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ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

A Cost-Benefit Analysis of the New York Independent System Operator: The Initial Years

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1. INTRODUCTION / OVERVIEW

The New York Independent System Operator ("NYISO") asked Analysis Group to conduct a study that would measure the costs and benefits associated with various aspects of the restructuring of the wholesale power market in New York. Our economic study focuses on certain key changes in operational performance of the power system during the initial years following the start-up of the NYISO.

NYISO began operation at the end of 1999, as part of the larger process to restructure the electric industry in New York State. At the wholesale level, restructuring included both changes in the institutions responsible for grid operation and in the dispatch and market rules implemented by the NYISO, as well as major changes in the ownership of generation assets. These combined changes – especially the new market rules that paid generators market clearing prices – created strong profit incentives for improving operational performance of power plants. We look at the effect of these changes. There were many other changes in the industry as well, not all of which are amenable to quantitative assessment.

To assess these larger changes in the economic environment, we examine broad measurable changes in wholesale power market performance, although we do not suggest that we have examined all factors comprehensively. Our spotlight focuses on the effects of changes in power plant dispatch rules and practices, and in incentives for improvement performance of generating units.

This report is organized as follows: Section 2 gives a very brief history of the evolution of institutions responsible for grid operations and wholesale market administration in New York State. In Section 3 we outline the central focus of our study – what topics we address and those we do not. To provide some context for our study, we surveyed selectively the literature on the costs and benefits of electricity restructuring in the US, and describe this literature in Section 4. Section 5 describes our methods in detail. We use production cost simulation both to estimate the benefits of changes in wholesale market operations and to value the efficiencies achieved by market participants in response to market incentives. Section 6 presents our results on the benefits of changes in wholesale market operation, principally the consolidation of the previous multiple control area operation into a more uniform and centralized operation administered by NYISO. In Section 7, we examine the benefits of improved generator availability. The main effect we observe in our study – an estimated 11% increase in nuclear output – is due to improved performance of the nuclear plants in New York associated with ownership changes prompted by electric industry restructuring in New York. We also estimate the value of improved availability of fossil-fired generators. In Section 8 we apply an estimate of the reduction in fossil fired generation operations and maintenance costs to New York data. In Section 9 we conduct a limited sensitivity test, to see the effect of changes in power plant investment patterns introduced by electric industry restructuring in the state. Section 10 compares these dollar savings to the costs of restructuring, using the NYISO operating budget as a proxy for those costs. Finally Section 11 brings all of the results together in a summary assessment.

We conclude that significant benefits have resulted from the impacts of NYISO operations and the market incentive effects we studied. The system-wide benefits exceed the NYISO budget costs in every year from 2000 through 2006. In the later years the difference is hundreds of millions of dollars, or roughly 5% of system-wide production and fixed O&M costs. In the earlier years the net benefits are lower, both in absolute value and as a percentage of system-wide production and fixed O&M costs. Benefits scale with fuel costs, particularly oil and gas costs, which have risen substantially over the period of analysis.

Given these benefits, then who has experienced them: consumers? owners of power plants? others? This question is not easy to answer, and our report has not attempted to determine in detail how these benefits have been allocated among various entities in New York and elsewhere. For one thing, the retail rate-making process is an imperfect mechanism for tracing with any precision the pass-through of year-to-year cost savings to consumers in retail rates. Notably, for example, during the period from before 2000 through 2003, most consumers' electricity rates in New York were affected by a package of "transition" policies aimed at providing a pathway from traditional regulation of utilities' rates to a more competitive retail and wholesale electric industry. Many factors went into multi-year rate agreements that partially distorted or postponed the effects of competition and which make it virtually impossible to sort out these questions of how consumers have benefited from efficiency gains from competition in the short run. Additionally, New York State did not experience to the same degree as other regions surplus capacity investments that might otherwise have created timing issues in the distribution of savings between producers and consumers.

That said, it is reasonable to expect that at least some of the efficiencies we observed from the introduction of consolidated unit commitment and co-optimized energy and reserve markets under NYISO, combined with better incentives for performance improvements and cost reductions at power plants, will flow through to consumers over time. For one thing, the retail rate reductions and freezes ended in New York for the most part in 2003.[1] This means that at least for the most recent years of our study, we can assume that the retail rate distortion should not be an issue and consumers should receive some, if not a substantial portion, of the savings. If energy market prices are lower today than they would have been in the absence of these changes, then prices to consumers will eventually reflect these market benefits. We expect, too, that some of the benefits also flow to owners of more efficient power plants (e.g., baseload plants such as the nuclear, hydro and coal-fired plants in the state), whose revenues and value have been enhanced by the changes in the structure of the New York wholesale power markets.

We note that a recent study by Harvey, McConihe and Pope (2006) ("HMP") provides some guidance in thinking about consumer savings. Focusing on residential customers of municipal and cooperative utilities in the NYISO region and the "classic" part of PJM (i.e., the Eastern part of PJM), the HMP found that households paid about $1.50/MWh less due to electric industry restructuring than they would have absent restructuring. If this result were able to be generalized to all NYISO customers, it would imply annual savings of approximately $200 million, since the demand of customers in NYISO-administered markets is about 144 million MWh.[2] HMP develop an alternative estimate for regions with less

[1] See Kwoka (2006), Table 2.

[2] See NYSERDA (2005). (144 million MWh times $1.50/MWh = approximately $200 million).

dependence on high cost oil and gas-fired generation, which is about half the larger estimate. If that were applicable to New York State as a whole, then consumer benefits would be approximately $100 million/year.

This range of savings for New York consumers – at $100 to $200 million per year – compares favorably with the results of our own simulation studies, as described above and in more detail below. Our study comparing changes in consolidation of control areas within New York, combined with reduced outage rates for nuclear and fossil generating units, results in differences between $100 and $200 million/year, which is similar to the HMP estimate.

While ratemaking policies may inhibit the timing with which such savings might be passed through to consumers, we think that this range is a reasonable representation of how the social cost benefits that we have estimated might be divided among consumers and producers of power. Depending upon how we draw the comparison, somewhere between a third and a half of the social cost benefits would show up as consumer benefits. Under some cases, the fraction might be as low as 15%, in others as high as 60%.

Those benefits which do not go to customers could be expected to flow primarily to the shareholders of the distribution companies (to the extent permitted by the regulators), to owners of economical power plants importing electricity into New York, and to the owners of baseload coal and nuclear plants in the region. Since these latter generators no longer enjoy the benefit of investment recovery previously afforded to vertically-integrated electric utilities and paid for by electric customers under traditional rate-base regulation (as was the case pre-restructuring), these producers of baseload power collect revenues from the energy market that compensate them for their capital investment and the loss of fixed cost recovery mechanisms built into retail rates under regulation.

2. HISTORY

The New York Power Pool – the predecessor to NYISO

Prior to NYISO's formation in 1999, the electric utilities[3] in New York State had been operating their systems cooperatively for decades, in an attempt to assure reliable, economic electric supplies for customers in the state. In the wake of the wide-scale Northeast blackout of 1965, the electric companies established a state-wide, wholesale power coordinating institution, the New York Power Pool ("NYPP"). The NYPP operated for several decades and was the predecessor to the NYISO. The cost to support NYPP were collected in consumers' electric rates, and just prior to ending the NYPP and converting it into the NYISO's, the operating budget of the NYPP was $32.5 million (1998 budget).[4]

Like its two neighboring regions (New England and the Mid-Atlantic states), New York set up NYPP as a "tight power pool" – a centralized reliability organization responsible for grid management as well as economic dispatch of the power plants in the state. Individual utilities owned and contracted for generating resources and transmission systems to serve their own requirements, and then they coordinated, or pooled, their operation for the mutual benefit of the participating companies. These same utilities established NYPP to act as their operating agent to accomplish these purposes.

NYPP carried out many of the reliability functions normally performed by a control area operator: balancing electric system supply and demand in real time, maintaining voltage, monitoring contingencies, managing operating reserves, and dispatching generation. In addition, it provided economic benefits by performing this latter function – dispatching generation – to reduce the variable cost of producing power for the combined system by arranging efficient trades. For this wholesale power production function, NYPP provided a forum for arranging short-term trades among the utilities in the state and then for allocating the benefits of these trades based on a "split-savings" price formula.

The contrast between "tight" pools and other wholesale market institutions in the pre-RTO/ISO period is that "tight" pools involved the maintenance of a centralized pool staff that facilitated trade on an hourly basis, rather than a more informal structure that was more of an umbrella entity under which bilateral transactions might occur.

One significant difference between the NYPP and the two other "tight" pools in the Northeastern US (i.e., the New England Power Pool and the PJM Interconnection), though, was the lack of centralized unit commitment in NYPP. The other pools at this time decided which units should be started and stopped, i.e., committed, on the basis of pool-wide

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3 The largest utility companies at the time were Consolidated Edison, Long Island Lighting Company, New York State Electric & Gas Company, Niagara Mohawk Power Corporation, Orange & Rockland Company, Rochester Gas & Electric Company, Central Hudson Gas & Electric Company, and the New York Power Authority.

4 NYPP (1998).

economics. The NYPP, instead, operated to dispatch units to balance pool-wide supply and demand after the individual utilities in the pool had decided which units they would commit to meet the loads of their own customers.[5]

Electric industry restructuring and the establishment of NYISO

The NYISO was created as part of an overall restructuring of the electric industry in New York. New York State's regulators, utilities and other stakeholders worked on a redesign of key elements of the industry to rely more on market forces for greater efficiency in operations of and investment in the system. This initiative was stimulated initially by federal regulators in FERC Order 888, which required the NYPP and its member companies to provide open access to the New York transmission system.

The changes in the structure of New York's electric industry were complex, and included the following:

- Allowing greater choice for customers in determining what entity would supply their generation services over wires that would continue to be owned by the electric utilities;
- Encouraging vertically integrated, investor-owned utilities to divest their generation so as to separate the competitive generation functions away from the monopoly "wires" functions;
- Requiring the electric distribution utility to remain "supplier of last resort" for retail customers;
- Streamlining the regulatory process for siting generation and transmission facilities; and
- Establishing an independent grid operator to manage the operations of the grid and electricity markets in a non-discriminatory way.

NYISO formally took over from NYPP the operational control of the bulk power transmission system and the dispatch of generation in New York State on December 1, 1999.[6] With this new role for NYISO, the administration of the wholesale market changed in design as well as in institutional form.

Around this same time, similar but not identical independent system operators were being established in other regions. A number of choices had to be made about governance of the new grid operator to assure its independence, the rules for the operations of the wholesale market, and the practices for operating the grid. NYISO adopted a governance structure that provided for shared participation by its Market Participants (including but not limited to the

[5] Within individual utilities, units were generally dispatched on a least cost basis to meet the needs of their own customers. If utility companies had generating resources remaining after meeting their own needs and other companies needed additional energy, then these remaining resources were dispatched on a least-cost basis to meet remaining pool-wide requirements, with the companies "sharing the savings" resulting from least cost system-wide dispatch.

[6] We note that bid-based energy markets actually commenced in November 1999.

electric utilities in the state) and an independent, non-affiliated Board of Directors of the NYISO.

For the wholesale market and operating protocols, NYISO adopted a centralized, bid-based energy market with localized marginal prices reflecting the impacts of any congestion on the grid. NYISO's approach featured a co-optimization of energy and operating reserves and a centralized unit-commitment. The intent was to maximize efficiencies in the operation of the state's generating resources and transmission grid to meet load and operating reserve requirements through a least-cost dispatch to meet these requirements.

Evolution of NYISO

In the six-plus years since NYISO started up, the New York electric market has evolved into what the State regulatory commission has recently called a well-functioning competitive market[7] with approximately 55% of the power in the New York control area purchased through NYISO-administered energy markets in 2005.[8] Total market volumes grew from $5.3 billion in 2000 to $7.3 billion in 2004, and to $10.7 billion in 2005.[9] Reserve margins have increased from approximately 14.8% in 2000 to 19.9% in 2004.[10] As of 2005, generating capacity in the NYISO region totaled approximately 37,500 megawatts, with approximately 10,775 miles of transmission lines.[11]

Of the generating capacity on line today, approximately 5000 MW of new power plants came into operation in New York in the 2000-2006 time period. Table 1 lists these units. The majority of this capacity was installed in the portions of the state that have traditionally been short of generation capacity: New York City and Long Island (Zones J and K).[12] The majority of new units are gas-fired and dual-fuel (gas and oil) combined cycle and peaking units.

While 5,000 MW is a sizable amount of new generation (amounting to about 15% of total capacity now in place), it is proportionally much less than the investment boom that accompanied restructuring in New England. New England is a somewhat smaller market than New York, but about twice as much new capacity was built in New England than in New York in the same time period.

7 "An evaluation of New York's wholesale electricity markets under several metrics (i.e., price, robustness of spot and forward markets, generation and transmission infrastructure, demand side response programs, and, generator performance) indicates that New York's wholesale markets are among the most advanced in the nation and that wholesale competition has led to significant efficiencies." (NYPSC, 2006), p. 1.

8 NYISO (2005c), p. 13.

9 Id., p. 24; and NYISO (2006c), p. 5.

10 Id.

11 http://www.nyiso.com/public/company/about_us/annual_report.jsp, see "Fast Facts."

12 A map of the transmission areas in New York State is given in Section 5 below.

Table 1
Units Installed in NYISO Between 2000 and 2006
By Transmission Area

Unit Name	Nameplate Capacity (MW)	Unit Type	Transmission Area	Installation Date
Jamestown	49	GT	AB	November 2001
Athens	1,080	CC	F	May 2004
Bethlehem Energy Center	750	CC	F	July 2005
Astoria (Poletti) CC	500	CC	J	December 2005
Astoria Energy	500	CC	J	June 2006
East River	360	CG	J	April 2005
Gowanus	90	GT	J	July 2001
Harlem River	93	GT	J	July 2001
Hell Gate	93	GT	J	June 2001
Kent	47	GT	J	August 2001
Pouch	44	GT	J	August 2001
Ravenswood	250	CG	J	March 2004
Vernon Blvd.	95	GT	J	August 2001
Bayswater Peaker	61	GT	K	July 2002
Bethpage	50	GT	K	July 2002
Bethpage Expansion	80	CC	K	July 2005
Brentwood	47	GT	K	July 2001
Freeport 2	48	GT	K	April 2004
Freeport Equus	47	GT	K	June 2004
Glenwood Landing	80	GT	K	May 2002
Greenport	54	GT	K	July 2003
Jamaica Bay	55	GT	K	July 2003
LIPA Temp Holtsville	44	IC	K	July 2004
LIPA Temp Shoreham	44	IC	K	July 2004
Pinelawn Babylon	79	CC	K	October 2005
Port Jefferson	80	GT	K	July 2002
PPL Edgewood Energy	80	GT	K	June 2002
Shoreham	80	GT	K	July 2002

Notes:
Unit types: CC = Combined Cycle, CG = Cogeneration, GT = Gas Combustion Turbine, IC = Internal Combustion.
List excludes 240 MW of wind and 15 MW of small GTs.

Source:
GED database.

3. CENTRAL FOCUS OF STUDY

Our study focuses on the key operational changes between the power system operated by NYPP (already a tight power pool) and the market administered by NYISO, studying a number of effects that define essential changes within New York's wholesale market. These include the change to a unified state-wide unit commitment process; co-optimization of energy and reserves; operational improvements associated with increased profit incentives created by competitive wholesale generation markets; and incentives to induce generation investment at locations where it is needed. We study these issues in varying depth, depending on the capability of available analytic methods and appropriate data.

By contrast, certain issues relevant to a full assessment of electricity industry restructuring are either too complex for available methods or require too many unprovable assumptions to be both relevant to New York and analytically tractable. In particular, we did not look such things as the net benefits of overall changes in investment, nodal-level changes in prices or other retail rate effects, capacity market design, demand response, or the shifting of risk between investors and customers. These are important features of the market, and efforts should continue to be made to assess them in analytically rigorous ways.

4. LITERATURE REVIEW

There is a growing literature that addresses the costs and benefits of electricity restructuring in the U.S. We review some of these studies briefly. None of the studies reviewed here attempt the comprehensive assessment of electricity industry restructuring that Newbery and Pollitt (1997) provide for England and Wales.[13] We consider studies that address consumer benefits, dispatch efficiency (i.e., market operations), improvements in generation efficiency, and investment effects of restructuring.

Overall effects of electric industry restructuring

There have been many studies of the benefits and costs of electricity restructuring in the past few years. Most focus on whether there have been savings for consumers. While this is a natural perspective to adopt in light of the goals of many advocates for restructuring, many issues prevent such an exercise from being as straight-forward or informative as one might like.

Kwoka Study

Kwoka (2006) gives a useful summary of these analytic and technical challenges in his review of such studies. Among the problems he identifies are a lack of precision in what is meant by "restructuring," with studies varying enormously in their definition of the reforms that they study; the fact that studies tend not to explicitly address the distorting effects of retail ratemaking policies during the transition period (e.g., rate reductions and freezes, stranded costs, and excess capacity); the extent to which the studies identify factors of causation (that is, whether or not reforms were actually responsible for some observed and properly measured change in price or cost); and the value of the functions provided by independent regional grid operators (Kwoka, pages 7-68).

One recent study that Kwoka does not review (Taber, Chapman and Mount, 2006), also reaches a conclusion similar to his, namely that statistical analysis does not reveal that restructuring and competition has reduced electricity rates.

Some of the factors that Kwoka identifies have relevance to our study, but perhaps to a lesser degree than in some other cases. In particular, the rate reductions and freezes implemented in many states ended in New York for the most part in 2003.[14] This means that at least for the

[13] That study applies a social cost framework for assessing the comparative costs of the actual evolution of the electricity industry in England and Wales with a counter-factual regulated case. The authors study a wide range of issues including changes in generation investment, improvements in generation efficiency, and the effects of restructuring on fuels markets. They also estimate the distribution of benefits to producers and consumers.

[14] See Kwoka (2006), Table 2.

most recent years of our study, which covers the period from 2000 to 2006, the retail rate distortion should not be an issue. Also, the excess capacity issue in New York is no where near as severe as it was in other regions such as New England, and therefore may not introduce several analytic problems in New York.[15] With these caveats from the Kwoka analysis, we are afforded some ability at least to consider how the social cost benefits that we have estimated from the restructuring of wholesale power markets in New York might be distributed between retail customers and producers.

Harvey, McConihe and Pope Study

One potentially useful approach is a recent study by Harvey, McConihe and Pope (2006) ("HMP"). Focusing on the impacts of competition in organized wholesale markets alone (that is, attempting to distinguish these impacts from those associated with retail competition), this study looks at a sample of municipal and cooperative utilities that are wholesale customers in the NYISO and PJM market regions.[16] The study compared this sample to a sample of utilities in regions without organized wholesale markets, over a 1990-2004 period. Using econometric methods that are similar to those recommended by Kwoka, HMP find that residential customers of the utilities (municipal and cooperative utilities) in the NYISO and Eastern PJM regions paid about $1.50/MWh less due to electric industry restructuring than they would have absent restructuring. If this result were able to be generalized to all NYISO customers, it would imply annual savings of approximately $200 million, since the NYISO demand is about 144 million MWh.[17]

There are some questions about how well the statistical estimate developed by HMP generalizes to customers of public and private utilities. The actual sample of New York customers used in their study is quite small, about 4 million MWh, which is less than 3% of total NYISO sales or about 10% of residential sales. The question of how representative the NY customers used in the study actually are is raised by comparing the average wholesale

[15] Note that in our study, described below in Sections 5-11, we observe that excess capacity is not a significant phenomenon in New York State, except perhaps in Zone F where we discuss combined cycle plant additions during the study period.

[16] Because the authors of this HMP study wanted to distinguish between the effects of restructuring of wholesale power markets from the effects of introduction of retail choice, they focused the study on a "comparison of average retail rates across utilities retaining a traditional long-term obligation to serve load, for a sample drawn from both utilities operating in coordinated and traditional markets. Since the obligation to serve has been retained in New York and PJM by public power entities, such as municipal utilities and cooperatives, the study compares the average retail rates of municipal utilities and cooperatives operating within coordinated wholesale markets with those operating in regions retaining the traditional utility market structure. In both coordinated and traditional markets these public utilities have retained the obligation to serve and have the ability to manage their energy costs by operating power plants or purchasing power under long-term contracts, and can lock in transmission costs by buying congestion hedging financial instruments or traditional firm transmission rights." See HMP (2006), p. 18

[17] See NYSERDA (2005). (144 million MWh times $1.50/MWh = approximately $200 million).

electricity price in New York, which varies from 4-12¢/kWh[18] to the rate for the sampled customers, which is on the order of 5¢/kWh (see HMP's Figure 1). Given how much lower the rates are for the sampled customers relative to New York customers as a whole, it might be that this rough estimate of consumer benefits (at $200 million) is too high. HMP develop an alternative estimate for regions with less dependence on high cost oil and gas-fired generation, which is about half the larger estimate. If that were applicable to New York State consumers as a whole, then consumer benefits of about $100 million/year would be appropriate.

New York Public Service Commission Staff Study

In March 2006, the staff of the New York Department of Public Service published its report on the status of electric industry restructuring in the state. (NYPSC, 2006.) This report "assesses the current state of New York's wholesale electric markets and retail electric and gas markets, describes progress that has been made over the past several years in creating such markets, and identifies opportunities for continued progress toward robust competition in New York State's energy industry."[19]

The report develops various metrics (e.g., price, robustness of spot and forward markets, investment in generation and transmission infrastructure, demand-side response programs, power plant performance) to evaluate the status of the state's wholesale and retail electricity markets. For example, the report indicates that:

> the total real (i.e., inflation-adjusted) electric price for a typical residential retail customer in New York, including supply and delivery charges, has dropped by an average of approximately 16% between 1996 and 2004. Most commercial and industrial customers have seen decreases in their real energy bills as well. While nominal wholesale commodity prices have gone up, reflecting increases in natural gas prices, on fuel-price-adjusted basis, wholesale commodity prices generally stayed flat during the period 2000-2005. The overall cost of supply embedded in retail rates in upstate New York was $50/MWh in 1996, prior to restructuring, and the all-in cost of supply in the upstate wholesale market was also $50/Mwh during 2002-2004, post- restructuring.[20]

The report notes the post-restructuring changes in the state's power plant mix, with new generation

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18 See Potomac Economics (2006) Figure 7, p. 9. This is the "all-in" price, reflecting the combined effects of prices for electric energy, capacity and ancillary services, plus uplift costs.

19 NYPSC (2006), p. 1.

20 Id., p. 2.

> being proposed and constructed in load areas where electric energy and capacity prices indicate a need for additional supply….Also, over 1,000 MW of additional capacity is being imported into the New York market. Nearly 1,000 MW of transmission capacity into the state has been added or is in the process of being added between New York and other control areas. Material progress has also been made in promoting greater demand elasticity with over 1,000 MW participating in the NYISO…programs, and increased implementation of mandatory hourly pricing for large electric utility customers. Generator availability has increased since the inception of the NYISO, and capacity factors of nuclear units have increased. Most importantly, the safety and reliability of the bulk power system has been preserved.[21]

Market operation issues

In this section we briefly summarize a recent review of RTO cost-benefit studies, and survey three other studies in particular that address issues similar to our assessment of operational economies. Given the regional diversity of the markets studied and study design differences, results are not directly comparable. Nonetheless, there are rough qualitative insights that these studies reveal.

Lawrence Berkeley National Laboratory Review Paper

Eto, Lesieutre and Hale of Lawrence Berkeley National Laboratory (2005) review eleven recent studies that examine the costs and benefits of RTOs. They focus primarily on prospective studies using production simulation methods that estimate the anticipated benefits of improved dispatch efficiency. The studies they review are prospective assessments, not retrospective analyses. The authors make a number of recommendations to improve the clarity and documentation of such studies, including the need for a discussion of model calibration and/or "tuning" parameters, description of transmission path ratings used, and any changes in such parameters in policy versus base case simulations. The authors suggest that future assessments of RTOs focus on actual data reflecting market performance and the measurement of effects beyond dispatch efficiency.[22] They also note this topic has been poorly "examined and potentially much larger benefits (and costs) resulting from the impacts of RTOs on reliability management, generation and transmission investment and operation, and wholesale electric market operation" need to be studied.

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[21] Id.

[22] Douglas (2006) uses actual data on coal plant operation in the Eastern US to make statistical inferences about improved dispatch efficiency associated with RTOs. His simulations of benefits focus only on savings within the coal segment of total production and are not comparable to studies using production cost simulation methods.

Florida Study

At the request of GridFlorida LLC, ICF (2005) studied the possibility of creating a Florida-wide RTO where one does not currently exist. ICF approached the study by comparing for a 13-year period the continuation of the status quo (multiple control areas, with multiple transmission providers) against two alternative cases, one with a “Day-1 only RTO” (a single state-wide transmission tariff and elimination of the “pancaking” of transmission rates across the state) and the other with a “Delayed Day-2 RTO” (with 3 years of Day-1 only followed by 10 years of Day-2 operation with state-wide centralized unit commitment and dispatch).

Florida has about 50 GW of installed generation. Nearly 50% of the generation is based on gas and residual oil. The four investor-owned utilities represent about 75% of electricity sales. The rest of the market consists of publicly owned utilities, most of which are quite small. The geographic isolation of the Florida peninsula makes imports an insignificant issue in the cost-benefit assessment. Decentralized unit commitment and pancaked transmission rates within Florida were the main barriers to efficient coordination examined in the study.

Using its production simulation model, ICF estimated that the benefits – mainly resulting from centralized unit commitment and dispatch, and elimination of rate pancaking across the service territories of the Florida transmission companies’ systems – were found to be approximately $100 million per year based on oil and gas costs in the range of $4-$6/MMBtu.[23]

Midwest Independent System Operator

The Midwest Independent System Operator (“MISO”) has conducted prospective studies on the potential costs and benefits of consolidating control areas across its large geographic footprint (MISO, 2006b). The MISO market region currently has 26 control areas. MISO expects to consolidate them into a smaller number. Because of limited experience, it is not clear exactly what the smaller number will be. The benefit/cost studies analyzing MISO estimate effects for consolidation to five control areas and consolidation to a single control area.

The MISO peak load in 2005 was 112,197 MW.[24] The generation mix in the MISO region is dominated by coal and nuclear, which account for more than 90% of energy production.[25] According to the MISO studies, which use a variety of methods including production simulation modeling, the expected benefits cover a range of actions including reserve reduction due to load diversity and more efficient use of plant carrying reserves. These actions are estimated to produce benefits in the range of $59-188 million/year.

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[23] See ICF (2005): Ex. 2-3 for the fuel mix, Ex. 2-5 for installed generation, Ex. 2-7 for sales by utility, Ex. 4-4 for benefits and Ex. A-4, A-5 and A-6 for fuel cost assumptions.

[24] See MISO (2006a), p. 8. This refers to the MISO market region which is smaller than the MISO reliability region.

[25] Gas generation is greatest in the third quarter of the year, and even then it is only about 7% of total generation. See MISO (2006a), p. 20.

MISO calculates an "Operating Reserves Market Implementation" scenario, in which the 26 control areas are consolidated into either one or five control areas. The benefit is estimated to be $51 million (five control area case) or $76 million (one control area case) annually.[26] Given the much larger amount of capacity in the MISO market area compared to Florida, it is likely that the lower cost fuel mix in MISO accounts for the comparatively smaller benefit as a fraction of market size.

NYPP 1990 Study

The possible benefits of moving to centralized unit commitment in New York was studied in 1990 by a working group within the NYPP that tested commercial software designed for this purpose (Broiles, Dignon and Mayo, 1990). This study covered only a one-week period, but did so intensively. No changes in imports were modeled, in part because regional databases were not widely available at the time of the study and regional modeling was not commonly done. Nonetheless, the documentation of results is unusually detailed. This allows a more careful qualitative understanding of where the economies found actually originate compared to what is available in the other studies. This level of detail contrasts, on the other hand, with the short period of study (one week). The short study period limits the ability to generalize from the results.

Appendix K of the study gives hourly differences in unit commitment between the actual and optimized unit commitment. Many of the estimated changes occur in the operation of New York City units. As compared to the base case (multiple control areas with non-centralized unit commitment), fewer and frequently larger generating units are committed in the optimized case. Less frequently, low-cost units from western New York (such as Dunkirk or Huntley) replace New York City generation when the decentralized unit-commitment is replaced with centralized unit commitment. For the week that was studied, the benefit of optimized unit commitment was $1.5 million, or about 3% of production costs at that time.

Generator efficiency improvements

Changes in generation efficiency can be reflected in cost reductions and availability improvements. Fabrizio, Rose and Wolfram (2004)[27] study reductions in non-fuel operations and maintenance ("O&M") costs for fossil fired generators. They find on average that these costs fell by about 5% in states that implemented wholesale restructuring compared to those that did not. Data on improved generator availability in restructured markets have been collected by Global Energy Decisions (GED, 2005), but not systematically analyzed. For nuclear plants, we have previously examined improvements in performance associated with

[26] See MISO (2006b). The load diversity and reserve efficiency estimates are based on actions taken before the implementation of an RTO-wide reserve market (items #1 and #2 on p.4 of Attachment A). The control area consolidation estimate is described at a high level on pp. 12-13 (also item #3 on p. 4 and p. 7 of Attachment A).

[27] In some references, this study is called the Markiewicz, Rose and Wolfram study.

plants that were sold as a result of restructuring and found an operational improvement tied to increased unit availability (Barmack, Kahn and Tierney, 2006).[28]

Investment effects

Among the initial expectations for electricity competition was anticipation that investment behavior would be more efficient than under regulation. Joskow (1997) gives arguments why this might occur. FERC (2005) documents the extent of the generation investment boom that occurred in the 2001-2003 period around the U.S. In its study for a group of electric power generators, marketers, and suppliers of the effects of introducing competitive wholesale markets in parts of the Eastern Interconnection of the U.S., GED (2005) constructs a counter-factual regulated investment case to compare with the investment boom period. GED's analysis does not consider the full life-cycle effects of investment by curtailing the analysis period prematurely.

We have conducted a study of electric industry restructuring in New England that addresses the investment boom which occurred in that region, compares it to a counter-factual case representing continued regulation, and estimates lifecycle costs (Barmack, Kahn and Tierney, 2006). Such comparisons of pre- and post-restructuring investment changes are challenging for a variety of reasons, including the very difficult issue of deciding where plants would have been sited in a counterfactual case – a variable with some importance to studies that attempt to take congestion effects into account**.**[29]

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[28] Our prior study focused on New England. In the study of NYISO that we describe below, we re-estimate the effects and confirm our previous results in the New York context.

[29] In their otherwise exemplary study, Newbery and Pollitt (1997) do not address generation location in their counterfactual investment case.

5. OVERALL METHOD

Study design

By contrast with the range of approaches used in different studies of competition, we focus here on several specific elements of particular interest in the New York State wholesale electric market. Specifically, we focus on the economic benefits of the change in dispatch from the NYPP system to centralized unit commitment and dispatch under the NYISO. We adopt a retrospective approach, looking over the six-year history of the NYISO and measuring both the direct benefits of the change in dispatch, as well as a number of important indirect effects as well.

The creation of clearing price markets provides powerful incentives for cost reduction. This incentive shows up, for example, in improved generator availability. The most dramatic effect of this kind that we identify involves the nuclear power generators operating in New York. As part of the restructuring activities in New York, all of the nuclear units in the state were sold to new owner/operators, who typically had more nuclear operating experience than the sellers. Similar ownership changes occurred in connection with restructuring in other regions as well. Using this national data on nuclear performance, we conduct in Section 7 our own statistical analysis of the effect that ownership changes have had on nuclear output. We then take the results of that analysis and estimate its economic value for New York State by using the same production cost simulation framework that we use to measure the effects of improved dispatch efficiency.

Additionally, we estimate the value of the less dramatic availability improvements achieved by fossil-fired generators. The estimate of these improvements is based on data collected by NYISO. We also apply the results of the Fabrizio, Rose and Wolfram (2004) study on non-fuel O&M cost savings associated with restructuring.

All of our analysis focuses on cost savings.[30] For the most part, we do not estimate the extent that such savings do or do not flow through to customer rates. Rate studies are complex. Estimating what would have happened to rates in the absence of the overall restructuring of the industry requires many assumptions and uncertainties,[31] and is affected significantly by the nature and effectiveness of retail regulation. In states where restructuring occurred, transition rate mechanisms were often put in place (and this was the case for New York). These pose analytic difficulties. Current rates and costs include the benefits of new investment that have taken place in restructured markets, but not necessarily their costs. Any counter-factual estimate of rates must also include an assessment of whether investment would have changed compared to the observed outcome, and what the rate effects of such

[30] The possible impacts of restructuring on environmental and reliability concerns are beyond the scope of this study.

[31] See Synapse Energy Economics (2004) for one example of a rate counter-factual. Joskow (2006) approach the rate issue by using a cross-sectional approach, comparing rate changes in states where restructuring occurred with those where it didn't, controlling for exogenous factors.

changes would have been. For our study, we treat investment as invariant between the actual and counter-factual cases. We conduct one sensitivity test addressing investment issues, but conduct no full-blown assessment of alternative investment patterns.

Study methodology

Using a production cost model, we conducted a number of simulation exercises designed to estimate cost changes due to the transition from the NYPP operational structure to the NYISO. The simulations are used to measure the effects of consolidated unit commitment, and to measure the value of the other indirect benefits of restructuring.

There are a number of market design features and operating parameters that are not easily measured using standard simulation tools. Prominent among these is the co-optimization of energy and ancillary services markets. Production simulation models represent certain aspects of reserve markets, but only approximately. Other software limits are described further below, after a general description of key technical issues in our study.

Basic simulation set-up

We used the Global Energy Decisions ("GED") database and PROSYM software to conduct our studies.[32] This is one of the standard industry simulation packages that is widely used to study electric system performance around the country. There are many possible configurations for running this software. We chose a regional representation discussed below because we wanted to capture the effect of changes in net imports as a result of unit commitment and other changes. Our approach allows us, in effect, to both construct supply curves for imports and exports and to measure their social cost. Net imports typically account for more than 10% of wholesale demand in New York.[33]

Topology

PROSYM uses a zonal representation of the electricity system. Transmission constraints apply across zones, but there are no constraints within zones. Users must specify the topology to be studied. Within New York, transmission constraints are important, and play a role in constraining the efficient dispatch of generating units in some parts of the state (as reflected in differences in locational prices between upstate and downstate New York).

Figure 1 shows the 11 traditional load control zones in New York. The GED default topology for New York aggregates these into six zones, namely: AB, CDE, F, GHI, J and K.

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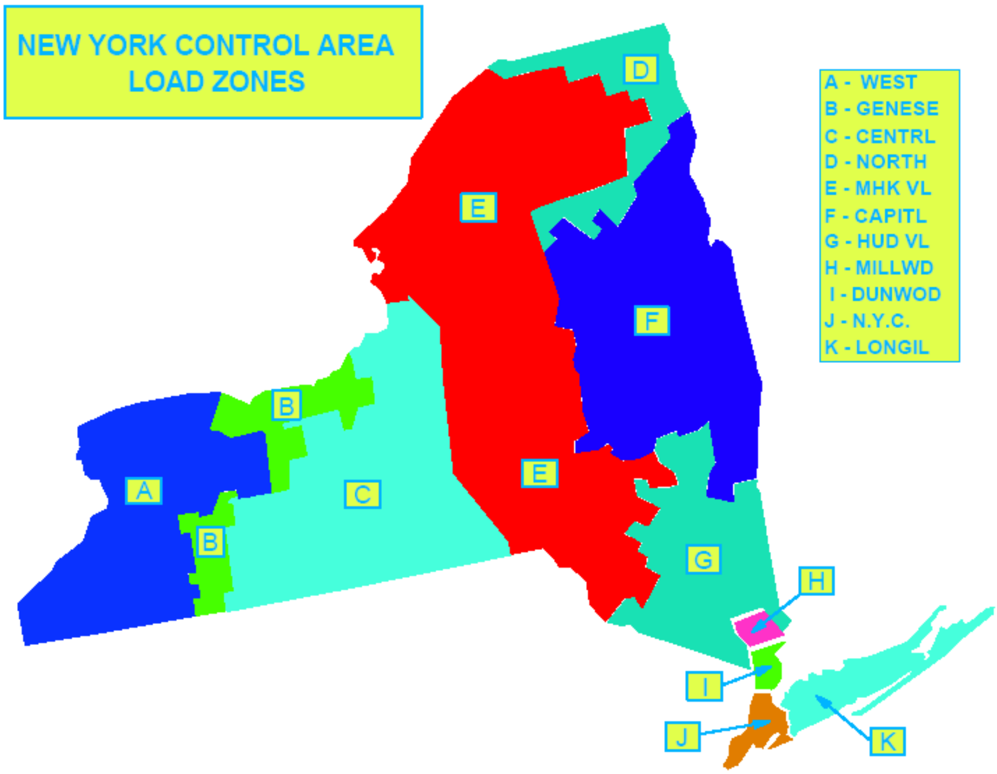
[32] For details, see http://www.globalenergy.com/products-ma-market-analytics.asp

[33] See NYSERDA (2005), Table 2-5, p. 27.

5. Overall Method

This is the zonal configuration we used in our study to depict unit commitment areas ("CA"). For the NYPP case we analyzed, the six zones are control areas, which corresponds to the institutional reality within the NYPP framework that the utilities committed units independently (i.e., to meet the requirements of own load) before trades were made via NYPP dispatch.[34] So we call this the "6 CA case".

Figure 1
New York Load Zones



Source: NYISO.

The GED zonal representation assumes that there are no transmission constraints within the zone, only across zones.[35] Commitment of generating units in PROSYM is done at the

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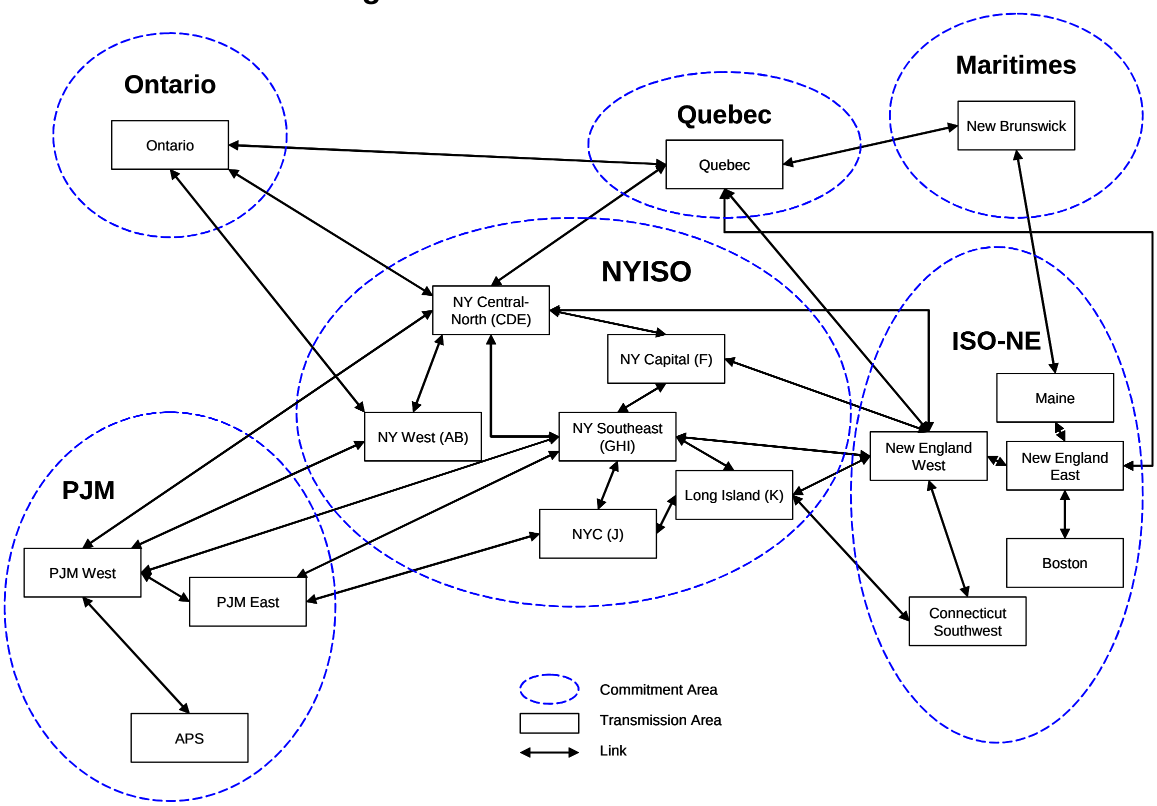
[34] Our discussions with NYISO staff confirm that this aggregation is reasonable both for representing the transmission system, and representing operation under the NYPP.

[35] Transmission constraints in PROSYM are represented as capacity limits; there is no representation of electrical constraints as in those models which calculate LMPs. This simplification is useful in high level economic impact studies such as this. It would not be appropriate for detail studies related to particular sites, for example.

control area level – again, what we call in our study the commitment area or "CA." A CA can be a single zone,[36] or multiple zones.

The regions connected to New York are included in the model, in order to capture inter-regional trades. These neighboring regions are represented in the following fashion. New England is divided into five zones: Boston, Southwest Connecticut, East, Maine and West. PJM is represented as PJM East, PJM West and Allegheny Power System ("APS"); other parts of the larger PJM footprint are not represented. Finally, Canada is represented by one zone each for Ontario, Quebec and the Maritimes. Figure 2 shows the regional topology used in this study. This figure shows both zones and CAs. For simplicity we use the 1 CA representation of New York.

Figure 2
NYISO Study Topology
Single New York Commitment Area



Transmission path ratings

Table 2 lists the transfer capacities between NYISO and adjacent regions. These capacities reflect the paths indicated in Figure 2 that connect to NYISO. Some of these transfer limit values between control areas were adjusted to reflect voltage constraints, dynamic constraints, typical phase angle regulator schedules, and/or to correlate with actual historic

[36] The GED documentation uses the term "Transmission Area" with the same meaning as we use the term zone above.

flows. The table includes the capacities in both directions. For other paths in the Figure 2 topology, we used default values in the GED database.

Table 2
Path Capabilities Used in PROSYM

From Zone	To Zone	Capacity (MW)	Reverse Capacity (MW)
NY AB	NY CDE	1,950*	2,250*
NY AB	Ontario	1,243*	1,118*
NY AB	PJMWX	550	242
NY CDE	NE-WEST	150	150
NY CDE	NY F	1,662	1,999
NY CDE	NY GHI	1,063	1,600
NY CDE	PJMWX	1,100	455
NY CDE	Quebec	873*	1,546*
NY F	NE-WEST	533*	492
NY F	NY GHI	4,000	1,999
NY GHI	NE-WEST	556	378
NY GHI	NY J	3,193*	3,626*
NY GHI	NY K	1,100	257*
NY GHI	PJMEX	425	800
NY GHI	PJMWX	425	287
NY J	NY K	250	420
NY J	PJMEX	1,000	1,000
NY K	NE-CTSW	100	100
NY K	NE-WEST	300	330
NY K	PJMEX	660	660

Notes:
* PROSYM path capacity varies monthly. Figure in table above reflects average PROSYM capacity from 2000-2006.

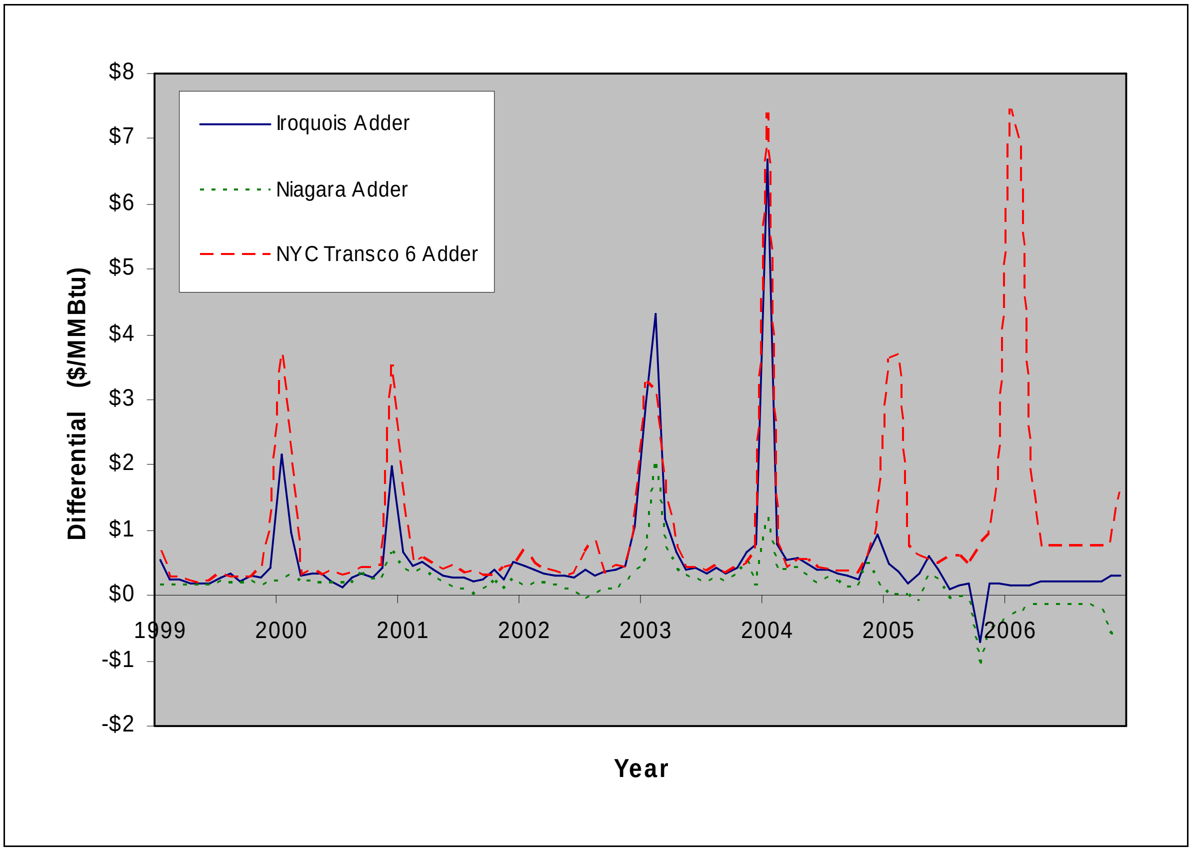
Fuels issues

Ideally, a simulation analysis should model as closely as possible the real-world conditions experienced in the region of study. Given model software constraints, approximations may be necessary. One example that is important for our study is fuel switching by particular generators. In New York, steam plants burn both gas and fuel oil #6 ("FO6"). FO6 is often cheaper, but the data in Appendix 1 illustrate that the actual burn pattern is complex. These data are monthly summaries which show that it is quite common for a plant to burn both gas and FO6 in a given month.[37] Patterns also change from year to year. PROSYM cannot model what appears to be daily optionality in fuel choice by generation units at these plants. In simulation software generally, fuel tends to be specified at monthly granularity. Since these models were originally designed to be used in longer-term planning studies, it is probably not inappropriate that they assume a single fuel used by a particular unit or plant in a given month. Given this rigidity in the model structure and our use of PROSYM to simulate a system with dispatch changes sometimes in five-minute intervals, we had to make some interpretations about which plants burned which fuels in which months. The choices made are summarized in Appendix 2.

Natural gas delivery costs are also an important issue in New York, so we needed to attempt to address geographic differences in delivered gas prices. New York State is served by three major pipelines, each of which can exhibit somewhat different pricing behavior. Zone J, served by Transco, typically has the highest prices, which commonly peak in the winter. Transco also serves Zones H, I and K. Figure 3 show a time series of the average monthly basis differential for the three gas pricing points in New York: NYC Transco Zone 6, Iroquois (serving Zones D, E, F and G) and Niagara (serving Zones A, B and C). The basis differential shown here is the difference between the wholesale price at a particular trading point and the Henry Hub price. This figure shows a substantial divergence in price between the Transco and the Iroquois and Niagara prices in the Winter of 2005 and 2006. This difference plays a role in many of the simulations that we report below, where displacing Zone J gas-fired generation is quite valuable during these periods.

[37] These data, from FERC Form 423, are only available at the plant level, not at the unit-specific level for a given plant.

Figure 3
Natural Gas Basis Differentials in New York



Notes:
Niagara consists of Zones A, B, and C.
Iroquois consists of Zones D, E, F, and G.
NYC Transco 6 consists of Zones H, I, J, and K.

6. OPERATIONAL BENEFITS: COMMITMENT AREA CONSOLIDATION

Analytic issues

Compared to NYPP operation, the NYISO represents a consolidation of commitment areas. Essentially, the NYPP was one for system-wide economic dispatch, three areas for reserves, and six areas for unit commitment; whereas the NYISO is one area for economic dispatch, three areas for reserves, and one area for unit commitment. Our representation of the NYPP in PROSYM is a 6 CA case with economic dispatch across these control areas unimpeded by transmission tariffs. We had to look for a simulation specification that would most closely capture the relevant constraints and measurable behavior under NYISO.

Given its software design, PROSYM cannot model the combination of (a) a single area for unit commitment and dispatch, with (b) sub-regional reserves in the multi-area configuration that we are using. The only way that PROSYM can get sub-regional reserves is to make each sub-region a CA, and commit generation to meet that area's load plus reserves. Therefore, we specify a 3 CA case to incorporate the NYISO geographic requirement for operating reserves. One CA consists of Zones ABCDE (Western NY); another is Zones FGHIJ (Eastern NY minus part of Long Island); and the third is Zone K (most of Long Island).

NYISO has requirements for Operating Reserves in three different, specific sub-regions within the state. Table 6.2 of NYISO's Ancillary Services Manual specifies certain reserve levels for Eastern NY (Zones FGHIJ), Long Island (Zone K), and NYCA as a whole.[38] Additionally, there are substantial real-time must-run units in Zone J.

In the next section we review the differences between a 1 CA and a 3 CA representation of NYISO, describe a metric we developed for deciding which representation is the best approximation and discuss the nature of the approximations involved.

Analysis of results of commitment area consolidation tests

Table 3 below shows our estimates of annual production costs for the 1 CA, 3 CA and 6 CA cases. The table includes the production costs in the regions adjacent to New York. Imports and exports are embedded in these costs since a dispatch is performed between control areas; imports reduce costs in the importing region and raise them in the exporting region. These effects are best seen in the differences between particular simulations. The benefits of NYISO control area consolidation are the cost differences between the 6 CA case (representing NYPP operation) and either the 1 CA or 3 CA representation of NYISO. There

[38] See NYISO (2005b). This is not quite the same as the geographic markets for ICAP, which have separate requirements for Zone J and Zone K (see NYISO (2006a), Attachment B).

are considerable differences in the estimated benefits between a 3 CA and a 1 CA representation of NYISO.

Table 3
Northeast Regional Production Costs ($million)
By Commitment Area, 2000-2006

		2000	2001	2002	2003	2004	2005	2006
1 NY Commitment Area	NYISO	3,275	2,922	2,841	3,724	4,013	5,504	5,946
	ISO NE	2,850	2,905	2,866	4,002	4,239	5,837	6,060
	Maritimes	507	503	511	613	682	829	856
	Ontario	1,735	1,839	1,722	2,074	2,116	2,464	2,572
	PJM	5,082	5,288	5,394	6,442	8,049	9,907	10,299
	Quebec	1,000	967	1,020	1,029	1,074	1,066	1,165
	Sum	**14,449**	**14,423**	**14,354**	**17,884**	**20,172**	**25,606**	**26,899**
3 NY Commitment Areas	NYISO	3,510	3,113	3,033	3,927	4,225	5,820	6,310
	ISO NE	2,822	2,880	2,839	3,969	4,217	5,792	6,018
	Maritimes	510	500	510	614	681	827	852
	Ontario	1,749	1,845	1,730	2,075	2,116	2,463	2,566
	PJM	5,081	5,271	5,366	6,442	8,042	9,911	10,278
	Quebec	998	966	1,021	1,029	1,075	1,070	1,165
	Sum	**14,669**	**14,576**	**14,499**	**18,057**	**20,357**	**25,882**	**27,189**
6 NY Commitment Areas	NYISO	3,534	3,154	3,062	4,001	4,353	6,028	6,580
	ISO NE	2,820	2,882	2,841	3,967	4,209	5,786	6,008
	Maritimes	511	501	509	613	681	824	850
	Ontario	1,748	1,844	1,728	2,073	2,116	2,462	2,563
	PJM	5,084	5,271	5,373	6,439	8,028	9,897	10,250
	Quebec	998	966	1,020	1,028	1,075	1,068	1,163
	Sum	**14,695**	**14,618**	**14,534**	**18,122**	**20,462**	**26,066**	**27,414**
Difference (1 CA - 6 CA)	NYISO	-259	-233	-221	-277	-340	-524	-633
	ISO NE	30	22	25	35	30	50	52
	Maritimes	-4	2	1	0	2	4	7
	Ontario	-13	-5	-6	1	0	2	10
	PJM	-1	17	21	3	20	11	49
	Quebec	2	1	0	1	-1	-3	1
	Sum	**-246**	**-196**	**-180**	**-238**	**-289**	**-459**	**-515**
Difference (3 CA - 6 CA)	NYISO	-25	-41	-29	-74	-128	-208	-269
	ISO NE	2	-2	-3	2	8	6	11
	Maritimes	-1	0	1	1	0	2	2
	Ontario	1	1	2	2	1	1	3
	PJM	-3	0	-7	3	14	14	27
	Quebec	0	-1	0	1	0	2	1
	Sum	**-26**	**-43**	**-35**	**-65**	**-105**	**-183**	**-225**

The 3 CA case allows for less substitution among plants in New York and fewer imports from adjacent regions than the 1 CA case. This is due to the substantially greater amount of New York generation running off-peak in the 3 CA case compared to the 1 CA case. Due to operating constraints, generation committed so that it is available for on-peak requirements, including reserves, must run off-peak as well to be available for the next day. The table shows the role of these commitment constraints in the 3 CA case by the greater cost reductions in New York and high production cost in adjacent regions in the 1 CA case compared to the 3 CA case. The production cost increases in adjacent regions typically represent increased coal output for export to New York, displacing higher cost oil and gas generation. Clearly the cost increases in adjacent regions are far smaller than the reductions in New York.

We need a metric to decide whether the 3 CA or the 1 CA case is the better representation of the NYISO. Neither is perfect. Clearly, the 1 CA case is not guaranteed to meet the geographic requirements for operating reserves, while the 3 CA case is designed precisely to meet those constraints, but perhaps not in the most economic fashion, since the economic dispatch and unit commitment are performed for three NY areas.[39] There are, however, other factors that also need to be taken into account in choosing between the 1 CA and the 3 CA representation. These involve issues relating to Zone J (New York City area). We have previously mentioned the real time Zone J must-run requirements. It is our understanding that Zone J must-run is difficult to specify simply. The 3 CA case is much more likely to capture these effects than the 1 CA case. Of equal importance is the economic importance of displacing Zone J oil and gas generation as a key to the value estimates in Table 3. Therefore a useful comparison is looking at the actual Zone J oil and gas generation to decide between the 3 CA and the 1 CA representation of NYISO operation. Table 4 below compares actual Zone J oil and gas generation with the 3 CA and 1 CA simulations. While both simulations generally show less generation than actually occurred, the 3 CA case is the more realistic.

Table 4
NY Zone J Output (GWh) for Natural Gas and Oil Units

	2000	2001	2002	2003	2004	2005	2006
Actual	20,932	21,328	20,568	21,410	21,865	21,184	n/a
PROSYM (1 CA)	18,590	18,368	19,404	18,083	18,581	18,878	20,427
Difference (PROSYM - Actual)	*-2,342*	*-2,960*	*-1,164*	*-3,327*	*-3,284*	*-2,306*	*n/a*
PROSYM (3 CA)	20,553	20,900	21,531	19,820	20,029	19,978	21,869
Difference (PROSYM - Actual)	*-379*	*-427*	*964*	*-1,590*	*-1,836*	*-1,206*	*n/a*

[39] It is possible that 1 CA case does meet the geographic reserve requirements. There are also ways to estimate what it would cost to guarantee that these requirements are met. The Zone J issues, however, make this line of inquiry moot since it is assumed that must run units in Zone J also meet reserve requirements.

Thus, a 3 CA approximation can capture both the regional reserve requirement and Zone J must-run, but it is a rough approximation. In fact, a 3 CA case is a conservative estimate of benefits because there must be times when regional reserves and must-run requirements can be met with a less restrictive commitment of units. Additionally, the monthly fuel specification suppresses the daily opportunity to switch fuels, which in turn would also allow for potentially more economic commitment choices. These factors imply that benefits have been under-estimated.

7. AVAILABILITY IMPROVEMENTS

Power plants can only operate when they are "available" – that is, when they are not out for repairs or other reasons, and when are capable of being dispatched if called upon by the grid operator. Certainly, not all plants that are available are actually dispatched, since the latter depends upon a variety of economic and reliability issues under the control of markets and grid operational requirements.

Some types of units – like nuclear, wind and hydro units – are characterized by very high fixed costs and very low variable costs. These units are thus in a position to benefit from a single clearing price regime, such as exists in New York. The more they are available to run, they more likely they are to be run and receive payments in hourly energy markets. Such a regime provides a very strong incentive for improved unit availability, and our review demonstrates that this has indeed been the case in New York.

Nuclear units – availability

As we have noted elsewhere,[40] one salient feature of restructuring is that it has also allowed the most efficient nuclear operators to consolidate ownership and operations of nuclear generating units. This certainly has been the case in New York, where every nuclear unit has changed hands since the restructured market opened. As we discuss below, this has had a significant impact on the amount of nuclear energy available to the market and consequently on production costs.

The U.S. nuclear industry exhibits a wide range of ownership and performance. At one extreme, there are the owners and operators of single plants. At the opposite extreme, companies such as Exelon, Entergy, and FP&L operate and/or own fleets of ten or more nuclear plants. As a general rule, owners with more nuclear capacity have tended to be more efficient than owners of just a single unit.

We estimate the effect of consolidation on performance using a simple econometric model. The econometric estimates are then used as inputs to our production simulations. Our econometric analysis here differs from our analysis for our New England paper in two main ways. First, our New England paper examined the effect of restructuring on capacity factors. Here we examine the effect of restructuring on output. Second, we incorporate two additional years of data in our analysis.

According to data collected by the Nuclear Energy Institute, there were 16 sales of nuclear plants that occurred in the 1999-2005 time period, including all of the plants in New York.[41] The purchasers were companies that had experience with operating multiple nuclear plants of

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40 Barmack, Kahn and Tierney (2006).

41 See http://www.nei.org/documents/U.S._Nuclear_Plant_Sales.pdf

their own. Of the 16 sales, several involved the sale of minority shares.[42] In our analysis, we only examine the effect of sales of majority ownership on performance, i.e., we essentially ignore the sales of minority shares of ownership. Some of the sales involved more than one operating unit. In all, 15 units were sold and remained in-service post-sale during our sample period.[43] All but one of these transactions occurred in contemporaneously restructured clearing-price electricity markets, i.e., ISO-NE, PJM, MISO, or NYISO. The one exception (the sale of the Clinton nuclear station in Illinois) occurred in a state where, at the time of the sale, there was wholesale and retail competition, but no clearing price market.[44] Some of the sales were made as part of stranded cost recovery requirements. Therefore, it appears that the sale of nuclear plants has a close connection with restructuring.

We collected data on the annual output of U.S. nuclear units from 1990 through 2005.[45] We analyzed the data to determine how operations changed over this time period and whether there is any difference between the plants that were sold and the rest of the population. The results of a simple regression of the natural log of output on a time trend, unit fixed-effects to capture time-invariant differences in output across units, and a "dummy" variable that is one for a unit in the years following the year of its sale are reported below.[46] The time trend shows that output at all U.S. nuclear generating units has been growing at approximately 2.3% per year.[47] The coefficient on the post sale dummy suggests that units that have been sold have experienced 11% improvements in output on average. Both parameter estimates are "statistically significant."[48]

[42] Including the sale by Conectiv of its shares in Peach Bottom 2 and 3, Hope Creek, and Salem 1 and 2 to Exelon and PSEG, the sale by Madison Gas & Electric of its share in Kewanee, and AEP's sale of a share of the South Texas Project to Texas Genco and CPS Energy.

[43] Millstone 1 was closed immediately following its sales.

[44] Since then, Illinois utilities have begun to participate in centrally organized markets administered by PJM and MISO.

[45] These data are available from NEI and EIA Form 906 and its predecessor forms.

[46] We consider a unit to be sold in a given year if it is under the control of the new owner for the entire calendar year.

[47] Our regression suggests that there is a secular upward trend in output that affects both divested and non-divested units. Given that annual average output is bounded at the upper limit by 100% of capacity utilization, our regression suggests that over long periods of time, the capacity factors of all units, both divested and non-divested, might converge. This issue is not be a concern for our analysis because we are focused on the period immediately following restructuring.

[48] The t-statistic on the post sale variable indicates that the coefficient is significant at better than the 5 % level. Note that the table reports White standard errors, which allow for a very general form of serial correlation between observations from different years from the same unit. The adjusted $R^2$of the model, a measure of the fraction of variation in the dependent variable—in this case the output of nuclear generating units—explained by the model, is approximately 0.3.

Table 5
Regression Analysis Results
Testing for Post-Nuclear Plant Sale Effects

	Coefficient	Standard error	t-statistic
Time trend	0.023	0.002	12.46
Post sale	0.110	0.050	2.22

Because the plant sales are so closely associated with restructuring, we attempted to identify separately the effects of restructuring and ownership changes. The performance of a plant that is sold might improve because its new owners are more efficient and/or because the new owners participate in deregulated retail and wholesale markets in which they have greater incentives to operate the plant efficiently. We were not able to find a statistically significant effect of restructuring alone, i.e., we could not find similar output improvements in units that were not sold but continued to operate under their pre-restructuring owners in restructured markets.[49] This could be due to relatively sparse data. There are relatively few nuclear units in restructured markets that have not been sold.[50] It is also worth noting that other authors have observed that "deregulation" has significantly improved the performance of nuclear power plants.[51]

We have no data to estimate the net costs, if any, of the nuclear production improvements that we model. It may be that the large-scale nuclear operators, such as Constellation and Entergy, that acquired the divested plants are just better than the previous owners and can achieve costless production improvements. There is some reason to believe this is the case. In particular, Exelon's Chief Nuclear Officer testifying in the Exelon-PSEG merger case, presents data showing roughly a doubling of output and a halving of unit production cost (fuel and O&M) for the Commonwealth Edison and then Exelon nuclear fleet over the period 1997-2004 (Crane, (2005a) page 9). This suggests that the productivity benefits came at zero net cost. In addition, Crane discusses Exelon's existing agreements to operate certain PSEG plants under contract. He suggests that the efficiency gains that can be realized through operating agreements are limited and certain types of efficiency gains can only be realized through full ownership (Crane 2005b). This claim supports our analysis which focuses on changes of ownership as key drivers of efficiency improvements. Alternatively, it is possible that net cost increases are necessary to achieve higher output levels. Absent any evidence that

49 For this purpose, we define a market as restructured if it has passed a law implementing retail competition according to EIA (2003).

50 Diablo Canyon and San Onofre in California are two notable examples. Fabrizio, Rose and Wolfram (2004) are able to identify separate effects of restructuring and ownership change in a broader sample of fossil generating units.

51 See Taber, Chapman and Mount (2006), in particular, Figure 5. These authors do not address the ownership change factor.

net costs did increase, we adopt the hypothesis that the new owners were just better than the previous ones.

We use the regression results in Table 5 to compute counter-factual nuclear generation, i.e., what the units would have produced had restructuring not occurred and hence the units had not been sold, for the New York nuclear generating units. The results are reported below. Even though we assume that the effect of a plant being sold does not change over time, the difference between the actual and counter-factual cases grows as more units are sold. These are the numbers that we incorporate in our production cost modeling to determine production cost savings.

Table 6
Actual and Counterfactual New York Nuclear Generation (TWh)

	2000	2001	2002	2003	2004	2005
Actual						
Fitzpatrick 1	6.0	7.1	6.6	7.0	6.5	7.1
Ginna 1	3.8	4.3	3.8	3.9	4.3	4.0
Indian Point 2	1.0	7.8	7.5	8.4	7.5	8.8
Indian Point 3	8.4	8.0	8.4	7.6	8.7	8.0
Nine Mile Point 1	4.3	4.4	4.9	4.4	5.0	4.6
Nine Mile Point 2	8.0	8.8	8.3	9.5	8.6	9.9
Total (Actual)	31.5	40.4	39.6	40.7	40.6	42.4
Counterfactual						
Fitzpatrick 1	6.0	6.4	5.9	6.2	5.8	6.3
Ginna 1	3.8	4.3	3.8	3.9	4.3	3.6
Indian Point 2	1.0	7.8	6.8	7.5	6.7	7.9
Indian Point 3	8.4	7.2	7.6	6.8	7.8	7.2
Nine Mile Point 1	4.3	4.4	4.4	3.9	4.5	4.1
Nine Mile Point 2	8.0	8.8	7.5	8.5	7.7	8.9
Total (Counterfactual)	31.5	38.8	35.9	36.9	36.9	38.1
% Difference in Totals	**0%**	**4%**	**9%**	**9%**	**9%**	**10%**

Table 7 summarizes the results of our simulations that incorporate the estimated availability improvements in Table 6.[52]

Table 7
Production Cost Benefits of Improved Nuclear Availability ($million)

	Nuclear Counterfactual Costs, net of Actual Nuclear Costs
2000	0
2001	46
2002	80
2003	137
2004	150
2005	258
2006	254

Fossil units – availability

Based on aggregated data on availability performance provided by the NYISO, we also conducted a test of the effects of having higher availability for non-nuclear units under the NYISO regime. We choose the 1999 data as representative of NYPP performance. The nuclear units produced 37 TWh in that year, which was the best performance in the previous 10 years. This resulted in the 1999 average outage rate being the lowest in the 1994-2000 period. The 1999 value of the outage rate measure was 9.5%, compared to the average of 5.5% for the 2001-2005 period. The 1999 value is 74% greater than the average value in the 2001-2005 period. For our test, therefore, in a counter-factual simulation we increased the PROSYM outage rate parameters by 74% (from an average of 4.8% for steam units to 8.4%, for example).[53] The results of that simulation are shown in Table 8.[54] These benefits are less than the nuclear availability benefits in Table 7.

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52 The results in Table 7 are based on the 6 CA representation for both the actual and counterfactual cases. This is a conservative estimate. A 3 CA representation for both cases gives results that are very similar.

53 There are a variety of outage rate and availability measures (NERC, 2005). The NYISO data uses a measure known as EFORd (effective forced outage rate). PROSYM uses a related measure.

54 The Table 8 results are based on the 6 CA representation for both the actual and counterfactual. The results are similar in the 3 CA case.

Table 8
Production Cost Benefits of Improved Fossil Plant Availability
($million)

	High EFOR Case – Actual
2000	25
2001	31
2002	27
2003	42
2004	35
2005	66
2006	49

8. NON-FUEL O&M

Here we adopt the Fabrizio, Rose and Wolfram (FRW, 2004) estimate of non-fuel operating cost reductions attributable to the incentives created by restructuring. Their paper is a careful econometric study of O&M costs for a sample ranging between 400 and 600 non-nuclear generating plants over the period 1981-1999. The authors find that privately owned plants "in restructuring regimes reduced their labor and nonfuel operating expenses by about 5%...relative to…plants in states that did not restructure their markets."

In Table 9, we collect O&M cost data for New York fossil fuel generators. The fixed O&M ("FOM") data come from the GED database used in PROSYM and derive primarily from FERC Form 1. The variable O&M ("VOM") are outputs from the 3 CA case. Table 9 then applies the FRW estimate.

Table 9
O&M Cost Reduction ($million)

Year	Non-Nuclear Total FOM	Non-Nuclear VOM	Non-Nuclear Total O&M	Benefit at 5%
2000	363	150	513	26
2001	370	153	523	26
2002	379	156	535	27
2003	387	153	540	27
2004	406	158	564	28
2005	418	170	588	29
2006	418	183	601	30

9. ZONE F GENERATION INVESTMENT SENSITIVITIES

We have treated the investment pattern under NYISO as invariant in all of our simulations. As Table 1 indicates, much of the generation investment in New York during the 2000-2005 period was in Zones J (NYC) and K (Long Island), which depend upon imported power to keep the lights on, and need new local generation. Arguably much if not all of the Zone J and Zone K generation needed for reliability purposes would have been built under the NYPP.

The new combined cycles located in Zone F (the "Capital Area") are a different matter. Zone F is not a large load center, but it is near the load centers in Zones J and K. Zone F also has a different source of natural gas supply than downstate New York. It is our understanding that some new generation was needed in Zone F to replace the Albany steam units which retired in early 2005. But those units totaled only about 400 MW. Therefore, the construction of about 1800 MW of combined cycle ("CC") generating capacity (the Athens and Bethlehem plants) in Zone F is a probable consequence of the incentives and opportunities presented by restructuring.

The Zone F CCs represent an opportunity to explore what difference, if any, resulted from the changes in investment signals in New York State associated with restructuring (and its locational prices, improved siting processes, and other effects that reduced barriers to entry in investment). As a limited sensitivity test, we examined what the cost consequence would have been if the Athens and Bethlehem CCs had not been built in Zone F, but instead peaking capacity (combustion turbines, or "CTs") of the same capacity had been built in that same sub-region. Table 10 shows the results of this test.[55]

Table 10
Zone F: Replacement of New CCs with New CTs ($million)

	CT Case – CC Case
2000	0
2001	0
2002	0
2003	0
2004	14
2005	55
2006	109

[55] The Table 10 results are based on the 6 CA representation for both the actual and counterfactual. The results are similar in the 3 CA case.

These results show that the Zone F CCs produced substantial operating cost savings compared to a CT alternative. We will not include these benefits in our overall assessment because we have no fully suitable estimate of investment costs to compare with the benefits. A full assessment of investments is complex. Simple estimates suggest that the Zone F combined cycle plants are efficient investments compared to a combustion turbine alternative. Their annual incremental fixed costs are roughly $75 million.[56] This is less than the 2006 annual benefits, the only year in which both units operated the full year. Nonetheless, it is unclear whether the CT alternative is the best comparison. It is possible that not all of this capacity was needed, or perhaps not needed in Zone F. Given these uncertainties, we omit the Zone F CC benefits from our overall assessment.

[56] This calculation is based on the following assumptions:

(1) incremental capital costs of CCs above the CT cost of $200/kW,

(2) annual fixed costs at 15%,

(3) incremental fixed O&M at $10/kW-yr.

These assumptions imply annual incremental fixed costs of $40/kW. The total capacity involved is 1830 MW. This results in $73.2 million per year, which we round to $75 million.

10. COST ANALYSIS

Total social cost of wholesale market changes is difficult to estimate. Therefore we take the NYISO operating budget as a first approximation of the implementation costs of electricity restructuring in New York. We know that this is not a perfect metric for a number of reasons. For example, under NYPP, there were direct and indirect costs associated with that tight power pool arrangement, some of which have now been replaced by the NYISO budget. The NYPP budget in 1998 was $32.5 million. There are costs of wholesale restructuring – e.g., transaction costs of market participants – not captured directly in the NYISO budget. Taking the budget as a whole rather than as some increment above the NYPP budget at least provides an attempt to quantify costs of NYISO operations. Table 11 shows the NYISO budget.[57]

Table 11
NYISO Operating Budget ($million)

2000	75.3
2001	103.7
2002	110.5
2003	118.1
2004	123.8
2005	129.0
2006	133.1

The costs of the availability benefits estimated in Section 7 above are difficult to observe. The FRW data show that O&M costs for their national sample of fossil fueled plants declined in restructured markets. For New York fossil-fired generators, availability increased. We do not know for sure whether the New York output gain came at negative cost. It is not unreasonable to assume that New York experience was no different than the national data. Similarly, for the nuclear availability gains, we cannot observe costs directly. There is evidence from Exelon, not a New York nuclear operator, that availability increases came at zero net cost (Crane, 2005a), and that these benefits are due to ownership changes (Crane, 2005b). It is not unreasonable to assume that nuclear availability increases in New York came at zero net cost.

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[57] See NYISO (2001), p. 28; NYISO (2003), p. 21; and NYISO (2005a), p. 24.

11. CONCLUSIONS

Net Benefits

In this section, we bring together the individual results discussed in Sections 6-10 into an overall assessment of benefits and costs. Table 12 below summarizes the estimated effects of consolidation of unit commitment (from Section 6), the nuclear availability benefits (from Section 7), the fossil availability benefits (also from Section 7), and the O&M cost reductions (estimated in Section 8). To put these benefits into perspective, the table also gives our estimate of the total system-wide production costs within New York, including fixed O&M costs.

The estimates in Table 12 are incremental. Case 1 is the CA consolidation benefits from Table 3 for the 6-CA to 3-CA simulations. Case 2 includes the nuclear availability benefits by comparing the 6-CA case with the nuclear counterfactual output to the 3-CA case with the actual nuclear production. The differences between Case 2 and Case 1 in Table 12 are approximately equal to the nuclear availability benefits in Table 7. This rough equality shows that the two effects are linearly additive, which is not obvious in principle. Case 3 adds the fossil EFOR counterfactual to the 6-CA results in Case 2 with nuclear counterfactual, and compares it to the 3-CA simulation with actual availability for both nuclear and fossil generation. The differences between Case 3 and Case 2 are slightly different from the stand-alone estimate of the fossil availability benefits in Table 8. The variance is comparatively small. Finally, Case 4 simply adds the O&M cost benefits from Table 9 to the Case 3 results. As previously discussed the Zone F investment sensitivity is not included in Table 12.

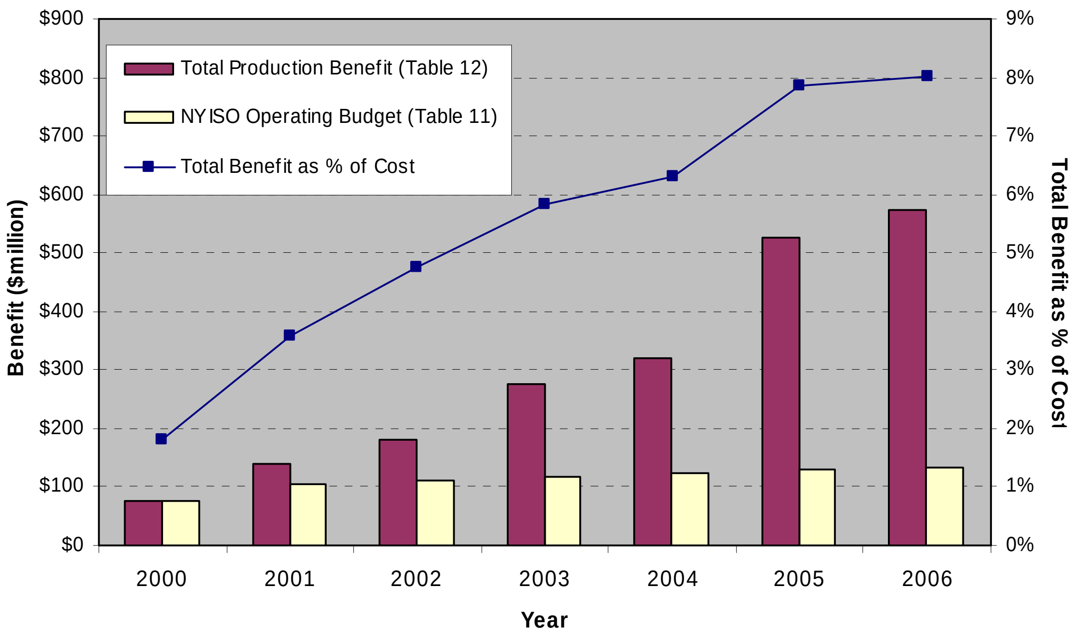
Table 12
Benefits of NYISO Operation ($million)
(Amounts are incremental relative to the previous case in column to its left)

Case #	1	2	3	4	
	Commitment Area Consolidation: 6 CA - 3 CA	6 CA with Nuclear Counterfactual - 3 CA with Nuclear Actual	6 CA Nuclear with High Fossil EFOR Counterfactual - 3 CA Nuclear & Fossil Actual	Case 3 Plus O&M Benefit	NYISO Production Cost + FOM
2000	26	26	51	77	4,273
2001	43	88	113	139	3,891
2002	35	115	153	180	3,798
2003	65	201	249	276	4,737
2004	105	255	291	319	5,064
2005	183	442	496	525	6,675
2006	225	479	545	575	7,164

The benefits in Case 4 of Table 12 exceed the NYISO budget costs from Table 11. In the later years the difference is hundreds of millions of dollars, or roughly 5% of the NYISO production and fixed O&M cost also given in Table 12. In the earlier years the net benefits are less both in absolute value and as a percentage of NYISO production and fixed O&M cost. It is fairly clear that benefits scale with fuel costs, which have risen substantially over the period of analysis.

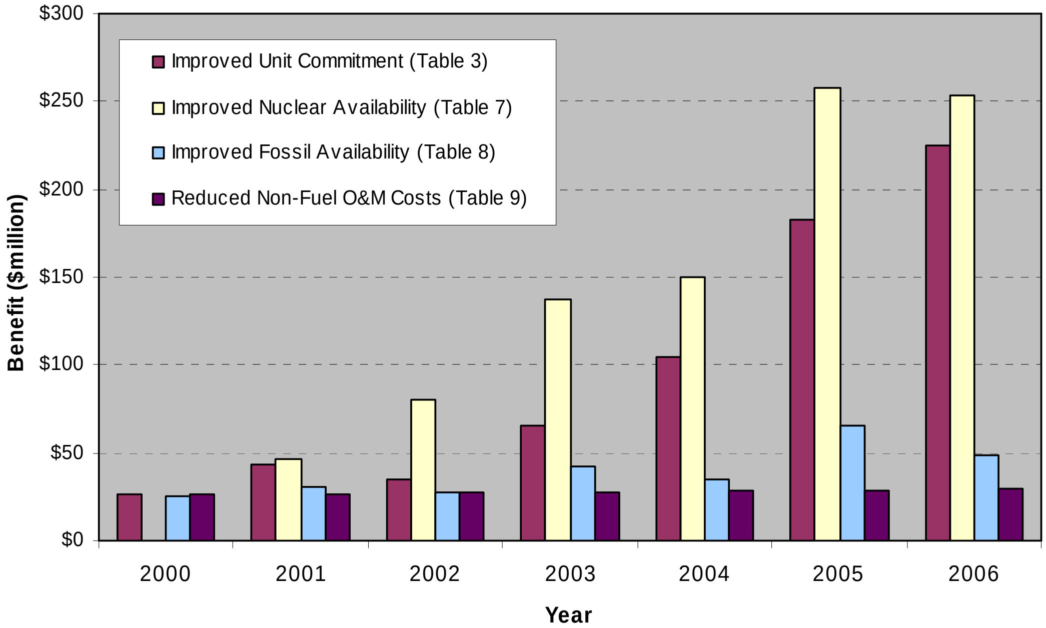
Graphically, the results are displayed as follows:

Figure 4
Benefits of Wholesale Market Changes Under NYISO Operation



While there are limitations to this study due to limits on data and analysis tools, we believe that the resulting estimates are nonetheless robust and reasonable. The direct and indirect benefits on NYISO operation are considerable and represent a positive contribution to the development of electricity markets in the region.

Figure 5
Breakdown of System-wide Power Production Benefit



Allocation of Benefits

Determining who receives the benefits of these savings – whether consumers or producers or both – is difficult for a number of reasons, many of which have been identified in other studies (see, for example, Kwoka (2006)). Among the analytic challenges he identifies – with which we agree – are the difficulty of distinguishing effects from economic efficiency as compared to such influences as distorting effects of ratemaking policies in place during the transition periods associated with restructuring.[58]

Some of the factors that he identifies have relevance to our study, but perhaps to a lesser degree than in some other cases. In particular, the rate reductions and freezes implemented in many states, including New York, ended in New York for the most part in 2003.[59] This means that at least for the most recent years of our study, which covers the period from 2000 to 2006, the retail rate distortion should not be an issue. Also, the excess capacity issue in

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58 Among the problems Kwoka identifies are the distorting effects of retail ratemaking policies during the transition period (e.g., rate reductions and freezes, stranded costs, and excess capacity); the extent to which the studies identify factors of causation (that is, whether or not reforms were actually responsible for some observed and properly measured change in price or cost); and the value of the functions provided by independent regional grid operators (Kwoka, pages vi, 19).

59 See Kwoka (2006) Table 2.

New York is nowhere near as severe as it has been in other regions such as New England, and therefore should reduce several analytic problems in studying New York.[60] With these caveats from the Kwoka analysis, we are afforded some ability at least to consider how the social cost benefits that we have estimated from the restructuring of wholesale power markets in New York might be distributed between retail customers and producers.

Also, the recent study by Harvey, McConihe and Pope (HMP, 2006) provides some guidance in thinking about consumer savings related to changes in wholesale market design and operation. Using econometric methods that are similar to those recommended by Kwoka, HMP compared the rates of customers served by traditional utilities in organized wholesale markets with those in non-restructured wholesale markets during the period from 1990 through 2004. HMP find that these residential customers of municipal and cooperative utilities in the NYISO and Eastern PJM regions paid about $1.50/MWh less due to electric industry restructuring than they would have absent restructuring. If this result were able to be generalized to all NYISO customers, it would imply annual savings of approximately $200 million, since the NYISO demand is about 144 million MWh.[61]

There are some questions about how well the statistical estimate developed by HMP generalizes to customers of public and private utilities. The actual sample of New York customers used in their study is quite small, about 4 million MWh, which is less than 3% of total NYISO sales (or about 10% of residential sales). Given how much lower the rates are for the sampled customers (on the order of 5¢/kWh) relative to New York customers as a whole (4-12¢/kWh), it might be that this rough estimate of consumer benefits (at $200 million) is too high. HMP develop an alternative estimate for regions with less dependence on high cost oil and gas-fired generation, which is about half the larger estimate. If that were applicable to New York State consumers as a whole, then consumer benefits of about $100 million/year would be appropriate.

An alternative form of consumer benefit estimate could be made using our simulation results, as described above. We have concentrated our comparison on the changes in total cost across different cases. The simulation software also calculates market clearing prices, which we can compare. We can look at the difference in marginal cost revenues between our 6 CA case with high outage rates for nuclear and fossil generation and compare it to those revenues in our 3 CA case with low outage rates for nuclear and fossil generation. This comparison results in differences between $100 and $200 million/year, which is similar to the HMP estimate. (See Appendix 3 for further observations on the consumer rate impacts associated with these savings.)

This calculation also has its challenges. The level of marginal cost revenues for our 3-CA case with low outage rates is below the level of revenues at observed prices. This undoubtedly reflects imprecision in the modeling of clearing prices, including the neglect of relevant constraints in the actual LMP process. Additionally, the 6-CA case with high outage

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60 Note that in our study, described below in Sections 5-11, we observe that excess capacity is not a significant phenomenon in New York State, except perhaps in Zone F where we discuss combined cycle plant additions during the study period.

61 See NYSERDA (2005). (144 million MWh times $1.50/MWh = approximately $200 million).

rates may not be a particularly good representation of how customers would have paid for energy under the NYPP, even if it simulates the NYPP dispatch reasonably well. Under the NYPP, the pricing formula relied on "split savings," not marginal cost pricing.

Putting aside the imprecision in both estimates of consumer benefit, however, we can get an order of magnitude estimate of how the social cost benefits that we have estimated might be divided. Depending upon how we draw the comparison precisely somewhere between a third and a half of the social cost benefits would show up as consumer benefits. Under some cases, the fraction might be as low as 15%, in others as high as 60%. Those benefits which do not go to customers could be expected to flow primarily to the shareholders of electric distribution companies (to the extent permitted by regulators) to the owners of baseload coal and nuclear plants. Since these generators no longer enjoy the benefit of investment recovery previously afforded to electric utilities and paid for by electric customers under traditional rate-base regulation (as was the case pre-restructuring), these generators earn rents from the energy market that compensate them for the loss of fixed cost recovery mechanisms built into retail rates under regulation.

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APPENDIX 1:
Monthly Actual Output (GWh) for NY Steam Gas/Oil Plants, 1999-2005

		1999		2000		2001		2002		2003		2004		2005	
	Month	NG	OIL-H	NG	OIL-H	NG	OIL-H	NG	OIL-H	NG	OIL-H	NG	OIL-H	NG	OIL-H
	1	227	167	20	2	16	113	9				6	268	11	22
	2	69	111	45	3	21	71			13		3	80	54	
	3	144	146	158	3	10	69	61		2	12	1	2		
	4	32	46			42	11	61		40	35	2	5		
	5	1,051	15	14	20	10	44	61		1	3	2	2		
Albany Steam Station	6	1,343	26			25	51	61		125	18	11	9		
	7	1,806	12			10	53	632		10	25	8	38		
	8	1,439	5	139	143	46	86	717		16	66	9	12		
	9	697	7	59	65	210		98				1	2		
	10	975		78	105	43				10		11	19		
	11	968		94	79	0		9		11		1	2		
	12	305	0	40	166	54		1,769	0	12		5	39		
	1	966	188	24	120	31	388	239	80	41	133	26	441	18	361
	2	1,213	99	1,160	69	3	18	100	35	80	187	11	141	7	4
	3	1,740	164	450	3	110	288	821	110	52	223	4	272	5	16
	4	2,052	15	408	44	296	113	1,480	44	39	281	12	269	13	16
	5	3,119	151	1,413	37	697	123	937	105	12	14	15	109		
Bowline Point	6	2,904	145	1,542	81	422	91	1,013	27	20	135	37	51	214	97
	7	2,845	375	572	4	945	55	2,113	117	134	291	57	235	306	171
	8	2,768	150	605	218	2,421	59	1,731	93	179	398	14	35	93	243
	9	2,536	26	361	73	1,565	20	715	18	0	0	36	4	108	270
	10	98		651	21	1,300	86	1,083	90		0	39	12	23	254
	11	1,248	11	179	65	474	70	733	161	31	46	0		2	0
	12	1,325	29	24	368	29	115	63	239	2	225	14	182		
	1	9	427	715	302	3	414	1,186	96	996	318	275	397	476	308
	2	3	262	913	181	1	350	1,217	27	572	257	1,396	159	1,429	87
	3			1,460	12	1	530	520	18	1,118	11	293	17	1,872	136
	4			1,392	33	7	42			1,571	76			878	46
	5	260	9	1,977	58	432	408	987	26	2,035	16	973	10	1,178	3
Charles Poletti	6	1,855	108	2,354	125	925	203	1,554	93	1,697	16	1,703	46	2,351	78
	7	2,144	66	2,550	102	65	266	1,567	166	2,088	78	1,979	49	2,279	87
	8	1,575	92	2,177	262	1,777	123	2,230	154	2,414	92	2,543	48	2,156	109
	9	1,587	100	1,707	257	71	272	2,400	20	2,147	18	2,691	32	1,338	95
	10	1,468	60	2,044	249	2,102	64	2,426	47	2,341	40	1,635	91	1,584	25
	11	1,051	62	2,012	247	1,533	101	2,638	102	1,373	116	1,346	35	269	47
	12	965	153	93	585	1,530	76	1,250	189	358	406	20	295		

Appendix 1

	Month	1999 NG	1999 OIL-H	2000 NG	2000 OIL-H	2001 NG	2001 OIL-H	2002 NG	2002 OIL-H	2003 NG	2003 OIL-H	2004 NG	2004 OIL-H	2005 NG	2005 OIL-H
Danskammer	1	65		208	12	17	33	11		8		8	4	27	40
	2	17		138	5			13		13	7	5	2	9	11
	3	52	3	441	1			22	2	18	4	10		10	7
	4	54		176		17	12	18	5	14	3	14		10	3
	5	344		311	0	16	17	14		8		23	13	3	
	6	543		324	0	28	7	37	6	14	2	9	8	339	45
	7	659		302		31	4	40	5	6		11		14	52
	8	398		312	2	121	2	96	12	78	11	14		10	55
	9	267	1	53	7	29	2	77	0	30		65	3	11	16
	10	269		139	1	6	3	17	1	29		12	1	78	30
	11	250		84	6	252	0	10	3	9		2		11	27
	12	187	0	43	51	22		15	14	16	2	2	2		
East River	1	206	50	275	25	0		285	31	94	26	184	68	509	74
	2	184	32	253	22	82	22	225	31	216	44	189	74	124	24
	3	142	51	237	24	143	90	263	39	246	31	695	20	1,011	71
	4	195	25	439	15	136	67	604	29	161	14	1,009	16	1,090	27
	5	582	85	611	21	915	4	867	6	475	35	1,062	43	2,176	17
	6	397	57	991	38	988	51	1,026	20	500	19	1,031	58	2,392	50
	7	999	80	919	39	782	33	1,114	46	1,005	47	1,085	32	3,014	22
	8	758	46	672	64	1,197	45	1,141	51	1,123	53	950	62	2,913	21
	9	472	43	731	40	1,044	42	929	30	527	27	919	24	2,164	8
	10	109	14	295	13	508	34	638	8	133		589	2	1,575	9
	11	258	28	1		298	33	230	13	302	33	144	19	2,039	
	12	274	19	0		284	27			229	49	585	44		
Port Jefferson	1	52	271	288	108	42	312	220	104	76	263	21	175	59	214
	2	40	243	286	136	33	215	246	91	34	145	31	207	57	238
	3	61	176	1,185	60	20	154	348	196	32	150	46	167	28	194
	4	499	119	1,064	84	70	135	448	207	23	136	41	239	28	128
	5	888	103	948	46	119	115	136	175	230	93	428	218	477	56
	6	1,164	88	438	206	1,476	66	566	199	406	162	420	220	553	194
	7	1,938	53	699	184	1,680	78	687	210	581	182	459	247	499	220
	8	1,651	69	341	274	1,897	90	960	172	444	171	124	226	439	238
	9	956	17	113	237	1,501	76	956	116	343	145	430	222	401	213
	10	855	16	64	282	1,370	15	448	88	36	174	47	268	50	142
	11	958		43	237	1,057	17	42	140	19	142	45	237	49	164
	12	761	36	46	266	656	53	51	224	20	203	42	228		

Appendix 1

	Month	1999 NG	1999 OIL-H	2000 NG	2000 OIL-H	2001 NG	2001 OIL-H	2002 NG	2002 OIL-H	2003 NG	2003 OIL-H	2004 NG	2004 OIL-H	2005 NG	2005 OIL-H
Ravenswood	1	326	25	1,935	295	440	717	2,503	117	498	192	394	448	208	416
	2	0		3,150	173	230	584	3,429	51	437	289	647	357	468	291
	3	1		4,683	19	810	252	3,668	154	1,330	370	515	428	100	254
	4	948	10	3,059	16	743	472	3,312	7	393	515	266	558	618	393
	5	3,412	116	4,634	40	3,592	99	3,390	8	495	220	285	613	1,040	125
	6			5,617	60	4,864	154	4,671	47	1,118	532	402	761	1,873	533
	7	5,503	100	5,530	24	6,251	46	6,826	168	4,950	337	312	956	3,602	403
	8	5,925	128	5,246	58	6,909	91	6,662	182	3,724	423	505	867	1,880	836
	9	5,848	142	3,860	114	5,296	32	5,993	112	4,689	159	2,758	467	1,192	759
	10	3,978	73	2,086	20	3,739	48	2,955	33	3,729	269	2,664	236	127	379
	11	1,204	4	940	323	1,689	56	1,316	34	1,838	219	1,371	313	207	562
	12	3,348	67	360	723	1,777	20	694	104	214	410	149	359		
Roseton	1	403	623	68	312	6	730	42	68	24	478	9	991	11	359
	2	301	607	188	204			31	42	24	316	7	762	9	477
	3	417	386	110	15			50	65	36	411	6	710	11	546
	4	196	316	508	127	11	238	110	145	14	714	4	622	10	261
	5	620	564	400	215	37		210	133	17	104	17	296	7	26
	6	720	644	199	433	28		381	130	19	312	10	473	12	420
	7	1,070	729	227	331		358	294	105	19	597	8	645	9	607
	8	695	481	111	494	489	528	160	115	16	684	24	483	1	932
	9	672	386	175	420	102	36	238	144	12	603	16	191	4	789
	10	754	424	99	633	55	136	22	168	2	318	13	157	9	644
	11	1,075	180	52	455	154	103	27	259	1	138	11	270	14	66
	12	189	45	13	803	251	239	34	430	21	542	18	503		

APPENDIX 2: Steam Plant Fuel Assignment

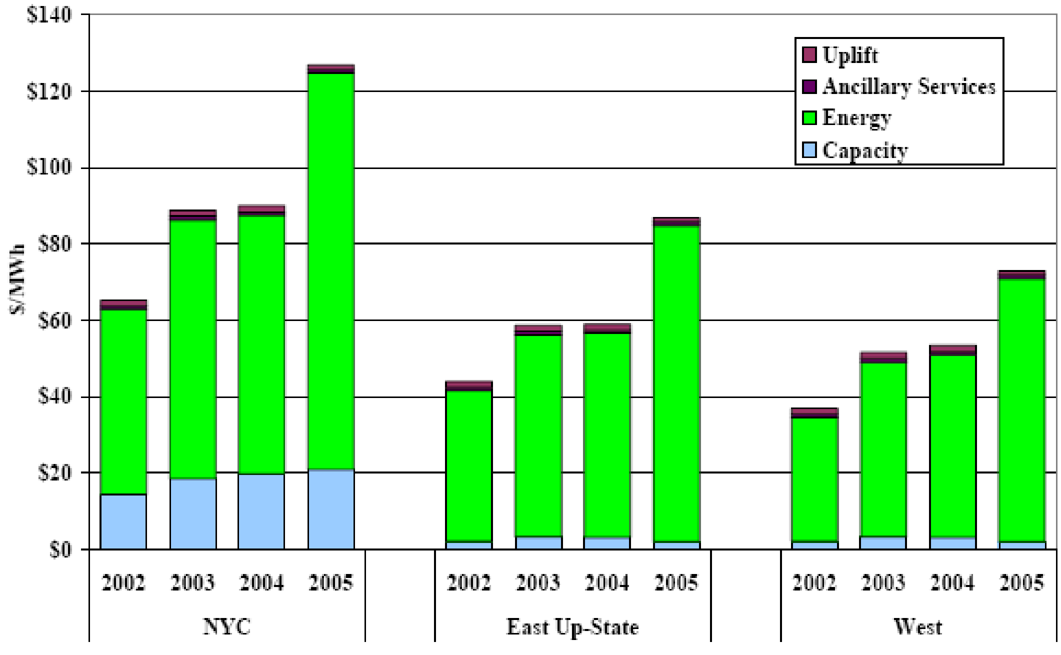
Plant Name	Fuel Use Pattern
Albany Steam Station	Natural Gas 1999, Oil 2000-2006
Astoria Generating Station	Oil January-March, Natural Gas April-December; 1999-2006
Bowline Point	Natural Gas 1999-2002, Oil 2003-2006
Charles Poletti	Oil December-February, Natural Gas March-November; 1999-2006
Danskammer	Natural Gas 1999-2004, Oil 2005-2006
East River	Natural Gas 1999-2006
Port Jefferson	Oil 1999-2006
Ravenswood	Natural Gas 1999-2002, Oil 2003-2006
Roseton	Oil 1999-2006

APPENDIX 3: Observations from Our Study with Respect to Potential Consumer Rate Impacts

In this Appendix we describe our simulation results from the viewpoint of potential consumer rate impacts rather than the social cost perspective we have adopted for the most part in this report.

Consumers pay load-weighted market-clearing prices for energy in the wholesale energy markets centrally administered by NYISO. Additionally, consumers pay for capacity and ancillary services, also at market prices. The capacity and ancillary services charges are small compared to energy charges. The figure reproduced below from the Potomac Economics 2005 State of the Market Report for NYISO show the relative size of all price components.

Figure 7: Average All-In Price
2002 – 2005



The total revenue moving through the NYISO-administered market in 2005 was approximately $10.7 billion, an increase of about $3 billion over 2004, reflecting the increases in gas prices (NYISO, 2005a, p. 12). As Table A3-1 below shows, our estimate of energy market revenues for those years is approximately in line with these results.[62]

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[62] Our energy market revenue estimates are somewhat lower than actual LMP outcomes because our simulation

We use our calculations of energy market revenues from two simulations to estimate the rate impacts from the change between the old NYPP system to system-wide energy markets administered by NYISO. As previously discussed in our report, we represent the NYPP with a 6-area commitment and dispatch, along with the counterfactual (i.e., higher than observed) outage rates for nuclear and fossil-fired generators. The marginal cost revenues for this case are used to approximate what would have happened under the NYPP. This approximation, which we discuss next, is rough for a number of reasons, but it is not unreasonable.

The NYPP operated a trading system based on the "split-savings" concept. This method of pricing trades can be thought of as a hybrid of marginal-cost pricing and avoided-cost pricing. In electric generation markets in recent decades, "avoided cost" is a concept typically used to describe a basis for pricing power sold to electric utilities by Qualifying Facilities ("QF") under the Public Utilities Regulatory Policies Act ("PURPA").[63] It is the price that the buyer would have paid but for the QF purchase in question. While it is possible for avoided costs to be below marginal costs, often avoided costs are the higher of the two, as where the former represent the costs of units more expensive than the marginal unit. Under split-savings, the transaction price is the average of the seller's marginal cost and the buyer's avoided cost.

If all power under the NYPP were sold on a split-savings basis, the marginal-cost revenue calculation would under-estimate wholesale costs. In reality, not all power under the NYPP regime was sold on the split-savings basis. We do not have any reliable estimate of how much power might have been sold on a split savings basis absent the NYISO.

Further complications in the comparison of wholesale production costs under NYPP with those under NYISO involve costs that were recovered in rates under the NYPP regime that are not explicitly part of the NYISO-administered markets regime. These include fixed O&M costs and recovery of fixed investment cost (e.g., recovery of undepreciated generation capital costs and return on investment). In addition, New York also imported energy under the NYPP, but not at market clearing prices. As previously argued, we have no way to take explicit and detailed account of these factors. All we can rely on is the general notion that customer rates have declined or stayed approximately flat, on a fuel adjusted basis, as a result of restructuring (NYPSC, 2006, p.2). Given that the general level of rates between the NYPP regime and the NYISO regime is comparatively flat, we can focus attention on the changes modeled in our simulations, which affect only a comparatively small, but nonetheless significant part of the overall rate level.

The estimates of the annual rate effect that are developed in Table A3-1 range between approximately \$100 and \$200 million. The year-to-year variation in these estimates is somewhat different than the pattern of the social cost savings summarized in Table 12. The social cost savings scale with the level of natural gas costs, which go up over the 2000-2006 period. This is not true in Table A3-1. Additionally, there are some potentially counter-intuitive results for Zone J in 2005 and 2006 (and to a smaller extent Zone K in 2006). In these cases, the marginal cost revenues under the

software neglects many of the local constraints implemented in the actual LMP market. The major constraints are adequately represented.

[63] Detailed discussions of avoided cost pricing can be found in Woo (1988) and Kahn (1995).

NYISO-administered markets (3-CA case) are higher than in the NYPP counter-factual (6-CA case). At first appearance this might seem puzzling, since we expect that typically a more efficient outcome should also produce a lower marginal price, and hence lower marginal cost revenues. Indeed, Kwoka's review of one restructuring study is quite critical because of precisely this phenomenon, which he describes as "global optimization is actually inferior to suboptimization" (page 59). This critique confuses the changes in the value of the objective function with the marginal results.

In our case, it is quite clear that the 3 CA case results in lower total costs (the objective function) than the 6 CA case. Because of the discrete unit, or "lumpiness," effects of unit commitment, it is possible to have a decrease in the value of the objective function accompanied by an increase in the cost of the marginal unit. This can happen simply by shutting down a large high cost unit that operated in the suboptimal commitment and replacing it in more optimal commitment with a smaller unit that has higher operating cost, but lower total cost. While such results may not occur frequently, they are neither impossible nor a sign that there is an error in the simulation process.

Table A3-1
Marginal Cost Energy Revenues:
"NYISO Case" (3-CA Basecase) versus
"NYPP Case" (6-CA With High Nuclear and Fossil EFORs)
By Year and Zone ($millions)

		MTM Cost (MCP * Load)		**Net savings under NYISO markets**
	Zone	***3-CA ("NYISO")***	***6-CA ("NYPP")***	***6-CA minus 3-CA***
2000	AB	751.1	766.9	15.8
	CDE	920.6	935.9	15.2
	F	448.9	455.8	6.9
	GHI	756.5	768.6	12.1
	J	2,056.2	2,079.1	22.9
	K	841.6	852.2	10.6
	Total	5,775.1	5,858.5	**83.4**
2001	AB	722.9	742.2	19.3
	CDE	856.9	879.5	22.5
	F	390.6	399.3	8.6
	GHI	652.4	667.2	14.8
	J	1,820.1	1,848.2	28.2
	K	756.6	772.6	16.0
	Total	5,199.5	5,309.0	**109.5**

Appendix 3

2002	AB	688.9	714.0	25.1
	CDE	812.2	839.7	27.5
	F	371.0	382.0	11.0
	GHI	614.4	632.7	18.3
	J	1,808.3	1,841.1	32.8
	K	771.7	788.6	16.9
	Total	5,066.5	5,198.2	**131.7**
2003	AB	947.1	980.8	33.7
	CDE	1,151.6	1,194.9	43.3
	F	509.4	524.0	14.6
	GHI	876.0	902.0	26.0
	J	2,460.2	2,514.0	53.8
	K	1,073.1	1,099.7	26.7
	Total	7,017.4	7,215.5	**198.1**
2004	AB	978.3	1,009.0	30.6
	CDE	1,181.4	1,213.8	32.4
	F	514.6	527.2	12.6
	GHI	899.7	922.3	22.6
	J	2,573.7	2,593.8	20.1
	K	1,101.8	1,112.9	11.2
	Total	7,249.5	7,379.0	**129.5**
2005	AB	1,333.2	1,387.0	53.8
	CDE	1,627.1	1,685.1	57.9
	F	712.4	730.3	17.9
	GHI	1,266.4	1,297.9	31.5
	J	3,674.2	3,659.7	-14.5
	K	1,619.8	1,624.9	5.1
	Total	10,233.0	10,384.9	**151.8**
2006	AB	1,440.0	1,486.6	46.6
	CDE	1,749.7	1,801.6	51.9
	F	741.9	755.6	13.7
	GHI	1,332.0	1,357.1	25.0
	J	3,814.8	3,785.4	-29.4
	K	1,734.4	1,731.2	-3.3
	Total	**10,812.9**	**10,917.4**	**104.5**
Grand Total				**908.5**

Note: Loads in 3-CA and 6-CA cases are the same