NEW YORK INDEPENDENT SYSTEM OPERATOR

10 Krey Boulevard ♦ Rensselaer, NY 12144

THIS FILING LETTER DOES NOT CONTAIN ANY PRIVILEGED OR CONFIDENTIAL INFORMATION. REPORT SECTIONS II AND III DO NOT CONTAIN ANY PRIVILEGED OR CONFIDENTIAL INFORMATION. THE BODY OF REPORT SECTION I, AND SECTION I ATTACHM ENTS I-A THROUGH I-D DO NOT CONTAIN ANY PRIVILEGED OR CONFIDENTIAL INFORMATION. REPORT SECTION I ATTACHMENTS I-E AND I-F CONTAIN PRIVILEGED AND CONFIDENTIAL INFORMATION AND ARE SUMITTED IN A SEPARATE DOCUMENT.

December 20, 2011

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Annual Report in Docket Nos. ER01-3001-___, ER03-647-___ and Request for Privileged Treatment of Attachments 1 and 2 to Report Section I

Dear Ms. Bose:

Enclosed for filing in the above-referenced dockets is the New York Independent System Operator's ("NYISO's") annual report to the Federal Energy Regulatory Commission ("Commission") on the NYISO's Installed Capacity ("ICAP") Demand Curves and New Generation Projects in the New York Control Area.[1] By order dated March 25, 2010, the Commission granted the NYISO permission to submit this annual report by December 20 of each year[2] and by Order dated February 3, 2010, directed the NYISO to file this report for informational purposes only.[3]

I. List of Documents Submitted

The NYISO submits this report comprised of the following separate sections:

I. Capacity Market Report and Withholding Analysis
II. Report on New Generation Projects
III. New Generation Projects and Net Revenue Analysis

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[1] *New York Independent System Operator, Inc.*, 117 FERC ¶ 61,086 (2006); *New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 (2003), 108 FERC ¶ 61,280 (2004), 121 FERC ¶ 61,090 (2007), 123 FERC ¶ 61,206 (2008). In Docket ER03-647, the NYISO files an annual report regarding its Demand Side Management programs on January 15, and a semi-annual report on its Demand Side Management programs and new generation projects on June 15 each year.

[2] *New York Independent System Operator, Inc.*, 130 FERC ¶ 61,237 (2010).

[3] *New York Independent System Operator, Inc.*, Order, Docket Nos. ER01-3001 and ER03-647 (Feb. 3, 2010).

II. Request for Confidential Treatment of Attachments 1 and 2 of Report Section I

In accordance with Sections 388.107 and 388.112 of the Commission's Regulations,[4] Article 6 of the NYISO's Market Administration and Control Area Services Tariff, Sections 1.0(4) and 4.0 of the NYISO's Code of Conduct, the NYISO requests Privileged and Confidential treatment of the contents of Confidential Attachments I-E and I-F of Report Section I (the "Confidential Attachments"). The NYISO also requests that Confidential Attachments be exempted from public disclosure under the Freedom of Information Act ("FOIA"), 5 U.S.C. §522.[5]

The Confidential Attachments contain privileged and commercially sensitive, and trade secret information that is not made public by the NYISO and that could cause competitive harm to the affected Market Participants,[6] and could adversely affect competition in the markets administered by the NYISO, if publicly disclosed. This information includes the identity of Installed Capacity Suppliers and offers, and the basis therefor, and costs of the Installed Capacity Suppliers. This confidential, commercially sensitive information is exempt from disclosure under 5 U.S.C. §522(b)(4). For this reason, the NYISO requests that the contents of Confidential Attachments received Privileged and Confidential treatment and be exempt from FOIA disclosure.

The NYISO requests waiver of any obligation it may have under the Commission's regulations or the Secretary's rules to submit a redacted version of the Confidential Attachments. The NYISO incorporated into the body of Report Section I a masked or aggregated version of the information that is contained in the Confidential Attachments and thereby makes publicly available the information contained in Confidential Attachments that is not confidential and commercially sensitive. In that regard, the NYISO has provided a redacted version of the information contained in the Confidential Attachments within the body of the report.

The Confidential Attachments I-E and I-F are submitted separately and are identified and marked in accordance with the Commission's regulations and rules published by the Secretary's Office for submitting Privileged information.

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[4] 18 C.F.R. §§ 388.107, 388.112 (2010).

[5] The information provided by the NYISO for which the NYISO claims an exemption from FOIA disclosure is labeled "Contains Privileged Information – Do Not Release."

[6] Terms with initial capitalization not defined herein have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff.

III. Correspondence

Copies of correspondence concerning this filing should be addressed to:

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Respectfully submitted,

/s/

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Michael Mc Laughlin
Kathleen E. Nieman
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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of Rule 2010 of the Rules of Practice and Procedure, 18 C.F.R. §385.2010.

Dated at Rensselaer, NY this 20th day of December, 2011.

/s/ Joy A. Zimberlin

Joy A. Zimberlin
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I. Capacity Market Report and Withholding Analysis

A. Overview

This report (the "December 2011 Report") reviews the outcomes of the Installed Capacity markets administered by the New York Independent System Operator ("NYISO"), assesses the effectiveness of the Installed Capacity[1] ("ICAP") Demand Curves in attracting investment in new generation, and examines potential withholding activity in the NYISO-administered Capacity auctions for the three Capacity regions in the New York Control Area ("NYCA"): New York City ("NYC"), Long Island ("LI"), and the Rest of State ("ROS").[2] The December 2011 Report covers the Winter 2010-2011 and Summer 2011 Capability Periods, which span from November 2010 through October 2011. Similar NYISO reports previously filed cover earlier periods. The analyses conducted for this report are consistent with the methodology established and first used for the report filed January 15, 2010 in these dockets[3] covering November 2008 through October 2009 ("January 2010 Report").

Capacity prices during the Winter 2010-2011 Capability Period exhibited less variation than the previous Winter Capability Periods for the NYCA, and the NYC and Long Island Localities. The addition of Capacity and an increase in Capacity imports into the NYCA, Long Island and NYC led to historically lower auction prices during the Winter Capability period. Auction prices for the Long Island Locality were set by the NYCA Market-Clearing Price in all six months of the Winter Capability Period.

During the Summer 2011 Capability Period, ICAP auction clearing prices in NYC exhibited large variation, but on average, were consistent with clearing prices from previous Summer Capability Periods. The average NYC ICAP Spot Market Auction price for Summer 2011 was $4.64/kW-month lower on average than the Summer 2010 average, which was mostly driven by increased Capacity in NYC. Summer 2011 Capacity prices in Long Island and for the NYCA were also lower on average than prices in Summer 2010. The Long Island price was set by the NYCA price for the all months except for September.

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[1] Terms in upper case not defined herein shall have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

[2] The NYISO administers three Capacity auctions: NYCA, New York City, and Long Island. References in this report to the Rest of State are to the geographic area within the NYCA that excludes the New York City and Long Island Localities.

[3] *See* New York Independent System Operator, Inc.'s Updated Status Report on Stakeholder Discussions Regarding Annual Installed Capacity Demand Curve Reports and Plan for Future Reports ("NYISO Updated Status Report") at p. 4 (filed with the Commission in these dockets on November 12, 2009). Section I. C. 3. of this report contains an updated analysis of NYCA unsold capacity.

For the December 2011 Report period, there was minimal change in the proportion of Load Serving Entity ("LSE") Capacity requirements being met from purchases in the NYISO-administered Capacity markets versus other sources, such as bilateral contracts, when compared to previous reporting periods. In UCAP terms, in the Winter 2010-2011 Capability Period, 47.31% of LSE Capacity requirements were met through bilateral purchases, while the remaining percent of LSE obligations were met through the NYISO-administered auctions. Similarly, in the Summer 2010 Capability Period, 48.39% of LSE capability requirements were met through bilateral purchases, while the remaining LSE obligations were satisfied through purchases made in the NYISO-administered auctions.

In the NYC and LI Localities, the seasonal average quantities of unsold and unoffered capacity were less than two percent of available supplies (*see* Charts 7 and 8). Unsold and unoffered capacity quantities from ROS resources were about 5.5 percent in Winter 2010-2011 and 3.2 percent in Summer 2011.[4] The ICAP offered and purchased in NYCA and each of the two Localities exceeded the Locational Minimum Installed Capacity Requirements, and prices have been below the net cost of new entry ("Net CONE") reflected on the ICAP Demand Curves.

Overall, the clearing prices resulting from the ICAP Demand Curves in the ICAP Spot Market Auctions support the conclusion that the ICAP Spot Market Auctions continue to be attractive to Installed Capacity Suppliers. It continues to be difficult to correlate the effects of the ICAP Demand Curves on investment in new generation in the NYCA mainly because over the past several years New York has had Capacity available in excess of the Locational Minimum Installed Capacity Requirements. The NYISO understands that developers will look to anticipated future revenues when making near-term investment decisions. At this time, the current ICAP market structure provides sufficient market signals to anticipate future revenues. While there were no Reliability Needs identified in the NYISO's 2010 Reliability Needs Assessment, the NYISO will continue to monitor potential reliability risks and other issues that may affect the reliability outlook for New York's bulk electric system. This effort includes tracking the planned development of new generation and other proposed interconnection projects, assessing demand response resources' participation in the ICAP/SCR program, tracking and evaluating potential reliability impacts of generator retirements, and evaluating the cumulative effect of emerging environmental regulations on the existing generation fleet.

[4] Section I. C. 3. of this report provides information and analysis of the unoffered and unsold capacity from ROS resources.

Over the past year, the NYISO has been engaged in several regulatory proceedings regarding its Installed Capacity market. These proceedings include revisions the ICAP Demand Curves, revisions to the In-City buyer-side capacity mitigation rules, added provisions for the potential creation of new capacity zones, and changes to the baseline load calculation for Special Case Resources ("SCRs").

The third triennial Demand Curve reset process was completed on September 15, 2011 with the Commission's acceptance of the ICAP Demand Curves, which were effective beginning with the October 2011 ICAP Spot Market Auction and will continue through Winter 2014-2015.[5] The fourth triennial Demand Curve reset process will begin in mid-2012 and will follow the process set forth in Section 5.14 of the Services Tariff.

On September 27, 2010, the NYISO proposed enhancements to its In-City buyer-side capacity mitigation measures in a filing at the Commission under Section 205 of the Federal Power Act.[6] On November 16, 2010, and in subsequent orders, the Commission accepted the tariff revisions (as revised, the In-City Buyer-Side Mitigation Measures).

The Commission issued an *Order on Compliance*[7] on September 8, 2011, directing the NYISO to develop and file tariff revisions that implement criteria for the determination of new capacity zones ("NCZs"). The NYISO's NCZ Compliance Filing on November 7, 2011[8] included modifications to the Services Tariff to identify the deliverability criteria that will be used to determine whether a NCZ is required. That filing is pending before the Commission as of the December 20, 2011 filing of this report.

The Commission issued a Final Rule on demand response compensation in wholesale energy markets on March 15, 2011. The DR Final Rule ensures that demand response resources are compensated at the market price for energy when the resources are dispatched and are cost-effective. The DR Final Rule prescribed a net-benefits test to determine when demand response resources are cost effective. The NYISO made its compliance filing on August 19, 2011. The DR Final Rule also requires a second compliance filing on the feasibility of the dynamic benefits test, which the NYISO plans to file in September 2012.

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[5] *New York Independent System Operator, Inc.*, 136 FERC ¶ 61,192 (2011).

[6] *See* FERC Docket ERl0-3043, "Proposed Enhancement to In City Buyer-Side Capacity Mitigation Measures, Request for Expedited Commission Action, and Contingent Request for Waiver of Prior Notice Requirement" (dated September 27, 2010).

[7] *New York Independent System Operator, Inc.*, 136 FERC ¶ 61,165 (2011).

[8] *See* FERC Docket Nos. ER04-449 and ER12-360, "NCZ Compliance Filing" (dated November 7, 2011).

The Commission issued a Final Rule on demand response compensation in wholesale energy markets on March 15, 2011.[9] The DR Final Rule provides for demand response resources are compensated at the market price for energy when the resources are dispatched and are cost-effective. However, the Commission specified in its December 15, 2011 Order that when the locational marginal price is greater than or equal to the threshold price, all demand resources that qualify for compensation will receive the locational marginal price payment, but if that price is less than the threshold price, the Final Rule does not apply to determine the payment to a demand response resource, and any payment will be governed by the existing RTO or ISO tariff.[10] The DR Final Rule prescribed a net-benefits test to determine the threshold price when demand response resources are cost effective. The NYISO made its compliance filing on August 19, 2011. The DR Final Rule also requires a second compliance filing, on the feasibility of the dynamic benefits test, which the NYISO plans to file in September 2012.

The NYISO continues to believe that the ICAP Demand Curves and their use for the NYISO ICAP markets remains sound. The Demand Curves are structured to provide signals to develop new Capacity when and where it is needed, particularly when compared to the *de facto* vertical demand curves in place prior to the Summer 2003 Capability Period.[11] Although the specific parameters of the ICAP Demand Curves (*i.e.*, the slope and the height), likely will continue to be subject to debate in the ICAP Demand Curve reset process, there can be little doubt that the ICAP Demand Curves provide better price signals to investors than the vertical demand curves. The ICAP Demand Curves by their very design ameliorate the unstable prices resulting from the prior vertical demand curves, provide market-driven compensation for Capacity above the minimum Capacity requirement, and reduce incentives for withholding.

B. Recent Installed Capacity Auction Results

Committed Capacity remains well above minimum Installed Capacity requirements for the NYCA, and for the NYC and Long Island Localities. In general, the Dependable Maximum Net Capability ("DMNC") available from many generators in the NYCA increases in the winter

[9] Demand Response Compensation in Organized Wholesale Energy Markets, Final Rule, 18 CFR Part 35, 134 FERC ¶ 61,187 [Order No. 745] (dated March 15, 2011)("DR Final Rule").

[10] *See* Order on Rehearing and Clarification, 745-A, issued December 15, 2011, 137 FERC ¶ 61,215 [Order No. 745-A] (dated December 15, 2011).

[11] Prior to the May 2003 ICAP Spot Market Auction, Deficiency Auctions used a "stepped" demand curve with a vertical line segment at the minimum requirement level. All NYISO Demand Curves have horizontal sections above and below these line segments, at a maximum price and $0.00/kW-month, respectively, as defined in the Services Tariff.

because of the lower ambient temperatures. Capacity offers from External Control Areas also fluctuate seasonally. Further, the NYCA Demand Curve price can decline to zero when supply exceeds the minimum Capacity requirement in the NYCA by 12 percent or more. Accordingly, the NYCA auction clearing prices are consistently at or below half of the estimated net cost of new entry for the peaking unit Capacity.

The amount of Capacity committed to the NYCA, including imports, continues to be high. The monthly average import levels into the entire NYCA were 1,905.4 MW in the Winter 2010-2011 Capability Period and 2,073.4 MW in the Summer 2011 Capability Period. This represents a 600 MW monthly increase over levels imported for the previous Winter Capability Period and a 100 MW monthly decrease relative to the prior Summer Capability Period.

ICAP Market Clearing Prices and auction activity levels from November 1999 through October 2011 for the NYCA, NYC, and Long Island are shown in tabular form in Attachment III-A. Market clearing prices are depicted in graphic form in Charts 1, 3, and 5, and Capacity commitment levels (including unsold MW) are depicted in Charts 2, 4, and 6, below. The NYCA Unsold MW depicted in Chart 2 includes unsold MW located in ROS, as well as the Unsold MW depicted in Charts 4 and 6 for the NYC, and Long Island Localities, respectively.

Chart 1. NYCA Market Clearing Prices

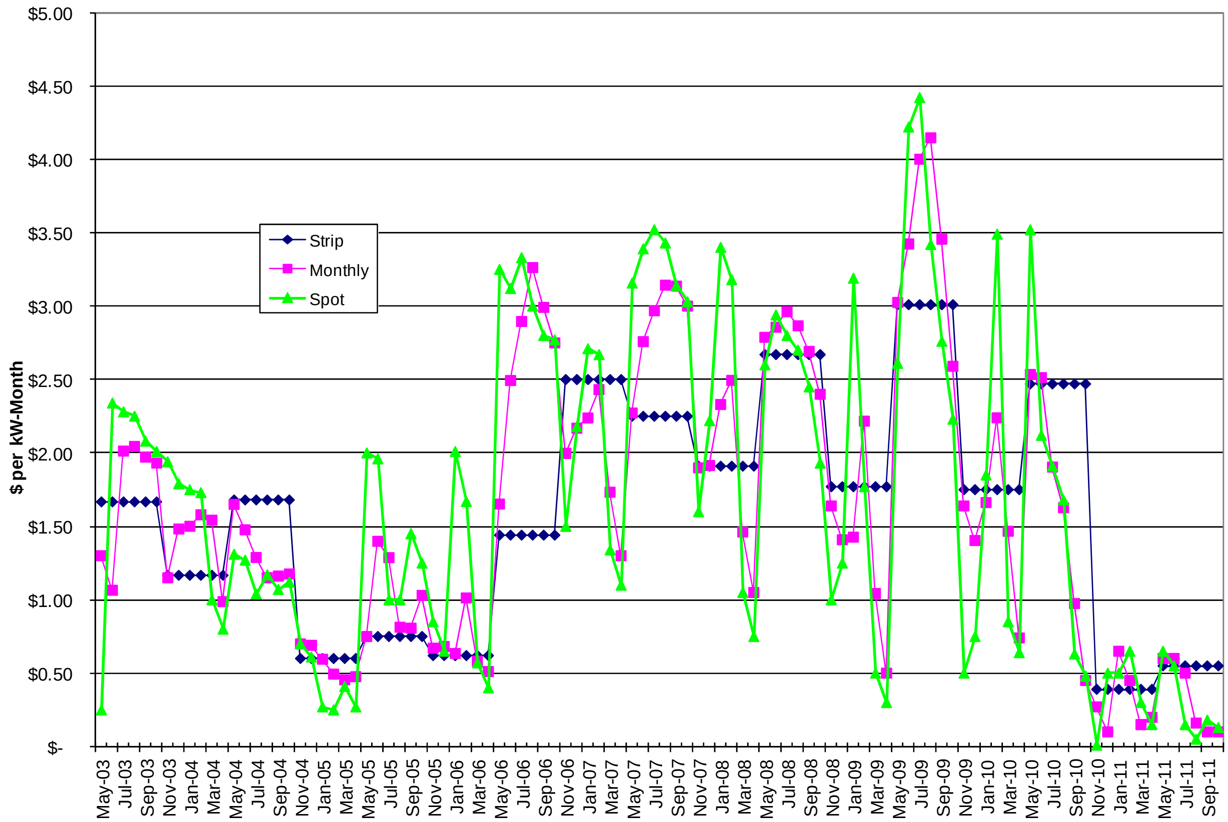


Chart 2. NYCA Offered MW

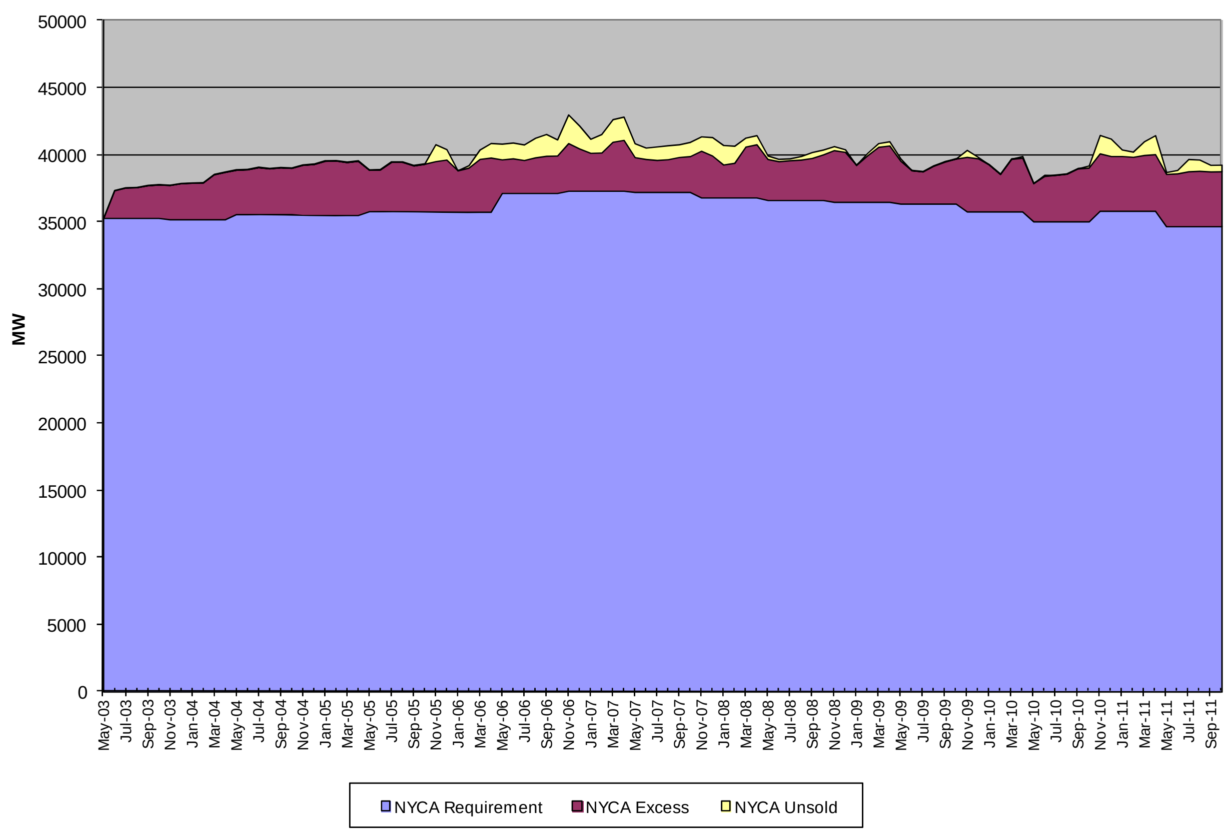


Chart 3. NYC Market Clearing Prices

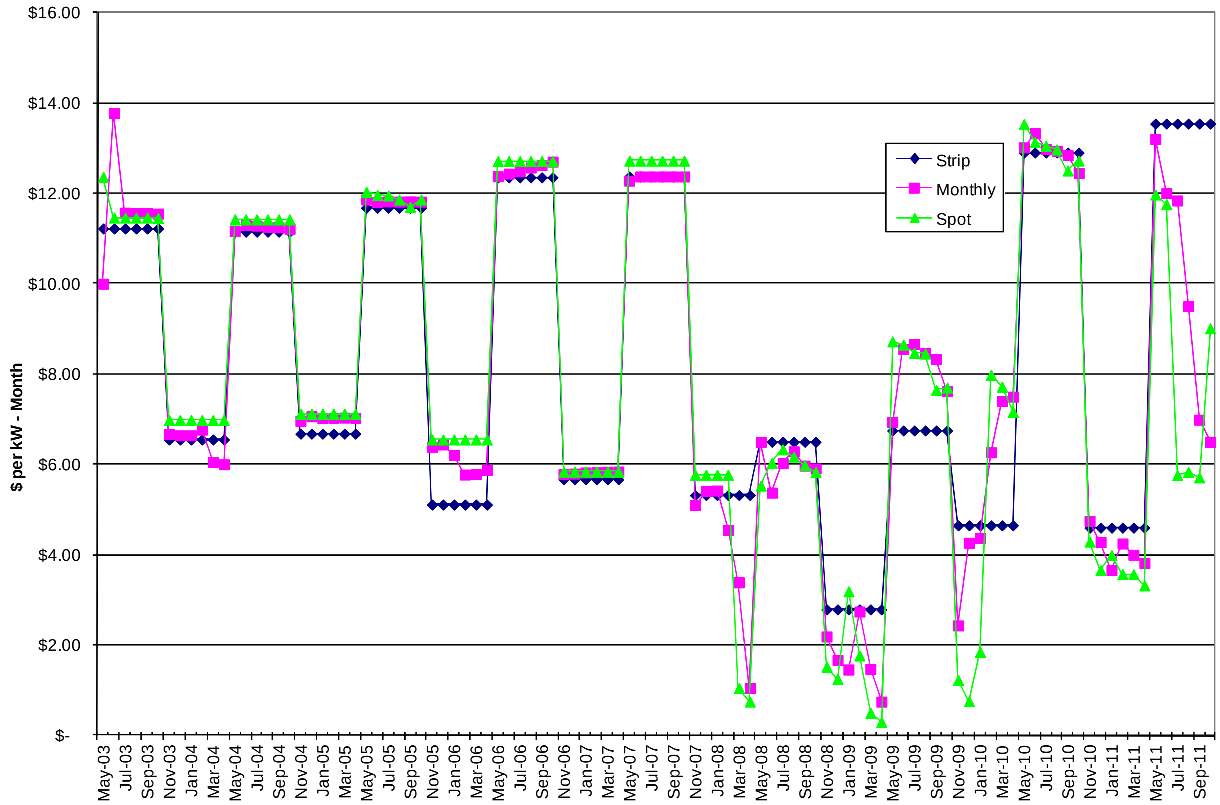


Chart 4. NYC Offered MW

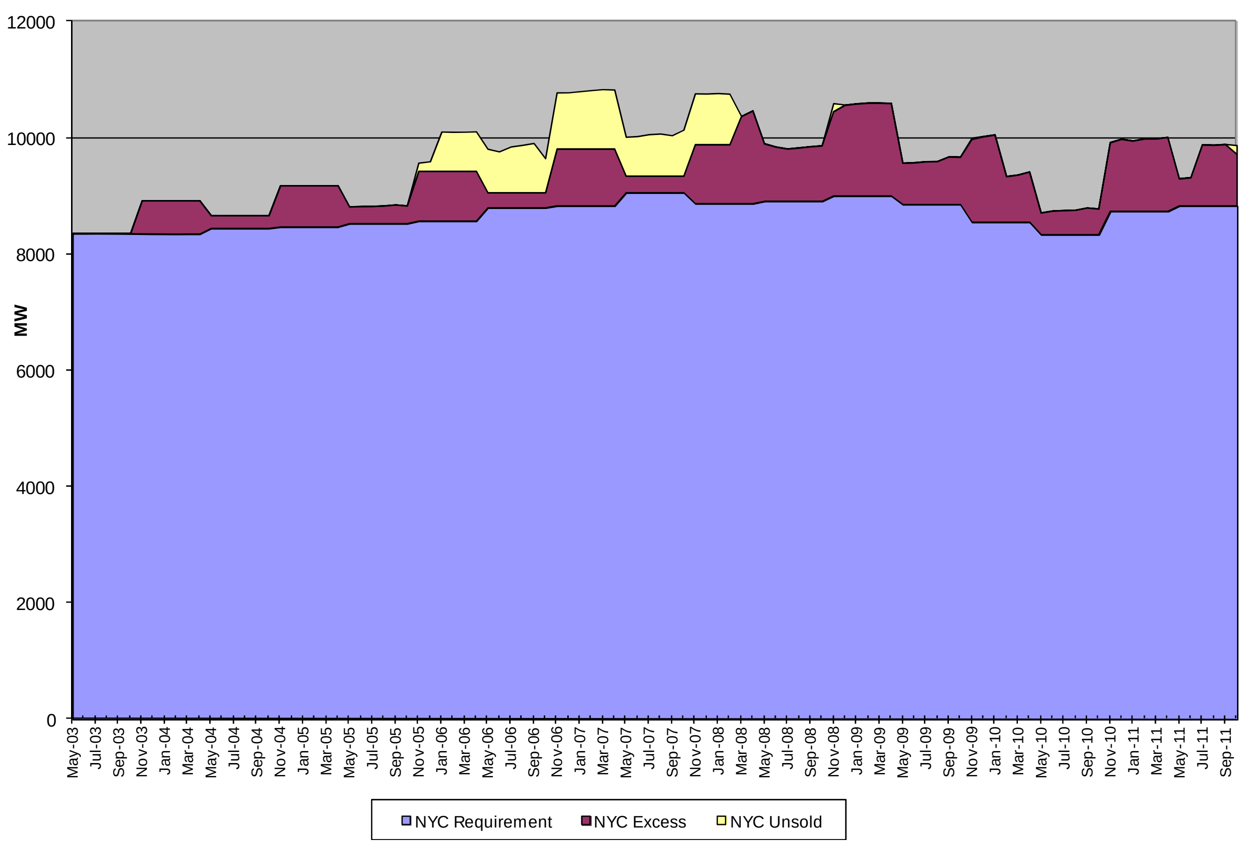


Chart 5. Long Island Market Clearing Prices

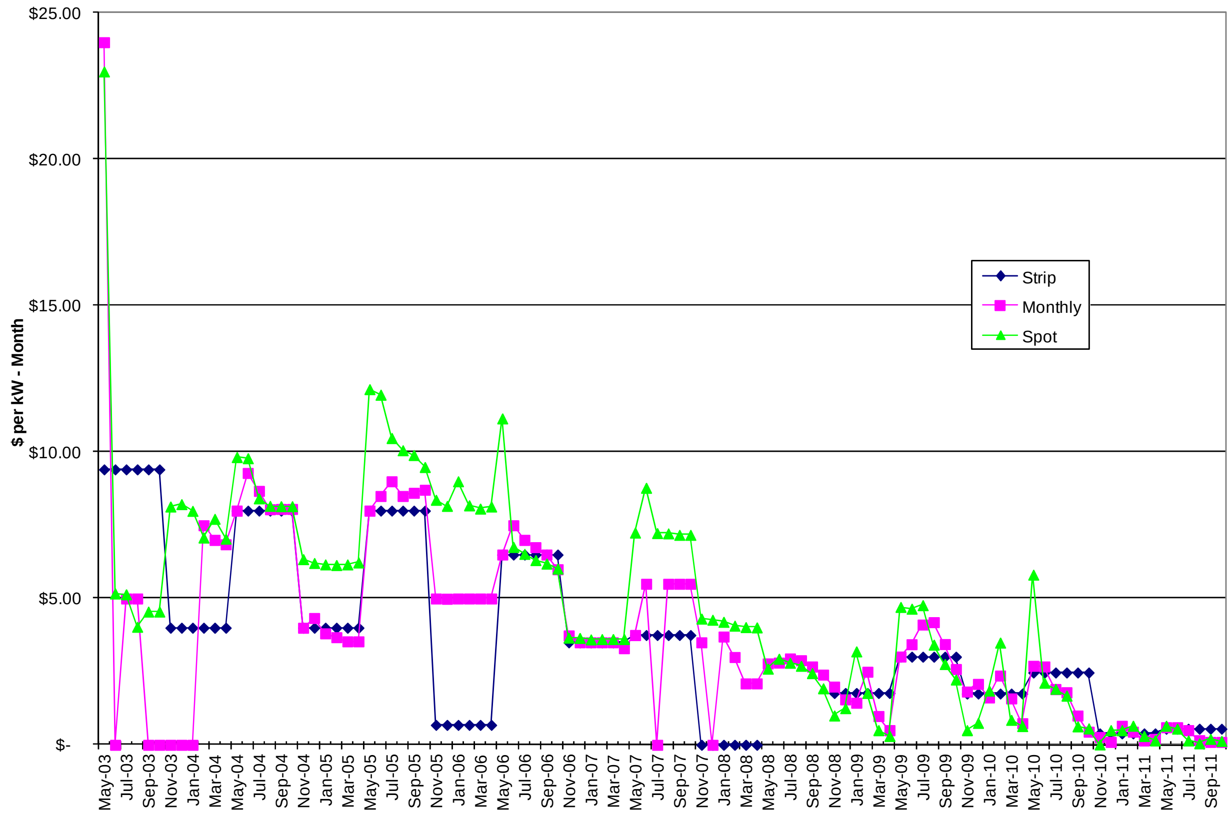
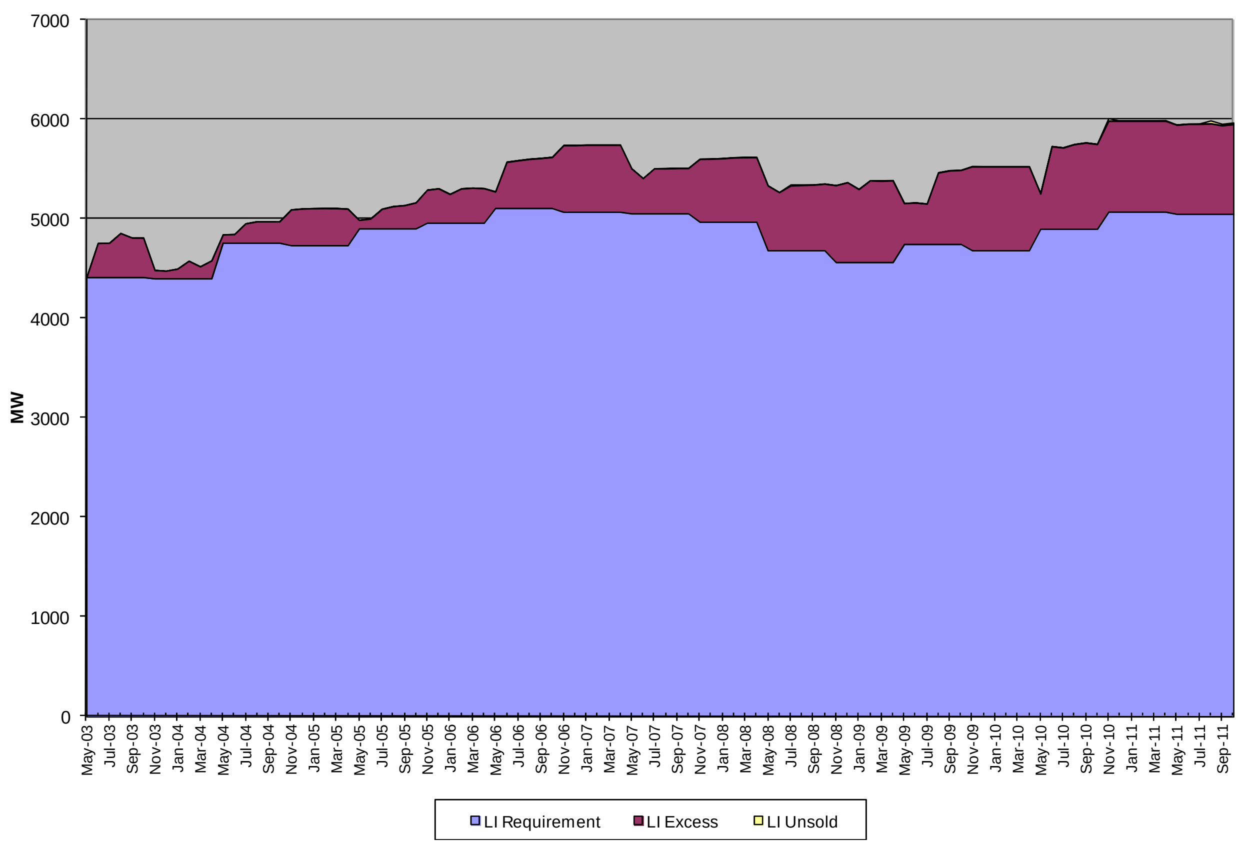


Chart 6. Long Island Offered MW



C. Potential Withholding in the Capacity Markets

1. All Regions in the NYCA

This section of the report addresses potential withholding in NYISO-administered Capacity auctions in all regions in the NYCA from November 2010 through October 2011. It focuses on market outcomes and related behavior since May 2007.

In order to determine for this report whether any potential withholding occurred, the NYISO analyzed the differences between available supply and the supply committed through self-supply, bilateral transactions, and the NYISO-administered auctions. In particular, the NYISO examined:

- the available NYCA Capacity that was available to be offered into the ICAP Spot Market Auctions but was not offered ("unoffered capacity"),[12]
- available NYCA Capacity that was offered into the Spot Market Auctions but was not sold ("unsold capacity"),
- unoffered capacity as a percentage of available Capacity, and
- unsold capacity as a percentage of offered Capacity.

When Capacity is available but not offered, it is an indication that physical withholding may have occurred. Similarly, when Capacity is offered at a price that causes it not to clear, it is an indication that economic withholding may have occurred. The amounts of unoffered and unsold capacity are determined from the ICAP Spot Market Auction results, because this auction is the last opportunity for Installed Capacity Suppliers to sell their Capacity. The existence of unoffered and unsold capacity, however, does not necessarily imply the intent to raise market prices.

As reflected in the NYISO's previous reports on the Installed Capacity Demand Curves, patterns of unsold capacity have varied across each of the Localities. For the entire NYCA, there generally has been more unsold capacity in winter months than summer months. In Long Island, historical levels of unsold capacity have averaged near zero; for this reporting period, the average level of unsold capacity increased slightly, by 5.1 MW per month on average, in Winter 2010-2011, and 9.2 MW per month, on average, in Summer 2011. In NYC, the high amounts of unsold capacity between Summer 2006 and Winter 2007-2008 coincided with the addition of

[12] Available supply is defined as the lesser of the NYISO-accepted DMNC tested capacity and the Capacity Resource Interconnection Service ("CRIS") MW value, with the Equivalent Demand Forced Outage Rates ("EFORd") applied.

approximately 1,000 MW of new Capacity. These amounts subsided with the introduction of the supply-side mitigation rules in 2008.

There are three types of ICAP auctions in each Capability Period: a Capability Period Auction (also referred to as the "six-month strip auction"), six Monthly Auctions, and six ICAP Spot Market Auctions. Capacity may be offered into any or all of the auctions. The NYCA ICAP requirements are settled for three locations: one each for the NYC and the Long Island Localities, and one for the NYCA as a whole. Local reliability rules require LSEs in NYC and on Long Island to procure minimum levels of Capacity from Installed Capacity Suppliers that are electrically located within the respective Locality. Such Capacity is also credited toward each NYC and Long Island LSE's overall NYCA obligation. The NYISO establishes Locational Minimum Installed Capacity Requirements on an annual basis according to NYISO Procedures.[13]

With the exception of the NYC Locality, the Services Tariff does not require Installed Capacity Suppliers to offer Capacity into the ICAP markets. Until the implementation of the ICAP mitigation measures set forth in Attachment H of the Services Tariff, which were effectuated in May 2008, the majority of Capacity in NYC – that of the "Divested Generation Owners" – had been subject to Commission-approved ICAP mitigation measures that imposed bid caps and required the units' Capacity to be offered into the ICAP auctions. Capacity resources constructed subsequent to the Commission's approval of the bid caps were not subject to bid caps or mandated to offer into the auctions. That Capacity and other Capacity inside and outside of the NYC Locality could be sold in bilateral transactions or offered in one or more of the NYISO's ICAP auctions. The Commission's March 7, 2008 Order[14] removed the requirements unique to the Divested Generation Owners and approved mitigation measures applicable to all In-City Capacity. The March 7, 2008 Order effectuated new In-City mitigation measures, based on Pivotal Supplier determinations combined with offering conduct and price impact thresholds, to determine whether an market power had been exercised. These measures are set forth in Attachment H of the Services Tariff (including revisions over time, "Supply-side Mitigation Measures").

In developing the information for this report, the NYISO examined auction outcomes of the Capability Periods from Summer 2007, which begins May 1, 2007, through Summer 2011,

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[13] *See* Section 2 and Attachment B of the NYISO Installed Capacity Manual.

[14] *New York Independent System Operator, Inc.*, Docket No. EL07-39-000, Order Conditionally Approving Proposal, 122 FERC ¶ 61,211.

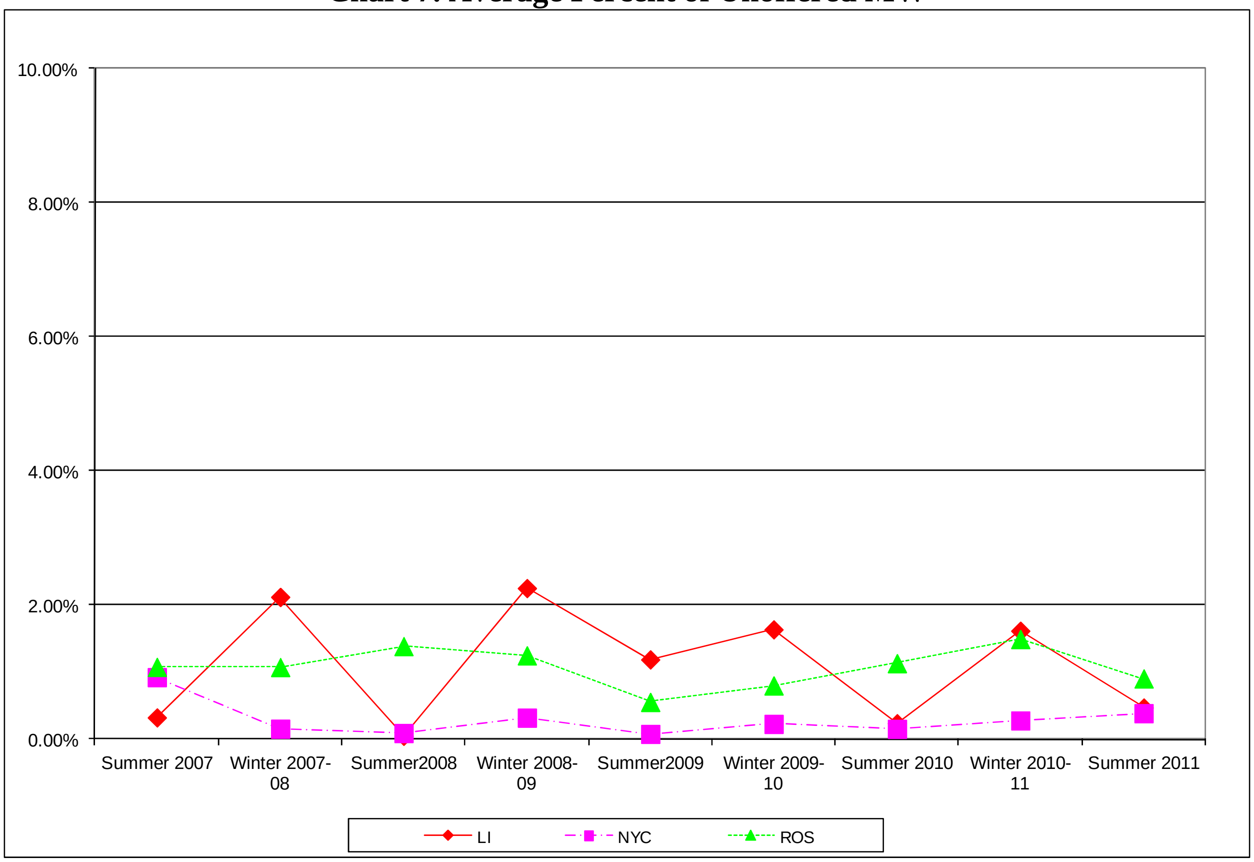
which ended October 31, 2011. Since the Capacity product transacted in NYISO-administered ICAP auctions is UCAP, the following information was examined:

1. Certification data, reflecting the certified MW of UCAP from all Resources within New York available to supply Capacity to the NYCA. The analysis did not include resources physically located outside of the NYCA.
2. The amount of UCAP supplied, which includes UCAP sold in any of the NYISO ICAP auctions, UCAP certified as self-supplied against an LSE's Capacity obligation, and UCAP committed through bilaterals.

Unoffered Capacity

Chart 7 displays unoffered capacity as a percent of available Capacity in each region, for each of the three regions.

Chart 7. Average Percent of Unoffered MW

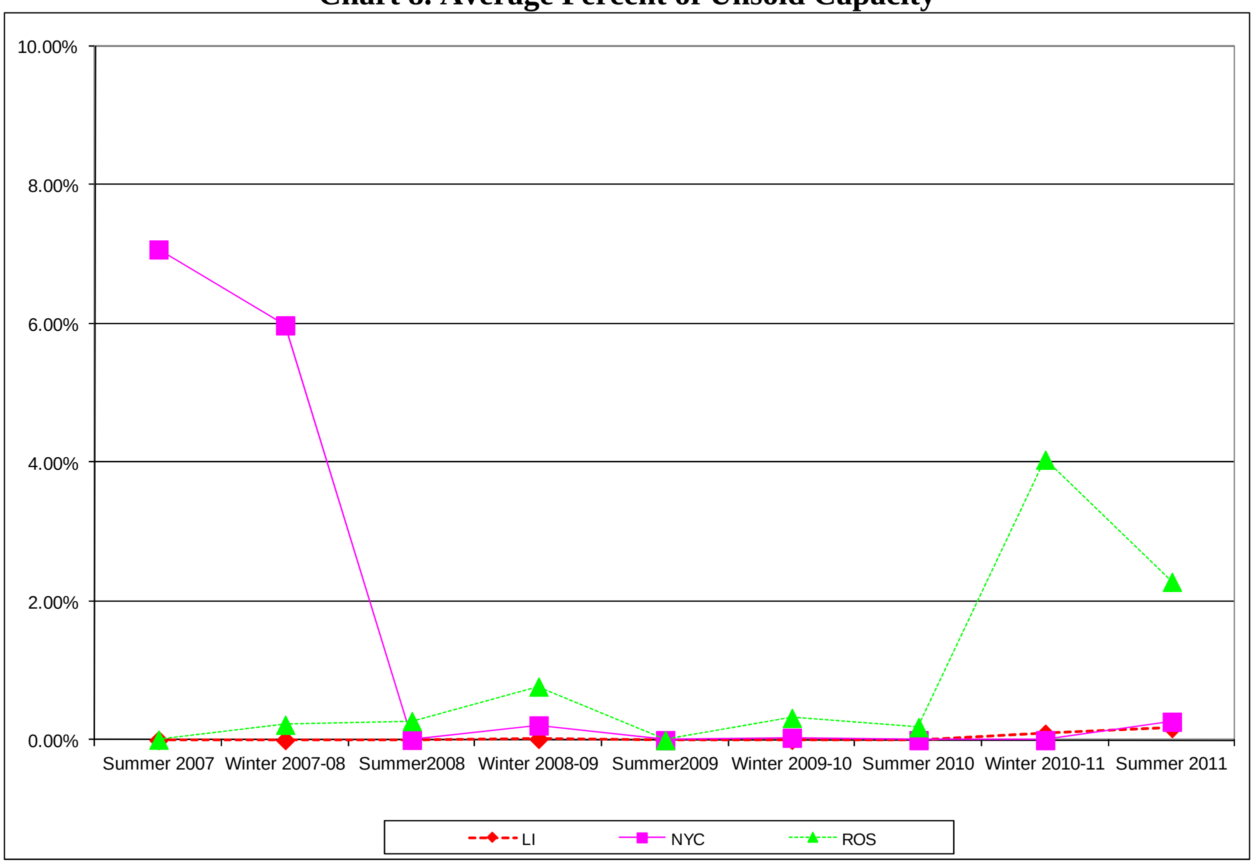


The Long Island Locality has fairly consistent seasonal fluctuations in the amounts of unoffered capacity, which can be seen in Chart 7. The Long Island Locality is characterized by Capacity procurement chiefly through bilateral transactions and self-supply. While it appears the amount of unoffered capacity on Long Island fluctuates between 0.01% and 2.26%, much of the unoffered capacity is not actually available. A portion of the unoffered capacity in Long Island is associated with generation stations permitted for less than 80 MW, although the DMNC of the units at each station when aggregated exceeds 80 MW. For example, in four instances on Long Island, there are two units at a site, and each individual unit at that site can produce more than 40 MW. In the event that one unit is out of service and the Market Participant wishes to run the other unit at output levels higher than 40 MW, the NYISO must have that higher (actual) DMNC value in its software system in order for the bid to pass validation. These units do not offer all of their available Capacity because the site permit restrictions limit the combined output to 79.9 MW.

Prior to Summer 2008, in NYC, the low level of unoffered capacity was principally due to the must-offer requirement applicable to the Divested Generation Owners. Beginning with the Summer 2008 Capability Period, the near absence of unoffered capacity can be attributed to the Supply-side Mitigation Measures effectuated in 2008.

Chart 8 displays unsold capacity as a percent of available Capacity in each region, for each of the three regions.

Chart 8. Average Percent of Unsold Capacity



Unsold Capacity

For all Capability Periods beginning with Summer 2007, nearly all Long Island Capacity that was offered was sold. In NYC, the average amount of unsold capacity as percentage of available Capacity trended at near zero levels from the start of the Summer 2008 Capability Period. For the Summer 2007 and after, nearly all the MW of Capacity resources located in ROS that offered Capacity into the ICAP auctions were sold. This result has been consistently observed despite a reduction in the NYCA Installed Reserve Margin from 18 to 16.5 percent for the 2007-2008 Capability Year and from 16.5 to 15 percent for the 2008-2009 Capability Year, which was then followed by increases to 16.5 percent for the 2009-2010 Capability Year and then 18% for the 2010-2011 Capability Year, before the latest reduction to 15.5 percent for the 2011-2012 Capability Year. As discussed below in the ROS section, the amount of unsold capacity in the ROS region displayed a significant increase in the Winter 2010-2011 and Summer 2011 Capability Periods.

Table 1 displays the breakdown of unsold and unoffered for each Locality. As part of the NYISO's August 24, 2010 ICAP compliance filing,[15] the NYISO stated that it would include unoffered and unsold capacity in the NYC Locality in its Installed Capacity Demand Curves reports filed annually with the Commission. The unoffered and unsold capacity values for NYC and ROS are also included to give a full representation of the data that underlies this report.

Table 1. Unoffered and Unsold Capacity by Locality

	Unoffered			Unsold		
Month	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**
Nov-10	44.3	83.9	310.2	0.0	23.6	1,378.3
Dec-10	15.1	84.6	305.5	0.0	0.0	1,301.7
Jan-11	47.9	82.9	317.2	0.0	0.0	487.9
Feb-11	19	90.6	431.6	0.0	0.0	389.0
Mar-11	12.2	102.0	432.6	0.0	2.6	1,026.7
Apr-11	25.1	98.3	425	0.0	4.6	1,418.1
May-11	26.6	17.2	298.2	0.0	0.0	141.4
Jun-11	23	14.5	176.5	0.0	0.0	262.3
Jul-11	25.4	14.7	90.2	0.3	1.0	921.3
Aug-11	35.3	11.2	90.9	0.0	27.8	844.1
Sep-11	62.6	68.3	390.8	0.0	12.8	499.3
Oct-11	47.5	24.3	212.2	149.0	13.6	495.7

[15] *See New York Independent System Operator, Inc.*, Resubmittal of August 24, 2010 Filing, Docket Nos. ER10-2210-000, EL07-39-____ and ER08-695-0004, ("August 2010 Compliance Filing") at p. 16.

2. New York City Locality

In NYC, Pivotal Suppliers are subject to Mitigation Measures. A Pivotal Supplier is an ICAP Supplier that, along with its Affiliated Entities, Controls In-City Capacity in excess of the pivotal control threshold.[16] The Capacity controlled by Pivotal Suppliers ("Mitigated UCAP") must be offered into the Spot Market Auction at a price at or below the lesser of the default UCAP Offer Reference Level ("Default Reference Price") or the ICAP Supplier's Going-Forward Costs. There is not a "must-offer" requirement for Capacity located in the ROS or Long Island Localities.

The NYC Capacity that was not sold, as a percent of available Capacity, was less than 0.26% per month on average for the Winter 2010-2011 and Summer 2011 Capability Periods. The low levels can be explained by the implementation of the Supplier-side Mitigation Measures that became effective as of the Summer 2008 Capability Period.[17]

Chart 9 below illustrates the effects of the Supplier-Side Mitigation Measures. As depicted in Chart 9, these measures include a Pivotal Control Threshold determined by the surplus amount of NYC Capacity above the Locality Capacity Requirement. An Entity is deemed a Pivotal Supplier if the number of MW it Controls is greater than the threshold. If an Entity is a Pivotal Supplier, then it is subject to the Default Reference Price. The Default Reference Price, as shown in Chart 9, becomes the cap that the Pivotal Supplier must offer at or below in the ICAP Spot Market Auction unless the Pivotal Supplier's Going Forward Costs ("GFCs"), as determined by the NYISO, are higher than the Default Reference Price.

The level of unoffered and unsold MW can be inferred from Chart 9 by comparing the NYC Spot Market Auction price to the UCAP Offer Reference Level (also referred to as the "Default Reference Price"). The Default Reference Price is the price on the demand curve if all available UCAP is offered and sold. The difference between the Spot Market Auction Price and Default Reference Price can be attributed to In-City Capacity that is either not offered or offered at a price above the Default Reference Price. Note that the NYC Spot Market Auction Price will diverge from the Default Reference Price when the NYCA ICAP Spot Market Auction sets the NYC Spot Market Auction price. This divergence is the result of the auction rules, and is not caused by unoffered or unsold NYC Capacity.

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[16] *See* Services Tariff Attachment H Sections 23.2.1 and 23.4.5.

[17] See earlier reports for the analysis of the New York City Locality prior to the effectuation of the Supplier-Side Mitigation Measures and removal of the bid-caps.

Chart 9. In-City Mitigation Results 2011

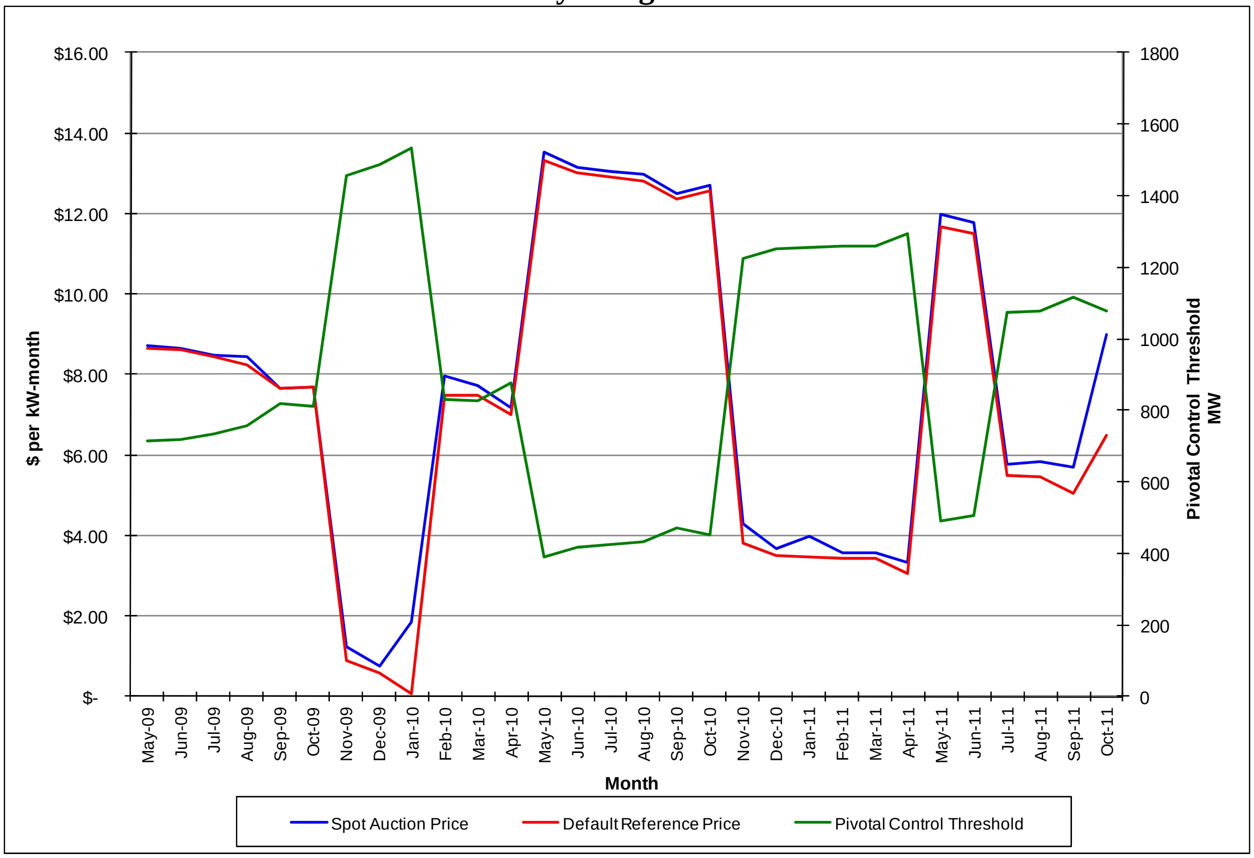
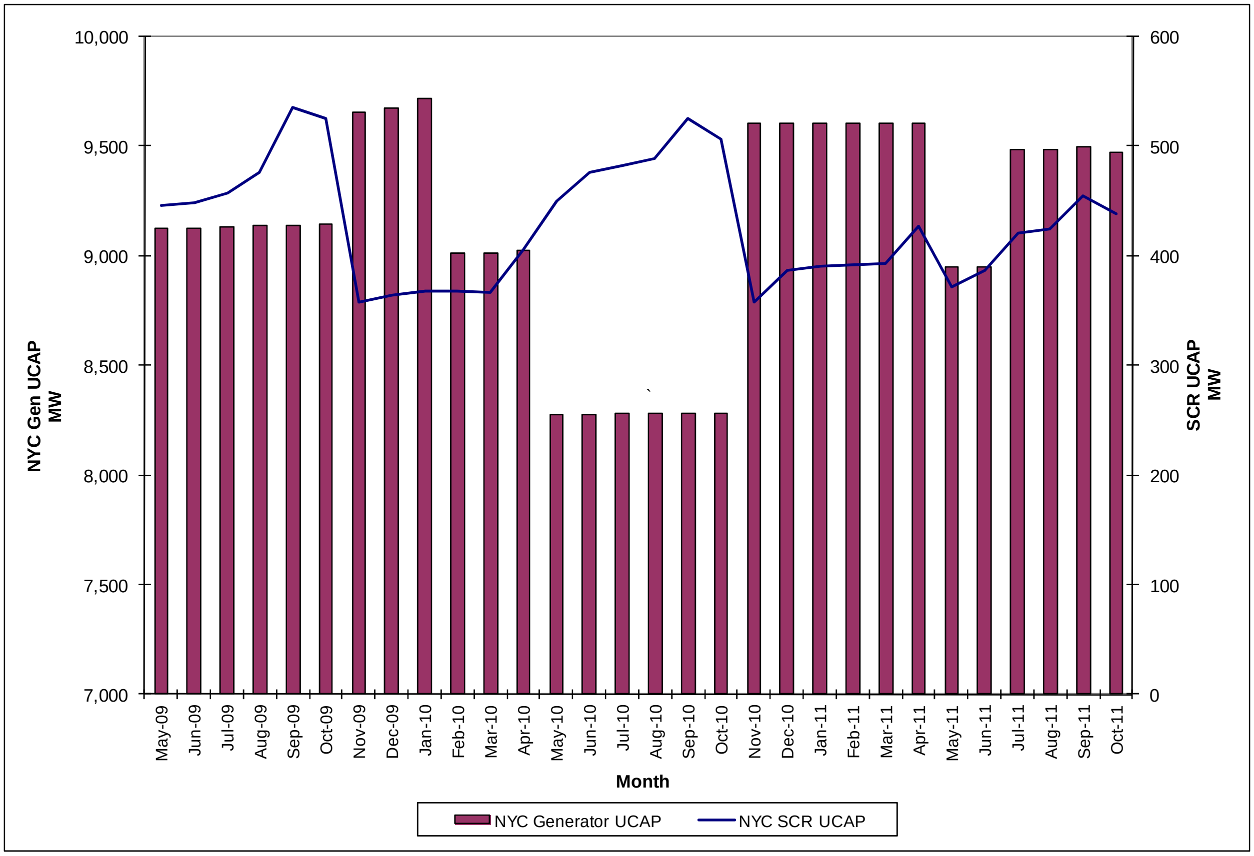


Chart 10 depicts the levels of available generator UCAP and SCR UCAP in the NYC Locality.

Chart 10. NYC Generator and SCR UCAP



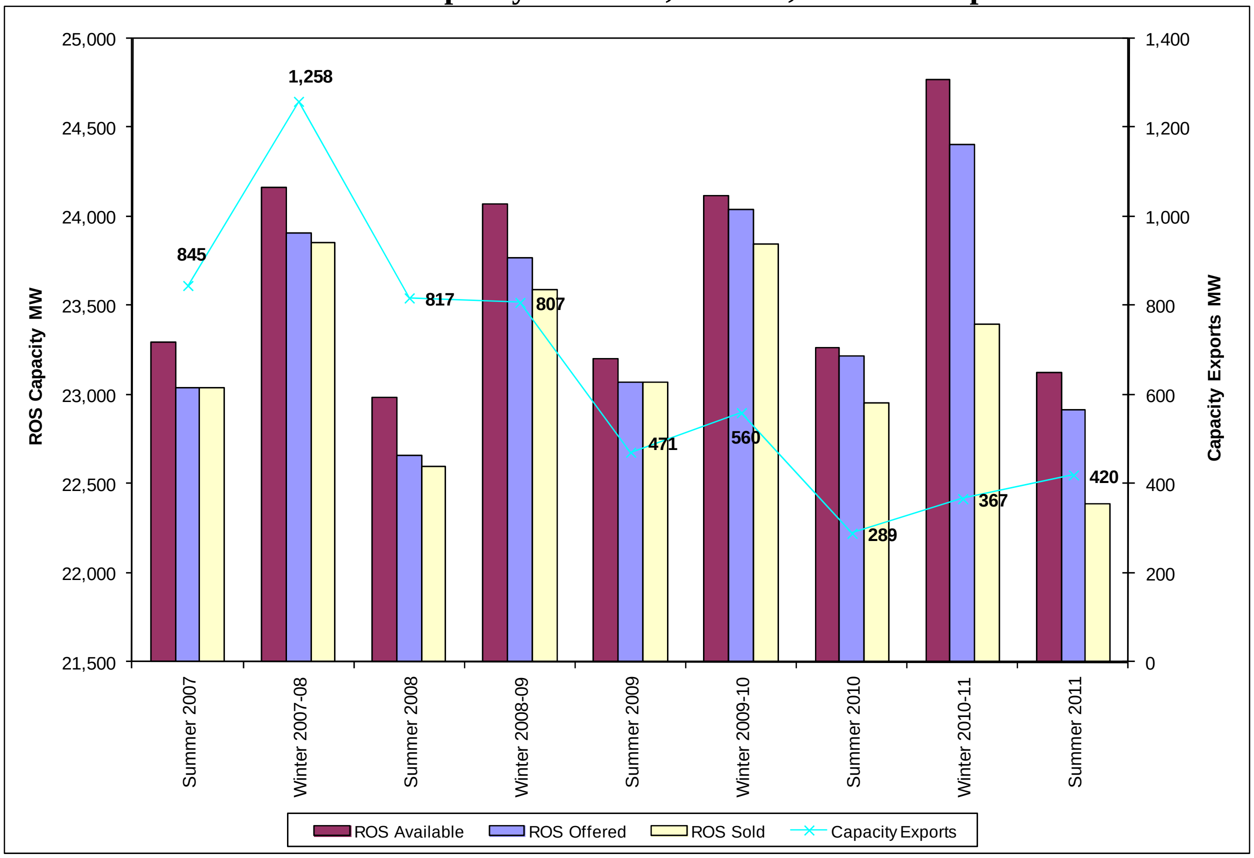
3. ROS Capacity Market

Additional Details

This section of the report addresses possible withholding of Capacity in the ROS region from November 2010 through October 2011. For this review, the NYISO conducted a detailed analysis of unoffered and unsold capacity from resources located in the ROS area of the NYCA; this section of the review does not pertain to Capacity located in NYC and on Long Island.

Chart 11 shows monthly average values over each Capability Period for four ROS Capacity variables: available, offered, sold, and exported.

Chart 11. ROS Capacity Available, Offered, Sold and Exported



Examination of ROS Capacity data pertaining to individual Market Participants revealed general patterns in unsold and unoffered capacity. The patterns suggest a three-way classification of suppliers by market sector: all generation-owning transmission owners, five ROS generation owners, and other suppliers, which includes SCRs. [18] Note that these classifications and the following table follow the same approach in displaying the unoffered and unsold capacity in the ROS area that was used in the NYISO's December 2010 Report.[19] Table 2 of this December 2011 Report summarizes the monthly averages for each Capability Period from the Summer 2008 Capability Period through October 2011.

[18] Special Case Resources participate in the NYISO's Capacity markets through Responsible Interface Parties.

[19] *See* ER01-3001, ER03-647, Motion for Leave to Respond, and Response, of the New York Independent System Operator, Inc. filed July 27, 2009.

Table 2. ROS Unoffered and Unsold Capacity MW by Type of Market Participant

	Summer 2008		Winter 2008-2009		Summer 2009		Winter 2009-2010		Summer 2010		Winter 2010-2011		Summer 2011	
	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW	Unoffered MW	Unsold MW
All ROS TOs	**204.5**	**0.0**	**64.1**	**0.0**	**69.2**	**0.0**	**91.0**	**0.0**	**158.2**	**0.0**	**127.7**	**0.0**	**92.3**	**0.0**
	60.11%	0.00%	21.22%	0.00%	56.79%	0.00%	46.98%	0.00%	59.90%	0.00%	26.16%	0.00%	33.97%	0.00%
5 ROS GenCos	**67.9**	**61.6**	**79.5**	**173.8**	**24.5**	**0.0**	**68.7**	**51.4**	**23.3**	**14.1**	**71.4**	**179.7**	**15.7**	**72.9**
	19.96%	100.00%	26.30%	95.00%	20.09%	0.00%	35.44%	66.69%	8.82%	32.66%	14.63%	16.46%	5.76%	6.91%
All Others incl. SCRs	**67.8**	**0.0**	**158.7**	**9.2**	**28.2**	**0.0**	**34.1**	**25.7**	**82.6**	**29.1**	**288.9**	**912.1**	**163.7**	**981.6**
	19.93%	0.00%	52.49%	5.00%	23.12%	0.00%	17.58%	33.31%	31.28%	67.34%	59.21%	83.54%	60.25%	93.09%
Total Unoffered/ Unsold	**340.2**	**61.6**	**302.3**	**183.0**	**122.0**	**0.0**	**193.7**	**77.0**	**264.2**	**43.2**	**488.0**	**1091.8**	**271.6**	**1054.5**
Total Available MW	22,980.0		24,071.0		23,197.0		24,116.5		23,262.1		24,768.7		23,126.6	

Notes:

(1) All ROS Transmission Owners category includes the TOs' SCRs

(2) 5 ROS Generating Companies category was used to maintain continuity with the previous reports

Salient facts from the above tables are:

- The group of all ROS generation-owning Transmission Owners consistently had unoffered capacity which ranged from 21% to 60% of total unoffered capacity.
- The group of all ROS generation-owning Transmission Owners had no Capacity that was offered and unsold capacity.
- The group of five generation owners consistently had unoffered capacity which ranged from 6% to 35% of total unoffered capacity.
- The group of five generation owners had unsold capacity which accounted for 0% to 100% of total Capacity that was offered and unsold capacity.
- The group of all Others including SCRs consistently had unoffered capacity that ranged from 18% to 60% of total unoffered capacity for the period Summer 2008 through Summer 2011.
- The group of all Others including SCRs had Capacity that was offered and unsold capacity that ranged from 0% to 93%.

Analysis of Unoffered Capacity

This section of the report provides a detailed analysis of the unoffered capacity in the ROS region. This section also presents the maximum price impact of the unoffered capacity, in each month and averaged over the six months of each Capability Period, consistent with the December 2010 Report. In general, the responses suggest that the Installed Capacity Suppliers' reasons for not offering the Capacity were benign, and none of the instances evidence behavior intended to artificially raise prices.

The NYISO contacted each Installed Capacity Supplier that had at least 15 MW of unoffered capacity in any one month in either the Winter 2010-2011 Capability Period or the Summer 2011 Capability Period for an explanation of why it did not offer all of its capacity.[20] There were 22 Market Participants with at least 15 MW of unoffered capacity in any month, and the NYISO sought explanations from each of them. The following information was provided to the NYISO by ICAP suppliers.

[20] Confidential Attachment I-F is filed as a confidential attachment, which provides a more detailed summary of Market Participants' explanations for having unoffered and unsold capacity.

1. Thirteen of the Market Participants individually responded that the failure to offer its capacity was the result of an administrative oversight. The NYISO's records showed that twelve of the thirteen Market Participants did not offer capacity in one month, and one Market Participant did not offer capacity in two months. The majority of instances had unoffered capacity ranging from 15 to 25 MW; however, in one instance, a Market Participant did not offer 243.5 MW. That instance was the largest amount of capacity not offered by a Market Participant due to administrative oversight.
2. A generation-owning Transmission Owner keeps approximately 30 MW of aging gas-fueled generation out of operation for the first five months during the Summer Capability Period due to environmental restrictions.
3. A renewable generation owner routinely does not offer approximately 15 MW to 25 MW of UCAP due to neighboring state rules.
4. Four ICAP Suppliers had unoffered capacity associated with their resources being permanently or temporarily withdrawn from the ICAP market.
5. A generation-owning Transmission Owner routinely does not offer the full quantity of capacity available from several of its resources. Over the analysis period for this report, this Market Participant did not offer an amount that ranged from approximately 50 MW to 110 MW in each month. This action was explained to be primarily due to a conservative operating approach.
6. A generation-owning Transmission Owner did not offer 54 MW in each of the Winter 2010-2011 Capability Period due to a natural gas fuel restriction that prevents the plant from being able to run at full capacity.
7. A generation owner has a PURPA contract that prohibits it from selling any Capacity above the level of the bilateral contract. The amount of unoffered capacity ranges from 23 MW in Summer Capability Period months to 67 MW in Winter months.

Table 3 below shows the maximum price impact of the unoffered capacity based on the slopes of the ICAP Demand Curves for the relevant Capability Periods. The maximum price impact is calculated as the greater of (1) the product of the monthly unsold MW and the slope of the ICAP Demand Curve and (2) the ICAP Spot Market Auction Market Clearing Price, since the price impact cannot exceed the auction price. Monthly basis and seasonal averages are reported. The maximum price impact of the unoffered capacity, averaged over the six months of the Winter 2010-2011 and Summer 2011 Capability Periods, was $0.35/kW-mo and $0.27/kW-mo, respectively.

Table 3. Maximum Price Impact of Unoffered Capacity

Month	Total Unoffered MW	Monthly Maximum Price Impact	Seasonal Average Maximum Price Impact
Nov-10	310.2	$0.01	$0.35
Dec-10	305.5	$0.50	
Jan-11	317.2	$0.50	
Feb-11	431.6	$0.65	
Mar-11	432.6	$0.30	
Apr-11	425	$0.15	
May-11	298.2	$0.65	$0.27
Jun-11	176.5	$0.46	
Jul-11	90.2	$0.15	
Aug-11	90.9	$0.05	
Sep-11	390.8	$0.18	
Oct-11	212.2	$0.13	

Analysis of Unsold Capacity

This section of the report analyzes and reports on unsold capacity in the ICAP Spot Market Auction. It also presents the maximum price impact of the unsold capacity, in any one month and the price impact average for the six months of the Capability Period. The NYISO contacted each generator for an explanation of its behavior if (a) the class of generators that it was in had more than 15 MW of unsold capacity in a given month and (b) if the generator had a ICAP Spot Market Auction offer that was greater than the generator's class average Net GFC with half net revenues ("GFCs with half net revenues", as described below).

In addition to calculating the monthly maximum and average maximum price impacts, three metrics were calculated in this report for the analysis period:

a. Class average going forward costs ("GFCs"), with and without a risk adjustment;

b. Estimated monthly price impacts of unsold capacity associated with offers above class average GFCs.

i. Monthly Price Impacts

Table 4 below includes the average monthly maximum price impact of unsold capacity for each Capability Period. The price impacts reported in Table 4 exceed the NYISO's threshold for determining whether GFCs are evaluated in all months of the analysis period, November 2010 through October 2011. Specifically, both of the Capability Period impacts exceeded the $0.20/kW-month threshold. The average price impacts were $0.35/kW-month and $0.24/kW-month in the Winter 2010/2011 and Summer 2011 Capability Periods, respectively.

Table 4. Maximum Price Impact of ROS Unsold MW

Month	Total Unsold MW	Monthly Maximum Price Impact	Seasonal Average Maximum Price Impact
Nov-10	1378.3	$0.01	$0.35
Dec-10	1301.7	$0.50	
Jan-11	487.9	$0.50	
Feb-11	389.0	$0.65	
Mar-11	1026.7	$0.30	
Apr-11	1418.1	$0.15	
May-11	141.4	$0.37	$0.24
Jun-11	262.3	$0.55	
Jul-11	921.3	$0.15	
Aug-11	844.1	$0.05	
Sep-11	499.3	$0.18	
Oct-11	495.7	$0.13	

ii. Class Average Going Forward Costs

The NYISO calculated class average GFCs for generator classes that had at least 15 MW of unsold capacity in a given month. Four generator classes had unsold capacity that met this criterion: natural gas combined cycle, Class A; no. 6 fuel oil steam turbine, Class F; natural gas steam turbine, Class G; and sub-critical coal steam turbine units, Class H.

The NYISO reviewed the ROS generating units listed in the NYISO's Load and Capacity Data Report (referred to as the "Gold Book") applicable to November 2010 through October 2011, and assigned the units to classes based on primary fuel and technology. Attachment I-B to this report, "Existing Generating Facilities", shows the generating units in ROS that the NYISO assigned to the four classes for which class average GFCs were calculated.

For purposes of this report, class average GFCs are defined as costs (other than production costs) that could be reasonably expected to be avoided if the plant was mothballed for at least one year. (*See* Table 5 for definitions.) These GFCs may provide insight into why a generator offered its Capacity at a non-zero offer price. The assumption for this report is that an Installed Capacity Supplier would only want to sell Capacity from a generator if the Capacity revenues it receives cover the generator's GFCs. In this analysis, GFCs are calculated for the entire Capacity of the plant. For this report, GFCs are calculated from industry data, such as labor rates, expenses for contract services, administrative and general, and insurance. Attachment I-C to this report, Class Average Avoidable Costs, presents the avoidable fixed cost components of the class average GFCs for classes A, F, G, and H.

Generators face uncertainty about net revenues, among other things, and this uncertainty may influence the prices at which they offer Capacity. To account for this uncertainty, the NYISO calculated class average GFCs including varying levels of net revenues: full, half, and none. Attachment I-D to this report, Class Average Going Forward Costs, shows the class average GFCs for classes A, F, G, and H, calculated as the avoidable costs from Attachment I-C less the varying levels of net revenues.

Table 5. Going Forward Cost Definitions

Going Forward Costs (GFCs)	Costs that would be avoided or deferred if a generator was mothballed for a year or more, based on the calculation of the industry average cost data for the type of generator.
Net energy and ancillary services revenues (net revenues)	Estimated energy plus ancillary services revenues minus estimated production costs, with a minimum value of zero.
GFCs with full net revenues	GFCs minus net revenues. This value is used to represent Net GFCs with certainty of net revenues.
GFCs with half net revenues	GFCs minus 0.5 times net revenues. This value is used to represent Net GFCs with some uncertainty.
GFCs with no net revenues	GFCs. This value is used to represent Net GFCs without certainty of net revenues.
Unit Specific Net GFCs with Recognized Adjustments	GFCs plus unit-specific adjustments (i.e., the dollar amount identified by the generator for an adjustment that is readily recognizable as an appropriate adjustment), minus the unit specific net revenues.
Unit Specific Net GFCs with all Adjustments	GFCs plus all unit-specific adjustments identified by the generator, minus the unit specific net revenues.

The NYISO estimated net Energy and Ancillary Services revenues for the units in the four classes over the analysis period. Net revenues were equal to estimated Energy revenues plus Ancillary Services revenues minus estimated production costs. A minimum value of zero was used for net revenues; that is, if production cost exceeded Energy and Ancillary Services revenues, a value of zero was used for the net revenue figure. Unit-specific net revenues were calculated for 19 generating units in the four classes listed above. Two of the 19 units had negative net revenue estimates. The net revenues were averaged across the units in each class; the class average net revenues are included in Attachment I-D.

The NYISO implemented the following several enhancements to the net revenue methodology the NYISO used in the December 2010 Report:

- Hourly fuel costs were calculated based on meter data using hourly fuel prices.
- For generators that could burn one or more fuels, hourly data from the EPA Continuous Emissions Modeling System (CEMS) were used to identify which fuel(s) were burned and in what proportion. These hourly fuel types or mixes were used as the cost basis for the hourly fuel cost calculation.
- The startup costs were calculated based on how long the generator had been offline, using meter data and the generator's startup cost reference curve.
- Incremental energy above the minimum generation amount was assigned a cost based on a weighted average heat rate calculated from the generator's energy reference curve.

GFCs with full net revenues were calculated for use as a proxy for net going forward costs with certainty of net revenues. Annual going forward costs minus full net revenues for the November 2010 to October 2011 period varied from $0.69/kW-year for Class A to $21.64/kW-year for Class H. Summer values ranged from $0.07/kW-month to $2.40/kW-month, and Winter values ranged from $0.04/kW-month to $1.20/kW-month.

GFCs with half net revenues was calculated for use as a proxy for net going forward costs with some uncertainty. Annual going forward costs minus half net revenues for the November 2010 to October 2011 period vary from $2.37/kW-year for Class A to $26.12/kW-year for Class H. Summer values range from $0.25/kW-month to $2.90/kW-month. Winter values range from $0.12/kW-month to $1.45/kW-month.

GFCs with no net revenues were calculated for use as a proxy for net going forward costs without certainty of net revenues. Annual going forward costs with no net revenues for the November 2010 to October 2011 period vary from $13.05/kW-year for Class G to $43.28/kW-year for Class H. Summer values range from $1.45/kW-month to $4.80/kW-month. Winter values range from $0.73/kW-month to $2.41/kW-month.

Table 6 below shows the amount of unsold capacity by month for which class average Net GFCs were calculated and the amount of unsold capacity for which class average Net GFCs were not calculated (*i.e.*, generators within classes with less than 15 MW of unsold capacity in each month). The total unsold capacity values in the second column are for the entire NYCA; they are equal to the monthly sums of unsold capacity across all three locations in Table 1. The unsold capacity used in the maximum price impact calculation in Table 4 is based on the ROS location only.

Table 6. Unsold MW Used for GFC Calculations

Month	Total Unsold MW	Total Unsold MW for which class average GFCs calculated (Unsold MW > 15)	Total Unsold MW for which class average GFCs not calculated (Unsold MW < 15)
Nov-10	1401.9	703.3	698.6
Dec-10	1301.7	1242.6	59.1
Jan-11	487.9	487.9	0.0
Feb-11	389.0	389.0	0.0
Mar-11	1029.3	903.0	126.3
Apr-11	1422.7	1278.1	144.6
May-11	141.4	141.4	0.0
Jun-11	262.3	262.3	0.0
Jul-11	922.6	888.3	34.3
Aug-11	871.8	617.2	254.6
Sep-11	512.1	485.5	26.6
Oct-11	658.3	545.9	112.4

iii. Unsold Capacity Impact Analysis

As part of the analysis of unsold capacity, the NYISO contacts generator owners for unit-specific information if a generator's offer for unsold capacity exceeded the class average "GFCs with half net revenues" for the class to which the generator was assigned. The values of these GFCs are shown in Attachment I-D. Of the 19 generators for which class average GFCs were calculated, six generators had offers that exceeded the class average GFCs with half net revenues. The NYISO calculated unit-specific GFCs for these six units, which were owned by two Market Participants. As part of this process, the NYISO provided the generation owners the class average avoidable costs and gave them the opportunity to provide information regarding adjustments to the class average values to reflect their unit-specific avoidable costs. Both of the generation owners provided qualitative explanations for their offering behavior but declined to provide quantitative information. In one case, the Market Participant stated that it does not analyze GFCs for its auction activity, and that its offering behavior was more related to short-term costs and risks associated with bidding into the Day Ahead Market. The other Market

Participant did not provide quantitative adjustments stating that its units' net revenues would have likely exceeded the avoidable costs, such that the resulting GFC calculation would have been about the same. Section II of Confidential Attachment I-F includes more detailed information regarding the explanations of unsold capacity for the two Market Participants that offered above GFCs with half net revenues.

After collecting unit-specific GFC information, the NYISO performed ICAP Spot Market Auction simulations for a more detailed understanding of how the non-zero price offers may have affected Market Clearing Prices. Because the two generators that were contacted did not have quantitative adjustments to the NYISO's class average GFC calculations, the NYISO did not analyze any scenarios with adjustments to GFCs.[21] Therefore, the NYISO simulated auction outcomes under three scenarios: GFCs with full net revenues, GFCs with half net revenues, and GFCs with no net revenues. These scenarios are labeled scenarios 1, 2, and 3 in Table 7.

The NYISO performed the simulations by replacing offers that originally did not clear with the unit-specific GFC at varying levels of net revenues in each of the three scenarios. For the other thirteen generators from whom the NYISO did not request information regarding GFC adjustments, the NYISO utilized GFC values reflecting class average avoidable costs. It is important to note that offers were only replaced with the GFC value if the offer was not awarded any MW. If the offer was marginal and only cleared a portion of its MW, or if the offer was inframarginal, the specific offers at the original offer prices were used. The offers that were analyzed for purposes of the simulations are provided in Attachment I-A.[22]

Table 7 shows the results of the auction simulations in each of the three scenarios, for each month of the analysis period. Column B shows the original NYCA ICAP Spot Market Auction prices. Columns C, D, and E show the simulated NYCA price under each of the three scenarios. Columns F, G, and H show the price reduction relative to the original clearing price. The simulation price deltas relative to the original clearing prices are strictly zero or negative. This results from the simulation methodology stated in the previous paragraph: only offers that entirely did not clear were replaced with GFCs. The amount of the price reduction shown in the

[21] In the January 2010 Report, for the Market Participants that had submitted GFC adjustments, the NYISO calculated GFCs in three manners: disregarding all adjustments, including some recognized adjustments, and including all adjustments.

[22] The unmasked unsold capacity offers are provided in Confidential Attachment I-F.

simulations is strictly decreasing as less revenues are recognized in the GFC calculations. That outcome is consistent with what would be expected.

Table 7. Price Impact Analysis Results

A	B	C	D	E	F	G	H
Month	Original MCP	S1	S2	S3	S1 delta	S2 delta	S3 delta
Nov-10	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Dec-10	0.50	0.25	0.28	0.28	(0.25)	(0.22)	(0.22)
Jan-11	0.50	0.25	0.35	0.35	(0.25)	(0.15)	(0.15)
Feb-11	0.65	0.50	0.64	0.64	(0.15)	(0.01)	(0.01)
Mar-11	0.30	0.15	0.15	0.15	(0.15)	(0.15)	(0.15)
Apr-11	0.15	0.01	0.05	0.05	(0.14)	(0.10)	(0.10)
May-11	0.65	0.65	0.65	0.65	0.00	0.00	0.00
Jun-11	0.55	0.30	0.30	0.30	(0.25)	(0.25)	(0.25)
Jul-11	0.15	0.01	0.05	0.05	(0.14)	(0.10)	(0.10)
Aug-11	0.05	0.02	0.05	0.05	(0.03)	0.00	0.00
Sep-11	0.18	0.10	0.10	0.10	(0.08)	(0.08)	(0.08)
Oct-11	0.13	0.08	0.09	0.09	(0.05)	(0.04)	(0.04)

S1: GFCs with full net revenues
S2: GFCs with half net revenues
S3: GFCs with no net revenues

iv. Conclusions

The results of the simulations shown in Table 7 indicate that the NYCA ICAP Spot Market Auction prices would have potentially been lower if the offers that entirely did not clear were offered at the GFC values. In all three scenarios, the price reductions ranged from $0.00/kW-month to $0.25/kW-month. For the first scenario in which unsold offers were replaced with GFCs with full net revenues, the price reduction was $0.12/kW-month on average. The second scenario with GFCs with half net revenues had an average reduction of $0.09/kW-month, and the third scenario with GFCs with no net revenues also had an average reduction of $0.09/kW-month.

While these potential price reductions represent a large percentage of the original Spot Market Auction clearing price, the reductions are a relatively small total dollar amount. As noted earlier, the simulations were performed by replacing only offers that entirely did not clear with GFCs, which is why the simulated prices all were lower than the original auction prices. If all offers were replaced with GFCs, it would be possible for the simulated prices to exceed the original prices. The unsold capacity analysis is based upon a considerably larger amount of unsold capacity than that historically observed. However, the associated low potential price impacts do not indicate that economic withholding occurred.

The analysis shows that the estimated Going Forward Costs did not indicate that significant economic withholding occurred over the analysis period. During this period, the NYCA ICAP Spot Market Auctions cleared well below the estimated Going Forward Costs for the majority of the ROS generators with unsold capacity, which indicates the absence of significant economic withholding in the ROS region.

A similar conclusion can be drawn regarding the MW amounts of unoffered and unsold capacity. Although there was a historically large amount of unoffered and unsold capacity shown in Tables 3 and 4, the associated maximum price impact was relatively low. This result is attributable to the fact that the existing UCAP levels consistently exceeded the NYCA zero crossing point throughout November 2010 through October 2011.

Attachment I-A. Unsold Capacity Offers (Masked)

AUCTION TYPE	AUCTION MONTH	LOCATION DESCRIPTION	OFFER CAPACITY	OFFER PRICE	PTID NAME	AWARDED CAPACITY	MARKET CLEARING PRICE	UNSOLD
Spot	11/1/2010	ROS	389.0	0.01	Unit 61	383.1	0.01	5.897
Spot	11/1/2010	ROS	313.1	0.01	Unit 62	308.4	0.01	4.746
Spot	11/1/2010	ROS	388.7	0.01	Unit 63	382.8	0.01	5.892
Spot	11/1/2010	ROS	100.0	0.01	Unit 60	98.5	0.01	1.516
Spot	11/1/2010	ROS	79.2	0.01	Unit 94	78.0	0.01	1.201
Spot	11/1/2010	ROS	39.0	0.01	Unit 83	38.4	0.01	0.591
Spot	11/1/2010	ROS	386.2	0.01	Unit 68	380.3	0.01	5.855
Spot	11/1/2010	ROS	57.6	0.01	Unit 69	56.7	0.01	0.873
Spot	11/1/2010	ROS	672.2	0.01	Unit 7	662.0	0.01	10.190
Spot	11/1/2010	ROS	3.1	0.01	Unit 56	3.1	0.01	0.047
Spot	11/1/2010	ROS	8.1	0.01	Unit 57	8.0	0.01	0.123
Spot	11/1/2010	ROS	0.2	0.01	Unit 55	0.2	0.01	0.003
Spot	11/1/2010	ROS	408.3	0.01	Unit 4	402.1	0.01	6.190
Spot	11/1/2010	ROS	31.8	0.01	Unit 20	31.3	0.01	0.482
Spot	11/1/2010	ROS	0.3	0.01	Unit 16	0.3	0.01	0.004
Spot	11/1/2010	ROS	52.7	0.01	Unit 123	51.9	0.01	0.799
Spot	11/1/2010	ROS	265.0	0.01	Unit 84	261.0	0.01	4.017
Spot	11/1/2010	ROS	104.5	0.01	Unit 85	102.9	0.01	1.584
Spot	11/1/2010	ROS	33.5	0.01	Unit 92	33.0	0.01	0.508
Spot	11/1/2010	ROS	1.1	0.01	Unit 33	1.1	0.01	0.017
Spot	11/1/2010	ROS	142.5	0.01	Unit 24	140.3	0.01	2.160
Spot	11/1/2010	ROS	40.7	0.01	Unit 25	40.1	0.01	0.617
Spot	11/1/2010	ROS	5.1	0.01	Unit 26	5.0	0.01	0.077
Spot	11/1/2010	ROS	59.6	0.01	Unit 27	58.7	0.01	0.903
Spot	11/1/2010	ROS	53.6	0.01	Unit 28	52.8	0.01	0.812
Spot	11/1/2010	ROS	24.9	0.01	Unit 29	24.5	0.01	0.377
Spot	11/1/2010	ROS	15.0	0.01	Unit 30	14.8	0.01	0.227
Spot	11/1/2010	ROS	47.0	0.01	Unit 31	46.3	0.01	0.712
Spot	11/1/2010	ROS	1.9	0.01	Unit 32	1.9	0.01	0.029
Spot	11/1/2010	ROS	2.1	0.01	Unit 34	2.1	0.01	0.032
Spot	11/1/2010	ROS	13.0	0.01	Unit 35	12.8	0.01	0.197
Spot	11/1/2010	ROS	13.9	0.01	Unit 36	13.7	0.01	0.211
Spot	11/1/2010	ROS	0.1	0.01	Unit 37	0.1	0.01	0.002
Spot	11/1/2010	ROS	4.7	0.01	Unit 38	4.6	0.01	0.071
Spot	11/1/2010	ROS	6.4	0.01	Unit 39	6.3	0.01	0.097
Spot	11/1/2010	ROS	4.6	0.01	Unit 40	4.5	0.01	0.070
Spot	11/1/2010	ROS	22.2	0.01	Unit 41	21.9	0.01	0.336
Spot	11/1/2010	ROS	4.0	0.01	Unit 118	3.9	0.01	0.061
Spot	11/1/2010	ROS	0.1	0.01	Unit 105	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.2	0.01	Unit 108	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.1	0.01	Unit 96	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.1	0.01	Unit 101	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.2	0.01	Unit 100	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.2	0.01	Unit 114	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.3	0.01	Unit 110	0.3	0.01	0.004
Spot	11/1/2010	ROS	0.7	0.01	Unit 107	0.7	0.01	0.011
Spot	11/1/2010	ROS	0.1	0.01	Unit 97	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.1	0.01	Unit 112	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.5	0.01	Unit 116	0.5	0.01	0.007
Spot	11/1/2010	ROS	0.1	0.01	Unit 95	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.3	0.01	Unit 115	0.3	0.01	0.004
Spot	11/1/2010	ROS	0.2	0.01	Unit 113	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.2	0.01	Unit 104	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.1	0.01	Unit 117	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.1	0.01	Unit 98	0.1	0.01	0.002
Spot	11/1/2010	ROS	1.0	0.01	Unit 106	1.0	0.01	0.015
Spot	11/1/2010	ROS	0.1	0.01	Unit 99	0.1	0.01	0.002
Spot	11/1/2010	ROS	0.3	0.01	Unit 109	0.3	0.01	0.004
Spot	11/1/2010	ROS	0.2	0.01	Unit 102	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.2	0.01	Unit 111	0.2	0.01	0.003
Spot	11/1/2010	ROS	0.6	0.01	Unit 103	0.6	0.01	0.009

AUCTION TYPE	AUCTION MONTH	LOCATION DESCRIPTION	OFFER CAPACITY	OFFER PRICE	PTID NAME	AWARDED CAPACITY	MARKET CLEARING PRICE	UNSOLD
Spot	11/1/2010	ROS	2.0	0.01	Unit 122	2.0	0.01	0.030
Spot	11/1/2010	ROS	1.6	0.01	Unit 121	1.6	0.01	0.024
Spot	11/1/2010	ROS	1.5	0.01	Unit 2	1.5	0.01	0.023
Spot	11/1/2010	ROS	0.3	0.01	Unit 1	0.3	0.01	0.004
Spot	11/1/2010	ROS	0.1	0.01	Unit 3	0.1	0.01	0.002
Spot	11/1/2010	ROS	39.0	0.05	Unit 93	0.0	0.01	39.000
Spot	11/1/2010	ROS	62.4	0.05	Unit 5	0.0	0.01	62.400
Spot	11/1/2010	ROS	34.6	0.05	Unit 42	0.0	0.01	34.600
Spot	11/1/2010	ROS	2.3	0.05	Unit 120	0.0	0.01	2.300
Spot	11/1/2010	ROS	100.0	0.05	Unit 43	0.0	0.01	100.000
Spot	11/1/2010	ROS	81.7	0.07	Unit 6	0.0	0.01	81.700
Spot	11/1/2010	ROS	2.1	0.1	Unit 45	0.0	0.01	2.100
Spot	11/1/2010	ROS	35.8	0.1	Unit 88	0.0	0.01	35.800
Spot	11/1/2010	ROS	38.9	0.1	Unit 90	0.0	0.01	38.900
Spot	11/1/2010	ROS	20.1	0.1	Unit 23	0.0	0.01	20.100
Spot	11/1/2010	ROS	60.5	0.1	Unit 91	0.0	0.01	60.500
Spot	11/1/2010	ROS	63.2	0.1	Unit 119	0.0	0.01	63.200
Spot	11/1/2010	ROS	10.8	0.1	Unit 58	0.0	0.01	10.800
Spot	11/1/2010	ROS	23.8	0.1	Unit 47	0.0	0.01	23.800
Spot	11/1/2010	ROS	34.5	0.1	Unit 48	0.0	0.01	34.500
Spot	11/1/2010	ROS	13.6	0.1	Unit 50	0.0	0.01	13.600
Spot	11/1/2010	ROS	20.3	0.1	Unit 49	0.0	0.01	20.300
Spot	11/1/2010	ROS	0.3	0.1	Unit 75	0.0	0.01	0.300
Spot	11/1/2010	ROS	0.9	0.1	Unit 76	0.0	0.01	0.900
Spot	11/1/2010	ROS	0.5	0.1	Unit 17	0.0	0.01	0.500
Spot	11/1/2010	ROS	100.0	0.1	Unit 44	0.0	0.01	100.000
Spot	11/1/2010	ROS	100.0	0.15	Unit 43	0.0	0.01	100.000
Spot	11/1/2010	ROS	100.0	0.2	Unit 44	0.0	0.01	100.000
Spot	11/1/2010	ROS	10.1	0.25	Unit 59	0.0	0.01	10.100
Spot	11/1/2010	ROS	107.8	0.25	Unit 43	0.0	0.01	107.800
Spot	11/1/2010	ROS	162.2	0.26	Unit 44	0.0	0.01	162.200
Spot	11/1/2010	ROS	0.2	0.3	Unit 71	0.0	0.01	0.200
Spot	11/1/2010	ROS	85.0	0.5	Unit 77	0.0	0.01	85.000
Spot	11/1/2010	ROS	10.0	0.6	Unit 79	0.0	0.01	10.000
	11/1/2010 Total		5,127.0			3,748.7		1,378.302
Spot	12/1/2010	ROS	388.7	0.5	Unit 63	164.2	0.5	224.5
Spot	12/1/2010	ROS	85.0	0.5	Unit 77	35.9	0.5	49.1
Spot	12/1/2010	ROS	50.0	0.5	Unit 80	21.1	0.5	28.9
Spot	12/1/2010	ROS	38.7	0.55	Unit 80	0.0	0.5	38.7
Spot	12/1/2010	ROS	11.3	0.55	Unit 81	0.0	0.5	11.3
Spot	12/1/2010	ROS	10.0	0.6	Unit 79	0.0	0.5	10.0
Spot	12/1/2010	ROS	50.0	0.6	Unit 81	0.0	0.5	50.0
Spot	12/1/2010	ROS	50.0	0.65	Unit 81	0.0	0.5	50.0
Spot	12/1/2010	ROS	50.0	0.7	Unit 81	0.0	0.5	50.0
Spot	12/1/2010	ROS	50.0	0.75	Unit 81	0.0	0.5	50.0
Spot	12/1/2010	ROS	69.5	0.85	Unit 81	0.0	0.5	69.5
Spot	12/1/2010	ROS	30.5	0.85	Unit 82	0.0	0.5	30.5
Spot	12/1/2010	ROS	389.0	0.93	Unit 61	0.0	0.5	389.0
Spot	12/1/2010	ROS	100.0	0.95	Unit 82	0.0	0.5	100.0
Spot	12/1/2010	ROS	100.0	1.15	Unit 82	0.0	0.5	100.0
Spot	12/1/2010	ROS	50.3	1.3	Unit 82	0.0	0.5	50.3
	12/1/2010 Total		1,523.0			221.3		1,301.7
Spot	1/1/2011	ROS	3.3	0.5	Unit 4	1.7	0.5	1.6
Spot	1/1/2011	ROS	201.8	0.5	Unit 63	104.5	0.5	97.3
Spot	1/1/2011	ROS	389.0	0.93	Unit 61	0.0	0.5	389.0
	1/1/2011 Total		594.1			106.2		487.9
Spot	2/1/2011	ROS	389.0	0.93	Unit 61	0.0	0.65	389.0
	2/1/2011 Total		389.0			0.0		389.0

AUCTION TYPE	AUCTION MONTH	LOCATION DESCRIPTION	OFFER CAPACITY	OFFER PRICE	PTID NAME	AWARDED CAPACITY	MARKET CLEARING PRICE	UNSOLD
Spot	3/1/2011	ROS	10.0	0.3	Unit 79	4.8	0.3	5.2
Spot	3/1/2011	ROS	389.0	0.3	Unit 61	187.8	0.3	201.2
Spot	3/1/2011	ROS	0.6	0.33	Unit 14	0.0	0.3	0.6
Spot	3/1/2011	ROS	0.4	0.33	Unit 12	0.0	0.3	0.4
Spot	3/1/2011	ROS	4.6	0.33	Unit 8	0.0	0.3	4.6
Spot	3/1/2011	ROS	0.1	0.33	Unit 15	0.0	0.3	0.1
Spot	3/1/2011	ROS	0.3	0.33	Unit 9	0.0	0.3	0.3
Spot	3/1/2011	ROS	0.8	0.33	Unit 10	0.0	0.3	0.8
Spot	3/1/2011	ROS	0.6	0.33	Unit 13	0.0	0.3	0.6
Spot	3/1/2011	ROS	0.7	0.33	Unit 11	0.0	0.3	0.7
Spot	3/1/2011	ROS	388.7	0.5	Unit 63	0.0	0.3	388.7
Spot	3/1/2011	ROS	110.4	0.5	Unit 77	0.0	0.3	110.4
Spot	3/1/2011	ROS	313.1	0.93	Unit 62	0.0	0.3	313.1
	3/1/2011 Total		1,219.3			192.6		1,026.7
Spot	4/1/2011	ROS	19.5	0.15	Unit 78	9.1	0.15	10.4
Spot	4/1/2011	ROS	388.8	0.15	Unit 43	180.6	0.15	208.2
Spot	4/1/2011	ROS	362.2	0.15	Unit 44	168.2	0.15	194.0
Spot	4/1/2011	ROS	10.1	0.25	Unit 59	0.0	0.15	10.1
Spot	4/1/2011	ROS	164.0	0.3	Unit 61	0.0	0.15	164.0
Spot	4/1/2011	ROS	10.0	0.3	Unit 79	0.0	0.15	10.0
Spot	4/1/2011	ROS	0.2	0.3	Unit 71	0.0	0.15	0.2
Spot	4/1/2011	ROS	0.4	0.3	Unit 70	0.0	0.15	0.4
Spot	4/1/2011	ROS	4.9	0.33	Unit 8	0.0	0.15	4.9
Spot	4/1/2011	ROS	0.3	0.33	Unit 9	0.0	0.15	0.3
Spot	4/1/2011	ROS	0.8	0.33	Unit 10	0.0	0.15	0.8
Spot	4/1/2011	ROS	0.9	0.33	Unit 11	0.0	0.15	0.9
Spot	4/1/2011	ROS	0.4	0.33	Unit 12	0.0	0.15	0.4
Spot	4/1/2011	ROS	0.6	0.33	Unit 13	0.0	0.15	0.6
Spot	4/1/2011	ROS	0.6	0.33	Unit 14	0.0	0.15	0.6
Spot	4/1/2011	ROS	0.1	0.33	Unit 15	0.0	0.15	0.1
Spot	4/1/2011	ROS	388.7	0.5	Unit 63	0.0	0.15	388.7
Spot	4/1/2011	ROS	110.4	0.5	Unit 77	0.0	0.15	110.4
Spot	4/1/2011	ROS	313.1	0.93	Unit 62	0.0	0.15	313.1
	4/1/2011 Total		1,776.0			357.9		1,418.1
Spot	5/1/2011	ROS	168.2	0.65	Unit 74	75.1	0.37	93.1
Spot	5/1/2011	ROS	48.3	0.93	Unit 62	0.0	0.37	48.3
	5/1/2011 Total		216.5			75.1		141.4
Spot	6/1/2011	ROS	262.3	0.93	Unit 62	0.0	0.55	262.3
	6/1/2011 Total		262.3			0.0		262.3
Spot	7/1/2011	ROS	5.1	0.15	Unit 73	2.1	0.15	3.0
Spot	7/1/2011	ROS	5.1	0.15	Unit 74	2.1	0.15	3.0
Spot	7/1/2011	ROS	50.0	0.15	Unit 4	20.6	0.15	29.4
Spot	7/1/2011	ROS	23.1	0.15	Unit 22	9.5	0.15	13.6
Spot	7/1/2011	ROS	100.0	0.15	Unit 43	41.2	0.15	58.8
Spot	7/1/2011	ROS	50.0	0.18	Unit 43	0.0	0.15	50.0
Spot	7/1/2011	ROS	50.0	0.2	Unit 4	0.0	0.15	50.0
Spot	7/1/2011	ROS	42.3	0.2	Unit 43	0.0	0.15	42.3
Spot	7/1/2011	ROS	50.0	0.25	Unit 4	0.0	0.15	50.0
Spot	7/1/2011	ROS	7.6	0.25	Unit 59	0.0	0.15	7.6
Spot	7/1/2011	ROS	82.2	0.3	Unit 4	0.0	0.15	82.2
Spot	7/1/2011	ROS	0.2	0.4	Unit 71	0.0	0.15	0.2
Spot	7/1/2011	ROS	0.3	0.4	Unit 70	0.0	0.15	0.3
Spot	7/1/2011	ROS	13.0	0.5	Unit 77	0.0	0.15	13.0
Spot	7/1/2011	ROS	236.2	0.5	Unit 63	0.0	0.15	236.2
Spot	7/1/2011	ROS	19.5	0.6	Unit 79	0.0	0.15	19.5
Spot	7/1/2011	ROS	262.3	0.93	Unit 62	0.0	0.15	262.3

AUCTION TYPE	AUCTION MONTH	LOCATION DESCRIPTION	OFFER CAPACITY	OFFER PRICE	PTID NAME	AWARDED CAPACITY	MARKET CLEARING PRICE	UNSOLD
	7/1/2011 Total		996.9			75.6		921.3
Spot	8/1/2011	ROS	35.2	0.05	Unit 42	19.9	0.05	15.3
Spot	8/1/2011	ROS	3.0	0.05	Unit 75	1.7	0.05	1.3
Spot	8/1/2011	ROS	0.9	0.05	Unit 76	0.5	0.05	0.4
Spot	8/1/2011	ROS	34.5	0.05	Unit 6	19.5	0.05	15.0
Spot	8/1/2011	ROS	14.3	0.05	Unit 49	8.1	0.05	6.2
Spot	8/1/2011	ROS	14.0	0.05	Unit 50	7.9	0.05	6.1
Spot	8/1/2011	ROS	1.4	0.1	Unit 45	0.0	0.05	1.4
Spot	8/1/2011	ROS	3.2	0.1	Unit 72	0.0	0.05	3.2
Spot	8/1/2011	ROS	15.6	0.1	Unit 87	0.0	0.05	15.6
Spot	8/1/2011	ROS	4.9	0.1	Unit 86	0.0	0.05	4.9
Spot	8/1/2011	ROS	4.7	0.1	Unit 66	0.0	0.05	4.7
Spot	8/1/2011	ROS	5.1	0.1	Unit 67	0.0	0.05	5.1
Spot	8/1/2011	ROS	3.8	0.1	Unit 52	0.0	0.05	3.8
Spot	8/1/2011	ROS	4.8	0.1	Unit 51	0.0	0.05	4.8
Spot	8/1/2011	ROS	4.5	0.1	Unit 53	0.0	0.05	4.5
Spot	8/1/2011	ROS	4.3	0.1	Unit 54	0.0	0.05	4.3
Spot	8/1/2011	ROS	48.3	0.1	Unit 18	0.0	0.05	48.3
Spot	8/1/2011	ROS	50.8	0.13	Unit 19	0.0	0.05	50.8
Spot	8/1/2011	ROS	6.4	0.15	Unit 20	0.0	0.05	6.4
Spot	8/1/2011	ROS	0.3	0.15	Unit 70	0.0	0.05	0.3
Spot	8/1/2011	ROS	0.2	0.15	Unit 71	0.0	0.05	0.2
Spot	8/1/2011	ROS	14.5	0.17	Unit 21	0.0	0.05	14.5
Spot	8/1/2011	ROS	100.0	0.18	Unit 44	0.0	0.05	100.0
Spot	8/1/2011	ROS	100.0	0.2	Unit 44	0.0	0.05	100.0
Spot	8/1/2011	ROS	7.6	0.25	Unit 59	0.0	0.05	7.6
Spot	8/1/2011	ROS	50.0	0.25	Unit 44	0.0	0.05	50.0
Spot	8/1/2011	ROS	100.0	0.28	Unit 43	0.0	0.05	100.0
Spot	8/1/2011	ROS	19.5	0.3	Unit 79	0.0	0.05	19.5
Spot	8/1/2011	ROS	39.7	0.3	Unit 43	0.0	0.05	39.7
Spot	8/1/2011	ROS	50.0	0.35	Unit 44	0.0	0.05	50.0
Spot	8/1/2011	ROS	25.0	0.4	Unit 44	0.0	0.05	25.0
Spot	8/1/2011	ROS	24.9	0.5	Unit 44	0.0	0.05	24.9
Spot	8/1/2011	ROS	110.3	0.5	Unit 77	0.0	0.05	110.3
	8/1/2011 Total		901.7			57.6		844.1
Spot	9/1/2011	ROS	0.3	0.2	Unit 70	0.0	0.18	0.3
Spot	9/1/2011	ROS	0.2	0.2	Unit 71	0.0	0.18	0.2
Spot	9/1/2011	ROS	13.3	0.2	Unit 23	0.0	0.18	13.3
Spot	9/1/2011	ROS	69.9	0.2	Unit 44	0.0	0.18	69.9
Spot	9/1/2011	ROS	7.6	0.25	Unit 59	0.0	0.18	7.6
Spot	9/1/2011	ROS	100.2	0.5	Unit 61	0.0	0.18	100.2
Spot	9/1/2011	ROS	307.8	0.93	Unit 63	0.0	0.18	307.8
	9/1/2011 Total		499.3			0.0		499.3
Spot	10/1/2011	ROS	53.0	0.13	Unit 43	24.0	0.13	29.0
Spot	10/1/2011	ROS	25.8	0.15	Unit 19	0.0	0.13	25.8
Spot	10/1/2011	ROS	36.0	0.16	Unit 44	0.0	0.13	36.0
Spot	10/1/2011	ROS	298.5	0.2	Unit 63	0.0	0.13	298.5
Spot	10/1/2011	ROS	13.3	0.2	Unit 23	0.0	0.13	13.3
Spot	10/1/2011	ROS	0.2	0.2	Unit 71	0.0	0.13	0.2
Spot	10/1/2011	ROS	0.3	0.2	Unit 70	0.0	0.13	0.3
Spot	10/1/2011	ROS	7.6	0.25	Unit 59	0.0	0.13	7.6
Spot	10/1/2011	ROS	85.0	0.5	Unit 77	0.0	0.13	85.0
	10/1/2011 Total		519.7			24.0		495.7

Attachment I-B. Existing Generating Facilities

2011 Capability Year

EXISTING GENERATING FACILITIES AS OF OCTOBER 2010

REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Location Cnty	Location St	In-Service Date YYYY-MM-DD	Name Plate Rating (MW)	SUM CRIS Cap (A) (MW)	2011 Capability (Megawatts) Summer	2011 Capability (Megawatts) Winter	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Fuel Type 2	Fuel Type 3	2010 Net Energy (GWh)	CF
1064	Athens Generating Company, LP	Athens 1	F	23668	Athens	039	36	2004-05-01	441.0	316.6	310.9	395.5		CC			NG			2,243.3	72.5%
1065	Athens Generating Company, LP	Athens 2	F	23670	Athens	039	36	2004-05-01	441.0	315.6	309.3	390.9		CC			NG			1,827.7	59.6%
1066	Athens Generating Company, LP	Athens 3	F	23677	Athens	039	36	2004-05-01	441.0	312.8	311.1	396.1		CC			NG			2,037.1	65.8%
1659	PSEG Energy Resource & Trade, LLC	Bethlehem GS1	F	323560	Bethlehem	001	36	2005-07-01	297.7	252.3	246.6	282.4		CC			NG	FO2		1,409.1	60.8%
1660	PSEG Energy Resource & Trade, LLC	Bethlehem GS2	F	323561	Bethlehem	001	36	2005-07-01	297.7	252.3	246.6	282.4		CC			NG	FO2		1,409.1	60.8%
1661	PSEG Energy Resource & Trade, LLC	Bethlehem GS3	F	323562	Bethlehem	001	36	2005-07-01	297.7	252.3	246.6	282.4		CC			NG	FO2		1,409.1	60.8%
	Class A Averages							**2004-11-30**	**369**	**284**	**279**	**338**								**1,723**	**63.8%**
1647	NRG Power Marketing LLC	Oswego 5	C	23606	Oswego	075	36	1976-02-01	901.8	850.3	822.0	844.5	N	ST	W	A	FO6			31.9	0.4%
1648	NRG Power Marketing LLC	Oswego 6	C	23613	Oswego	075	36	1980-07-01	901.8	835.2	826.0	843.0	N	ST	W	A	FO6			32.8	0.4%
1335	International Paper Company	Ticonderoga	F	23804	Ticonderoga	031	36	1970-01-01	42.1	7.6	9.8	10.2	Y	ST			FO6			0.1	0.1%
1119	Dynegy Power Marketing, Inc.	Danskammer 1	G	23586	Newburgh	071	36	1951-12-01	72.0	67.0	66.5	65.7	N	ST	T	A	FO6	NG	FO2	3.0	0.5%
1120	Dynegy Power Marketing, Inc.	Danskammer 2	G	23589	Newburgh	071	36	1954-09-01	73.5	62.7	61.7	63.7	N	ST	T	A	FO6	NG	FO2	4.3	0.8%
1126	Dynegy Power Marketing, Inc.	Roseton 1	G	23587	Newburgh	071	36	1974-12-01	621.0	614.8	609.7	626.0	N	ST	T	A	FO6	NG	FO2	204.6	3.8%
1127	Dynegy Power Marketing, Inc.	Roseton 2	G	23588	Newburgh	071	36	1974-09-01	621.0	605.7	602.5	605.0	N	ST	T	A	FO6	NG	FO2	159.0	3.0%
	Class F Averages							**1968-12-18**	**462**	**435**	**428**	**437**								**62**	**1.6%**
1421	Mirant Energy Trading, LLC	Bowline 1	G	23526	West Haverstraw	087	36	1972-09-01	621.0	577.7	578.3	558.0	N	ST	T	A	NG	FO6		180.4	3.6%
1422	Mirant Energy Trading, LLC	Bowline 2	G	23595	West Haverstraw	087	36	1974-05-01	621.0	557.4	529.1	561.8	N	ST	W	A	NG	FO6		112.6	2.4%
	Class G Averages							**1973-07-01**	**621**	**568**	**554**	**560**								**146**	**3.0%**
1006	AES Eastern Energy, LP	Somerset	A	23543	Somerset	063	36	1984-08-01	655.1	686.5	678.0	684.1	N	ST	W	A	BIT			4,596.1	77.0%
1639	NRG Power Marketing LLC	Dunkirk 1	A	23563	Dunkirk	013	36	1950-11-01	100.0	96.2	75.0	74.9	N	ST	T	A	BIT			358.7	54.6%
1640	NRG Power Marketing LLC	Dunkirk 2	A	23564	Dunkirk	013	36	1950-12-01	100.0	97.2	75.0	74.9	N	ST	T	A	BIT			365.7	55.7%
1641	NRG Power Marketing LLC	Dunkirk 3	A	23565	Dunkirk	013	36	1959-09-01	217.6	201.4	185.0	185.0	N	ST	T	A	BIT			1,053.1	65.0%
1642	NRG Power Marketing LLC	Dunkirk 4	A	23566	Dunkirk	013	36	1960-08-01	217.6	199.1	185.0	184.9	N	ST	T	A	BIT			889.8	54.9%
1644	NRG Power Marketing LLC	Huntley 67	A	23561	Tonawanda	029	36	1957-12-01	218.0	196.5	189.5	187.5	N	ST	T	A	BIT			973.9	59.0%
1645	NRG Power Marketing LLC	Huntley 68	A	23562	Tonawanda	029	36	1958-12-01	218.0	198.0	189.5	187.5	N	ST	T	A	BIT			1,073.6	65.0%
1001	AES Eastern Energy, LP	Cayuga 1	C	23584	Lansing	109	36	1955-09-01	155.3	154.1	154.0	154.5	N	ST	T	A	BIT			837.9	62.0%
1002	AES Eastern Energy, LP	Cayuga 2	C	23585	Lansing	109	36	1958-10-01	167.2	154.7	158.7	155.1	N	ST	T	A	BIT			943.7	69.5%
1726	Trigen-Syracuse Energy Corp.	Syracuse Energy ST2	C	323598	Syracuse	067	36	1991-08-01	90.6	58.9	62.8	61.9	N	ST			BIT	FO2		24.5	4.6%
1121	Dynegy Power Marketing, Inc.	Danskammer 3	G	23590	Newburgh	071	36	1959-10-01	147.1	137.2	138.5	137.0	N	ST	T	A	BIT	NG	FO2	652.9	54.4%
1122	Dynegy Power Marketing, Inc.	Danskammer 4	G	23591	Newburgh	071	36	1967-09-01	239.4	236.2	236.7	236.5	N	ST	T	A	BIT	NG	FO2	1,073.7	51.9%
	Class H Averages							**1963-01-25**	**210**	**201**	**194**	**194**								**1,070**	**63.0%**

Attachment I-C. Class Average Avoidable Costs

Classification of ROS Generating Units

	Class A	Class F	Class G	Class H
Technology	Combined Cycle	Steam Electric	Steam Electric	Steam Electric
Primary Fuel	Natural Gas	#6 Fuel Oil	Natural Gas	Coal
Total Units in Group	6	7	2	12
Dual-Fueled Units in Group	3	4	2	2
Average Capacity Factor	63.8%	1.6%	3.0%	63.0%
Average In-Service Date	30-Nov-2004	18-Dec-1968	1-Jul-1973	25-Jan-1963
Average Nameplate Rating (MW)	369.4	461.9	621.0	210.5
Net Plant Capacity - Summer (MW)	278.5	428.0	553.4	193.2
Net Plant Capacity - Winter (MW)	338.3	436.9	559.9	193.7
Net Plant Capacity - Summer/Winter Average (MW)	308.4	432.4	556.7	193.4

Fixed O&M and Fixed Cost Assumptions

	Class A	Class F	Class G	Class H
Average Labor Rate, incl. Benefits (2011$/hour)	58.33	58.33	58.33	58.33
Number of Operating and Maintenance Staff	27.00	25.00	21.00	41.00
Labor - Routine O&M (2011$/year)	3,275,756	3,033,108	2,547,810	4,974,297
Routine Materials and Contract Services (2011$/year)	3,037,500	4,050,000	3,825,000	2,405,250
Administrative and General (2011$/year)	585,000	540,000	483,750	802,125
Other Fixed Cost Assumptions				
Insurance Rate	0.30%	0.30%	0.30%	0.30%
Market value of plant (2011$/kW)	1,238	788	788	900
Insurance (2011$/year)	1,371,212	1,091,205	1,467,113	568,328
Total Fixed O&M and Fixed Costs	8,269,468	8,714,313	8,323,673	8,749,999
$/kW-year (2011$)	$26.81	$20.15	$14.95	$45.24

Avoidable Cost Percentages for a Mothballed Unit

	Class A	Class F	Class G	Class H
Labor - Routine O&M	82.18%	75.42%	75.42%	88.71%
Materials and Contract Services - Routine	90.00%	90.00%	90.00%	90.00%
Administrative and General	84.46%	80.06%	80.06%	90.16%
Insurance	60.00%	60.00%	60.00%	60.00%
PJM Category for Percent Avoidable	Combined Cycle 2 on 1, Frame F	Oil and Gas Steam	Oil and Gas Steam	Subcritical Coal

Annual Avoidable Costs for a Mothballed Unit (2011$/year)

	Class A	Class F	Class G	Class H
Labor - Routine O&M	2,692,016	2,287,611	1,921,593	4,412,774
Materials and Contract Services - Routine	2,733,750	3,645,000	3,442,500	2,164,725
Administrative and General	494,091	432,311	387,279	723,232
Insurance	822,727	654,723	880,268	340,997
Total Annual Avoidable Costs	6,742,585	7,019,645	6,631,639	7,641,727
Total Annual Avoidable Costs (2011$/kW-year)	$21.86	$16.23	$11.91	$39.51

Attachment I-D. Class Average Going Forward Costs

	November 2010 - October 2011 (2011$)			
	Class A ROS	**Class F ROS**	**Class G ROS**	**Class H ROS**
Technology	Combined Cycle	Steam Electric	Steam Electric	Steam Electric
Primary Fuel	Natural Gas	#6 Fuel Oil	Natural Gas	Coal
Avoidable Costs - Mothball ($/kW-yr)	**21.86**	**16.23**	**11.91**	**39.51**
Avoidable Costs - Mothball ($/kW-yr) - UCAP basis[1]	**23.95**	**17.78**	**13.05**	**43.28**
Net Revenues ($/kW-yr) - Actual	**53.19**	**6.19**	**8.13**	**34.30**
Going forward costs minus full net revenues ($/kW-yr)[2]	**0.69**	**11.59**	**5.39**	**21.64**
Summer ($/kW-month)	0.07	1.28	0.60	2.40
Winter ($/kW-month)	0.04	0.64	0.30	1.20
Going forward costs minus half net revenues ($/kW-yr)	**2.37**	**14.68**	**8.98**	**26.12**
Summer ($/kW-month)	0.25	1.62	1.00	2.90
Winter ($/kW-month)	0.12	0.81	0.50	1.45
Going forward costs minus zero net revenues ($/kW-yr)	**23.95**	**17.78**	**13.05**	**43.28**
Summer ($/kW-month)	2.48	1.96	1.45	4.80
Winter ($/kW-month)	1.24	0.98	0.73	2.41

Note 1. All remaining values in this table are expressed in UCAP terms

Note 2. The three GFC calculations reflect the average costs and revenues of the underlying generators within the class. Because individual generator GFCs are assigned a minimum value of zero, averaging across a group produces a different result from showing the results individually.

Confidential Attachment I-E. Unsold Capacity Offers (Unmasked)

(Not included with the public filing.)

Confidential Attachment I-F. Market Participant Explanations

(Not included with the public filing.)

II. Report on New Generation Projects

In its October 23, 2006 order, the Commission ordered the NYISO to submit "a list of investments in new generation projects in New York (including a description and current status of each such project), regardless of the stage of project development at the time of the filing."[23] The NYISO keeps a list of Interconnection Requests and Transmission Projects for the New York Control Area ("NYCA") that includes information about all generation projects in the State that have requested interconnection.

The NYISO interconnection process is described in two attachments of the NYISO OATT: Attachment X entitled, "Standard Large Facility Interconnection Procedures," and Attachment Z entitled, "Small Generator Interconnection Procedures." Attachment X applies to Generating Facilities that exceed 20 MW in size and to Merchant Transmission Facilities, collectively referred to as "Large Facilities." Attachment Z applies to Generating Facilities no larger than 20 MW.

Under Attachment X, Developers of Large Facilities must submit an Interconnection Request to the NYISO. The NYISO assigns a Queue Position to all valid Interconnection Requests. Under Attachment X, proposed generation and transmission projects undergo up to three studies: the Feasibility Study, the System Reliability Impact Study, and the Facilities Study. The Facilities Study is performed on a Class Year basis for a group of eligible projects pursuant to the requirements of Attachment S of the NYISO OATT. Under Attachment Z, proposed small generators undergo a process that is similar, but with different paths and options that are dependent on the specific circumstances of the project.

Proposed generation and transmission projects currently in the NYISO Interconnection Process are listed on the list of Interconnection Requests and Transmission Projects for the NYCA ("NYISO Interconnection Queue"). The generation projects on that list are shown in Attachment A, which is dated November 30, 2011. The NYISO updates the NYISO Interconnection Queue on at least a monthly basis and posts the most recent list on the NYISO's public web site at

http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

[23] *New York Indep. Sys. Operator, Inc.*, 117 FERC ¶ 61,086, at P 14 (2006).

Explanations for the various columns of the list are provided in the notations on the last page of the list. The status of each project on the NYISO Interconnection Queue is shown in the column labeled "S." An explanation of this column is provided in Attachment B. Also, note that the proposed in-service date for each project is the date provided to the NYISO by the respective Owner/Developer, is updated only on a periodic basis, and is subject to change.

Attachment II-A. Interconnection Queue

INTERCONNECTION REQUESTS AND TRANSMISSION PROJECTS / NEW YORK CONTROL AREA

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	WP (MW)	Type/ Fuel	Location County/State	Z	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service Original	Proposed In-Service Current
20	KeySpan Energy, Inc.	Spagnoli Road CC Unit	5/17/99	250		CC-NG	Suffolk, NY	K	Spagnoli Road 138kV	LIPA	8	3/31/10	SRIS	2006	2013/06
106	TransGas Energy, LLC	TransGas Energy	10/5/01	1100		CC-NG	Kings, NY	J	E13St, Rainey, or Farragut-345kV	CONED	8	2/26/08	SRIS	2007	2012/Q3
115	Central Hudson Gas & Electric	East Fishkill Transformer	4/24/02	N/A		AC	Dutchess, NY	G	East Fishkill 345kV/115kV	CONED/CHG&E	4	8/19/08	None	2007/06	2012
119	ECOGEN, LLC	Prattsburgh Wind Farm	5/20/02	78.2		W	Yates, NY	C	Eelpot Rd-Flat St. 115kV	NYSEG	10	9/30/10	SRIS, FS	2005/02	2012/05
127A	Airtricity Munnsville Wind Farm, LLC	Munnsville	10/9/02	6		W	Madison, NY	E	46kV line	NYSEG	11	4/30/11	SRIS, FS	2005/12	2013/12
147	NY Windpower, LLC	West Hill Windfarm	4/16/04	31.5		W	Madison, NY	C	Oneida-Fenner 115kV	NM-NG	10	9/30/10	SRIS, FS	2006/Q4	2012/09
154	KeySpan Energy for LIPA	Holtsville-Brentwood-Pilgrim	8/19/04	N/A		AC	Suffolk, NY	K	Holtsville & Pilgrim 138kV	LIPA	5	3/31/11	None	2007/06	2017
155	Invenergy NY, LLC	Canisteo Hills Windfarm	9/17/04	148.5		W	Steuben, NY	C	Bennett-Bath 115kV	NYSEG	6	2/28/11	FES, SRIS	2006/08	2013/12
157	BP Alternative Energy NA, Inc.	Orion Energy NY I	10/12/04	100	100	W	Herkimer, NY	E	Watkins Rd.-Inghams 115kV	NM-NG	6	6/30/10	FES, SRIS	2006/07	2013/12
161	Marble River, LLC	Marble River Wind Farm	12/7/04	84	84	W	Clinton, NY	D	Willis-Plattsburgh WP-1 230kV	NYPA	11	7/31/11	SRIS, FS	2006	2012/10
166	St. Lawrence Windpower, LLC	St. Lawrence Wind Farm	2/8/05	79.5	79.5	W	Jefferson, NY	E	Lyme Substation 115kV	NM-NG	10	6/30/11	SRIS, FS	2006/12	2013/09
168	Dairy Hills Wind Farm, LLC	Dairy Hills Wind Farm	2/8/05	120	120	W	Wyoming, NY	C	Stolle Rd.-Meyer 230kV	NYSEG	8	3/31/10	SRIS	2006/11	2012/02
169	Alabama Ledge Wind Farm, LLC	Alabama Ledge Wind Farm	2/8/05	79.8	79.8	W	Genesee, NY	B	Oakfield-Lockport 115kV	NM-NG	9	10/31/11	FES, SRIS	2007/12-2009/12	N/A
171	Marble River, LLC	Marble River II Wind Farm	2/8/05	132.3	132.3	W	Clinton, NY	D	Willis-Plattsburgh WP-2 230kV	NYPA	11	7/31/11	SRIS, FS	2007/12	2012/10
180A	Green Power	Cody Rd	3/17/05	10	10	W	Madison, NY	C	Fenner - Cortland 115kV	NM-NG	11	3/31/11	None	None	2011/Q4
182	Howard Wind, LLC	Howard Wind	3/21/05	57.4	57.4	W	Steuben, NY	C	Bennett-Bath 115kV	NYSEG	13	11/30/11	FES, SRIS, FS	2007/10	2011/12
189	PPM Energy, Inc.	Clayton Wind	4/8/05	126	126	W	Jefferson, NY	E	Coffeen St-Thousand Island 115k\	NM-NG	8	2/28/11	FES, SRIS	2006/12	2013/10
197	PPM Roaring Brook, LLC / PPM	Roaring Brook Wind	7/1/05	78	78	W	Lewis, NY	E	Boonville-Lowville 115kV	NM-NG	11	3/31/11	FES, SRIS, FS	2009/12	2012/12
198	New Grange Wind Farm, LLC	Arkwright Summit Wind Farm	7/21/05	79.8	79.8	W	Chautauqua, NY	A	Dunkirk-Falconer 115kV	NM-NG	9	10/31/11	FES, SRIS	2008/12	N/A
201	NRG Energy	Berrians GT	8/17/05	200	200	CC-NG	Queens, NY	J	Astoria West Substation 138kV	CONED	9	6/30/11	FES, SRIS	2008/02	2014/06
204A	Duer's Patent Project, LLC	Beekmantown Windfarm	10/31/05	19.5	19.5	W	Clinton, NY	D	Kents Falls - Sciota 115kV	NYSEG	10	4/30/11	None	2008/06	2013/06
205	National Grid	Luther Forest	11/2/05	40	40	L	Saratoga, NY	F	Round Lake 115kV	NM-NG	6	5/31/11	SIS	2007/08	2012/Q2
206	Hudson Transmission Partners	Hudson Transmission	12/14/05	660	660	DC/AC	NY, NY - Bergen, NJ	J	West 49th Street 345kV	CONED	12	11/30/11	FES, SRIS, FS	2009/Q2	2013/05
207	Cape Vincent Wind Power, LLC	Cape Vincent	1/12/06	210	210	W	Jefferson, NY	E	Rockledge Substation 115kV	NM-NG	10	6/30/11	FES, SRIS, FS	2009/Q4	2013/09
213	Noble Environmental Power, LLC	Ellenburg II Windfield	4/3/06	21	21	W	Clinton, NY	D	Willis-Plattsburgh WP-2 230kV	NYPA	10	10/31/11	SRIS, FS	2007/10	N/A
216	Nine Mile Point Nuclear, LLC	Nine Mile Point Uprate	5/5/06	168	168	NU	Oswego, NY	C	Scriba Station 345kV	NM-NG	11	9/30/11	SRIS, FS	2010/Q3	2012/06-2014/06
222	Ball Hill Windpark, LLC	Ball Hill Windpark	7/21/06	90	90	W	Chautauqua, NY	A	Dunkirk-Gardenville 230kV	NM-NG	10	11/30/11	FES, SRIS	2008/10	2011/12
224	NRG Energy, Inc.	Berrians GT II	8/23/06	50	90	CC-NG	Queens , NY	J	Astoria West Substation 138kV	CONED	9	6/30/11	FES, SRIS	2010/06	2014/06
227A	Laidlaw Energy Group Inc.	Laidlaw Energy & Env.	10/30/06	7	7	Wo	Cattaraugus, NY	A	13.2kV	NM-NG	7	10/28/09	None		N/A
231	Seneca Energy II, LLC	Seneca	11/2/06	6.4	6.4	M	Seneca, NY	C	Goulds Substation 34.5kV	NYSEG	10	4/30/11	SRIS, FS	2009/07	2011/12
232	Bayonne Energy Center, LLC	Bayonne Energy Center	11/27/06	500	500	CT-D	Bayonne, NJ	J	Gowanus Substation 345kV	ConEd	12	11/30/11	FES, SRIS	2008/11	2012/05
234	Steel Winds, LLC	Steel Winds II	12/8/06	15	15	W	Erie, NY	A	Substation 11A 115kV	NM-NG	11	10/31/11	SRIS, FS	2007/12	N/A
237	Allegany Wind, LLC	Allegany Wind	1/9/07	72.5	72.5	W	Cattaraugus, NY	A	Homer Hill – Dugan Rd. 115kV	NM-NG	10	11/30/11	FES, SRIS	2009/10	N/A
239	Western Door Wind, LLC	Western Door Wind	1/30/07	100	100	W	Yates, NY	C	Greenidge – Haley Rd. 115kV	NYSEG	6	6/30/11	FES, SRIS	2010/10	2012/10
239A	Innovative Energy System, Inc.	Modern Innovative Plant	1/31/07	6.4	6.4	M	Niagara, NY	A	Youngstown – Sanborn 34.5kV	NM-NG	8	5/31/11	None	2007/12	2012/07
241	Noble Chateaugay Windpark II, LLC	Chateaugay II Windpark	3/15/07	19.5	19.5	W	Franklin, NY	D	Chateaugay Substation 34.5kV	NYSEG	6	10/31/11	None	2008/07	N/A
245	Innovative Energy System, Inc.	Fulton County Landfill	4/17/07	3.2	3.2	M	Montgomary, NY	F	Ephratah – Amsterdam 69kV	NM-NG	14	11/30/11	None	2008/Q3	I/S
246	PPM Energy, Inc	Dutch Gap Wind	6/1/07	250	250	W	Jefferson, NY	E	Indian River - Black Rive 115kV	NM-NG	6	5/31/11	FES, SRIS	2010/12	2013/12
247	RG&E	Russell Station	6/11/07	300	325	CC-NG	Monroe, NY	B	Russell Station 115kV	RG&E	6	8/31/10	SRIS	2013/07	2013/07
250	Seneca Energy II, LLC	Ontario	7/2/07	5.6	5.6	M	Ontario, NY	C	Haley Rd. - Hall 34.5kV	NYSEG	11	11/30/11	None	2009/10	N/A
251	CPV Valley, LLC	CPV Valley Energy Center	7/5/07	656	753	CC-NG	Orange, NY	G	Coopers – Rock Tavern 345kV	NYPA	8	11/30/11	FES/SRIS	2012/05	2012/10
253	Marble River, LLC	Marble River SPS	8/13/07	TBD	TBD	AC	Clinton, NY	D	Moses-Willis-Plattsburgh 230kV	NYPA	5	7/31/11	None	2007/12	2012/10
254	Ripley-Westfield Wind LLC	Ripley-Westfield Wind	8/14/07	124.2	124.2	W	Chautauqua, NY	A	Ripley - Dunkirk 230kV	NM-NG	8	10/31/11	FES, SRIS	2007/12	N/A
260	Stephentown Regulation Services, LL	Stephentown	9/25/07	20	20	F	Rensselaer, NY	F	Stephentown 115kV	NYSEG	14	11/30/11	None	2008/10	I/S

INTERCONNECTION REQUESTS AND TRANSMISSION PROJECTS / NEW YORK CONTROL AREA

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	WP (MW)	Type/ Fuel	Location County/State	Z	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service Original	Proposed In-Service Current
261	Astoria Generating Company	South Pier Improvement	10/2/07	105	108	CT-NG	Kings, NY	J	Gowanus 138kV	ConEd	8	10/31/11	FES, SRIS	2010/06	2015/01
263	Stony Creek Wind Farm, LLC	Stony Creek Wind Farm	10/12/07	88.5	88.5	W	Wyoming, NY	C	Stolle Rd - Meyer 230kV	NYSEG	10	11/30/11	FES, SRIS	2010/01	2012/12
264	RG&E	Seth Green	10/23/07	2.8	2.8	H	Monroe, NY	B	11kV	RG&E	7	6/30/10	None	2008/04	N/A
266	NRG Energy, Inc.	Berrians GT III	11/28/07	744	789	CC-NG	Queens, NY	J	Astoria 345kV	NYPA	8	9/30/11	FES, SRIS	2010/06	2013/06
267	Winergy Power, LLC	Winergy NYC Wind Farm	11/30/07	601	601	W	New York, NY	J	Gowanus Substation 345kV	ConEd	5	8/31/10	FES	2015/01	2017/01
270	Wind Development Contract Co LLC	Hounsfield Wind	12/13/07	268.8	268.8	W	Jefferson, NY	E	Fitzpatrick - Edic 345kV	NYPA	6	12/31/10	FES/SRIS	2010/09	N/A
271	State Line Wind Power LLC	State Line Wind	12/20/07	124.8	124.8	W	Chautauqua, NY	A	South Ripley - Dunkirk 230kV	NM-NG	6	10/31/11	FES, SRIS	2010/12	N/A
276	Air Energie TCI, Inc.	Crown City Wind Farm	1/30/08	90	90	W	Cortland, NY	C	Cortland - Fenner 115kV	NM-NG	6	5/31/11	FES, SRIS	2011/12	2014/12
284	Broome Energy Resources, LLC	Nanticoke Landfill	3/6/08	1.6	1.6	M	Broome, NY	C	Nanticoke Landfill Plant 34.5kV	NYSEG	10	6/30/10	None	2008/07	N/A
285	Machias Wind Farm, LLC	Machias I	3/27/08	79.2	79.2	W	Cattaraugus, NY	A	Gardenville - Homer Hill 115kV	NM-NG	5	6/30/10	FES	2010/12	2012/12
289	New York State Electric & Gas	Corning Valley Trans.	4/1/08	N/A	N/A	AC	Steuben, NY	C	Avoca and Hillside 230kV	NYSEG	14	9/30/11	SIS	2010/12	I/S
290A	Green Island Power Authority	Green Island Power	4/7/08	20	20	L	Albany, NY	F	Maplewood - Johnson Rd 115kV	NM-NG	6	11/30/11	SIS	2009/12	2012/Q4
291	Long Island Cable, LLC	LI Cable - Phase 1	4/14/08	440	440	W	Suffolk, NY	K	Ruland Road 138kV	LIPA	5	8/31/10	FES	2013/01	2016/01
292	Long Island Cable, LLC	LI Cable - Phase 2a	4/14/08	220	220	W	Suffolk, NY	K	Ruland Road 138kV	LIPA	5	8/31/10	FES	2013/06	2016/01
294	Orange & Rockland	Ramapo-Sugarloaf	4/29/08	N/A	N/A	AC	Orange/Rockland, NY	G	Ramapo - Sugarloaf 138kV	O&R	6	8/31/10	SIS	2009/06	2011/12
295	CCH Holdings Group, LLC	Cross Hudson II	5/6/08	800	800	AC	New York, NY-NJ	J	West 49th St. Substation 345kV	ConEd	5	12/31/10	FES	2011/06	2013/06
305	Transmission Developers Inc.	Transmission Developers NYC	7/18/08	1000	1000	DC	Quebec - NY, NY	J	Astoria Substation 345kV	ConEd/NYPA	6	5/31/11	FES, SRIS	2014/Q1	2016/Q2
307	New York Wire, LLC	New York Wire-Phase 1	7/29/08	550	550	DC	NJ - Kings, NY	J	Gowanus Substation 345kV	ConEd	5	11/3/10	FES	2013/07	2014/10
308	Astoria Energy II, LLC	Astoria Energy II	8/20/08	576	617.2	CS-NG	Queens, NY	J	Astoria 345kV	NYPA	14	11/30/11	SRIS	2011/05	I/S
310	Cricket Valley Energy Center, LLC	Cricket Valley Energy Center	9/22/08	1002	1115	CC-NG	Dutchess, NY	G	Pleasant Valley - Long Mt. 345kV	ConEd	9	9/30/11	FES, SRIS	2014/12	2014/12
311	New York State Electric & Gas	Concord Casino	9/24/08	48.0	48.0	L	Sullivan, NY	E	Coopers Corner - Rock Hill	NYSEG	5	10/28/09	None	2009/09	N/A
315	CRC Renewables, LLC	Onondaga Renewables	10/23/08	47	47	Wo	Onondaga, NY	C	Geres Lock 115kV	NM-NG	5	5/31/11	None	2011/03	2013/06
319	AES Energy Storage, LLC	Cayuga Energy Storage	12/3/08	20	20	ES	Onondaga, NY	C	Milliken 115kV	NYSEG	5	12/31/10	None	2010/07	N/A
320	AES Energy Storage, LLC	Somerset Energy Storage	12/3/08	20	20	ES	Niagara, NY	A	Somerset 69kV	NYSEG	5	12/31/10	None	2010/07	N/A
322	Rolling Upland Wind Farm, LLC	Rolling Upland Wind	1/13/09	59.4	59.4	W	Madison, NY	E	County Line - Brothertown 115kV	NYSEG	5	5/31/11	FES	2012/12	2014/12
326	NYSEG/RG&E	Rochester SVC/PST Trans.	3/9/09	N/A	N/A	AC	Monroe, NY	B	Station 124 115kV	NYSEG	6	3/31/11	SIS	2011/12	2012-2013
330	Long Island Solar Farm LLC	Upton Solar Farms	4/7/09	31.5	32	S	Suffolk, NY	K	8ER Substation 69kV	LIPA	14	11/30/11	SRIS	2011/05	I/S
331	National Grid	Northeast NY Reinforcement	4/22/09	N/A	N/A	AC	Saratoga, NY	F	NGrid 230kV	NM-NG	12	10/31/11	SIS	2010-2019	2010-2019
333	National Grid	Western NY Reinforcement	5/5/09	N/A	N/A	AC	Cattaraugus, NY	A	NGrid 115kV	NM-NG	5	7/31/09	None	2014/Q2	2014/Q2
335	NextEra Energy Resources, LLC	Cold Creek Spring Wind	6/9/09	150.7	150.7	W	Cattaraugus, NY	A	Salamanca - Falconer 115kV	NM-NG	5	9/30/11	FES	2012/12	2012/12
336	Enfield Energy, LLC	Black Oak Wind	6/29/09	50	50	W	Thompkins, NY	C	Black Oak Rd 115kV	NYSEG	5	10/31/11	FES	2010/10	2013/10
337	Long Island Power Authority	Northport Norwalk Harbor	7/14/09	N/A	N/A	AC	Suffolk, NY	K	Northport 138kV	LIPA	6	1/31/11	SIS	2016	2016
338	RG&E	Brown's Race II	8/11/09	8.3	8.3	H	Monroe, NY	B	Station 3 / Station 137 34.5kV	RG&E	9	10/31/11	None	2011/08	N/A
339	RG&E	Transmission Reinforcement	8/17/09	N/A	N/A	AC	Monroe, NY	B	Niagara - Kintigh 345kV	RG&E	6	10/31/11	SIS	2015/09	2015/09
340	RG&E	Brown's Race III	9/2/09	2	2	H	Monroe, NY	B	Station 6 34.5 kV	RG&E	7	12/31/10	None	2010/12	N/A
342	Albany Energy, LLC	Albany Landfill	9/3/09	4.8	4.8	M	Albany, NY	F	34.5kV	NM-NG	9	7/31/11	None	2010/12	2012/01
343	Champlain Wind Link, LLC	Champlain Wind Link I	9/29/09	600	600	AC	Clinton, NY - VT	D	Plattsburgh - New Haven, VT 230kV	NYPA	5	8/31/10	None	2014/06	2014/06
344	Champlain Wind Link, LLC	Champlain Wind Link II	9/29/09	600	600	AC	Clinton, NY - VT	D	Plattsburgh - New Haven, VT 345kV	NYPA	4	12/22/09	None	2014/06	2014/06
346	Beacon Power	Scotia Industrial Park	11/24/09	20	20	F	Schenectady, NY	F	Spier - Rotterdam	NM-NG	6	3/31/11	None	2011/08	2012/08
347	Franklin Wind Farm, LLC	Franklin Wind	12/2/09	50.4	50.4	W	Delaware, NY	E	Sidney - Delhi 115kV	NYSEG	3	5/31/11	None	2012/12	2012/12
349	Taylor Biomass Energy, LLC	Taylor Biomass	12/30/09	22.6	22.6	SW	Montgomery, NY	F	Maybrook - Rock Tavern	CHGE	9	6/30/11	SRIS	2012/04	2012/Q4
350	Lake Erie Wind, LLC	Lake Erie Wind	2/16/10	810	810	W	Chautauqua, NY	A	Dunkirk - Gardenville 230kV	NM-NG	4	9/30/11	FES	2015/12	2015/12
351	Linden VFT, LLC	Linden VFT Uprate	3/2/10	15	15	AC	Richmond, NY-NJ	J	Goethals 345kV	CONED	9	6/30/11	SRIS	2010/11	N/A
353	Chautauqua County	Chautauqua County Landfill	4/26/10	3.2	3.2	M	Chautauqua, NY	A	Hartfield – South Dow 34.5kV	NM-NG	14	6/30/11	None	2011/03	I/S

INTERCONNECTION REQUESTS AND TRANSMISSION PROJECTS / NEW YORK CONTROL AREA

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	WP (MW)	Type/ Fuel	Location County/State	Z	Interconnection Point	Utility	S	Last Update	Availability of Studies	Proposed In-Service Original	Proposed In-Service Current
354	Atlantic Wind, LLC	North Ridge Wind	5/13/10	100	100	W	St. Lawrence, NY	E	Nicholville - Parishville 115kV	NM-NG	5	6/30/11	FES	2014/12	2014/12
355	Brookfield Renewable Power	Stewarts Bridge Hydro	8/3/10	3	3	H	Saratoga, NY	F	Spier Falls - EJ West	NM-NG	5	3/31/11	None	2012/10	2012/10
357	NRG Energy	NY Power Pathway	9/10/10	1000	1000	DC	Albany, Orange or Westchester, NY	F, G or H	New Scotland - Roseton or Buchanan 345kV	NM-NG/CenHud or Coned	3	2/28/11	None	2016/07	2016/07
358	Anabaric Northeast & PowerBridge	West Point Transmission	9/13/10	1000	1000	DC	Greene, Westchester, NY	F, H	Leeds - Buchanan North 345kV	NM-NG/ConEd	3	6/30/11	None	2015/05-2016/05	2015/05-2016/05
360	NextEra Energy Resources, LLC	Watkins Glen Wind	12/22/10	300.8	300.8	W	Schuyler, NY	C	Hillside - Meyer 230 kV	NYSEG	3	6/30/11	None	2013/09	2013/06
361	US PowerGen Co.	Luyster Creek Energy	2/15/11	401	444	CC	Queens, NY	J	Astoria Substation	CONED	3	9/30/11	None	2014/06	2014/06
362	Monticello Hills Wind, LLC	Monticello Hills Wind	3/7/11	20	20	W	Otsego, NY	E	W. Winfield - Richfield Spring 46kV	NYSEG	5	7/31/11	None	2012/11	2012/11
363	Poseidon Transmission, LLC	Poseidon Transmisssion	4/27/11	500	500	DC	Suffolk, NY	K	Ruland Rd. Substation	LIPA	3	10/31/11	None	2016/05	2016/05
364	Bruce Hill Wind, LLC	Bruce Hill Wind	5/4/11	18	18	W	Delaware, NY	E	Axtell Road Substation 34.5 kV	NYSEG	3	11/30/11	None	2013/12	2013/12
365	Transmission Developers Inc.	Champlain Hudson SPS	7/15/11	TBD	TBD	AC	Queens, NY	J	Astoria and Farragut Subsations	ConEd/NYPA	4	7/31/11	None	2016/Q1	2016/Q1
366	NextEra Energy Resources, LLC	Watkins Glen East	8/2/11	150.6	150.6	W	Schuyler, NY	C	Montour Falls Substation	NYSEG	2	11/30/11	None	2013/Q3	2014/Q2
367	Orange & Rockland	North Rockland Transformer	9/14/11	TBD	TBD	AC	Rockland, NY	G	Line Y94 345kV	ConEd	4	9/30/11	None	2016/06	2016/06
368	Consolidated Edison Company of NY	Feeder 76 Ramapo to Rock Tav	10/13/11	TBD	TBD	AC	Orange, Rockland, NY	G	Ramapo to Rock Tavern 345 kV	ConEd/CenHud	4	11/30/11	None	2016/08	2016/08
369	Clover Leaf Power, LLC	Clover Leaf Hollers Ave	10/24/11	173.9	192.8	CT	Bronx, NY	J	Parkchester City Substation 138 kV	ConEd	1	11/30/11	None	2016/12	2016/12
370	Smokey Avenue Wind, LLC	Smokey Avenue Wind	10/28/11	18	18	W	Otsego, NY	E	Worcester - Schenevus 23kV	NM-NG	2	11/30/11	None	2013/12	2013/12
371	Ridgeline Eastern Energy	Ridgeline Eastern Energy	10/31/11	18	18	W	Delaware, NY	E	River Rd Substation 46kV	NYSEG	2	11/30/11	None	2013/11	2013/11
372	Dry Lots Wind, LLC	Dry Lots Wind	10/31/11	33	33	W	Herkimer, NY	E	Schuyler to Whitesboro	NM-NG	2	11/30/11	None	2014/11	2014/11

NOTES:
- *The column labeled 'SP' refers to the maximum summer megawatt electrical output. The column labeled 'WP' refers to the maximum winter megawatt electrical output.*
- *Type / Fuel. Key: ST=Steam Turbine, CT=Combustion Turbine, CC=Combined Cycle, CS= Steam Turbine & Combustion Turbine, H=Hydro, PS=Pumped Storage, W=Wind, NU=Nuclear, NG=Natural Gas, M=Methane, SW=Solid Waste, S=Solar, Wo=Wood, F=Flywheel ES=Energy Storage, O=Oil, C=Coal, D=Dual Fuel, AC=AC Transmission, DC=DC Transmission, L=Load*
- *The column labeled 'Z' refers to the zone*
- *The column labeled 'S' refers to the status of the project in the NYISO's LFIP. Key: 1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS/SIS Pending, 5=SRIS/SIS in Progress, 6=SRIS/SIS Approved, 7=FS Pending, 8=Rejected Cost Allocation/Next FS Pending, 9=FS in Progress, 10=Accepted Cost Allocation/IA in Progress, 11=IA Completed, 12=Under Construction, 13=In Service for Test, 14=In Service Commercial, 0=Withdrawn*
- *Availability of Studies Key: None=Not Available, FES=Feasibility Study Available, SRIS=System Reliability Impact Study Available, FS=Facilities Study and/or ATRA Available*
- *Proposed in-service dates are shown in format Year/Qualifier, where Qualifier may indicate the month, season, or quarter.*

Interconnection Queue Status Key

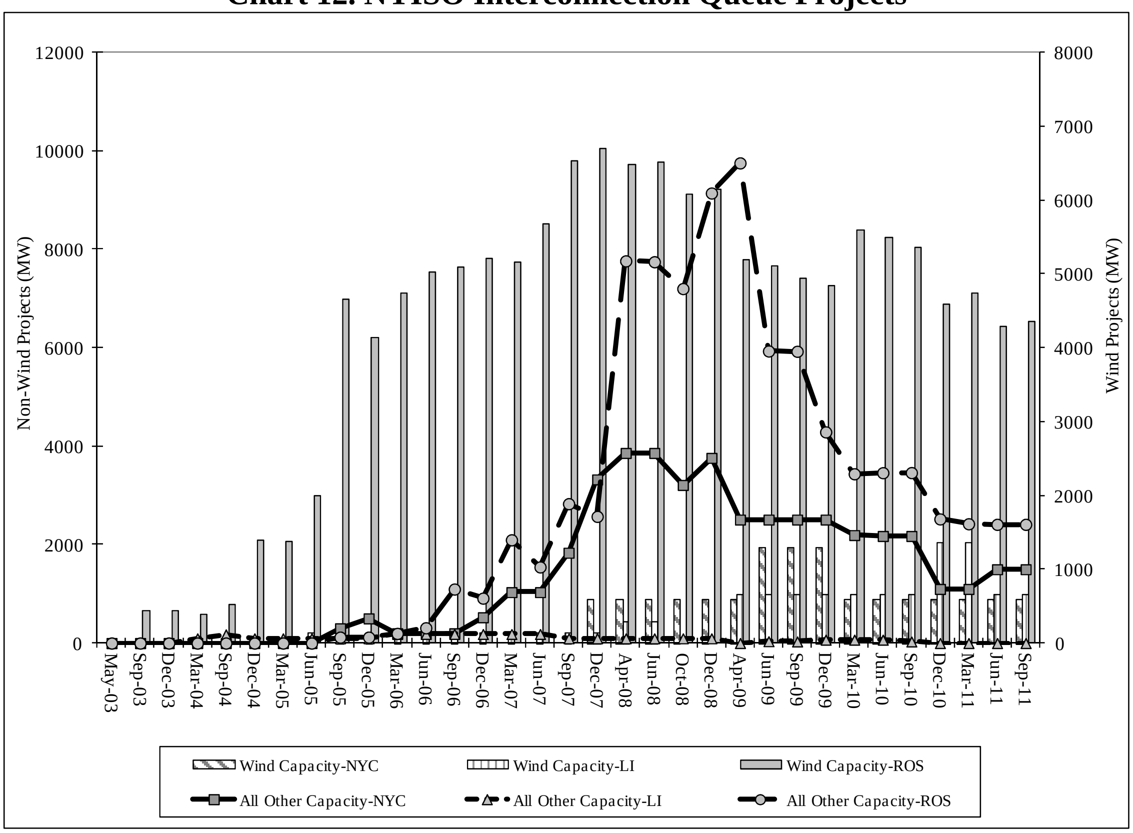
1=	Scoping Meeting Pending	Interconnection Request has been received, but scoping meeting has not yet occurred
2=	FESA Pending	Awaiting execution of Feasibility Study Agreement
3=	FES in Progress	Feasibility Study is in Progress
4=	SRIS Pending	Awaiting execution of SRIS Agreement and/or OC approval of SRIS scope
5=	SRIS in Progress	
6=	SRIS Approved	SRIS Approved by NYISO Operating Committee
7=	FS Pending	Awaiting execution of Facilities Study Agreement
8=	Rejected Cost Allocation/ Next FS Pending--	Project was in prior class year, but rejected cost allocation—Awaiting execution of Facilities Study Agreement for next Class Year or the start of the next Class Year
9=	FS in Progress	Project in current Class Year Facilities Study
10=	Accepted Cost Allocation/ IA in Progress	Interconnection Agreement is being negotiated
11=	IA Completed	Interconnection Agreement is executed and/or filed with FERC
12=	Under Construction	Project is under construction
13=	In Service for Test	
14=	In Service Commercial	
0=	Withdrawn	Project is no longer in the Queue

III. New Generation Projects and Net Revenue Analysis

The ICAP Demand Curves are designed to send signals to build new generation when it is needed. In past reports, the NYISO stated that it is difficult to relate the development of new generation to the ICAP Demand Curves given the lead time required to site, develop, and construct new generation, and the address other barriers to new entry. The NYISO utilizes in this section of the report the same methodology it as in past reports and it is continuing to review the methodology for potential enhancements for future reports. In the summer of 2011, a 550 MW combined cycle facility located in New York City entered the Capacity market. The NYISO anticipates that planned new generation projects will commence commercial operation. The projects currently in the study processes are listed on the NYISO's interconnection queue in accordance with the time schedules provided by the developers.

The graph below depicts the amount of generation listed on the NYISO's interconnection queue since 2003 in New York City, Long Island, and Rest of State – with wind projects depicted separately from generation projects with other fuel types.

Chart 12. NYISO Interconnection Queue Projects



This analysis is based on periodically updated versions of the NYISO interconnection queue dating from May 2003 through October 2011.[24] For purposes of this analysis, only projects that entered the queue after May 1, 2003 were considered. Since the queue includes projects at various stages, for purposes of this study it is reasonable to include only projects that are deemed active. Accordingly, pre-2005 period projects with codes 'I', 'W', or 'C' were excluded; for 2005 and beyond, status codes 0, 1, 12, 13, and 14 were omitted.

Generally, the amount of generation in the interconnection process has increased since the ICAP Demand Curves became effective in May 2003. The number of MW associated with projects based on technologies other than wind (measured on the left Y-axis, above) did not increase significantly until the summer of 2005. The graph above shows that beginning with the Winter 2007-2008 Capability Period, Rest of State has seen a sharply rising trend in the number of MW in the interconnection queue, particularly new non-wind projects. Since the January 2009 report and continuing through the date of this report, there has been a decrease in the total amount of Rest of State generation and New York City non-wind generation in the interconnection queue. Chart 12 does not include proposed HVDC connections into New York City, which currently total more than 4,200 MW -- an increase of roughly 1,900 MW from late 2008.

Proposed Resource Additions

In January 2011, the NYISO Board of Directors approved the 2010 Comprehensive Reliability Plan ("CRP"), which was the fifth CRP since its introduction in 2006. Like the 2009 report, the 2010 CRP determined that there are no additional resource needs through the ten-year Study Period under expected Bulk Power System conditions. The NYISO continues to track on a quarterly basis the market-based projects that were submitted for the 2008 CRP, the last year of which resource needs were identified. Table 8 presents the market-based projects and

[24] Each project in the queue is provided a status code that identifies its position in the study process that ranges from the initial scoping meeting to being in service. Prior to 2005, each project was provided a status-code based on the NYISO System Reliability Impact Study from the following: *P=Pending, A=Active, I=Inactive, R=Under Review, C=Completed, W=Withdrawn.* Starting in 2005, the classification system was changed and status-codes were based on the standard steps in the NYISO's interconnection process as follows: *1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS Pending, 5=SRIS in Progress, 6=SRIS Approved, 7=FS Pending, 8=Rejected Cost Allocation/Next FS Pending, 9=FS in Progress, 10=Accepted Cost Allocation/IA in Progress, 11=IA Completed, 12=Under Construction, 13=In Service for Test, 14=In Service Commercial, 0=Withdrawn, where FES=Feasibility Study Available, SRIS=System Reliability Impact Study Available, FS=Facilities Study and/or ATRA Available.*

Transmission Owners' plans that were submitted in response to requests for solutions and were included in the 2008 CRP. The table indicates that, as of June 2011, 520 MW of solutions are still being reported to the NYISO as moving forward with development. The Empire Generation Project, a market-based project in the 2008 CRP, went in-service in August 2010 and, therefore is not listed in the Table 8. There are a number of other projects in the NYISO interconnection queue that also are moving forward in the interconnection process, but which have not been offered as market based solutions in the CRPP process.

Table 8. June 2011 Status of the 2008 CRP Market – Based Solutions and TOs' Plans

Project Type	Submitted	MW	Zone	Original In-Service Date	Current Status[1]
Resource Proposals					
Gas Turbine NRG Astoria Re-powering[2]	CRP 2005, CRP 2007, CRP 2008	520 MW	J	Jan - 2011	New Target June 2014 NYISO interconnection queue projects # 201 and # 224
Transmission Proposals					
Back-to-Back HVDC, AC Line HTP	CRP 2007, CRP 2008 and was an alternative regulated proposal in CRP 2005	660 MW	PJM - J	Q2/2011 PJM Queue O66	New Target May 2013 NYISO interconnection queue projects # 206
TOs' Plans					
ConEd M29 Project	CRP 2005	N/A	J	May - 2011	In-Service 2011 NYISO interconnection queue projects # 153

[1] Status as provided by Market Participant as of June 2011

[2] NRG submitted three proposals, one of which was withdrawn. For the purposes of the Market-Based solutions' evaluation, the NYISO assumed the lowest MW proposal.

<u>*Revenue Analysis*</u>

The Commission's order directing the NYISO to submit this filing stated that the NYISO should include a complete net revenue analysis to provide information about whether NYISO market revenues are adequate to incent new capacity resources in regions where Capacity is needed. Where there is growing pressure on existing Capacity, *e.g.*, the reserve margin is shrinking, there should be a rise in combined revenues from energy and Capacity markets. As the NYISO did for prior annual reports, for this report, the NYISO examined the level of "need" for additional Capacity by looking at the percentage of Capacity in excess of the applicable minimum Installed Capacity requirement. The NYISO then looked at possible revenues from the Capacity and energy markets for a hypothetical combustion turbine. Based on the methodology used, which is the same as used in past years, the analysis shows that, in general, there is a tendency for revenues to increase as the percentage of excess Capacity decreases and vice versa.

Quantification of "Need"

For purposes of this analysis, the excess of Capacity relative to the minimum requirement was used as a proxy for need. Capacity Margins are calculated as:

$$\text{Capacity Margin \%} = \frac{\text{Availability}}{\text{Requirement}} \times 100$$

Using this definition, a value in excess of 100% reflects an excess Capacity margin. A relatively high value indicates less of a need for new Capacity and, conversely, declining values suggest an increased need. The following table displays the required and available amounts of Capacity (UCAP) as calculated from detailed data from monthly certifications, auction offers, and sales awards.

Table 9. Available Capacity vs. Required Capacity

		2007	2008	2009	2010	2011
NYCA	Requirement (MW)	37,228	36,633	36,362	35,045	34,684
	Available Cap. (MW)	38,641	38,192	38,217	37,272	38,041
	Capacity margin %	**103.8%**	**104.3%**	**105.1%**	**106.4%**	**109.7%**
NYC	Requirement (MW)	9,058	8,911	8,855	8,336	8,832
	Available Cap. (MW)	10,158	9,858	9,612	8,753	9,660
	Capacity margin %	**112.1%**	**110.6%**	**108.5%**	**105.0%**	**109.4%**
LI	Requirement (MW)	5,056	4,685	4,749	5,021	5,052
	Available Cap. (MW)	5,192	5,353	5,331	5,864[25]	5,952
	Capacity margin %	**102.7%**	**114.3%**	**112.3%**	**116.8%**	**117.8%**

In Table 9, the required Capacity is based on the annual NYCA Minimum Installed Capacity Requirement and for each of NYC and Long Island, the respective Locational Minimum Installed Capacity requirements. Available Capacity reflects the aggregate of UCAP

[25] The available capacity for Long Island (LI) in 2010 was 5,864 MW; however, this table in the 2010 annual report incorrectly stated it was 5,662 MW. Consequently, the capacity margin for Long Island in the 2010 annual report should have been stated as 116.8%.

ratings excluding the amount imported via external transactions.[26] In 2011, the NYCA capacity margin increased in part due to a decrease in the IRM from 18.0% to 15.5%.

Measure of Revenues

As with the analysis in prior reports, for this report, the NYISO assumed a revenue requirement based on the ICAP Demand Curve for the respective years. It uses a levelized annual revenue requirement for a given capability year (May – April) that is derived from a cost of new entry ("CONE") of a gas-fueled simple-cycle, combustion turbine ("GT") for a given location in the NYCA or the respective Locality. For purposes of the annual report analysis, the NYISO used prior reports' methodology, which is based on Summer/Winter DMNCs, to convert these annual revenue requirements into Summer and Winter $/kW-month equivalents. Next, these monthly UCAP values were used to compute annual revenue requirements for each year from 2007 through 2011.

Table 10, below, shows the annual revenue requirement for a hypothetical new entry unit based on the assumptions in ICAP Demand Curves for the corresponding Capability Years, including the financial assumptions and different benchmark technologies for each of New York City, Long Island and the NYCA. For example, the notional figures for New York City in 2007 were based on a pair of LM 6000 Combustion Turbines, and the 2008 - 2011 Demand Curves were based on an LMS 100 unit.

Table 10. Annual Revenue Requirements in UCAP Terms ($/MW)

	2007	**2008**	**2009**	**2010**	**2011**
NYCA	$98,964	$103,835	$103,312	$105,115	$110,577
NYC	$208,650	$209,747	$213,943	$244,147	$233,486
LI	$186,021	$180,914	$194,743	$211,069	$214,785

Table 11 below shows the individual elements of revenues (*i.e.*, those earned in the Energy, Ancillary Services, and ICAP markets) that a hypothetical GT may have received based

[26] In contrast to the prospective figures used in the NYISO's annual Load & Capacity Reports, these charts reflect data based on realized outcomes over the summer Capability Periods.

on actual LBMPs, natural gas prices, and other reasonable parameters used to calculate variable costs.[27]

For this and previous reports, a model has been used to calculate the Energy and Ancillary Services revenue for the hypothetical Demand Curve peaking plants: net energy revenues are earned in hours when the day-ahead market LBMP price exceeds the calculated variable cost; otherwise, day-ahead Ancillary Services revenues are earned. This approach is similar to the “standard method” used by the MMU in its annual State of the Market reports.

In past annual reports, Ancillary Services revenues were based on 10 minutes reserve prices. In this report, the NYISO revised the input so that the Ancillary Services revenues earned by the hypothetical Demand Curve peaking plant reflected the capability of the applicable Demand Curve peaking plant. This update required a change so that Ancillary Service revenues for the hypothetical NYCA GT are based on Day-Ahead 30 minutes reserve prices. As a result, the benchmark Ancillary Services revenues for NYCA have been recalculated for years 2007 – 2011. The results of the analysis are presented in Table 11. Because Table 12 and Chart 13 are derived from data in Table 11, the adjustment reflected in Table 11 also affected the corresponding NYCA revenue margins in Table 12 and Chart 13 for years 2007 through 2011.

[27] The assumed parameters for the 2011 benchmark combustion turbines are based on the latest NERA Demand Curve Report (15 November 2010): For NYCA, Heat Rate = 10,206 btu/kWh, Variable Operating & Maintenance Costs (VOM) = $1/MWh, and Forced Outage Rate = 3%; For NYC and LI, Heat Rate = 9023 btu/kWh, VOM = $5/MWh, and Forced Outage Rate = 3.84%.

Table 11. Benchmark Annual Revenues in UCAP Terms ($/MW)

		Revenue Elements in $					Revenue Elements as % of Total				
		2007	2008	2009	2010	2011	2007	2008	2009	2010	2011
NYCA [28]	Energy	$6,220	$6,251	$5,291	$20,815	$16,646	16%	15%	14%	52%	80%
	A/S	$1,825	$8,641	$4,058	$1,161	$341	5%	21%	11%	3%	2%
	Capacity	$31,310	$26,050	$27,920	$18,420	$3,820	80%	64%	75%	46%	18%
	Total	$39,355	$40,942	$37,269	$40,397	$20,807	100%	100%	100%	100%	100%
NYC	Energy	$32,575	$41,243	$24,221	$59,052	$59,028	21%	37%	25%	34%	41%
	A/S	$13,002	$17,894	$14,155	$7,648	$12,892	8%	16%	15%	4%	9%
	Capacity	$111,220	$51,980	$58,640	$104,600	$72,440	71%	47%	60%	61%	50%
	Total	$156,797	$111,117	$97,016	$171,299	$144,360	100%	100%	100%	100%	100%
Long Island	Energy	$58,548	$48,229	$32,795[29]	$84,130	$95,780	43%	49%	43%	76%	86%
	A/S	$9,804	$16,998	$11,829	$5,356	$11,400	7%	17%	16%	5%	10%
	Capacity	$67,830	$33,970	$30,800	$20,790	$3,840	50%	34%	41%	19%	3%
	Total	$136,182	$99,197	$75,424	$110,276	$111,020	100%	100%	100%	100%	100%

In order to assess revenue adequacy for purposes of this report, Revenue Margin" is used. "Revenue Margin"is Benchmark Revenues expressed as a percentage of Required Revenues, as the metric. Revenue Margins are calculated as:

$$\text{Revenue Margin \%} = \frac{\text{Benchmark Revenue}}{\text{Required Revenue}} \times 100$$

Using this approach, a higher value indicates a greater degree of adequacy of revenues. The following table displays the values of Revenue Margins for the hypothetical peaking plant:

Table 12. Revenue Margins

	2007	2008	2009	2010	2011
NYCA	40%	39%	36%	38%	19%
NYC	75%	53%	45%	70%	62%
LI	73%	55%	39%	52%	52%

In 2011, Revenue Margins fell in both NYCA and New York City, largely due to the decrease in capacity revenues. On Long Island, the decrease in capacity revenue was offset by an increase in the projected energy and ancillary services revenues, resulted in a Revenue Margin similar to 2010.

[28] These values are for the Capital Zone (Zone F), which is used as a representation for revenues in the NYCA .

[29] The energy and A/S revenues for Long Island (LI) in 2009 have been updated to $32,759 and $11,829/MW from the $48,229 and $16,998/MW previously reported.

To assess whether revenue stream for the hypothetical unit is adequate in relation to the level of need for new Capacity, data from Tables 9 and 12 are graphed below, showing revenue (Chart 13) and Capacity (Chart 14) margins. Chart 15 plots the Installed Capacity revenue component of the total net revenue as a percentage of the cost of new entry in the NYCA and in each Locality. In Chart 14, the high levels of excess Capacity in 2008 through 2010 do not lead to corresponding declines in Capacity revenue. The reason they do not is the market rules provide that UCAP Market Clearing Price is the greater of the NYCA or the respective Locality clearing price. Both NYCA and New York City exhibit declining trends in revenue margins in 2011. If such conditions persist, it is reasonable to expect levels of excess Capacity to decline.

Chart 13. UCAP-based Revenue Margins

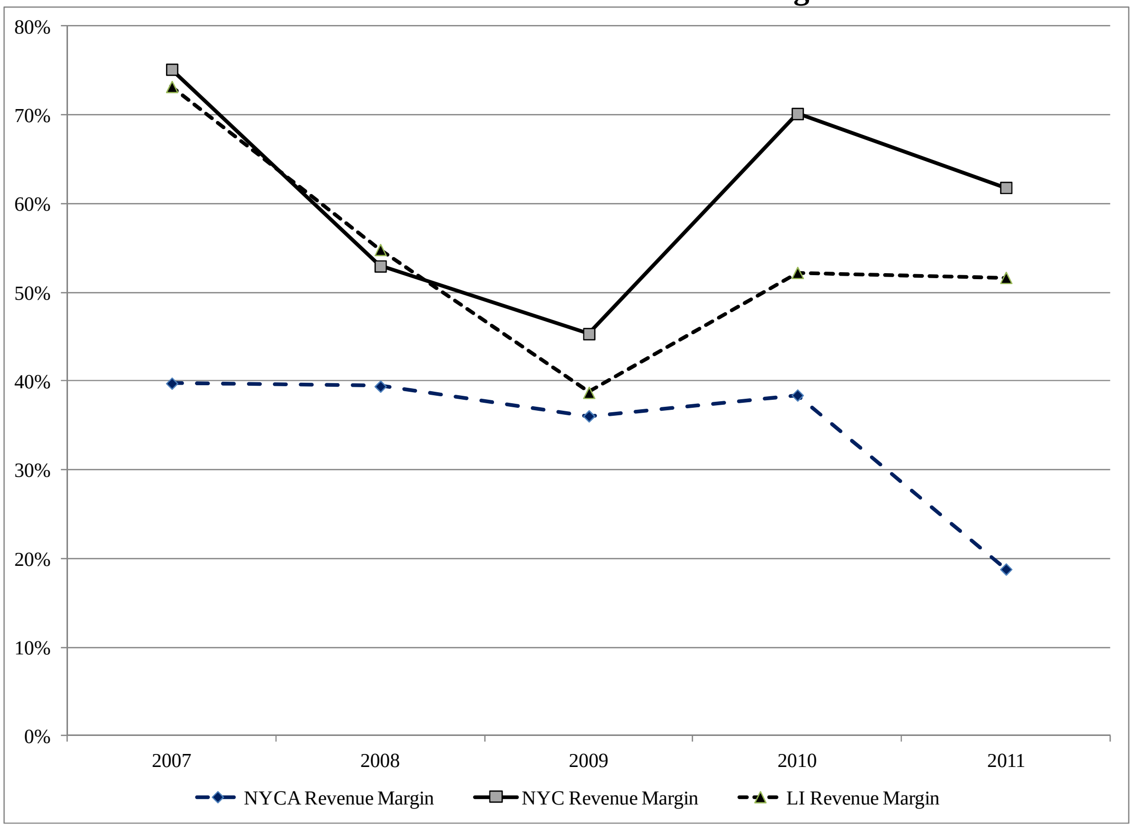


Chart 14. UCAP-based Capacity Margins

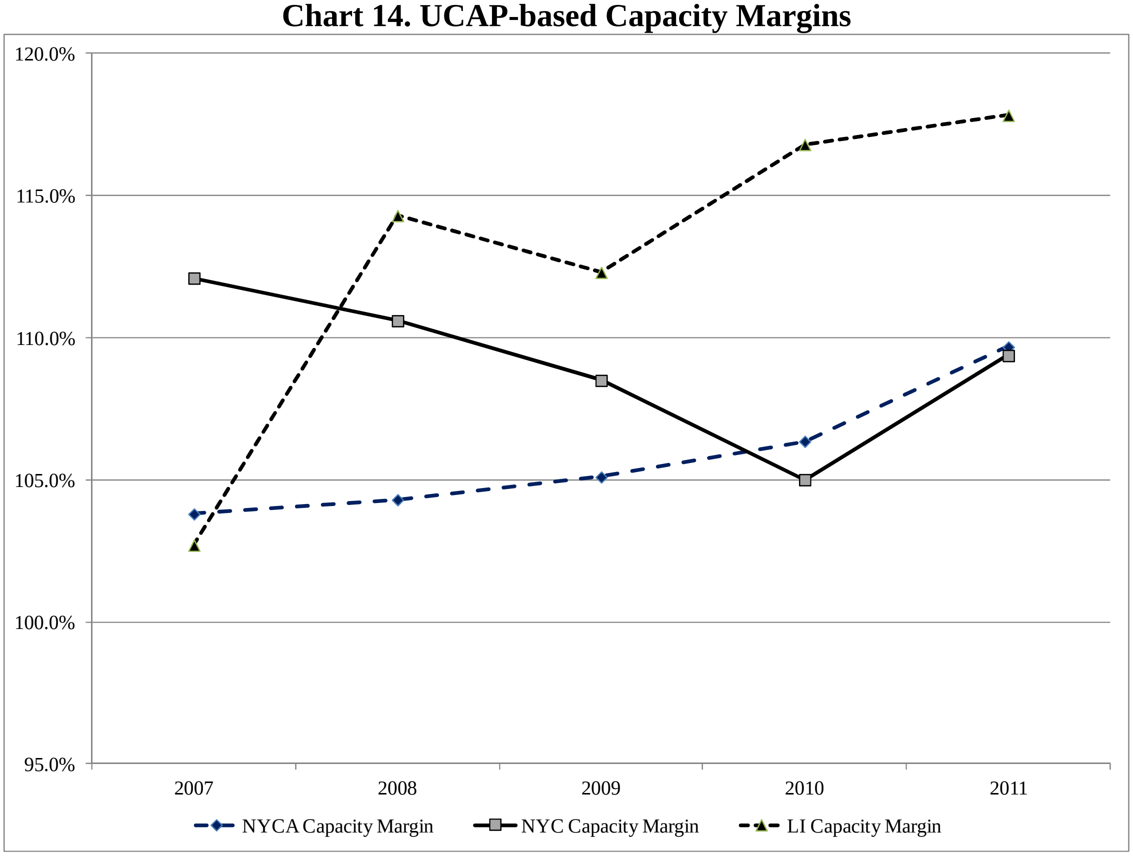
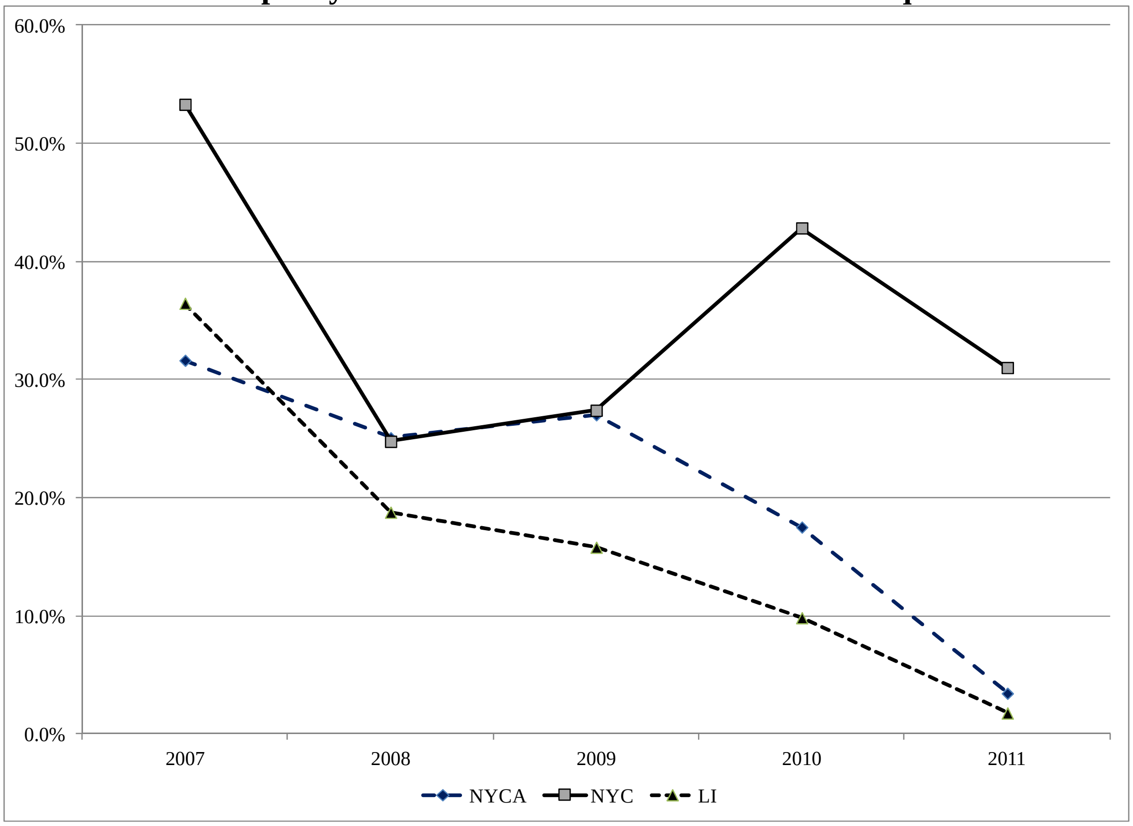


Chart 15. Capacity Market Revenues Relative to CONE Requirements



Attachment III-A

November 1999 – December 2009
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
November-99							35563.1	
December-99							35563.1	
January-00	Installed Capacity Market Existed but all purchases and sales were bilateral						35563.1	
February-00							35563.1	
March-00							35563.1	
April-00							35563.1	
May-00	1976.0	$1.50	434.2	$1.30	32.7	$0.50	35636.0	1976.0
June-00	1976.0	$1.50	528.4	$1.40	37.1	$1.28	35563.1	1976.0
July-00	1976.0	$1.50	344.2	$1.80	140.8	$1.98	35563.1	1976.0
August-00	1976.0	$1.50	351.4	$1.62	194.8	$1.77	35563.1	1976.0
September-00	1976.0	$1.50	648.9	$1.32	81.3	$1.16	35563.1	1976.0
October-00	1976.0	$1.50	681.6	$1.30	96.9	$0.89	35563.1	1976.0
November-00	4010.6	$1.04	1813.6	$1.00	157.7	$0.80	35563.1	4010.6
December-00	4010.6	$1.04	1854.1	$0.97	167.2	$0.86	35563.1	4010.6
January-01	4010.6	$1.04	1847.6	$0.97	170.5	$0.85	35563.1	4010.6
February-01	4010.6	$1.04	1893.8	$0.95	177.2	$0.83	35563.1	4010.6
March-01	4010.6	$1.04	2032.8	$0.95	208.1	$0.79	35563.1	4010.6
April-01	4010.6	$1.04	1659.7	$0.87	192.3	$0.59	35563.1	4010.6
May-01	2738.6	$1.90	852.3	$2.25	1022.2	$9.58	36132.0	2738.6
June-01	2738.6	$1.90	397.6	$2.68	1521.0	$9.41	36132.0	2738.6
July-01	2738.6	$1.90	1776.6	$4.31	1534.9	$9.44	36132.0	2738.6
August-01	2738.6	$1.90	1788.4	$4.56	1601.3	$9.35	36132.0	2738.6
September-01	2738.6	$1.90	1701.2	$4.16	1498.0	$9.21	36132.0	2738.6
October-01	2738.6	$1.90	1787.1	$4.03	1473.4	$9.14	36132.0	2738.6
November-01	1760.4	$2.00	878.0	$0.10	5.8	$ -	32892.3	1760.4
December-01	1760.4	$2.00	687.2	$0.49	6.5	$ -	32892.3	1760.4
January-02	1760.4	$2.00	750.5	$0.84	133.0	$0.75	32892.3	1760.4
February-02	1760.4	$2.00	836.2	$0.70	25.5	$ -	32892.3	1760.4
March-02	1760.4	$2.00	901.3	$0.61	30.0	$0.25	32892.3	1760.4
April-02	1760.4	$2.00	677.9	$0.69	5.6	$0.02	32892.3	1760.4
May-02	3201.6	$1.75	552.1	$0.33	2.3	$ -	32479.5	3201.6
June-02	3201.6	$1.75	438.3	$0.36	20.3	$0.01	32479.5	3201.6
July-02	3201.6	$1.75	721.9	$0.97	11.1	$0.01	32479.5	3201.6
August-02	3201.6	$1.75	722.6	$0.91	55.4	$0.01	32479.5	3201.6
September-02	3201.6	$1.75	714.0	$0.25	71.2	$0.01	32479.5	3201.6
October-02	3201.6	$1.75	712.1	$0.16	1.4	$ -	32479.5	3201.6
November-02	3486.7	$0.65	1024.3	$0.50	85.0	$0.40	34169.7	3486.7
December-02	3486.7	$0.65	1219.3	$0.28	51.4	$0.10	34169.7	3486.7

Figure 1.a.

November 1999 – December 2009
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-03	3486.7	$0.65	1584.4	$0.26	189.1	$2.10	34169.7	3486.7
February-03	3486.7	$0.65	1623.1	$0.34	85.6	$0.50	34169.7	3486.7
March-03	3486.7	$0.65	1825.9	$0.32	58.8	$0.25	34169.7	3486.7
April-03	3486.7	$0.65	1571.5	$0.15	4.2	$0.01	34169.7	3486.7
May-03	2889.2	$1.67	1634.8	$1.30	101.5	$0.25	35303.5	0
June-03	2889.2	$1.67	1866	$1.06	2148.7	$2.34	35303.5	2073.2
July-03	2889.2	$1.67	1249.2	$2.01	2824.2	$2.28	35303.5	2274.1
August-03	2889.2	$1.67	1344.1	$2.04	3096.6	$2.25	35303.5	2299.3
September-03	2889.2	$1.67	1396.7	$1.97	3134.1	$2.08	35303.5	2448.1
October-03	2889.2	$1.67	1408.4	$1.93	3253.2	$2.01	35303.5	2504.8
November-03	2163.2	$1.17	2128.8	$1.15	6833	$1.94	35203.4	2566.9
December-03	2163.2	$1.17	1860.1	$1.48	7203.1	$1.79	35203.4	2698.6
January-04	2163.2	$1.17	2083.6	$1.50	6972.2	$1.75	35203.4	2732.1
February-04	2163.2	$1.17	2475.9	$1.58	6379.9	$1.73	35203.4	2747.4
March-04	2163.2	$1.17	2180	$1.54	6569.8	$1.00	35203.4	3369.3
April-04	2163.2	$1.17	2646.7	$0.99	6987.5	$0.80	35203.4	3543.8
May-04	2441	$1.68	2489.7	$1.65	6189.1	$1.31	35584.5	3328
June-04	2441	$1.68	2133.6	$1.48	6239.9	$1.27	35584.5	3355.3
July-04	2441	$1.68	1756.7	$1.29	6410.6	$1.04	35584.5	3518.8
August-04	2441	$1.68	2046.5	$1.15	6544.7	$1.17	35584.5	3428.1
September-04	2441	$1.68	2258.8	$1.16	6456.2	$1.07	35584.5	3499.6
October-04	2441	$1.68	2460.8	$1.18	6633.9	$1.12	35584.5	3465.6
November-04	3050.7	$0.60	2344.4	$0.70	6730.6	$0.70	35515.9	3759.3
December-04	3050.7	$0.60	3058.4	$0.69	6011.5	$0.61	35515.9	3823.5
January-05	3050.7	$0.60	2945.8	$0.59	5928.6	$0.27	35515.9	4064.8
February-05	3050.7	$0.60	2769.6	$0.49	6256.2	$0.25	35515.9	4082.2
March-05	3050.7	$0.60	2890.9	$0.45	6025.4	$0.41	35515.9	3966.2
April-05	3050.7	$0.60	2891.5	$0.48	6241.1	$0.27	35515.9	4064.8
May-05	2624.6	$0.75	1630	$0.75	6975.7	$2.00	35799.2	3110.8
June-05	2624.6	$0.75	1752.9	$1.40	6306.6	$1.96	35799.2	3135.2
July-05	2624.6	$0.75	4077.8	$1.29	5073.3	$1.00	35799.2	3703.4
August-05	2624.6	$0.75	3819.1	$0.81	5147.3	$1.00	35799.2	3703.4
September-05	2624.6	$0.75	3412.5	$0.81	5303.5	$1.45	35799.2	3436.7
October-05	2624.6	$0.75	3861.2	$1.03	5142	$1.25	35799.2	3555.2
November-05	2987.1	$0.62	2676.1	$0.67	6661.9	$0.85	35761.5	3789
December-05	2987.1	$0.62	3466.7	$0.68	6306	$0.65	35761.5	3907.2

Figure 1.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-06	2987.1	$0.62	3966.1	$0.63	5625.3	$2.01	35761.5	3102.5
February-06	2987.1	$0.62	3379.8	$1.01	6432.7	$1.67	35761.5	3305.2
March-06	2987.1	$0.62	5214.9	$0.58	5234.1	$0.57	35761.5	3954.5
April-06	2987.1	$0.62	4899.7	$0.51	5357.5	$0.40	35761.5	4055
May-06	3014.5	$1.44	2196.7	$1.64	6936.8	$3.25	37154.2	2526.4
June-06	3014.5	$1.44	2747.7	$2.38	6163	$3.12	37154.2	2601.6
July-06	3014.5	$1.44	2914.1	$2.58	5901.1	$3.33	37154.2	2481.4
August-06	3014.5	$1.44	3447.6	$2.85	5488.5	$3.00	37154.2	2675.1
September-06	3014.5	$1.44	4041.3	$2.75	5087.8	$2.80	37154.2	2295.3
October-06	3014.5	$1.44	4258	$2.62	5368.3	$2.77	37154.2	2814.8
November-06	3167.7	$2.50	3170.9	$1.73	7454.7	$1.50	37319.2	3577.8
December-06	3167.7	$2.50	2475.7	$2.30	7841.7	$2.18	37319.2	3170.5
January-07	3167.7	$2.50	2756.5	$2.45	7780.6	$2.71	37319.2	2853.4
February-07	3167.7	$2.50	3308.7	$2.51	7029.1	$2.67	37319.2	2876.6
March-07	3167.7	$2.50	4699.7	$1.80	5932.2	$1.34	37319.2	3673.8
April-07	3167.7	$2.50	4653.5	$1.61	5912	$1.10	37319.2	3817.9
May-07	3196.6	$2.25	2610.6	$2.40	6283.6	$3.16	37228.3	2618.7
June-07	3196.6	$2.25	2748	$2.81	5876.5	$3.39	37228.3	2485.6
July-07	3196.6	$2.25	2849.9	$2.99	5749.7	$3.52	37228.3	2407.6
August-07	3196.6	$2.25	3136.7	$2.98	5334.6	$3.43	37228.3	2462.4
September-07	3196.6	$2.25	3694.8	$2.90	5513.6	$3.14	37228.3	2631.6
October-07	3196.6	$2.25	3943.4	$2.82	5503.1	$3.03	37228.3	2698.2
November-07	3064.4	$1.91	2586.1	$1.90	9045.5	$1.60	36819.2	3503.7
December-07	3064.4	$1.91	2743.1	$1.98	8009.1	$2.22	36819.2	3149.2
January-08	3064.4	$1.91	3753.2	$2.25	7053.4	$3.40	36819.2	2477.3
February-08	3064.4	$1.91	3065.0	$2.50	6848.0	$3.18	36819.2	2602.7
March-08	3064.4	$1.91	4215.1	$1.48	8288.3	$1.05	36819.2	3818.1
April-08	3064.4	$1.91	4308.8	$1.17	7759.5	$0.75	36819.2	3989.6
May-08	2994.7	$2.67	1851.8	$2.80	8294.8	$2.60	36632.5	3080.6
June-08	2994.7	$2.67	2460.9	$2.87	7684.7	$2.94	36632.5	2909.9
July-08	2994.7	$2.67	1972.8	$2.96	8324.1	$2.80	36632.5	2981.6
August-08	2994.7	$2.67	2542.7	$2.87	7451.6	$2.70	36632.5	3030.1
September-08	2994.7	$2.67	3494.7	$2.73	6766.6	$2.45	36632.5	3156.4
October-08	2994.7	$2.67	3526.1	$2.55	6944.8	$1.93	36632.5	3418.3
November-08	2810.1	$1.77	2596.0	$1.60	9114.6	$1.00	36492.6	3877.473
December-08	2810.1	$1.77	2200.1	$1.50	9113.9	$1.25	36492.6	3752.079

Figure 1.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York Control Area (NYCA) Capacity

NYCA	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-09	2810.1	$1.77	2987.3	$1.50	6134.4	$3.19	36492.6	2779.0
February-09	2810.1	$1.77	3863.7	$2.50	5837.4	$1.77	36492.6	3492.1
March-09	2810.1	$1.77	3674.6	$1.10	5781.5	$0.50	36492.6	4128.2
April-09	2810.1	$1.77	3991.3	$0.50	5849.7	$0.30	36492.6	4228.6
May-09	2371.1	$3.01	2500.2	$3.01	7374.3	$2.61	36362.4	3216.7
June-09	2371.1	$3.01	3034.3	$3.50	7545.3	$4.22	36362.4	2505.4
July-09	2371.1	$3.01	3915.6	$4.11	6357.9	$4.42	36362.4	2420.6
August-09	2371.1	$3.01	4459.5	$4.19	5789.5	$3.42	36362.4	2857.0
September-09	2371.1	$3.01	4413.9	$3.49	5838.0	$2.76	36362.4	3147.7
October-09	2371.1	$3.01	4957.6	$2.59	5533.5	$2.23	36362.4	3380.5
November-09	3201.1	$1.75	3044.6	$1.55	6845.8	$0.50	35785.3	4081.4
December-09	3201.1	$1.75	3125.0	$1.30	6162.9	$0.75	35785.3	3976.7
January-10	3201.1	$1.75	3765.0	$1.66	8871.7	$1.85	35785.3	3505.4
February-10	3201.1	$1.75	3948.2	$2.24	8506.4	$3.49	35785.3	2810.0
March-10	3201.1	$1.75	4425.9	$1.47	8381.1	$0.85	35785.3	3933.4
April-10	3201.1	$1.75	4420.5	$0.74	8433.0	$0.64	35785.3	4021.8
May-10	2868.1	$2.47	3372.0	$2.54	7827.0	$3.52	35045.3	2860.2
June-10	2868.1	$2.47	4521.8	$2.51	8863.7	$2.12	35045.3	3396.5
July-10	2868.1	$2.47	4335.2	$1.90	6036.0	$1.91	35045.3	3475.3
August-10	2868.1	$2.47	3982.7	$1.63	5467.0	$1.68	35045.3	3563.7
September-10	2868.1	$2.47	4376.5	$0.97	7993.5	$0.63	35045.3	3964.3
October-10	2868.1	$2.47	4178.9	$0.45	8165.3	$0.48	35045.3	4022.9
November-10	2691.9	$0.39	4179.3	$0.27	9383.4	$0.01	35832.5	4295.9
December-10	2691.9	$0.39	4173.1	$0.10	8433.9	$0.50	35832.5	4100.2
January-11	2691.9	$0.39	3272.7	$0.65	9786.2	$0.50	35832.5	4100.2
February-11	2691.9	$0.39	3848.7	$0.45	8839.8	$0.65	35832.5	4040.0
March-11	2691.9	$0.39	4111.8	$0.15	8199.3	$0.30	35832.5	4180.1
April-11	2691.9	$0.39	4450.5	$0.20	8448.2	$0.15	35832.5	4240.0
May-11	3280.5	$0.55	3416.9	$0.60	7530.4	$0.65	34684.4	3911.1
June-11	3280.5	$0.55	3475.2	$0.60	7382.8	$0.55	34684.4	3948.7
July-11	3280.5	$0.55	3769.6	$0.50	7562.7	$0.15	34684.4	4104.2
August-11	3280.5	$0.55	3922.3	$0.16	7786.3	$0.05	34684.4	4142.8
September-11	3280.5	$0.55	3832.0	$0.10	7936.4	$0.18	34684.4	4093.1
October-11	3280.5	$0.55	4200.8	$0.10	7384.2	$0.13	34684.4	4105.9

Figure 2.a.

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
November-99							8305.6	
December-99							8305.6	
January-00	Installed Capacity Market Existed but all purchases and sales were bilateral						8305.6	
February-00							8305.6	
March-00							8305.6	
April-00							8305.6	
May-00	5408.8	$8.75	59.4	$12.50	0.0	-	8272.0	
June-00	5408.8	$8.75	313.4	$9.46	52.7	$12.50	8272.0	
July-00	5408.8	$8.75	342.7	$9.40	100.0	$12.50	8272.0	
August-00	5408.8	$8.75	332.6	$9.42	133.9	$12.50	8272.0	
September-00	5408.8	$8.75	344.5	$9.40	149.5	$12.50	8272.0	
October-00	5408.8	$8.75	304.2	$9.49	214.0	$12.50	8272.0	
November-00	4861.4	$8.75	735.0	$8.74	170.3	$8.75	8272.0	
December-00	4861.4	$8.75	785.1	$8.74	154.8	$8.75	8272.0	
January-01	4861.4	$8.75	899.5	$8.74	154.8	$8.75	8272.0	
February-01	4861.4	$8.75	921.7	$8.71	154.8	$8.75	8272.0	
March-01	4861.4	$8.75	936.5	$8.74	156.0	$8.75	8272.0	
April-01	4861.4	$8.75	985.6	$8.56	156.7	$8.72	8272.0	
May-01	5316.6	$8.75	248.7	$8.75	235.1	$12.50	8375.0	(est.)
June-01	5316.6	$8.75	228.4	$10.92	299.0	$12.18	8375.0	(est.)
July-01	5316.6	$8.75	407.8	$9.77	292.5	$8.83	8375.0	(est.)
August-01	5316.6	$8.75	440.1	$8.38	350.1	$9.46	8375.0	(est.)
September-01	5316.6	$8.75	434.9	$8.42	316.0	$8.34	8375.0	(est.)
October-01	5316.6	$8.75	430.1	$7.99	343.4	$8.72	8375.0	(est.)
November-01	3972.5	$9.40	772.8	$9.00	77.7	$4.80	7613.3	
December-01	3972.5	$9.40	906.8	$6.88	11.5	$ -	7613.3	
January-02	3972.5	$9.40	492.6	$5.47	377.3	$8.25	7613.3	
February-02	3972.5	$9.40	631.1	$6.69	229.3	$9.20	7613.3	
March-02	3972.5	$9.40	784.3	$6.92	90.6	$7.50	7613.3	
April-02	3972.5	$9.40	932.9	$7.12	11.6	$9.40	7613.3	
May-02	4355.2	$9.20	684.1	$9.38	30.5	$9.39	7621.6	
June-02	4355.2	$9.20	671.2	$6.11	16.7	$0.50	7621.6	
July-02	4355.2	$9.20	684.7	$5.34	0.3	$0.01	7621.6	
August-02	4355.2	$9.20	693.8	$5.15	15.1	$2.00	7621.6	
September-02	4355.2	$9.20	688.4	$4.83	24.5	$0.01	7621.6	
October-02	4355.2	$9.20	699.0	$4.72	19.2	$1.95	7621.6	
November-02	4540.0	$7.00	748.1	$6.40	61.1	$4.10	8021.8	
December-02	4540.0	$7.00	762.7	$4.09	29.9	$2.80	8021.8	

Figure 2.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-03	4540	$7.00	787.9	$4.02	13.3	$2.10	8021.8	
February-03	4540	$7.00	808.6	$3.51	1.5	$3.00	8021.8	
March-03	4540	$7.00	799.7	$3.97	21.9	$4.00	8021.8	
April-03	4540	$7.00	829.7	$3.39	9.1	$3.60	8021.8	
May-03	2501.7	$11.22	3016.3	$10.00	110.2	$12.36	8356.7	0.0
June-03	2501.7	$11.22	683	$13.78	2375.5	$11.46	8356.7	0.0
July-03	2501.7	$11.22	527.9	$11.57	2558	$11.46	8356.7	0.0
August-03	2501.7	$11.22	567.9	$11.56	2497.9	$11.46	8356.7	0.0
September-03	2501.7	$11.22	558.1	$11.56	2499.5	$11.46	8356.7	0.0
October-03	2501.7	$11.22	638.8	$11.55	2415.1	$11.45	8356.7	0.0
November-03	475	$6.55	579.3	$6.67	5029.3	$6.98	8346.1	571.0
December-03	475	$6.55	909.4	$6.64	4711	$6.98	8346.1	571.0
January-04	475	$6.55	968.9	$6.64	4644.8	$6.98	8346.1	571.0
February-04	475	$6.55	2167.5	$6.77	3422.4	$6.98	8346.1	571.0
March-04	475	$6.55	1938	$6.05	3841.5	$6.98	8346.1	571.0
April-04	475	$6.55	2047.2	$6.00	3779.1	$6.98	8346.1	571.0
May-04	1245.3	$11.15	2022.4	$11.16	2898.3	$11.42	8444.6	214.9
June-04	1245.3	$11.15	2532.8	$11.29	2391.9	$11.42	8444.6	214.9
July-04	1245.3	$11.15	2705.7	$11.29	2261.3	$11.42	8444.6	214.9
August-04	1245.3	$11.15	3126.1	$11.25	1854.4	$11.42	8444.6	214.9
September-04	1245.3	$11.15	3272.4	$11.25	1798.6	$11.42	8444.6	214.9
October-04	1245.3	$11.15	2771.9	$11.21	2336.3	$11.42	8444.6	214.9
November-04	2249.4	$6.68	1253.8	$6.96	3137.5	$7.12	8469.5	705.9
December-04	2249.4	$6.68	1606	$7.07	2758.3	$7.12	8469.5	705.9
January-05	2249.4	$6.68	2433.6	$7.03	1919.3	$7.12	8469.5	705.9
February-05	2249.4	$6.68	2596.5	$7.03	1761.5	$7.12	8469.5	705.9
March-05	2249.4	$6.68	2671.8	$7.03	1784	$7.12	8469.5	705.9
April-05	2249.4	$6.68	2611.4	$7.03	1851.9	$7.12	8469.5	705.9
May-05	2547.2	$11.68	1035.2	$11.86	2547.1	$12.03	8526.8	284.0
June-05	2547.2	$11.68	2657.9	$11.80	974.2	$11.96	8526.8	291.3
July-05	2547.2	$11.68	2742.6	$11.82	992.5	$11.95	8526.8	292.5
August-05	2547.2	$11.68	2689.7	$11.82	1134.8	$11.86	8526.8	301.6
September-05	2547.2	$11.68	2842	$11.82	1086.6	$11.70	8526.8	318.2
October-05	2547.2	$11.68	2644.5	$11.82	1238.1	$11.86	8526.8	301.6
November-05	1846.4	$5.11	943.9	$6.39	3865.4	$6.55	8569.2	854.3
December-05	1846.4	$5.11	2130.4	$6.44	2674.7	$6.55	8569.2	854.3

Figure 2.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-06	1846.4	$5.11	2558.2	$6.21	2116.6	$6.55	8569.2	854.3
February-06	1846.4	$5.11	3162.5	$5.78	2037.4	$6.55	8569.2	854.3
March-06	1846.4	$5.11	2704.7	$5.78	2031.7	$6.55	8569.2	854.3
April-06	1846.4	$5.11	3237.1	$5.88	1540.4	$6.55	8569.2	854.3
May-06	2186.7	$12.35	1422.7	$12.43	2209.8	$12.71	8798.1	255.9
June-06	2186.7	$12.35	1447.8	$12.41	2165.3	$12.71	8798.1	255.9
July-06	2186.7	$12.35	1580.0	$12.45	1909.6	$12.71	8798.1	255.9
August-06	2186.7	$12.35	1604.5	$12.51	1870.7	$12.71	8798.1	255.9
September-06	2186.7	$12.35	1603.6	$12.51	1953.5	$12.71	8798.1	255.9
October-06	2186.7	$12.35	1628.1	$12.54	2316.7	$12.71	8798.1	255.9
November-06	3298.4	$5.67	1023.5	$5.80	2057.8	$5.84	8831.5	974.8
December-06	3298.4	$5.67	1039.2	$5.84	2018.8	$5.84	8831.5	974.8
January-07	3298.4	$5.67	1193.4	$5.82	1973.8	$5.84	8831.5	974.8
February-07	3298.4	$5.67	1143.1	$5.81	2144.0	$5.84	8831.5	974.8
March-07	3298.4	$5.67	1199.7	$5.80	2008.8	$5.84	8831.5	974.8
April-07	3298.4	$5.67	1105.5	$5.82	1971.6	$5.84	8831.5	974.8
May-07	1894.0	$12.37	1099.1	$12.34	3125.4	$12.72	9058.3	281.1
June-07	1894.0	$12.37	1209.4	$12.36	2951.5	$12.72	9058.3	281.1
July-07	1894.0	$12.37	1154.3	$12.36	3073.0	$12.72	9058.3	281.1
August-07	1894.0	$12.37	1162.6	$12.36	3153.8	$12.72	9058.3	281.1
September-07	1894.0	$12.37	1252.0	$12.36	3037.9	$12.72	9058.3	281.1
October-07	1894.0	$12.37	1339.4	$12.36	2942.8	$12.72	9058.3	281.1
November-07	908.2	$5.32	1393.5	$5.61	4438.1	$5.77	8870.8	1009.5
December-07	908.2	$5.32	1632.1	$5.60	4067.3	$5.77	8870.8	1009.5
January-08	908.2	$5.32	1551.7	$5.43	4662.5	$5.77	8870.8	1009.5
February-08	908.2	$5.32	1388.9	$5.57	4442.2	$5.77	8870.8	1009.5
March-08	908.2	$5.32	3039.2	$3.78	3348.7	$1.05	8870.8	1494.9
April-08	908.2	$5.32	3696.4	$2.74	2964.9	$0.75	8870.8	1591.6
May-08	494.9	$6.50	903.4	$6.52	4987.2	$5.53	8910.6	985.9
June-08	494.9	$6.50	2100.2	$5.65	3745.8	$6.03	8910.6	930.1
July-08	494.9	$6.50	2071.5	$5.86	3758.3	$6.33	8910.6	896.9
August-08	494.9	$6.50	2490.8	$6.03	3349.2	$6.17	8910.6	914.8
September-08	494.9	$6.50	2790.4	$5.92	3083.4	$5.98	8910.6	935.7
October-08	494.9	$6.50	2652.6	$5.88	3230.1	$5.83	8910.6	951.9
November-08	1260.8	$2.79	1378.2	$2.28	3974.3	$1.52	9003.4	1447.1
December-08	1260.8	$2.79	1234.1	$1.59	4186.0	$1.25	9003.4	1558.1

Figure 2.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
New York City Locality (NYC) Capacity

NYC	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-09	1260.8	$2.79	1559.5	$1.51	4151.0	$3.19	9003.4	1579.9
February-09	1260.8	$2.79	2094.1	$3.06	3729.9	$1.77	9003.4	1592.0
March-09	1260.8	$2.79	1867.6	$1.49	3622.8	$0.50	9003.4	1592.0
April-09	1260.8	$2.79	1706.0	$0.75	3755.6	$0.30	9003.4	1586.6
May-09	436.7	$6.75	757.9	$7.00	4976.3	$8.72	8855.3	707.3
June-09	436.7	$6.75	1782.7	$8.60	3854.3	$8.65	8855.3	714.2
July-09	436.7	$6.75	2593.8	$8.71	2930.4	$8.47	8855.3	732.7
August-09	436.7	$6.75	2509	$8.52	2960.2	$8.45	8855.3	735.1
September-09	436.7	$6.75	2162.5	$8.40	3403.2	$7.65	8855.3	816.4
October-09	436.7	$6.75	2495.1	$7.62	2926.6	$7.70	8855.3	811.1
November-09	825.2	$4.65	2274.7	$1.94	3124.0	$1.23	8551.6	1422.3
December-09	825.2	$4.65	1757.6	$1.68	3607	$0.76	8551.6	1467.4
January-10	825.2	$4.65	1186.5	$4.38	4257.0	$1.85	8551.6	1497.1
February-10	825.2	$4.65	1180.1	$6.27	4240.3	$7.98	8551.6	782.0
March-10	825.2	$4.65	1787.4	$7.40	3472.0	$7.72	8551.6	807.3
April-10	825.2	$4.65	1995.3	$7.50	3468.4	$7.16	8551.6	860.1
May-10	1096.8	$12.90	335.7	$13.01	4004.2	$13.53	8336.0	372.0
June-10	1096.8	$12.90	1896.7	$13.33	2571.5	$13.13	8336.0	403.6
July-10	1096.8	$12.90	1700.8	$12.98	2797.1	$13.05	8336.0	412.1
August-10	1096.8	$12.90	1484.3	$12.94	3025.4	$12.97	8336.0	418.7
September-10	1096.8	$12.90	1847.1	$12.84	2799.0	$12.50	8336.0	457.8
October-10	1096.8	$12.90	1758.3	$12.45	2855.1	$12.72	8336.0	439.2
November-10	1109.8	$4.60	829.9	$4.75	4571.0	$4.29	8737.5	1179.5
December-10	1109.8	$4.60	914.2	$4.28	3389.7	$3.66	8737.5	1237.6
January-11	1109.8	$4.60	1975.7	$3.66	3135.3	$3.99	8737.5	1207.6
February-11	1109.8	$4.60	1670.3	$4.25	3516.2	$3.57	8737.5	1245.8
March-11	1109.8	$4.60	1723.0	$4.00	4231.1	$3.57	8737.5	1246.0
April-11	1109.8	$4.60	1719.8	$3.82	3509.6	$3.32	8737.5	1269.1
May-11	726.5	$13.54	1663.8	$13.20	3354.4	$11.97	8832.0	462.4
June-11	726.5	$13.54	2216.9	$12.00	2896.2	$11.76	8832.0	482.3
July-11	726.5	$13.54	1926.1	$11.84	3301.5	$5.76	8832.0	1046.9
August-11	726.5	$13.54	1645.3	$9.50	3361.6	$5.83	8832.0	1040.8
September-11	726.5	$13.54	1334.0	$6.99	3680.6	$5.71	8832.0	1052.3
October-11	726.5	$13.54	1280.1	$6.49	3511.6	$9.01	8832.0	883.0

Figure 3.a.

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
November-99							4555.3	
December-99							4555.3	
January-00	Installed Capacity Market Existed but all purchases and sales were bilateral						4555.3	
February-00							4555.3	
March-00							4555.3	
April-00							4555.3	
May-00	0	-	0	-	0	-	4638.0	
June-00	0	-	0	-	0	-	4638.0	
July-00	0	-	0	-	0	-	4638.0	
August-00	0	-	0	-	0	-	4638.0	
September-00	0	-	0	-	0	-	4638.0	
October-00	0	-	0	-	0	-	4638.0	
November-00	0	-	0	-	0	-	4638.0	
December-00	0	-	0	-	0	-	4638.0	
January-01	0	-	0	-	0	-	4638.0	
February-01	0	-	0	-	0	-	4638.0	
March-01	0	-	0	-	0	-	4638.0	
April-01	0	-	0	-	0	-	4638.0	
May-01	0	-	0	-	3.2	$10.83	4625.0	
June-01	0	-	0	-	7.0	$10.83	4625.0	
July-01	0	-	0	-	20.2	$10.83	4625.0	
August-01	0	-	0	-	21.3	$10.83	4625.0	
September-01	0	-	0	-	33.0	$10.83	4625.0	
October-01	0	-	0	-	33.0	$10.83	4625.0	
November-01	0	-	0.6	$3.50	8.5	$12.33	4077.6	
December-01	0	-	1.3	$3.50	37.4	$12.33	4077.6	
January-02	0	-	1.3	$5.00	39.7	$12.33	4077.6	
February-02	0	-	0	$ -	40.6	$11.50	4077.6	
March-02	0	-	14.0	$11.50	26.4	$11.49	4077.6	
April-02	0	-	41.4	$11.48	0	-	4077.6	
May-02	0	-	0	-	0	-	4177.8	
June-02	0	-	0	-	0	-	4177.8	
July-02	0	-	0	-	0	-	4177.8	
August-02	0	-	0	-	0	-	4177.8	
September-02	0	-	0	-	0	-	4177.8	
October-02	0	-	0	-	0	-	4177.8	
November-02	0	-	0	-	0	-	4256.2	
December-02	0	-	0	-	0	-	4256.2	

Figure 3.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-03	0	-	0	-	0	-	4256.2	
February-03	0	-	0	-	0	-	4256.2	
March-03	0	-	0	-	0	-	4256.2	
April-03	0	-	0	-	0	-	4256.2	
May-03	6.6	$9.41	2.2	$24.00	0.2	$23.00	4415.3	0.0
June-03	6.6	$9.41	0.0	--------	341.9	$5.17	4415.3	341.9
July-03	6.6	$9.41	1.0	$5.00	344.7	$5.14	4415.3	344.7
August-03	6.6	$9.41	1.1	$5.00	441.8	$4.03	4415.3	441.8
September-03	6.6	$9.41	0.0	--------	397.8	$4.55	4415.3	396.2
October-03	6.6	$9.41	0.0	--------	397.8	$4.55	4415.3	396.0
November-03	0.0	$4.00	0.0	--------	114.3	$8.14	4401.9	83.7
December-03	0.0	$4.00	0.0	--------	107.5	$8.22	4401.9	76.9
January-04	0.0	$4.00	0.0	--------	128.2	$7.99	4401.9	97.0
February-04	0.0	$4.00	0.6	$7.50	202.6	$7.08	4401.9	176.0
March-04	0.0	$4.00	0.6	$7.00	142.6	$7.72	4401.9	119.9
April-04	0.0	$4.00	0.6	$6.85	199	$7.04	4401.9	179.7
May-04	11.2	$8.00	1.6	$8.00	97.5	$9.83	4761.5	81.2
June-04	11.2	$8.00	11.2	$9.29	90.8	$9.79	4761.5	84.3
July-04	11.2	$8.00	15.9	$8.67	193.4	$8.42	4761.5	192.9
August-04	11.2	$8.00	16.4	$8.05	213.1	$8.16	4761.5	213.1
September-04	11.2	$8.00	16.2	$8.06	214.2	$8.15	4761.5	214.2
October-04	11.2	$8.00	16.2	$8.06	214.2	$8.15	4761.5	214.2
November-04	13.9	$4.00	10.9	$4.00	358.2	$6.34	4736.0	357.7
December-04	13.9	$4.00	9.0	$4.33	368.5	$6.21	4736.0	367.6
January-05	13.9	$4.00	9.0	$3.81	372.1	$6.16	4736.0	371.4
February-05	13.9	$4.00	7.6	$3.68	373.3	$6.14	4736.0	372.8
March-05	13.9	$4.00	7.0	$3.54	371.9	$6.16	4736.0	371.9
April-05	13.9	$4.00	7.0	$3.54	367.4	$6.23	4736.0	365.8
May-05	10.6	$8.00	2.7	$8.00	85.5	$12.15	4904.9	85.4
June-05	10.6	$8.00	2.0	$8.50	100.4	$11.96	4904.9	97.8
July-05	10.6	$8.00	4.3	$9.00	195.3	$10.48	4904.9	195.0
August-05	10.6	$8.00	4.6	$8.50	222.5	$10.06	4904.9	222.5
September-05	10.6	$8.00	4.6	$8.61	233	$9.90	4904.9	233.0
October-05	10.6	$8.00	4.6	$8.71	260	$9.49	4904.9	260.0
November-05	15.0	$0.68	10.0	$5.00	330.5	$8.37	4962.4	330.5
December-05	15.0	$0.68	10.1	$4.99	344.5	$8.16	4962.4	344.5

Figure 3.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity

LI	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-06	15.0	$0.68	10.0	$5.00	288.1	$9.00	4962.4	288.1
February-06	15.0	$0.68	10.0	$5.00	343.1	$8.18	4962.4	343.1
March-06	15.0	$0.68	10.0	$5.00	350.8	$8.07	4962.4	350.8
April-06	15.0	$0.68	10.0	$5.00	346.1	$8.14	4962.4	346.1
May-06	4.0	$6.50	9.0	$6.50	166.8	$11.15	5110.3	165.0
June-06	4.0	$6.50	2.3	$7.50	469.3	$6.76	5110.3	462.5
July-06	4.0	$6.50	3.0	$7.00	483.0	$6.52	5110.3	478.8
August-06	4.0	$6.50	3.0	$6.75	497.2	$6.31	5110.3	493.0
September-06	4.0	$6.50	4.6	$6.50	503.4	$6.19	5110.3	500.8
October-06	4.0	$6.50	7.2	$6.00	513.6	$6.02	5110.3	512.6
November-06	1.5	$3.50	9.6	$3.75	672.0	$3.66	5072.2	669.4
December-06	1.5	$3.50	11.1	$3.50	670.6	$3.65	5072.2	669.7
January-07	1.5	$3.50	14.6	$3.50	673.0	$3.60	5072.2	672.9
February-07	1.5	$3.50	14.6	$3.50	672.3	$3.61	5072.2	672.3
March-07	1.5	$3.50	14.6	$3.50	672.3	$3.61	5072.2	672.3
April-07	1.5	$3.50	14.6	$3.32	672.3	$3.61	5072.2	672.3
May-07	2.2	$3.75	3.0	$3.75	450.3	$7.25	5056.3	450.2
June-07	2.2	$3.75	3.0	$5.50	353.1	$8.78	5056.3	353.1
July-07	2.2	$3.75	0.0	$0.0	451.5	$7.23	5056.3	451.4
August-07	2.2	$3.75	1.0	$5.50	454.0	$7.22	5056.3	672.3
September-07	2.2	$3.75	1.3	$5.50	455.6	$7.17	5056.3	672.3
October-07	2.2	$3.75	1.4	$5.50	455.7	$7.17	5056.3	450.2
November-07	0.0	$0.00	2.0	$3.50	631.5	$4.31	4972.5	630.6
December-07	0.0	$0.00	0.0	$0.00	635.9	$4.27	4972.5	633.0
January-08	0.0	$0.00	1.9	$3.70	640.3	$4.20	4972.5	637.4
February-08	0.0	$0.00	7.2	$3.00	645.1	$4.07	4972.5	645.1
March-08	0.0	$0.00	2.8	$0.00	648.5	$4.02	4972.5	648.5
April-08	0.0	$0.00	2.8	$0.00	648.8	$4.01	4972.5	648.8
May-08	0.0	$2.80	21.8	$2.80	652.1	$2.60	4684.9	650.8
June-08	0.0	$2.80	130.5	$2.88	644.9	$2.94	4684.9	583.3
July-08	0.0	$2.80	168.2	$2.94	653.4	$2.80	4684.9	650.8
August-08	0.0	$2.80	165.7	$2.86	657.4	$2.70	4684.9	656.3
September-08	0.0	$2.80	102.0	$2.80	659.4	$2.45	4684.9	658.9
October-08	0.0	$2.80	108.2	$2.77	668.7	$1.93	4684.9	668.7
November-08	0.3	$1.77	1.8	$1.60	772.8	$1.00	4566.1	772.6
December-08	0.3	$1.77	10.0	$1.50	802.4	$1.25	4566.1	802.2

Figure 3.a. (cont'd)

November 1999 – December 2009
Installed Capacity Auction Activity
Long Island Locality (LI) Capacity[30]

LI	Capability Period* (Strip)		Monthly		Spot Market		Minimum Required	Excess
								Sold
Month	MW	Price	MW	Price	MW	Price	MW	MW
January-09	0.3	$1.77	210.8	$1.50	847.0	$3.19	4566.1	733.9
February-09	0.3	$1.77	135.6	$2.50	821.1	$1.77	4566.1	820.9
March-09	0.3	$1.77	117.7	$1.10	849.1	$0.50	4566.1	816.9
April-09	0.3	$1.77	88.5	$0.50	821.1	$0.30	4566.1	820.9
May-09	53.3	$3.01	69.5	$3.01	414.8	$4.71	4748.5	410.4
June-09	53.3	$3.01	46.5	$3.50	415.8	$4.65	4748.5	415.8
July-09	53.3	$3.01	75.9	$4.11	404.9	$4.77	4748.5	404.8
August-09	53.3	$3.01	72.9	$4.19	717.8	$3.42	4748.5	717.8
September-09	53.3	$3.01	73.5	$3.49	742.9	$2.76	4748.5	738.9
October-09	53.3	$3.01	48.9	$2.59	749.3	$2.23	4748.5	743.1
November-09	35.0	$1.75	31.0	$1.55	843.5	$0.50	4685.0	843.3
December-09	35.0	$1.75	124.0	$1.30	875.3	$0.75	4685.0	842.3
January-10	35.0	$1.75	180.8	$1.62	843.4	$1.85	4685.0	843.3
February-10	35.0	$1.75	129.0	$2.37	843.3	$3.49	4685.0	843.3
March-10	35.0	$1.75	39.7	$1.59	843.3	$0.85	4685.0	843.3
April-10	35.0	$1.75	87.9	$0.74	855.4	$0.64	4685.0	843.3
May-10	26.2	$2.47	16.8	$2.70	354.8	$5.81	4901.0	354.0
June-10	26.2	$2.47	56.8	$2.68	829.0	$2.12	5,021	829.0
July-10	26.2	$2.47	137.8	$1.90	816.9	$1.91	5,021	816.9
August-10	26.2	$2.47	82.4	$1.79	851.2	$1.68	5,021	851.2
September-10	26.2	$2.47	58.8	$1.00	865.9	$0.63	5,021	865.9
October-10	26.2	$2.47	46.1	$0.45	851.8	$0.56	5,021	851.8
November-10	1.2	$0.39	6.1	$0.27	913.4	$0.01	5073.8	913.3
December-10	1.2	$0.39	17.7	$0.10	915.8	$0.50	5073.8	913.3
January-11	1.2	$0.39	140.4	$0.65	913.3	$0.50	5073.8	913.3
February-11	1.2	$0.39	170.7	$0.45	913.3	$0.65	5073.8	913.3
March-11	1.2	$0.39	94.9	$0.15	926.6	$0.30	5073.8	913.3
April-11	1.2	$0.39	120.7	$0.20	918.4	$0.15	5073.8	913.3
May-11	1.2	$0.55	60.4	$0.60	895.3	$0.65	5051.7	895.3
June-11	1.2	$0.55	104.7	$0.60	904.5	$0.55	5051.7	904.5
July-11	1.2	$0.55	97.2	$0.50	906.1	$0.15	5051.7	904.5
August-11	1.2	$0.55	64.5	$0.16	910.8	$0.05	5051.7	908.3
September-11	1.2	$0.55	76.4	$0.10	892.1	$0.20	5051.7	890.0
October-11	1.2	$0.55	99.4	$0.10	900.9	$0.13	5051.7	900.9

[30] The Locational Minimum Installed Capacity Requirement for Long Island for June 2010 through October 2010 was 5,021; and was incorrectly stated in the 2010 annual report as 4,901.