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Mr. Christopher Russo is a Vice President and the Head of CRA's Energy Practice. He advises domestic and international clients in the electricity and gas industries in the areas of investment strategy and economic analysis, asset valuation, energy technology, and generation and transmission development. His experience covers electricity and gas markets in North America, Europe and the Middle East, where he uses an analytic approach to assist clients in developing strategies for electricity and gas markets. Prior to joining CRA, Mr. Russo was a senior consultant with Cambridge Energy Research Associates in Paris, and prior to that, owned his own energy consulting firm and held positions with ABB Corporate Research. He started his career at MIT as the Plant Engineer for the campus cogeneration plant, and later held an academic appointment as a Visiting Scientist at the MIT Energy Laboratory. Mr. Russo holds a BS degree from Tufts University and a SM degree in Technology and Policy from the Massachusetts Institute of Technology.

Areas of expertise

Mr. Russo is an engineer and energy economics analyst with expertise in the following areas:

- Economics of electricity and gas markets in North America, Europe and worldwide, including market operations, regulatory economics, financial market characteristics, physical and economic transmission network characteristics, generation/dispatch system operations, and power plant operations.
- Financial and due diligence valuations and assessments of generation and transmission assets
- Master planning for energy systems, including assessments of upstream supply sources, energy conversion, transmission, and demand sectors

Selected consulting project experience

- Mr. Russo is currently the expert witness in an international arbitration claim damages claim related to the shutdown of nuclear units in Germany. This engagement consists of economic analysis of government policies, and includes simulation and financial analysis of the interconnected European power system.
- Mr. Russo has directed the analysis of over one hundred transmission and generation assets for utilities, equity and debt investors, sovereign wealth funds, regulators and market operators.
- Mr. Russo directed an engagement for a client to assist in the purchase and contracting of large amounts of electricity to support aluminum smelting operations. This consisted of financial analysis of North American power markets and financial evaluation of proposed contract structures.

- For a merchant transmission developer, Mr. Russo designed and directed the economic and technical analysis of a 2,000 MW HVDC project in the northeast US.
- For the City of New York, Mr. Russo led a major effort to investigate the reliability and economic and environmental impact of the closure of the Indian Point Nuclear Energy Center on consumers and the economy. This comprised a report as well as testimony before various commissions.
- Mr. Russo provided expert testimony in an international arbitration case related to the operation of a South American powerplant and the quantification of damages related to the improper operation of the plant.
- Mr. Russo led an effort to develop an electrical market model for Europe for a Paris-based client. Working with the production-cost modeling software and his team, he assembled databases of resources, demand, fuel prices, and transmission network characteristics to build a comprehensive model of the EU grid. His efforts concentrated on modeling competitive market bidding behavior and developing and modeling scenarios incorporating various exogenous factors and strategic choices.
- Working for the mayor and city council of a major US city, Mr. Russo managed a due diligence effort to determine the feasibility of supporting new nuclear licensing applications for a municipally owned utility. This included a review of nuclear technology, market conditions, Nuclear Regulatory Commission (NRC) resource constraints, and federal regulatory policy related to nuclear loan guarantee programs.
- Mr. Russo led a major review of new nuclear development strategy, including technical reviews, risk analyses, economic forecasts and prudence reviews for a US-based electric utility.
- For a private equity client, Mr. Russo led the valuation effort for a waste coal asset in PJM and supported the client through arbitration and legal proceedings.
- For a major offshore wind developer, Mr. Russo led the analysis of market impacts of proposed projects and assisted in developing commercial and regulatory strategy.
- For a private equity firm, Mr. Russo directed the due diligence assessment of an energy storage technology manufacturer, focusing on the analysis of market opportunities for energy storage.
- For the City of New York, Mr. Russo led the analysis and evaluation of several proposed power procurement options for public and private consumers
- For a major global semiconductor manufacturer, Mr. Russo led an effort to develop a global energy procurement strategy, analyze potential power contracts, and benchmark procurement activities against other similar firms
- Mr. Russo directed the review of the internal technical and financial modeling processes for an investor in the liberalized UK energy market.
- For a gas pipeline developer, Mr. Russo directed the analysis of a new pipeline project's impact on gas basis differentials.

- For a major European utility, Mr. Russo designed and managed a process to develop internally consistent analysis scenarios to enhance corporate planning. The effort involved soliciting input from different groups throughout the enterprise, designing scenarios, analyzing the results, and presenting the results to internal and external stakeholders.
- Mr. Russo advised the developers of a merchant transmission line on regulatory, financial, and technical strategies to develop their project in PJM and New York.
- For a major Internet search provider, Mr. Russo led an effort to identify potential sites for data centers in Europe and the US to develop sourcing strategies and integrate potential sourcing strategies with the company's environmental mandates and goals.
- For a major Asian utility, Mr. Russo managed an engagement to develop a growth strategy for a subsidiary of the parent firm, including a review of current operations, market positioning, potential risks, and strategic alliances, culminating in a concrete division growth plan.
- Mr. Russo managed a major effort for the City of New York to develop a master electrical transmission plan to address economic and reliability needs in the context of a multi-stakeholder process, incorporating the Mayor's Office, Economic Development Corporation, NYISO, ConEd, and the NYS Public Service Commission. The program addresses the economic and technical factors associated with electrical transmission, as well as the policy and financial impacts of public-private partnerships and equity investment strategies.
- For a major power development company, Mr. Russo led several projects to determine the optimal strategy for entering the gas-fired development market under pending environmental constraints and regulations. In a related project, he led efforts to investigate the feasibility of new and waste coal development in the PJM energy market.
- Working with numerous clients, Mr. Russo has provided overviews of market conditions and forecasts of market drivers and prices in major markets in the US and Europe.
- Working for the Executive Office of Sheikh Mohammed of Dubai, Mr. Russo was a principal in a major study examining the effectiveness of Dubai's current electric utility, petrochemical resources, and water resources. Working closely with local personnel, he spent significant time interviewing Dubai Electricity and Water Authority (DEWA) and Dubai Supply Authority (DUSUP) personnel, Emirati leaders, and stakeholders; evaluating petrochemical and water resources; and developing a comprehensive multi-attribute, multi-scenario energy system model of the emirate for evaluation of future energy strategies.
- Mr. Russo was a principal in a project to restructure a major utility in the United Arab Emirates, including long-term planning functions, regulatory efforts, customer service systems, IT architecture, and financial systems.
- For several domestic and foreign clients, Mr. Russo has provided detailed briefings on market conditions in numerous US markets, including New York, PJM, Electric Reliability Council of Texas (ERCOT), and California.

- Mr. Russo led a project for a major Hong Kong-based utility to help them adapt their management processes, planning infrastructure, and IT systems to pending emissions and energy trading regulations through performing needs assessments, sourcing strategies, and drafting RFPs.
- While with ABB, Mr. Russo helped design and organize the China Energy Technology Program, a joint ABB/AGS program to investigate sustainable energy systems in China, which included Electric Generation Expansion Analysis (EGEAS) modeling of the eastern China power network to identify long-term, cost-effective strategies for environmental improvement.
- Working with the MIT Cogeneration Plant, Mr. Russo provided continuing guidance and expertise on cogeneration plant and gas turbine operations, as well as conducting several economic cost-benefit analyses to plan future plant expansion.
- For a major software firm and federal clients, Mr. Russo helped prepare and develop a wide-area synchronized phasor measurement system to measure phase angle and frequency perturbations across the Eastern Interconnection to enhance grid stability.
- For PJM, Mr. Russo developed software and systems to visualize market participant bidding behavior to assist market monitors and dispatchers.
- For New York ISO, Mr. Russo designed and implemented a PI data historian system for tracking all operational data. He also trained system operators on its use, played an integral part in the standard market design to implementation and EMS development and developed various software applications to analyze system operations.
- For the California ISO, Mr. Russo worked as a consultant during the startup, developing systems to track generator dispatch operations and identify anomalous generator behavior to assist market surveillance personnel find market gaming activity. During the power crises and rolling blackouts, he managed and maintained a critical system in use by all ISO personnel and developed a system to analyze results of Stage 2 and 3 events.

Professional history

2007–Present	*Vice President*, Charles River Associates, Cambridge, MA
2006	*Senior Consultant*, Cambridge Energy Research Associates (CERA), Paris, France, and Dubai, United Arab Emirates
1999–2006	*Principal and Founder*, Russo & Associates LLC, Boston, MA • Worked as a consultant to various energy firms, individually and with subcontractors with numerous regulators and market participants in markets in the US and abroad.
1998–2002	*Consultant*, Department of Energy & Global Change, ABB Corporate Research Center, Baden-Dättwil, Switzerland • Investigated CO_2 reduction strategies, new generation, and end-use technologies and helped to initiate the China Energy Technology Program.

Acted as liaison between ABB and MIT. Held a Visiting Scientist appointment at MIT Energy Laboratory.

1995–1998 *Plant Engineer*, MIT Cogeneration Project, Massachusetts Institute of Technology, Cambridge, MA

- Managed gas turbine and cogeneration plant operations, negotiated environmental permits, managed gas market purchases and contracts, and performed regular performance analyses for a cogeneration and district energy plant. Was a guest lecturer in the Department of Aeronautics teaching students about gas turbine technology.

Additional professional training

- New York ISO Market Operations Course
- New York ISO DSS Market Participants Course
- California ISO Market Participants Course

Selected books

"Data Collection," chapter in *Integrated Assessment of Sustainable Energy Systems in China: The China Energy Technology Program*. Baldur Eliasson. Kluwer Academic Publishers, 2003.

Selected public testimony

Testimony before the New York State Assembly on the economic and reliability impact of the potential closure of the Indian Point Nuclear Energy Center, January 2012

Testimony before the New York State Public Service Commission in the Article VII proceeding for the proposed Hudson Transmission Partners cable, April 2010

Testimony before the Public Utility Commission of Texas on the Cost-Benefit Analysis of the Texas Nodal Market, December 2008

United States Federal Energy Regulatory Commission, Electric System Investigation Team, Reliability Recommendation Consultation. Philadelphia, PA, December 2003. Presented findings on frequency instability and grid separation issues preceding the August 2003 blackout.

Citizenship and languages

Mr. Russo is a dual citizen of the United States and Italy.

- English (native)
- Italian (proficient)
- German and French (basic)

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Project Team

This study was prepared by the Energy & Environment Practice of Charles River Associates. The project manager and principal author of this report was Christopher Russo. Other project team members included Dr. Richard Tabors, Oliver Kleinbub, Michael Kline, Edward Kim, Jonathan Pike and Emily Luksha.

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"Greater reliance on nuclear power for the Con Edison service area in the 1990s, while perhaps compelling by economic, and to a lesser extent, environmental logic, will require the endorsement of society. The future societal judgment concerning nuclear power constitutes the largest uncertainty in long-range electric energy planning."

Strategic Planning for Electric Energy in the 1980s for New York City and Westchester County, *MIT Energy Laboratory, 1981. MIT report MIT-EL-81-008*

1.1. INTRODUCTION

The Indian Point Energy Center (IPEC) is a nuclear powerplant consisting of one retired and two active reactors, sited in Buchanan, New York, in Westchester County. Unit 1 (IP1) was retired in 1974. Units 2 and 3 (IP2 and IP3) each generate approximately 1,020 MW of electrical energy, or 2,040 MW combined. This makes IPEC one of the largest powerplants in New York State, and its location on the electric grid near the major load center of New York City (NYC) gives it substantial impact in engineering, environmental, and economic contexts.[1]

Recent events in Japan have led to calls for a thorough examination of the safety and environmental issues surrounding the continued operation of IPEC, and various proposals have been put forth, at least in general terms, to replace some or all of IPEC's generating capacity. IPEC's two federal operating licenses expire in September 2013 and December 2015 respectively, and recent debate has centered on the question of whether the reactors should continue to operate after their licenses expire.

Charles River Associates (CRA) was retained by the New York City Department of Environmental Protection (NYCDEP) to develop an analysis of the impact of an IPEC retirement from economic, environmental and reliability perspectives. The purpose of this analysis is to help the City of New York and other key energy stakeholders understand the implications of IPEC's potential retirement. This is not an analysis intended to answer the

[1] Various sources contend that IPEC supplies anywhere from five to thirty percent of NYC's energy. The measurement of IPEC's contribution to the grid as a single number is an oversimplification, and can be misleading. The contribution of any given powerplant to the system is a function of its size, its position relative to transmission constraints, and the location of load on the system. IPEC's physical generation output cannot be directed to any specific location on the grid; its physical output flows over the network to the broader New York and regional energy markets, affecting the prices and flows of energy over a very wide area, beyond New York's borders. Part of IPEC's output is economically contracted to load-serving entities (e.g. ConEdison and NYPA) in NYC and Westchester County. This contracted percentage, however, is purely an economic construct, and has little relevance to actual physical flows of energy on the system and IPEC's effect on the power markets.

question of whether IPEC should retire, but rather to systematically examine the implications of such a retirement should it occur.

Any powerplant, including IPEC, can be retired, but not without costs and tradeoffs. It is crucial to understand that the critical question is not whether IPEC can be retired, but rather what the economic, reliability and environmental impacts of such a decision are. In the case of IPEC's potential retirement, these impacts are sufficiently large to warrant careful consideration.

It is also important to understand the distinction between an effect of IPEC's retirement, and the effect of a response to its retirement. Economic and environmental impacts can be mitigated through policy actions, but these policy actions come with their own costs and implications. We have focused in this study on the effects of IPEC's retirement; the question of the best policy response to potentially mitigate the effects of this retirement lacks a simple answer and will be answered differently by those with differing objectives.

IPEC's retirement will exert measurable net economic and environmental costs, which we have quantified in part here. Broadly speaking, the question is how the different nuclear safety[2] risks and water quality effects at IPEC compare to the costs which would be incurred by the public in its retirement. Numerous parties have opposed the continued operation of IPEC because of claimed effects on the Hudson River and its marine life. The benefits of altered risk and environmental impact (e.g. Hudson River effects vs. deleterious effects on air quality) resist simple quantification, and properly lie within the realm of public policy.

We conducted our study with the input of a technical advisory group (Group) representing numerous energy interests in NYC and New York State (NYS), including Con Edison, the New York Independent System Operator (NYISO), the New York Power Authority (NYPA), and the City of New York.[3] With the input of these parties, we developed appropriate methodologies and assumptions so that our analysis was as accurate, comprehensive, and unbiased as possible. Our Group members were not always unanimous in their views, and we have attempted to provide a balanced representation of their input.[4] We would like to express our thanks to them for their valuable input.

Our analysis is not exhaustive, nor is it intended to be, in considering all possible reliability, economic or environmental perspectives. We have quantified what we reasonably can given

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[2] The retirement of IPEC will still mean indefinite storage of spent nuclear fuel at the Buchanan site, either in storage pools or eventually in dry-cask storage. There is currently neither long-term storage site for spent nuclear fuel (e.g. the proposed Yucca Mountain site in Nevada), reprocessing facilities for spent uranium, nor regulations which would permit the transport of the spent fuel off the Buchanan site.

[3] The plant's owner, Entergy Nuclear (Entergy), was neither a Group member nor a participant in this analysis, although the company did verify some technical details regarding IPEC, for which we express our thanks. No private project developers were engaged in this study.

[4] Group members do not explicitly endorse the analytical results or the views expressed in this study.

the constraints of finite schedules and resources, and we have identified those less-obvious costs which must be given full treatment in a comprehensive accounting. We have not attempted to quantify all these costs; many of them are well beyond the scope of this analysis.

The inclusion of conceptual projects is intended to help decision-makers identify and evaluate options that have not previously been analyzed, and to provide guidance as to potentially valuable initiatives which might warrant further consideration. Despite the similarity of some conceptual projects to actual proposals that have been put forth or discussed, the intent is not to analyze specific commercial proposals for projects.

1.2. Options Evaluated

In order to serve all New York customers reliably, there must be enough installed generating capacity to meet peak loads, plus a reserve margin. Therefore, barring a radical change in the demand for electricity, an IPEC retirement means that new generation or transmission capacity will be required at some point; we framed our analysis around this basic concept. Following discussions with the parties, we evaluated three distinct options for replacing the prospect of IPEC's lost capacity. They are not necessarily intended to represent or select the "best" options, but rather those that may represent what could be commercially feasible and plausible in a regulatory context.[5] Every option evaluated comes with tradeoffs, and different parties will necessarily define the "best" option according to different criteria.

In addition to the three replacement options we evaluated, we also evaluated a scenario in which no new generation was added to replace IPEC. Such a scenario is not feasible from a reliability standpoint, but it represents a bounding scenario for our analysis, and a rough approximation of the economic effects of a scenario in which just enough conservation measures were employed to avoid some reliability issues. Every scenario in this study assumes that three major new projects, Astoria Energy II, the Bayonne Energy Center (BEC), and the Hudson Transmission Partners (HTP) Cable are constructed and in service by the time of IPEC's retirement.

[5] We had the option of constraining our analysis to a set of limited replacement options which may technically feasible by 2016, or analyzing options which may yield greater benefits but may not necessarily be available by the date of IP3's retirement. We adopted the latter approach in this analysis, and the inclusion of any specific replacement option should not be construed as a finding that such a solution could be operational by the date of IP3's retirement.

Status Quo

The status quo scenario consists of federal relicensing of the reactors for an additional twenty years. This is our "base case" for comparisons. We did not assume that cooling towers were installed at the site.[6]

Conventional Thermal

In the Conventional Thermal scenario, we assumed that 500 MW of capacity was constructed at the IPEC site in the Lower Hudson Valley (LHV) upon IP3's retirement, followed by an additional 500 MW of capacity constructed in New York City in 2018. In addition to this basic scenario, we also modeled a scenario in which 500 MW of gas-fired combined cycle (CC) capacity was developed at the IPEC site in the LHV, with no additional capacity in New York City (NYC), upon IPEC's retirement. The scenario in which only 500 MW of capacity is developed at or near the IPEC site can be a considered a rough approximation of a market-based response to IPEC's retirement.[7]

Low-Carbon

The low-carbon scenario consists of the construction of a 1,000 MW High-Voltage Direct Current (HVDC) line to New York City, combined with a 500 MW offshore-wind farm interconnected into Brooklyn. This scenario was chosen to investigate the possibility of a conscious policy decision to implement a low-carbon replacement plan that takes into account the beneficial greenhouse gas effects of IPEC.

One-for-One

The one-for-one scenario consisted of replacing IPEC's capacity with an equivalent amount (2,000 MW) of gas-fired combined cycle capacity at or near IPEC's current site. For the purposes of this analysis, this option need not consist of a single power plant, but of the equivalent amount of new generation located in the LHV. This scenario is perhaps the

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[6] One current issue surrounding IPEC is whether cooling towers would need to be installed to be compliant with the NYS Department of Environmental Conservation (NYSDEC) decision to deny IPEC a Clean Water Act permit. Entergy is contesting the need for such towers, and that issue is now being addressed in a DEC administrative proceeding. It is unclear whether Entergy could or would stage the installation of the cooling towers so that both reactors were not offline simultaneously, avoiding a reliability violation. Had we developed a status quo base case in which cooling towers were retrofit, it may have reduced the economic impact to consumers, as the base case would have higher energy prices. Note, however, that requiring the installation of cooling towers will increase the cost to consumers, since during the period in which the towers are being installed, prices would rise. Finally, note that our economic analysis starts in 2016 – if any cooling tower retrofit were to be completed before the scheduled retirement of the second reactor, there would be no effect on our analysis. Entergy has stated that the both reactors could need to be closed simultaneously for 42 weeks to retrofit the cooling towers, and that these costs could exceed $1billion. (http://www.nytimes.com/2010/04/04/nyregion/04indian.html)

[7] As detailed in section 4.2.2, a hypothetical 500 MW combined cycle unit installed in the LHV was the only replacement option analyzed which would not require subsides to be constructed and operated.

simplest one conceptually, but with perhaps the most complex implementation, and raises serious potential issues related to fuel supply adequacy at its site.

1.3. KEY FINDINGS

IPEC's retirement will increase the cost to New York's consumers under every feasible scenario

Every replacement option studied will result in a cost increase to energy consumers throughout the state, either through increased market prices or subsides to new generators. If the market is allowed to function without subsidies for new generation, consumer prices will see marked increases.

The state market would see wholesale cost increases of approximately $1.5 billion per year[8], or roughly a 10% increase under our base-case scenarios. NYC consumers would pay approximately $300 million per year more for wholesale energy, or approximately a 5-10% increase.[9] IPEC's retirement will force greater reliance on fossil-fueled generation resources, increasing the sensitivity of electricity prices to volatility in natural gas prices, which we did not explicitly quantify in this study. Retail price increases (in percentage terms, but not absolute amount) will be lower than wholesale price increases.

These price increases do not include financial support which would be necessary to construct projects which would otherwise be uneconomic, nor does it include other costs which would be necessary to reinforce the grid to support new generation. It is likely, given our analysis, that additional ratepayer support would be necessary to develop these new generation resources, in which case these costs would be passed on to utilities, and ultimately to consumers. Our analysis indicates that the additional costs to consumers from the various options range from a total net present value (NPV) of $691 million for a combined cycle thermal replacement option in the LHV and NYC to $2.1 billion for a low-carbon solution. These costs are in addition to increased costs for energy, and given the large uncertainties associated with project development, should be considered a minimum.

IPEC's retirements may have far-reaching ancillary economic impacts. IPEC is a major employer in the region, employing approximately 1,100 people, with additional jobs created through indirect and induced economic activity. We have focused our analysis on the electricity market impacts of a potential IPEC retirement, but the ancillary economic impacts may be substantial. We have not attempted to calculate these induced and indirect benefits in this analysis, although other studies have been conducted on this topic.[10]

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[8] All dollar amounts in this report, unless otherwise stated, are expressed in real 2010 dollars.

[9] Consumers saw cost increases in neighboring regions, such as PJM, but those effects are not summarized here.

[10] Economic Benefits of Indian Point Energy Center, Nuclear Energy Institute, April 2004

Finally, and least predictably, there may be costs associated with a regulatory or legal settlement associated with retiring IPEC. In the event IPEC is forced to retire, Entergy may pursue legal action. We have not attempted to quantify any costs associated with litigation in this study, although legal action is almost inevitable even if the ultimate outcome is uncertain.

IPEC's retirement without new generation or transmission system additions will compromise the reliability of the electricity grid

The grid must meet multiple criteria to be considered reliable. These include resource adequacy, regional and local transmission system security, and system operation. We only analyzed the first of these items. There are proprietary analyses from some Group members which strongly suggest that there are other factors which will result in local (*i.e.*, in-City) and broader system reliability issues. Some transmission issues will remain even if sufficient generation capacity is available to meet resource adequacy criteria upon IPEC's retirement. The system cannot be considered to be reliable until these other issues are analyzed.

A common metric used to assess the reliability of power systems is the level of "resource adequacy." A highly simplified definition of resource adequacy is that there must be enough powerplants to adequately serve consumer electrical demand for all reasonably expected operating conditions. Resource adequacy considers the limitations of the transmission lines which connect the powerplants to consumers, but does not encompass a comprehensive analysis of all transmission limitations. This methodology measures the probability of interruption to consumer service (blackouts) due to insufficient generating and transmission capability. This probability is defined as the Loss of Load Expectation (LOLE), and by Northeast Power Coordinating Council (NPCC) and NYS regulations can be no greater than experiencing an event not more than once in ten years, or an LOLE of 0.1. Lower LOLEs indicate greater resource adequacy and a more reliable system, while higher LOLEs indicate a less reliable system.

Unless new generation or transmission capacity is constructed beyond those additions currently planned, the retirement of IP3 in 2015 would cause the grid to fall short of minimum resource adequacy standards in the summer of 2016, with an LOLE for New York of 0.113. Therefore, new generation or transmission must be constructed if IPEC is to retire.

The resource adequacy impact of IPEC's retirement is highly dependent on the load forecast assumed, which has changed substantially over time. We used the NYISO's 2011 load forecast ("Gold Book"), adjusted for historical rates of energy conservation achievement and have explicitly included the impacts of energy efficiency and conservation programs in our analyses.[11] New capacity will be needed eventually, and these changes in demand will postpone, not eliminate, the need for new capacity if IPEC retires.

[11] Since 2009, the level of energy conservation versus target levels in New York has been 57%. The most recent 2011 NYISO load forecast assumes 91% achievement of energy efficiency penetration and an aggressive implementation schedule in the future. We have assumed 50% achievement in our study, in order to develop a realistic picture of the impact of an IPEC retirement.

Load forecasts are axiomatically imprecise; reliability analyses, conducted by the NYISO with the best available data over the last two years, have shown a range of seven years in the need date for new capacity. A 2009 analysis by the NYISO[12] found that reliability criteria would be violated upon the retirement of the first of IPEC's reactors in 2013 and that approximately two gigawatts (GW) of new generating capacity would be necessary to maintain reliability. A 2010 NYISO analysis found that the retirement of both reactors would violate reliability criteria[13] in 2016, as did we in our analysis. The NYISO has not yet released a 2011 assessment of the reliability impact of IPEC's retirement. Small changes in future energy consumption (on the order of 1-2%) can determine whether the system will meet reliability standards upon IPEC's retirement. The amount of electrical demand which may determine whether an IPEC retirement violates reliability standards is well within the range of uncertainty of the load forecast.

Resource adequacy is only one component of overall system reliability, and meeting the resource adequacy criterion alone will not make the system reliable. We emphasize that independent analyses from some of our Group members indicate that there are reliability issues raised by the loss of IPEC which go beyond resource adequacy and would need to be addressed even if minimum resource adequacy standards were met. [14] Simply adding capacity or reducing load cannot be assumed to ensure a reliable system. More analysis is necessary on this topic.

Each option for replacement of IPEC's capacity would measurably increase air emissions

IPEC is able to provide approximately 2 GW of baseload generation with no direct[15] air emissions. Its retirement will cause a substantial increase in air emissions under all the scenarios analyzed in our study. Our analysis indicates that both NYC and NYS would see approximately a 15% increase in carbon emissions under most conventional replacement scenarios, with roughly a 7-8% increase in NO_x emissions.

Even lower-carbon scenarios such as hydropower imported from Canada combined with offshore wind would cause carbon and NO_x increases of between 5-10% in NYC and statewide. This is because the plausible increases in imports from Canada we modeled would be insufficient to totally replace IPEC's capacity; additional generation from conventional thermal powerplants would be required.

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12 NYISO 2009 Comprehensive Reliability Plan (CRP)

13 NYISO 2010 Reliability Needs Assessment (RNA)

14 One example is the second contingency design (N-1-1) of the Con Edison electric system, which allows the system to maintain reliability with the loss of the system's two largest elements during peak conditions.

15 There is a considerable amount of embedded life-cycle energy in the enriched uranium fuel and the construction of plant itself, but the latter is a characteristic of all plants, not just IPEC.

Developing a solution in which there is no net emissions increase would be extraordinarily expensive. The largest commercial-scale projects currently proposed amount to slightly more than half of IPEC's generating capacity.[16] Retirement of IPEC would substantially reduce the possibility of reaching *PlaNYC*'s goals of reducing NYC's carbon emissions by 30% from 2007 levels.

The largest uncertainties are regulatory

While a great deal of discussion has been devoted to the impact of exogenous factors such as natural gas prices, demand growth and potential emissions policies, the largest uncertainties surrounding the impact of IPEC's potential retirement are regulatory in nature.

The principal and most obvious uncertainty is the shutdown of IPEC itself. While positions have been staked out regarding environmental permits and license reissuance, there is a substantial chance that the decision whether and under what circumstances to retire IPEC will be decided in the regulatory arena, and ultimately by litigation.

Another principal uncertainty relates to the state of the markets themselves. New York has a regulatory system oriented towards competitive entry and market-based solutions. There have been some recent projects, however, which have not entered the market on a pure merchant basis, but rather through power-purchase agreements with regulated entities or by New York's Power Authorities[17].

New York has competitive wholesale markets for both energy and installed capacity. Several recent and pending rules in the installed capacity market may have a substantial impact on the economic effects of an IPEC retirement. NYISO has considered implementing new zones for capacity in the Lower Hudson Valley (LHV)[18], and various measures for mitigating market power. How one interprets the prospects for these regulations will have a major impact on the economic impacts of IPEC's retirement. NYISO's wholesale market rules have changed numerous times since their creation, both by regulatory mandate and through the NYISO's stakeholder governance process. As a result, one needs to consider the possibility that other changes could occur with unknown future impacts.

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[16] We have included in our replacement scenarios some which incorporate renewable resources. Renewable resources must be de-rated to account for their intermittent nature. For instance, the best-performing offshore wind farms proposed for the NYC region would have a capacity factor of approximately 40%, with a capacity de-rate for reliability purposes of approximately 35%. This means that in order to generate the equivalent amount of energy from a 500 MW thermal plant, 1,500 MW of offshore wind would be required. Onshore wind is derated to approximately a 10% capacity factor, meaning that approximately 5,000 MW of terrestrial wind capacity would be required to replace the capacity of one combined-cycle gas-fired plant.

[17] A notable recent exception is the Bayonne Energy Center.

[18] The New York market utilizes market zone definitions, which define geographical areas for metrics related to the markets. These zones are defined as Zone A through Zone K, where Zone A is in Western NY and Zone K is Long Island. The other zones are in between. The LHV comprises Zones G, H, and I, while NYC is Zone J.

Consistent and clear regulation, and a thorough understanding of the effects of that regulation, are critical to ensuring a secure grid and a stable market which can produce economically rational outcomes.

Action will be necessary to ensure the grid's reliability

In the event of IPEC's retirement, and absent action by policymakers or merchant-based solutions, NYISO "backstop" processes will likely be triggered in which transmission owners will provide proposed solutions to maintain the grid's reliability. Whether pre-emptive or by regulatory mandate, action will be necessary to maintain the grid's reliability if IPEC retires.

Some of the scenarios considered in this report are similar to those that could be backstop-process proposals. These proposals will invariably be subject to similar comparisons and analyses as are being conducted now. Forming a contingency plan now allows the benefit of time to carefully weigh the relative costs and benefits of each potential solution. Action by policymakers and decision-makers to weigh these alternatives now is in the best interest of consumers.

Energy conservation must be considered in a realistic context

The issue of energy efficiency and conservation are often discussed in the context of an IPEC retirement. Conservation is a critical part of the State's and City's overall energy strategy, and progress has been made in achieving conservation objectives, but it is important to adopt an informed approach to considering its impact. Increased energy efficiency and conservation measures may forestall a resource adequacy crisis upon IPEC's retirement, but will still result in increased consumer prices and air emissions. Eventual construction of new powerplants, transmission lines, or gas pipelines in the Lower Hudson Valley or New York City is an inevitable consequence of IPEC's retirement.

Over the past three years, NYS has achieved 57% of its targets for energy efficiency, which has had an impact on the grid and markets. The most recent forecasts for energy consumption[19], however, forecast 91% achievement in the future, with many programs forecast to achieve virtually all of their potential impact by 2018. If these programs fall behind schedule, or do not achieve greater success in the future than they have in the past, then the load could be higher than forecast and the reliability consequences could be substantial upon IPEC's retirement. We have assumed in our study that 50% of energy efficiency targets will be achieved over the timeframe of our study to address these factors.[20]

[19] The NYISO's 2011 "Gold Book", described in greater detail in the next section.

[20] These assumptions are discussed at greater length in section 3.2.1.

New replacement options may not be fully supported by market revenues; subsidies or contracts may be required

For the purposes of our electric market simulation, we assumed that new capacity enters the market without regard to its funding source to ensure system reliability. If that new capacity does enter the market, it is unlikely that the revenues from the wholesale markets will provide a sufficient return for investors for these projects, meaning that consumers will partially bear the costs of these projects through above-market subsidies.

In recent years, many projects have entered the market (Astoria Energy II, the Neptune Cable, and soon HTP) with some form of contract with a load-serving entity (or off-taker) of the project's output. The role of this power-purchase agreement, or PPA, is often critical to these projects' development. Construction of generation and transmission projects is highly capital-intensive, and securing a PPA allows developers to seek financing to construct their projects because of revenue certainty.[21]

We developed high-level estimates of project costs and representative *pro-forma* financial analyses for each project. These analyses indicate that these projects would not be supported by market revenues, and would need additional financial contractual support from the City or other off-takers (e.g. NYPA, LIPA). It is not clear precisely how this contractual support may be reflected in consumer rates, but because the support would come from an off-taker who would presumably serve end-use customers, the costs would have to flow through in some manner.

There is uncertainty about the capital cost of these projects themselves, as well as the engineering system upgrades (*e.g.* interconnection upgrades) necessary to actually construct them. In general however, the consumer effects that are seen through increased energy prices and contractual support for projects dominate the calculation of cost impact.

New resources will be necessary to replace IPEC's lost capacity – the only question is when they would be required. When considering how to weigh different costs under different scenarios, it is important to remember that if energy prices and revenues are lower (through lower demand, greater energy efficiency, reduced gas prices, or other factors), then the subsidies or financial support necessary for such projects will be higher.

"Letting the market function" is an option. There are two important caveats to this approach, however. The first is that there is a real chance that market-based solutions may not have sufficient time to develop by 2016, and there is a chance of reverting to the backstop process. The second is that a hands-off, market-based approach will result in higher consumer prices. Based on our analysis, only an increase in market prices will provide revenues sufficient to support a market-based solution.

Any solution to the retirement of IPEC which includes subsidies to replacement capacity may also precipitate legal challenges at the state and federal level from market participants. The

[21] The PPA also has the effect, in many cases, of transferring risk from the investors to the consumers.

impact of these challenges must be factored into plans for the development of replacement capacity.

Not all replacement options for IPEC's capacity may be available upon IPEC's scheduled retirement

Assuming the retirement of both units by December of 2015, the critical date is the following peak demand period, which is the summer of 2016. Our analysis indicates that given the current prospects for new capacity in New York, resource adequacy will fall below acceptable levels at that point unless new generation is constructed.

For planning purposes, the critical piece of information is not when the IP3 unit is scheduled to retire, but rather when Entergy announces its intention, or a final regulatory decision concerning the fate of the plants is made. It is unlikely that a private market participant would commit capital and resources to the development of new resources without knowing with certainty if and when IPEC would retire. Similarly, a public or quasi-public entity cannot reasonably be expected to seek new sources of energy and capacity necessary to maintain reliability without definitive knowledge of IPEC's future status.

If Entergy were to announce its intentions at the latest possible date[22], there would be insufficient time to put a solution in place unless new generation were already under construction. Development and construction of large capital projects can take many years however, and a duration of 4-5 years for development of a major (500 MW or larger) project is not unusual.[23] Working backwards from the scheduled IP3 retirement date of December 2015, this means that development on its replacement should already be well underway now.

Several transmission and generation projects have been proposed to provide new generating and transmission capacity, and are at various early stages of development, but significant challenges still remain to developing these projects. Some Group members felt that some projects (including several CC units in the LHV) proposed by developers were ready for construction and could be developed rapidly; others felt that the development difficulties were underestimated.

Time is a valuable commodity; solutions are available that can act as an interim reliability measure, but more sustainable and economically beneficial solutions will take considerable time to be planned and implemented.

[22] Entergy could submit a notice of retirement as late as 180 days prior to actual unit retirement. See NYPSC Case No. 05-E-0889, Proceeding on Motion of the Commission to Establish Policies and Procedures Regarding Generation Unit Retirements, Order Adopting Notice Requirements for Generation Unit Retirements (issued and effective December 20, 2005); see also NYISO Technical Bulletin 185 (establishing procedures for generation unit retirements).

[23] Astoria Energy Phase II, entering service in July of 2011, was proposed in an RFP in 2007. The HTP cable was originally proposed in response to that same RFP.

Gas-fired generation development in the Lower Hudson Valley may be an attractive option, but with important tradeoffs and uncertainty

There was distinct difference of opinion in our Group regarding whether the development of an equivalent (2,000 MW) amount of gas-fired capacity in the LHV warranted inclusion in our option set. While the ability to replace IPEC's inframarginal (*i.e.*, base-load) generation capacity with a roughly equivalent amount of inframarginal gas-fired capacity is intuitively appealing from the perspective of minimizing wholesale market price impacts, substantial uncertainty, risks and tradeoffs accompany this option.

This option could yield nearly no increase in one of the metrics evaluated, wholesale energy rates, but with the highest required subsidies of any conventional solution we studied. Based on our analysis, the development of 2,000 MW of capacity in the LHV would require a NPV of $1.4 billion of support to developers, costs that would be passed on to consumers.

An issue of concern to some Group members was that the difficulty of developing this new capacity was being substantially underestimated. Constructing two new 1,000 MW gas-fired CC units would mean constructing the two largest gas-fired power plants in the northeast United States in the LHV, traditionally one of the most difficult locations to develop power projects. Development uncertainties are nearly impossible to quantify, but planning centered on construction of large amounts of capacity in the LHV should incorporate a realistic view of development risk.

In addition, there is substantial uncertainty regarding electrical system, and gas pipeline system upgrade costs. We did not conduct a detailed assessment of physical upgrades which may be necessary to develop the gas pipeline capacity needed to support operation of these plants, nor the economic impact of firm gas supply contracts which would be necessary to supply them. To be clear, every option we studied had some amount of inherent uncertainty related to incremental infrastructure costs necessary to support the project, but some in our group felt that the uncertainties of this option were distinctly larger.

One of the Group members performed a high-level analysis of the potential gas system upgrades which would be required to support this generation option. Their analysis indicates that the upgrade costs would be approximately $350 million, and would include the construction of a new gas service line to interconnect with the Algonquin Pipeline, associated meter facilities, and an expansion of the Algonquin Pipeline which would include a horizontal drilling effort under the Hudson River. This infrastructure would also require filing an application with the Federal Energy Regulatory Commission for approval to construct the necessary facilities, a process estimated to take up to five years. These cost estimates were based on industry-standard parameters, and could be higher because of the necessity to construct these upgrades in congested or environmentally sensitive areas in the LHV.

While a full replacement of IPEC's capacity with CC units in the LHV would likely have little impact on wholesale market electricity prices, it would require the largest project subsidies among the conventional options studied and also result in the largest emissions increases of the all the options studied. Thermal generation, even with high-efficiency and modern control emission equipment, would result in the largest CO_2 and NO_x emissions increases of any option we evaluated. Westchester County is also an environmental non-attainment zone, raising further difficulties related to project siting.

This option is often put forward as a response to the retirement of IPEC in the public debate, and at the present time, this option has captured the attention of those looking to mitigate the impact of IPEC's potential retirement. These factors warrant further analysis of this option, which goes beyond the scope of this report. The ultimate choice as to whether this is the best option for New York, however, may not be decided solely by complex quantitative analyses, but rather by the importance which policymakers and the public ascribe to the tradeoffs and uncertainties which accompany this approach.

1.3.1. Implications for policymakers

Every option will require tradeoffs

Articulating planning objectives is critical in the public debate, as the decision of how to address IPEC's retirement can be viewed as a tradeoff between increased consumer cost, increased emissions, and increased development risk.[24] There is no option, including plausible increases in energy conservation, which achieves low increases in cost, low increases in emissions, and an easy development process. The decisions regarding these tradeoffs will lie in the realm of public policy. Those who assert that there are "cheap" and "simple" solutions simply fail to acknowledge these tradeoffs.

Additionally, policymakers must consider the long-term policy consequences of their actions. We take as given in our analysis that there is a fundamental orientation towards market-based approaches to electricity markets in New York State; a desire to minimize consumer impacts should take into account the effects on the goal of having an economically sustainable electricity market.

The importance of IPEC to New York's energy portfolio means that coordinated planning among key stakeholders in the region is necessary to prepare contingency plans in the event of IPEC's retirement. This study, and others like it, is evidence that there is already a public debate underway regarding the impact of an IPEC retirement.

Location and type of new generation

Policymakers face a choice not only of whether to encourage the development of new generation and transmission, but if so, where? Because of the structure of New York's grid and markets, the location of the generation which might replace IPEC is an important decision. *Ceteris paribus*, new generation capacity in the LHV is a higher priority than generation in NYC. New generating or transmission capacity in NYC is valuable and

[24] We have not identified reliability as a tradeoff because we assume that the grid must meet minimum reliability standards, and thus reliability is a binary quality and constraining characteristic of any replacement option.

contributes to overall system reliability, but is not a complete substitute for generation in the LHV.

Additional generation in NYC will, however, contribute to system reliability. The question of whether new generation in NYC is repowered generation or new development is not material to the question of system reliability; the overall net increase in capacity is the important metric. While we have assumed for this study that new NYC generation would be greenfield development, it could just as easily be repowering of an existing site; the economic and reliability effects would be similar, although there may be other benefits to repowering not fully captured in our methodology.

Renewable generation can and should be part of the State's energy mix. Because of IPEC's substantial influence on the reliability of the grid, however, the reliability impact of renewable technologies on the grid must be considered and fully analyzed.

Finally, NYC and the LHV are among the most challenging places in North America to construct new power plants, transmission lines, and gas pipelines. High development costs, stringent environmental regulations, a complex regulatory system and strong community concerns are significant challenges for any project. New efforts by the State to streamline the process may mitigate some of these factors, but development risk is still high. Solutions which assume rapid development of new or repowered power projects in southeast New York must take these factors into account.

Decisions on new capacity can be postponed, but not avoided.

If no action is taken by private developers in the market-based context, there is a process by which backstop reliability solutions would be implemented to prevent compromising the grid's reliability. Upon the NYISO's determination that reliability criteria would be violated (as would likely happen if IPEC's retirement is announced), the NYISO would solicit market-based solutions and direct the New York Transmission Owners (NYTOs) to develop regulatory backstop solutions to maintain the grid's reliability. If and when that occurs, the debate over the relative merits, economics and costs of each option will be similar to the discussion today, with the only difference being there would be less time to make critical decisions. The economic, reliability, and environmental consequences of an IPEC retirement are sufficiently large that adequate time must be allocated to reach a well-considered and prudent decision regarding its replacement; more time will help ensure such an outcome.

Lack of regulatory and commercial certainty will impede market-based solutions

Power plant development in any market, and especially in New York, is a challenging endeavor. The regulatory, economic and financial environment all present a great amount of inherent uncertainty. Power projects, whether in the form of transmission or generation, are large, capital-intensive projects, and investors will understandably require some measure of certainty to commit that capital. In this instance, it is reasonable to assume that that no private entity will commit capital to replacement solutions for IPEC unless and until there is a high degree of certainty as to its retirement date.

Costs for Upstate versus Downstate

The price impact is not confined to southeast New York consumers. The wholesale cost of electricity to consumers consists of two principal components, energy and capacity. The cost of energy is relatively straightforward: it is the cost of producing and delivering electrical energy in various locations throughout the State, and it is determined principally by generation mix, fuel prices, and transmission topology.

The second component is installed capacity, or ICAP. This is a market in which generators are paid for having physical power plants available. The State is divided into three zones: Long Island, NYC, and the rest of NYS (ROS). IPEC is located in the ROS zone; its retirement will reduce supply in the ROS zone, and those effects will be felt everywhere in New York outside of NYC and Long Island. Because there is an economic surplus of supply in the NYC market, these effects will be somewhat attenuated in NYC.[25] To generalize, the principal impact on energy markets is felt in the LHV and NYC regions, while principal impact on ICAP markets is felt upstate.

Paying for Replacement Options

Despite the fact that New York has among the highest electricity prices in the country, NYS as a whole, and NYC in particular, currently have a level of generation supply which yields relatively low (compared to historical levels) energy and capacity prices and makes new entry by merchant (*i.e.* non-contracted) generation challenging because of the high costs associated with developing new generation and transmission here. The slow rate of load growth, increasing penetration of energy efficiency, and low natural gas prices contribute to these effects.

While some have stated that these factors combine to create an ideal opportunity to retire IPEC, they also make the development of privately-funded market-based solutions much more challenging. Based on our analysis, the new generation which would be required to maintain system reliability may not be supported by market revenues, and would likely need contractual support or subsides to be constructed. These costs (including associated infrastructure upgrades) will eventually be passed on to consumers through higher rates or other mechanisms. The magnitude of these costs is debatable, but they are real and significant.

[25] IPEC's retirement may help precipitate the formation of a new LHV ICAP zone, but for this analysis, we analyzed the market as it exists today. Formation of such a zone would reduce, but not eliminate, the effect of increased costs on upstate consumers.

1.4. Summary of Results

1.4.1. Reliability Impacts

We conducted a resource adequacy analysis of the New York system to determine whether IPEC's retirement would violate reliability criteria, and the effect of each replacement option on system reliability (*i.e.*, resource adequacy).

Resource adequacy is only one component of overall system reliability. There are many system reliability impacts related to the potential retirement of IPEC which we did not analyze, including but not limited to transmission system security, generation deliverability, and voltage support issues. Resource adequacy is a necessary, but not sufficient, criterion for overall system reliability.

Other analyses have been conducted related to the potential retirement of IPEC. While some of these have addressed resource adequacy, many of them have focused on other issues related to transmission system security and generation deliverability. Initial results from these analyses show that there are system reliability concerns which go beyond resource adequacy; adding capacity sufficient to meet resource adequacy criteria (or reducing demand) cannot be assumed to be sufficient alone to ensure overall system reliability. To be clear, changes in the grid can be effected to address these other system reliability concerns, but will likely require substantial cost.

Table 1 displays the LOLE for the New York Control Area (NYCA) using the base-case assumptions for the scenarios described at the beginning of section 1.2. Shaded and bold-text cells indicate those years in which the standard of 0.1 days/year is violated, indicating the system does not meet minimum reliability standards. Resource adequacy criteria are violated in 2016 in the case in which IPEC retires.

Table 1 - NYCA LOLE, Base-Case Assumptions

	IPEC Relicensed	No New Generation[26]	Conv. Thermal - LHV & NYC CCs	Low-Carbon
2012	0.002	0.002	0.002	0.002
2013	0.002	0.001	0.001	0.001
2014	0.002	0.011	0.018	0.018
2015	0.002	0.01	0.016	0.016
2016	0.003	**0.113**	0.063	0.017
2017	0.005	**0.151**	0.085	0.027
2018	0.004	**0.173**	0.089	0.027
2019	0.009	**0.27**	0.072	0.044
2020	0.015	**0.41**	**0.107**	0.068

1.4.2. Economic Impacts

In this analysis, we focused on changes in wholesale energy and capacity prices for New York City and New York State.[27] Prior analyses the City has conducted have focused on the relative costs and benefits from various projects in a regulatory context, calculated according to several different metrics. In this analysis, however, we have focused on the wholesale energy and capacity price impact rather than on retail price increases.

Table 2 and Table 3 summarize the impact of IPEC's retirement on wholesale[28] prices for consumers. The amounts shown in these tables indicate the aggregate sum of increased cost for consumers on a State and City level. The gray columns indicate those solutions which are less likely to be feasible from a system reliability perspective.

[26] Note that the results for the scenario in which no new generation is added do include the addition of Astoria Energy II, Bayonne Energy Center, and the HTP cable.

[27] The results of our analysis indicate that consumer costs also increased in New Jersey and surrounding states, although they are not summarized in this report.

[28] Defined here as the sum of energy (MWh) and installed capacity (MW) for simplicity.

Table 2 - NYS Total Incremental Consumer Cost ($million)

	No New Gen.		Conv. Thermal - CC in LHV only		Conv. Thermal - CCs in LHV and NYC		Low Carbon	
2016	$2,059	14%	$1,501	10%	$1,371	9%	$1,685	11%
2017	$2,123	13%	$1,611	10%	$1,436	9%	$1,707	11%
2018	$2,216	13%	$1,688	10%	$1,510	9%	$1,814	10%
2019	$2,256	12%	$1,650	9%	$1,535	8%	$1,740	9%
2021	$2,291	12%	$1,698	9%	$1,524	8%	$1,820	9%
2023	$2,349	11%	$1,774	9%	$2,031	10%	$2,159	11%
2025	$2,309	11%	$1,757	8%	$1,871	9%	$1,787	8%
2027	$2,239	10%	$1,680	7%	$1,040	4%	$1,259	5%
2030	$2,229	9%	$1,692	7%	$913	4%	$1,078	4%

Table 3 - NYC Total Incremental Consumer Cost ($million)

	No New Gen		Conv. Thermal - CC in LHV only		Conv. Thermal - CCs in LHV and NYC		Low Carbon	
2016	$485	8%	$327	6%	$254	4%	$271	5%
2017	$524	9%	$390	6%	$289	5%	$276	4%
2018	$523	8%	$391	6%	$292	4%	$304	4%
2019	$579	8%	$376	5%	$316	4%	$284	4%
2021	$595	8%	$433	6%	$313	4%	$339	5%
2023	$636	8%	$478	6%	$556	7%	$504	7%
2025	$620	8%	$474	6%	$512	6%	$348	4%
2027	$571	7%	$421	5%	$82	1%	$82	1%
2030	$571	6%	$408	5%	$39	0%	$14	0%

The wholesale energy and capacity price impact is roughly proportional, but not equivalent to, the consumer bill impact. Retail consumers are served by LSEs; these entities procure power on the wholesale market to serve their customers, but it is only a portion of their cost of service. In general, the bill impact to consumers is less than the wholesale price impact, although performing a detailed analysis of this impact requires information specific to each individual utility (*e.g.*, Con Edison) and its cost structure. Note that the percentage changes expressed here will be less when applied to bill impact, but the absolute impacts in dollars remain constant, as those costs are passed directly through. The incremental consumer costs summarized in Table 2 through Table 5 do not include the costs to consumers of additional subsidies, which are summarized in Table 6.

Table 4 and Table 5 show the net present value (NPV) of the cost of each replacement option to consumers for both NYS and NYC, calculated at a real 6% discount rate.

Table 4 – 15-Year NPV of Incremental Wholesale Market Consumer Costs, NYS ($million)

NYS	No New Gen	Conv. Thermal - CC in LHV only	Conv. Thermal - CCs in LHV and NYC	Low Carbon
2016	$2,059	$1,501	$1,371	$1,685
2017	$2,123	$1,611	$1,436	$1,707
2018	$2,216	$1,688	$1,510	$1,814
2019	$2,256	$1,650	$1,535	$1,740
2020	$2,274	$1,674	$1,530	$1,780
2021	$2,291	$1,698	$1,524	$1,820
2022	$2,320	$1,736	$1,778	$1,990
2023	$2,349	$1,774	$2,031	$2,159
2024	$2,329	$1,765	$1,951	$1,973
2025	$2,309	$1,757	$1,871	$1,787
2026	$2,274	$1,719	$1,455	$1,523
2027	$2,239	$1,680	$1,040	$1,259
2028	$2,234	$1,686	$976	$1,168
2029	$2,234	$1,686	$976	$1,168
2030	$2,229	$1,692	$913	$1,078
NPV	**$16,256**	**$12,179**	**$10,822**	**$12,262**

Table 5 – 15-Year NPV of Incremental Wholesale Consumer Costs, NYC ($million)

NYC	No New Gen	Conv. Thermal - CC in LHV only	Conv. Thermal - CCs in LHV and NYC	Low Carbon
2016	$485	$327	$254	$271
2017	$524	$390	$289	$276
2018	$523	$391	$292	$304
2019	$579	$376	$316	$284
2020	$587	$405	$314	$312
2021	$595	$433	$313	$339
2022	$616	$455	$435	$422
2023	$636	$478	$556	$504
2024	$628	$476	$534	$426
2025	$620	$474	$512	$348
2026	$595	$447	$297	$215
2027	$571	$421	$82	$82
2028	$571	$415	$60	$48
2029	$571	$415	$60	$48
2030	$571	$408	$39	$14
NPV	**$4,156**	**$3,012**	**$2,209**	**$2,018**

The analysis indicates that through 2030, NYC consumers will pay between $2 to $3 billion in higher energy costs, while NYS consumers will pay between $10-$12 billion in higher energy costs. The costs for NYC consumer are included in the costs for the State as a whole.

Table 6 displays the necessary contractual support for each proposed replacement option. These costs represent the amount of additional revenue that would be required for a private investor to develop the project at a commercially feasible rate of return.

A solution in which one 500 MW CC was constructed in the LHV did not require subsidies in our analysis, but additional capacity would lower market prices, and so a scenario in which 2,000 MW of capacity was constructed in the LHV (i.e. the One-for-One scenario) required $1.4 billion of additional subsidies.

Table 6 – 15-Year NPV of Additional Support Required for Replacement Options ($million)

NYC	Conv. Thermal - CC in LHV Only	Conv. Thermal - CCs in LHV and NYC	Low Carbon
2016	$0	$691	$2,109

We have not allocated these costs to consumers, as it is not clear how these costs might be passed on. They could be recovered through higher energy prices, or by another mechanism.

1.4.3. Air Emissions Impact

Table 7 and Table 8 show the effect of IPEC's retirement on the air emissions in NYS and NYC.[29] Emissions changes have been expressed in percentage terms to aid in comparison.[30]

Table 7 - NYS Incremental Air Emissions Impact

	Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
No New Gen	NO_x	10%	10%	11%	10%	11%	12%	12%	11%	10%
	SO_x	1%	1%	4%	3%	7%	6%	5%	8%	8%
	CO_2	13%	13%	12%	12%	12%	13%	13%	12%	10%
Conv. Thermal - LHV CC Only	NO_x	9%	9%	9%	8%	9%	10%	10%	9%	8%
	SO_x	0%	0%	2%	1%	4%	4%	4%	6%	6%
	CO_2	14%	14%	13%	13%	13%	14%	14%	12%	11%
Conv. Thermal - CCs in LHV & NYC	NO_x	7%	8%	8%	7%	8%	8%	8%	8%	7%
	SO_x	0%	0%	2%	2%	3%	3%	4%	5%	5%
	CO_2	15%	15%	14%	14%	14%	14%	14%	13%	11%
Low Carbon	NO_x	5%	4%	5%	5%	6%	6%	6%	6%	5%
	SO_x	0%	-1%	2%	-1%	4%	1%	5%	1%	2%
	CO_2	7%	7%	6%	6%	7%	7%	7%	7%	5%

[29] Changes in SO2 emissions for NYC are not shown in this table; the percentage changes in NYC's very small SO2 emissions can appear disproportionate to their importance.

[30] Air emissions here are defined here as the change in emissions from all powerplants physically sited in New York State. Our analysis indicates that emissions also increase in adjoining areas such as PJM and ISO-NE, although those higher emissions are not included in this report.

Table 8 - NYC Incremental Air Emissions Impact

	Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
No New Gen	NO_x	16%	15%	15%	16%	15%	15%	16%	14%	14%
	CO_2	19%	19%	17%	17%	18%	18%	20%	17%	14%
Conv. Thermal - LHV CC Only	NO_x	10%	11%	11%	9%	10%	11%	13%	9%	8%
	CO_2	13%	14%	12%	12%	14%	15%	16%	12%	10%
Conv. Thermal - CCs in LHV & NYC	NO_x	10%	10%	11%	10%	10%	10%	12%	9%	8%
	CO_2	19%	19%	18%	18%	18%	19%	20%	16%	15%
Low Carbon	NO_x	5%	3%	6%	6%	5%	4%	8%	5%	4%
	CO_2	8%	7%	7%	7%	8%	8%	11%	7%	5%

The retirement of IPEC's 2,000 MW of capacity results in a substantial increase in air emissions for the City and State. Even in the low-carbon scenario in which Canadian hydropower is coupled with offshore wind energy, CO_2 emissions increase by 7% above today's levels.

2. BACKGROUND & CONTEXT

2.1. NEW YORK'S POWER GRID TODAY

2.1.1. Energy Markets

The NYISO operates day-ahead and real-time spot electricity markets and dispatches generators throughout NYS to meet load, comply with applicable reliability standards and manage transmission congestion. Owners of generating assets can bid their units into the NYISO spot markets or self-schedule units so that they are dispatched at the owners' requests. Units that are self-scheduled or have bids accepted in the day-ahead market have a financial obligation to provide generation in real-time, and, if unable to provide the physical supply to match their obligation, must purchase generation from the real-time market. Generation sold within the NYISO markets is paid the locational-based market price (LBMP) for the node at which the generator is connected to the grid.

2.1.2. Installed Capacity Markets

The ICAP market is an integral part of the NYISO market design, through which it ensures system reliability and resource adequacy by providing the appropriate pricing signals for sufficient generation resources. Each (LSE is required to procure sufficient capacity to meet its share of specified reserve requirements. Units selected through the capacity auctions must either be bid into the day-ahead energy market or notify the NYISO of outages/deratings. In return, these resources are paid for each megawatt of capacity, regardless of whether the resource is actually called upon to supply energy or ancillary services.

The NYSRC sets the statewide installed capacity requirement. Based on the statewide requirement, the NYISO establishes locational requirements for New York City and Long Island which determines the portion of the statewide requirements that must be purchased in these localities to meet the resource adequacy reliability criterion. The locational requirements are the result of transmission limitations into those localities or zones. For the capability year which began May 1, 2011, the statewide requirement is 115.5 percent of peak electrical load demand (peak load). The 2011/2012 locational requirements for New York City and Long Island are 81 percent and 101.5 percent of the peak load in each zone, respectively. LSEs in those zones must purchase at least that quantity of capacity from resources internal to the zone, while meeting the remainder of their total ICAP requirement with ROS resources. Each locational capacity market is cleared independently to provide price signals for entry where additional capacity is needed. This means, for example, that if New York City is facing tighter installed capacity conditions relative to its requirement than is the State overall, the capacity price for New York City will be above the statewide price, providing an incentive to site new generation within Zone J.

Because the capacity price for ROS reflects the overall NYISO capacity requirement, not just the capacity requirement in ROS zones, the available capacity resources in constrained pockets will also affect the ROS price. Unlike the energy market, in which the level of demand within a constrained area will not affect prices in unconstrained areas once a closed transmission limit is binding, an increase in demand within New York City or Long Island will also impact the statewide market and the ROS price through an increase in the market-wide capacity requirement. Hence, even for assets located outside of the New York City and Long Island capacity zones, the market price paid for the capacity from these units will still be affected by the capacity supply and demand in those zones, and price projections for the ROS area need to reflect market conditions across all locations.

Capacity from external resources can also be sold into the NYCA as ROS resources.[31] Imports from adjoining regions are limited both by the capacity of the transmission inter-ties as well as an overall import limit for the NYISO. The ROS zone of the NYISO system is directly connected with ISO New England, Inc. (ISO-NE), the PJM Interconnection L.L.C. (PJM) and the Ontario Independent Electric System Operator (IESO) via alternating current (AC) transmission lines. Additionally, it is connected with Hydro Quebec ("HQ") via HVDC cables. The New York City and Long Island zones also have interconnections with external areas. Long Island is connected to eastern PJM through the HVDC Neptune Cable and to ISO-NE by way of the HVDC Cross Sound Cable. New York City is connected to eastern PJM via the Linden VFT cables. Because each of these external connections in New York City and Long Island involves a controllable transmission line, the imports on the lines count towards the locational capacity requirement, rather than ROS capacity.

[31] External resources directly connected to New York City or Long Island (*e.g.*, generator leads) may qualify as capacity in those zones.

2.2. LEGAL AND REGULATORY CONTEXT

A great deal has been written regarding the legal and regulatory issues surrounding the NYSDEC's staff recommendation for a denial of a water quality certificate; the purpose of this report is not to attempt to summarize or shed new light on that issue. Nevertheless, it is important to recognize a few basic facts regarding IPEC's potential retirement.

One seldom-discussed aspect of the issue is whether IPEC can retire if doing so would violate reliability criteria. While the issue of whether IPEC must retire or be relicensed is often cast as a public policy issue, IPEC is owned and operated by Entergy Nuclear, a corporation. While Entergy has stated its desire to keep IPEC online, it is free to retire IPEC if it chooses.[32]

The question of what would ensue in a regulatory context if doing so were to violate reliability criteria is an unanswered question. There is no regulatory mechanism to compel Entergy to keep IPEC open. The NYISO'S reliability planning process contains backstop provisions[33] which could require the NYTOs to submit generation or transmission proposals to address the reliability violations that would occur due to IPEC's retirement. There is a question, however, whether these solutions could be implemented in time if Entergy were to announce its intention to retire IPEC at the end of the licenses.

The interplay between state and federal jurisdiction is also critical to understanding the regulatory issues. While the water quality certificate issued by the NYSDEC is a state issue[34], the operating license issued by the Nuclear Regulatory Commission (NRC) is a federal issue. It is unclear whether the NRC would issue an operating license to IPEC if a water permit were not granted by the State. Statutorily, one is not contingent upon the other, but it is unclear what decision the NRC will reach.

Additionally, the reliability standards to which the NYISO must adhere in planning and operating the New York State power grid are set by mandatory federal and state requirements. The NYISO follows federal planning and operating standards adopted by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC), as well as resource adequacy standards approved by the NYS PSC.

In addition, the NYISO follows planning and operating criteria and rules of the Northeast Power Coordinating Council (NPCC), and of the New York State Reliability Council (NYSRC). Under Section 215 of the Federal Power Act, the NYSRC promulgates and the New York

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[32] There is no guarantee that Entergy would choose to retire its units according to the schedule shown here. Because of their orientation towards multi-reactor sites, refueling schedules and other factors, it is possible that they could choose to retire IP3 at the same time as IP2 or at any other time.

[33] http://www.nyiso.com/public/webdocs/newsroom/current_issues/nyiso_planning_process_ferc_presentation07162008.pdf, accessed June 2011

[34] More precisely, the Clean Water Act is a federal requirement which is implemented at the state level.

State Public Service Commission adopts reliability rules for New York State that are more specific or more stringent than federal and regional reliability rules. In any event, the state-specific rules cannot set requirements that are less stringent than the regional and federal requirements, which include resource adequacy and transmission security rules for planning and operating the bulk power system.

3. PROJECT OVERVIEW

3.1. PROJECT APPROACH

3.1.1. Production Cost Simulation

We developed an economic security-constrained dispatch model of the interconnected power system using the GE MAPS program. Our model encompassed the NYISO, ISO-NE, PJM, and IESO systems. Interconnections to Quebec were modeled as price-sensitive supply functions based on analyses of historic market behavior. Further details of our assumptions and the results of our market simulation calibration are included in section 3.2.1.

GE MAPS

We used the GE MAPS model to simulate the interconnected power system. 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 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, 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.

3.1.2. Resource Adequacy Analysis

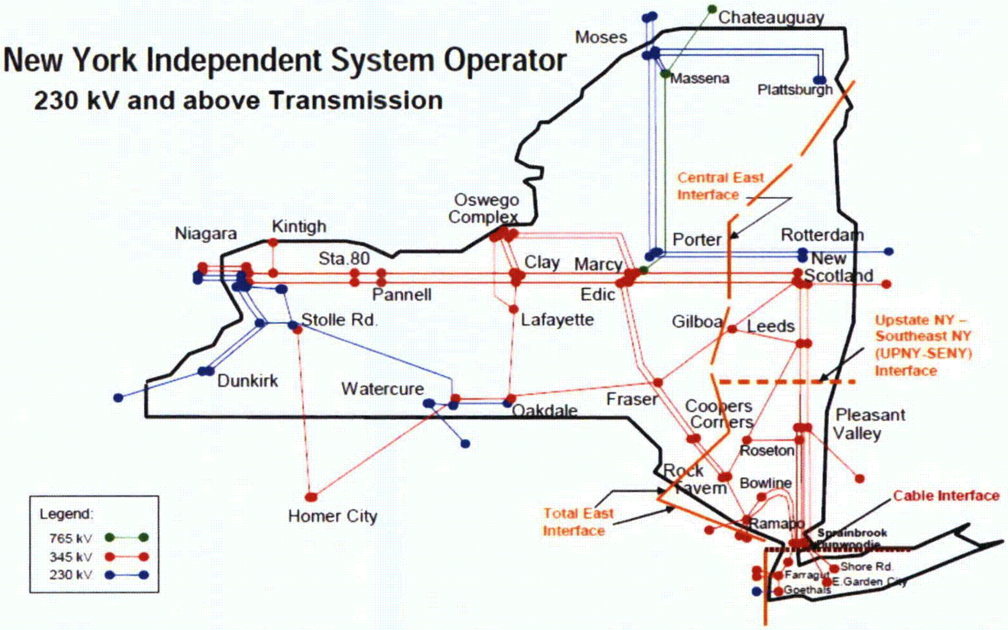
In this study, we have analyzed exclusively the resource adequacy of the NYISO system. Resource adequacy is only one portion of a system's reliability. Resource adequacy by itself is a necessary, but not sufficient, condition for overall system reliability.

The principal measure of resource adequacy is Loss of Load Expectation (LOLE). The LOLE is a probabilistic calculation which indicates the probability the need to interrupt load in a given year. The standard in use for system planning by the NYISO is 0.1, or a resource inadequacy not more than once in every ten years.[35]

Because of transmission constraints throughout the network, not all generation capacity can serve load in all regions. A shortage of generation on Long Island, for instance, cannot necessarily be served by adding generation in Buffalo.

IPEC is located at an important point in the New York system. The New York City region is a net consumer of electricity, and so most electricity flows towards NYC, crossing several constrained interfaces in the system such as the Central-East and UPNY-SENY, as shown in Figure 1. IPEC is located on the "downstream" side of these constraints and so provides a supply resource near the load area which reduces the amount of transmission that is required to deliver power from upstate resources.

Figure 1 - New York State Transmission System



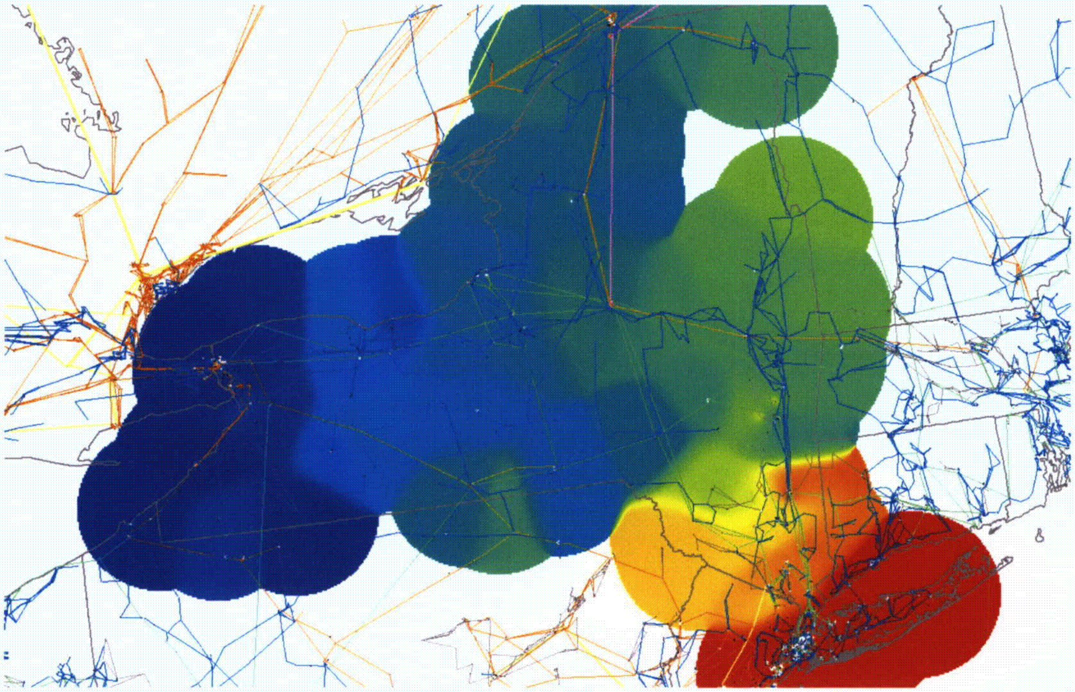
In particular, it provides a source of local generation for the LHV and NYC areas. In addition to providing active power generation, the reactive power reserves provided by IPEC support the voltage necessary to keep the transmission system secure.

[35] The Installed Reserve Margin (IRM) is set by "working backwards" from the LOLE to determine the amount of excess capacity necessary to ensure that the LOLE stays below 0.1.

Figure 2 shows typical price contours for NYS. High prices are indicated in red, and lower prices are indicated in blue. Prices are generally low in the eastern and northern portion of the State, with transmission constraints causing higher prices in the southeastern portion of the State.[36] The distinct boundaries in the figure below clearly highlight the Central-East interface, the UPNY-SENY interface (the green/orange boundary south of Albany), and the UPNY-ConEd interface (the orange/red boundary in Westchester County).

IPEC is physically located in Westchester County, on the "downstream" side of the UPNY-SENY and Central-East constraints, making its energy output sited at a particularly important location.

Figure 2 - Typical New York Energy Prices



In addition, an often-overlooked component of energy security is the security of the interstate gas transmission system. Given the current environmental, regulatory and policy environment, it is likely that any replacement capacity constructed would be natural gas-fired. While the interstate gas transmission system has a great deal of capacity, it is a finite limit, and the use of large amounts of gas at the IPEC site may introduce gas system reliability concerns.[37]

[36] In the contour map below, higher-priced areas are indicted in red, lower-priced areas indicated by blue

[37] We did not conduct a rigorous analysis of the gas system constraints that might exist, but did perform a cursory analysis of gas pipeline nomination data and prices. This high-level check suggests that there are capacity issues that must be addressed.

We conducted a resource adequacy analysis of the New York system using GE MARS.[38] The analysis started from the NYISO's 2010 RNA base-case database.[39] The NYISO's 2010 RNA dataset was modified to adjust for the load forecast used in this study, and the capacity additions which differed from those in the NYISO 2010 RNA, including the HTP cable. The modifications made to the NYISO database are detailed in section 3.2. The transfer limits, unit forced outage rates, and other inputs were identical to those used in the 2010 RNA.

The principal change in the resource mix was the inclusion of the HTP cable. We modeled it with both as 320 MW of firm capacity, with a sensitivity where we modeled it with no firm capacity. [40]

The retirement of IPEC would change the transfer limits employed in the resource adequacy analyses (shown in Figure 3), meaning that our analysis would have to be adjusted for this fact. While we have not analyzed the change in the transfer limits, our expectation (and the expectation of some Group members) is that transfer limits would decrease, meaning that the actual amount of capacity necessary to maintain minimum reliability standards may be higher than reported here, meaning that LOLEs could be higher than analyzed here.

Given project schedule and resource constraints, we conducted the resource adequacy analysis only under our base set of assumptions with the exception of an additional analysis of the impact of the NYISO's 2011 Gold Book load forecast, released during our study. Capacity additions sufficient to maintain reliability under the base case would, of course, be sufficient to maintain reliability under a low-load forecast.

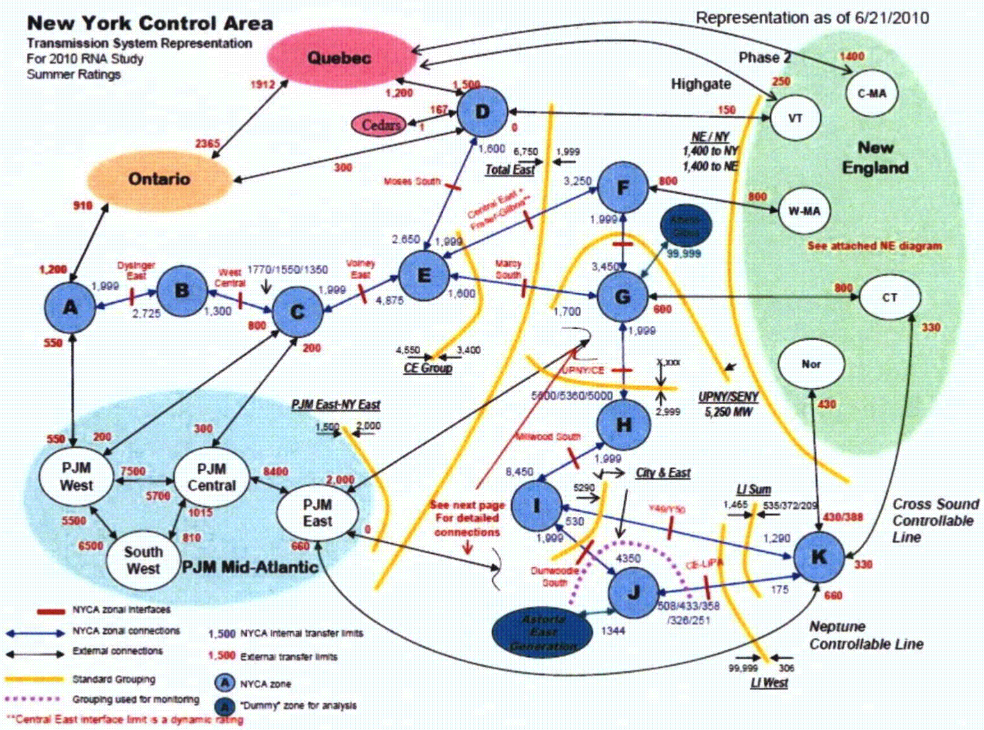
Figure 3 displays the system topology from the 2010 NYISO RNA base case.

[38] The actual operation of the GE MARS model was performed by General Electric.

[39] The NYISO supplied the database for our analysis and confirmed that no confidential data were released, but has neither reviewed or endorsed the analytical results presented here.

[40] HTP is capable of transferring up to 660 MW of electrical energy into NYC, but it has only 320 MW of "Firm" Transmission Withdrawal Rights (FTWRs) from PJM, meaning that the maximum capacity it could reliably export to NYC would be 320 MW without grid reinforcements in New Jersey. The line's operator would need to purchase the right to use a power plant's output in PJM to supply NYC, "delisting" that capacity.

Figure 3 - NYISO MARS Topology



Source: NYISO

GE MARS

GE MARS enables electric utility planners to quickly and accurately assess the ability of a power system, comprised of any number of interconnected areas, to adequately satisfy customer load requirements.

Based on a full sequential Monte Carlo simulation, GE MARS performs a chronological hourly simulation of the system, comparing the hourly load demand in each area to the total available generation in the area, which has been adjusted to account for planned maintenance and randomly occurring forced outages. Areas with excess capacity will provide emergency assistance to those areas that are deficient, subject to the transfer limits between the areas.

Typical MARS applications include:

- Resource adequacy assessments
- Locational capacity requirements
- Effective Load Carrying Capability (ELCC) calculations
- Benefits of load diversity

- Tie-line effectiveness
- Expected need for Emergency Operating Procedures (EOPs)

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

GE MARS calculates, on an area and pool basis, the standard indices of daily and hourly Loss of Load Expectation (LOLE, days/year and hours/year) and expected unserved energy (LOLE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). To model the impact of EOPs, the program also calculates the expected number of days per year at specified positive and negative margin states.

In addition to calculating the expected values for the reliability indices, MARS (through a separate post-processor program) also produces probability distributions that show the actual yearly variations in reliability that the system could be expected to experience.

MARS provides for the detailed representation of the utility system required to accurately assess the reliability of the generation system. In addition, the program has been written so its dimensions (number of areas, pools, units, etc.) can be easily changed to fit the program to the system being studied.

3.1.3. ICAP Market Simulation

We modeled capacity benefits in this study using our proprietary model of the NYISO ICAP 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 May 2011. After May 2011, CRA has assumed that the annual revenue requirement used to set the demand curve will increase at the rate of general inflation.

Pricing in the NYISO Unforced Capacity (UCAP) spot auctions is driven by an administratively-determined demand curve. The demand curve is constructed by the NYISO with the objective of providing a payment to the marginal new technology (currently frame gas turbines for upstate New York and LMS 100 gas turbines for New York City and Long Island) that, net of energy and ancillary services payments, covers its all-in capital and operating costs. Separate curves are established for the NYCA, NYC, and Long Island. Generators offer capacity into the market at specified prices, with the offers forming a supply curve. The market clearing price is set by the intersection of the supply and demand curves.

In addition to the demand curve, estimating market clearing prices requires a supply curve. We obtained unit ratings for all existing capacity resources from the 2011 NYISO Gold Book. Assumptions regarding new capacity resources are detailed elsewhere in this report. The offer curves modeled for NYC reflect the NYISO rules for mitigation of market power; existing resources are offered on a price-taking basis, and new resources not qualifying for an exemption from mitigation are subject to an offer floor calculated as the lower of 75 percent of the net cost of new entry (CONE) or the resource's own unit net CONE.[41]

There was discussion among the Group regarding the appropriate reserve margin, or surplus, to use in determining capacity additions for NYC and NYS. Electricity markets in NYC have an economic surplus of generation right now relative to historical levels. In the next several years, this economic surplus is expected to grow as new generation resources (Astoria Energy II, BEC, HTP) are added to the market. Table 9 and Figure 4 shows the base-case IRM summary for the NYCA. The important column is the one at the right: it indicates the ICAP as a percentage of the IRM. A figure of 100% would indicate that the ICAP is at the IRM. Our capacity additions assume the market "tightens" with respect to ICAP.

This is in part due to a view that current ICAP and energy prices may not be sustainable for a long-term competitive market. It is important to note that if one assumes that a greater surplus continues to exist in the base case (*i.e.*, the market does not tighten), then the costs of an IPEC retirement would be higher.

Table 9 - Base Case NYCA IRM Summary

Capability Year	Peak Load Fore-cast	ICAP Require-ment	Available ICAP Re-sources	ICAP as Pct of IRM
2010	33,025	38,970	42,037	108%
2011	32,699	37,767	42,946	114%
2012	33,615	39,035	43,408	111%
2013	33,985	39,677	42,814	108%
2014	34,345	40,312	43,902	109%
2015	34,642	40,878	44,703	109%
2016	34,991	41,289	44,703	108%
2017	35,273	41,622	44,703	107%
2018	35,646	42,062	44,703	106%
2019	36,042	42,530	44,728	105%
2020	36,503	43,074	44,730	104%
2021	36,869	43,505	44,730	103%
2022	37,279	43,989	44,980	102%
2023	37,694	44,479	44,983	101%
2024	38,113	44,974	44,985	100%

41 The net CONE calculation performed by the NYISO takes into account the energy revenues received by generators, and so all else equal, a higher energy price would yield a lower net CONE. We have not adjusted our net CONE to account for this fact, but we do not believe the change would materially impact the results.

2025	38,537	45,474	45,513	100%
2026	38,966	45,980	46,015	100%
2027	39,399	46,491	46,518	100%
2028	39,838	47,009	47,520	101%
2029	40,281	47,531	47,523	100%
2030	40,729	48,060	48,050	100%

Figure 4 - Base Case NYCA IRM Summary

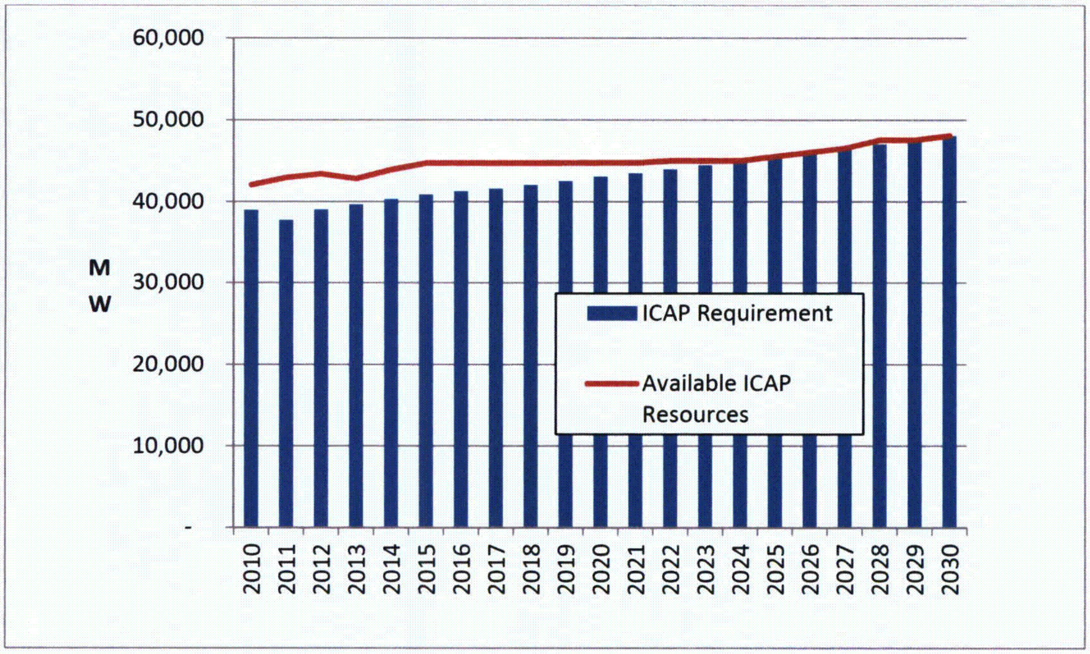


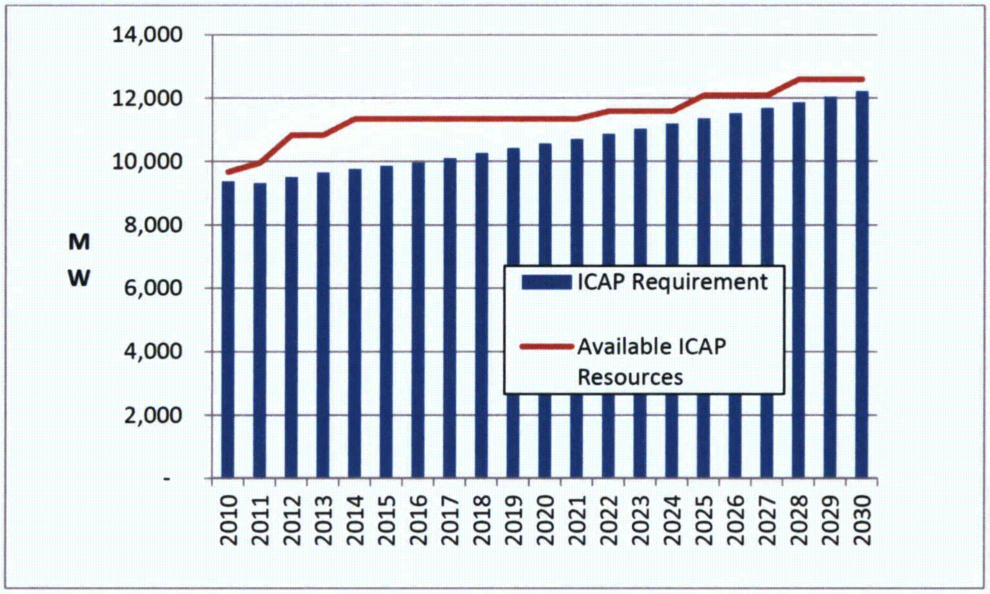
Table 10 and Figure 5 display a summary of our IRM for the NYC region. The columns are defined as in Table 9. In our capacity addition pattern, we add capacity to maintain the market surplus at a level similar to 2010's, approximately 3 percent.

Table 10 - Base Case NYC IRM Summary

Capability Year	Peak Load Forecast	ICAP Requirement	Available ICAP Resources	ICAP as Pct of IRM
2010	11,725	9,380	9,675	103%
2011	11,514	9,326	9,956	107%
2012	11,752	9,519	10,826	114%
2013	11,915	9,651	10,826	112%
2014	12,056	9,765	11,338	116%
2015	12,173	9,860	11,338	115%
2016	12,299	9,962	11,338	114%

2017	12,473	10,103	11,338	112%
2018	12,663	10,257	11,338	111%
2019	12,861	10,417	11,338	109%
2020	13,046	10,567	11,338	107%
2021	13,224	10,711	11,338	106%
2022	13,419	10,869	11,588	107%
2023	13,616	11,029	11,588	105%
2024	13,817	11,192	11,588	104%
2025	14,020	11,356	12,088	106%
2026	14,227	11,524	12,088	105%
2027	14,436	11,693	12,088	103%
2028	14,649	11,865	12,588	106%
2029	14,864	12,040	12,588	105%
2030	15,083	12,217	12,588	103%

Figure 5 - Base Case NYC IRM Summary



3.1.4. Simplified Pro-Forma Analyses

There is uncertainty regarding the cost of proposed projects and the amount of additional financial support that might make these conceptual replacement projects viable. The overall market for energy and capacity in NYS has been soft in recent years, and this soft market is forecast to persist for some time, especially in NYC.

We analyzed a hypothetical project financing pro-forma with nominal financing assumptions to determine whether these notional projects would be supported by market revenues and could conceivably enter the market as a merchant generator (or transmission) operator.

It is important to understand what the quantity we have identified as "additional support" or "subsidies" represents. Powerplants and transmission lines earn revenue through sales of energy and capacity into the New York markets. These revenues, however, may not be sufficient to support capital recovery for the project at a level to earn a sufficient financial return for investors. Put simply, the project may be in the red.

In the simplest case, a project which does not recover its capital costs and supply an adequate return to its investors would not be built by a merchant developer. In the case of a project whose output is contracted for by an off-taker (*e.g.*, NYPA, Con Edison, LIPA), the additional support required would be supplied in the form of above-market contract payments which would flow to the project's investors.

The precise analysis of any individual project's finances is beyond the scope of this study. There are invariably generalizations in the financing assumptions which may not be entirely accurate for any given project. Nevertheless, we believe the assumptions and methodology we have employed here represent suitable general assumptions to yield an approximate answer. Table 11 displays our financing analysis assumptions. The real cost of equity, 9.8%, represents the real hurdle rate.

Table 11 - Pro-Forma Financial Analyses Assumptions

Working Capital (% of FOM)	12.50%
Federal Income tax	35.00%
NY state income tax	7.10%
NYC income tax	8.85%
Composite tax rate	45.37%
Insurance rate	5.00%
Gross Property tax rate	5.000%
Assessment rate	45.00%
Net Property tax rate	2.25%
Equity percent	50%
Debt percent	50%
Risk-free rate	4.72%
Equity Beta	1.2
Equity risk premium	6.47%

Cost of equity (nominal)	12.48%
Cost of debt (nominal)	7.25%
Debt Amortization (years)	20
Tax depreciation (MACRS)	20
Book Depreciation	20
Equity Recovery Period	20
Inflation rate	2%
Nominal WACC	9.87%
Cost of equity (real)	9.84%
Cost of debt (real)	4.74%
Before-Tax (real) WACC	7.29%
After-Tax (real) WACC	6.22%

3.1.5. Evaluation Metrics

There are numerous methods to calculate the economic impact of a power project: production cost impact, consumer cost impact, NYC cost impact, and overall interconnected-system impact. Our analysis focuses on the impact of a potential IPEC retirement, and so the impact on NYC ratepayers is the foremost economic metric used for evaluation.

Consumer cost benefit is defined as 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 (for energy prices) of consumer impact. This metric is sometimes favored by regulators, as it is the most direct impact on consumers.

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, and generators pay a higher cost to emit air pollutants, including these costs in their bids.

3.1.6. Replacement Options

We started from the basic assumption that IPEC's retirement would

- Require action to maintain electric system reliability, and;
- Precipitate development of new generation or transmission resources, independent of their funding source.

In approaching the problem, we had two principal options. The first was to use a capacity expansion model to determine a single economically optimal system expansion, taking into account reliability constraints. The second was to develop a range of feasible replacement scenarios reflective of actual market conditions and relevant to actual proposed projects. We chose the latter approach and with input from our Group, developed set of replacement options which could conceivably be developed upon IPEC's retirement. These options were then winnowed through analysis of their reliability impact to a set of options analyzed here.

3.2. DEVELOPMENT OF INPUT ASSUMPTIONS AND SCENARIOS

Table 12 shows a summary of the scenarios and the replacement options we analyzed.

Table 12 - Scenarios and Options Analyzed

	Base Case	High Case	Low Case
Status Quo	X	X	X
No New Generation	X		
One-for-One	X		
CCs in LHV and NYC	500 MW & 1,000 MW	1,000 MW	1,000 MW
Low Carbon	X	X	X

3.2.1. Common Assumptions

The initial phase of the project focused on the development of key assumptions and the methodology. Complex analyses of the type undertaken here involve a large number of assumptions. In a study such as this, the objective is to develop assumptions that allow us to compare options on an equal footing. We modified some of our standard assumptions based on input and feedback from the Group. We highlight here some of the key assumptions employed:

- The load forecast used was a modified 2011 Gold Book load forecast from the NYISO. Energy efficiency penetration was assumed to be 50% of targets. This assumption is described in greater detail below.
- We have assumed that a national mandatory carbon policy is imposed starting in 2018 with prices starting at $15 at that time. This largely mirrors current industry consensus forecasts, although it is lower than estimates from several years ago. Changes in the price of carbon reflect the effects of a changing cap. The Regional Greenhouse Gas Initiative (RGGI) is assumed to remain in force until 2018.
- We have assumed that the Hess Bayonne Energy Center (BEC) is online and operational by 2013.
- We utilized a modified 2008-series Eastern Interconnection Reliability Assessment Group (ERAG) power flow case for our production cost simulations.
- We modeled strategic bidding behavior (*i.e.*, "bid adders") and transmission outages, detailed below.
- We assumed that the Hudson Transmission Partners cable (HTP) is in service in 2013 with 320 MW of firm capacity.

We modeled the following years: 2016-2019, 2021, 2023, 2025, 2027 and 2030. Interpolated values between these modeled years are shown in some tables and calculations. All dollar values are shown in real 2010 dollars unless otherwise noted.

ICAP Market Assumptions

The NYISO ICAP market is a major component of the analysis for the replacement options. Some of the key assumptions we employed were:

- We did not assume the creation of a new LHV capacity zone. The retirement of IPEC could be the precipitating event for the creation of such an ICAP zone, but with input from the Group, we modeled the ICAP zones as they exist today.
- Our demand curve has been updated to reflect the impact of recent property tax abatement rulings

Capacity market mitigation assumptions were the topic of a great deal of discussion in the Group. The state of capacity market mitigation rules is highly fluid. There have been numerous disputes regarding these rules over the last several months, and predicting what these rules may be fifteen years from now with any certainty is nearly impossible.

At a high level, we have included in our analysis the assumption that a capacity market offer floor exists in the market for the foreseeable future, and that new entrants who enter when a surplus exists (as is assumed for all NYC replacement options in our analysis) are compelled to offer at the offer floor until such time as they clear for a pre-determined number of months in the market.

Given the current economic market surplus in NYC, and our assumption regarding mitigation of new entrants, we believe it is likely that any new entrant would not clear in the market for many years.[42] Given a reasonable discount rate, the amount of capacity that clears near the end of the study timeframe would not likely have a material impact on the overall project economics and market effects.

Table 13 - ICAP Market Reference Point at 100% on Demand Curve

Capability Year	NYC	LI	NYCA
2016	32.93	10.75	10.15
2017	33.59	10.96	10.36
2018	34.26	11.18	10.56
2019	34.94	11.40	10.77

[42] The NYS DPS asserts that new capacity needed for "legitimate policy goals" may be exempt from mitigation and not subject to the floor. FERC, in its September 30, 2008 order on docket EL07-39-002, indicates that the NYS PSC is entitled to petition under the Federal Power Act to have new capacity exempted from the price floor. If new capacity in NYC is exempted from mitigation, it may have a downward effect on NYC ICAP prices.

2020	35.64	11.63	10.99
2021	36.36	11.86	11.21
2022	37.08	12.10	11.43
2023	37.82	12.34	11.66
2024	38.58	12.59	11.90
2025	39.35	12.84	12.13
2026	40.14	13.10	12.38
2027	40.94	13.36	12.62
2028	41.76	13.63	12.88
2029	42.60	13.90	13.13
2030	43.45	14.18	13.40

Demand and Load

The load forecast utilized figures fundamentally into the analysis of IPEC's retirement impact. Demand (MWh) and peak load (MW) assumptions for New York were based on the most recent NYISO forecast available when we began our analytical work, dated March 17, 2011.[43]

The load forecast from the NYISO forecasts an overall energy efficiency achievement of 91% of the PSC's Energy Efficiency Portfolio Standard (EEPS) goal (about 30% of the entire 15x15 goal). The historical achievement of energy efficiency versus target levels was 57% from 2009 through 2010.[44] The most recent forecast from the NYISO assumes few incremental conservation benefits post-2017 (as demonstrated in Figure 8), as the PSC's EEPS goal is projected to be achieved by 2018.

The NYISO and others have noted in the past that energy efficiency programs are more likely to under-achieve than over-achieve[45], and there is considerable debate regarding the appropriate amount of energy conservation to forecast for reliability purposes, and how "conservative" reliability load forecasts should be.[46] In an effort to be realistic regarding future demand growth, we assumed 50% achievement of energy efficiency targets, a level selected after extensive discussion some Group members.

[43] The March 17, 2011 forecast from the NYISO contains only co-incident peak loads. Because non-coincident peaks, necessary for GE MARS and GE MAPS modeling, were not available, we calculated regional coincidence factors based on 2010 data, yielding non-coincident 2011 forecasts which differed by less than one megawatt from the final 2011 non-coincident forecast.

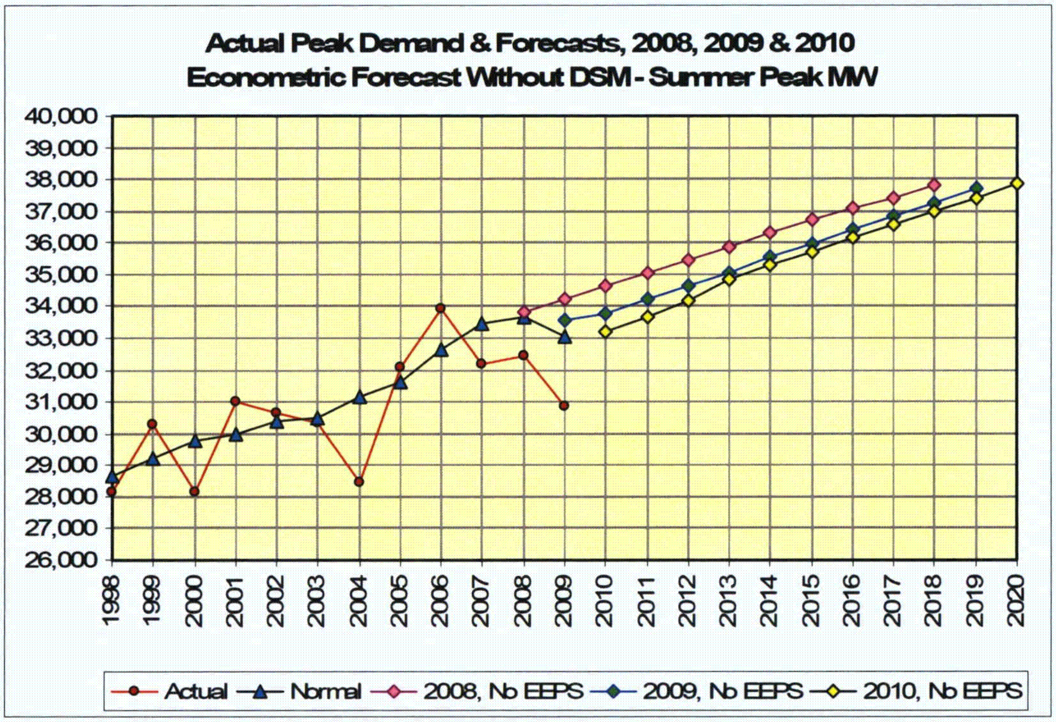
[44] NYISO's Energy Efficiency Program Status Report, presentation to the Electric System Planning Working Group (ESPWG), dated February 17, 2011

[45] This is partly due to the fact that energy efficiency penetration is typically measured against technical potential.

[46] NYISO's 2010 RNA Forecast, presentation to the ESPWG, dated March 5, 2010

Figure 6, from a recent NYISO presentation, shows the load growth of the system compared to the forecast load. Forecasts over the past decade have neither consistently under- nor over-estimated load.

Figure 6 - Long Term Trend of Load Growth



Source: NYISO

Figure 7 shows how the load forecast for 2016 has evolved over time in succeeding Gold Books, showing a substantially-decreasing peak load forecast. Part of this is due to changing forecasts of economic activity, and part of it to assumptions of greater energy efficiency penetration.

Figure 7 - Change in 2016 NYC Peak Load Forecast

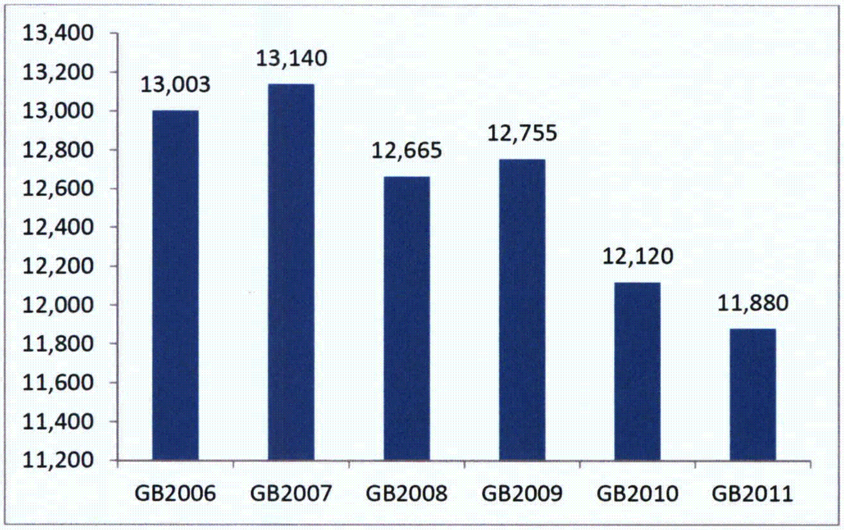


Figure 8 displays data taken from the 2011 Gold Book which details energy efficiency impacts on peak load for NYC and NYS. Forecasts from the NYISO show growing energy efficiency impacts, both as an absolute number, and as a percentage of load, over the coming ten years. The Gold Book indicates that energy efficiency initiatives are forecast to comprise approximately 1% of NYC's peak load in 2011, rising to 8% by the end of the study period. This represents is a total of 837 MW in peak load reduction for NYC in 2016. The data also show that almost all energy efficiency measures forecast for NYC are achieved by 2017; a delay in the programs' implementation would yield higher load forecasts prior to 2016.

Figure 8 - Forecast Peak Load Reductions from Energy Efficiency (MW)

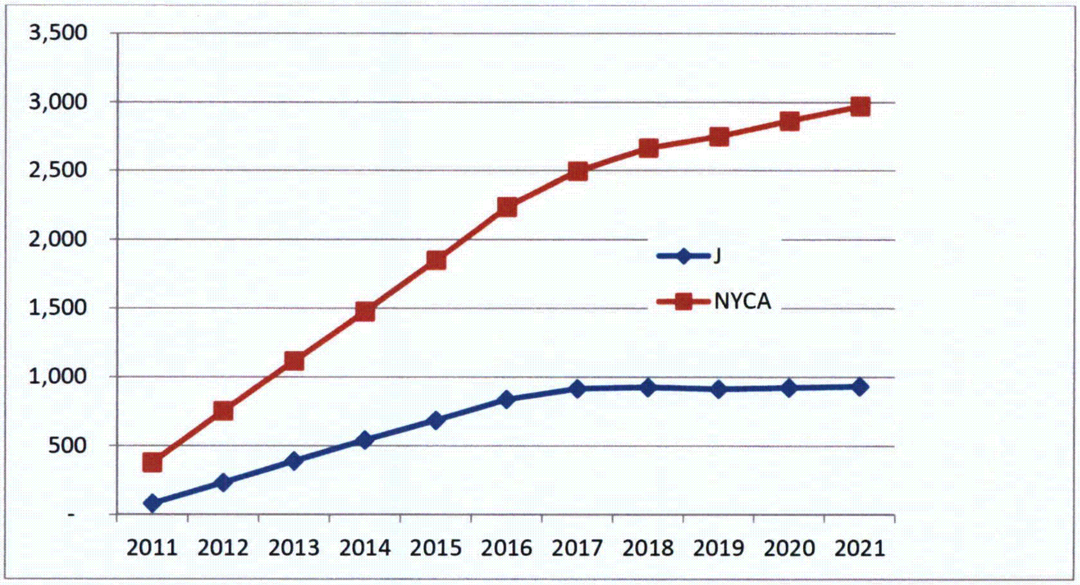


Table 14 and Table 15 show the annual zonal and aggregate NYISO demand and peak load.

Table 14 - New York Non-Coincident Summer Peak (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2011	2,670	2,029	2,892	660	1,395	2,253	2,294	732	1,468	11,555	5,477	32,870
2012	2,695	2,059	2,941	870	1,394	2,294	2,342	746	1,504	11,752	5,600	33,615
2013	2,724	2,075	2,953	879	1,383	2,310	2,362	762	1,526	11,915	5,686	33,985
2014	2,766	2,090	2,997	885	1,380	2,328	2,385	772	1,847	12,056	5,731	34,345
2015	2,781	2,104	3,016	897	1,394	2,347	2,407	778	1,559	12,173	5,783	34,642
2016	2,786	2,123	3,034	915	1,412	2,371	2,432	788	1,567	12,299	5,867	34,991
2017	2,775	2,132	3,035	916	1,417	2,355	2,444	798	1,584	12,473	5,913	35,273
2018	2,772	2,150	3,043	922	1,423	2,410	2,465	803	1,596	12,663	6,004	35,646
2019	2,773	2,170	3,058	926	1,433	2,432	2,492	809	1,613	12,861	6,081	36,042
2020	2,785	2,201	3,085	935	1,450	2,468	2,526	817	1,629	13,046	6,173	36,503
2021	2,784	2,219	3,097	939	1,457	2,488	2,551	829	1,651	13,224	6,158	36,869

Table 15 - New York Annual Energy (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2011	15,589	10,027	16,516	4,802	7,927	11,343	10,542	2,977	6,184	54,631	22,694	163,229
2012	15,681	10,125	16,713	6,337	7,895	11,470	10,702	3,022	6,273	55,411	23,076	166,697
2013	15,801	10,155	16,730	6,424	7,817	11,485	10,719	3,037	6,293	55,592	23,357	167,408
2014	16,002	10,194	16,919	6,450	7,780	11,521	10,764	3,057	6,262	55,939	23,552	168,508
2015	16,046	10,218	16,969	6,552	7,831	11,551	10,793	3,075	6,302	56,202	23,760	169,357
2016	16,046	10,274	17,019	6,675	7,923	11,626	10,853	3,102	6,410	56,625	24,122	170,672
2017	15,951	10,291	16,979	6,698	7,941	11,653	10,872	3,117	6,437	56,863	24,361	171,160
2018	15,893	10,344	16,982	6,732	7,971	11,704	10,917	3,146	6,501	57,432	24,659	172,279

2019	15,875	10,425	17,036	6,768	8,016	11,788	10,997	3,174	6,567	58,009	24,969	173,610
2020	15,929	10,556	17,148	6,828	8,102	11,927	11,135	3,215	6,651	58,757	25,369	175,614
2021	15,901	10,633	17,184	6,846	8,140	12,002	11,216	3,238	6,699	59,130	25,647	176,684

ISO-NE, PJM and IESO load forecasts were based on the most recent published forecasts of each respective system operator. For modeling years beyond each system operator's forecast horizon, the last-five-year average annual growth rate was be projected to continue into the future.

Our high and low demand scenarios consist of the following peak load forecasts.

Table 16 - High Load New York Non-Coincident Summer Peak (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2011	2,680	2,037	2,903	664	1,400	2,261	2,303	738	1,477	11,649	5,522	33,070
2012	2,728	2,085	2,977	884	1,411	2,322	2,372	763	1,533	12,052	5,689	34,215
2013	2,787	2,123	3,022	903	1,416	2,364	2,417	790	1,571	12,433	5,832	35,036
2014	2,864	2,165	3,103	915	1,429	2,411	2,469	806	1,915	12,689	5,939	35,765
2015	2,913	2,204	3,160	937	1,460	2,459	2,522	815	1,621	12,899	6,056	36,413
2016	2,952	2,250	3,215	966	1,497	2,513	2,577	827	1,635	13,085	6,209	37,089
2017	2,965	2,278	3,242	974	1,514	2,517	2,611	843	1,662	13,369	6,310	37,678
2018	2,976	2,309	3,266	985	1,529	2,588	2,646	851	1,682	13,636	6,453	38,268
2019	2,987	2,337	3,293	992	1,543	2,620	2,681	859	1,703	13,887	6,577	38,821
2020	3,003	2,372	3,324	1,002	1,563	2,661	2,720	868	1,721	14,093	6,697	39,356
2021	3,004	2,392	3,340	1,007	1,572	2,684	2,747	881	1,747	14,290	6,691	39,779

Table 17 - Low Load New York Non-Coincident Summer Peak (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2011	2,665	2,025	2,886	658	1,392	2,248	2,290	730	1,463	11,508	5,454	32,769

2012	2,679	2,046	2,922	862	1,386	2,279	2,327	737	1,489	11,602	5,555	33,315
2013	2,692	2,050	2,918	866	1,367	2,283	2,334	749	1,503	11,656	5,614	33,460
2014	2,717	2,053	2,944	870	1,355	2,287	2,342	755	1,813	11,739	5,626	33,635
2015	2,715	2,053	2,945	878	1,360	2,290	2,349	760	1,527	11,809	5,646	33,756
2016	2,702	2,059	2,943	889	1,369	2,300	2,359	768	1,533	11,905	5,696	33,942
2017	2,680	2,059	2,932	887	1,368	2,274	2,361	775	1,545	12,024	5,714	34,070
2018	2,669	2,071	2,931	891	1,371	2,321	2,375	779	1,553	12,176	5,780	34,334
2019	2,666	2,087	2,941	893	1,377	2,338	2,397	784	1,568	12,348	5,834	34,653
2020	2,677	2,116	2,965	901	1,393	2,372	2,430	791	1,583	12,523	5,911	35,076
2021	2,674	2,132	2,975	905	1,400	2,390	2,453	803	1,604	12,690	5,891	35,413

Gas Prices

Natural gas prices are based on NYMEX traded futures (March 25, 2011 trade date) and the Energy Information Administration Annual Energy Outlook (EIA AEO) 2011 forecast (Early Release, December 2010). Delivered gas prices are calculated using our GASCAST forecasting software. The GASCAST forecast is based on the historic relationships of local prices to hub prices. Prices are forecasted monthly, accounting for seasonal differences in supply and demand. For NYC, we have assumed that the Spectra pipeline project in New Jersey is placed into service, and have incorporated its effects on basis differentials.[47]

Average annual gas prices for the base case are shown below in Table 18 in 2010 $ per mmBTU.

Table 18 - Base Case Gas Prices ($/MMBTU)

	Henry Hub	Transco Zone 6 Non-NY	Transco Zone 6 NY
2011	4.60	5.41	6.00
2012	4.95	5.57	6.08
2013	5.13	5.68	6.05

[47] In the context of another project, we performed an independent analysis of the effects of Spectra's pipeline on NY and NJ basis differentials. The results of that analysis are incorporated here. If the Spectra pipeline does not proceed, the economic impact of IPEC's retirement would be greater.

2014	5.30	5.82	6.10
2015	5.51	6.05	6.35
2016	5.69	6.24	6.55
2017	5.86	6.42	6.74
2018	6.01	6.59	6.92
2019	6.14	6.73	7.06
2020	6.24	6.83	7.18
2021	6.33	6.94	7.29
2022	6.42	7.04	7.39
2023	6.51	7.13	7.50
2024	6.54	7.10	7.43
2025	6.56	7.14	7.48
2026	6.58	7.18	7.53
2027	6.61	7.22	7.57
2028	6.63	7.25	7.61
2029	6.66	7.28	7.65
2030	6.68	7.31	7.68

We also ran cases with high gas and low gas prices. To derive these prices, the EIA AEO 2010 high fuel price and low fuel price forecast have been used to adjust the base case figures from the EIA AEO 2011 report. The gas prices in these two scenarios are shown in Table 19 and Table 20 below.

Table 19 - High Scenario Gas Prices ($/MMBTU)

	Henry Hub	**Transco Zone 6 Non-NY**	**Transco Zone 6 NY**
2011	4.84	5.65	6.25
2012	5.21	5.83	6.35
2013	5.40	5.95	6.33
2014	5.58	6.10	6.38
2015	5.81	6.34	6.64
2016	6.00	6.55	6.86
2017	6.17	6.73	7.05
2018	6.33	6.91	7.24
2019	6.46	7.05	7.39
2020	6.57	7.16	7.51
2021	6.67	7.27	7.62
2022	6.76	7.38	7.73
2023	6.86	7.48	7.84
2024	6.89	7.45	7.78
2025	6.91	7.50	7.84
2026	6.94	7.54	7.89
2027	6.97	7.58	7.93
2028	7.00	7.61	7.97
2029	7.03	7.65	8.01

2030	7.05	7.68	8.05

Table 20 - Low Scenario Gas Prices ($/MMBTU)

	Henry Hub	Transco Zone 6 Non-NY	Transco Zone 6 NY
2011	4.23	5.04	5.64
2012	4.55	5.17	5.69
2013	4.71	5.27	5.64
2014	4.88	5.39	5.68
2015	5.07	5.61	5.90
2016	5.24	5.79	6.10
2017	5.39	5.95	6.27
2018	5.53	6.10	6.44
2019	5.64	6.23	6.57
2020	5.74	6.33	6.68
2021	5.82	6.43	6.78
2022	5.91	6.52	6.88
2023	5.99	6.61	6.97
2024	6.01	6.58	6.91
2025	6.04	6.62	6.96
2026	6.06	6.66	7.01
2027	6.09	6.69	7.05
2028	6.11	6.73	7.09
2029	6.14	6.76	7.12
2030	6.16	6.79	7.16

DISTILLATE AND RESIDUAL OIL PRICES

Long-term distillate and residual oil prices are based on the EIA AEO 2011 crude oil price forecasts. The differential between crude oil and refined products is based on historical relationships. New York Harbor oil prices are shown in Table 21.

Table 21 - Base Case Oil Prices ($/MMBTU)

	New York Harbor		
	1% FO6	**.3% FO6**	**FO2**
2015	11.67	14.22	20.41
2016	12.06	14.70	21.08
2017	12.44	15.16	21.72
2018	12.79	15.60	22.32
2019	13.12	16.00	22.88

2020	13.42	16.36	23.38
2021	13.70	16.71	23.86
2022	13.96	17.03	24.31
2023	14.21	17.34	24.73
2024	14.44	17.62	25.12
2025	14.64	17.87	25.46
2026	14.82	18.09	25.76
2027	15.00	18.31	26.06
2028	15.13	18.47	26.29
2029	15.26	18.62	26.49
2030	15.37	18.77	26.69

Our high and low fuel price scenarios include adjustments to oil prices, using the same methodology as described for natural gas. Resulting oil prices are shown in Table 22 and Table 23.

Table 22 - High Case Oil Prices ($/MMBTU)

	New York Harbor		
	1% FO6	**.3% FO6**	**FO2**
2015	18.49	22.60	32.26
2016	19.16	23.41	33.41
2017	19.80	24.20	34.51
2018	20.40	24.93	35.54
2019	20.96	25.63	36.51
2020	21.47	26.25	37.39
2021	21.96	26.84	38.22
2022	22.41	27.40	39.00
2023	22.84	27.93	39.74
2024	23.24	28.42	40.43
2025	23.60	28.86	41.04
2026	23.92	29.25	41.58
2027	24.23	29.64	42.13
2028	24.48	29.94	42.55
2029	24.70	30.22	42.93
2030	24.92	30.49	43.31

Table 23 - Low Case Oil Prices ($/MMBTU)

	New York Harbor

	1% FO6	.3% FO6	FO2
2015	6.88	8.35	12.15
2016	6.83	8.29	12.06
2017	6.79	8.23	11.97
2018	6.74	8.18	11.89
2019	6.70	8.12	11.81
2020	6.66	8.07	11.72
2021	6.61	8.02	11.65
2022	6.58	7.97	11.58
2023	6.55	7.93	11.52
2024	6.52	7.90	11.46
2025	6.49	7.87	11.41
2026	6.46	7.83	11.36
2027	6.45	7.81	11.33
2028	6.43	7.79	11.28
2029	6.41	7.77	11.25
2030	6.41	7.76	11.23

Environmental Assumptions

The future of federal carbon policy remains highly uncertain. Although a national carbon policy appears unlikely in the next few years, there remains a possibility for some type of federal price on carbon in the longer term. With regard to CO_2 regulation we modeled a $15 per metric ton federal carbon price starting in 2018. Prior to the imposition of national CO2 regulation, the current RGGI scheme is assumed. RGGI is a regional trading program and without a significant tightening of the program it is not anticipated that RGGI CO_2 allowances will trade above the minimum reserve price prior to 2018. Carbon emissions reported in this study already take into account the effect of a national mandatory carbon policy and cap via the assumed carbon price.

We modeled the current Clean Air Interstate Rule (CAIR) policy, plus a Hazardous Air Pollutants (HAPs) policy requiring the maximum achievable control technology (MACT) for uncontrolled coal units by 2015. We modeled a HAPs policy that requires all uncontrolled coal units to install a dry scrubber, fabric filter, or sorbent injection.

Estimated allowance prices based on recent results of our North American Electricity and Environment Model (NEEM) for CAIR and HAPs are shown in Table 24 below. We expect that the combination of a national carbon price with a HAPs policy will cause substantial coal retirements. The remaining coal-fired facilities will need to install significant abatement technology to comply with the HAPs policy. These required environmental retrofits (combined with the economic retirement of older coal-fired power plants) are expected to marginalize provisions under a CAIR/Clean Air Transport Rule program resulting in prices for NO_x and SO_2 allowances approaching $0 per ton.

After the bulk of analytical work on this study was completed, but prior to the final version of this report, the Cross-State Air Pollution Rule (CSAPR) was finalized (although it is still subject to legal challenge) by the U.S. Environmental Protection Agency (EPA). NO_x caps under CSAPR2 may tighten the annual and seasonal NOx caps beyond those finalized in CSAPR1, which could constrain emissions both in the base case, and in the case in which IPEC is retired. Note however, that the tightening of NO_x caps could lead to higher prices for NO_x emissions, increasing the economic effect of the retirement of IPEC's baseload generation capacity, which has no direct air emissions.

Table 24 - Emissions Price ($/Metric Ton)

	CO_2	NO_x	SO_x
2015	$0	$0	$0
2018	$15	$0	$0
2020	$16.53	$0	$0
2023	$19.14	$0	$0
2025	$21.10	$0	$0
2030	$26.93	$0	$0

Planned Capacity Additions

Planned capacity additions include Astoria Energy II, BEC, and renewable projects procured through the New York State Energy Research and Development Authority (NYSERDA) Renewable Portfolio Standard (RPS) solicitations. Furthermore, after 2013, 250 MW (nameplate) of generic wind capacity is assumed to enter into the NYISO market in each year until RPS goals are achieved, after which time 25 MW per year are assumed to enter. In addition to the capacity additions shown in Table 25 below, generic CC capacity will be added in the later years of the analysis to maintain proper reserve balances. In addition to the below capacity additions, the 660 MW HTP cable is assumed to enter service in 2013, including 320 MW of firm capacity into NYC.

Table 25 - Planned Capacity Additions

Plant Name	Zone	Unit Type	Effective Date	Summer Capacity (MW)
Astoria Energy II	J	CCGT	June 2011	550
Gilboa (Uprates)	E	Pumped Storage	May 2010	30
Gilboa (Uprates)	E	Pumped Storage	May 2011	30
Bayonne Energy Center	J	Gas Turbine	Jan 2014	512
Montgomery	G	Steam Turbine	Jan 2011	100

Biomass				
NYSERDA Biomass	A, C & F	Steam Turbine	2011	100
NYSERDA Wind	A,C & E	Wind	2011	260
Generic Wind	A,C & E	Wind	2012-2019	250/yr
Generic Wind	A, C & E	Wind	2020-2030	25/yr

The following generic capacity additions will be added to meet the Installed Capacity Requirement of 115.5% in the ROS area. Capacity is added in NYC to meet the 81% Installed Capacity Requirement, while capacity is added in Long Island to maintain the 101.5% Installed Capacity Requirement. Note that these capacity additions reflect net changes as well as the assumed market surplus level detailed in section 3.1.3. For example, in the case of a one-for-one repowering, the net capacity addition would be zero. The addition of 500 MW on Long Island in 2018 is assumed to result from LIPA's recent RFP.

Table 26 - New Capacity Additions for Base Case

Effective Date	Zone	Unit Type	Summer Capacity (MW)
2018	K	CCGT	500
2025	J	CCGT	500
2026	G	CCGT	500
2027	F	CCGT	500
2028	J	CCGT	500
2028	K	CCGT	500
2030	G	CCGT	500

Capacity Retirements

The introduction of HAPs rules in 2015 is likely to require expensive retrofits on many older coal-burning plants. Based on results from our NEEM model, the following plants in NYS are likely to be retired.

Table 27 - Planned Capacity Retirements

Plant Name	Zone	Unit Type	Effective Date	Summer Capacity (MW)
Samuel Carlson	A	Steam Turbine	2015	44
Trigen Syracuse	A	Steam Turbine	2015	66
Dunkirk	A	Steam Turbine	2015	164
Westover 8	C	Steam Turbine	2015	82
Greenidge 4	C	Gas Turbine	2011	106

For the high demand scenario, the following capacity additions will be added to meet the Installed Capacity Requirements in each of the capacity zones. (The same generic CCGT capacity additions will be applied in the low demand scenario as shown above for the base case.)

Table 28 - Capacity Additions for High Case

Effective Date	Zone	Unit Type	Summer Capacity (MW)
2018	G	CCGT	500
2019	J	CCGT	500
2020	K	CCGT	500
2021	F	CCGT	500
2022	J	CCGT	500
	G	CCGT	500
2023	F	CCGT	500
2024	G	CCGT	500
2025	J	CCGT	500
	K	CCGT	500
2026	F	CCGT	500
2027	J	CCGT	500
	G	CCGT	500
2028	F	CCGT	500
2029	J	CCGT	500
2030	K	CCGT	500
	G	CCGT	500

Planned Transmission Additions

The starting point for the transmission topology will be the 2013 ERAG Load Flow. Specific additions include the M29 project, as well as major transmission projects in New England (New England East-West Solution, Maine Power Reliability Program, Scobie-Tewksbury) and PJM (Trans-Allegheny Interstate Line, Susquehanna-Roseland). Note that the Potomac Appalachian Transmission Highline (PATH) project has been excluded, and HTP has been included.

Model Calibration

In order to better align model outcomes with actual market outcomes, we have modified our model to account for actual market conditions. One method we have used to accomplish this is to use bid adders for certain types of generation. This allows units that are dispatched out of merit to capture reasonable margins in the energy markets. We also modeled reductions in the transfer limit of the Dunwoodie-South interface, based on analysis of historical interface transfer capabilities, including transmission outages.

We conducted a simplified back-cast simulation to calibrate Zone J outcomes against 2010 actual market results. Historical heat rates were calculated based on 2010 hourly NYISO day-ahead market prices and 2010 daily ICE natural gas prices

Figure 12 and Figure 13 show the results of our model calibration, comparing actual 2010 implied heat rates to our modeled results. Our model is likely to slightly understate peak prices when the system is constrained. A model which fully captures the impacts of peak prices during congested periods would increase the costs of an IPEC retirement.

Figure 9 - Model Calibration - Zone J Prices

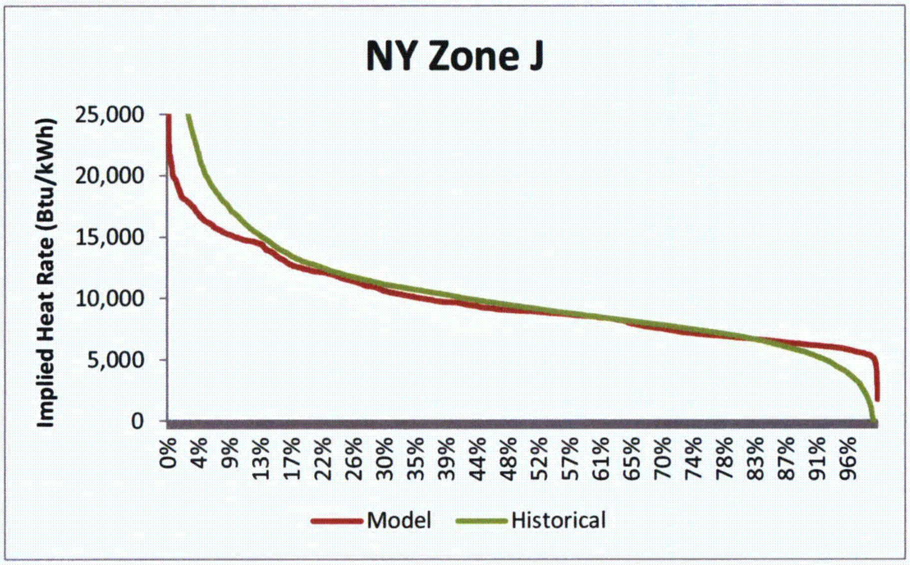
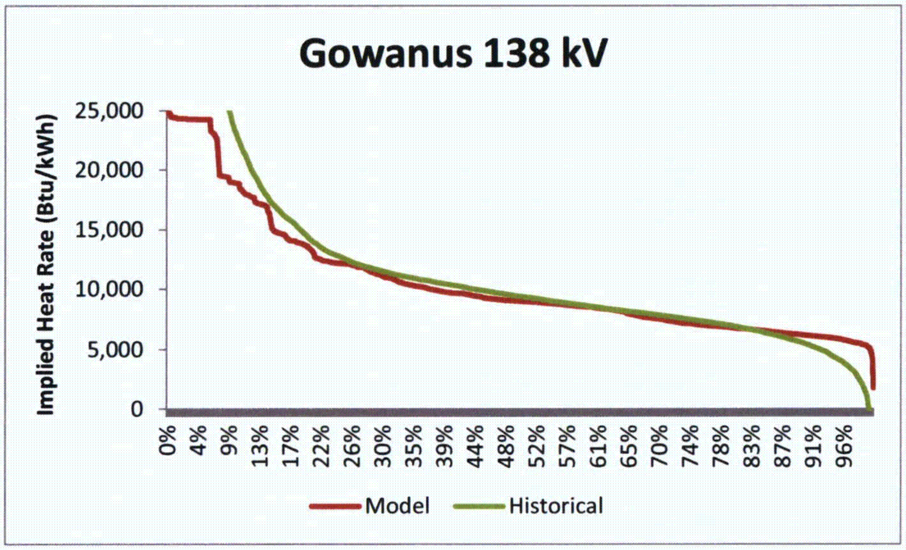


Figure 10 - Model Calibration - Load Pocket Prices



4. ANALYSIS RESULTS

4.1. Summary of Findings

4.1.1. Reference Case Energy Market Summary

The Reference Case is made up of four different scenarios:

1. Status Quo: IP2 and IP3 remain online and in service
2. Conventional Thermal: IP2 and IP3 are retired and a 500 MW CC unit comes online in the LHV in one conventional thermal scenario; a 500 MW CC unit in NYC plus a 500 MW CC unit in the LHV come online in a second conventional thermal scenario
3. Low Carbon: IP2 and IP3 are retired and a 1,000 MW HVDC line interconnects to NYC from HQ and a 500 MW offshore wind farm also interconnects to the City
4. One-for-One: IP2 and IP3 are retired and two 1,000 MW CC units directly replace IPEC in the LHV

All four of these reference case scenarios were modeled using the same fuel prices (*e.g.*, natural gas, oil, and coal), the same load, and the same regulatory regime for emissions.

Figure 11 - Reference Case Market LBMPs in NYC for All-Hours ($/MWh)

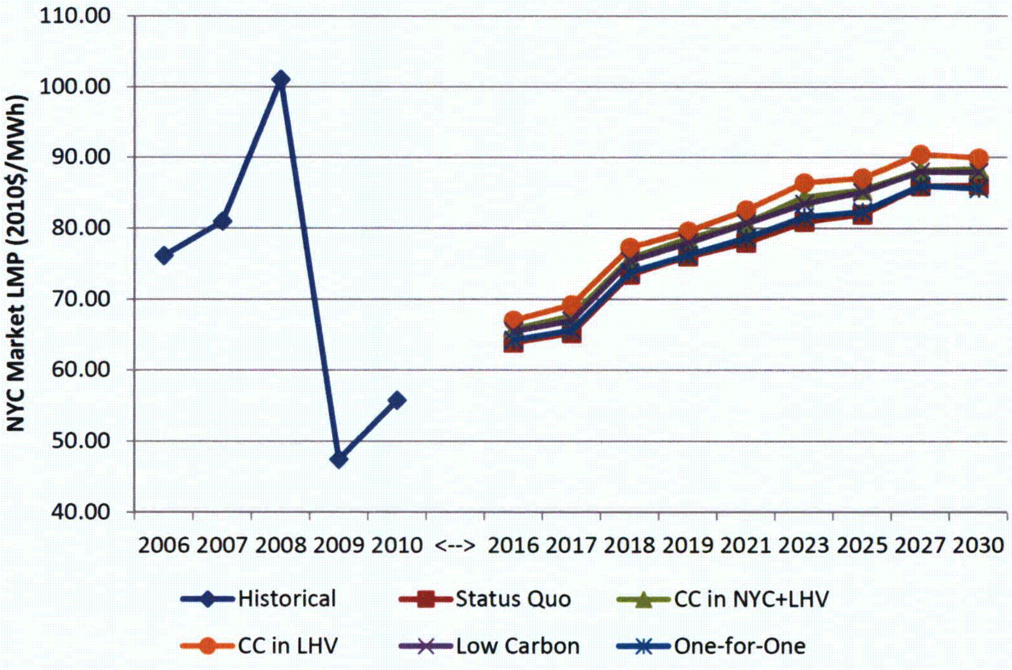
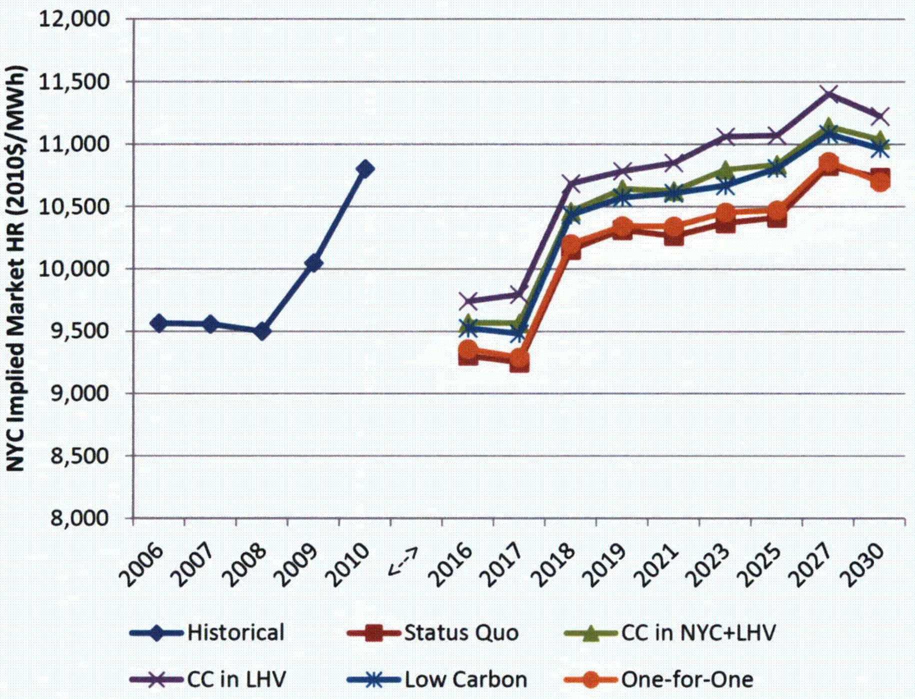


Figure 12 - Reference Case Implied Heat Rates in NYC for All-Hours (Btu/kWh)



4.1.2. Reference Case Capacity Market Summary

The NYISO capacity market is well established and has been operating with a demand curve clearing mechanism since 2003. However, recent rule changes for NYC have significantly affected pricing and market structure in that locational market.

Revised market power mitigation measures for NYC adopted in 2008 have had a substantial impact on the in-City capacity market. Under this set of rules, the Divested Generation Owner (DGO) price and offer caps have been removed and replaced with a must-offer requirement at a reference price set by the expected market clearing price if all available capacity were to clear the market. The rule applies to all generation owners with 500 MW or more of capacity. Generators may offer above this reference price only by providing documentation of higher avoidable costs in order to demonstrate to the NYISO's Market Mitigation and Analysis Department that a higher offer is justifiable. New resources not qualifying for an exemption from mitigation are subject to an offer floor calculated as the lower of 75 percent of net CONE or the resource's own unit net CONE.

This change to the market power mitigation rules has had a substantial impact on the New York City market. Historically, enough of the DGO capacity had been offered at the DGO caps that the price typically never dropped below the DGO caps, and several hundred MW of DGO capacity went unsold. Under the new must-offer requirement, all of the previously unsold capacity has in effect been forced to clear the market, which initially pushed capacity prices in NYC down significantly, especially in the winter. However, with the retirement of the Poletti Steam Station in early 2010, the excess capacity has been absorbed. The combination of the Astoria Energy II unit, which commenced commercial operation at the end of June 2011 and the Linden VFT project, which commenced commercial operation on November 1, 2009,has resulted in capacity clearing prices approximately equivalent to the levels that existed prior to the closure of Poletti.

One remaining source of uncertainty regarding application of the mitigation rules stems from an order issued by FERC in 2010 addressing a specific issue related to how the offer floor for new capacity will be applied. The Commission ordered the 75 percent minimum offer threshold should be applied to a value lower than the reference point used to set the demand curve. The basis for this decision was that the reference point includes a margin above the CONE to account for expected oversupply, as discussed earlier in this report. The order specified that the appropriate value of net CONE should instead be the price level on the demand curve that corresponds to the expected level of surplus in the market, which corresponds to approximately 65 percent of the reference level under the current demand curve.

Potential for a Lower Hudson Valley Capacity Zone

A second issue of importance for the capacity market is the potential creation of a new capacity zone. This prospective LHV Zone would be in addition to, rather than in place of, the current NYC and Long Island Zones. Such a zone would be created in order to address resource adequacy concerns south of the Leeds-Pleasant Valley constraints. These constraints limit the amount of power physically deliverable into the LHV, but there is currently no capacity market mechanism to incent new capacity builds in that region (but outside of NYC and Long Island).

The creation of this zone would be a potential upside for existing downstate resources, as an initial analysis of the current supply/demand balance in the region indicates that the market would be binding, with prices falling somewhere between the current NYCA and NYC levels. The prospects for the creation of the LHV zone are not directly linked to the fate of IPEC, but the retirement of IPEC could contribute to a need for a capacity market mechanism which targets this specific region.

Figure 13 and Table 29 display results from our reference case ICAP market analysis.

Figure 13 - Average Seasonal UCAP Prices Base Case

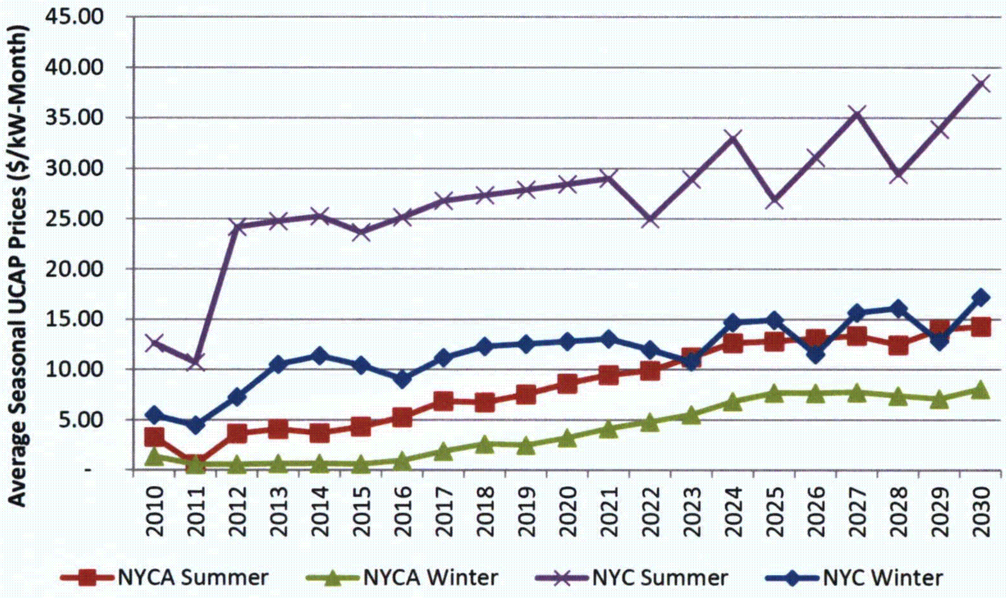


Table 29 - Reference Case Capacity Market Prices (Nominal)

	NYCA			NYC		
Calendar Year	NYCA Summer	NYCA Winter	Annual	NYC Summer	NYC Winter	Annual
2016	5.26	0.95	3.10	25.16	9.02	17.09
2017	6.86	1.87	4.37	26.80	11.16	18.98
2018	6.74	2.59	4.66	27.33	12.29	19.81
2019	7.54	2.48	5.01	27.88	12.54	20.21
2020	8.61	3.23	5.92	28.44	12.79	20.61
2021	9.46	4.15	6.80	29.01	13.04	21.02
2022	9.88	4.81	7.35	24.96	11.97	18.47
2023	11.24	5.53	8.38	28.92	10.77	19.84
2024	12.63	6.84	9.74	32.97	14.68	23.83
2025	12.82	7.70	10.26	26.89	14.93	20.91
2026	13.08	7.66	10.37	31.09	11.51	21.30
2027	13.37	7.76	10.56	35.39	15.66	25.53
2028	12.46	7.42	9.94	29.40	16.09	22.75
2029	13.99	7.10	10.55	33.87	12.81	23.34
2030	14.28	8.08	11.18	38.44	17.21	27.83

4.1.3. Reference Case Total Consumer Cost Summary

Table 30 through Table 32 summarize the total consumer cost of energy and capacity for NYS. Percentage values indicate the percentage change from the reference case.

Table 30 – NYS Incremental Consumer Cost of Energy ($million)

	No New Gen		CC in LHV only		CCs in LHV and NYC		Low Carbon	
2016	$620	6%	$422	4%	$292	3%	$246	2%
2017	$686	7%	$516	5%	$341	3%	$270	3%
2018	$740	6%	$552	5%	$374	3%	$338	3%
2019	$794	6%	$524	4%	$409	3%	$278	2%
2021	$911	7%	$634	5%	$460	4%	$440	3%
2023	$997	7%	$762	6%	$547	4%	$377	3%
2025	$977	7%	$749	5%	$521	4%	$532	4%
2027	$986	7%	$714	5%	$471	3%	$402	3%
2030	$974	6%	$725	5%	$516	3%	$393	3%

Table 31 – NYS Incremental Consumer Cost of Capacity ($million)

	No New Gen		CC in LHV only		CCs in LHV and NYC		Low Carbon	
2016	$1,439	30%	$1,079	22%	$1,079	22%	$1,439	30%
2017	$1,438	25%	$1,094	19%	$1,094	19%	$1,438	25%
2018	$1,476	25%	$1,137	19%	$1,137	19%	$1,476	25%
2019	$1,462	24%	$1,126	19%	$1,126	19%	$1,462	24%
2021	$1,380	20%	$1,064	16%	$1,064	16%	$1,380	20%
2023	$1,352	20%	$1,012	15%	$1,484	21%	$1,782	26%
2025	$1,331	17%	$1,007	13%	$1,349	18%	$1,255	16%
2027	$1,253	15%	$966	11%	$570	7%	$857	10%
2030	$1,255	14%	$967	11%	$396	4%	$685	8%

Table 32 – NYS Incremental Total Consumer Cost ($million)

	No New Gen		CC in LHV only		CCs in LHV and NYC		Low Carbon	
2016	$2,059	14%	$1,501	10%	$1,371	9%	$1,685	11%
2017	$2,123	13%	$1,611	10%	$1,436	9%	$1,707	11%
2018	$2,216	13%	$1,688	10%	$1,510	9%	$1,814	10%
2019	$2,256	12%	$1,650	9%	$1,535	8%	$1,740	9%
2021	$2,291	12%	$1,698	9%	$1,524	8%	$1,820	9%
2023	$2,349	11%	$1,774	9%	$2,031	10%	$2,159	11%
2025	$2,309	11%	$1,757	8%	$1,871	9%	$1,787	8%
2027	$2,239	10%	$1,680	7%	$1,040	4%	$1,259	5%
2030	$2,229	9%	$1,692	7%	$913	4%	$1,078	4%

Table 33 through Table 35 summarizes the total consumer cost of energy and capacity for NYC.

Table 33 - NYC Incremental Consumer Cost of Energy ($million)

	No New Gen		CC in LHV only		CCs in LHV and NYC		HQ HVDC & Offshore Wind	
2016	$297	8%	$183	5%	$110	3%	$82	2%
2017	$342	9%	$248	6%	$147	4%	$94	2%
2018	$335	8%	$243	6%	$145	3%	$116	3%
2019	$394	8%	$230	5%	$170	4%	$99	2%
2021	$431	9%	$303	6%	$183	4%	$175	4%
2023	$470	9%	$361	7%	$229	4%	$147	3%
2025	$445	8%	$345	7%	$232	4%	$210	4%
2027	$435	8%	$312	5%	$152	3%	$124	2%
2030	$430	7%	$297	5%	$183	3%	$130	2%

Table 34 – NYC Incremental Consumer Cost of Capacity ($million)

	No New Gen		CC in LHV only		CCs in LHV and NYC		HQ HVDC & Offshore Wind	
2016	$188	9%	$144	7%	$144	7%	$188	9%
2017	$182	8%	$142	6%	$142	6%	$182	8%
2018	$188	8%	$148	6%	$148	6%	$188	8%
2019	$185	8%	$146	6%	$146	6%	$185	8%
2021	$164	7%	$130	5%	$130	5%	$164	7%
2023	$167	7%	$117	5%	$328	13%	$357	15%
2025	$175	7%	$128	5%	$280	11%	$138	5%
2027	$136	5%	$109	4%	($69)	-2%	($42)	-1%
2030	$140	4%	$111	3%	($144)	-4%	($116)	-4%

The negative numbers in Table 34 indicate a reduced cost to consumers as capacity in the NYC market clears as it is no longer subject to the mitigation floor.

Table 35 - NYC Incremental Total Consumer Cost ($million)

	No New Gen		CC in LHV		CCs in LHV and NYC		HQ HVDC & Offshore Wind	
2016	$485	8%	$327	6%	$254	4%	$271	5%
2017	$524	9%	$390	6%	$289	5%	$276	4%
2018	$523	8%	$391	6%	$292	4%	$304	4%
2019	$579	8%	$376	5%	$316	4%	$284	4%

2021	$595	8%	$433	6%	$313	4%	$339	5%
2023	$636	8%	$478	6%	$556	7%	$504	7%
2025	$620	8%	$474	6%	$512	6%	$348	4%
2027	$571	7%	$421	5%	$82	1%	$82	1%
2030	$571	6%	$408	5%	$39	0%	$14	0%

4.1.4. Reference Case Resource Adequacy Summary

Table 36 and Table 37 show the results of our base case resource adequacy analysis. These results were developed by starting from the 2010 NYISO RNA database, modifying it to adjust for changes in capacity additions, using the modified Gold Book forecast from Table 14.

Assumptions regarding the load forecast are described in greater detail in section 3.2.1. All else equal, lower load forecast would yield a lower LOLE and increased reliability. Because generic capacity additions are minor in the downstate zones we have analyzed, it is reasonable to extrapolate the LOLE results shown here to years with similar loads for approximate results. Put differently, because we are adding very few plants, the LOLE results could be "shifted" by several years to account for different loads to yield an approximate answer.

The retirement of IPEC would likely change the transfer limits employed in resource adequacy analyses (shown in Figure 3), meaning that our analysis would have to be adjusted for this fact. While we have not analyzed the change in the transfer limits, our expectation (and the expectation of some Group members) is that transfer limits would decrease, meaning that the actual amount of capacity necessary to maintain minimum reliability may be higher than reported here, and that LOLEs could be higher than analyzed here.

In the base case, in which IPEC does not retire, minimum resource adequacy standards are maintained. Results for Zones A through F are not shown in some of the following tables because the analysis did not indicate any measurable probability of a load-shedding event.

Table 36 - Base Case Resource Adequacy

	G	H	I	J	K	NYCA
2011	0	0	0.001	0	0	0.001
2012	0.001	0	0.002	0.002	0	0.002
2013	0.001	0	0.001	0.001	0	0.002
2014	0.001	0	0.001	0.001	0	0.002
2015	0.001	0	0.001	0.001	0	0.002
2016	0.001	0	0.002	0.002	0.001	0.003
2017	0.002	0	0.005	0.004	0.001	0.005

2018	0.001	0	0.004	0.004	0	0.004
2019	0.002	0	0.008	0.008	0	0.009
2020	0.004	0	0.013	0.014	0	0.015

Table 37 and Table 38 display the results of our resource adequacy analysis in which both IPEC units retire. Upon the retirement of IP3, minimum resource adequacy standards are violated. In this scenario, the HTP cable is in service and has 660 MW of capacity available for flow, but no firm capacity available in PJM to serve NYC load. Zones which do not meet minimum reliability standards are shown in bold.

Table 37 - No New Generation Resource Adequacy

	G	H	I	J	K	NYCA
2011	0	0	0.001	0	0	0.001
2012	0.001	0	0.002	0.002	0	0.002
2013	0.001	0	0.001	0.001	0	0.001
2014	0.007	0.003	0.017	0.015	0.001	0.018
2015	0.006	0.002	0.014	0.014	0.001	0.016
2016	0.046	**0.116**	**0.12**	**0.111**	0.018	**0.14**
2017	0.061	**0.143**	**0.156**	**0.146**	0.01	**0.175**
2018	0.062	**0.163**	**0.177**	**0.161**	0.002	**0.197**
2019	0.091	**0.242**	**0.265**	**0.25**	0.003	**0.297**
2020	**0.131**	**0.347**	**0.376**	**0.378**	0.01	**0.434**

We also analyzed the impact of HTP securing 320 MW of firm capacity in PJM (equal to the amount of its firm transmission withdrawal rights from PJM) on LOLE, shown in Table 38.

Table 38 - Reference Case with 320 MW Firm HTP Capacity

	G	H	I	J	K	NYCA
2011	0	0	0.001	0	0	0.001
2012	0.001	0	0.002	0.002	0	0.002
2013	0	0	0.001	0.001	0	0.001
2014	0.004	0.002	0.01	0.008	0	0.011
2015	0.004	0.002	0.008	0.008	0.001	0.01
2016	0.041	0.092	0.096	0.084	0.016	**0.113**
2017	0.056	**0.121**	**0.134**	**0.118**	0.009	**0.151**
2018	0.059	**0.141**	**0.154**	**0.13**	0.002	**0.173**
2019	0.09	**0.22**	**0.24**	**0.212**	0.003	**0.27**
2020	**0.134**	**0.327**	**0.354**	**0.337**	0.009	**0.41**

The results indicate that 320 MW of firm capacity from PJM over HTP is not sufficient to maintain minimum reliability standards, although the violation of LOLE standards is small. Slightly more capacity or slightly less load might postpone, but not avoid, a resource violation.

In addition to analyzing the LOLE using our base-case load forecast, we also undertook an analysis using the most recent 2011 Gold Book forecast from the NYISO, shown in Table 39. The principal difference between the base-case 2011 Gold Book forecast and the base-case load forecast for our study is energy efficiency penetration. The basis for these assumptions is discussed in greater detail in section 3.2.1.

Table 39 - NYCA LOLE with 2011 Gold Book Forecast

	G	H	I	J	K	NYCA
2011			0.001			0.001
2012	0.001		0.002	0.002		0.002
2013			0.001	0.001		0.001
2014	0.002	0.001	0.004	0.004		0.005
2015	0.002	0.001	0.004	0.004		0.005
2016	0.014	0.036	0.038	0.031	0.003	0.045
2017	0.020	0.049	0.053	0.044	0.001	0.059
2018	0.018	0.053	0.057	0.044		0.064
2019	0.028	0.080	0.088	0.072		0.096
2020	0.037	**0.110**	**0.120**	**0.107**	0.001	**0.134**

Table 40 displays the same analysis with the addition of 320 MW of firm capacity on the HTP cable. The need date is the same in both cases, 2020.

Table 40 - NYCA LOLE with 2011 Gold Book Forecast and 320 MW HTP Capacity

	G	H	I	J	K	NYCA
2011	0.000	0.000	0.001	0.000	0.000	0.001
2012	0.001	0.000	0.002	0.002	0.000	0.002
2013	0.000	0.000	0.000	0.000	0.000	0.000
2014	0.001	0.001	0.002	0.002	0.000	0.002
2015	0.001	0.001	0.002	0.002	0.000	0.002
2016	0.010	0.024	0.025	0.019	0.003	0.030
2017	0.015	0.033	0.037	0.028	0.001	0.042
2018	0.014	0.037	0.041	0.029	0.000	0.046
2019	0.024	0.062	0.067	0.051	0.000	0.075
2020	0.032	0.091	0.099	0.080	0.001	**0.113**

In order to determine the amount of capacity necessary to maintain system reliability in the event of an IPEC retirement, we calculated the amount of new capacity necessary in the LHV to meet minimum standards, shown in the rightmost column in Table 41.

Table 41 - MW Necessary to Maintain LOLE

	G	H	I	J	K	NYCA	MW Necessary
2011	0	0	0.001	0	0	0.001	
2012	0.001	0	0.002	0.002	0	0.002	
2013	0.001	0	0.001	0.001	0	0.001	
2014	0.007	0.003	0.017	0.015	0.001	0.018	
2015	0.006	0.002	0.014	0.014	0.001	0.016	
2016	0.032	0.077	0.081	0.076	0.012	0.095	250
2017	0.035	0.078	0.085	0.083	0.006	0.096	400
2018	0.031	0.079	0.086	0.082	0.001	0.098	450
2019	0.033	0.038	0.088	0.087	0.002	0.096	700
2020	0.031	0.004	0.086	0.089	0.003	0.095	950

Upon the retirement of IP3, 250 MW of new capacity would be necessary to maintain system reliability, with a total need of 950 MW by 2020. Note that minimum capacity additions may be greater than those indicated here to maintain voltage support or other reliability requirements; these figures should be taken as a minimum. New generating capacity in NYC can be a partial, but not total, substitute for new generating capacity in the LHV. It cannot be assumed that the capacity indicated in Table 41 could be sited in NYC with the same effect on system reliability.

An illustration of this is shown in Table 47. We know from Table 41 that 950 MW of capacity in the LHV would be sufficient to maintain system reliability, but the scenario in which 900 MW is added, split between the LHV and NYC, is insufficient to meet reliability standards, violating them (albeit by a small amount) in 2020.

While it is generally believed that a scenario in which one reactor retired and one stayed online is unlikely, given Entergy's trend towards multi-reactor sites, we did analyze this scenario, shown in Table 42. In this scenario, system reliability is maintained until 2020.

Table 42 - LOLE with One Unit Retired

	G	H	I	J	K	NYCA
2011	0	0	0.001	0	0	0.001
2012	0.001	0	0.002	0.002	0	0.002
2013	0.001	0	0.001	0.001	0	0.001
2014	0.007	0.003	0.017	0.015	0.001	0.018
2015	0.006	0.002	0.014	0.014	0.001	0.015
2016	0.008	0.003	0.02	0.02	0.004	0.023
2017	0.013	0.004	0.033	0.032	0.003	0.035
2018	0.012	0.005	0.034	0.033	0	0.037
2019	0.02	0.007	0.054	0.054	0.001	0.059
2020	0.028	0.01	0.081	0.082	0.002	0.089

4.2. Reference Case Results

4.2.1. Status Quo Scenario

Project Description & Commentary

In the Status Quo scenario, IPEC remains online and in-service. The annual average market LBMPs are shown in the tables below for NYS and NYC.

Table 43 - Status Quo Market LBMP for NYS ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	54.14	54.99	62.59	64.10	66.40	68.80	69.64	71.40	73.49

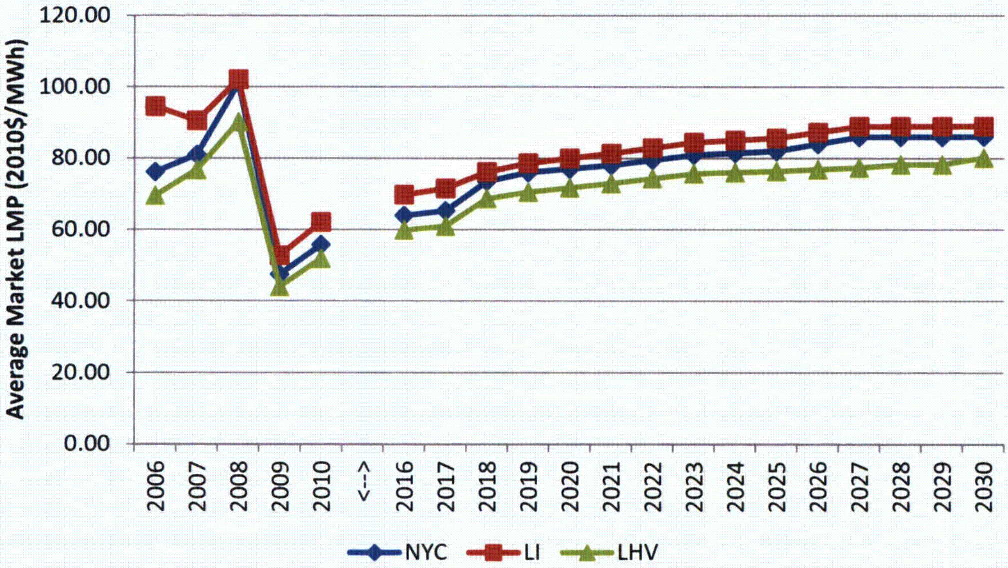
Peak	57.74	58.61	65.98	67.67	70.33	73.04	73.63	75.74	77.52
Off Peak	50.03	50.80	58.67	59.98	61.88	63.89	65.02	66.42	68.84

Table 44 - Status Quo Market LBMP for NYC ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	63.89	65.23	73.48	76.02	77.99	80.89	81.94	85.92	86.04
Peak	69.05	70.61	78.88	82.09	84.41	87.79	88.75	94.34	93.12
Off Peak	58.01	59.01	67.23	69.00	70.62	72.92	74.07	76.27	77.85

Figure 14 shows the historical and forecasted market LBMPs for NYC, Long Island, and the LHV. The forecasted market LBMPs are based off of our GE MAPS analysis.

Figure 14 - Status Quo Market LBMP ($/MWh)



The tables below show the implied market heat rates for the status quo scenario.

Table 45 - Status Quo Implied Market Heat Rate for NYS (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	8,597	8,497	9,450	9,476	9,529	9,609	9,654	9,826	10,021
Peak	9,174	9,055	9,957	9,992	10,098	10,198	10,204	10,427	10,565
Off Peak	7,940	7,853	8,863	8,879	8,878	8,928	9,019	9,137	9,392

Table 46 - Status Quo Implied Market Heat Rate for NYC (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	9,303	9,249	10,155	10,313	10,265	10,368	10,412	10,827	10,732
Peak	10,069	10,018	10,900	11,135	11,132	11,261	11,285	11,916	11,623
Off Peak	8,429	8,361	9,294	9,362	9,271	9,337	9,403	9,578	9,703

4.2.2. Conventional Thermal Scenario

Project Description & Commentary

The Conventional Thermal scenario evolved into two distinct scenarios:

1. A 500 MW CC unit is added at the Buchanan substation upon IP3's retirement
2. A 500 MW CC unit is added at the Gowanus substation upon IP2's retirement. Another 500 MW CC unit is added at the Buchanan substation upon IP3's retirement.

In both of these scenarios, IP2 is retired in September 2013 and IP3 is retired in December 2015.

We did not explicitly analyze the interconnection costs to allow these projects to interconnect to the bulk power system, but they are material and non-trivial, although they are generally small in relation to the market-price impacts.

For the purposes of our market simulation, we chose to interconnect each generator at the Buchanan 345 kV substation (where IPEC currently connects) and the Gowanus 345 kV substation. The interconnection point is only a minor factor on the units' impact on wholesale energy, and has no impact on the units' effect on the ICAP market. There is limited congestion in between the 345 kV nodes in NYC, and limited congestion between Buchanan and other geographically close 345 kV nodes.

Reliability Impact

A solution in which one 500MW CC unit is constructed in the LHV would satisfy resource adequacy criteria through 2018, as shown by the results in Table 41. More capacity would be necessary after that point to maintain minimum resource adequacy standards.

Table 47 shows our calculation of the LOLEs for the LHV and NYC CC units. The analysis shows that system reliability is violated for the NYCA in 2020, albeit by a very small amount. Because of an inconsistency in input assumptions between our reliability and economic analyses, this table shows the results for a 400 MW CC unit in NYC instead of a 500 MW CC. It is reasonable to assume that an additional 100 MW of capacity (or 100 MW reduction in forecast load) in NYC might avoid a reliability violation in the final year of the study.

Table 47 - LOLE for LHV and NYC CCs

	G	H	I	J	K	NYCA
2011	0	0	0.001	0	0	0.001
2012	0.001	0	0.002	0.002	0	0.002
2013	0.001	0	0.001	0.001	0	0.001
2014	0.007	0.003	0.017	0.015	0.001	0.018
2015	0.006	0.002	0.014	0.014	0.001	0.016
2016	0.021	0.049	0.053	0.051	0.009	0.063
2017	0.031	0.069	0.075	0.073	0.006	0.085
2018	0.029	0.074	0.079	0.075	0.001	0.089
2019	0.026	0.059	0.064	0.058	0.001	0.072
2020	0.036	0.087	0.093	0.092	0.003	**0.107**

Environmental Impact

Table 48 through Table 51 show the emissions impact results for different pollutants for NYS and NYC. Positive numbers indicate an increase in emissions.

Table 48 - NYS Environmental Impact, 500 MW LHV

Year	NO_x	SO_x	CO_2
2016	9%	0%	14%
2017	9%	0%	14%
2018	9%	2%	13%
2019	8%	1%	13%
2021	9%	4%	13%
2023	10%	4%	14%
2025	10%	4%	14%
2027	9%	6%	12%
2030	8%	6%	11%

Table 49 - NYC Environmental Impact, 500 MW LHV

Year	NO_x	CO_2
2016	10%	13%

2017	11%	14%
2018	11%	12%
2019	9%	12%
2021	10%	14%
2023	11%	15%
2025	13%	16%
2027	9%	12%
2030	8%	10%

Table 50 - NYS Environmental Impact, 500 MW LHV + 500 MW NYC

Year	NO_x	CO_2
2016	7%	15%
2017	8%	15%
2018	8%	14%
2019	7%	14%
2021	8%	14%
2023	8%	14%
2025	8%	14%
2027	8%	13%
2030	7%	11%

Table 51 - NYC Environmental Impact, 500 MW LHV + 500 MW NYC

Year	NO_x	CO_2
2016	10%	19%
2017	10%	19%
2018	11%	18%
2019	10%	18%
2021	10%	18%
2023	10%	19%
2025	12%	20%
2027	9%	16%
2030	8%	15%

Economic Impact

The following tables show the delta in forecasted market LBMP between the Conventional Thermal scenario and the Status Quo scenario.

Table 52 – Delta in NYS Market LBMP, 500 MW CC in LHV ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	2.63	2.87	3.01	2.92	3.22	3.71	3.63	3.55	3.43

Peak	2.86	3.26	3.61	3.34	3.66	4.10	4.28	4.30	4.40
Off Peak	2.37	2.42	2.32	2.44	2.72	3.25	2.86	2.70	2.31

Table 53 - Delta in NYS Market LBMP, 500 MW CC in NYC + 500 MW CC in LHV ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	1.96	2.13	2.19	2.35	2.54	2.84	2.66	2.76	2.64
Peak	2.18	2.34	2.67	2.72	2.87	3.22	3.19	3.32	3.39
Off Peak	1.72	1.88	1.64	1.94	2.17	2.40	2.04	2.11	1.79

Table 54 - Delta in NYC Market LBMP, 500 MW CC in LHV ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	3.14	3.98	3.80	3.55	4.59	5.52	5.16	4.53	3.90
Peak	3.42	4.65	4.58	4.10	5.21	6.18	6.04	5.28	5.07
Off Peak	2.83	3.21	2.91	2.91	3.87	4.76	4.13	3.68	2.54

Table 55 - Delta in NYC Market LBMP, 500 MW CC in NYC + 500 MW CC in LHV ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	1.90	2.41	2.27	2.53	2.78	3.48	3.44	2.24	2.35
Peak	2.09	2.67	2.80	2.98	3.04	3.96	4.04	2.32	3.07
Off Peak	1.69	2.11	1.66	2.00	2.48	2.93	2.74	2.15	1.51

The following tables show the delta in implied market heat rate between the Conventional Thermal scenario and the Status Quo scenario.

Table 56 - Delta in NYS Implied Market Heat Rate, 500 MW CC in LHV (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	408	431	442	427	455	510	498	492	470
Peak	445	490	530	489	519	567	588	595	601
Off Peak	367	363	341	356	382	445	394	374	318

Table 57 - Delta in NYS Implied Market Heat Rate, 500 MW CC in NYC + 500 MW CC in LHV (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	306	322	323	346	359	389	365	385	363
Peak	339	354	394	401	406	441	439	465	464
Off Peak	268	284	241	284	305	328	280	293	246

Table 58 - Delta in NYC Implied Market Heat Rate, 500 MW CC in LHV (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	439	546	529	470	585	692	658	575	493
Peak	482	640	641	547	669	782	774	670	638
Off Peak	389	438	400	380	488	589	524	466	326

Table 59 - Delta in NYC Implied Market Heat Rate, 500 MW CC in NYC + 500 MW CC in LHV (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	266	317	305	329	361	428	425	317	306
Peak	295	352	380	393	401	492	504	340	401
Off Peak	233	277	218	254	316	354	334	291	196

NYC has an economic surplus of installed capacity (see Figure 19), and despite its importance to NYC's energy security, IPEC is located in the ROS capacity zone. Its retirement has limited effect on the supply and demand balance in NYC. The ROS ICAP zone includes all areas in the state except NYC and Long Island. However, removing 2 GW of capacity from the ROS ICAP market has a substantial effect on the price of capacity, resulting in a substantial economic impact.

There is at least one potential regulatory change which might mitigate this impact, the creation of a new LHV ICAP zone in the NYISO markets. This would reduce the impact of IPEC's retirement on the ICAP market outside of the LHV, and likely reduce the overall impact. This change in the NYISO markets has been discussed, but not agreed upon. It is plausible that the retirement of IPEC may be the catalyst for the creation of this new zone, but we modeled the market rules as they exist today.

The tables below show the impact of the replacement of IPEC with the Conventional Thermal scenario on NYS and NYC wholesale prices.

These two scenarios represent a proportionally larger impact on energy prices in NYC, and capacity prices in NYS. The reason for this is the relative shortage and surplus in each region for each product.

Table 60 – NYS Incremental Economic Impact, 500 MW CC in LHV, $million

	Energy	Capacity	Total	Percentage
2016	$1,079	$1,501	$2,579	9%
2017	$1,438	$2,123	$3,561	9%
2018	$1,476	$2,216	$3,692	9%
2019	$1,462	$2,256	$3,718	8%
2021	$1,380	$2,291	$3,672	8%
2023	$1,352	$2,349	$3,701	10%

2025	$1,331	$2,309	$3,640	9%
2027	$1,253	$2,239	$3,491	4%
2030	$1,255	$2,229	$3,484	4%

Table 61 – NYS Incremental Economic Impact, 500 MW CC in NYC + 500 MW LHV, $million

	Energy	Capacity	Total	Percentage
2016	$1,371	$1,079	$2,450	9%
2017	$1,436	$1,094	$2,530	9%
2018	$1,510	$1,137	$2,647	9%
2019	$1,535	$1,126	$2,661	8%
2021	$1,524	$1,064	$2,588	8%
2023	$2,031	$1,484	$3,515	10%
2025	$1,871	$1,349	$3,220	9%
2027	$1,040	$570	$1,610	4%
2030	$913	$396	$1,309	4%

Table 62 - NYC Incremental Economic Impact, 500 MW CC in LHV, $million

	Energy	Capacity	Total	Percentage
2016	$144	$327	$471	4%
2017	$182	$524	$707	5%
2018	$188	$523	$710	4%
2019	$185	$579	$764	4%
2021	$164	$595	$759	4%
2023	$167	$636	$803	7%
2025	$175	$620	$795	6%
2027	$136	$571	$707	1%
2030	$140	$571	$711	0%

Table 63 - NYC Incremental Economic Impact, 500 MW CC in NYC + 500 MW LHV, $million

	Energy	Capacity	Total	Percentage
2016	$254	$144	$398	4%
2017	$289	$142	$430	5%
2018	$292	$148	$440	4%
2019	$316	$146	$461	4%
2021	$313	$130	$443	4%
2023	$556	$328	$884	7%
2025	$512	$280	$791	6%

2027	$82	($69)	$13	1%
2030	$39	($144)	($106)	0%

Project Economics

The question of whether these projects might be supported by market revenues was one which was discussed by the Group. Based on the results of our energy and capacity market simulations, we created highly simplified pro-forma analyses of each project to look at the overall project gross margins. Table 64 shows abbreviated results for two years (for ease of display) for one unit in the LHV in the replacement scenario where two CC units replace IPEC's capacity.

For the purposes of this analysis, we assumed an all-in capital cost of $1,500 per kW to construct a CC unit in the LHV, and $2,000 per kW to construct a CC unit in NYC.[48]

Table 64 - Two CC Units Project Economics – LHV unit

Calendar Year	2016	2017
Market Details		
Average Energy Price Received ($/MWh)		
Capacity Price ($/kW year)	$73.75	$91.33
SO_2 Price ($/ton)	$0.00	$0.00
NO_x Price ($/ton)	$0.00	$0.00
CO_2 Price ($/ton)	$0.00	$0.00
Revenue		
Generation (MWh)	4,092,594	4,105,843
Energy Revenue	$292,829,328	$307,698,565
Capacity Revenue	$36,875,845	$45,664,399
Energy & Capacity Revenue	$329,705,173	$353,362,964
Costs		
SO_2 Emission Costs	$0	$0
NO_x Emission Costs	$0	$0
CO_2 Emission Costs	$0	$0
VOM	$11,296,387	$11,559,615
FOM	$11,592,848	$11,824,705
Fuel Costs	$202,223,493	$215,169,673

48 The purpose of this study was not to conduct a detailed project cost estimate, but rather an economic evaluation. The development of detailed cost estimates were beyond the scope of this study.

Operating Costs	$225,112,728	$238,553,994
EBITDA	$104,592,444	$114,808,970
Capital Structure		
Loan Balance start of year	$375,000,000	$366,099,435
Principal	$8,900,565	$9,545,856
Interest	$27,187,500	$26,542,209
Balance at end of year	$366,099,435	$356,553,579
Book Value of Equity	$352,102,874	$316,627,426
Rate Base		
Capital Cost		
Tax Depreciation Rate	3.75%	7.22%
Tax Depreciation	$28,125,000	$54,142,500
Accumulated Tax Depreciation	$28,125,000	$82,267,500
Net PP&E (Tax)	$721,875,000	$667,732,500
Book Depreciation Rate	5.00%	5.00%
Book Depreciation	$37,500,000	$37,500,000
Accumulated Book Depreciation	$37,500,000	$75,000,000
Net PP&E (Book)	$712,500,000	$675,000,000
Deferred Tax Assets (Liabilities)	$4,253,203	($3,297,083)
Working Capital Requirement	$1,449,106	$1,478,088
Rate Base	$718,202,309	$673,181,005
Net Income		
Energy & Capacity Revenue	$329,705,173	$353,362,964
Operating Costs	($225,112,728)	($238,553,994)
Insurance	($41,403,030)	($42,231,091)
Property Taxes	($18,631,364)	($19,003,991)
Interest Expense	($27,187,500)	($26,542,209)
Depreciation of PP&E	($37,500,000)	($37,500,000)
Pre-Tax Net Income	($20,129,449)	($10,468,320)
Income Tax Expense	$9,132,228	$4,749,215
Net Income	($10,997,221)	($5,719,105)
Cash Flow from Operations		
Net Income	($10,997,221)	($5,719,105)
Depreciation	$37,500,000	$37,500,000
Decrease (Increase) in Deferred Tax Assets	($4,253,203)	$7,550,286

Change in Working Capital	($1,449,106)	($28,982)
Net Cash Flow from Operations	$20,800,469	$39,302,199
Change in Debt Capital	($8,900,565)	($9,545,856)
Free Cash Flow to Equity	$11,899,904	$29,756,343
Present Value Factor	94%	84%
Present Value to Equity	$11,220,335	$24,944,028

The results for the scenario in which two CC units were developed indicate that on a levelized cost basis, a 500 CC unit constructed in the LHV would require $95m contractual support, and a CC unit in NYC would require $595m of contractual support. A scenario in which only one 500 MW unit is constructed in the LHV would not require subsidies, the only scenario we analyzed which did not.

A larger plant in the LHV (as would be required by reliability requirements) would lower energy and installed capacity market prices, thus reducing the possibility that it would be supported by market revenues, requiring greater subsidies, as seen below in the case where 2,000 MW are constructed in the LHV.

4.2.3. Low Carbon (Transmission/Wind) Scenario

Project Description & Commentary

Numerous proposals have been submitted to construct transmission lines from Canada, more specifically Quebec, to the NYC area. There have also been numerous proposals to construct offshore wind farms in the NYC region to provide renewable energy generation. With the input of the Group, we crafted a scenario designed to reflect a conscious policy decision to attempt to minimize carbon and other air emissions at the cost of a higher price.

We analyzed a 1,000 MW HVDC line interconnected into NYC, backed by 1,000 MW of hydropower from Canada. The interconnection point chosen for this analysis was the 345 kV bus at the Academy substation. Other proposals for interconnection points for similar projects have included the Gowanus 345 kV bus.

Con Edison and other members of the Group have indicated that more suitable locations might be the West 49th Street 345 kV substation and the Rainey 345 kV substation. While the project cost and reliability impact may vary significantly, the economic impact on system dispatch is relatively minor when comparing similar projects interconnecting at different points on NYC's 345 kV network; there is much lower congestion between nodes on NYC's 345 kV system than between the 345 and 138 kV systems.

There would likely be significant interconnection costs associated with connecting at any of these points to ensure that the power is deliverable. We have not attempted to quantify these costs independently – they are beyond the scope of this analysis. Anecdotal and informal discussions with the Group have indicated that these costs could range from $300m to $900m, although these estimates were not independently verified.

We modeled the transmission project as a price-sensitive supply function, meaning that suppliers would sell energy into the NYC market based on rational economic strategies. The line operated at a capacity factor of approximately 89% in our model, with its energy supply being inframarginal the majority of the time.

Table 65 Transmission Line Incremental Bid Curve (BTU/kWh)

MW	Marginal Heat Rate
0	4,000
250	5,340
500	6,670
750	8,000

The transmission line was coupled in this scenario with a 500 MW offshore wind farm with an interconnection to the Gowanus substation. This wind farm was chosen to be similar to recent proposals for the ConEd/LIPA/NYPA consortium project, as well as commercial proposals from private market participants.

Reliability Impact

For the purposes of our reliability analysis, we assumed that the line was a constant 1,000 MW flow into New York City. This assumption considerably simplified the LOLE analysis, and would likely not materially affect the basic results.

Table 66 shows the result of our analysis for the Low Carbon scenario. The combination of 1,000 MW of transmission and 500 MW of wind power into NYC is sufficient to maintain minimum LOLE standards during the study timeframe. However, meeting that resource adequacy criterion alone is not sufficient to meet overall reliability standards.

Table 66 - Low Carbon LOLE Summary

	G	H	I	J	K	NYCA
2011	0	0	0.001	0	0	0.001
2012	0.001	0	0.002	0.002	0	0.002
2013	0.001	0	0.001	0.001	0	0.001
2014	0.007	0.003	0.017	0.015	0.001	0.018
2015	0.006	0.002	0.014	0.014	0.001	0.016
2016	0.007	0.012	0.015	0.009	0.004	0.017
2017	0.011	0.021	0.024	0.015	0.003	0.027
2018	0.011	0.022	0.024	0.015	0	0.027
2019	0.018	0.036	0.039	0.028	0.001	0.044
2020	0.025	0.055	0.059	0.045	0.002	0.068

Environmental Impact

Table 67 and Table 68 show the impact of the combination of transmission/hydropower and wind on NYS and NYC respectively.

Table 67 - NYS Environmental Impact, Low Carbon

Year	NO_x	SO_2	CO_2
2016	4%	0%	6%
2017	4%	-1%	5%
2018	4%	2%	5%
2019	4%	-1%	5%
2021	6%	4%	6%
2023	5%	1%	5%
2025	5%	4%	6%
2027	5%	0%	5%
2030	4%	1%	4%

Table 68 - NYC Environmental Impact, Low Carbon

Year	NO_x	CO_2
2016	3%	4%
2017	1%	4%
2018	4%	4%
2019	3%	4%
2021	3%	5%
2023	2%	5%
2025	6%	9%
2027	2%	4%
2030	2%	3%

As with the results for the Conventional Thermal scenario, we have omitted the effect on SO_2 emissions in NYC, as percentage changes in very small numbers can be appear disproportionate to their importance.

The combination of wind and Canadian hydropower imports may be among the lowest-carbon options available to replace IPEC's capacity, but a measurable increase in emissions is still observed because of increased output from conventional thermal power plants.

Economic Impact

The following tables show the increase in forecasted market LBMPs between the Low Carbon scenario and the Status Quo scenario.

Table 69 - Delta in Market LBMP for NYS, Low Carbon ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030

All Hours	1.80	1.93	2.05	1.82	2.41	2.29	2.71	2.44	2.23
Peak	1.77	2.02	2.34	1.98	2.62	2.29	3.21	2.85	2.76
Off Peak	1.84	1.82	1.71	1.64	2.17	2.29	2.13	1.96	1.62

Table 70 - Delta in Market LBMP for NYC, Low Carbon ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	1.58	1.77	1.95	1.93	2.69	2.55	3.14	2.08	1.87
Peak	1.26	1.67	2.16	1.97	2.79	2.29	3.62	1.97	2.27
Off Peak	1.95	1.90	1.71	1.88	2.56	2.83	2.58	2.19	1.40

The following tables show the increase in implied market heat rate between the Low Carbon scenario and the Status Quo scenario.

Table 71 - Delta in Implied Market Heat Rate for NYS, Low Carbon (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	282	290	300	271	340	311	371	335	305
Peak	279	303	345	298	371	314	442	394	376
Off Peak	285	274	248	239	305	308	289	267	223

Table 72 - Delta in Implied Market Heat Rate for NYC, Low Carbon (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All	223	232	277	260	343	301	394	256	233

Hours									
Peak	181	215	317	273	360	273	462	245	283
Off Peak	270	250	231	244	324	333	315	269	176

The following tables show the economic impact of the Low Carbon scenario.

Table 73 – NYS Economic Impact - Low Carbon $

	Energy	Capacity	Total	Percentage
2016	$246	$1,439	$1,685	11%
2017	$270	$1,438	$1,707	11%
2018	$338	$1,476	$1,814	10%
2019	$278	$1,462	$1,740	9%
2021	$440	$1,380	$1,820	9%
2023	$377	$1,782	$2,159	11%
2025	$532	$1,255	$1,787	8%
2027	$402	$857	$1,259	5%
2030	$393	$685	$1,078	4%

Table 74 - NYC Economic Impact - Low Carbon $

	Energy	Capacity	Total	Percentage
2016	$82	$188	$271	5%
2017	$94	$182	$276	4%
2018	$116	$188	$304	4%
2019	$99	$185	$284	4%
2021	$175	$164	$339	5%

2023	$147	$357	$504	7%
2025	$210	$138	$348	4%
2027	$124	($42)	$82	1%
2030	$130	($116)	$14	0%

Project Economics

The capital cost of an HVDC transmission line such as the one analyzed here is highly uncertain. Developers of projects proposed similar to the one analyzed here have communicated estimated capital costs of $3,500/kW to Group members, so we have used a capital cost of $3,500 here. If project capital costs and capital recovery requirements are lower, the amount of support necessary would be lower. Our analysis indicates that an all-in capital cost of $1,305/kW would be necessary to "break even" on market revenues over 15 years given our energy and capacity market analysis. A longer timeframe for capital recovery might reduce the necessary contractual support, although this is not a foregone conclusion, as a longer debt amortization period could outweigh the costs of a longer investment time horizon.

It is important to understand exactly what the results represent. This financial analysis represents a highly simplified view of financing assumptions as well as project structure. It represents the project from the viewpoint of a project developer which must finance its investment for the *transmission line only* through revenues from merchant sales of power into the NYC market. This hypothetical developer purchases power at the line's origin from an independent generation shipper and sells it into NYC. If new hydropower resources are presumed to be developed to supply the line, the investment in new generation capacity would also have to be recovered by the generation supplier. We have made the fundamental and important assumption that any power supplied from the line's terminus in Canada has an opportunity cost, and is not truly "free."

Our average "arbitrage value" between the costs of supply on the line and the sale price into NYC averages $36 in real 2010 dollars. Our hypothetical "purchase price" over the same time period is $44. Using the same financing assumptions as applied to the transmission line, this implies that in order for the *generation developer* to recover its costs to the same level of return, the development cost of 1,000 MW of generation resources should not exceed $1,665/kW. Some Group members have expressed the view that the cost of new hydropower development in North America may be on the order of $3,000/kW.

In order to not have the results of the financial analysis skewed by the presence of offshore-wind in NYC, the *pro-forma* analysis of the HVDC project was conducted using market prices from a special run we conducted in which only the HVDC line was present. Had we modeled the financial performance of the transmission project with the off-shore wind present, the offshore wind would have reduced market prices for energy in NYC, decreasing the margin for the transmission line and increasing the needed contractual support.

We emphasize that this represents neither an exhaustive nor complete financial analysis; it is intended only to establish rough guidelines for the cost of potential replacements.

Our analysis indicates that the NPV of additional support required will be approximately $2.1b in 2010 dollars based on a capital cost of $3,500/kW. This project, however, represents a conscious policy decision to develop low-carbon supplies of electricity, and to pay above-market rates for that energy. The ancillary benefits of such a project must be weighed in this context.

We did not explicitly analyze the project economics of the wind project. The decision to develop offshore wind in New York was thought to be driven by factors other than overall project economics (*e.g.*, RPS standards, clean energy mandates). It is likely, however, that an offshore wind project may require contractual support through above-market rates.

4.2.4. One-for-One Scenario

Project Description

The One-for-One scenario consists of 2,000 MW of gas-fired generation installed in the LHV. For the purposes of this analysis, the capacity was installed at the Buchanan bus interconnection point, but economic and environmental results would be roughly similar for an equivalent amount of capacity installed elsewhere in Westchester County or the LHV. These units were modeled with a heat rate of 7,500 Btu/kWh and operational parameters similar to other modern CC units. This project configuration has (along with the low-carbon HVDC line from Canada to NYC) the largest development uncertainties of any option analyzed in our study. The construction of this large amount of gas-fired capacity in the LHV poses critical questions regarding the dependence on natural gas, both from a commodity and a reliability perspective. From an economic perspective, it increases the sensitivity of market prices to fluctuations in natural gas prices.[49] Further, the need to deliver gas to support 2,000 MW of generation will increase flow on gas pipelines, increasing the level and volatility in basis differentials (*i.e.*, delivery costs).

There are numerous questions which must be addressed regarding how these notional units could be constructed or built. It is not clear where they could physically be located, as developing them at the existing site while IPEC is in operation would not be feasible. Additional transmission system reinforcements may be necessary to support them. Finally, although development of generating resources anywhere in NYS is challenging, construction

[49] The commodity price of natural gas is essentially a global price, with adjustments (basis differentials) made for delivery to particular locations. Increased development of gas resources in NYS through increased drilling and hydro-fracking may not have a material impact on the market price of natural gas, although it may affect basis differentials.

of new power plants and gas transmission lines in Westchester County or the LHV may pose unique regulatory challenges.

An issue of concern to some Group members was that the difficulty of developing this new capacity was being substantially underestimated. Constructing two new 1,000 MW gas-fired CC units would mean constructing the two largest gas-fired power plants in the northeast United States in the LHV, traditionally one of the most difficult locations to develop power projects. Development uncertainties are nearly impossible to quantify, but planning centered on construction of large amounts of capacity in the LHV should incorporate a realistic view of development risk.

In addition, there is substantial uncertainty regarding electrical system, and gas pipeline system upgrade costs. We did not conduct a detailed assessment of physical upgrades which may be necessary to develop the gas pipeline capacity needed to support operation of these plants, nor the economic impact of firm gas supply contracts which would be necessary to supply them. To be clear, every option we studied had some amount of inherent uncertainty related to incremental infrastructure costs necessary to support the project, but some in our group felt that the uncertainties of this option were distinctly larger.

The intent of our analysis was not to conduct an engineering-level study of these projects, but these very significant uncertainties associated with the engineering of these projects must be analyzed in greater detail before this scenario can be considered feasible.

Reliability Impact

We did not explicitly analyze the resource adequacy impact of this scenario. It can be reasonably assumed, based on other components of our analysis, that an equivalent amount of gas-fired capacity will have a similar (although not identical) reliability impact to nuclear capacity.

The often-overlooked reliability impact is not on the electric system, but rather the gas pipeline system. We have not explicitly analyzed the impact on the gas transmission system, but some Group members have conducted their own analyses. Anecdotal information from gas pipeline operators and a cursory review of gas nomination and scheduling data indicate that the amount of gas necessary to support 2,000 MW of gas-fired generation may not feasible given current pipeline and pressure support constraints. Constraints on the interstate gas pipeline system have the potential to be expensive to address and need further analysis.

One of the Group members in our study performed a high-level analysis of the potential gas system upgrades which would be required to support this generation option. Their analysis indicates that the upgrade costs would be approximately $350 million, and would include the construction of a new gas service line to interconnect with the Algonquin Pipeline, associated meter facilities, and an expansion of the Algonquin Pipeline which would include a horizontal drilling effort under the Hudson River. This infrastructure would also require filing an application with the Federal Energy Regulatory Commission for approval to construct the necessary facilities, a process estimated to take up to five years. These cost estimates were based on industry-standard parameters, and could be higher because of the necessity to construct these upgrades in congested or environmentally sensitive areas in the LHV.

In addition, the supply of gas to the LHV may have a substantial impact on the operation of the energy market. An important, but little-known, component of NYC's energy security is the supply of natural gas. The NYC market always operates a base level of oil-fired generating capacity to avoid electrical load shedding events in the event of an interruption to gas pipeline flows. There is a substantial possibility that the requirement to depend on gas flows to support 2,000 MW of generation in the LHV could introduce additional reliability constraints and changes in market operations with unknown economic consequences.

Environmental Impact

The air emissions impacts in NYS and NYC for the One-for-One scenario are shown in Table 75 and Table 76, respectively. This scenario results in the highest increases in emissions. It is higher than the case in which no new generation is added upon IPEC's retirement because in that case, additional imports from PJM and other regions fill part of the gap.[50] The capacity from the new generators in this scenario are inframarginal the majority of the time and thus displace imports.

Table 75 - NYS Environmental Impact, One-for-One

Year	NO_x	SO_x	CO_2
2016	5%	1%	16%
2017	5%	0%	16%
2018	5%	1%	16%
2019	5%	0%	16%
2021	5%	1%	16%
2023	5%	1%	15%
2025	5%	2%	16%
2027	6%	-1%	15%
2030	4%	0%	13%

Table 76 - NYC Environmental Impact, One-for-One

Year	NO_x	CO_2
2016	1%	0%
2017	2%	1%
2018	1%	0%
2019	1%	1%
2021	1%	1%
2023	0%	0%
2025	1%	1%
2027	1%	0%
2030	-1%	1%

50 In every scenario studied, emissions also increase in PJM, but are not summarized in this study.

Economic Impact

The economic impact is limited compared to some other options. This is because the replacement capacity technology chosen, gas-fired CC units, have heat rates sufficiently low to be inframarginal in the generation stack the majority of the time, similar to IPEC's position in the dispatch stack. Because both units are inframarginal, the marginal price is still set by another resource, and so the end-user prices are little-changed, although generator margins are affected.

This does not mean, however, that the economic impact can be dismissed as immaterial. The most important point is that the marginal generating cost of these units is now highly correlated to the price of natural gas, whereas the marginal cost of IPEC is not. In addition, the extraction of this amount of natural gas from the system may cause an increase in the basis differential, or locational transportation cost of natural gas, increasing economic effects above those shown here.

The following tables show the delta in forecasted market LBMP between the One-for-One scenario and the Status Quo scenario.

Table 77 - Delta in Market LBMP for NYS, One-for-One ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	0.28	0.35	0.37	0.20	0.35	0.40	0.41	0.36	0.23
Peak	0.21	0.29	0.45	0.11	0.31	0.29	0.50	0.37	0.24
Off Peak	0.36	0.41	0.26	0.30	0.39	0.52	0.31	0.35	0.23

Table 78 - Delta in Market LBMP for NYC, One-for-One ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	0.37	0.40	0.30	0.19	0.65	0.70	0.39	0.06	-0.46
Peak	0.42	0.35	0.36	0.13	0.53	0.55	0.34	-0.11	-0.57
Off Peak	0.30	0.47	0.23	0.27	0.78	0.88	0.44	0.25	-0.33

The following tables show the delta in implied market heat rate between the One-for-One scenario and the Status Quo scenario.

Table 79 - Delta in Implied Market Heat Rate for NYS, One-for-One (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	44	49	54	36	50	54	60	50	34
Peak	33	38	68	25	45	39	75	50	34
Off Peak	57	61	38	48	55	71	44	50	34

Table 80 - Delta in Implied Market Heat Rate for NYC, One-for-One (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	55	40	46	31	76	86	59	33	-35
Peak	64	28	57	24	58	66	58	16	-43
Off Peak	44	55	32	39	96	109	61	54	-26

Project Economics

Using parameters similar to those used for other generation projects analyzed here, with an all-in overnight capital cost of $1,500/kW, the necessary support for each 1,000 MW unit would be $707m and $688m over fifteen years. (The difference results from the fact that one unit is in operation for a slightly longer period.)

4.3. High Case Results

We ran the High Case using higher NYCA load, higher fuel prices (*i.e.*, natural gas and oil), and additional generic CC capacity additions. Table 81 shows the increase in peak load for the High Case compared to the Reference Case for NYC and for the entire state. This load scenario was developed using the scenarios in the NYISO Gold Book as a basic framework.

Table 81 – Increase in Peak Load for High Case Scenario

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
NYC	6.4%	7.2%	7.7%	8.0%	8.1%	9.4%	10.7%	12.0%	14.0%
NYCA	6.0%	6.8%	7.4%	7.7%	7.9%	9.0%	10.1%	11.2%	12.9%

Table 82 shows the percentage increase in natural gas prices at Henry Hub, Transco Zone 6 Non-NY, and Transco Zone 6 NY for the High Case. Table 83 shows the percentage increase in oil prices at New York Harbor for the High Case. The increase in natural gas and oil prices is based on the high fuel scenario in the EIA AIO and our analysis.

Table 82 - Increase in Natural Gas Prices for High Case Scenario

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
Henry Hub	5.4%	5.3%	5.3%	5.2%	5.4%	5.4%	5.3%	5.4%	5.5%
TZ6 Non-NY	5.0%	4.8%	4.9%	4.8%	4.8%	4.9%	5.0%	5.0%	5.1%
TZ6 NY	4.7%	4.6%	4.6%	4.7%	4.5%	4.5%	4.8%	4.8%	4.8%

Table 83 - Increase in New York Harbor Oil Prices for High Case Scenario

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
1% FO6	59%	59%	59%	60%	60%	61%	61%	62%	62%
.3% FO6	59%	59%	59%	60%	60%	61%	61%	62%	62%
FO2	59%	59%	59%	60%	60%	61%	61%	62%	62%

The High Case was also broken down into a series of different scenarios similar to the Reference Case. We used the same fuel prices, the same load, and the same regulatory regime for emissions in all the High Case scenarios. The High Case is made up of the following scenarios:

1) High Case Status Quo: IPEC remains online and in-service
2) High Case Conventional Thermal: IPEC is retired and replaced with a 500 MW CC unit in NYC plus a 500 MW CC unit in the LHV
3) High Case Low-Carbon: IPEC is retired and replaced with a 1000 MW HVDC transmission line from HQ to NYC and a 500 MW offshore wind farm

Table 84 indicates the overall impact to NYS consumers for the cases analyzed. The impacts are relative to the High Case Status Quo scenario, and that build patterns are adjusted to account for increased demand.

Table 84 - High Case NYS Consumer Impact

	CCs in LHV and NYC		Low Carbon	
2016	$1,456	8%	$1,543	8%
2017	$1,417	7%	$1,461	7%
2018	$826	4%	$813	4%
2019	$1,055	4%	$1,209	5%
2021	$1,619	7%	$744	3%
2023	$1,666	7%	$1,265	5%
2025	$1,677	6%	$864	3%
2027	$1,633	6%	$1,173	4%
2030	$1,654	6%	$1,305	4%

Table 85 displays the relative impact for the high case on NYC consumers. The change from a consumer cost to a consumer "benefit" is driven principally by the increased amount of capacity clearing in the NYC ICAP market and depends a great deal on the assumptions used for the capacity market mitigation.

Table 85 - High Case NYC Consumer Impact

	CCs in LHV and NYC		Low Carbon	
2016	$296	4%	$159	2%
2017	$274	4%	$129	2%
2018	$47	1%	($145)	-2%
2019	$146	2%	$97	1%
2021	$394	4%	($90)	-1%
2023	$371	4%	$90	1%
2025	$419	4%	($47)	0%
2027	$334	3%	$28	0%
2030	$324	3%	$121	1%

4.3.1. High Case Status Quo Scenario

In the High Case Status Quo scenario, IPEC remains in service.

The annual average market LBMP for NYS and NYC is shown in the tables below.

Table 86 - High Case Status Quo LBMP for NYS ($/MWh)

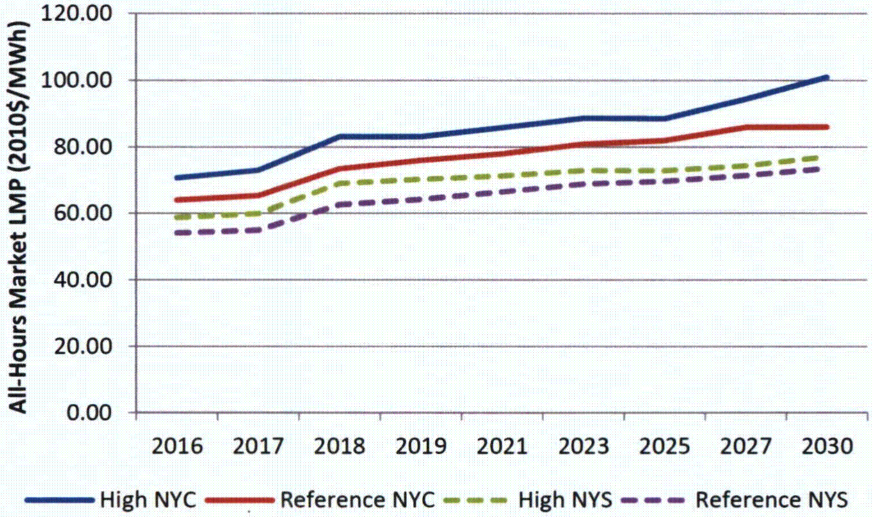
Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	58.69	59.87	68.98	70.22	71.26	72.90	72.84	74.33	77.10
Peak	62.86	64.32	73.61	74.95	76.03	77.79	77.37	78.94	81.89
Off Peak	53.93	54.72	63.62	64.74	65.78	67.24	67.59	69.04	71.57

Table 87 - High Case Status Quo LBMP for NYC ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	70.64	72.93	83.10	83.14	85.84	88.68	88.52	94.42	100.95
Peak	77.33	80.36	91.40	90.64	94.29	97.77	97.23	104.85	112.96
Off Peak	63.01	64.35	73.50	74.46	76.14	78.16	78.45	82.45	87.07

Figure 15 shows the comparison of all-hours market LBMP between the High Case Status Quo scenario and Reference Case Status Quo scenario in NYC and NYS.

Figure 15 - Comparison of High Case and Reference Case Status Quo Market LBMP



The implied market heat rates for the High Case Status Quo scenario are shown in the tables below.

Table 88 - High Case Status Quo Implied Market Heat Rate for NYS (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	8,883	8,815	9,910	9,885	9,739	9,702	9,618	9,742	9,987
Peak	9,521	9,470	10,569	10,542	10,393	10,352	10,215	10,352	10,600
Off Peak	8,155	8,060	9,148	9,125	8,989	8,950	8,928	9,042	9,278

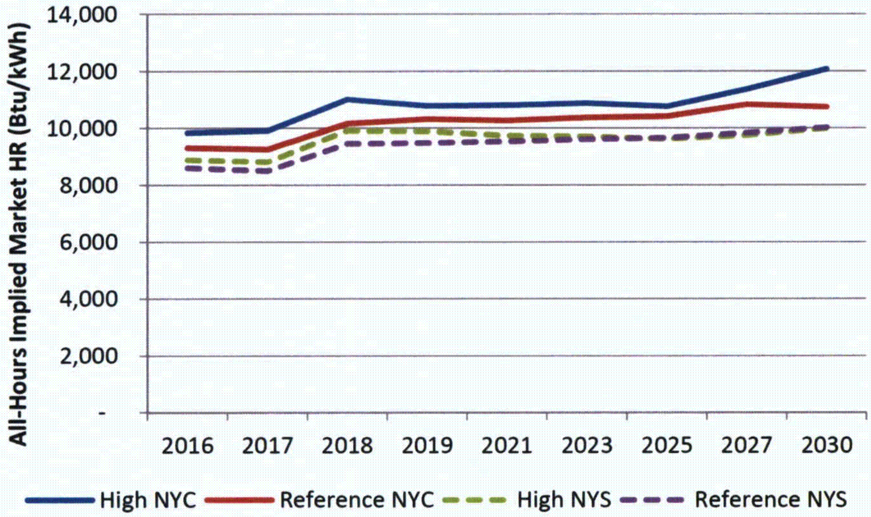
Table 89 - High Case Status Quo Implied Market Heat Rate for NYC (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	9,834	9,905	11,006	10,778	10,801	10,871	10,758	11,366	12,070
Peak	10,792	10,929	12,120	11,753	11,891	12,006	11,835	12,656	13,524

Off Peak	8,742	8,722	9,719	9,651	9,550	9,558	9,513	9,887	10,388

Figure 21 shows the comparison of the implied heat rates between the High Case Status Quo and Reference Case Status Quo in NYC and NYS.

Figure 16 – Comparison of High Case and Reference Case Status Quo Implied Market Heat Rate



4.3.2. High Case Conventional Thermal Scenario

In contrast to the Reference Case Conventional Thermal scenario, we only ran one subset of the High Case Conventional Thermal scenario. In this scenario, IP2 is retired in September 2013 and IP3 is retired in December 2015. A 500 MW CC unit is added at the Gowanus substation upon IP2's retirement, and another 500 MW CC unit is added at the Buchanan substation upon IP3's retirement.

The following tables show the delta in forecasted market LBMP between the High Case Conventional Thermal scenario and the High Case Status Quo scenario.

Table 90 - Delta in NYS Market LBMP, High Case Conventional Thermal ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	2.42	2.74	2.88	2.73	3.00	2.99	2.72	2.58	2.78
Peak	2.75	3.02	3.39	3.23	3.58	3.60	3.43	3.27	3.59

Off Peak	2.06	2.42	2.29	2.16	2.33	2.28	1.90	1.79	1.83

Table 91 - Delta in NYC Market LBMP, High Case Conventional Thermal ($/MWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	2.52	2.73	3.39	2.99	3.12	2.90	3.01	1.61	1.47
Peak	3.06	2.99	4.06	3.78	3.89	3.50	4.16	2.15	2.18
Off Peak	1.90	2.43	2.63	2.08	2.24	2.22	1.68	0.99	0.66

The following tables show the delta in the implied market heat rate between the High Case Conventional Thermal scenario and the High Case Status Quo scenario.

Table 92 - Delta in NYS Implied Market Heat Rate, High Case Conventional Thermal (Btu/kWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	366	393	417	388	413	395	359	341	369
Peak	417	436	495	461	496	478	453	433	479
Off Peak	308	344	327	304	317	299	251	236	242

Table 93 - Delta in NYC Implied Market Heat Rate, High Case Conventional Thermal (Btu/kWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	360	337	452	382	384	347	352	244	175
Peak	447	377	550	492	488	423	497	325	264
Off	261	290	340	255	264	258	185	151	73

Peak	

4.3.3. High Case Low-Carbon (Transmission/Wind) Scenario

In the High Case Low-Carbon scenario, IP2 retires in September 2013 and IP3 retires in December 2015. These units are replaced by a 1,000 MW HVDC transmission line from HQ into NYC before 2016. Furthermore, a 500 MW offshore wind farm is connected to the Gowanus substation before 2016.

The following tables show the delta in market LBMP between the High Case Low-Carbon scenario and the High Case Status Quo scenario.

Table 94 - Delta in Market LBMP for NYS, High Case Low-Carbon ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	1.84	2.14	2.20	2.24	2.60	2.61	2.40	2.44	2.63
Peak	1.85	2.07	2.27	2.29	2.91	2.97	2.81	3.12	3.29
Off Peak	1.82	2.23	2.11	2.19	2.24	2.19	1.93	1.67	1.87

Table 95 - Delta in Market LBMP for NYC, High Case Low-Carbon ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	0.84	0.99	1.31	2.45	3.02	2.53	2.58	1.63	2.24
Peak	0.19	0.14	0.60	2.40	3.51	2.87	3.21	2.23	3.19
Off Peak	1.59	1.97	2.13	2.50	2.46	2.13	1.84	0.95	1.14

The following tables show the increase in implied market heat rate between the High Case Low-Carbon scenario and the High Case Status Quo scenario.

Table 96 - Delta in Implied Market Heat Rate for NYS, High Case Low-Carbon (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All	273	306	320	308	355	345	319	324	342

Hours									
Peak	274	296	335	316	401	395	374	416	430
Off Peak	270	318	303	299	303	288	255	219	240

Table 97 - Delta in Implied Market Heat Rate for NYC, High Case Low-Carbon (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	118	94	147	284	367	296	315	199	267
Peak	27	-27	48	274	436	341	399	275	387
Off Peak	222	233	262	295	288	244	218	111	128

4.4. Low Case Results

We ran the Low Case using lower NYCA load, lower fuel prices (*i.e.*, natural gas and oil), and less generic CC capacity additions than in the Reference Case. Table 98 shows the decrease in peak load for the Low Case compared to the Reference Case for NYC and NYCA. This load scenario was developed using the scenarios in the NYISO Gold Book as a basic framework.

Table 98 - Decrease in Peak Load for Low Case Scenario

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
NYC	-3.2%	-3.6%	-3.8%	-4.0%	-4.0%	-3.8%	-3.6%	-3.4%	-3.1%
NYCA	-3.0%	-3.4%	-3.7%	-3.9%	-4.0%	-4.1%	-4.2%	-4.3%	-4.4%

Table 99 shows the percentage decrease in natural gas prices at Henry Hub, Transco Zone 6 Non-NY, and Transco Zone 6 NY for the Low Case. Table 100 shows the percentage decrease in oil prices at New York Harbor for the Low Case. The decrease in both natural gas and oil prices is based on the low fuel scenario in the EIA AIO and our analysis.

Table 99 - Decrease in Natural Gas Prices for Low Case Scenario

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030

Henry Hub	-7.9%	-8.0%	-8.0%	-8.1%	-8.1%	-8.0%	-7.9%	-7.9%	-7.8%
TZ6 Non-NY	-7.2%	-7.3%	-7.4%	-7.4%	-7.3%	-7.3%	-7.3%	-7.3%	-7.1%
TZ6 NY	-6.9%	-7.0%	-6.9%	-6.9%	-7.0%	-7.1%	-7.0%	-6.9%	-6.8%

Table 100 - Decrease in New York Harbor Oil Prices in Low Case Scenario

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
1% FO6	-43%	-45%	-47%	-49%	-52%	-54%	-56%	-57%	-58%
.3% FO6	-44%	-46%	-48%	-49%	-52%	-54%	-56%	-57%	-59%
FO2	-43%	-45%	-47%	-48%	-51%	-53%	-55%	-57%	-58%

Like the High Case, the Low Case was also broken down into a series of different scenarios. We used the same fuel prices, the same load, and the same regulatory regime for emissions in all the Low Case scenarios. The Low Case is made up of the following scenarios:

1) Low Case Status Quo: IPEC remains online and in-service
2) Low Case Conventional Thermal: IPEC is retired and replaced with a 500 MW CC unit in NYC plus a 500 MW CC unit in the LHV
3) Low Case Low-Carbon: IPEC is retired and replaced with a 1000 MW HVDC transmission between HQ and NYC and a 400 MW offshore wind farm

Table 101 displays the price impacts for NYS consumers under the Low Case. Note that the impacts are relative to the Low Case Status Quo scenario, and that build patterns are adjusted to account for increased demand.

Table 101 - NYS Consumer Cost Impact - Low Case

	CCs in LHV and NYC		Low Carbon	
2016	$1,027	9%	$1,347	12%
2017	$1,149	9%	$1,423	11%
2018	$1,302	9%	$1,608	11%
2019	$1,367	9%	$1,701	11%
2021	$1,438	9%	$1,757	11%

2023	$1,520	9%	$1,887	12%
2025	$3,079	18%	$2,852	17%
2027	$2,681	14%	$2,912	16%
2030	$402	2%	$594	3%

Table 102 displays the consumer impact to NYC consumers under the Low Case scenario relative to the Low Case Status Quo scenario.

Table 102 - NYC Consumer Impact - Low Case

	CCs in LHV and NYC		Low Carbon	
2016	$207	5%	$244	5%
2017	$234	5%	$241	5%
2018	$245	4%	$257	5%
2019	$259	4%	$297	5%
2021	$278	5%	$295	5%
2023	$318	5%	$371	6%
2025	$1,014	16%	$804	13%
2027	$836	12%	$835	12%
2030	($158)	-2%	($192)	-2%

4.4.1. Low Case Status Quo Scenario

In the Low Case Status Quo scenario, IPEC remains in service. The annual average forecasted market LBMP for NYS and NYC are shown in the tables below.

Table 103 - Low Case Status Quo LBMP for NYS ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	49.76	50.32	58.88	59.85	61.14	63.21	64.09	66.40	69.66
Peak	52.80	53.34	61.96	62.89	64.33	66.47	67.21	69.94	73.40
Off Peak	46.29	46.84	55.32	56.33	57.50	59.44	60.47	62.34	65.34

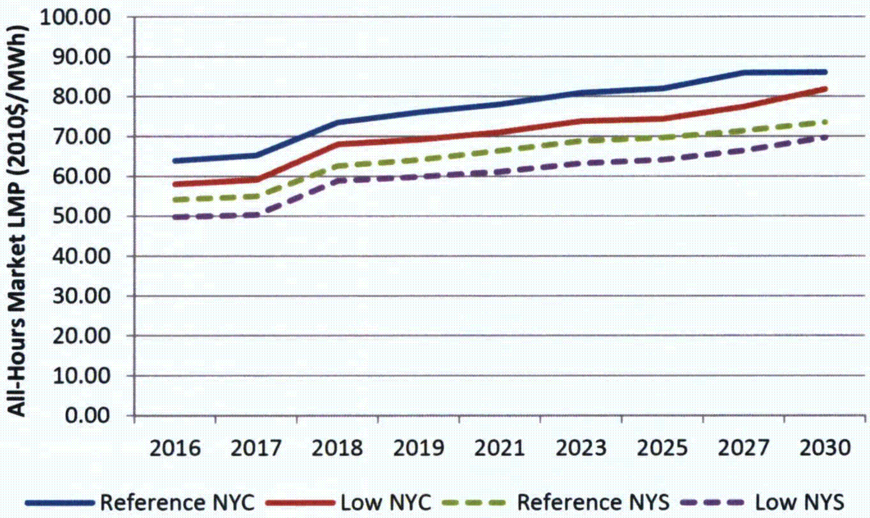
Table 104 - Low Case Status Quo LBMP for NYC ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030

All Hours	58.03	59.10	68.01	69.13	71.01	73.78	74.31	77.39	81.80
Peak	62.54	63.56	72.78	73.92	76.13	79.31	79.62	83.57	88.49
Off Peak	52.88	53.93	62.49	63.59	65.14	67.39	68.17	70.30	74.06

Figure 17 shows the comparison of all-hours market LBMP between the Low Case Status Quo scenario and the Reference Case Status Quo scenario in NYC and NYS.

Figure 17 - Comparison of Low Case and Reference Case Status Quo Market LBMP



The implied market heat rates for the Low Case Status Quo scenario are shown in the tables below.

Table 105 - Low Case Status Quo Implied Market Heat Rate for NYS (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	8,883	8,815	9,910	9,885	9,739	9,702	9,618	9,742	9,987
Peak	9,521	9,470	10,569	10,542	10,393	10,352	10,215	10,352	10,600

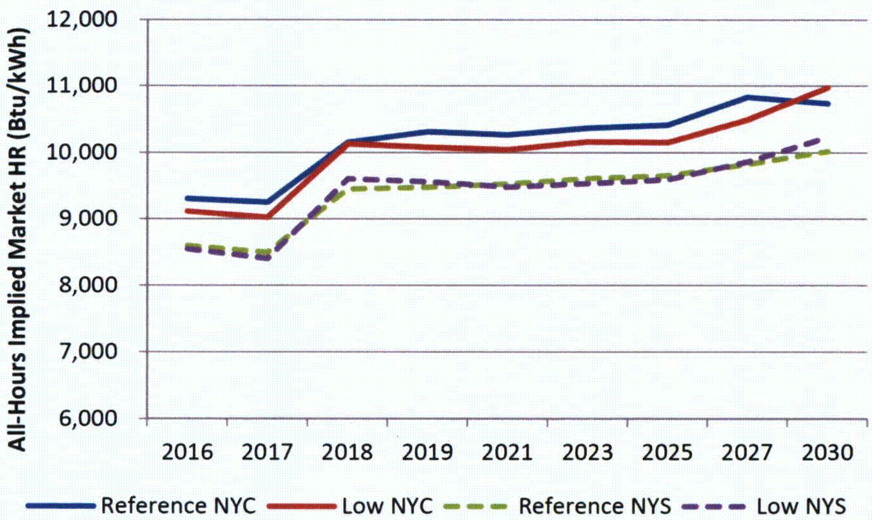
Off Peak	8,155	8,060	9,148	9,125	8,989	8,950	8,928	9,042	9,278

Table 106 - Low Case Status Quo Implied Market Heat Rate for NYC (Btu/kWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	9,834	9,905	11,006	10,778	10,801	10,871	10,758	11,366	12,070
Peak	10,792	10,929	12,120	11,753	11,891	12,006	11,835	12,656	13,524
Off Peak	8,742	8,722	9,719	9,651	9,550	9,558	9,513	9,887	10,388

Figure 18 shows the comparison of implied heat rates between the Low Case Status Quo scenario and the Reference Case Status Quo scenario in NYC and NYS.

Figure 18 - Comparison of Low Case and Reference Case Status Quo Implied Market HR



4.4.2. Low Case Conventional Thermal Scenario

As for the High Case Conventional Thermal scenario, we ran one subset of the Low Case Conventional Thermal scenario. IP2 is retired in September 2013 and IP3 is retired in December 2015. A 500 MW CC unit is added at the Gowanus substation upon IP2's retirement, and another 500 MW CC unit is added at the Buchanan substation upon IP3's retirement.

The following tables show the delta in forecasted market LBMP between the Low Case Conventional Thermal scenario and the Low Case Status Quo scenario.

Table 107 - Delta in NYS Market LBMP, Low Case Conventional Thermal ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	1.79	1.90	1.79	1.76	2.05	2.20	2.35	2.48	2.46
Peak	1.97	2.02	2.03	2.03	2.42	2.53	2.73	2.82	2.77
Off Peak	1.58	1.77	1.52	1.44	1.62	1.83	1.91	2.08	2.10

Table 108 - Delta in NYC Market LBMP, Low Case Conventional Thermal ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	1.88	2.19	1.91	1.95	2.19	2.51	2.93	2.90	3.17
Peak	1.82	2.29	2.11	2.12	2.50	2.68	3.27	3.18	3.50
Off Peak	1.95	2.08	1.69	1.77	1.83	2.31	2.54	2.58	2.78

The following tables show the delta in the implied market heat rate between the High Case Conventional Thermal scenario and the High Case Status Quo scenario.

Table 109 - Delta in NYS Implied Market Heat Rate, Low Case Conventional Thermal (Btu/kWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	297	309	284	278	320	333	351	371	361
Peak	326	326	321	321	378	382	408	422	405

Off Peak	264	290	242	228	253	276	285	312	309

Table 110 - Delta in NYC Implied Market Heat Rate, Low Case Conventional Thermal (Btu/kWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	273	306	263	274	306	328	390	386	423
Peak	261	315	290	296	352	349	436	421	468
Off Peak	286	296	231	249	254	303	338	347	371

4.4.3. Low Case Low-Carbon (Transmission/Wind) Scenario

The Low Case Low-Carbon scenario is the same as the High Case Low-Carbon scenario except that fuel prices, load, and generic CC additions are lower. The following tables show the delta in forecasted market LBMP between the Low Case Low-Carbon scenario and the Low Case Status Quo scenario.

Table 111 - Delta in Market LBMP for NYS, Low Case Low-Carbon ($/MWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	1.55	1.58	1.58	1.61	1.90	2.04	2.12	2.09	2.04
Peak	1.55	1.51	1.69	1.74	2.14	2.19	2.33	2.25	2.20
Off Peak	1.54	1.66	1.44	1.47	1.62	1.86	1.88	1.92	1.84

Table 112 - Delta in Market LBMP for NYC, Low Case Low-Carbon ($/MWh)

Year	**2016**	**2017**	**2018**	**2019**	**2021**	**2023**	**2025**	**2027**	**2030**
All Hours	1.53	1.65	1.55	1.91	1.84	2.30	2.60	2.50	2.39
Peak	1.20	1.48	1.54	1.87	1.93	2.24	2.67	2.47	2.40

Off Peak	1.92	1.85	1.57	1.96	1.75	2.36	2.53	2.53	2.39

The following tables show the increase in implied market heat rate between the Low Case Low-Carbon scenario and the Low Case Status Quo scenario.

Table 113 - Delta in Implied Market Heat Rate for NYS, Low Case Low-Carbon ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	256	254	249	253	292	302	316	312	294
Peak	255	240	269	274	331	326	348	336	318
Off Peak	257	270	227	230	247	275	280	285	267

Table 114 - Delta in Implied Market Heat Rate for NYC, Low Case Low-Carbon ($/MWh)

Year	2016	2017	2018	2019	2021	2023	2025	2027	2030
All Hours	225	231	215	272	254	304	351	333	302
Peak	172	203	216	271	270	299	361	330	299
Off Peak	284	263	215	273	235	309	338	338	306

All Hours Average Yearly LMPs

	Node Name	
Year	INDIAN POINT 2	INDIAN POINT 3
2004	$52.81	$52.73
2005	$78.38	$77.91
2006	$64.17	$64.22
2007	$72.73	$72.86
2008	$87.58	$87.71
2009	$43.08	$43.14
2010	$51.03	$51.00
2011	$48.56	$48.62
2012	$37.35	$37.33
2013	$50.07	$50.15

Source: Energy Velocity, ISO Real Time & Day Ahead LMP Pricing – Monthly Summary, Accessed February 6, 2014

On-Peak Average Yearly LMPs

	Node Name	
Year	INDIAN POINT 2	INDIAN POINT 3
2004	$61.62	$61.49
2005	$92.43	$92.01
2006	$77.12	$77.22
2007	$87.27	$87.47
2008	$102.93	$103.16
2009	$50.10	$50.21
2010	$59.56	$59.54
2011	$56.68	$56.78
2012	$44.23	$44.22
2013	$58.93	$59.03

Source: Energy Velocity, ISO Real Time & Day Ahead LMP Pricing – Monthly Summary, Accessed February 6, 2014

Off-Peak Average Yearly LMPs

	Node Name	
Year	**INDIAN POINT 2**	**INDIAN POINT 3**
2004	$45.07	$45.04
2005	$66.18	$65.66
2006	$52.96	$52.95
2007	$60.08	$60.15
2008	$74.09	$74.14
2009	$36.90	$36.93
2010	$43.58	$43.54
2011	$41.49	$41.50
2012	$31.39	$31.36
2013	$42.34	$42.39

Source: Energy Velocity, ISO Real Time & Day Ahead LMP Pricing – Monthly Summary, Accessed February 6, 2014

Average Monthly Natural Gas Prices for Transco Zone 6 Delivery Point

Year	Month	Average of Mean LMP Price $/MWh
2013	January	$78.69
	February	$91.87
	March	$48.94
	April	$45.90
	May	$50.10
	June	$49.18
	July	$73.76
	August	$42.76
	September	$41.99
	October	$39.26
	November	$41.72
	December	$59.70
2014	January	$186.67
	February	$93.11

Source: Energy Velocity, ISO Real Time & Day Ahead LMP Pricing – Monthly Summary, Accessed February 6, 2014

Before the
New York State Department of Environmental Conservation

In the Matter of

Entergy Nuclear Indian Point 2, LLC
Entergy Nuclear Indian Point 3, LLC

DEC: 3-5522-00011/00004
SPDES: NY-0004472
DEC: 3-5522-00011/00030
DEC: 3-5522-00011/00031

March 28, 2014

Rebuttal Testimony of:

Christopher J. Russo

Charles River Associates
200 Clarendon Street
Boston, MA 02116

On Behalf of:

The City of New York

Q. Would you please state your name, employer, and business address?

A. My name is Christopher Russo, and I am employed by Charles River Associates ("CRA"), a/k/a CRA International, Inc. My normal place of business is 200 Clarendon Street, Boston, Massachusetts 02116.

Q. Are your educational background and experience outlined in your prior testimony?

A. Yes. This information was provided in Exhibit City-1.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this rebuttal testimony before the New York State Department of Environmental Conservation ("NYSDEC") on behalf of the City of New York ("City").

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the pre-filed direct testimony of NYSDEC/Department of Public Service ("DPS") and Riverkeeper, Inc. ("Riverkeeper") witnesses related to issues that I addressed in my direct testimony.

Q. Are you sponsoring an exhibit with your testimony?

A. Yes. I offer City-5, which is comments that Cricket Valley Energy Center ("Cricket Valley") filed with the New York State Public Service Commission ("PSC") in Case 12-E-0503.

Q. Do you have any general comments regarding the pre-filed direct testimony that you reviewed?

A. Yes. In general, the analyses presented by NYSDEC/Department of Public Service Staff ("DPS") witnesses Dr. Thomas Paynter, Leka Gjonaj and David

Wheat, and Riverkeeper witness Robert Fagan, focused only on relatively narrow aspects of the potential system reliability, economic, and emissions impacts that may be associated with an extended outage or retirement of the Indian Point Energy Center ("IPEC"). Also, the modeling analyses included with the pre-filed direct testimony of those witnesses do not provide sufficient information to support either the accuracy or merit of their statements and conclusions.

I also note that no one has attempted to estimate the contractual support that may be necessary to support the construction and operation of replacement capacity resources. My analysis in the "Indian Point Energy Center Retirement Analysis" ("Retirement Report"; included previously as Exhibit City-2) demonstrated that the above-market cost of such contractual support can have a significant impact on New York electricity consumers as well as an effect on the economic sustainability of competitive electricity markets in New York State.

Q. Please explain what you mean by your characterization of the Paynter, Gjonaj, Wheat and Fagan analyses as "narrow?"

A. Dr. Paynter does not account for certain factors that should have been reflected in the analyses underlying his direct testimony. Messrs. Gjonaj and Wheat focus only on the impacts from a short- or long-term IPEC outage, and do not examine the impacts that may result if that facility instead were to retire. Although Mr. Fagan considers the possibility of retirement to a limited extent, his consideration of economic impacts associated with the scenarios modeled is very narrow. In addition, Messrs. Gjonaj, Wheat and Fagan focus primarily on the potential economic impact that the installation and operation of closed-cycle cooling

("CCC") may have on IPEC, and relegate to a secondary consideration the more important questions regarding the economic costs associated with the installation of, and outages associated with, CCC.

Each of those witnesses considers the possibility of construction-related outages of both IPEC units, but they do not analyze or consider what effect such outages might have on Entergy's decision to keep the facility online. I believe that it is important to consider the potential system reliability, economic, and emissions impacts that may be associated with decisions regarding the Best Technology Available ("BTA") for cooling at IPEC.

These witnesses focus their analyses on the system reliability, economic and emissions impacts that may be associated with the use of CCC as part of IPEC's normal operations. Although such analyses are a necessary part of the decision-making process in these proceedings, they are inadequate unless complemented with an objective evaluation of the full range of possible outcomes that may flow from the BTA determination. One such possible outcome is that the loss of market revenue that Entergy would realize while either or both IPEC units are offline, combined with the significant capital cost to install CCC and volatile market conditions, could lead Entergy to make the business decision to mothball or retire IPEC.

Q. Are there any other reasons why you characterized the analyses of Gjonaj and Wheat as being too narrow?

A. As I explained in the Retirement Report, new capacity resources that may be developed are unlikely to be compensated fully by market revenues. Specifically, I found that capacity additions larger than approximately 500 MW would require above-market payments. In their analyses, Messrs. Gjonaj and Wheat do not disclose where they expect capacity additions to appear, and so we cannot assess the need for or potential amount of contractual support that these additions would require.

DR. PAYNTER TESTIMONY

Q. Do you have any comments regarding the pre-filed direct testimony of Dr. Paynter?

A. Yes. The scope of Dr. Paynter's analysis is insufficient to provide insight regarding the potential economic impacts that may be associated with an extended outage or retirement of IPEC.

Q. Please explain.

A. Dr. Paynter explains that the purpose of his testimony is to estimate the capacity market impacts that may arise under certain outage scenarios defined by NYSDEC Staff. According to Dr. Paynter, one such analysis examined the "CCC Outage Case," a scenario in which Dr. Paynter assumed that both IPEC units would be out of service for the summer period and winter period in 2016 and 2022. Dr. Paynter concluded that, of the scenarios that he examined, the CCC Outage Case for 2016 would yield the highest price impact.

Initially, it is unclear why this scenario was included. Messrs. Gjonaj and Wheat did not model any scenario in which IPEC would be unavailable for a full year, as Dr. Paynter did. Dr. Paynter does not explain why his assumptions do not mirror those of his colleagues in this regard.

Dr. Paynter also implicitly assumes that it will be feasible from a system reliability perspective for IPEC to be unavailable in 2016. Messrs. Gjonaj, Wheat, and Fagan similarly assume in certain scenarios that extended outages of IPEC during peak summer demand would be feasible. The 2012 Reliability Needs Assessment ("RNA") conducted by the New York Independent System Operator, Inc. ("NYISO") concluded that the simultaneous outage of both IPEC reactors in 2016 would violate electric system reliability rules. Dr. Paynter and Messrs. Gjonaj and Wheat, and even Mr. Fagan, did not establish that sufficient replacement resources would be available to avoid potentially significant system reliability and customer cost impacts if both IPEC units were to be unavailable as of that date. Nor did they demonstrate that such replacement capacity would be economic.

Q. Do you agree with Dr. Paynter's assertion that the rise in ICAP prices would provide financial incentives for new resources to enter the market?

A. All else equal, yes, I agree that price signals may induce the development of new resources under certain circumstances. However, Dr. Paynter asserts that higher installed capacity ("ICAP") prices would provide a sufficient incentive for new capacity to enter the market, thereby limiting price increases. Dr. Paynter fails to account for certain factors that would impact the price signals that he assumes will function to induce new market entry.

One significant factor absent from Dr. Paynter's testimony is consideration of regulatory uncertainty and market intervention by New York State, particularly the PSC. Dr. Paynter's testimony considers the creation and effect of price signals in the context of a "pure" market guided solely by principles of economics. In recent years, however, the PSC has crafted policy on numerous occasions, including proceedings on the Danskammer and Dunkirk plants, new alternating current ("AC") transmission lines in the Hudson Valley, and on replacing the capacity of IPEC, with the intent of affecting electricity market outcomes. Given the relevance of capacity market effects to a potential IPEC retirement and the PSC's recent actions, it would be reasonable to conclude that further regulatory intervention in the capacity market may occur.

Dr. Paynter omits consideration of these potential effects and what actions his own agency might take to mitigate price increases in the effect of an IPEC retirement. Moreover, the PSC's actions can create a measure of uncertainty in the electricity markets and reduce developer willingness to proceed with new facilities on a merchant basis, in reliance on short-term capacity price signals.

Q. Please elaborate on your last point.

A. Prices in the New York capacity market are based on demand curves that generally mimic the core economic theory of supply and demand. That is, as demand increases and supply decreases, capacity prices increase. The NYISO ICAP market provides prices for capacity for periods of up to several months in the future, beyond which prices are the result of future auctions. (This stands in contrast to some markets such as PJM in which installed capacity prices are determined on a multi-year "forward" basis.)

Demand curves are set every three years, so the signals they provide are also indicative only of short-term market prices. In contrast, a new combined cycle generating facility could remain in service for 40 years or longer. Many developers are unwilling to rely solely on the short-term price signals conveyed by the capacity markets. They may, however, consider trends in those price signals and their drivers over time.

Recently, the NYISO proposed, and the FERC approved, a new capacity zone ("NCZ") covering the lower Hudson Valley. Capacity prices in that area are expected to increase as a result. The PSC has taken a number of steps to try to prevent or delay those price increases, including seeking a phase-in of the new zone and evaluating the retirement notice submitted for the Danskammer Plant based on economic considerations.

Developers will look to the PSC's intervention in the capacity markets in combination with the other trends in the price signals. That intervention creates uncertainty in future price projections and a lack of confidence that the markets will be allowed to operate consistent with economic theory (that is, that prices will be allowed to fluctuate based on market conditions).

Q. Is Dr. Paynter's position consistent with the PSC's stated position on this topic?

A. No. The PSC issued an order on November 4, 2013, in Case 12-E-0503, in which the PSC stated "we disagree that a reasonable planning approach under the circumstances should rely solely on market-based projects to appear…", given the prospect of a potential IPEC retirement. The potential capacity market impacts are likely to be very different for projects developed on a merchant basis, as compared to projects developed in reliance on contractual support. I discuss this distinction again later in my testimony.

Q. Are there other factors Dr. Paynter failed to consider?

A. Yes. Although replacement capacity would be needed immediately upon the retirement or extended outage of IPEC, the price signals that may induce new supply would not be present until IPEC exits the market. This assumes that the price signals are not affected by regulatory intervention.

Regardless, there can be a significant lag between price signals and the development of new supply resources, even those which have already started the development process. The lead time for new facilities is at least two years. For many projects, it can take even longer to secure the regulatory approvals, permits and financing needed to begin construction and commence commercial operations.

The PSC has acknowledged this timing issue, stating in its November 2013 order in Case 12-E-0503 that "there would unlikely be sufficient time to address the resulting reliability needs" if a sufficient amount of replacement capacity is not available at the time that IPEC becomes unavailable. I also note in this regard that Cricket Valley stated in comments filed with the PSC – which are attached as Exhibit City-5 – that it would require approximately three years from the date of signing a power purchase agreement to commence commercial operations.

Dr. Paynter asserts that the cost of new entry ("CONE") limits ICAP price increases because new supply would be encouraged to enter the market as ICAP prices approach the CONE, thereby limiting further price increases. As noted above, however, it is an oversimplification to suggest that capacity prices would be constrained by CONE while the market waits for new supply to come online.

Q. Do you have other concerns regarding Dr. Paynter's discussion of capacity market price signals?

A. Dr. Paynter's statement that price signals associated with higher ICAP prices would induce new capacity to enter the market can only be correct if one also assumes that the new capacity would not be subject to mitigation in the New York ICAP market.

Q. Would you explain what it means for a capacity resource to be "mitigated"?

A. As a preliminary matter, I note that the power system must be designed to meet peak summer demand, thus ordinarily creating surplus capacity during non-peak periods. Capacity markets are designed primarily to allow the marginal market entrant to receive revenues that compensate the generator for the full cost of new entry. In theory, revenue from capacity markets, along with revenue from energy markets, should allow merchant generators to rely on private capital to recover their costs, with an adequate rate of return.

The capacity market provides a revenue stream which is essential for the continued operation and development of many plants. Numerous facilities rely on capacity market revenues to economically sustain operations. To the extent that a developer or owner of such resources is foreclosed from the capacity market by application of the mitigation rules established by FERC, it becomes extremely difficult to finance and construct generation and transmission facilities without contractual support.

Under those market rules, a resource may be "mitigated" if its projected cost of new entry exceeds the CONE established for the market in which it will operate. Mitigated resources are prohibited from offering their contracted capacity into the market at an inframarginal price, and thus the exclusion of this capacity supply from the market sustains higher capacity prices.

Although this explanation oversimplifies the complex rules and interactions that characterize the New York State capacity market, it fairly illustrates the point that supply entering the market neither inexorably nor immediately leads to lower prices, given that new capacity potentially may be excluded from the ICAP market.

Q. Did Dr. Paynter adequately consider the impact of market mitigation?

A. No. Dr. Paynter assumed that all generators receive the capacity spot market price, except facilities owned by regulated utilities or public power agencies. It appears, therefore, that Dr. Paynter did not consider the impact of market mitigation.

Q. What are the implications of Dr. Paynter's failure to consider the impact of market mitigation?

A. As noted above, capacity prices would not be reduced by the introduction of new supply from a mitigated resource, and access to revenues from the capacity market is a significant consideration for deciding whether or not a project is developed. This issue is material, and would have a significant impact on the customer cost impacts associated with an IPEC retirement or extended outage.

Q. Do you have any further comments regarding Dr. Paynter's testimony?

A. Given the importance of revenue certainty with respect to plant financing, new market entrants are likely to prefer the risk reduction and assured revenue stream associated with a power purchase agreement to the project and financial risks associated with developing a project on a merchant basis. As noted above, the PSC has signaled that contractual support may be considered for new facilities that will provide replacement power and capacity. Dr. Paynter does not consider issues pertaining to the contractual support that new resources may require to be developed.

GJONAJ-WHEAT TESTIMONY

Q. What assumptions regarding the increased availability of capacity resources in southeast New York State were made by Messrs. Gjonaj and Wheat?

A. In their pre-filed direct testimony, Messrs. Gjonaj and Wheat explain that they assumed replacement capacity would be available from resources located in southeast New York State in a manner consistent with the PSC's November 2013

Order. There, the PSC found that approximately 1,500 MW of new capacity would be needed to avoid a reliability deficiency in the summer of 2016, if both IPEC units were to retire upon expiration of their existing permits. The PSC assumed in its November 2013 Order that a roughly equivalent amount of existing capacity resources could return to service if market conditions improve sufficiently. In their Base Case scenario, Messrs. Gjonaj and Wheat assume that a sufficient amount of those resources re-enter the market to avoid a reliability deficiency.

Notably, they have not offered any explanation of why they believe that any particular resource may resume operations in the future, or demonstrated that the market conditions they anticipate in the future would be adequate to induce such return to the market without contractual support. In short, they assume adequate capacity replacement based on a PSC finding that has no specific analytic support.

They also fail to address the full range of relevant considerations potentially associated with reentry of resources. Existing resources that re-enter the market may be inefficient and have greater emissions as compared to IPEC or other potential resources. For instance, although the formerly-retired Danskammer power plant located in Newburgh, New York reportedly may attempt to resume operations, the facility as currently configured burns coal as well as natural gas. Also, the Danskammer facility relied on a once-through cooling system. It is apparent from these proceedings that once-through cooling systems can face regulatory challenges. It is unclear whether Danskammer would be able to secure required air and water permits and resume operations while continuing to rely on such equipment, or would need to make a substantial investment in new air treatment and cooling systems in addition to the investment that would be required to repair the facility so that it may resume commercial operations.

Q. Do you agree with the assumptions that Messrs. Gjonaj and Wheat made regarding the market re-entry of unspecified resources located in southeastern New York State?

A. No. Their decision to add capacity in or near New York City is understandable in the sense that multiple entities – including the PSC – have recognized that substantial, incremental capacity resources will be needed in southeastern New York State to maintain resource adequacy if IPEC retires. Messrs. Gjonaj and Wheat, however, provide no analysis to support their conclusion that the units will be able to re-enter the market on an economic basis, in the sense of being fully compensated by market revenues, as opposed to requiring contractual support to resume operations. Given that the resources alluded to in the PSC's November 2013 Order were mothballed due to the poor economics of facility operations, were subject to a forced outage and/or derated, or would require repairs before resuming operations, one would have to examine the particular circumstances of each resource individually before reaching an informed decision on whether or not one or more of those units could re-enter the market, or under what circumstances, and with what consequences, it may do so.

Another critical omission from this analysis is that the analyses conducted by Messrs. Gjonaj and Wheat had to assume either that the unspecified capacity resources would re-enter the market on a merchant basis, or they assumed that contractual support would be required to induce such return. If they assumed contractual support, they did not estimate the customer cost associated with those contracts.

Finally, Messrs. Gjonaj and Wheat do not state that they conducted any resource adequacy analysis before concluding that the capacity located in southeastern New York that they assumed would re-enter the market actually would contribute to compliance with minimum resource adequacy standards that the system must satisfy. The lack of such analysis makes it impossible to conclude, as they have done, that system reliability violations can be avoided in summer 2016, if IPEC is unavailable.

Q. Do you have any concerns regarding the database underlying the scenarios modeled by Messrs. Gjonaj and Wheat?

A. I have concerns, but the direct testimony and exhibits of Messrs. Gjonaj and Wheat are missing critical details that would be necessary to develop definitive conclusions regarding their work.

Q. What fuel source would replacement capacity rely on?

A. Messrs. Gjonaj and Wheat do not specify the type of capacity that would be added to the system. However, given current environmental regulations and siting requirements, it is highly likely that replacement capacity resources would be predominantly gas-fired.

Q. What are the implications of replacement capacity relying on gas?

A. The State already is heavily dependent on natural gas for electricity, as well as for heating. The 2011 and 2012 Gold Books issued by the NYISO reported that the proportion of electricity generated from resources that relied exclusively or primarily on natural gas increased from 38 percent in 2011, to 45 percent in 2012. From 2012 to 2013, the installed capacity of those gas resources increased from 53 percent of the State's generating capability to 55 percent of same.

Given the likelihood that gas-fired resources are most likely to account for most or all of the energy that would replace IPEC in the event of retirement or an extended outage, the diversity of the State's generation mix would decrease, and the State's reliance on natural gas would increase. This loss of fuel diversity would increase the linkage between energy market prices and natural gas prices.

Although gas prices generally are low by historical standards, they can be volatile and subject to sharp spikes. This winter, the NYISO area set an all-time record for peak winter electric demand in January, 2014, and average natural gas prices at Transco Zone 6 (New York City) in January/February 2014 were almost 400% greater than the price in December, 2013.

Q. Do you have other concerns regarding the energy market forecasts prepared by Messrs. Gjonaj and Wheat?

A. Yes. The PSC has approved a group of Transmission Owner Transmission Solution ("TOTS") projects for implementation as part of its contingency planning for a potential IPEC retirement. Although the transmission owners that are developing the TOTS projects will recover their costs from utility customers, it does not appear that any party has included such cost impacts in their analyses. The rate impact associated with these projects would be incremental to the wholesale energy and capacity effects associated with an extended IPEC outage or retirement.

There is a secondary economic effect of TOTS that also should be considered. The NCZ recently approved for implementation by FERC is intended, in part, to produce price signals that may induce the development of new generation resources. However, construction of the TOTS projects would increase the transfer capability into the NCZ, thus adding additional supply and decreasing capacity and energy prices. Thus, the TOTS projects would tend to moderate the price signals to new entrants that the NCZ is intended to provide. It is unclear whether the net effect of the TOTS projects on the NCZ would elicit the development of new merchant supply projects, or if developers instead would wait for contractual support. It appears, however, that the interplay between these two current policy initiatives has not been examined carefully by any party in these proceedings.

Q. Do Messrs. Gjonaj and Wheat accurately describe the long-term impact of an IPEC retirement or extended outage?

A. As I understand the usage, the short term is a period of time during which neither production capacity nor technology can adapt to a change such as IPEC retirement or extended outage. The long term, conversely, is a period of time after which all possible changes arising from such retirement or extended outage have taken place, including changing the amount, type, and location of generating capacity and production. Put a different way, the long term is a point at which an economic equilibrium is reached.

Messrs. Gjonaj and Wheat note this fact, and correctly assume that in the long term, new capacity should enter the market in the presence of higher prices, which returns the market to equilibrium. They assert, however, that wholesale energy markets tend to decline and diminish over time. This is true only if new capacity is entering the market for economic reasons. I explained earlier the real possibility that capacity entering the market in response to or in anticipation of an IPEC outage or retirement would not do so for economic reasons, but would require contractual support.

Messrs. Gjonaj and Wheat also assert that the air emissions increases associated with the retirement of IPEC would not diminish over time as new capacity enters the market. I agree. For the reasons described in my pre-filed direct testimony, the increased air emissions resulting from an IPEC retirement would persist for the foreseeable future.

FAGAN TESTIMONY

Q. How would you characterize the analysis presented by Mr. Fagan?

A. Mr. Fagan's testimony, and the Synapse Report included as Exhibit 109 to which he refers, are more accurately characterized as a proposed retirement plan rather than an impact analysis. Mr. Fagan's report concludes that the reliability and economic impacts associated with an IPEC retirement or extended outage are minimal. Those conclusions are based on the consideration of several measures that potentially may mitigate the reliability and economic consequences associated with such retirement or outage. Mr. Fagan, however, omits any mention of the feasibility or cost of the mitigation measures that are the bases for his conclusions.

Q. How did Mr. Fagan characterize the impact of energy efficiency in his analyses?

A. Mr. Fagan presents several scenarios in which he uses both a base-case energy efficiency impact as well as a scenario consistent with achievement of the State's energy efficiency targets by December 31, 2015. Although it is appropriate to attempt to estimate the impact of energy efficiency gains, the potential development of this resource must be considered in a realistic context.

In my direct testimony, I noted that the NYISO assumes that the Energy Efficiency Portfolio Standard by which the State is pursuing its efficiency goals will fall short of its savings targets. Mr. Fagan, therefore, appropriately notes in the Synapse Report that the "15 by 15" energy efficiency target is unlikely to be achieved.

Despite this, Mr. Fagan models a number of scenarios that assume the State achieves the 15 by 15 goal. Given that the State will not achieve that goal, model scenarios that rely on this assumption are inherently flawed and do not produce meaningful results.

Q. Does Mr. Fagan make any other unsupported assumptions?

A. Yes. Mr. Fagan assumes that 185 MW of incremental demand side energy efficiency, demand response, and combined heat and power on-site generation resources will be available by 2016. Although this assumption is based, in part, on the PSC's November 2013 Order, PSC approval of programs does not guarantee that the goals and targets of those programs will be satisfied by the target date. As noted above, the State may not achieve other, previously-announced energy efficiency savings goals, despite numerous PSC orders approving efficiency programs that cost hundreds of millions of dollars. Mr. Fagan has made no independent attempt to validate the amount of energy efficiency, demand response, and/or on-site generation that actually will be achieved by January 1, 2016.

Q. **Mr. Fagan describes the NYISO's reliability process on page 7 of his pre-filed direct testimony. Is his description accurate?**

A. No. Mr. Fagan omitted a critical part of that process from his testimony and report by failing to discuss the concept and measurement of resource adequacy.

Mr. Fagan describes the NYISO's test for reliability as a snapshot of time using power flow models under a worst case scenario. This is only a part of the NYISO's analysis, and ignores the resource adequacy test, which is a critical component of tests for system robustness. I discussed the importance and role of resource adequacy in my direct testimony. Resource adequacy can be roughly described as a test of whether sufficient generation and transmission exists to ensure that the demand for electricity can be fully met with an acceptably low probability of outage.

Q. Did Mr. Fagan consider this concept in his testimony?

A. Mr. Fagan asserts that "ongoing developments" and the "anticipated availability of market-based capacity" would eliminate any reliability concerns if "IPEC were out of service for *any* reason as of 2016" (emphasis in the original). Mr. Fagan is simply stating that if new capacity were constructed or load reduced, IPEC could be retired without jeopardizing reliability. This somewhat circular statement is intuitively obvious but, to the extent that it simply assumes replacement measures without considering their impact, it does not amount to an informative conclusion for regulators and State policy makers to act upon.

For example, Mr. Fagan does not address how the assumed incremental capacity would be constructed, whether the energy efficiency targets that he assumes actually are feasible, or how project development risk should be treated. At numerous points in his testimony, Mr. Fagan reaches the conclusion that the system would be reliable under different scenarios, but he conditions each such conclusion with a statement that this is true only if future events transpire in a particular pattern. In sum, Mr. Fagan has provided no analysis to support his conclusion that future events will transpire in the specific patterns assumed by Mr. Fagan, nor considered the economic costs with doing so.

Q. Does the testimony of Mr. Fagan or any other witness that you reviewed consider development risk?

A. I did not note any detailed discussion of development risk in the pre-filed direct testimony of Mr. Fagan, Dr. Paynter, or Messrs. Gjonaj and Wheat. Large capital projects often involve some element of risk, which could include schedule risk, cost risk, or a risk that the project may not be completed successfully. In the case of large, capital-intensive power plants or transmission lines, these risks can be significant.

It is possible that the State could take steps to mitigate development risk, including expediting permit processes and allowing power purchase agreements for certain assets. Significant development risk, however, would remain even if the State intervened to ensure contractual support for new resources. The need to obtain environmental permits, negotiate interconnection agreements, obtain physical and financial fuel supplies, and resolve financing issues (which are complex and often difficult) still would remain. The fact that a generation project is included on the NYISO queue is not a sufficient basis to assume that the project will be constructed; historically, many projects have remained in the queue for years, and a large percentage of such projects never commence operations.

In this regard, I note that Mr. Fagan cited two generation projects under development that currently are in the interconnection queue as potential sources of replacement capacity for IPEC. Those projects are the proposed Cricket Valley and CPV Valley electric generation facilities. Regarding Cricket Valley, Entergy witness Dr. Harrison noted that the developers of Cricket Valley have been informed by the NYISO that they must pay approximately $280 million of interconnection costs before the project may proceed. According to Dr. Harrison, the Cricket Valley developers are contesting that assessment. As to CPV Valley, the current in-service estimate is 2018, and my understanding is that the project developers have not yet learned what their responsibility for system upgrade costs may be before the new facility, if constructed, may interconnect to the system.

To the extent that new gas-fired power plants are contemplated, their developers will need to access bulk natural gas sources, which can be a very expensive endeavor that also can raise public concerns.

Until a facility is constructed and operational, it is dangerous to assume that it will appear at a date certain in the future. These examples are intended to be illustrative of the point that units proposed as replacement resources for IPEC may experience developmental delays, cost overruns, or may fail for numerous reasons, and increased operations from incumbent generators may present environmental concerns.

Q. What material did you rely on in preparing your testimony?

A. I relied on the NYISO's 2012 Reliability Needs Assessment, and the NYISO's 2011, 2012, and 2013 Load and Capacity Data ("Gold Book").

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

In the Matter of a Renewal and Modification of a State Pollutant Discharge Elimination System ("SPDES") Permit Pursuant to article 17 of the Environmental Conservation Law And Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York parts 704 and 750 *et seq.* by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, Permittee,	**DEC # 3-5522-00011/00004** **SPDES # NY-0004472**

-and-

In the Matter of the Application by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, for a Certificate Pursuant to §401 of the Federal Clean Water Act	**DEC # 3-5522-00011/00030** **DEC # 3-5522-00011/00031**

February 28, 2014

Prepared Testimony of:

THOMAS S. PAYNTER
Supervisor of Regulatory Economics
Office of Regulatory Economics
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

Witness Information

Q. Will the witness please state his full name and business address?

A. My name is Thomas S. Paynter. My business address is Three Empire State Plaza, Albany, New York 12223-1350.

Q. Have you previously provided Witness Information for this proceeding?

A. Yes. I offered my educational and professional experience in mid-December. This is attached as Exhibit_(TP-1).

Overview

Q. What is your role in this case?

A. I have been assigned to act as an independent consultant to the Staff of the New York Department of Environmental Conservation (NYS DEC). In this role, I have developed forecasts of wholesale capacity market impacts from Indian Point outage scenarios defined by NYS DEC Staff.

Q. Could you please describe what you mean by forecasts of wholesale capacity market impacts?

A. Wholesale capacity market impacts relate to forecast changes in the price of installed capacity (ICAP), a component of electricity prices. NYS DEC Staff's outage scenarios may limit Indian Point's ability to supply ICAP, thus tending to tighten the ICAP markets and increase ICAP prices. Impacts from these outages are measured relative to an Indian Point business as usual Base Case.

Purpose and Summary

Q. What is the purpose of your pre-filed testimony?

A. The purpose of my testimony is to describe how I modeled capacity market cases based on Indian Point outage scenarios defined by NYS DEC Staff, and to provide forecasts of wholesale capacity market impacts. My forecasts complement the wholesale energy market impacts developed by my colleagues David Wheat and Leka Gjonaj at the New York State Department of Public Service (DPS).

Q. Can you briefly describe your capacity market cases?

A. I have modeled three capacity market cases: 1) no capacity supply from either Indian Point 2 (IP2) or Indian Point (IP3) for Combined Cycle Cooling construction (CCC Outage Case); 2) no capacity supply from IP2 and only winter period capacity supply from IP3 (Intermediate Case); and 3) only winter period capacity supply from both IP2 and IP3 (Protective Outage Case). I also modeled a Base Case, in which both IP2 and IP3 would be supplying capacity for the full year.

Q. Please explain how your capacity market cases relate to the outage scenarios defined by NYS DEC Staff and the energy market scenarios (Runs) of Witnesses Wheat and Gjonaj.

A. My CCC Outage Case applies to NYS DEC Staff’s preferred scenarios, and to Runs 1 and 2 from Witnesses Wheat and Gjonaj. My Intermediate Case models NYS DEC Staff's scenarios with CCC at IP2 and protective outages at IP3, and applies to Runs 3, 4, 5, and 6. My Protective Outage Case models NYS DEC Staff's scenarios with protective outages during the summer at both IP2 and IP3, and applies to Runs 7, 8, 9, and 10.

Q. Please explain how you estimated capacity market impacts of NYS DEC Staff's scenarios.

A. I forecasted capacity spot market prices for the Base Case and for the three capacity market outage cases, for the years 2016 and 2022 (the years modeled by Witnesses Wheat and Gjonaj). I also estimated capacity market revenues in each case, which represent payments by customers to generators, assuming all generators receive the capacity spot market price, except those owned by regulated utilities or public power agencies. Finally, I estimated capacity market impacts as the difference between each capacity outage case and the Base Case.

Q. Can the impact estimates you provide be expected to persist over the long term, or are they shorter term in nature?

A. ICAP market impacts tend to be relatively large but short term. ICAP prices are very sensitive to relatively small changes in generation supply. For example, in New York City (NYC), the entry of a new 500 megawatt (MW) plant (the size of many fossil-fueled plants) could cause ICAP prices to decrease by about $5 per kiloWatt-month (kW-month), or $60 per kW-year; this could reduce ICAP revenues by half, and lead to retirements of some existing plants - which would offset the initial impacts. Similarly, a significant tightening of the ICAP market (due to load growth or supply reductions) will initially cause large increases in ICAP prices; but the higher prices will tend to encourage new investment, and again the market response will offset the initial impacts.

Q. Is there a limit to how high ICAP prices can go?

A. Yes. As ICAP prices increase, they become attractive to investors, who can add new plants in the Lower Hudson Valley at an average cost of approximately $10/kW-month. This "cost of new entry" (CONE) acts as an effective cap on ICAP prices, since as prices approach CONE, new supply is encouraged, which tends to limit further increases in ICAP prices. Moreover, if the ICAP market becomes so tight that reliability is threatened, the New York Independent System Operator (NYISO) may call on the utilities to facilitate additional supply to ensure reliability; this will again tend to limit any price increases above CONE.

Q. What are the results of your analysis?

A. My analysis shows that the Indian Point outage cases have the potential to create relatively large impacts on wholesale capacity markets. However, the impacts are limited by the potential for new entry as capacity markets tighten and prices approach CONE in the Base Case. Thus potential price impacts are more likely to be large in the near term, since ICAP prices are currently well below the estimated CONE in most regions. In later years, forecasted ICAP prices are already near CONE in the Base Case (due primarily to expected load growth), so there is less potential for further increases.

Q. Would you expect ICAP market impacts to be lower if construction outages were to occur after 2022?

A. Yes. Although I did not conduct specific analyses for years beyond 2022, ICAP markets would be expected to be tighter, and forecasted ICAP prices higher, in the Base Case due to load growth. As a result, the potential for further price increases would be limited by the addition of new capacity to offset shortages.

Q. Are there any other factors that would tend to mitigate the capacity market impacts of the NYS DEC Staff's scenarios?

A. Yes. Generally, speaking, greater advance certainty in terms of construction and/or protective outages at Indian Point would facilitate the capacity market's ability to respond over time. In addition, close coordination between DEC and the NYISO and local utilities would facilitate the development of schedules that could minimize reliability impacts and resulting capacity market impacts.

Scenarios and Methodology Description

Q. Could you briefly describe the ICAP market?

A. The ICAP market is intended to ensure sufficient supply of generation resources (measured in MegaWatts, or MWs) to reliably serve New York's summer peak electricity demand. The NYISO, in conjunction with the New York State Reliability Council, annually establishes minimum ICAP requirements for the state and for several regions within the state. The NYISO operates monthly and semiannual auctions through which customers procure ICAP from suppliers, at prices determined by supply and demand.

Q. Could you briefly describe how the Closed Cycle Cooling scenario defined by NYS DEC Staff could affect the ICAP market?

A. NYS DEC Staff estimates that the implementation of Closed Cycle Cooling at Indian Point would require a construction outage of 35-42 weeks. Thus the NYISO would not be able to rely on the plant for most of a year. I have modeled this in the capacity market CCC Outage Cases by assuming Indian Point exits the ICAP market (summer and winter periods) for 1 year, allowing for contingencies. If the construction outage were completed more quickly, the market impacts would be proportionately reduced.

Q. Could you describe how the Protective Outage scenarios defined by NYS DEC Staff could affect the NYISO's ICAP market?

A. NYS DEC Staff's Protective Outage scenarios have the potential to restrict Indian Point from supplying ICAP during the summer peak load periods (May - October). Under the Protective Outage scenarios, Indian Point would be unavailable for 42 or 62 days each summer, between May 10 and August 10, until Closed Cycle Cooling could be implemented. Because this period covers New York's summer peak load season, Indian Point might not be available to meet annual summer peak loads. The NYISO would have to evaluate the reliability of New York's bulk power system under these constraints. In its 2012 Reliability Needs Assessment, the NYISO determined that the retirement of Indian Point would leave the NYISO with insufficient resources to reliably serve summer peak loads in the Lower Hudson Valley and downstate New York. Although the Protective Outage scenarios would not restrict the availability of Indian Point as much as the retirement of Indian Point, the NYISO might conclude that the annual summer Protective Outages would create a similar reliability need.

Q. If the NYISO were to conclude that annual summer Protective Outages create such a reliability need, how might it respond?

A. In that case, the NYISO would likely signal the need for additional reliability resources through the ICAP market, e.g. by determining that Indian Point would not qualify as an ICAP supplier, at least during the summer peak periods when availability is restricted by the annual Protective Outages. This would reduce the ICAP supply, thereby tightening the market and increasing the market price of ICAP, in order to encourage additional ICAP supply to maintain reliability. The NYISO could also call for regulated solutions to a reliability need, such as adding ratebased generating capacity.

Q. Based on these potential impacts to the ICAP market and the NYISO's potential response, what assumption do you make in the Protective Outage Case?

A. My capacity market Protective Outage Case models this by assuming Indian Point would not qualify as an ICAP supplier in the Summer ICAP period (May-October).

Q. Could you briefly describe how the Intermediate scenarios defined by NYS DEC Staff could affect the ICAP market?

A. The intermediate scenarios assume CCC is required for IP2 only, while Protective Outages apply to IP3. My capacity market Intermediate Case models these as a full year outage of IP2, with IP3 available in the winter period only

(November-April).

Q. Can you be certain that the outage scenarios defined by NYS DEC Staff would lead to the specific reductions in capacity supply that you modeled?

A. No. The NYISO would evaluate the specific terms of any proposed construction or protective outages, to determine their reliability impacts. The NYISO might determine that Indian Point could supply ICAP for at least a portion of the summer periods, which would reduce the capacity market impacts. The NYISO might also take other actions than what I have modeled. There might also be other market responses that would mitigate the impacts of the outages.

Q. Would you please explain the methodology used to develop forecast capacity market impacts?

A. My capacity market forecast is based on demand (load forecasts) and ICAP supply for 2016 and 2022 from the NYISO's <u>2013 Load & Capacity Data</u> ("Gold Book"), with adjustments as described by DPS Staff Witnesses Wheat and Gjonaj.

Q. How did you convert demand and supply into ICAP prices?

A. I developed a spreadsheet, provided in Exhibit_(TP-2), to forecast the results of the NYISO's spot auctions. These auctions use administratively determined demand curves, which have been set through 2016; I modeled these and assumed that the price parameters continue to increase at the current rate of inflation. ICAP supply is assumed to be offered at $0 (since there is little incremental cost in supplying ICAP), except for the transmission line owned by Hudson Transmission partners, LLC (HTP), which is currently subject to a bid floor that prevents it from supplying ICAP until the New York City market is relatively tight (ICAP prices near CONE). I modeled this by excluding HTP from the ICAP market in 2016, due to relatively low ICAP prices. The intersection of the supply and demand curves determines the ICAP market price and quantity.

Q. Did you make any adjustments to the prices as set by the demand and supply curves?

A. Yes. I assumed that shortages (supply below minimum requirements) in any region were offset by new investment to eliminate the shortage. I also took account of the "nesting" of ICAP regions, which leads to the rule that the price in the Lower Hudson Valley cannot drop below the statewide price, and the price in NYC (NYISO Zone J) cannot drop below the price in the "New Capacity Zone" (G-J Zone), which in turn cannot drop below the statewide price.

Q. How did you estimate price impacts from the ICAP market changes?

A. Price impacts were calculated as the difference in annual average spot market prices between the Base Case and each capacity market Outage Case.

Q. How did you estimate revenue (dollar) impacts from the ICAP market changes?

A. I assumed that all supply in each region sold at the ICAP spot market prices as determined above, except for supply listed in Table III-2 of the NYISO "Gold Book" as owned by regulated utilities or public power agencies or municipalities—the New York Power Authority (NYPA), the Long Island Power Authority (LIPA), and the Jamestown Board of Public Utilities—which were assumed to be cost-based and not impacted by the ICAP spot market prices. I also assumed that any new entry received the spot market price (at CONE). Summer and winter period monthly revenues were multiplied by 6 months/period, and added to get annual values. Impacts were calculated as changes in annual values from the Base Case to each capacity market Outage Case.

Wholesale Capacity Market Impacts

Q. Please describe DPS Staff's forecasts of wholesale capacity market impacts.

A. Wholesale capacity market impacts are provided in Exhibit_(TP-2), for each capacity region in the capacity markets administered by the NYISO. Suppliers in New York City (NYC) and on Long Island (LI) receive the respective NYC and LI prices. The New Capacity Zone price applies to suppliers in the Lower Hudson Valley (LHV). The statewide price applies to suppliers in the "Rest of State" (ROS) region, outside of the nested capacity regions. The exhibit provides estimated impacts on annual average ICAP prices ($/kW-month), and revenue ($) impacts as explained above.

Q. How would you describe the nature of these forecasts?

A. These forecasts should be regarded as illustrative only: The ICAP markets are very sensitive to small changes in load growth, new entry, and retirements, which cannot be reliably forecasted many years into the future. The difference between the two forecast years illustrates the uncertainty inherent in ICAP market price forecasts.

Q. Please summarize the forecasted capacity market impacts for 2016.

A. In 2016, each of the capacity market Outage Cases has a relatively large impact on ICAP prices, except for Long Island. NYC prices increased by about $2 to $7/kW-month. LHV prices increased by about $3 to $7/kW-month. The ROS price increased by about $1 to $2.50/kW-month. ICAP Revenues ($) increased roughly proportionately, with a total increase of about $500 million (Protective Outage Case) to $1.5 billion (CCC Outage Case) statewide. The relatively large increases are due to the relatively low prices in the Base Case, which in part reflect forecasts of significant new entry (e.g. return to service of mothballed units) in response to recent higher prices. This illustrates the high variability in short-term ICAP price forecasts.

Q. Please summarize the forecasted capacity market impacts for 2022.

A. In 2022, each of the capacity market Outage Cases has a smaller impact on ICAP prices. NYC prices increased by about $0 to $3/kW-month. LHV prices increased by about $1 to $4.50/kW-month. The ROS price increased by $0 to about $1.50/kW-month. The revenue ($) impacts ranged from about $50 million (Protective Outage Case) to about $800 million (CCC Outage Case) statewide. The relatively smaller increases are due to the relatively tight capacity market and high prices in the Base Case, due largely to forecasted load growth between 2016 and 2022. As a result, prices cannot increase much before shortages and high prices trigger new entry.

Q. Did the estimated prices exceed the cost of new entry (CONE) in any cases?

A. The estimated prices in the Base Cases and the Protective Outage cases did not exceed the regional CONEs. For the CCC and Intermediate Outage Cases, the Lower Hudson Valley (LHV) and Rest of State (ROS) prices did significantly exceed the estimated CONE for the regions. However, those Cases would only apply for the single year of the construction outage, so I did not model any market response to that price signal.

Q. What do you conclude from your analysis?

A. As expected, ICAP market results are very sensitive to the Base Case conditions. If the market has a significant amount of excess supply in the Base Case, the Outage Scenarios will lead to significant price increases in the short run. However, in the long run, prices are expected to be closer to equilibrium, and the market will respond more readily to offset the impacts of an Outage Scenario.

Q. What material did you rely on in preparing your testimony?

A. The material I relied on in preparing my testimony includes the NYISO's <u>2012 Reliability Needs Assessment</u>[1] and the NYISO's <u>2013 Load and Capacity Data</u> ("<u>Gold Book</u>").[2] My spreadsheet is provided in Exhibit_(TP-2).

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[1] Section 4.3.2 (pp. 48-49), available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2012_RNA_Final_Report_9-18-12_PDF.pdf

[2] Table III-2 (pp. 26-45), Table III-3a (p. 48), Table III-3b (p. 49), Table V-2a (p. 66), and Table V-2b (p. 67), available at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf

Q. Does this conclude your testimony at this time?

A. Yes.

Witness Information for Thomas S. Paynter

Q. What is your name and business address?

A. Thomas S. Paynter, New York State Department of Public Service, 3 Empire State Plaza, Albany New York 12223-1350.

Q. By whom are you employed and in what capacity?

A. I am employed by the New York State Department of Public Service as Supervisor of Regulatory Economics in the Office of Regulatory Economics.

Q. Please describe your educational background.

A. I received a Ph.D. in Economics from the University of California at Berkeley (1985), with fields in econometrics and labor economics. I have a B.A. in Physical Science and a B.A. in Economics, also from the University of California at Berkeley (1975). I am a member of the American Economic Association.

Q. Please describe your professional experience.

A. From 1983 to 1986, I was an Assistant Professor of Economics at Northern Illinois University, where I taught graduate and undergraduate courses in economic theory. From 1986 to 1990, I was employed by the Illinois Commerce Commission as a Senior Economic Analyst in the Policy Analysis and Research Division; I was also a member of the Electricity Subcommittee of the National Association of Regulatory Utility Commissioners, and authored an article concerning coordination and efficient pricing for independent power producers, "Coordinating the Competitors," published by The Electricity Journal in November 1990. I joined the New York Department of Public Service in November of 1990.

Q. Have you testified previously before the New York Public Service Commission?

A. Yes. I have testified in numerous rate cases and other proceedings before the New York Public Service Commission, including the Article VII siting cases for the Hudson Transmission Project and the Champlain Hudson Power Express project, as well as the Article X siting cases for Athens and Brookhaven.

Q. What are your current responsibilities?

A. My current responsibilities include analyzing competitive issues, efficient pricing, marginal costs, regulatory policies, and system planning. I am a member of a staff team responsible for analyzing and commenting upon the pricing rules of the New York Independent System Operator, Inc. (NYISO), which operates the New York transmission system. I have participated in numerous NYISO committee meetings related to capacity markets, energy and transmission pricing, system planning, and other issues.

Potential Capacity Market Impacts

2016

Annual Average ICAP Price ($/kW-month)				
Zone	Base	Protective	Intermed.	CCC Out
NYC	$5.95	$8.22	$10.76	$12.68
LHV	$5.24	$8.22	$10.76	$12.68
LI	$6.00	$6.00	$6.57	$7.20
ROS	$4.57	$5.55	$6.53	$7.16

Price Impact ($/kW-month)			
Zone	Protective	Intermed.	CCC Out
NYC	$2.27	$4.80	$6.73
LHV	$2.99	$5.52	$7.44
LI	$0.00	$0.56	$1.19
ROS	$0.98	$1.96	$2.59

ICAP Revenue ($M, Market-Based)				
Zone	Base	Protective	Intermed.	CCC Out
NYC	$683	$939	$1,241	$1,470
LHV	$267	$341	$415	$439
LI	$80	$80	$87	$95
ROS	$846	$1,028	$1,208	$1,324
Total	$846	$2,388	$2,951	$3,328

ICAP Revenue Impact ($M)			
Zone	Protective	Intermed.	CCC Out
NYC	$256	$558	$787
LHV	$74	$148	$172
LI	$0	$7	$15
ROS	$182	$362	$478
Total	$512	$1,075	$1,451

2022

Annual Average ICAP Price ($/kW-month)				
Zone	Base	Protective	Intermed.	CCC Out
NYC	$11.12	$11.14	$14.35	$14.45
LHV	$9.90	$11.14	$14.35	$14.45
LI	$8.48	$8.48	$9.80	$9.84
ROS	$8.48	$8.48	$9.80	$9.84

Price Impact ($/kW-month)			
Zone	Protective	Intermed.	CCC Out
NYC	$0.02	$3.23	$3.33
LHV	$1.24	$4.44	$4.54
LI	$0.00	$1.32	$1.36
ROS	$0.00	$1.32	$1.36

ICAP Revenue ($M, Market-Based)				
Zone	Base	Protective	Intermed.	CCC Out
NYC	$1,321	$1,324	$1,718	$1,730
LHV	$505	$533	$608	$609
LI	$184	$184	$213	$213
ROS	$1,537	$1,537	$1,776	$1,782
Total	$3,547	$3,579	$4,314	$4,335

ICAP Revenue Impact ($M)			
Zone	Protective	Intermed.	CCC Out
NYC	$3	$396	$409
LHV	$29	$103	$104
LI	$0	$28	$29
ROS	$0	$239	$245
Total	$32	$767	$788

Base Case*

	NYC			NCZ			LI (NCPeak)			NYCA		
	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter
IRM/LCR %	85.00%			88.00%			107.00%			117.00%		
DC Length %	18.00%			15.00%			18.00%			12.00%		
2016 Capacity Adjustments:												
IPEC IN												
2016												
Ref Price (S/W & average)	$14.68	$19.37	$9.99	$9.80	$12.68	$6.91	$6.69	$8.30	$5.08	$7.44	$9.23	$5.65
Peak Load	12006			16537			5688			34556		
ICAP LCR	10205.1			14552.56			6086.16			40430.52		
DC Length MW	1836.918			2182.884			1095.509			4851.662		
Slope	-0.010545			-0.00581			-0.00758			-0.0019		
Total Supply		11270.16	11953		15580.88	16246.14		6204.096	6574.303		42455.9	43301.5
Excess Supply		1065.061	1747.899		1028.324	1693.576		117.936	488.1425		2025.38	2870.98
Regional Reliability Additions**		0	0		0	0		0	0		0	0
Augmented Supply		11270.16	11953		15580.88	16246.14		6204.096	6574.303		42455.9	43301.5
Augmented Excess		1065.061	1747.899		1028.324	1693.576		117.936	488.1425		2025.38	2870.98
DC Price	$4.54	$8.14	$0.94	$4.77	$6.71	$2.84	$6.00	$7.41	$4.60	$4.57	$5.38	$3.77
ICAP Price	$5.95	$8.14	$3.77	$5.24	$6.71	$3.77	$6.00	$7.41	$4.60	$4.57	$5.38	$3.77
Regional Supply**		11270	11953		4311	4293		6204	6574		20671	20481
Market-Based Supply**		9398	9923		4254	4235		1131	1073		15510	15289
Annual Market Revenue ($M)**	$683	$459	$224	$267	$171	$96	$80	$50	$30	$846	$500	$346
2022												
Ref Price (S/W & average)	$16.73	$22.07	$11.38	$11.16	$14.45	$7.87	$7.62	$9.46	$5.79	$8.48	$10.52	$6.44
Peak Load	12833			17616			6060			36355		
ICAP LCR	10908.05			15502.08			6484.2			42535.35		
DC Length MW	1963.449			2325.312			1167.156			5104.242		
Slope	-0.011241			-0.00621			-0.0081			-0.00206		
Total Supply		11590.16	12273		15900.88	16566.14		6910.096	7280.303		43177.3	44018.1
Excess Supply		682.1115	1364.949		398.8038	1064.056		425.896	796.1025		641.95	1482.75
Regional Reliability Additions**		0	0		0	0		0	0		0	0
Augmented Supply		11590.16	12273		15900.88	16566.14		6910.096	7280.303		43177.3	44018.1
Augmented Excess		682.1115	1364.949		398.8038	1064.056		425.896	796.1025		641.95	1482.75
DC Price	$10.57	$14.40	$6.73	$9.90	$11.97	$7.84	$4.51	$6.01	$3.01	$8.33	$9.19	$7.46
ICAP Price	$11.12	$14.40	$7.84	$9.90	$11.97	$7.84	$8.48	$9.36	$7.60	$8.48	$9.36	$7.60
Regional Supply**		11590	12273		4311	4293		6910	7280		20366	20172
Market-Based Supply**		9718	10243		4254	4235		1837	1779		15205	14980
Annual Market Revenue ($M)**	$1,321	$840	$482	$505	$306	$199	$184	$103	$81	$1,537	$854	$683

*IP In service; assumes Astoria 2 and 4 return to service by 2016.

**NCZ regional supplies are LHV only (excluding NYC supply); NYCA regional supplies are ROS only.

Protective Outage Case*

	NYC			NCZ			LI (NCPeak)			NYCA		
	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter
IRM/LCR %	85.00%			88.00%			107.00%			117.00%		
DC Length %	18.00%			15.00%			18.00%			12.00%		
2016 Capacity Adjustments:												
IPEC OUT Summer Only					-2068.7						-2068.7	
2016												
Ref Price (S/W & average)	$14.68	$19.37	$9.99	$9.80	$12.68	$6.91	$6.69	$8.30	$5.08	$7.44	$9.23	$5.65
Peak Load	12006			16537			5688			34556		
ICAP LCR	10205.1			14552.56			6086.16			40430.52		
DC Length MW	1836.918			2182.884			1095.509			4851.662		
Slope	-0.010545			-0.00581			-0.00758			-0.0019		
Total Supply		11270.16	11953		13512.18	16246.14		6204.096	6574.303		40387.2	43301.5
Excess Supply		1065.061	1747.899		-1040.38	1693.576		117.936	488.1425		-43.32	2870.98
Regional Reliability Additions**		0	0		1040.376	0		0	0		0	0
Augmented Supply		11270.16	11953		14552.56	16246.14		6204.096	6574.303		41427.58	43301.5
Augmented Excess		1065.061	1747.899		0	1693.576		117.936	488.1425		997.0562	2870.98
DC Price	$4.54	$8.14	$0.94	$7.76	$12.68	$2.84	$6.00	$7.41	$4.60	$5.55	$7.33	$3.77
ICAP Price	$8.22	$12.68	$3.77	$8.22	$12.68	$3.77	$6.00	$7.41	$4.60	$5.55	$7.33	$3.77
Regional Supply**		11270	11953		3282	4293		6204	6574		20671	20481
Market-Based Supply**		9398	9923		3226	4235		1131	1073		15510	15289
Annual Market Revenue ($M)**	$939	$715	$224	$341	$245	$96	$80	$50	$30	$1,028	$682	$346
2022												
Ref Price (S/W & average)	$16.73	$22.07	$11.38	$11.16	$14.45	$7.87	$7.62	$9.46	$5.79	$8.48	$10.52	$6.44
Peak Load	12833			17616			6060			36355		
ICAP LCR	10908.05			15502.08			6484.2			42535.35		
DC Length MW	1963.449			2325.312			1167.156			5104.242		
Slope	-0.011241			-0.00621			-0.0081			-0.00206		
Total Supply		11590.16	12273		13832.18	16566.14		6910.096	7280.303		41108.6	44018.1
Excess Supply		682.1115	1364.949		-1669.9	1064.056		425.896	796.1025		-1426.75	1482.75
Regional Reliability Additions**		0	0		1669.896	0		0	0		0	0
Augmented Supply		11590.16	12273		15502.08	16566.14		6910.096	7280.303		42778.5	44018.1
Augmented Excess		682.1115	1364.949		0	1064.056		425.896	796.1025		243.1462	1482.75
DC Price	$10.57	$14.40	$6.73	$11.14	$14.45	$7.84	$4.51	$6.01	$3.01	$8.74	$10.02	$7.46
ICAP Price	$11.14	$14.45	$7.84	$11.14	$14.45	$7.84	$8.48	$9.72	$7.24	$8.48	$9.72	$7.24
Regional Supply**		11590	12273		3912	4293		6910	7280		20366	20172
Market-Based Supply**		9718	10243		3855	4235		1837	1779		15205	14980
Annual Market Revenue ($M)**	$1,324	$842	$482	$533	$334	$199	$184	$107	$77	$1,537	$886	$651

*Assumes IP not qualified to provide Summer ICAP due to Protective Unit Outage Days

**NCZ regional supplies are LHV only (excluding NYC supply); NYCA regional supplies are ROS only.

Intermediate Case*

	NYC			NCZ			LI (NCPeak)			NYCA		
	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter
IRM/LCR %	85.00%			88.00%			107.00%			117.00%		
DC Length %	18.00%			15.00%			18.00%			12.00%		
2016 Capacity Adjustments:												
IP2 Out IP3 Summer Out					-2068.7	-1031.3					-2068.7	-1031.3
2016												
Ref Price (S/W & average)	$14.68	$19.37	$9.99	$9.80	$12.68	$6.91	$6.69	$8.30	$5.08	$7.44	$9.23	$5.65
Peak Load	12006			16537			5688			34556		
ICAP LCR	10205.1			14552.56			6086.16			40430.52		
DC Length MW	1836.918			2182.884			1095.509			4851.662		
Slope	-0.010545			-0.00581			-0.00758			-0.0019		
Total Supply		11270.16	11953		13512.18	15214.84		6204.096	6574.303		40387.2	42270.2
Excess Supply		1065.061	1747.899		-1040.38	662.2763		117.936	488.1425		-43.32	1839.68
Regional Reliability Additions**		0	0		1040.376	0		0	0		0	0
Augmented Supply		11270.16	11953		14552.56	15214.84		6204.096	6574.303		41427.58	42270.2
Augmented Excess		1065.061	1747.899		0	662.2763		117.936	488.1425		997.0562	1839.68
DC Price	$4.54	$8.14	$0.94	$10.76	$12.68	$8.83	$6.00	$7.41	$4.60	$6.53	$7.33	$5.73
ICAP Price	$10.76	$12.68	$8.83	$10.76	$12.68	$8.83	$6.57	$7.41	$5.73	$6.53	$7.33	$5.73
Regional Supply**		11270	11953		3282	3262		6204	6574		20671	20481
Market-Based Supply**		9398	9923		3226	3204		1131	1073		15510	15289
Annual Market Revenue ($M)**	$1,241	$715	$526	$415	$245	$170	$87	$50	$37	$1,208	$682	$526
2022												
Ref Price (S/W & average)	$16.73	$22.07	$11.38	$11.16	$14.45	$7.87	$7.62	$9.46	$5.79	$8.48	$10.52	$6.44
Peak Load	12833			17616			6060			36355		
ICAP LCR	10908.05			15502.08			6484.2			42535.35		
DC Length MW	1963.449			2325.312			1167.156			5104.242		
Slope	-0.011241			-0.00621			-0.0081			-0.00206		
Total Supply		11590.16	12273		13832.18	15534.84		6910.096	7280.303		41108.6	42986.8
Excess Supply		682.1115	1364.949		-1669.9	32.75634		425.896	796.1025		-1426.75	451.45
Regional Reliability Additions**		0	0		1669.896	0		0	0		0	0
Augmented Supply		11590.16	12273		15502.08	15534.84		6910.096	7280.303		42778.5	42986.8
Augmented Excess		682.1115	1364.949		0	32.75634		425.896	796.1025		243.1462	451.45
DC Price	$10.57	$14.40	$6.73	$14.35	$14.45	$14.25	$4.51	$6.01	$3.01	$9.80	$10.02	$9.59
ICAP Price	$14.35	$14.45	$14.25	$14.35	$14.45	$14.25	$9.80	$10.02	$9.59	$9.80	$10.02	$9.59
Regional Supply**		11590	12273		3912	3262		6910	7280		20366	20172
Market-Based Supply**		9718	10243		3855	3204		1837	1779		15205	14980
Annual Market Revenue ($M)**	$1,718	$842	$875	$608	$334	$274	$213	$110	$102	$1,776	$914	$862

*Assumes IP2 out for Closed Cycle Cooling Construction Outage; assumes IP3 out for Summer ICAP due to Protective Unit Outage Days
**NCZ regional supplies are LHV only (excluding NYC supply); NYCA regional supplies are ROS only.

CCC Outage Case*

	NYC			NCZ			LI (NCPeak)			NYCA		
	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter	Average	Summer	Winter
IRM/LCR %	85.00%			88.00%			107.00%			117.00%		
DC Length %	18.00%			15.00%			18.00%			12.00%		
2016 Capacity Adjustments:												
IPEC OUT					-2068.7	-2075.6					-2068.7	-2075.6
2016												
Ref Price (S/W & average)	$14.68	$19.37	$9.99	$9.80	$12.68	$6.91	$6.69	$8.30	$5.08	$7.44	$9.23	$5.65
Peak Load	12006			16537			5688			34556		
ICAP LCR	10205.1			14552.56			6086.16			40430.52		
DC Length MW	1836.918			2182.884			1095.509			4851.662		
Slope	-0.010545			-0.00581			-0.00758			-0.0019		
Total Supply		11270.16	11953		13512.18	14170.54		6204.096	6574.303		40387.2	41225.9
Excess Supply		1065.061	1747.899		-1040.38	-382.024		117.936	488.1425		-43.32	795.38
Regional Reliability Additions**		0	0		1040.376	382.0237		0	0		0	0
Augmented Supply		11270.16	11953		14552.56	14552.56		6204.096	6574.303		41427.58	41607.92
Augmented Excess		1065.061	1747.899		0	0		117.936	488.1425		997.0562	1177.404
DC Price	$4.54	$8.14	$0.94	$12.68	$12.68	$12.68	$6.00	$7.41	$4.60	$7.16	$7.33	$6.99
ICAP Price	$12.68	$12.68	$12.68	$12.68	$12.68	$12.68	$7.20	$7.41	$6.99	$7.16	$7.33	$6.99
Regional Supply**		11270	11953		3282	2600		6204	6574		20671	20481
Market-Based Supply**		9398	9923		3226	2542		1131	1073		15510	15289
Annual Market Revenue ($M)**	$1,470	$715	$755	$439	$245	$193	$95	$50	$45	$1,324	$682	$641
2022												
Ref Price (S/W & average)	$16.73	$22.07	$11.38	$11.16	$14.45	$7.87	$7.62	$9.46	$5.79	$8.48	$10.52	$6.44
Peak Load	12833			17616			6060			36355		
ICAP LCR	10908.05			15502.08			6484.2			42535.35		
DC Length MW	1963.449			2325.312			1167.156			5104.242		
Slope	-0.011241			-0.00621			-0.0081			-0.00206		
Total Supply		11590.16	12273		13832.18	14490.54		6910.096	7280.303		41108.6	41942.5
Excess Supply		682.1115	1364.949		-1669.9	-1011.54		425.896	796.1025		-1426.75	-592.85
Regional Reliability Additions**		0	0		1669.896	1011.544		0	0		0	0
Augmented Supply		11590.16	12273		15502.08	15502.08		6910.096	7280.303		42778.5	42954.04
Augmented Excess		682.1115	1364.949		0	0		425.896	796.1025		243.1462	418.6937
DC Price	$10.57	$14.40	$6.73	$14.45	$14.45	$14.45	$4.51	$6.01	$3.01	$9.84	$10.02	$9.65
ICAP Price	$14.45	$14.45	$14.45	$14.45	$14.45	$14.45	$9.84	$10.02	$9.65	$9.84	$10.02	$9.65
Regional Supply**		11590	12273		3912	3229		6910	7280		20366	20172
Market-Based Supply**		9718	10243		3855	3171		1837	1779		15205	14980
Annual Market Revenue ($M)**	$1,730	$842	$888	$609	$334	$275	$213	$110	$103	$1,782	$914	$868

*Assumes IP out for full year for Closed Cycle Cooling Construction outage.

**NCZ regional supplies are LHV only (excluding NYC supply); NYCA regional supplies are ROS only.

Demand and Supply Forecasts

Load	A	B	C	D	E	F	G	H	I	J	K	K NCPeak	NYCA	NCZ (G-J)	ROS (A-F)
2013	2615	2040	2868	783	1404	2325	2250	678	1410	11485	5421	5514.6	33279	15823	12035
2016	2683	2111	2958	811	1451	2413	2347	709	1475	12006	5592	5688	34556	16537	12427
2022	2712	2185	3059	818	1477	2530	2456	758	1569	12833	5958	6060	36355	17616	12781
Summer Capacity															
2013										10351.16	6154.096		41451.9	14661.88	20635.92
2016										11270.16	6204.096		42455.9	15580.88	20670.92
2022 Add HTP										11590.16	6910.096		43177.3	15900.88	20366.32
Winter Capacity															
2013										11034	6524.303		42217.7	15327.14	20366.26
2016										11953	6574.303		43301.5	16246.14	20481.06
2022 Add HTP										12273	7280.303		44018.1	16566.14	20171.66

Note: Brattle assumed 635 MW UDRs for J, 760 MW UDRs for K in 2016

Adjustments to 2013 Supply for 2016, per Brattle:

	S	W	Zone	
Dunkirk	-75	-75.2	A	
Ravenswood	-11	-11	J	
GTs	40	40	J	
Generic	260	340	ROS (inc. wind)	
TOTS	325	325	J	SIU (225) + Upstate Shift (100)
TOTS	50	50	K	Upstate Shift
TOTS	-150	-150	ROS	Upstate Shift

DPS Additional Base Case Additions:

Astoria 2&4	565	565	J
Total	1004	1083.8	

Adjustments to 2016 Supply for 2022 (Brattle included in 2016 and 2022 MAPS runs):

Cayuga	-304.6	-309.4	C	
Caithness	706	706	K	For 2018
HTP	320	320	J	

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2013 Capability by Zone (per Gold Book)

Zone	A	B	C	D	E	F	G	H	I	J	K	NYCA	NCZ (G-J)	ROS	
Summer	4463.8	779.1	6560.5	1633.6	1030.8	4407	2113.2	2121	0	9534.1	5276.8	37919.9	13768.3	18874.8	Gen from Table III-3a
	436.881	85.71081	152.4705	7.17846	41.4915	138.6878	38.90725	6.173475	31.44165	502.0615	117.296	1558.3	578.5838	862.4201	SCR ICAP estimate*
										315	760	1075	315	0	UDRs**
												898.7		898.7	Remainder (Net Imports etc.)
	4900.681	864.8108	6712.97	1640.778	1072.291	4545.688	2152.107	2127.173	31.44165	10351.16	6154.096	41451.9	14661.88	20635.92	Total from Table V-2a
Winter	4523.6	793.5	6738.2	1687.9	1061	4951.2	2122.4	2129.6	0	10416.5	5715.6	40139.5	14668.5	19755.4	Gen from Table III-3b
	305.9274	37.9454	87.47537	9.220377	22.22347	61.46918	24.82409	2.600619	13.71235	302.4993	48.7025	916.6	343.6363	524.2612	SCR ICAP estimate*
										315	760	1075	315	0	UDRs**
												86.6		86.6	Remainder (Net Imports etc.)
	4829.527	831.4454	6825.675	1697.12	1083.223	5012.669	2147.224	2132.201	13.71235	11034	6524.303	42217.7	15327.14	20366.26	Total from Table V-2b
SCR UCAP Sales															
Summer	304.3	59.7	106.2	5	28.9	96.6	27.1	4.3	21.9	349.7	81.7	1085.4	403	600.7	SCR UCAP Sales Sep 2013
Winter	258.8	32.1	74	7.8	18.8	52	21	2.2	11.6	255.9	41.2	775.4	290.7	443.5	SCR UCAP Sales April 2013

*Estimate SCR ICAP by zone = SCR UCAP Sale by zone * SCR ICAP total (from Table V-2) / SCR UCAP Sale total
**Brattle assumed 635 MW UDRs for J, 760 MW UDRs for K in 2016

Non-Market Capacity by Region
per 2013 Gold Book

	Summer	Winter
NYC	1872	2030
LHV	57	58
LI	5073	5502
ROS	5161	5192

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

In the Matter of a Renewal and Modification of a State Pollutant Discharge Elimination System ("SPDES") Permit Pursuant to article 17 of the Environmental Conservation Law And Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York parts 704 and 750 *et seq*. by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, Permittee,

DEC # 3-5522-00011/00004
SPDES # NY-0004472

-and-

In the Matter of the Application by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, for a Certificate Pursuant to §401 of the Federal Clean Water Act

DEC # 3-5522-00011/00030
DEC # 3-5522-00011/00031

February 28, 2014

Prepared Testimony of:

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Witness Information

Q. Will the first witness of the panel please state his full name and business address?

A. My name is Leka P. Gjonaj. My business address is Three Empire State Plaza, Albany, New York 12223-1350.

Q. Will the second member of the panel please state his full name and business address?

A. My name is David V. Wheat. My business address is Three Empire State Plaza, Albany, New York 12223-1350.

Q. Have you previously provided Witness Information for this proceeding?

A. Yes. We offered our educational and professional experience in mid-December. This is attached as Exhibit_(GW-1).

Overview

Q. What are your roles in this case?

A. We have been assigned to act as independent consultants to the Staff of the New York State Department of Environmental Conservation (NYS DEC Staff). In this role, we were asked to develop forecasts of air emissions impacts, along with wholesale energy market impacts, from

Indian Point outage scenarios defined by NYS DEC Staff. Impacts from these outages are measured relative to an Indian Point business as usual Base Case.

Q. Why would outages be required at Indian Point?

A. According to NYS DEC Staff, outages (35 or 42 weeks) would be required to facilitate the construction of Closed Cycle Cooling (CCC) facilities at one or both of the Indian Point 2 and Indian Point 3 generating units. These are referred to as construction outages. These would be coupled with annual protective outages, which are of shorter duration (42 or 62 unit outage days to be scheduled during the period May 10-August 10), and would be required in years prior to the installation of CCC to mitigate impacts to various fish species. Other scenarios defined by NYS DEC Staff involve variants of construction and/or protective outages.

Q. Would you please describe the types of air emissions impacts that you forecast?

A. We present forecast air emissions impacts for sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and carbon dioxide (CO_2).

Q. Would you please describe what you mean by forecasts of wholesale energy market impacts?

A. Wholesale energy market impacts relate to forecast changes in the energy component of electricity prices, referred to as location based marginal prices (LBMP). These are sometimes also referred to as ratepayer impacts.

Purpose and Summary

Q. What is the purpose of your pre-filed testimony?

A. The purpose of our testimony is to 1) describe how we developed forecast impacts for the Indian Point outage scenarios defined by NYS DEC Staff 2) present forecast air emissions impacts that we have provided to NYS DEC Staff 3) provide forecasts of wholesale energy market impacts, and 4) provide concluding comments.

Q. Please explain why you are estimating air emission impacts and wholesale energy market price impacts.

A. NYS DEC Staff asked specifically for air emissions impacts. Additionally, we believe the NYS DEC should be aware of wholesale energy market impacts as well.

Q. Can the impact estimates you provide be expected to persist over the long term, or are they shorter term in nature?

A. The air emission impacts could be expected to persist over the long-term, but only to the extent Indian Point outages continue in future years. Emissions impacts under construction outage scenarios, for example, would only last for the 35 or 42 week duration of the outages in one year. These emissions impacts would not persist into the future, whereas emissions impacts resulting from continuing protective outages would. Wholesale energy market benefits, in contrast, tend to be shorter term in nature, meaning that they can be expected to decline and diminish over time as market participants (suppliers and consumers) adjust their behavior in response to the immediate reduction in prices expected to result from additional supply.

Q. Are wholesale market impacts similar to ratepayer impacts?

A. They should be similar if wholesale market impacts were to flow through immediately to ratepayers. Due to the use of hedging arrangements to guard against price volatility and the existence of Transmission Congestion Contracts, however, the direct correlation between the two is lessened.

Q. In addition to your energy market impact estimates, do the Department of Public Service (DPS) Staff witnesses testifying in these proceedings provide forecasts of capacity market impacts?

A. Yes. DPS Staff witness Paynter provides DPS Staff's forecasts of capacity market impacts.

Q. What are the results of your analysis?

A. Our analysis shows that the largest impacts, in terms of increases in wholesale energy market prices and air emissions, result from the scenarios in which construction outages would be required at both Indian Point 2 and Indian Point 3 to facilitate the construction of CCC. The intermediate scenarios, which couple construction outages at Indian Point 2 with protective outages at Indian Point 3, increase wholesale energy market prices and air emissions, but to a lesser extent than the construction outages scenarios. The protective outage scenarios, where both Indian Point 2 and Indian Point 3 would be unavailable for 42 day or 62 day periods during May 10-August 10, tend to have the smallest impacts.

Q. Did you consider a scenario where Indian Point would be unavailable for a full year?

A. No, we did not. The NYS DEC Staff did not request that we consider a full year Indian Point unavailability scenario. The scenarios we modeled only consider Indian Point as being unavailable partially during a given year, in accordance with the scenarios the NYS DEC Staff asked us to model. Therefore, our analysis does not forecast potential air emission impacts that might be associated with Indian Point being unavailable for a full year or years.

Q. Is the generation capability assumed in your modeling efforts consistent with the State Energy Plan as required by State Environmental Quality Review Act (SEQRA) and associated regulations?

A. Yes. Because the modeling assumptions described in our testimony are intended to provide an adequate level of capability for electric system reliability, electric system needs will be satisfied in a manner reasonably consistent with the most recent State Energy Plan.

Scenarios and Methodology Description

Q. Would you please explain the methodology used to develop forecast energy market impacts?

A. We performed our analysis using General Electric's Multi-Area Production Simulation (GE-MAPS) computer software tool to simulate the electric system with construction and/or protective outages at Indian Point. Impacts are estimated relative to a business as usual Base Case in which Indian Point is available without any construction outages or protective outages. GE-MAPS is an industry recognized electric system planning/analysis tool that relies on a myriad of detailed inputs, such as forecasts of electric demand and fuel costs, generating unit characteristics (e.g., heat rates, forced outage rates, planned outages, and emission rates), and the electric transmission system topology.

Q. How was the GE-MAPS data set developed?

A. The GE-MAPS data DPS Staff is using for this NYS DEC proceeding was originally put together by the New York Independent System Operator, Inc. (NYISO) for its Congestion Assessment and Resource Integration Studies (CARIS) economic planning process. The NYISO used GE-MAPS to perform electricity energy market simulations of Base Case and other scenarios as described in the NYISO 2011 CARIS Report. The NYISO modified these data over time, for such things as generation retirements in New York and consideration of Transmission Owner Transmission Solutions (TOTS) proposed in a New York Public Service Commission (PSC) Proceeding (Case 12-E-0503 - Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans), before providing it to the Brattle Consulting Group (Brattle) in early summer 2013.

Q. Why did the NYISO provide its GE-MAPS data to the Brattle?

A. Brattle was hired as a consultant to assist the DPS/PSC in the development of Indian Point Retirement Contingency Plans as part of the PSC Proceeding on Motion of the Commission to Review

Generation Retirement Contingency Plans (Case 12-E-0503). It obtained GE-MAPS data pursuant to a confidentiality agreement (Exhibit_(GW-2))from the NYISO so it could perform energy market analyses for the DPS/PSC. Brattle revised these data by incorporating forecasts of natural gas prices and coal prices from the NYISO's CARIS 2013 process, generation retirements in neighboring regions that are generally consistent with assumptions in the CARIS 2013 process, and emission allowance prices. The Brattle consultants also reviewed the NYISO TOTS modeling and incorporated generic capacity additions in New York going forward (if deemed necessary in a given scenario) based upon their capacity market model forecasts.

Q. What emission allowance prices are incorporated into the GE-MAPS data?

A. Brattle assumes emission allowance prices of $0 /Ton for both SO2 allowances and NOx allowances. The forecast of CO2 prices was developed by the states participating in the Regional Greenhouse Gas Initiative (RGGI), utilizing an Integrated Planning Model process conducted by ICF

International, and is consistent with what the NYISO is assuming in the CARIS 2013 process.

Q. Does Brattle assume a national CO2 program going forward?

A. No. Brattle does not assume that a national CO2 program would be implemented in the foreseeable future. It assumes that the RGGI would continue going forward.

Q. Did DPS Staff revise Brattle's input data assumptions?

A. Yes. DPS Staff modified Brattle's modeling to incorporate outages for New York nuclear facilities to be consistent with assumptions in the CARIS 2013 process. Indian Point 2 is assumed to be on scheduled maintenance for approximately 4 weeks during even numbered years, while Indian Point 3 is assumed to be on scheduled maintenance during odd numbered years. We also incorporated coal to natural gas fuel switching in Ontario (Lambton, Nanticoke, and Thunder Bay generation facilities) and in New England (Brayton Point generation facility in Massachusetts). Additionally, DPS Staff is assuming that TOTS are in the Base Case (to be consistent with the Indian Point Contingency Plan PSC Order of November 4, 2013 in case 12-E-503) along with the un-mothballing[1] of resources located in New York City.

Q. What years did DPS Staff conduct simulations for?

A. Brattle developed the data set so that it could conduct simulations for the year 2016, and the year 2022. We did year-2022 simulations for all of the scenarios. For the protective outage scenarios, we also did simulations for the year 2016.

Q. In the Indian Point outage scenarios where Indian Point is unavailable during parts of the year, did you need to make assumptions about replacement capacity?

A. Yes. The scenarios defined by the NYS DEC Staff require Indian Point to be unavailable during portions of the summer capability period (the 6-month period during May-October). As a result, we assumed replacement capability would be available from other resources, in a manner that

[1] A mothballed generation unit is one that for various reasons is not providing energy or capacity in the New York generation markets and is also not officially retired.

is consistent with the Indian Point Contingency Plan PSC Order and, as a practical matter, conceivably obtainable.

Q. Please explain your assumptions.

A. We adopted the reliability need assumptions developed by Brattle for the year 2016 as well as the year 2022. In 2016, the Brattle consultants advised that in addition to capability expected to be available from TOTS, capacity would be required from other resources to meet reliability requirements. For our modeling purposes, DPS Staff assumes other capacity would be available from generating facilities located in southeast New York via an increased capability rating and the return to service of New York City mothballed resources. These assumptions are intended to provide a proxy measure of the capability that could be expected to be required to maintain a reliable electric system, rather than a prediction of what resources would actually provide this capability. Moving to the year 2022, Brattle advised that additional capacity could be expected to be needed to meet forecast load growth. As a result, in the year-2022 Indian Point outage modeling scenarios, DPS Staff assumes that this additional capability would come from new gas turbines sited in the Millwood zone where Indian Point is located. The general modeling characteristics of these generic resources, including their location and how the required capability is estimated, was developed by the Brattle consultants.

Q. Could you please describe in more detail the scenarios which NYS DEC Staff asked DPS Staff to conduct GE-MAPS simulations for?

A. Yes. Exhibit_(GW-3) identifies the scenarios. The left-hand side of this Exhibit describes the scenarios NYS DEC Staff originally developed. In order to simulate NYS DEC Staff's proposed scenarios using Brattle's GE-MAPS data, and given that Brattle developed the data sets to support simulations for the years 2016 and 2022, DPS Staff determined that ten Indian Point outage scenarios would need to be simulated. These are described in the right-hand side of Exhibit_(GW-3).

Q. What outages are incorporated into the Base Case modeling for Indian Point?

A. The Base Case assumes that Indian Point 2 is on scheduled maintenance for approximately 4 weeks per year during even numbered years. Indian Point 3, in contrast, is assumed to be on scheduled maintenance in odd-numbered years. Since we perform simulations for the year 2016 and the year 2022, our Base Case modeling only captures Indian Point 2 on scheduled maintenance.

Q. What are the effects of this on your forecast impact estimates?

A. Since forecast impacts are estimated relative to the Base Case, our impact estimates reflect a construction outage at Indian Point 3 that is 4 weeks longer than Indian Point 2, as compared to the Base Case. As shown in Exhibit_(GW-3), this is consistent with how the NYS DEC characterizes a construction outage at Indian Point 3 as being longer than Indian Point 2 construction outages by 4 weeks. The DPS modeling reported in the Exhibit show that for a given scenario, the construction outages at each Indian Point unit are identical, to reflect our modeling in these Indian Point outage scenarios.

Air Emissions Impacts

Q. Please describe DPS Staff's forecasts of air emissions impacts.

A. Air emissions impacts are provided in Exhibit_(GW-4), for New York State and sub-regions of New York. Emissions are aggregated for LBMP zones west and north of Albany, while they are shown separately for each LBMP zone south of Albany. Forecast air emissions impacts are presented for SO_2, NO_x, and CO_2, in both absolute tons per year, and in percentage change relative to the Base Case. The projected impacts are generally largest in the construction outage scenarios, lower in the intermediate scenarios involving construction outages at Indian Point 2 and protective outages at Indian Point 3, and lowest in the protective outage scenarios.

Q. Please provide an example of a projected air emissions impact for New York to illustrate the magnitude of impacts.

A. Using projected CO_2 emissions impacts in the year 2022 as an example, total impacts in New York are approximately 4-5 million tons in the construction outage scenarios, approximately 2-3 million tons in the intermediate scenarios, and approximately 1.0 million tons in the protective outage scenarios.

This represents increases of up to approximately 14% in the construction outage scenarios, up to approximately 8% in the intermediate scenarios, and up to approximately 3% in the protective outage scenarios.

Wholesale Market Impacts

Q. Please describe DPS Staff's forecasts of wholesale market impacts.

A. Wholesale market impacts are provided in Exhibit_(GW-5), for New York State and each pricing zone in the energy markets administered by the NYISO. These are provided in terms of impacts on LBMPs, and $ impacts which we estimate by multiplying LBMPs times energy requirements.

Q. Please provide an example of wholesale energy market impacts for New York to illustrate the magnitude of impacts.

A. Using LBMP impacts in the year 2022 as an example, total impacts in New York are approximately $1-$2 /MWH in the construction outage scenarios and under $1 /MWH in the other scenarios.

This represents increases of up to approximately 2% in the construction outage scenarios, and up to approximately 1% the other scenarios.

Concluding Comments

Q. Are there wholesale energy market and air emissions impacts in areas outside of the New York State?

A. Yes. To the extent Indian Point outages affect generation dispatch and energy transactions between and among New York State and neighboring regions, there are impacts outside of New York State as well.

Q. What regions are modeled in the GE-MAPS database?

A. The generation and transmission resources of four regions, typically referred to as control areas, are modeled. In addition to New York, this includes New England, Ontario, and the Reliability First Corporation which includes what has historically been referred to as the Pennsylvania-Jersey-Maryland interconnection (PJM) and extends west into Ohio and south into Virginia. Quebec is not modeled explicitly but is modeled via non-synchronous interties.

Q. Please provide an example of an impact estimate for all of the regions in the model including New York.

A. Using projected CO2 emissions impacts in the year 2022 as an example, total impacts from the four modeled control areas are approximately 6-8 million tons in the construction outage scenarios, approximately 3-4 million tons in the intermediate scenarios, and approximately 1-2 million tons in the protective outage scenarios. This represents increases of up to approximately 1.4% in the construction outage scenarios, up to approximately 1% in the intermediate scenarios, and up to 0.3% in the protective outage scenarios.

Q. What material did you rely on in preparing your testimony?

A. The material we relied on in preparing our testimony includes the Indian Point Contingency Plan PSC Order[2], and the information developed by the Brattle Group in support of that effort including the GE-MAPS data that the NYISO had provided to the Brattle consultants on a confidential basis. Furthermore, our modeling effort required us to incorporate assumptions regarding a proxy representation of additional capability going forward, which we attempted to draw from existing resources as much as possible to complement resources cited in the Indian Point Contingency Plan PSC Order. Finally, we note that general references relating to planning and modeling are available on the NYISO website, including NYISO economic planning reports associated with the biennial CARIS process[3].

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[2] Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing, NYPSC Case 12-E-0503, November 4, 2013 (http://documents.dps.ny.gov/public/Common/SearchResults.aspx?MC=0&DFF=11/03/2013&DFT=11/04/2013&DT=Orders&CI=1).

[3] The NYISO's 2011 Congestion Assessment and Resource Integration Study (CARIS) Report (March 20, 2012), and 2013 CARIS Report (November 19, 2013) are CARIS-Phase 1 Final Reports that are available at

Q. Does this conclude your testimony at this time?

A. Yes.

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http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

Witness Information for Leka P. Gjonaj

Q. What is your name and business address?

A. My name is Leka P. Gjonaj. My business address is Three Empire State Plaza, Albany, New York 12223-1350.

Q. By whom are you employed and in what capacity?

A. I am employed by the New York State Department of Public Service (DPS) as a Utility Supervisor in the Office of Electric, Gas, and Water.

Q. Please describe your educational background.

A. I hold a Bachelor of Science degree in Mechanical Engineering from Clarkson University (1985) and a Master of Science in Mechanical Engineering degree from Rensselaer Polytechnic Institute (1995). I am also a licensed Professional Engineer in New York State.

Q. Please describe your professional experience.

A. Before joining the DPS in November 1990, I was employed by General Electric in its Defense Systems Division. I was responsible for designing, implementing, and recommending manufacturing and quality control equipment needed for the production of highly specialized weapons components and systems for the United States Navy.

Q. Have you testified previously before the New York Public Service Commission?

A. Yes. I have testified in numerous rate cases and other proceedings before the Commission including Article VII siting cases, with the most recent cases being Article VII Hudson Transmission Partners, LLC proposal in Case 08-T-0034, and the Article VII Champlain Hudson Power Express, Inc. transmission proposal in Case 10-T-0139.

Q. What are your current responsibilities?

A. My areas of responsibility include regulatory oversight of the planning, design and operation of the high voltage transmission lines and the availability of adequate electric generation in New York State to reliably serve and meet the needs of New York electric customers. As part of fulfilling those responsibilities, I conduct electric system computer modeling simulations, review and analyze proposed power plant siting projects, review and analyze proposed electric transmission siting projects under Public Service Law Article VII, participate in utility rate case proceedings, meet regularly with representatives of the transmission owners, generator owners and others and participate in the activities of the New York Independent System Operator (NYISO).

Witness Information for David V. Wheat

Q. What is your name and business address?

A. David V. Wheat, New York State Department of Public Service (DPS), 3 Empire State Plaza, Albany New York 12223-1350.

Q. By whom are you employed and in what capacity?

A. I am employed by the DPS as a Principal Economist in the Office of Regulatory Economics.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree with a double major in economics and financial management from the State University of New York at Brockport in 1978, and a Master of Arts degree in economics from the State University of New York at Albany in 1981. In 1988, I completed the Certificate Program in Regulatory Economics at the State University of New York at Albany.

Q. Please describe your professional experience.

A. Since May 1987, I have been employed by the DPS.

I have provided analyses and testimony on electric issues in Commission proceedings and have participated in analyses relating to the Regional Greenhouse Gas Initiative (RGGI), the Renewable Portfolio Standard (RPS), the Energy Efficiency Portfolio Standard (EEPS), wholesale electricity markets, and the New York Independent System Operator (NYISO). Before joining the DPS, I was employed by the New York State Energy Office as an Energy Policy Analyst from 1979 to 1987. My responsibilities there focused on electricity system modeling and forecasting and included economic, financial, and environmental analysis.

Q. Have you testified previously before the New York Public Service Commission?

A. Yes. I have testified before the Commission in rate case and other proceedings on issues involving marginal costs, long-run avoided costs, utility incentive fuel adjustment clause mechanisms, and independent power producer contracts. Most recently, I testified before the Commission concerning the Article VII Hudson Transmission Partners, LLC proposal in Case 08-

T-0034, and the Article VII Champlain Hudson Power Express, Inc. transmission proposal in Case 10-T-0139.

Q. What are your current responsibilities?

A. My current responsibilities include analyzing issues relating to electricity and natural gas, including the use of General Electric's Multi-Area Production Simulation (GE-MAPS) computer software forecasting tool to simulate the electricity system. The issues I have recently been involved in analyzing relate to proposals by market participants in New York to upgrade transmission, retire generation, and repower generation.

THE Brattle GROUP

REQUEST FOR EXEMPTION FROM FOIL DISCLOSURE

August 28, 2013

Via Electronic Mail to recordsaccessofficer@dps.ny.gov
And Via FedEx

Donna Giliberto, Esq.
Records Access Officer
State of New York Department of Public Service
Three Empire State Plaza, 18th Floor
Albany, New York 12223-1350

Re: Submittal of Confidential Information
Indian Point Energy Center Contingency Plan Project (Case Number 12-E-0503)

Dear Ms. Giliberto:

The Brattle Group, Inc. ("Brattle"), in its capacity as a consultant to The New York Independent System Operator, Inc. ("NYISO"), hereby provides confidential information relating to the Indian Point Energy Center Contingency Plan Project. A password-protected USB drive containing the confidential information referenced in this letter will be provided by overnight mail.

The information that Brattle is providing, which includes modifications to the MAPS Database, includes confidential and commercially sensitive business information protected from disclosure under Public Officers Law, §87(2)(d). This commercially sensitive information constitutes Confidential Information as defined in the NYISO's Code of Conduct contained in Attachment F to the NYISO's Open Access Transmission Tariff. Brattle provides this information in its capacity as the NYISO's consultant and notes that the NYISO's consent to the submittal of this information is based upon the understanding that Confidential Information is not subject to disclosure and that the NYSDPS will protect that information from disclosure pursuant to Public Officers Law, Section 87(2)(d) because it is commercially sensitive information "that if disclosed would cause substantial injury to the competitive position of the subject enterprise." (N.Y.Pub.Off.L. § 87(2)(d) (2013)).

If requests for disclosure of this or future reports are received by the NYDPS, we respectfully request prompt notice to both Brattle and the NYISO so that the NYISO can address the confidential nature of the information provided.

REQUEST FOR EXEMPTION FROM FOIL DISCLOSURE

Upon completion of the processing of this cover letter and the accompanying password protected USB drive, please forward copies to authorized NYSDPS personnel, including Warren Meyers.

Please contact me at (617) 864.7900 or at barbara.levine@brattle.com if you have any questions or concerns.

Very truly yours,

Barbara Levine

Barbara Levine
General Counsel

USB Drive Enclosure (*via overnight mail only*)

Cc: By Electronic Mail Only; Without Referenced Files or USB Drive Enclosure

David Drexler, Esq., NYSDPS
Warren Meyers, NYSDPS

Indian Point Outage Scenario Definitions for GE-MAPS Simulations

<------------Scenarios as Identified by the DEC------------------->

Scenario		Start Year	Construction Outages [Concurrent, Continuous] Unit 2	Unit 3	Protective Outages [5/10 through 8/10] Unit 2	Unit 3
1	A	2028	38 weeks	42 weeks	None	None
	B	2026	38 weeks	42 weeks	None	None
	C	2028	31 weeks	35 weeks	None	None
	D	2026	31 weeks	35 weeks	None	None
2	A	2026	38 weeks	None	None	42 UOD
	B	2024	38 weeks	None	None	42 UOD
	C	2026	31 weeks	None	None	42 UOD
	D	2024	31 weeks	None	None	42 UOD
3	A	2026	38 weeks	None	None	62 UOD
	B	2024	38 weeks	None	None	62 UOD
	C	2026	31 weeks	None	None	62 UOD
	D	2024	31 weeks	None	None	62 UOD
4		2016	None	None	42 UOD	42 UOD
5		2016	None	None	62 UOD	62 UOD

<-----------------------------------DPS Scenario Modeling-----------------------------------> <-------Scenario Description------->

MAPS Run	Scenario	Run Year	Construction Outages [Must be Concurrent, Continuous] Unit 2	Unit 3	Protective Outages [Must Occur During 5/10 through 8/10] Unit 2	Unit 3	Scenarios
Run 1	1A + 1B	2022	42 weeks 01JAN-21JUN & 01SEP-31DEC	42 weeks 01JAN-21JUN & 01SEP-31DEC	None in CCC Year Req'd pre-CCC Year	None in CCC Year Req'd pre-CCC Year	CCC at IP2-3, Protective Outages pre-CCC DEC's Preferred Scenario
Run 2	1C + 1D	2022	35 weeks 01JAN-03MAY & 01SEP-31DEC	35 weeks 01JAN-03MAY & 01SEP-31DEC	None in CCC Year Req'd pre-CCC Year	None in CCC Year Req'd pre-CCC Year	CCC at IP2-3, Protective Outages pre-CCC DEC's Preferred Scenario
Run 3	2A + 2B	2022	42 weeks 01JAN-21JUN & 01SEP-31DEC	None	None in CCC Year Req'd pre-CCC Year	42 UOD 10MAY-20JUN	CCC at IP2, 42 Day Protective Outage IP3 IP2 Protective Outage pre-CCC Year
Run 4	2C + 2D	2022	35 weeks 01JAN-03MAY & 01SEP-31DEC	None	None in CCC Year Req'd pre-CCC Year	42 UOD 10MAY-20JUN	CCC at IP2, 42 Protective Outage IP3 IP2 Protective Outage pre-CCC Year
Run 5	3A + 3B	2022	42 weeks 01JAN-21JUN & 01SEP-31DEC	None	None in CCC Year Req'd pre-CCC Year	62 UOD 10MAY-10JUL	CCC at IP2, 62 Day Protective Outage IP3 IP2 Protective Outage pre-CCC Year
Run 6	3C + 3D	2022	35 weeks 01JAN-03MAY & 01SEP-31DEC	None	None in CCC Year Req'd pre-CCC Year	62 UOD 10MAY-10JUL	CCC at IP2, 62 Day Protective Outage IP3 IP2 Protective Outage pre-CCC Year
Run 7	4A	2016	None	None	42 UOD 10MAY-JUN20	42 UOD 10MAY-20JUN	No CCC, 42 Day Protective Outages
Run 8	4B	2022	None	None	42 UOD 10MAY-10JUN	42 UOD 10MAY-20JUN	No CCC, 42 Day Protective Outages
Run 9	5A	2016	None	None	62 UOD 10MAY-10JUL	62 UOD 10MAY-10JUL	No CCC, 62 Day Protective Outages
Run 10	5B	2022	None	None	62 UOD 10MAY-10JUL	62 UOD 10MAY-10JUL	No CCC, 62 Day Protective Outages

Notes

DEC	New York State Department of Environmental Conservation
DPS	New York State Department of Public Service
MAPS	Multi-Area Production Simulation model
CCC	Closed Cycle Cooling
UOD	Unit Outage Days

In the Base Case, Indian Point 2 is on scheduled maintenance for approximately 4 weeks per year.
Construction outages in the Indian Point construction outage scenarios overlap the 4 week scheduled hours in the Base Case.

Year-2022 Forecast Air Emissions and Generation Impacts from Indian Point Outage Scenarios

	R1_SAB-R0	R2_S1CD-R0	R3_S2AB-R0	R4_S2CD-R0	R5_S3AB-R0	R6_S3CD-R0	R8_S4B-R0	R10_S5B-R0	R1_SAB-R0 %	R2-S1CDR0 %	R3_S2AB-R0 %	R4_S2CD-R0 %	R5_S3AB-R0 %	R6_S3CD-R0 %	R8_S4B-R0 %	R10_S5B-R0 %
Energy GWh in 2022																
NY	(3,824)	(3,063)	(2,095)	(1,714)	(2,261)	(1,878)	(370)	(707)	(3.31%)	(2.65%)	(1.81%)	(1.48%)	(1.96%)	(1.63%)	(0.32%)	(0.61%)
NY-PJM-NE-Ontario	(77)	(90)	(64)	(9)	(69)	(13)	(73)	(75)	(0.01%)	(0.01%)	(0.01%)	(0.00%)	(0.01%)	(0.00%)	(0.01%)	(0.01%)
West, Genesee, Central, North, Mohawk Valley	947	825	613	555	639	581	195	239	2.12%	1.85%	1.37%	1.24%	1.43%	1.30%	0.44%	0.54%
Capital	2,253	1,767	1,365	1,163	1,442	1,241	384	511	14.09%	11.05%	8.53%	7.27%	9.02%	7.76%	2.40%	3.19%
Hudson Valley	110	110	75	75	79	79	63	75	42.03%	41.82%	28.49%	28.40%	30.17%	30.06%	24.14%	28.49%
Dunwoodie	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA
Millwood	(13,195)	(10,821)	(7,033)	(5,861)	(7,524)	(6,350)	(1,692)	(2,657)	(74.69%)	(61.25%)	(39.81%)	(33.17%)	(42.58%)	(35.94%)	(9.58%)	(15.04%)
NYC	5,237	4,418	2,507	2,080	2,686	2,260	596	924	20.40%	17.21%	9.77%	8.10%	10.46%	8.80%	2.32%	3.60%
LI	824	638	379	274	416	311	85	201	7.29%	5.64%	3.35%	2.43%	3.68%	2.75%	0.75%	1.78%
SO2 Tons in 2022																
NY	1,782	1,490	883	704	930	746	212	413	9.09%	7.60%	4.50%	3.59%	4.74%	3.80%	1.08%	2.11%
NY-PJM-NE-Ontario	5,770	4,629	3,058	2,539	3,124	2,605	605	892	0.26%	0.21%	0.14%	0.11%	0.14%	0.12%	0.03%	0.04%
West, Genesee, Central, North, Mohawk Valley	808	688	456	379	473	392	64	92	6.06%	5.16%	3.42%	2.85%	3.55%	2.94%	0.48%	0.69%
Capital	8	6	4	4	5	4	1	1	13.61%	10.96%	7.55%	6.42%	7.99%	6.86%	1.95%	2.57%
Hudson Valley	57	56	37	37	41	40	31	56	50.91%	50.16%	33.42%	33.31%	36.80%	36.17%	27.95%	50.52%
Dunwoodie	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA
Millwood	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NYC	96	82	41	34	47	40	4	17	31.81%	27.02%	13.53%	11.13%	15.67%	13.29%	1.41%	5.73%
LI	814	659	344	250	364	270	111	246	14.04%	11.37%	5.94%	4.31%	6.28%	4.65%	1.92%	4.25%
NOx Tons in 2022																
NY	1,512	1,262	764	615	843	697	266	439	7.35%	6.13%	3.71%	2.99%	4.10%	3.39%	1.29%	2.13%
NY-PJM-NE-Ontario	3,914	3,151	2,142	1,766	2,301	1,928	481	848	0.56%	0.45%	0.30%	0.25%	0.33%	0.27%	0.07%	0.12%
West, Genesee, Central, North, Mohawk Valley	236	211	116	101	122	110	(1)	8	2.40%	2.15%	1.19%	1.04%	1.24%	1.13%	(0.01%)	0.08%
Capital	75	61	45	39	48	42	11	16	9.83%	7.92%	5.85%	5.06%	6.22%	5.43%	1.46%	2.06%
Hudson Valley	179	178	138	137	147	146	124	145	74.58%	74.01%	57.17%	57.00%	61.08%	60.70%	51.62%	60.42%
Dunwoodie	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Millwood	13	12	11	10	11	10	9	9	1.21%	1.10%	1.01%	0.94%	1.03%	0.97%	0.85%	0.91%
NYC	633	505	294	213	337	255	88	163	23.48%	18.72%	10.93%	7.88%	12.50%	9.47%	3.27%	6.03%
LI	376	296	160	115	179	133	34	98	6.24%	4.91%	2.66%	1.91%	2.97%	2.21%	0.56%	1.62%
CO2 Tons in 2022																
NY	5,057,580	4,200,309	2,643,274	2,207,357	2,831,883	2,397,037	791,385	1,164,295	13.71%	11.38%	7.16%	5.98%	7.68%	6.50%	2.15%	3.16%
NY-PJM-NE-Ontario	7,511,231	6,151,667	3,985,483	3,331,072	4,274,139	3,619,828	975,412	1,562,966	1.36%	1.11%	0.72%	0.60%	0.77%	0.66%	0.18%	0.28%
West, Genesee, Central, North, Mohawk Valley	474,419	405,362	272,684	236,070	287,448	250,582	29,062	53,655	4.14%	3.53%	2.38%	2.06%	2.51%	2.18%	0.25%	0.47%
Capital	938,953	735,327	568,542	484,026	601,214	517,082	161,181	214,511	13.92%	10.90%	8.43%	7.18%	8.92%	7.67%	2.39%	3.18%
Hudson Valley	64,232	63,910	43,552	43,412	46,166	46,001	36,862	44,407	55.89%	55.61%	37.89%	37.77%	40.17%	40.02%	32.07%	38.64%
Dunwoodie	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA
Millwood	308,518	280,801	256,447	239,987	261,278	245,594	216,324	230,285	NA	NA	NA	NA	NA	NA	NA	NA
NYC	2,793,104	2,347,925	1,289,130	1,054,893	1,398,082	1,164,589	304,197	500,718	21.69%	18.23%	10.01%	8.19%	10.85%	9.04%	2.36%	3.89%
LI	478,354	366,985	212,920	148,970	237,695	173,188	43,758	120,718	8.41%	6.45%	3.74%	2.62%	4.18%	3.05%	0.77%	2.12%

Year-2016 Forecast Air Emissions and Generation Impacts from Indian Point Outage Scenarios

Energy GWh in 2016	R7_S4A-R0	R9_S5A-R0	R7_S4A-R0 %	R9_S5A-R0 %
NY	(864)	(1,290)	(0.73%)	(1.09%)
NY-PJM-NE-Ontario	11	24	0.00%	0.00%
West, Genesee, Central, North, Mohawk Valley	143	193	0.32%	0.43%
Capital	340	489	2.49%	3.58%
Hudson Valley	97	114	43.79%	51.51%
Dunwoodie	0	0	NA	NA
Millwood	(2,079)	(3,069)	(11.73%)	(17.32%)
NYC	544	798	1.79%	2.63%
LI	90	185	0.80%	1.64%
SO2 Tons in 2016				
NY	348	487	1.69%	2.37%
NY-PJM-NE-Ontario	2,521	3,258	0.12%	0.16%
West, Genesee, Central, North, Mohawk Valley	199	241	1.93%	2.34%
Capital	1	1	1.76%	2.70%
Hudson Valley	50	78	56.06%	87.93%
Dunwoodie	0	0	NA	NA
Millwood	0	0	0.00%	0.00%
NYC	6	14	1.53%	3.96%
LI	92	152	0.95%	1.56%
NOX Tons in 2016				
NY	392	546	1.79%	2.49%
NY-PJM-NE-Ontario	1,288	1,802	0.19%	0.27%
West, Genesee, Central, North, Mohawk Valley	56	68	0.60%	0.74%
Capital	10	14	1.31%	1.95%
Hudson Valley	164	195	85.59%	101.88%
Dunwoodie	0	0	NA	NA
Millwood	0	0	0.00%	0.00%
NYC	111	165	3.28%	4.90%
LI	52	103	0.70%	1.41%
CO2 Tons in 2016				
NY	664,020	981,426	1.73%	2.56%
NY-PJM-NE-Ontario	1,399,707	2,049,584	0.26%	0.39%
West, Genesee, Central, North, Mohawk Valley	96,870	125,647	0.89%	1.15%
Capital	141,581	203,977	2.45%	3.53%
Hudson Valley	56,907	67,813	62.96%	75.03%
Dunwoodie	0	0	NA	NA
Millwood	0	0	NA	NA
NYC	309,487	461,721	2.01%	3.00%
LI	59,175	122,268	0.95%	1.97%

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Exhibit_(GW-5)

Year-2022 Forecasts of Wholesale Energy Market Impacts from Indian Point Outage Scenarios

LBMP $/MWH Load Weighted in 2022	R1_SAB-R0	R2_S1CD-R0	R3_S2AB-R0	R4_S2CD-R0	R5_S3AB-R0	R6_S3CD-R0	R8_S4B-R0	R10_S5B-R0	R1_SAB-R0 %	R2-S1CDR0 %	R3_S2AB-R0 %	R4_S2CD-R0 %	R5_S3AB-R0 %	R6_S3CD-R0 %	R8_S4B-R0 %	R10_S5B-R0 %
NY	$1.64	$1.22	$0.65	$0.48	$0.78	$0.62	($0.27)	$0.00	2.30%	1.71%	0.92%	0.68%	1.10%	0.87%	(0.38%)	0.00%
NE	($0.48)	($0.67)	($0.38)	($0.47)	($0.34)	($0.41)	($0.08)	$0.04	(0.61%)	(0.87%)	(0.49%)	(0.60%)	(0.43%)	(0.52%)	(0.11%)	0.05%
PJM	$0.12	($0.01)	$0.02	($0.01)	$0.03	$0.03	($0.16)	($0.13)	0.21%	(0.01%)	0.03%	(0.01%)	0.06%	0.05%	(0.29%)	(0.23%)
OH	$0.57	$0.42	$0.34	$0.32	$0.30	$0.27	$0.03	($0.02)	0.90%	0.66%	0.54%	0.50%	0.48%	0.42%	0.05%	(0.02%)
West	$1.03	$0.88	$0.60	$0.56	$0.58	$0.53	$0.04	$0.03	1.76%	1.49%	1.02%	0.95%	0.98%	0.91%	0.07%	0.06%
Genesee	$1.17	$0.97	$0.65	$0.61	$0.63	$0.57	$0.08	$0.06	1.92%	1.58%	1.07%	1.00%	1.02%	0.93%	0.13%	0.10%
Central	$1.38	$1.14	$0.78	$0.71	$0.77	$0.68	$0.11	$0.12	2.20%	1.81%	1.25%	1.14%	1.22%	1.09%	0.18%	0.18%
North	$1.30	$1.11	$0.74	$0.68	$0.74	$0.67	$0.09	$0.12	2.17%	1.86%	1.23%	1.14%	1.24%	1.13%	0.15%	0.19%
Mohawk Valley	$1.43	$1.20	$0.78	$0.72	$0.78	$0.70	$0.08	$0.10	2.25%	1.89%	1.24%	1.14%	1.23%	1.11%	0.13%	0.16%
Capital	$1.43	$1.26	$0.84	$0.80	$0.82	$0.77	$0.16	$0.15	2.01%	1.78%	1.18%	1.12%	1.16%	1.08%	0.23%	0.22%
Hudson Valley	$3.33	$2.60	$1.48	$1.14	$1.69	$1.37	($0.22)	$0.23	4.50%	3.51%	2.00%	1.55%	2.29%	1.85%	(0.30%)	0.32%
Dunwoodie	$2.91	$2.25	$1.19	$0.89	$1.44	$1.15	($0.46)	$0.04	3.89%	3.01%	1.60%	1.19%	1.92%	1.54%	(0.62%)	0.06%
Millwood	$2.54	$1.88	$0.99	$0.68	$1.25	$0.96	($0.50)	$0.04	3.42%	2.52%	1.33%	0.91%	1.69%	1.29%	(0.68%)	0.06%
NYC	$2.17	$1.58	$0.77	$0.51	$1.00	$0.76	($0.48)	($0.01)	2.86%	2.07%	1.02%	0.68%	1.32%	1.00%	(0.64%)	(0.01%)
LI	$0.21	($0.14)	($0.32)	($0.47)	($0.13)	($0.27)	($0.68)	($0.32)	0.27%	(0.18%)	(0.40%)	(0.60%)	(0.17%)	(0.35%)	(0.86%)	(0.41%)

Wholesale Energy $ Millions in 2022	R1_SAB-R0	R2_S1CD-R0	R3_S2AB-R0	R4_S2CD-R0	R5_S3AB-R0	R6_S3CD-R0	R8_S4B-R0	R10_S5B-R0	R1_SAB-R0 %	R2-S1CDR0 %	R3_S2AB-R0 %	R4_S2CD-R0 %	R5_S3AB-R0 %	R6_S3CD-R0 %	R8_S4B-R0 %	R10_S5B-R0 %
NY	$276	$205	$110	$81	$132	$104	($46)	$0	2.30%	1.71%	0.92%	0.68%	1.10%	0.87%	(0.38%)	0.00%
NY-PJM-NE-Ontario	$393	$183	$131	$68	$162	$116	($166)	($89)	0.55%	0.25%	0.18%	0.09%	0.23%	0.16%	(0.23%)	(0.12%)
West	$15	$13	$9	$8	$9	$8	$1	$0	1.76%	1.49%	1.02%	0.95%	0.98%	0.91%	0.07%	0.06%
Genesee	$11	$9	$6	$6	$6	$6	$1	$1	1.92%	1.58%	1.07%	1.00%	1.02%	0.93%	0.13%	0.10%
Central	$22	$18	$12	$11	$12	$11	$2	$2	2.20%	1.81%	1.25%	1.14%	1.22%	1.09%	0.18%	0.18%
North	$9	$8	$5	$5	$5	$5	$1	$1	2.17%	1.86%	1.23%	1.14%	1.24%	1.13%	0.15%	0.19%
Mohawk Valley	$10	$8	$6	$5	$6	$5	$1	$1	2.26%	1.89%	1.24%	1.14%	1.23%	1.11%	0.13%	0.16%
Capital	$16	$14	$9	$9	$9	$9	$2	$2	2.01%	1.78%	1.18%	1.12%	1.16%	1.08%	0.23%	0.22%
Hudson Valley	$34	$27	$15	$12	$17	$14	($2)	$2	4.50%	3.51%	2.00%	1.55%	2.29%	1.85%	(0.30%)	0.32%
Dunwoodie	$9	$7	$4	$3	$4	$4	($1)	$0	3.89%	3.01%	1.60%	1.19%	1.92%	1.54%	(0.62%)	0.06%
Millwood	$17	$12	$6	$4	$8	$6	($3)	$0	3.42%	2.52%	1.33%	0.91%	1.69%	1.29%	(0.68%)	0.06%
NYC	$127	$92	$45	$30	$59	$45	($28)	($1)	2.86%	2.07%	1.02%	0.68%	1.32%	1.00%	(0.64%)	(0.01%)
LI	$5	($4)	($8)	($12)	($3)	($7)	($17)	($8)	0.27%	(0.18%)	(0.40%)	(0.60%)	(0.17%)	(0.35%)	(0.86%)	(0.41%)

Year-2016 Forecasts of Wholesale Energy Market Impacts from Indian Point Outage Scenarios

LBMP $/MWH in 2016	R7_S4A-R0	R9_S5A-R0	R7_S4A-R0 %	R9_S5A-R0 %
NY	$0.13	$0.35	0.2%	0.7%
NE	$0.05	$0.04	0.1%	0.1%
PJM	$0.01	$0.05	0.0%	0.1%
OH	$0.07	$0.06	0.2%	0.1%
West	$0.10	$0.09	0.2%	0.2%
Genesee	$0.14	$0.14	0.3%	0.3%
Central	$0.15	$0.16	0.3%	0.3%
North	$0.09	$0.13	0.2%	0.3%
Mohawk Valley	$0.14	$0.16	0.3%	0.3%
Capital	$0.10	$0.09	0.2%	0.2%
Hudson Valley	$0.26	$0.63	0.5%	1.2%
Dunwoodie	$0.17	$0.57	0.3%	1.0%
Millwood	$0.17	$0.59	0.3%	1.1%
NYC	$0.16	$0.52	0.3%	0.9%
LI	($0.02)	$0.32	0.0%	0.6%

Wholesale Energy $ Millions in 2016	R7_S4A-R0	R9_S5A-R0	R7_S4A-R0 %	R9_S5A-R0 %
NY	$20	$56	0.2%	0.7%
NY-PJM-NE-Ontario	$49	$107	0.1%	0.2%
West	$2	$1	0.2%	0.2%
Genesee	$1	$1	0.3%	0.3%
Central	$2	$2	0.3%	0.3%
North	$1	$1	0.2%	0.3%
Mohawk Valley	$1	$1	0.3%	0.3%
Capital	$1	$1	0.2%	0.2%
Hudson Valley	$3	$6	0.5%	1.2%
Dunwoodie	$0	$2	0.3%	1.0%
Millwood	$1	$4	0.3%	1.1%
NYC	$9	$29	0.3%	0.9%
LI	($0)	$7	0.0%	0.6%

BEFORE THE
STATE OF NEW YORK
DEPARTMENT OF ENVIRONMENTAL CONSERVATION

In the Matter of a Renewal and Modification of a State Pollutant Discharge Elimination System ("SPDES") Permit Pursuant to article 17 of the Environmental Conservation Law And Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York parts 704 and 750 *et seq*. by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, Permittee,	**DEC # 3-5522-00011/00004** **SPDES # NY-0004472**

-and-

In the Matter of the Application by Entergy Nuclear Indian Point 2, LLC and Entergy Nuclear Indian Point 3, LLC, for a Certificate Pursuant to §401 of the Federal Clean Water Act	**DEC # 3-5522-00011/00030** **DEC # 3-5522-00011/00031**

March 28, 2014

Rebuttal Testimony of:

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Witness Information

Q. Will the witnesses of the panel please state your names and business addresses?

A. Our names are Leka P. Gjonaj, and David V. Wheat. We are employed by the New York State Department of Public Service (DPS), Three Empire State Plaza, Albany, New York 12223-1350.

Q. Have you previously sponsored testimony in these proceedings?

A. Yes. We offered pre-filed direct testimony, as independent consultants to the Staff of the New York State Department of Environmental Conservation (NYS DEC Staff). We provided forecasts of energy market impacts, including air emissions and wholesale energy market price impacts, from Indian Point outage scenarios defined by NYS DEC Staff.

Q. Is your educational and professional experience described in your pre-filed direct testimony in these proceedings?

A. Yes.

Purpose and Summary

Q. What is the purpose of your rebuttal testimony?

A. We provide comments on forecasting energy market impacts, including air emissions and wholesale energy prices, to illustrate that both the magnitude and direction of forecast impacts are tied to the assumptions underlying any analysis. We believe this is important to note since several other parties have submitted forecasts of energy market impacts, including air emissions impacts, in this proceeding using different underlying assumptions. In some cases, the forecasts submitted by other parties also used different electricity simulation forecasting tools.

Q. Please summarize the methodology you used to develop forecast energy market impacts that you presented in your pre-filed direct testimony.

A. Our analysis was performed using General Electric's Multi-Area Production Simulation (GE-MAPS) computer software tool. We simulated the electric system under an Indian Point business as usual Base Case, along with various Alternative Scenarios where Indian Point was assumed to be unavailable for part of a year due to construction and/or protective outages. To measure impacts, we subtracted the results for each Alternative Scenario from our Indian Point business as usual Base Case.

Q. Could you please identify the other parties in this proceeding who provided forecasts of energy market impacts?

Q. Yes. Several witnesses provided forecasts of energy market impacts, including air emissions and wholesale energy prices. These include National Economic Research Associates (NERA) Economic Consulting (David Harrison, Jr., on behalf of Entergy), Charles River Associates (CRA)a/k/a CRA International, Inc. (Christopher J. Russo, on behalf of the City of New York), and Synapse Energy Economics, Inc. (Robert M. Fagan, on behalf of Riverkeeper).

Q. Did any of these parties use the GE-MAPS energy market simulation tool?

A. Yes. CRA developed its forecasts using GE-MAPS. NERA and Synapse developed their forecasts using software tools that are alternatives to GE-MAPS. As these witnesses explain in their direct testimony and supporting Exhibits, NERA used PROMOD IV, whereas Synapse used PROSYM.

Q. Can these energy market forecasting tools be expected to provide similar forecast estimates of energy market impacts?

A. These tools would only be expected to provide similar forecasts of energy market impacts when the underlying assumptions are similar. This would include similarities not only in the input data assumptions, but also similarities in each forecasting model's underlying energy market simulation methodologies.

Q. Could you please explain what you mean by similarities in each forecasting model's underlying energy market simulation methodologies?

A. Yes. For example, GE-MAPS generally is used to model the entire transmission system (including transmission lines and interfaces depicting transmission capability between regions), whereas other models might use a more simplified transmission system representation (interfaces only). The point is that there are a variety of factors which affect the forecasts estimated by electricity system forecasting models.

Q. How do energy market forecasting tools take into consideration reliability concerns?

A. Generally, reliability concerns are determined and addressed initially using reliability-specific forecasting tools. Then, when the modeling turns to tools such as the GE-MAPS energy market forecasting model, for example, satisfactory capability to maintain a reliable electricity system is a required input into the model.

Q. In the modeling exercise you performed, did you take reliability concerns into consideration in this manner?

A. Yes. This is why, in the modeling exercise being performed in these proceedings where Indian

Point is modeled as being unavailable, DPS Staff assumes that adequate capability to address reliability concerns would be provided by transmission and generation resources in accordance, generally, with the PSC Indian Point Contingency Plan Order (issued November 4, 2013) in Case 12-E-0503, to which we referred in our direct testimony.

Q. Do you consider assuming a reliable electricity system to be a required prerequisite before using a model such as GE-MAPS to develop forecasts of energy market impacts?

A. Yes. In order to develop credible forecasts of energy market impacts, assuming a reliable electricity system is a prerequisite for any modeling exercise.

Q. Could you provide an example to illustrate how energy market impact estimates, including air emissions impacts, can vary?

A. Yes. Our first example illustrates how impact estimates could be expected to vary depending on what the resource mix is assumed to be when resources, such as the Indian Point generating units, are modeled as being unavailable. If the replacement resources are assumed to be provided largely by fossil fuel resources, for example, then the air emissions impacts would be expected to increase. DPS Staff's forecasts assume this. The CRA forecasts also assume this, although not necessarily in precisely the same manner (CRA witness Russo direct testimony, page 6 (lines 7-9), page 23 (lines 15-23) through page 26 (lines 1-7)). Page 2 (lines 17-21) of witness Russo's testimony cites Exhibit [CJR-2], which is the CRA Indian Point Energy Center Retirement Analysis ("Retirement Report"). NERA's forecasts are also based on this assumption of replacement resources being provided largely by fossil fuel-fired resources, although again not necessarily in precisely the same manner as DPS Staff's assumptions (NERA witness Harrison direct testimony, page 3 (lines 6-10), citing *Impacts to the New York State Electricity System if Indian Point Energy Center Were Not Available*

(December 2013)(Entergy Ex. 296E) (the "Impacts Report")).

Q. How would forecasted air emissions impacts change if replacement resources are assumed to include a large amount of non-emitting resources?

A. In contrast, if the replacement resources are assumed to include a large amount of resources having negligible air emissions (such as hydroelectric resources), then the air emissions impacts could be expected to be small and potentially decrease (thereby depicting benefits). We believe this is consistent with the Synapse forecasts, which assume numerous supply additions including the proposed Champlain Hudson Power Express (CHPE) high-voltage direct current transmission project, which would increase New York's capability to import power from Quebec.

Q. What does Synapse forecast with respect to air emissions impacts?

A. Synapse witness Fagan's testimony states that generally, emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) decrease under Indian Point outage scenarios, while carbon dioxide (CO_2) emissions decline starting in 2019 (Fagan direct testimony, page 9 (lines 16-27), and page 10 (lines 1-26)). We believe that this is driven by the assumed clean energy resources providing a large amount of energy in the Indian Point outage scenarios. Part 1, Page 21, of Riverkeeper's Exhibit 109 states that resources common to all 10 scenarios analyzed include CHPE transmission, Astoria unmothballing, proposed natural gas combined cycle generation facilities (the Competitive Power Ventures, Inc. (CPV) project is referred to as CPV Valley, and the Cricket Valley Energy project is referred to as Cricket Valley) along with a baseline amount of energy efficiency and wind/renewables. Some scenarios layer more energy efficiency and wind/renewables on top of the resources assumed in the starting point scenarios.

Q. Could you please provide another example of how differing assumptions might result in different forecasts of energy market impacts, including air emissions impacts?

A. Yes. Our second example illustrates that forecast energy market impacts, including air emissions impacts, are directly correlated with the length of time resources, such as the Indian Point generating units, are assumed to be unavailable. The impacts would be expected to be greater when the resource is assumed to be unavailable for a full year, rather than for part of a year. The forecast impacts by NERA (Impacts Study), CRA (Retirements Study, Section 4.2.2, page 69), and Synapse (Fagan direct testimony, page 6 (lines 1-15) are full year impact estimates. In contrast, DPS Staff's estimates are partial year impact estimates.

Q. Please summarize the point you are highlighting in your rebuttal testimony.

A. Both the magnitude and direction of forecast impacts are tied to the assumptions underlying any analysis. This includes not only input data assumptions, but also the underlying methodology the modeling software uses to simulate the energy market.

Q. Does this conclude your testimony at this time?

A. Yes.