New York Independent System Operator, Inc.

MARKET ANALYSIS OF MERCHANT GENERATORS IN THE NEW YORK WHOLESALE ELECTRIC MARKET

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I. EXECUTIVE SUMMARY

PURPOSE OF THE ASSIGNMENT

The New York Independent System Operator, Inc. ("NYISO") has retained Concentric Energy Advisors, Inc. ("Concentric") to conduct an independent analysis of historic merchant generator profit margins in the New York wholesale electric market. The analysis examines, over a nine year period, the costs incurred and revenues realized by generators and derives estimates of the return on invested capital for select resource types. The analysis is intended to help facilitate consideration by stakeholders of the ability of the wholesale market to provide capital returns to generation investors commensurate with business risk.

ANALYTIC APPROACH

The historic profitability of individual merchant generators is closely guarded commercial information, access to which typically is provided only under strict confidentiality provisions, if at all. Lacking access to reliable and public sources of generator profitability, Concentric has approached this assignment by defining five types of generation resources that encompass the preponderance of merchant generation facilities operating in the New York wholesale electric market (i.e., the "generic resources"). The generic resources analyzed in this report are:

- A generic dual-fuel gas/oil steam resource in New York Zone J
- A generic gas-fired peaking resource in Zone J
- A generic gas-fired combined-cycle resource in Zone F
- A generic nuclear resource in Zone C
- A generic coal resource in Zone A

For each generic resource, we modeled power production costs and revenues over nine calendar years (2000-2008) using reported historic fuel and power market prices and applying industry standard assumptions for key operating and financial parameters (e.g. capacity factors by resource type). This approach allowed us to estimate profitability for each generic resource type during this nine year period. Our approach and results are not intended to represent any given generator in the wholesale market, but provide a meaningful approximation of generator profitability for various types of generators operating in the New York market. This analysis allows us to identify key drivers of generator profitability and reach certain conclusions regarding the functioning of the New York wholesale electric market and its effectiveness in sending appropriate investment signals to investors.

It is important to note that this analysis does not include some market products, operational restrictions and other market dynamics, as described below. As a result, we believe our analysis may overstate the Net Income actually realized by some resources operating in the wholesale market for the following reasons:

1) This analysis does not consider revenues from products in the ancillary services market, including, but not limited to, operating reserves, regulation, and voltage support. Since operating reserves, which represent the majority of the potential revenues associated with ancillary services, are co-optimized with energy, a generator should be indifferent as to whether it is receiving revenues from the energy or reserves market. Therefore, our analysis is likely to be insensitive to ancillary services.
2) This analysis does not include operational constraints such as environmental limitations, minimum run time, minimum down time, start-up time, and other costs such as start-up and no-load costs, all of which increase the operating costs of a generating resource and its ability to realize the level of Net Income shown in this analysis relative to the costs we assume in our analysis.
3) The Net Income and Return on Asset calculated for each resource assumes that all energy is sold in the day-ahead market. In reality, over 50% of the energy sold in the New York wholesale market is transacted under some form of contract, and the prices paid under these contracts are not publicly available.

CONCLUSIONS

Based on our analysis, Concentric concludes:

1) Nuclear and coal-fired generating resources achieved the highest Net Income and Return on Asset over the nine year period as compared to dual-fuel gas/oil, combined-cycle, and peaking generating resources. For example, in 2007, nuclear and coal-fired generating resources realized a Return on Asset of 36.40% and 20.10%, respectively. This compares to 20.29% for a combined-cycle resource, 16.84% for a dual-fuel resource, and 13.80% for a gas-fired peaking resource. By 2008, the Return on Asset for a dual-fuel resource decreased to -4.32%, while the Return on Asset for a simple-cycle peaking resource decrease to -6.91%. This was primarily due to decreases in capacity revenues as discussed below.
2) Gas prices are one of the biggest drivers of baseload coal-fired and nuclear generating resource profitability, as shown in Appendix A. Gas-fired resources are the marginal resource in most hours and therefore set the clearing price in the market. Gas prices increased by 101%, on average, from 2000 to 2008. Over this time period, revenues for nuclear assets increased by 92%, while revenues for coal-fired assets increased by over 72%. Currently, gas prices are approximately 50% lower than gas prices at this time last year, and LMPs are approximately 70% lower on average. An analysis comparing Return on Asset and Net Income in 2008 to estimated year-to-date Return on Asset and Net Income in 2009 shows a significant decrease for all resources, except for dual-fuel resources, which experienced a nominal increase in Return on Asset due to their ability to arbitrage their fuel flexibility.
3) Capacity prices are another significant driver of resource profitability for all resource types. Since the changes in mitigation rules in the capacity market were implemented in 2008, capacity prices in Zone J have decreased by 53%, contributing to a decrease in Net Income

for resources in this zone of over 200%. This market rule change is reflective of the type of regulatory risk which investors incur for which they seek compensation.

4) Investment signals are critically important to the functioning of an efficient wholesale market. While coal-fired and nuclear resources were quite profitable from 2000-2008, the regulatory and operating risks associated with these types of resources are significantly greater than those associated with other types of generating resources, and investors expect a return on their capital commensurate with these risks. Since regulatory and public policy issues make the construction of new coal-fired and nuclear generating resources in New York difficult, it is vital that the appropriate investment signals are sent to encourage more "acceptable" types of resources, such as gas-fired combined-cycle, and peaking resources, when they are needed in particular locations. According to the 2009 NYISO Comprehensive Reliability Plan ("2009 CRP"), the New York Control Area is expected to have adequate capacity to meet projected demand and required reserve margins for the next 10 years. However, there are multiple scenarios that could, in the future, cause reliability violations such as a higher than expected growth in demand, unexpected generation retirements, or cancellation of future projects that are currently included in the 2009 CRP, and upon which the NYISO is relying to meet projected capacity requirements. Clearly, some expectation of profitability is required to send the investment signals needed to not only incent new entry when needed, but to maintain existing resources that are critical to system reliability.

The remainder of this report is organized into the following sections:

- Section II provides context for our analytic approach. It outlines the structure of the New York wholesale electric market, reviews the types and locations of generators, summarizes key rules governing how wholesale electric prices are determined, and explains the difference between the electric markets administered by the NYISO and the bilateral contracting market.
- Section III presents the assumptions and data sources Concentric relied upon in preparing this analysis.
- Section IV presents the results of our analysis.
- Section V summarizes the conclusions reached based on this analysis.

II. BACKGROUND

OVERVIEW OF WHOLESALE ELECTRICITY MARKET OPERATIONS

The NYISO, a not-for-profit corporation which began operation in December of 1999, is responsible for managing an open, competitive, and nondiscriminatory wholesale market for electricity through the scheduling and controlling of the bulk power flow of more than 335 power plants in New York State. In addition, the NYISO ensures the reliable, safe, and efficient operation of the 10,775-mile network of high-voltage lines that carry electricity throughout the state. The NYISO is regulated by the Federal Energy Regulatory Commission ("FERC") and governed by an independent 10-member Board of Directors and a committee of stakeholders.

The New York wholesale electric marketplace consists of three basic markets: energy, capacity, and ancillary services. These markets are augmented by various tools to manage risk such as financial transmission rights and virtual bidding of supply and load.

Energy Market

The energy market in New York consists of a two-settlement system made up of a financially-binding day-ahead market and a real-time balancing market. The day-ahead market is a financial market in which clearing prices are calculated for each hour of the next operating day based on scheduled hourly quantities. A generator whose offer clears and a Load Serving Entity ("LSE") whose bid clears in the day-ahead market are paid based on the day-ahead clearing price. The real-time market is a physical market based on actual hourly deviations from day-ahead scheduled quantities with real-time prices calculated every five minutes and integrated over the hour. LSEs pay prices for any demand that exceeds their day-ahead scheduled quantities and will receive revenue for demand deviations below their scheduled quantities. Generators are paid real-time prices for generation that exceeds the day-ahead scheduled quantities and will pay for generation deviations below their scheduled quantities. The day-ahead and real-time price calculations are based on the concept of "locational marginal pricing."

Locational marginal prices ("LMPs"), on which the financial settlement for both generation and load is settled, is based on the short-run marginal cost of supplying energy. These prices, which are location-specific, are made up of three components: energy, congestion, and losses. The energy component (or marginal cost) is defined as the cost to serve the next increment of demand at the specific location, or node, that can be produced from the least expensive generating unit in the system that still has available capacity. The energy component of LMPs is the same at all nodes on the system. The congestion component of the LMP is defined as the cost of serving the next increment of energy when it cannot be delivered from the least expensive unit on the system because it would cause overloading on the transmission system or violate transmission operating criteria. In this case, the congestion component is calculated as the difference between the energy component of the LMP and the marginal cost of the resource providing the additional, more expensive energy to that location. Finally, the loss component of the LMP is calculated to account for the losses incurred in transmitting energy over the bulk power system.

Capacity Market

The capacity market is designed to provide efficient economic signals by location that supplement the signals provided by the energy and ancillary services markets to govern investment decisions for generation and transmission in order to ensure resource adequacy. Capacity markets compensate supply resources and demand resources either for the electricity they are capable of producing if needed or, in the case of demand resources, for the electricity they avoid using to ensure that enough electricity capacity exists to meet regional reliability requirements.

The New York capacity market is divided into three zones: New York City, Long Island, and the "Rest of State." The capacity requirement for the Control Area is calculated based on the forecast maximum demand plus a reserve margin. Each LSE is then allocated a share of the total requirement in the zone(s) in which they serve load, which can be met through self-supply or bilateral transactions with generators, or by voluntary participation in one of the NYISO's six-month or monthly forward auctions. Any remaining obligations at the end of each month are settled against the NYISO's monthly spot auction where clearing prices are determined by a capacity demand curve, which is designed to address the inherent price volatility in the capacity market. Without the demand curve, the capacity market signal encourages the supply of exactly the required capacity amount, so that any excess capacity is unsold and clearing prices are extremely low. However, as soon as there is a capacity deficiency, prices tend to increase drastically. The demand curve corrects for this volatility by setting the price for capacity so that it varies gradually with the supply of capacity.

Ancillary Services

The ancillary services market is designed to ensure that the bulk power system can sustain sudden system disturbances caused by either generation or transmission. Because the ancillary services markets are co-optimized with the energy markets, clearing prices reflect the most efficient use of resources to meet system energy and reserves requirements. Reserve products are subject to locational requirements that ensure the reserves are located where they can respond to system contingencies.

The NYISO currently procures all market-based ancillary services through the day-ahead and real-time markets. These market-based ancillary services include (i) ten-minute spinning reserves, (ii) ten-minute total reserves, (iii) thirty-minute reserves, and (iv) regulation. Ten-minute spinning reserves are generating units that are synchronized to the system and can provide additional output within 10 minutes. Ten-minute total reserves can be supplied by synchronized 10-minute spinning resources or off-line resources that can be synchronized and produce within 10 minutes. Thirty-minute reserves may be supplied by any unit that can be ramped up in 30 minutes or that can start up and produce within 30 minutes. Regulation service is necessary to continuously balance generation with short-term increases and decreases in load by moving the output of selected generators up and down via control systems.

PRICE FORMATION IN THE ENERGY MARKET

The NYISO uses a single clearing-price auction to determine the uniform energy price necessary to meet regional demand in the day-ahead and real-time markets. In simple terms, generating resources submit offers to sell electricity and LSEs submit bids to purchase electricity on behalf of their customers. The system operator then "stacks" these offers and bids by price until supply exactly meets demand. The last generating resource chosen to meet demand sets the "clearing" price. All producers that offer their resources at or below the clearing price are scheduled to operate and earn the clearing price for their production. Those that offer too high are not selected to run, creating a built-in incentive for suppliers to offer their energy at their short-run marginal cost.

Because the single-clearing price auction design is based on the offer of the last generator chosen to meet demand, many generators are paid more than their offer. This results in "inframarginal" revenues, defined as those revenues earned in the energy market in excess of a resource's variable and fuel costs. When a generating resource is paid more than its offer, it realizes an operating profit, which contributes to its fixed costs, such as fixed operating and maintenance costs and debt service. These inframarginal revenues are necessary to cover a generator's fixed investment and capital costs and they provide a critical economic signal that the market requires for new investment.

While generating resources are incented to offer at a price that reflects their marginal cost of producing energy, the NYISO has mechanisms in place to ensure that the market is workably competitive through the mitigation of market power abuses. The NYISO monitors the market for potentially disruptive activities in the following three areas: (1) the physical withholding of a generating facility, (2) the economic withholding of a generating facility, and (3) uneconomic production from a generating facility. The physical withholding of a generating facility is defined as "not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Administered Market."[1] The NYISO defines the economic withholding of a generating facility as "submitting bids for an Electric Facility that are unjustifiably high so that (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a market clearing price."[2] Finally, the NYISO monitors the market for uneconomic production from a generating resource. The NYISO defines uneconomic production as "increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint."[3]

In addition to the above conduct thresholds, the NYISO has impact thresholds designed to measure impacts on the market when the above thresholds are triggered. If the NYISO determines that conduct on the part of a generator has met specified thresholds for certain market price and other payment impacts, bids will be mitigated and sanctions may be applied.

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[1] New York Independent System Operator, FERC Electric Tariff, Original Volume No. 2, Attachment H, Sixth Revised Sheet No. 469.

[2] Id.

[3] Id at Fifth Revised Sheet 470.

BILATERAL CONTRACTING VS. MARKET SALES

While installed capacity resources are obligated under current market rules to offer their physical supply into the day-ahead energy market, much of the financial settlement associated with the sale and purchase of energy takes place outside of these markets through bilateral contracts. These bilateral contracts can be physical in that they represent the purchase or sale of supply from a generating resource, or they can be financial in that they represent a hedge against volatility in market prices. In either case, neither of these types of transactions affects the incentive for a generating resource to be dispatched when available, and the NYISO has rules in place to ensure that generators do not physically or economically withhold from the market. According to a recent presentation to the New York State Public Service Commission on the supply portfolios of investor-owned utilities, over 70% of the electricity required to supply full service residential and small commercial and industrial customers is purchased through bilateral contracts or is self-supplied.[4] Regardless of whether transactions occur through the market or through physical or financial transactions, the LMP provides an important price signal on which to base the pricing contained in such contracts, since sellers are not incented to sell far below the LMP without some commensurate decrease in risk, and buyers are not incented to purchase at prices above the LMP without a decrease in risk or some other benefit. Therefore, it is reasonable to use energy and capacity market prices as a proxy for calculating merchant generator profit margins through the sale of energy and other products.

[4] New York State Public Service Commission Summer Price Outlook 2009.

III. ASSUMPTIONS

The key market and operating assumptions relied upon in this analysis are shown in Appendix B. The sources of information underlying our assumptions are shown in Appendix C. The following provides a summary of the key assumptions underlying our analysis.

TECHNOLOGIES

Each of the five generic resources reflects a power generation technology operating in the New York market in 2000-2008. Our assumptions for generic resource unit size (expressed in megawatts ("MW") of generating capacity) and unit heat rate (expressed in Btu/kWh) are based on publicly available information of average unit nameplate capacity in New York and industry average heat rate for each resource type.

CAPACITY FACTOR

For each generic resource, we developed an assumed annual capacity factor based on publicly available information of average annual unit capacity factor for 2000-2008 for all units of the same resource type operating in the same zone as our generic resource. The annual capacity factors include all unit outages.

We calculated a unit's annual generation as the product of: (i) MW of capacity, (ii) annual capacity factor, and (iii) number of hours/year. For fossil-fired generating resources, we then allocated annual generation to peak and off-peak hours by first assuming each unit is 100% available on-peak and then, to the extent additional generation is required to achieve the assumed annual generation for that resource, we assumed additional generation during off-peak hours. For the nuclear unit, we assumed it would operate at a constant capacity factor across peak and off-peak hours. This resulted in the following generation profile by resource:

- Peaking generation is 100% on-peak
- Combined-cycle generation is 99% on-peak and 1% off-peak
- Dual-fuel gas/oil generation is 100% on-peak
- Coal-fired generation is 66% on-peak and 34% off-peak
- Nuclear generation is 47% on-peak and 53% off-peak

ELECTRIC AND FUEL PRICES

We modeled two sources of electric generation revenue for each generic resource:

- We assumed the generators sell all energy generated into the NYISO energy market. For each generator in each year, we calculated the product of: (i) the assumed generation (see

Capacity Factor above) and (ii) the average monthly peak and off-peak LMPs for the relevant NYISO Zone.[5]

- We further assumed the generators sell capacity into the NYISO capacity market. For each year, we calculated capacity revenues as the product of: (i) installed capacity, (ii) forced outage rate, and (iii) the average annual monthly auction capacity price for the relevant capacity zone (New York City locality for the peaking resource and dual-fuel resources; Rest of State for the nuclear, coal and combined-cycle units).
- We did not assume revenues from the ancillary services market since the NYISO co-optimizes energy and reserves in the dispatch of generating resources. This co-optimization results in the efficient dispatch of generation to meet energy and reserves requirements and as a result, a generator should be indifferent as to whether it is receiving it revenues from the energy or reserves market.

We modeled power plant fuel prices as follows:

- We assumed the peaking, combined cycle, and dual-fuel generating resources purchased natural gas on a spot market basis. For the New York City peaking and dual-fuel resources, we used a monthly average of daily Transco Z-6 NY prices for April 2001-2008, plus a 3.9% markup to reflect the cost of local delivery to the burnertip. Due to data limitations, prices for 2000-March 2001 were calculated by adjusting a Northeastern spot price average by the average spread between Transco Z-6 NY and the Northeastern spot price average from April 2001-2008. For the gas combined-cycle unit in Zone F, we used the monthly average of the daily Dominion North prices for 2000-2008. We assumed the combined-cycle resource bought gas directly off the pipeline and incurred no local delivery cost adder. The volume of gas through Dominion North is relatively small, which means there are days in which no pricing data is available. To fill these gaps in data, we calculated the values in the same fashion as described above for Transco Z-6 NY.
- We assumed the dual-fuel generating resource bought 0.3% sulfur #6 oil at a monthly average of 2000-2008 daily spot New York Harbor prices. We assumed that costs associated with oil storage, taxes/fees, and delivery to the burnertip added an 11.4% markup to the spot price.
- For the coal-fired generating resource, we used the annual average delivered to power plant price of coal in New York for 2000-2008.
- We assumed a $4.90 per megawatt-hour ("MWh") cost of nuclear fuel.

FIXED COSTS

We modeled several types of generator fixed costs:

[5] Only on-peak LMPs were used for gas-fired peaking generating resources since these resources were assumed to operate only during on-peak hours.

- We assumed a fixed annual operation and maintenance ("O&M") cost per MW of installed capacity based on publicly available information of industry average values for each resource type.
- We assumed a fixed annual property tax as the product of: (i) publicly available information for property tax rates in effect during this period for New York City (the peaker and dual-fuel resources) and Rest of State (combined cycle and baseload generators) and (ii) the assumed market value of each generator. For each resource type, we assumed that the market value equaled the average transaction price (in $/MW) for generators sold in New York State in 1999 following industry restructuring. This value also provided the basis of our calculation of annual depreciation expense.
- For the nuclear resource, we assumed a fixed annual nuclear decommissioning fee in $/MW of capacity based on actual historic decommissioning costs of three New York nuclear units.

VARIABLE COSTS

We modeled the following variable input costs:

- We assumed each generic resource paid the NYISO Rate Schedule 1 fee for each MWh of generation during the nine year modeled period.
- Variable O&M costs were calculated as the product of: (i) MWh of annual generation (see Capacity Factor above) and (ii) publicly available information of industry average variable O&M cost data (expressed in $/MWh of generation) for each resource type.
- For the fossil fuel resources, SO_2 and NO_x emissions expense equaled the product of: (i) the emissions rates for the relevant fuel, (ii) each unit's monthly fuel consumption, and (iii) monthly average SO_2 and NO_x spot allowance prices for 2004-2008. In 2008, we assumed the generating resources continued to incur emission costs at the market price of allowances from June, when the CAIR rule was vacated, through December, when it was restored.
- Fuel Expense:
    - For the fossil fueled generating resources, variable fuel costs were calculated as the product of: (i) our assumed delivered cost of fuel (expressed in $/MMBtu), (ii) our assumed heat rate, and (iii) MWh of annual generation (see Capacity Factor above).
    - For the nuclear generating resources, variable fuel costs were calculated as the product of: (i) a flat $4.90/MWh and (ii) MWh of annual generation.

FINANCIAL

Our model included a variety of financial assumptions that we applied consistently across each of the generic resources:

- Interest cost:
  - Assumed plant acquisition in 1999 financed with 50% debt (0% for nuclear)[6]
  - Assumed Moody's Baa utility bond index cost of debt in 1999
- Inflation rate
- Depreciation rate (assumes 20 year MACRS depreciation of 1999 plant value)
- Federal and State income tax rate

In addition, we assumed annual capital expenditures (expressed in $/MW of installed capacity) for each resource type based on publicly available information of industry average capital expenditures by resource type.

[6] 100% equity assumed for nuclear generating resources since when these assets were sold, they were financed with 100% equity.

IV. RESULTS

PROFIT MARGIN BY RESOURCE TYPE

Shown in Table 1 below are the average capacity sizes of each resource, the Net Income, and Return on Asset. The Net Income included estimated revenues from the energy and capacity markets, and all expenses including (i) fuel, (ii) variable and fixed operating and maintenance costs, (iii) debt service, (iv) property taxes, (v) income taxes, (vi) NYISO administrative expenses, (vii) depreciation, and (viii) decommissioning expenses in the case of a nuclear asset only. Return on Asset is calculated as Net Income plus debt expense divided by Net Plant.

TABLE 1 – SUMMARY OF RESULTS

	2000	2001	2002	2003	2004	2005	2006	2007	2008	YTD 2009
Coal										
Total Capacity (MW)	236	236	236	236	236	236	236	236	236	236
Net Income	$ 6,075,830	$ 9,911,604	$ (4,122,999)	$ 12,541,760	$ 7,887,308	$ 20,063,924	$ 5,792,856	$ 13,344,091	$ 19,036,480	$ (5,015,696)
Return on Assets	10.90%	15.22%	-0.43%	18.37%	13.22%	27.33%	11.07%	20.10%	27.19%	-6.40%
Gas CC										
Total Capacity (MW)	322	322	322	322	322	322	322	322	322	322
Net Income	$ 4,883,630	$ 10,714,328	$ 1,896,597	$ 1,678,185	$ (139,280)	$ 5,709,734	$ 5,253,929	$ 12,918,222	$ 11,621,396	$ 2,998,975
Return on Assets	8.34%	13.59%	6.38%	6.45%	5.00%	11.10%	11.18%	20.29%	19.94%	13.41%
Gas Peaking										
Total Capacity (MW)	29	29	29	29	29	29	29	29	29	29
Net Income	$ 49,948	$ 364,988	$ (480,201)	$ 333,890	$ 488,973	$ 579,433	$ 591,906	$ 488,525	$ (707,356)	$ (452,602)
Return on Assets	4.98%	9.49%	-2.29%	9.64%	12.33%	14.20%	14.95%	13.80%	-6.91%	-9.22%
Gas-Oil Steam										
Total Capacity (MW)	510	510	510	510	510	510	510	510	510	510
Net Income	$ 6,488,368	$ 16,773,537	$ 3,983,880	$ 15,787,441	$ 16,401,922	$ 19,313,181	$ 13,424,824	$ 11,977,368	$ (10,188,354)	$ (3,045,065)
Return on Assets	9.13%	17.25%	7.72%	17.58%	18.71%	21.95%	17.47%	16.84%	-4.32%	0.36%
Nuclear										
Total Capacity (MW)	928	928	928	928	928	928	928	928	928	928
Net Income	$ 48,472,558	$ 74,810,640	$ 29,564,995	$ 97,889,756	$ 98,757,785	$ 193,399,390	$ 130,546,311	$ 151,515,626	$ 185,400,698	$ 29,769,053
Return on Assets	11.48%	17.68%	6.98%	23.11%	23.36%	45.90%	31.15%	36.40%	44.93%	13.11%

ANALYSIS OF RESULTS

As can be seen from Table 1, nuclear and coal-fired generating resources have realized the highest Net Income and Return on Asset, on average, of all the resource types analyzed. This is expected since the variable costs associated with these types of resources are significantly lower than gas-fired resources, which are the marginal units setting price in most hours. As a result, these baseload resources realize significant inframarginal revenues from the energy market, as well as considerable

revenues from the capacity market. While these resources have higher fixed costs, the inframarginal and capacity revenues more than compensate for this fixed cost "adder."

Both the simple-cycle gas resources and the combined-cycle gas resources realize a much lower Net Income and Return on Asset. Since fuel cost makes up the largest component of these resources marginal cost of producing energy, and gas-fired resources are setting price in most hours, Net Income for gas-fired resources is mainly a product of their efficiency relative to the resource setting price. To the extent that a gas-fired resource is more efficient, its variable cost will be lower and it will realize some level of inframarginal revenues.

Gas prices are one of the biggest drivers of baseload coal-fired and nuclear generating resource profitability since gas-fired resources are the marginal resource in most hours and therefore set the clearing price in the market. Gas prices increased by 101%, on average, from 2000 to 2008. Over this time period, revenues for nuclear assets increased by 92%, while revenues for coal-fired assets increased by over 72%. Currently, gas prices are approximately 50% lower than gas prices at this time last year, and LMPs are approximately 70% lower, on average. An analysis comparing Return on Asset and Net Income in 2008 to estimated year-to-date Return on Asset and Net Income in 2009 shows a significant decrease for all resources, except for dual-fuel resources. This decrease is especially significant for nuclear resources, as well as coal-fired resources, which have not been able to cover their fixed costs thus far in 2009.

It is important to note that the significant decrease in Net Income and Return on Asset for the dual-fuel gas/oil resource and the gas-fired peaking resource in 2008 were driven by decreased capacity revenues, as well as a delay in the Poletti Station retirement and decreased load. Beginning in the summer of 2008, existing mitigation rules for divested in-city generation were changed, including offer caps, revenue caps, and restrictions on bilateral transactions. These rules were replaced with default reference prices and pivotal supplier tests that have resulted in a 53% decrease in capacity prices in Zone J in July 2008 as compared to July 2007, and contributed to a decrease in Net Income of over 200% for peaking resources.

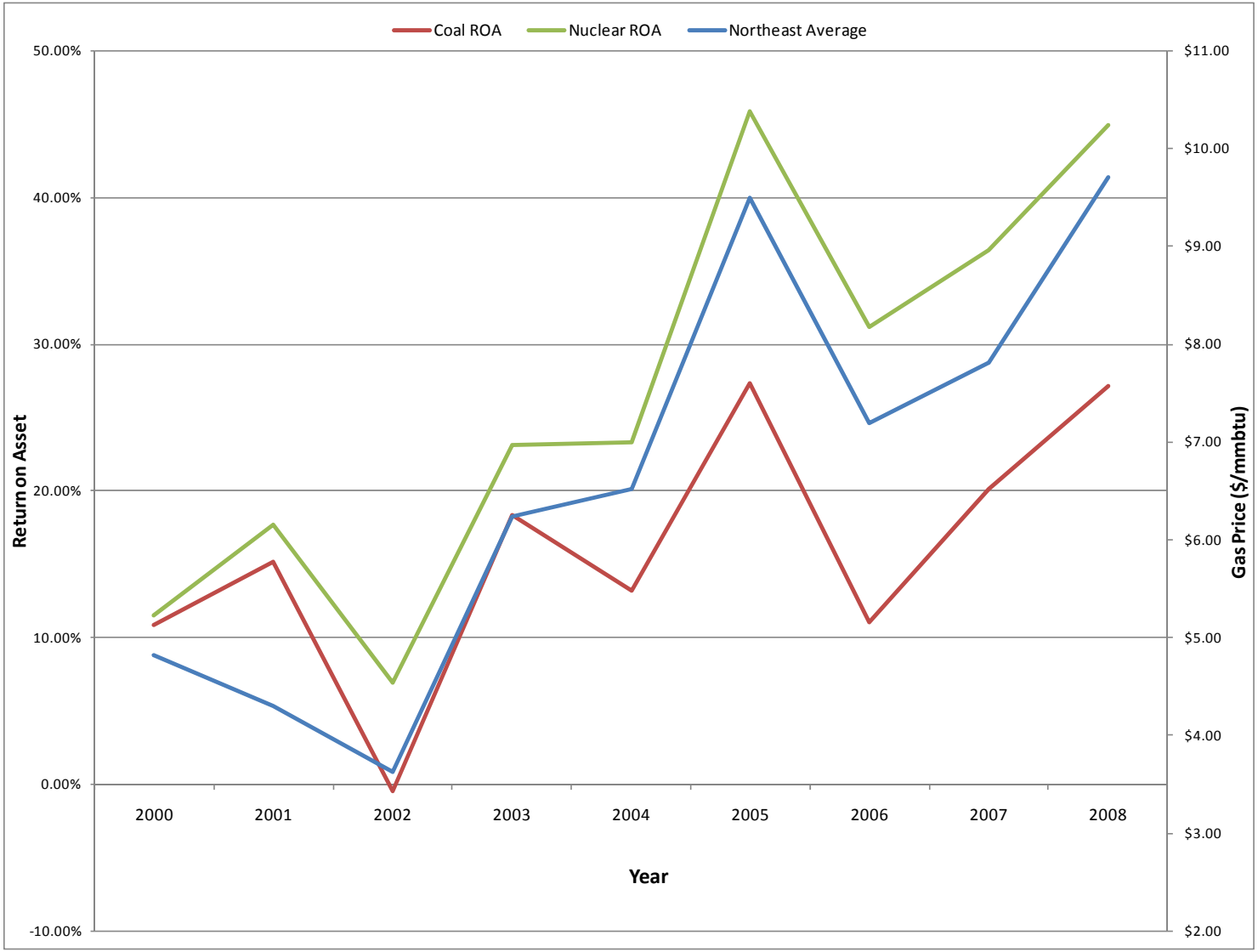
This analysis does not include operational constraints such as minimum run time, minimum down time, and start-up and no-load costs, all of which affect the cost structure of a generating resource and its ability to realize the level of Net Income shown in this analysis. Therefore, the results shown in Table 1 would tend to overstate the actual Net Income realized by a resource operating in the market.

V. CONCLUSION

This analysis shows that nuclear and coal-fired generating resources are the most profitable resources in the market. This outcome is appropriate, since the regulatory and operating risks associated with these types of resources are significantly greater than those associated with other types of generating resources, and investors expect a return on their capital commensurate with these risks. Alternatively, combined-cycle generating resources have shown modest profitability, while dual-fuel gas/oil and peaking generating resources have recently shown little to no profitability, largely due to lower capacity and energy prices.

While nuclear and coal-fired generating resources were quite profitable from 2000 through 2008, it is challenging to build these types of resources to meet future resource adequacy and reliability needs in New York due to complex political and regulatory hurdles. As a result, it is critical that investment signals are sent to encourage other types of resources that have proven to be more successful in being able to achieve market entry, such as gas-fired resources, when they are needed to meet specific locational reliability needs. While the NYISO 2009 CRP shows that the Control Area is expected to have adequate capacity to meet projected demand and required reserve margins for the next 10 years, unanticipated events could cause reliability violations such as a higher than expected growth in demand, unexpected generation retirements, or cancellation of future projects. In the event that one or more of these events trigger a need for additional resources, some expectation of profitability is required to send the investment signals needed to incent new entry.

Equally important to the need to incent new entry when needed is the need to maintain existing resources that are critical to system reliability. Gas-fired peaking and dual-fuel resources in Zone J were unable to recover their fixed costs in 2008 and this trend is expected to continue in 2009. These resources must have some expectation of profitability over a long-term horizon in order to remain in the market. Therefore, if there is a need for additional resources in the future, the signal that is critical to incent market entry will be equally as critical to ability of existing resources to ensure system reliability.



Note: Northeast Average is the Bloomberg Northeast Average Natural Gas Price for – Niagara; Waddington, Iroquois Zone 2; Transco Zone 6;Tennessee Gas Pipeline Zone, 6 200 Leg; Tennessee Gas Dracut, MA; Dominion South; Columbia Gas Transmission TCO Pool; Boston/New England City Gate via Algonquin Pipeline; Buffalo City Gate; Transco Zone 6 Non-NY; TETCO M3.

Summary of Assumptions

	General	Specific				
		Coal	Gas CC	Gas Peaker	Gas-Oil Steam	Nuclear
Revenue						
Capacity	New York plants, by comparable technology, fuel type, and zone	236	322	29	510	928
Capacity Factor (%)	New York plants, by comparable technology, fuel type, and zone	71.02%	45.07%	8.01%	21.46%	90.87%
Energy Generated (MWh)	Dispatch - all possible on-peak hours, balance of remaining hours dispatched off-peak (except nuclear) Heat Rate - Industry Averages by resource type	Heat Rate - 9,916	Heat Rate - 7,102	Heat Rate - 9,662	Heat Rate - 11,289	Heat Rate - 10,264 Dispatch evenly over on-peak and off-peak hours
Energy Revenues ($)	LMP pricing, monthly on-peak/ off-peak prices	Zone A	Zone F	Zone J	Zone J	Zone C
Capacity Revenues ($)	2 Zones, NYC and Rest of State Installed capacity less forced outages (EFORd)	Rest of State EFORd - 7.07%	Rest of State EFORd - 6.93%	NYC EFORd - 7.68%	NYC EFORd - 5.63%	Rest of State EFORd - 3.84%
Expenses						
Fixed O&M ($)	Industry Averages by resource type Per kW capacity	24.92 ($/kW-yr)	12.29 ($/kW-yr)	40.69 ($/kW-yr)	11.90 ($/kW-yr)	112.00 ($/kW-yr)
Variable O&M ($)	Industry Averages by resource type Per MWh	7.24 ($/MWh)	2.86 ($/MWh)	3.55 ($/MWh)	2.50 ($/MWh)	2.67 ($/MWh)
Fuel Expense	Varies by resource type	Delivered Cost Annual average prices used for years 2000 and 2001	Transportation adder Gaps in data were estimated using average spread of Dominion North spot price and a Northeast Average spot price	Transportation adder Prices before 4/1/2001 were estimated using average spread of Transco Z6 spot price and a Northeast Average spot price	Based on Astoria EIA data for historical fuel mix. 2000 fuel mix was based on monthly averages from 2001 to 2008 Total Fuel Cost was derived from NY Zone J Gas/Oil Steam average heat rate and average oil heat content Gas prices before 4/1/2001 were estimated using average spread of Transco Z6 spot price and a Northeast Average spot price	NEI - Flat 0.49 Cents/KWh

Summary of Assumptions

	General	Specific				
		Coal	Gas CC	Gas Peaker	Gas-Oil Steam	Nuclear
Emissions Expense	Historical NY emissions rates by fuel/resource type Spot market emissions allowance pricing. Assumes market reflects value of emissions allowances despite any changes in regulations. Also assumes an opportunity cost for any emissions allocated or retained, as unused emissions alowances could be sold on the spot market. No emissions charges incurred prior to 2004.				% of emissions gas/oil based on Astoria EIA data. 2000 fuel mix was based on monthly averages from 2001 to 2008	
Payment on Debt Interest	Applies value of plant at sale in 1999, percent debt financing, and the cost of debt cost at time of sale Fixed debt					NA
Property Tax	NYC and Rest of State Market value of plant - assumed sale price in 1999	Rest of State - 2.00% of market value of the plant	Rest of State - 2.00% of market value of the plant	NYC - 4.53% of market value of the plant	NYC - 4.53% of market value of the plant	Rest of State - 2.00% of market value of the plant
NYISO Administrative Fees	RS1 Fee ($0.1626/MWh)					
Decommissioning Expense	Only for Nuclear					Based on Nine Mile, Fitzpatrick historical balances
Financial						
Federal Income Tax	35%					
State Income Tax	8.0% for 2000-2001, 7.5% for 2002-2007, 7.1% for 2008					
Depreciation	20-year MACRS tax depreciation schedule Assuming a sale of plant in 1999 as Beginning plant value	$383/kW	$402/kW	$266/kW	$275/kW	$452/kW
CAPEX	Based on Inustry Averages by resource type	$23/kW Coal plant over 30 years old	$8/kW Oil or gas steam plant	$8/kW Oil or gas steam plant	$8/kW Oil or gas steam plant	$31/kW Nuclear plant over 30 years old
Book Life	20 years					
Tax Life	20 years					
Equity %		50%	50%	50%	50%	100%
Debt %		50%	50%	50%	50%	0%
Cost of Debt	Fixed at Moody's Baa Utility bond index for 1999	8.28%	8.28%	8.28%	8.28%	NA
Inflation	2.50%					

Summary of Sources

	General	Specific				
		Coal	Gas CC	Gas Peaker	Gas-Oil Steam	Nuclear
Revenue						
Capacity	SNL - New York Plants by technology and zone					
Capacity Factor (%)	SNL - New York Plants by technology and zone					
Energy Generated (MWh)	Various industry reports	EIA Average Heat Rates by Prime Mover & Energy Source USDOE/NETL Cost and Performance Baseline for Fossil Energy Plants MIT Study Future of Coal	EIA Average Heat Rates by Prime Mover & Energy Source ISONE 2007 Scenario Analysis USDOE/NETL Cost and Performance Baseline for Fossil Energy Plants CEC 2007 AEO 2009 Assumptions	NERA ICAP Working Group Lazard Report	SNL - New York Plants by technology and zone	EIA Average Heat Rates by Prime Mover & Energy Source ISONE 2007 Scenario Analysis CEC 2007 AEO 2009 Assumptions
Energy Revenues ($)	NYISO					
Capacity Revenues ($)	Price - NYISO Monthly Spot Market Forced Outage Rates - NERC					
Expenses						
Fixed O&M ($)	Various industry reports	USDOE/NETL Cost and Performance Baseline for Fossil Energy Plants	USDOE/NETL Cost and Performance Baseline for Fossil Energy Plants CEC 2007 AEO 2009 Assumptions	NERA ICAP Working Group Lazard Report	CEC 2007 AEO 2009 Assumptions	CEC 2007 AEO 2009 Assumptions
Variable O&M ($)	Various industry reports	USDOE/NETL Cost and Performance Baseline for Fossil Energy Plants MIT Study Future of Coal	USDOE/NETL Cost and Performance Baseline for Fossil Energy Plants CEC 2007 AEO 2009 Assumptions	NERA ICAP Working Group Lazard Report	CEC 2007 AEO 2009 Assumptions	CEC 2007 AEO 2009 Assumptions

Summary of Sources

	General	Specific				
		Coal	Gas CC	Gas Peaker	Gas-Oil Steam	Nuclear
Fuel Expense		Price - Actual NY contracts from SNL.	Price - Dominion North Bloomberg spot prices.	Price - Transco Zone 6 Bloomberg spot prices.	Capacity - Fuel mix from Astoria EIA data. Price - Transco Zone 6 Bloomberg spot prices & RFO #6 Bloomberg data.	NEI
Emissions Expense	Emissions rates from SNL Emissions prices from Bloomberg				% of emissions gas/oil based on Astoria EIA data.	
Payment on Debt Interest						
Property Tax	NERA - Independent Study to Establish Parameters of the ICAP Demand Curve for the NYISO					
NYISO Administrative Fees	NYISO					
Decommissioning Expense						2009 Decommissioning Funding Status Report filed with NRC for Fitzpatrick & Nine Mile Point plants
Financial						
Federal Income Tax						
State Income Tax	Tax Foundation -- State Corporate Income Tax Rates as of July 13, 2009					
Depreciation	Based on sales in New York of comparable plants	Huntley and Dunkirk in 1999 and Danskammer and Roseton in 2001	Portions of Selkirk in 2000, 2004, and 2005	Astoria, Gowanus, and Narrows in 1999	Ravenswood in 2000	Indian Point 3 and Fitzpatrick in 2000 and Nine Mile in 2001
CAPEX	Assumptions to EIA's 2009 Annual Energy Outlook	Coal plant over 30 years old	Oil or gas steam plant	Oil or gas steam plant	Oil or gas steam plant	Nuclear plant over 30 years old
Book Life	Assumption					
Tax Life	Assumption					
Equity %	Assumption					
Debt %	Assumption					
Cost of Debt	Bloomberg - annual Moody's Utility index					
Inflation	Assumption					