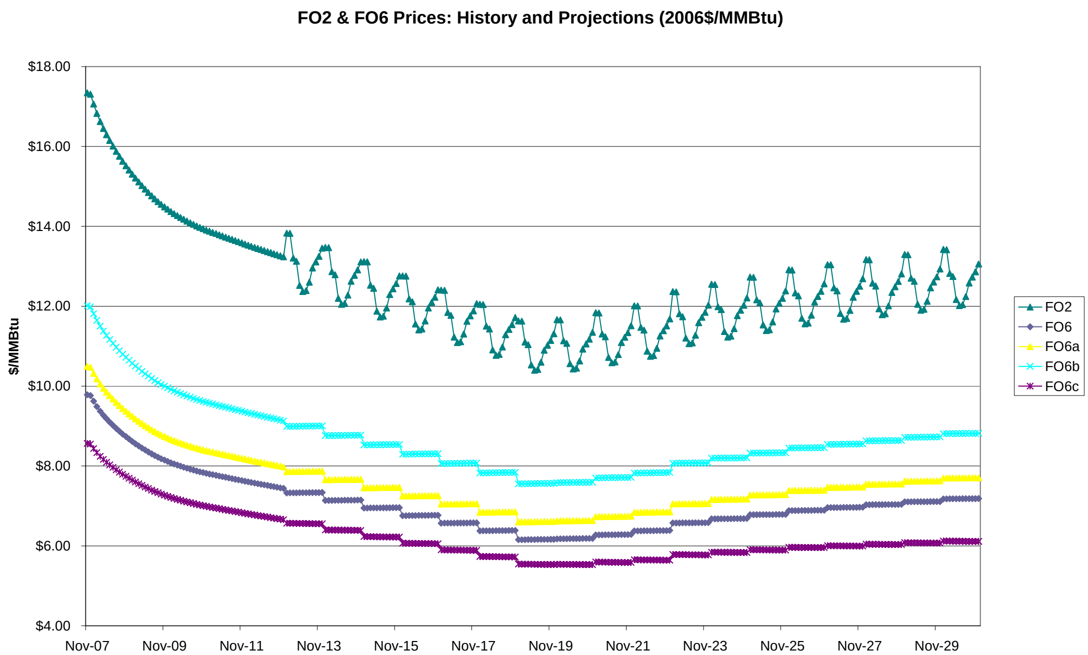
Basis Differentials by Region: CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. In the near term (through 2012), the basis forecast is derived from NYMEX Clearport hub futures settlement as of Oct 1, 2007. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this time frame, CRA derives summer and winter differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub.

Local Delivery Charges: Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies. CRA estimates this local component at $0.07/MMBtu for all units. For older units CRA estimates extra LDC charges derived from AGA statistics.

Seasonal Pattern: Natural gas prices are varied seasonally based on NYMEX futures data in the near term.

D.6.2 Fuel Oil Price Forecast

Figure 38: Fuel Oil Price Forecast



Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast: In the near term (through 2012), the forecast is derived from the NYMEX futures prices for light sweet crude oil. For later years the forecast is an interpolation between the futures and the AEO2008. The CRA Base Case forecast for light sweet crude oil is presented above.

Regional Prices: CRA forecasts prices for fuel oil #2 and #6 by US census region. This forecast is prepared in two steps. First CRA uses a regression model calibrated on historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. Second, we apply historical basis multipliers for each census regions against the mid-Atlantic Census region (includes New York Harbor).

Seasonal Pattern: Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term and based on historical monthly patterns in the longer term.